BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Tampa Electric Company	DOCKET NO. 130040-EI Filed: July 15, 2013

DIRECT TESTIMONY AND EXHIBITS OF JEFFRY POLLOCK

ON BEHALF OF THE FLORIDA INDUSTRIAL POWER USERS GROUP

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ORIGINAL

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LIST OF ACRONYMS

Term	Definition
12CP	Twelve Coincident Peak
AD	Average Demand
CCR	Capacity Cost Recovery
CP	Coincident Peak
CCGTs	Combined Cycle Gas Turbines
CCOSS	Class Cost-of-Service Study
Duke	Duke Energy Florida
EAD	Expected Annual Damage
ECRC	Environmental Cost Recovery Clause
EP	Equivalent Peaker
FERC	Federal Energy Regulatory Commission
FIPUG	Florida Industrial Power Users Group
FPL	Florida Power & Light Company
GSD	General Service Demand
Gulf	Gulf Power Company
IS	Interruptible Service
kW	Kilowatt
kWh	Kilowatt-hour
MW	Megawatt
MDS	Minimum Distribution System
NOAA	National Oceanic and Atmospheric Administration
O&M	Operation and Maintenance
TECO	Tampa Electric Company
USOA	Uniform System of Accounts

1. INTRODUCTION, QUALIFICATIONS, AND SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock; 12647 Olive Blvd., Suite 585, St. Louis, MO 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. 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. My qualifications are documented in **Appendix A.** A partial list of my appearances is provided in **Appendix B** 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). The participating FIPUG members are customers of Tampa Electric Company (TECO) who take electricity service on the General Service Demand (GSD), Interruptible Service (IS) and Standby rate classes

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A I am addressing TECO's proposals to:

- Consolidate the GSD and IS rate classes;
- Adopt yet another new production plant cost allocation methodology—Twelve Coincident Peak and 50% Average Demand (12CP-50%AD);
- Classify a portion of the distribution network as customer-

related; and

- Increase its storm reserve.

In addition, I am addressing:

- The design of the GSD rate schedules;
- The design of the IS rate schedules if TECO's proposed GSD-IS class consolidation is rejected; and
- Test year outage expenses.

Q ARE YOU SPONSORING ANY EXHIBITS?

A Yes. I am sponsoring **Exhibits ___ (JP-1)** through **___ (JP-10)**.

Q ARE YOU ADDRESSING EVERY ISSUE THAT MAY BE IN DISPUTE IN THIS CASE?

A No. However, the fact that I am not addressing a particular issue is not and should not be interpreted as an endorsement of TECO's position.

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations are as follows:

GSD-IS Consolidation

- TECO's proposal to consolidate the GSD and IS rate classes (and eliminate the IS rate schedules) should be rejected. A similar proposal by TECO was rejected in TECO's last rate case. TECO has provided no new evidence to support consolidation in this case.
- The GSD and IS rates classes are not homogeneous; that is, they have significantly different load characteristics. This means that GSD and IS should have different rate structures to reflect the corresponding differences in their respective costs to serve.
- Further, contrary to Mr. Ashburn's assertions about inequities under the current class rate structures, consolidating the GSD and IS classes would be grossly inequitable to the IS customers. This is because the IS customers would experience an 11.1% base rate increase under TECO's consolidation proposal but no rate increase (or a decrease) if IS remains a separate stand-alone class. The cost of serving IS does not change just because it is consolidated with

GSD.

- The so-called "transition" referred to by Mr. Ashburn ended when the interruptibility was transferred from the IS rate schedules to the GSLM Riders (which occurred in TECO's last rate case). Under this structure, all non-firm customers are paid the same for their interruptibility, and the interruptible credits remain cost-effective under this Commission's rules. This transition has nothing to do whatsoever with eliminating the IS rate schedules.

- The IS rate schedules should be retained at a minimum; further the Commission should consider re-opening the IS rate schedules to all eligible customers.

<u>GSD/IS Rate Design</u>

- Rate design is a continuation of the cost allocation process. Thus, a proper cost-based rate design should include a Customer charge that recovers customer-related costs, a Demand charge that recovers demand-related costs, and an Energy charge to recover non-fuel energy costs.

- The current GSD Energy charge is already above cost. The proposed charge would be 91% higher than the unit cost. Thus, any increase in Energy charges is unwarranted. This includes TECO's proposal to raise the On-Peak Energy charge by 38%. Not only is this increase contrary to cost-based ratemaking, it would violate gradualism.

- To reflect cost, all of the increase allocated to the GSD class should be collected in the Basic Service and Demand charges.

- If, despite my objections, the GSD and IS classes are consolidated, the Delivery Voltage Adjustment applicable to sub-transmission service should be $0.53 per kW higher than the credit proposed by TECO. Because the IS class takes service primarily at sub-transmission voltage, raising the credit by an additional $0.53 would mitigate the higher rates that would result from the GSD-IS class consolidation.

- No increase should be allocated to the IS class. This class is currently providing a 1.10 parity ratio under TECO's proposed revenue requirements. Thus, IS base rates would have to be reduced to achieve parity, something the Commission may want to consider. However, at a minimum, applying a zero increase is also consistent with Commission practice.

- The current IS Energy charge is more than 166% above cost. The current IS Demand charge is 81% below cost. Consequently, if the IS class is retained, the Basic Service charge should be set to cost, the Energy charge should be reduced by at least 25%, and the remaining revenue requirement should be collected in the Demand charge.

Production Plant Allocation

- TECO has failed to support changing the production plant allocation method to 12CP-50%AD as it proposes. This method is not supported by:

  (1) How other Florida utilities plan and operate their generation systems because Duke Energy Florida (Duke), Florida Power & Light Company (FPL) and Gulf Power Company (Gulf) continue to use 12CP-1/13thAD, and the Commission has approved 12CP-1/13thAD in their most recent rate cases.

  (2) TECO's investment in base and intermediate load capacity, which has remained relatively unchanged since its last rate case.

  (3) TECO's plan to convert Polk Units 2-5 to combined cycle generation, which won't occur until 2017 (well beyond the test year) because it overlooks the load following and other reliability enhancements provided by CCGTs. TECO's position is not unique for Florida utilities, given that FPL has committed to add over 3,800 MW of new combined cycle gas turbines (CCGTs) to complement its existing nuclear and coal (base load) generation fleet, yet FPL continues to support 12CP-1/13thAD.

  (4) Minimizing the RS and GS revenue requirements, which is contrary to the reasons for selecting a cost allocation method: to reflect cost causation. Rate minimization is appropriately addressed in determining class revenue allocation and rate design and not by selecting a cost allocation methodology.

- 12CP-50%AD represents yet another change in allocation methods. TECO has never proposed the same production plant allocation factor in the four rate cases it has filed since 1985. This constant churn in cost allocation methods creates instability in class cost relationships, which is not a desirable attribute of a good rate design.

- 12CP-50%AD would classify 57% of TECO's net production plant costs to energy. This is comparable to the Equivalent Peaker (EP) method, which classifies between 40% and 75% of production plant costs to energy. Like EP, 12CP-50%AD is based on the erroneous assumption that fuel cost savings drive investment decisions.

- The Commission has previously rejected EP because EP allocates plant costs beyond the economic break-even point. This is also the case with 12CP-50%AD. The only difference between EP and 12CP-

50%AD is the application of judgment in determining the portion of plant costs allocated on energy.

- The Commission should adopt 12CP-1/13th AD for TECO, just as it has adopted this method for Duke, FPL and Gulf. Alternatively, if the Commission determines that no change is appropriate, it should retain 12CP-25%AD, which was approved in TECO's last rate case.

- If, contrary to my recommendation, 12CP-50%AD is adopted, then the 12CP should be replaced with the Summer/Winter CP method because the Summer/Winter CP best reflects TECO's system load characteristics that drive the need for capacity and it would not allocate demand-related costs beyond the economic breakeven point, as is the case with 12CP. Further, the cost study should also recognize that some fuel costs are incurred for reliability (*e.g.,* start-up, stabilization).

<u>Distribution Plant Allocation</u>

- I agree with TECO's proposal to classify a portion of the distribution network investment as customer-related. This is consistent with accepted practice. Further, the results of TECO's minimum distribution system (MDS) method are reasonable relative to other utilities that use MDS or other methods to determine the customer-related portion of distribution network costs.

<u>Planned Outage Expense</u>

- The Commission should disallow $3.7 million of planned outage expenses because TECO's test year expenses are clearly abnormal (26% higher) relative to prior years.

<u>Storm Damage Reserve</u>

- TECO's proposal to increase its storm damage reserve is unwarranted. Not only is the current reserve more than adequate to handle almost three consecutive years of damage (including Category 1 and all but the most severe of Category 2 hurricanes), TECO's analysis fails to recognize the substantial investment in storm hardening, which should lessen future expenses and it ignores the Commission's directives. Specifically, the Commission has stated that the storm reserve should be adequate to accommodate most (but not all) storm years and utilities can seek recovery of all storm damage.

- The target storm reserve should not increase. Accruals to the storm reserve should cease.

2. GSD-IS CLASS CONSOLIDATION

Q IS TECO PROPOSING ANY CHANGES AFFECTING THE CUSTOMERS TAKING SERVICE ON THE INTERRUPTIBLE SERVICE RATE?

A Yes. TECO is proposing to consolidate the GSD and IS rate classes and completely eliminate the IS rate schedules. If approved, IS customers would take service on the various GS and GSD rate schedules.

Q DID TECO PREVIOUSLY PROPOSE ELIMINATING THE INTERRUPTIBLE SERVICE RATE?

A Yes. TECO proposed eliminating the IS rate schedules in its last rate case.

Q WAS TECO'S PROPOSAL TO ELIMINATE THE INTERRUPTIBLE SERVICE RATE APPROVED?

A No. The Commission rejected TECO's proposal.

Q WHY IS TECO ONCE AGAIN PROPOSING TO CONSOLIDATE THE GSD AND INTERRUPTIBLE SERVICE RATE CLASSES AND ELIMINATE THE INTERRUPTIBLE SERVICE RATE SCHEDULES?

A TECO's rate design witness, Mr. Ashburn, cites two reasons in his pre-filed testimony for consolidating the GSD and IS rate classes and eliminating the IS rate schedules. First, he explains that consolidation would allow TECO to "complete the transition of the customers on the IS rate schedules to the GSD rate schedules."[1] Second, he asserts that maintaining the IS rate would preserve "inequitable situations" that exist between the existing IS customers and new interruptible customers.[2]

As explained later, neither reason justifies consolidating the GSD and IS rate classes. Further, TECO's proposed consolidation would be grossly inequitable to the IS customers.

Q TURNING TO THE FIRST REASON FOR CONSOLIDATION, TO WHAT TRANSITION IS MR. ASHBURN REFERRING?

A Mr. Ashburn stated that IS customers are fully aware that their "grandfathered" status has been extended for decades.[3] I can only assume from this statement that he is referring to the transition that commenced in 1985, when the Commission closed the IS-1 rate schedules.[4] However, this was not a transition that would ultimately lead to eliminating the IS class. The stated reason for closing the IS-1 rate schedules was that interruptible service was no longer cost-effective.

Q DID CLOSING THE INTERRUPTIBLE SERVICE RATES PROVIDE A CLEAR INDICATION THAT THEY WOULD EVENTUALLY BE ELIMINATED?

A No. Closing the IS rate schedules meant that no new interruptible customers could opt for non-firm service under these rates. It did not mean that the IS class would be eliminated. In fact, the IS rate schedules continued to be subject to periodic adjustments in rate cases even though they were closed to new business.

Q ARE THE CURRENT INTERRUPTIBLE SERVICE RATES THE SAME AS THE RATES THAT WERE CLOSED TO NEW BUSINESS?

A No. In TECO's last rate case, the "interruptibility" was removed from the IS rate schedules. This transformed IS from an interruptible to a cost-based firm service rate. As such, it marked the end of the transition to ensure that non-firm service remains a viable option for all customers and that the rates for this service remain cost-effective. Thus, it is inaccurate to assert that there was ever a decades-long transition that would ultimately result in eliminating the IS rate schedules.

Q HAVE INTERRUPTIBLE CUSTOMERS KNOWN FOR DECADES THAT THEIR RATE CLASS WAS GOING TO BE ELIMINATED?

A No. The proposal to eliminate the IS class was made for the first time in TECO's last rate case. That case was filed in August, 2008. As previously stated, the Commission rejected TECO's proposal to eliminate IS in that case. Thus, IS customers could not have had any reasonable expectation that the IS rate schedules would be eliminated. Put simply, the IS rate should not be eliminated, and witness Ashburn speculates about the mindset of the IS customers. As discussed later, there is no legitimate reason not to retain and re-open IS allowing the rates to be applicable to all similarly situated customers.

Q DO YOU AGREE WITH MR. ASHBURN'S ASSERTION THAT MAINTAINING THE INTERRUPTIBLE SERVICE RATE WOULD PRESERVE INEQUITABLE SITUATIONS THAT HE SAYS EXIST BETWEEN THE INTERRUPTIBLE SERVICE CUSTOMERS AND GSD CUSTOMERS THAT OPT FOR INTERRUPTIBLE SERVICE?

A No. Mr. Ashburn's assertion is based on an assumption that differences between the GSD and IS rates are inequitable. However, both the GSD and IS rates were set by the Commission in TECO's last rate case using an approved class cost-of-service study and rate design. Thus, his assertion that there are inequities between interruptible customers taking service on the GSD and IS rate schedules misses the mark.

Q ARE THE DIFFERENCES BETWEEN THE GSD AND INTERRUPTIBLE SERVICE RATES INEQUITABLE?

A No. It is not uncommon or improper to charge different rates for different customer classes based on differences in the cost of providing service. A class's cost-of-service is highly dependent on its load and usage characteristics. Two classes with different usage characteristics will have different costs to serve. If a cost-of-service study is used to design rates (which is a common practice in Florida), it follows that the rates will be different.

Q. DO THE GSD AND INTERRUPTIBLE SERVICE CLASSES HAVE DIFFERENT LOAD CHARACTERISTICS?

A Yes. In fact, Mr. Ashburn concedes that the 42 remaining customers in the IS class have more favorable load characteristics than the 14,000 customers being served on the GSD rate schedules. He even candidly admits that the IS customers have a "cost-supported rate advantage."[5]

I will provide an in-depth comparison between the GSD and IS load characteristics later in my testimony. These differences support retaining both the GSD and IS rate schedules. Thus, there is nothing inequitable about the current GSD and IS rates. They are both cost-based rates for firm service. Contrary to Mr. Ashburn's assertion, eliminating the IS rate schedules would cause an even greater inequity.

Q PLEASE EXPLAIN.

A The IS class is providing a 7.43% rate of return at current rates under TECO's preferred class cost-of-service study (CCOSS). TECO is only seeking a 6.74%

rate of return at proposed rates.[6] In other words, the IS class already has a 1.10 parity ratio relative to TECO's *proposed* rate of return. If the Commission approves a lower revenue requirement than TECO has proposed, the IS class's parity ratio could be higher than 1.10. A parity ratio above 1.0 at proposed rates means that *IS customers are currently paying more for their electricity service than is justified by TECO's CCOSS*.

In order to move to parity, base rates for IS customers would have to be reduced. However, the Commission's policy disfavors one customer class receiving a rate decrease when rates are increasing. Under these specific circumstances, the IS class should receive zero increase.

Rather than retaining the IS rate class and maintaining the current base rates, TECO is proposing an 11.1% base rate increase for IS customers.[7] *The 11.1% increase is solely the result of TECO's proposal to consolidate the GSD and IS classes and eliminate the IS rate class.* Forcing the IS customers to absorb a significant base rate increase when TECO's CCOSS supports no increase or even a decrease to the stand-alone IS rate class would be grossly inequitable. TECO's proposal to fold the IS class into the GSD class would also financially penalize many large businesses that employ scores of people and are important participants in the local economy. For this reason alone, TECO's consolidation proposal should be rejected.

Q WOULD THE COST OF SERVICING INTERRUPTIBLE SERVICE CUSTOMERS CHANGE JUST BECAUSE THAT CLASS IS CONSOLIDATED WITH THE GSD CLASS?

A No. Consolidation does not change the level of costs caused by the IS rate class. It would, however, result in charging much higher rates to IS customers because the consolidated GSD-IS class costs would be spread to both GSD and IS customers. In other words, consolidation would simply hide the substantial subsidies that IS customers are currently providing and, with an 11.1% base rate increase that would result if IS were consolidated with GSD, would exacerbate the subsidy being paid by IS customers.

Q WHY ELSE SHOULD TECO'S RATE CONSOLIDATION PROPOSAL BE REJECTED?

A As previously stated, the GSD and IS classes are not homogeneous; that is, they do not have similar load and usage characteristics. Combining dissimilar customer classes is contrary to accepted practice, which is to define customer classes based on homogeneous load and usage characteristics. For example:

> After the costs have been functionalized and classified the next step is to allocate them among the customer classes. ***To accomplish this, the customers served by the utility are separated into several groups based on the nature of the service provided and load characteristics.*** The three principal customer classes are residential, commercial and industrial. ***It may be reasonable to subdivide the three classes based on, characteristics such as size of load the voltage level at which the customer is served and other service characteristics such as whether a residential customer is all-electric or not.*** Additional customer classes that may be established are street lighting, municipal, and agricultural.[8] (emphasis added)

An additional example to further reiterate this mainstream concept and practice:

> A public utility is normally engaged in furnishing service to different classes of customers under varying circumstances of delivery, consumption and/or utilization wherein such variation furnishes a basis for differentials in the pricing of the service rendered. ***These variations in types of utilization and in patterns of consumption may cause differences in the cost of rendering the various classes of service. Such variations are commonly referred to as load characteristics. Foremost among the load characteristics are rates of consumption, the relationship between average and maximum rates of consumption (referred to as load factor) and coincidence of consumption of customers within a particular classification***

as well as among customers served under other classifications. Differences in load characteristics frequently furnish the basis for separate classifications of customers for rate making purposes.[9] (emphasis added)

Q ARE THE GSD AND INTERRUPTIBLE SERVICE CLASSES HOMOGENEOUS?

A No. **Exhibit ___(JP-1)** is an analysis of the characteristics of GSD and IS classes for the Test Year. Page 1 shows the characteristics at the class level. Page 2 shows the characteristics by delivery voltage. 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.

Test Year Usage, Load, and Service Characteristics
GSD vs. IS Classes

Characteristic	Description	GSD	IS
Size	Avg. kWh Per Month	45,674	1,684,336
	Avg. kW Per Month	119	6,672
Load Factor	12 Coincident Peak	70%	110%
	Non-Coincident Peak	61%	67%
	Billing Demand	52%	35%
Coincidence Factor	12CP to NCP	87%	61%
	12CP to Billing Demand	75%	32%
Delivery Voltage	% at Secondary	84%	0%
	% at Sub-Transmission	0.1%	72%

Further, the differences in load characteristics are not unique to the Test Year, as shown in the table below.

Historical Load Characteristics
GSD Vs. IS Classes

	2010		2011		2012	
Description	**GSD**	**IS**	**GSD**	**IS**	**GSD**	**IS**
Coincident Load Factor	77%	94%	75%	94%	77%	95%
Coincidence Factor	85%	69%	75%	56%	83%	61%

Q WHAT IS COINCIDENT LOAD FACTOR?

A Coincident load factor is the ratio of each class's average demand to its twelve coincident peak (12CP) demand. Thus, it measures how intensively electricity is used during the peak hours of the month.

Q WHAT IS COINCIDENCE FACTOR?

A Coincidence factor is the ratio of 12CP demand to Non-Coincident Peak (NCP) demand. It measures how much of the class's peak demand occurs coincident with the system peak.

Q HOW ARE COINCIDENT LOAD FACTOR AND COINCIDENCE FACTOR RELEVANT IN DETERMINING WHETHER CUSTOMER CLASSES ARE HOMOGENEOUS?

A A class with a high coincident load factor uses electricity more intensively during peak hours. By contrast, a class with a low coincident load factor uses electricity more intensively during non-peak hours. As can be seen, the IS class has a lower coincident load factor than the GSD class.

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 kilowatt (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 below. As can be seen above, the IS class has a lower coincidence factor than the GSD class.

Q HOW DO DIFFERENCES IN COINCIDENCE FACTOR AFFECT THE DESIGN OF A COST-BASED RATE STRUCTURE.

A 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 (column 3), the lower per unit demand charge (column 5), 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 AND INTERRUPTIBLE SERVICE CLASSES SHOULD BE COMBINED?

A As shown previously, the GSD and IS classes have very different coincident load factors and coincidence factors. Thus, they are not homogeneous. Ignoring these differences by consolidating the GSD and IS rate classes would result in inappropriate cross subsidies.

Q ARE THERE OTHER REASONS THE GSD AND INTERRUPTIBLE SERVICE CLASSES SHOULD NOT BE COMBINED?

A Yes. Delivery voltage is another characteristic that can be used to define a customer class. For example, FPL has several rate classes that take service solely at transmission voltage. TECO's IS class is similarly situated because a preponderance of service is delivered at sub-transmission voltage. This is in stark contrast to GSD, where almost no electricity is delivered to customers at this high voltage level.

Consolidation would also result in TECO having the fewest rate classes of any investor-owned electric utility in Florida. The number of rate classes by utility is summarized in the table below. Based on my experience, TECO has the fewest rate classes of the vast majority of integrated electric utilities with which I am familiar that serve residential, commercial and industrial customers.

Number of Rate Classes Used in Class Cost-of-Service Studies by Florida Investor-Owned Electric Utilities

Utility	Number of Rate Classes*
FPL	13
Duke	6
Gulf	6
TECO	4

* Lighting is considered as 1 rate class.

The fact that most other utilities have more rate classes than TECO underscores how TECO is at odds with industry practice. Additionally, having too few rate classes means each class cannot be as homogeneous as is required to accurately allocate costs and design rates that reflect the cost of serving each customer. This would be particularly true with respect to TECO's GSD class (both before and after consolidation).

Q PLEASE SUMMARIZE YOUR RECOMMENDATION ON TECO'S PROPOSAL TO CONSOLIDATE THE GSD AND INTERRUPTIBLE SERVICE CLASSES.

A The Commission should once again reject TECO's proposal to consolidate the GSD and IS classes. Contrary to Mr. Ashburn's purported "justifications", there has been no decades-long transition to eliminate the IS rate schedules, and there are no inequities in maintaining separate cost-based GSD and IS rate schedules. What Mr. Ashburn characterizes as inequities are in fact legitimate cost-based differences between the GSD and IS rates, as determined by this Commission in TECO's last rate case. Further, Mr. Ashburn concedes that these differences currently exist, and my analysis confirms that the differences in the GSD and IS load, usage and service characteristics support maintaining the status quo. While having homogeneous classes is one of the criteria that Mr. Ashburn references in describing a proper rate design,[10] he has failed to follow his own criterion in this instance. And finally, IS customers do not require a rate increase because the IS class is already above parity relative to TECO's proposed Florida Jurisdictional rate of return. For all of these reasons, the IS class should remain intact.

<u>GSD Rate Design</u>

Q HOW SHOULD THE GSD RATE SCHEDULES BE DESIGNED?

A Rate design is a continuation of the cost allocation process. Thus, a properly designed GSD rate should track cost causation as defined in the class cost-of-service study (CCOSS). This means that Customer (or Basic) charges should reflect customer-related costs, Demand charges should reflect demand-related costs, and Energy charges should reflect energy-related costs. The table below summarizes the unit customer, demand and energy costs of the consolidated GSD-IS rate class with the corresponding proposed rates for service at secondary voltage.

TECO's Proposed Consolidated GSD Rate Design Vs. Unit Cost at Secondary Voltage		
Charge	**Standard Rate**	**Unit Cost**
Basic Charge (per month)	$30.00	$28.31
Demand Charge (per kW-month)	$9.50	$12.60
Energy Charge (per kWh)	1.829¢	0.956¢
Source	E-13c	E-1

Q DOES TECO'S PROPOSED GSD RATE DESIGN FOLLOW THE COSTING PHILOSOPHY DESCRIBED ABOVE?

A No. As can be seen, only the Basic charge reflects unit cost as derived in TECO's preferred CCOSS at proposed rates. The proposed standard Energy charge is nearly double unit cost. In fact, the current GSD Energy charge of 1.583¢ is already above cost. As a consequence of setting Energy charges well above cost, the proposed Demand charges are being set below cost. TECO's workpapers reveal that the proposed $9.50 per kW Demand charge was an input and was not justified by a specific cost support.

Q DO TECO'S PROPOSED GSD STANDARD ENERGY CHARGES AFFECT ANY OTHER CHARGES?

A Yes. The proposed GSD Standard Energy charge is used to derive the On-Peak Energy charge. Specifically, the On-Peak Energy charge is the difference between the proposed Standard and Off-Peak Energy charges weighted for the percent of on and off-peak hours. The proposed Off-Peak Energy charge was set at average unit energy cost. The present and proposed On and Off-Peak Energy charges are summarized in the table below.

TECO's Proposed On and Off-Peak Energy Charges at Secondary Voltage (per kWh)			
Charge	Present	Proposed	Percent Increase
On-Peak	2.898¢	3.999¢	38.5%
Off-Peak	1.046¢	0.946¢	9.6%

The result of this formulation is a 38% increase in the On-Peak Energy charge and a 10% decrease in the Off-Peak Energy charge. These compare to an overall 11.6% base revenue increase for the GSD class. In my opinion, increasing any charge by more than three times the class average increase is both excessive and violates the principle of gradualism.

Q WHAT DO YOU MEAN BY GRADUALISM?

A Gradualism is a concept that is applied that limits the movement of rates to cost to prevent "rate shock." Although TECO is not proposing to move the GSD Energy charges to cost, the excessive increases in the On-Peak Energy charge, which exceeds three times the class average increase, would result in rate shock.

Q SHOULD TECO'S PROPOSED GSD ENERGY CHARGES BE ADOPTED?

A No. The proposed 1.829¢ Standard Energy charge is 91% above actual cost. The above-cost Standard Energy charge also explains the excessive increase in the On-Peak Energy charge. Thus, TECO's proposed GSD Energy charges not only fail to track actual cost, they are contrary to cost-based ratemaking and the principle of gradualism. For these reasons, TECO's proposed GSD rate design should be rejected.

Q HOW SHOULD THE GSD ENERGY CHARGES BE DESIGNED?

A Consistent with the results of TECO's CCOSS and with the objective of aligning rates to reflect actual cost, there should be no increase in the GSD Energy charges. All of the increase should be collected in the Basic Service and Demand charges.

Q SHOULD ANY OTHER CHANGES BE MADE TO THE GSD RATE DESIGN IF THE COMMISSION APPROVES CONSOLIDATING THE GSD AND INTERRUPTIBLE SERVICE RATE SCHEDULES?

A Yes. As previously stated, the IS class is already earning a 1.10 times parity ratio relative to TECO's *proposed* rate of return. Thus, pricing the IS customers on the proposed GSD rate would further exacerbate the subsidy provided by the IS class. For this reason, if the two classes are consolidated, I recommend that the Delivery Voltage Adjustments for sub-transmission service be increased to help mitigate this subsidy. Most of the IS class sales are at sub-transmission voltage. Thus, increasing the applicable Delivery Voltage Adjustment would target most of the relief to the IS customers.

Q BY HOW MUCH SHOULD THE SUB-TRANSMISSION DELIVERY VOLTAGE ADJUSTMENT BE INCREASED?

A The sub-transmission Delivery Voltage Adjustment should provide an additional credit to offset the proposed base revenue increase to the IS class, or $581,000. This would translate into an additional $0.53 credit in the sub-transmission Delivery Voltage Adjustment. Of course, the better solution would be to retain the IS rate schedules.

<u>Interruptible Service Rate Design</u>

Q IF TECO'S PROPOSED GSD-IS CLASS CONSOLIDATION IS REJECTED,

HOW SHOULD THE IS RATE BE DESIGNED?

A The same costing philosophy described above for GSD should also apply to the IS rate schedules. Further, because the IS class is presently providing a rate of return higher than TECO's proposed return, the IS rate design should remain revenue neutral. This does not mean that the IS rate design should be unchanged. As can be seen in the table below, the current Demand and Energy charges bear no semblance whatsoever to cost-based rates under TECO's CCOSS.

Current Interruptible Service Rate Design Vs. Unit Cost		
Charge	**Current Rate**	**Unit Cost**
Basic Charge (per month)	$622/$2,372	$1,032
Demand Charge (per kW-month)	$1.45	$7.75
Energy Charge (per kWh)	2.504¢	0.942¢
Source	E-13c	E-1

The Energy charge is 166% above cost, while the Demand charge is 81% below cost.

Q SHOULD ANY CHANGES BE MADE TO THE IS RATE DESIGN?

A Yes. If the Commission retains the IS rate schedules, I recommend that the Basic Charge be set to unit cost, the Energy charge should be reduced by 25%, and the remaining revenue requirement be collected in the Demand charge. This would result in the following rates.

Recommended Interruptible Service Rate Design Assuming No Change in IS Base Revenues		
Charge	**Recommended Rate**	**Unit Cost**
Basic Charge (per month)	$520/$2,150	$1.032
Demand Charge (per kW-month)	$5.19	$7.75
Energy Charge (per kWh)	1.878¢	0.942¢

Q **WOULD YOUR RECOMMENDED INTERRUPTIBLE SERVICE RATE DESIGN VIOLATE GRADUALISM?**

A No. Although the recommended changes in the Energy and Demand charges may appear extreme, this is a reflection of how far current rates are from actual cost. Further, it assumes no increase or decrease in the IS class base revenues. Thus, the impact of much higher Demand charges would be offset by the much lower Energy charges. This end result will be a more cost-based rate design than currently exists.

3. CLASS COST-OF-SERVICE STUDY

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

A Yes. TECO filed both the Commission required and preferred CCOSS at present and proposed rates. The Commission required CCOSS is based on the Twelve Coincident Peak (12CP) and 1/13th Average Demand (AD) method, or 12CP-1/13thAD. However, TECO's preferred CCOSS uses 12CP-50%AD to allocate production plant-related costs, and the minimum distribution system (MDS) methodology is used to classify and allocate certain distribution network costs on a customer basis. TECO's preferred CCOSS at proposed rates also assumes consolidation of the GSD and IS classes.

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

A With the exceptions I will discuss below, it generally does. TECO's CCOSS recognizes the different types of costs as well as the different ways electricity is used by various customers.

Q DO YOU AGREE WITH EVERY ASPECT OF TECO'S PREFERRED CLASS COST-OF-SERVICE STUDY?

A No. As previously explained, the GSD and IS rate classes should not be consolidated. Further, I strongly disagree with TECO's proposed 12CP-50%AD method.

First, it would result in yet another substantial change in production cost allocation methodologies. As explained later, TECO has proposed a different production cost allocation method in every rate case dating back to 1985.

Second, Mr. Ashburn relies on four points in suggesting the Commission adopt the 12CP-50%AD approach:

Reason #1. The manner in which power plants are planned and operated in Florida[11];

Reason #2. TECO has installed a significant amount of base and intermediate load generation which is more expensive to install than alternative peaking generation, but less expensive to operate over time[12];

Reason #3. The proposed conversion of the existing simple cycle peakers at TECO's Polk Power Station to a combined cycle structure[13], which means it is investing in more expensive generating units and associated units to provide more efficient fuel conversion for the generation of electricity; and

Reason #4. To minimize the revenue requirements for the RS and GS rate classes.[14]

None of the four reasons cited by Mr. Ashburn support allocating twice as many production plant costs to energy as under the currently approved methodology: 12CP-25%AD. In fact, Mr. Ashburn's four reasons support adopting the Commission's preferred 12CP-1/13thAD method. 12CP-1/13thAD was also approved by the Commission and used by Duke Energy Florida (Duke), Florida Power & Light Company (FPL) and Gulf Power Company (Gulf) to determine class revenue allocation and rate design in their most recent rate cases.

Third, TECO's proposed 12CP-50%AD would place undue emphasis on year-round energy.[15] In total, 57% of base rate production plant costs would be allocated on an energy basis. By allocating over 57% of TECO's base rate production fixed costs on energy, it gives far less emphasis on peak demand which drives the need for TECO and other utilities to install generation capacity. As explained later, Average Demand is not a cost driver.

Finally, 12CP-50%AD is consistent with the percentage of costs typically allocated on an energy basis under the Equivalent Peaker (EP) Method. EP methods generally result in 40% to 75% of total production plant costs being classified as energy-related.[16] Further, like EP, 12CP-50%AD allocates production plant costs to hours beyond the economic break-even point. This is the reason why the Commission rejected EP in 1990. Thus, given the similarities between EP and 12CP-50%AD, the Commission should also reject 12CP-50%AD and adopt the 12CP-1/13thAD methodology.

Q DO YOU AGREE WITH ANY OF THE CHANGES TO THE CLASS COST-OF-SERVICE STUDY THAT TECO IS PROPOSING?

A Yes. I agree with TECO's proposal to use MDS to classify some portion of network distribution plant-related costs as customer related. TECO's proposal recognizes the reality that the utility is required to invest in a minimal distribution network to attach a customer to the system and provide the voltage support necessary to support reliable electricity service. Stated differently, these costs are incurred regardless of the amount of power and energy usage by customers. Thus, they should be allocated to classes relative to the number of customers served.

Background

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

A A class cost-of-service study (CCOSS) is an analysis used to determine each class's responsibility for the utility's costs. Thus, it determines whether a class generates sufficient revenues to recover the class's cost of service. A CCOSS 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 TO CONDUCT A CLASS COST-OF-SERVICE STUDY?**

A The basic procedure for conducting a CCOSS 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 (USOA) developed by the Federal Energy Regulatory Commission (FERC).

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.

<u>Production Plant Allocation</u>

Q WHAT IS THE 12CP-50%AD METHOD?

A The 12CP-50%AD method allocates production plant costs using both 12CP (which is also used to allocation transmission plant related costs) and energy (or average demand). Specifically, the 12CP-50%AD allocation factors are derived as follows:

$$\mathbf{12}\boldsymbol{CP} - \mathbf{50\%}\boldsymbol{AD} = \mathbf{12}\boldsymbol{CP}\% \ \boldsymbol{X}\ \mathbf{50\%} + \boldsymbol{Average\ Demand}\% \ \boldsymbol{X}\ \mathbf{50\%}$$

Q HAS THIS COMMISSION EVER APPROVED THE 12CP-50%AD METHOD?

A No.[17]

Q DID TECO ALSO PROPOSE THE 12CP-50%AD METHOD IN ITS LAST RATE CASE?

A No. TECO proposed and the Commission approved the 12CP-25%AD method in the last rate case. Before TECO's last rate case, it used the 12CP-1/13thAD approach, the same methodology used by Duke, FPL and Gulf today.

Q HAS TECO CONSISTENTLY USED THE SAME PRODUCTION PLANT ALLOCATION METHODOLOGY IN EACH OF ITS PRIOR RATE CASES?

A No. As can be seen in the table below, TECO has proposed a different production plant cost allocation method in each of its last four rate cases, including this case, dating back to 1985.

Summary of Production Plant Cost Allocation Methods Proposed by TECO

Docket No.	Methodology
850050	Equivalent Peaker
920324	12CP-1/13AD
080317	12CP-25%AD
130040	12CP-50%AD

Thus, 12CP-50%AD is another new proposed methodology. Witness Ashburn admitted during his deposition that the approach was proposed in part simply because the Commission accepted the 12CP-25%AD approach during the last rate case, and maybe the Commission would look favorably on yet another change.[18] Under 12CP-50%AD, TECO is now proposing to roughly double the amount of production plant related costs that would be allocated on an energy basis. Coupled with its proposal to directly classify the costs associated with the Big Bend scrubber and Polk Plant gassifier to energy, 12CP-50%AD would result in classifying 57% of net production plants and related fixed costs on an energy basis.

Q IF THE COMMISSION WERE TO ADOPT 12CP-50%AD WILL THIS ALSO CHANGE HOW CERTAIN NON-BASE RATE COSTS ARE ALLOCATED AND COLLECTED?

A Yes. TECO currently uses 12CP-25%AD to allocate the demand related portion of purchased power capacity costs in its Capacity Cost Recovery (CCR) rider and certain environmental investment that is being collected in the Environmental Cost Recovery Clause (ECRC). If the Commission were to adopt 12CP-50%AD for allocating base rate costs, this would require a similar change in how costs are allocated and collected in both the CCR and ECRC. Thus, any change in how production plant is allocated in determining base rates will result in corresponding allocation changes in both the CCR and ECRC.

Q MR. ASHBURN'S REASON #1 IS THAT 12CP-50%AD IS JUSTIFIED BECAUSE IT REFLECTS HOW POWER PLANTS ARE PLANNED AND OPERATED IN FLORIDA. IS THIS AN ACCURATE STATEMENT?

A No. If 12CP-50%AD reflected how power plants are planned and operated in Florida, one should logically expect that this method would be embraced by all Florida investor-owned electric utilities. However, TECO is the only utility in Florida investor-owned electric utility proposing 12CP-50%AD. Again, Duke, FPL and Gulf currently use 12CP-1/13thAD.

Q HOW IS THE FACT THAT 12CP-1/13THAD IS USED BY DUKE, FPL AND GULF PERTINENT TO TECO?

A Duke, FPL and Gulf are among the other Florida utilities that plan and operate generating systems in Florida (*i.e.,* **Reason #1**). Further, these utilities have recently completed rate cases before the Commission. In these cases, with the exception of Duke, who ultimately agreed to continue using the 12CP-13thAD approach, neither FPL nor Gulf proposed changing the 12CP-1/13thAD method. For example, in its most recent rate case, FPL supported 12CP-1/13thAD stating that:

> ***The 12 CP and 1/13^th^ methodology recognizes that the decision to add generating capacity is driven primarily by peak demands on the system.*** This methodology classifies 12/13ths. or approximately 92% of costs on the basis of coincident peak demand and 1/13th, or approximately 8%, of costs on the basis of energy. That portion classified to demand is allocated to the individual rate classes based on their 12 CP contributions, adjusted for losses, while the portion classified to energy is allocated based on their kWh sales, adjusted for losses. ***Under the 12 CP and 1/13th methodology, all generating units are treated consistently based on their function (i.e. production), their classification (12/13th demand and 1/13th energy), and their allocation (contribution to the system peak and kWh of energy).*** The 12 CP and 1/13th methodology has a significant history of regulatory acceptance in Florida. The 12 CP and 1/13th methodology was used in Docket No. 830465-EI and Docket No. 080677-EI. Furthermore, the FPSC has approved the 12 CP and 1/13th methodology in rate cases involving other investor-owned utilities.[19] (emphasis added)

Q **IS THERE ANY REASON TO BELIEVE THAT TECO PLANS ITS SYSTEM DIFFERENTLY THAN FPL?**

A No.

Q **TURNING TO MR. ASHBURN'S REASON #2, DOES THE FACT THAT TECO HAS INSTALLED A SIGNIFICANT AMOUNT OF BASE AND INTERMEDIATE LOAD GENERATION JUSTIFY CHANGING THE CURRENTLY APPROVED PRODUCTION PLANT COST ALLOCATION METHOD?**

A No. TECO's capacity mix is relatively unchanged since the addition of the simple cycle peakers that were reflected in the Step 2 rates approved in its last rate case. Thus, TECO's production plant investment reflects the same investment (plus capital additions less depreciation and interim retirements) as was included in base rates in TECO's last rate case.

Q WHAT DOES MR. ASHBURN MEAN BY THE TERM INTERMEDIATE LOAD GENERATION?

A I presume Mr. Ashburn is referring to combined cycle gas turbines (CCGTs) because he specifically referenced TECO's existing generation mix, which includes CCGTs at Bayside Units 1 and 2, and TECO's proposed conversion of Polk Units 2-5.

Q DOES MR. ASHBURN'S REASON #3 (THE PLANNED CONVERSIONS AT POLK) SUPPORT ADOPTING 12CP-50%AD?

A No. First, the planned conversions at Polk Units 2-5 will not be placed into commercial operation until 2017, which is beyond the test year.[20] Thus, any recognition of the conversion would be premature and beyond the scope of this proceeding.

Second, TECO is not the only utility adding CCGTs to its system. FPL, recently installed over 1,295 megawatts (MW) of new CCGTs. It is currently planning to install an additional 2,545 MW of capacity.

Q HAS FPL'S DECISION TO INSTALL SUBSTANTIAL AMOUNTS OF COMBINED CYCLE GENERATION PROMPTED IT TO CHANGE ITS PRODUCTION PLANT ALLOCATION METHODOLOGY?

A No. FPL has supported and continues to support 12CP-1/13thAD despite converting its older steam generation into modern efficient CCGTs. These conversions complement FPL's existing nuclear capacity, which are more capital intensive than CCGTs. Thus, FPL's decision to invest in more capital intensive generation capacity has not prompted it to allocate a much larger percentage of its production plant costs on an energy basis.

Q IS IT ACCURATE TO STATE THAT PRODUCTION PLANT INVESTMENT INCURRED TO PROVIDE MORE EFFICIENT FUEL CONVERSION FOR THE GENERATION OF ELECTRICITY IS CAUSED BY YEAR-ROUND ENERGY USAGE?

A No. Mr. Ashburn's statement is an over-simplification of the system planning process, and it confuses cost causation with benefits.

Q HOW IS MR. ASHBURN'S STATEMENT AN OVERSIMPLIFICATION OF THE SYSTEM PLANNING PROCESS?

A System planners are faced with the dual dimensions of: (1) providing reliable service; and (2) minimizing total cost. Because electric energy cannot be stored in large quantities for any significant length of time, providing reliable service requires construction of sufficient generating capacity to meet the projected system peak demands and to provide an adequate reserve margin. This will ensure that whenever a consumer flips the switch an electric light or other appliance will operate.

Cost minimization is the requirement that the utility provide the service at the lowest overall cost. The utility strives to install the mix of generating capacity (*i.e.*, base, intermediate and peaking) that, along with the existing generation, yields the lowest total cost. In other words, the economic choice between a base load plant and a peaking plant must consider both investment-related costs (*i.e.*, capital costs) and operating costs. Therefore the type of generating unit selected is a function of average *total* costs.

Q ARE THERE OTHER FACTORS, BESIDES THE ECONOMIC TRADE-OFFS, THAT CAN AFFECT UTILITY INVESTMENT DECISIONS?

A Yes. A generating unit represents a 30 to 60-year investment. The long life-cycle makes it difficult for a utility to anticipate every contingency, such as new regulations that require utilities to cease using certain types of fuels, limit operations or install costly equipment to meet prevailing emissions standards or changes in public policy. These contingencies could transform what is otherwise an economical resource under today's circumstances into an uneconomical resource under different circumstances. Thus, it behooves a utility to manage these risks by installing a diversified portfolio of generating resources.

Q WHY DO UTILITIES INSTALL COMBINED CYCLE GENERATION?

A CCGTs provide flexible operating capacity. They can be started up more quickly than older steam units and have considerable load-following capability. Load following means that generator output can be automatically adjusted from moment-to-moment so that the available supply always matches the utility's loads in real time. Flexible capacity is especially important for systems having substantial amounts of intermittent resources (*i.e.,* solar, hydro, wind).

With more flexible capacity, CCGTs can also be used to supply Contingency Reserves, which consist of generation and interruptible loads available within 15 minutes. Contingency Reserves are necessary to assure that sufficient capability exists to meet the NERC Disturbance Control Standard and to reestablish resource and demand balance following a Reportable Disturbance.[21] These functions are clearly necessary to maintain system reliability. As such, it is an oversimplification to claim that any "extra" investment that may be incurred to install CCGTs is driven by fuel savings.

Q DO PROJECTED FUEL SAVINGS CREATE THE NEED TO ADD GENERATION CAPACITY?

A No. The primary driver for generation capacity additions is the utility's projected peak demand. According to TECO's 2013 Ten-Year Site Plan:

> To meet the expected system demand and energy requirements over the next ten years, both peaking and intermediate resources are needed. The peaking capacity need will be met by purchased power agreements for peaking capacity secured through 2016. In 2017, Tampa Electric currently expects to meet its intermediate load needs by converting Polk Power Station's simple cycle combustion turbines (Polk Units 2-5) to a natural gas combined cycle (NGCC) unit. The operating and cost parameters associated with the capacity additions resulting from the analysis are shown in Schedule 9. Beyond 2017, the company foresees the future needs being that of additional peaking capacity, which it will meet by combustion turbine additions and/or future purchased power agreements.[22]

Thus, as demonstrated by TECO's own Ten-Year Site Plan, the factor driving the need for new capacity is the growth in projected peak demand. In other words, peak demand is the cost causer, while fuel savings is the outcome of installing more efficient generation capacity. Mr. Ashburn would have us believe that the opposite is true (*i.e.* fuel savings drive plant investment) which is clearly contradicted by the facts.

Q IF MR. ASHBURN'S THEORY (THAT FUEL SAVINGS ARE THE PRIMARY DRIVER FOR TECO'S INVESTMENT IN BASE AND INTERMEDIATE LOAD CAPACITY) IS VALID, WOULD 12CP-50%AD ACCURATELY REFLECT HIS THEORY?

A No. Mr. Ashburn's system planning theory is premised on a flawed application of the theory of capacity substitution (CAPSUB). Capital Substitution assumes that utilities invest in more capital-intensive generation (*i.e.* coal and CCGTs) in order to save fuel costs. However, as explained in **Appendix C,** 12CP-50%AD fails to correctly apply capital substitution theory because production plant investment is allocated to the hours beyond the economic break-even point. Further, TECO made no attempt to define that portion of fuel costs that are incurred for reliability and not to provide kWh. Such reliability-driven fuel costs should be allocated on a demand, and not an energy, basis.

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 peaking capacity is the same as a other types of capacity. The illustration in **Appendix C** assumes 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, other types of capacity will be more economical.

Therefore, *annual energy usage* (or Average Demand) 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 usage is no longer a factor in the decision to select a specific type of generation capacity.

Q **HOW DOES 12CP-50%AD RESULT IN ALLOCATING PRODUCTION PLANT COSTS TO HOURS BEYOND THE ECONOMIC BREAK-EVEN POINT?**

A This is demonstrated in **Exhibit___ (JP-2),** which shows TECO's load duration curve (in blue) with each of the 12CPs (in green) and average demand (in red) also plotted. A load duration curve is TECO's system demand sorted in descending order with the system peak shown on the left most side of the curve and system minimum demands shown on the right most portion of the curve. In the interest of brevity, only a portion of TECO's load duration curve is shown.

First, 12CP-50%AD assigns 50% of production plant cost to all 8,760 hours in a typical year (the red area under the load duration curve). However, the economic break-even point of peaking capacity occurs around 800 hours per year. Thus, the vast majority of the hours occur beyond the break-even point. Second, three of the 12CPs also occur beyond the economic break-even point.

Q HOW DID YOU DETERMINE THAT THE ECONOMIC BREAK-EVEN POINT OCCURS AT ABOUT 800 HOURS?

A I analyzed the operating hours of TECO's peaker units over the past 3 years. This is shown in **Exhibit___ (JP-3).** As can be seen, TECO typically operates its peakers between 551 and 1,037 hours per year. This translates into 800 hours per year per unit on average.

Q HAS THE COMMISSION PREVIOUSLY REJECTED METHODS THAT ALLOCATE PRODUCTION PLANT COSTS TO ALL 8,760 HOURS?

A Yes. The same issue arose in connection with the Equivalent Peaker (EP) method of allocation. Under EP, 40% to 75% of production plant costs is classified to energy and allocated on Average Demand. The remaining costs are allocated on a CP basis. This is similar to 12CP-50%AD, which allocates 50% of production plant costs on Average Demand and the remaining demand-related costs on 12CP. Both methods allocate significant costs beyond the economic break-even point.

However, in 1990 the Commission rejected the EP method. Specifically, the Commission stated:

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

Thus, the Commission has previously determined that methods like EP and 12CP-50%AD, which allocate investment to hours beyond the economic break-even point, are clearly 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 capacity to install. Only the production up to the break-even point determines the lowest cost capacity addition.

Q ARE THERE ANY MATERIAL DIFFERENCES BETWEEN 12CP-50%AD AND EQUIVALENT PEAKER METHODS?

A No. The only real difference between EP and 12CP-50% AD is how the percent of energy-related costs is derived. EP methods typically use a more rigorous analysis, while TECO relied on judgment.[24] Given that EP and 12CP-50%AD are for all intents and purposes the same method, the Commission should reject 12CP-50%AD just as it rejected EP.

Q DOES MR. ASHBURN'S REASON #4 JUSTIFY ADOPTING 12CP-50%AD?

A No. Mr. Ashburn's fourth reason (that 12CP-50%AD would minimize the revenue requirements for the RS and GS rate classes) has nothing to do with selecting a class cost-of-service methodology. That selection should be based on the application of the principle of cost causation. Cost causation means allocating costs to those classes that cause the utility to incur the specific costs. It does not mean picking a cost allocation method to minimize the rate impact on certain rate classes (*i.e.*, picking winners and losers while disregarding cost causation). Were it to do so, the Commission would effectively be engaging in "price-based costing" rather than "cost-based pricing." The Commission's long-standing policy has employed "cost-based pricing." In doing so, rate impacts are properly addressed in determining the appropriate allocation of a base rate increase and in the design of the applicable rates, not in the selection of a cost-of-service methodology.

<u>Recommendation</u>

Q SHOULD THE COMMISSION ADOPT 12CP-50%AD?

A No. 12CP-50%AD is not consistent with cost causation and does not accurately reflect the system planning process. Further, 12CP-50%AD is not supported by any changes in TECO's system planning process or its current generation mix relative to the mix that existed in TECO's last rate case. As explained previously, 12CP-50%AD allocates plant costs beyond the economic break-even point and classifies about the same percentage of costs to energy as EP methods, which the Commission long-ago rejected. Finally, 12CP-50%AD is not being used by Duke, FPL or Gulf. This is relevant because these utilities have invested in significant base and intermediate load capacity resources. Mr. Ashburn has failed to demonstrate how TECO is different than Duke, FPL or Gulf.

Q ARE THERE ANY OTHER REASONS FOR REJECTING 12CP-50%AD?

A Yes. Adopting 12CP-50%AD would cause undue instability in both class revenue requirements and rate design. As previously stated, TECO has proposed a new cost allocation methodology in every rate case since 1985. This current change in methodologies is particularly dramatic in light of the fact that it would double the amount of TECO's total production fixed costs (both base rate and cost recovery clauses) allocated in/or collected on an energy basis. Instability is not a desirable attribute of a rate design.

Q **WHAT PRODUCTION PLANT ALLOCATION METHOD SHOULD THE COMMISSION ADOPT FOR TECO?**

A TECO has provided no evidence that it plans its generation system any differently than other Florida electric utility. The Commission has adopted 12CP-1/13thAD for Duke, FPL and Gulf. Unless there are clear differences between TECO and other Florida utilities, 12CP-1/13AD should also be adopted for TECO.

Alternatively, if the Commission does not want to again change its production plant allocation approach, then it should not approve any change in the currently approved cost allocation methodology: 12CP-25%AD. It should not adopt TECO's proposed 12CP-50%AD proposal.

Q **IF THE COMMISSION ACCEPTS TECO'S 12CP-50%AD APPROACH, SHOULD ANY OTHER CHANGES BE MADE?**

A Yes. If the Commission decides that more than 25% of production fixed costs (other than then Big Bend scrubber and Polk gassifier) should be allocated on an energy basis, then it should replace 12CP with an allocator that more closely reflects TECO's actual system load characteristics and does not allocate as many production fixed costs to hours beyond the break-even point as does 12CP-50%AD.

Q **WHAT ALLOCATION METHODOLOGY BEST REFLECTS TECO'S SYSTEM LOAD CHARACTERISTICS?**

A The summer and winter system coincident demand (Summer/Winter CP) method best reflects TECO's load and supply characteristics.

Q **HOW DO TECO'S LOAD CHARACTERISTICS SUPPORT THE USE OF THE SUMMER/WINTER CP METHOD?**

A TECO experiences its maximum annual demand for electricity in either the summer or winter months. This is shown in **Exhibit ____ (JP-4)**, page 1, which is an analysis of TECO's monthly firm peak demands as a percent of the annual system peak for the years 2008 through 2012. TECO routinely peaks in both the summer and winter months. 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-4)**, page 2. As can be seen:

- The minimum month peak is generally below 66% of the annual system peak.
- Monthly peak demands are only 85% of the annual system peak.
- Peak demands are 10% (or higher) of the non-peak demands.
- And with one exception, TECO has a 57% average annual load factor.

These ratios confirm that TECO has seasonal load characteristics. Thus, electricity demands in the spring and fall months are not particularly 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 months when planned outages have occurred than during the peak summer and winter months. This is shown in **Exhibit ___ (JP-5)**.

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 reserve margins in the summer and winter peak months, adjusted for scheduled outages, have been well below the corresponding non-peak month reserve margins.

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

A The analyses demonstrate that both summer and winter peak demands 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. For these reasons, if the Commission allocates an increasing amount of production plant costs to energy, it should also adopt the Summer/Winter CP method.

Q HOW WOULD THE SUMMER/WINTER CP METHOD AVOID ALLOCATING AS MANY COSTS BEYOND THE BREAK-EVEN POINT?

A Both the summer and winter annual peak demands are well within the hours up to the break-even point. As previously explained, this is not the case with 12CP.

Q **WHAT OTHER CHANGES IN THE COST ALLOCATION METHODOLOGY SHOULD BE MADE IF THE COMMISSION DECIDES TO ALLOCATE MORE THAN 25% OF PRODUCTION FIXED COSTS ON AN ENERGY BASIS?**

A The Commission should recognize that not all variable costs are energy related. As explained below, some variable costs are being incurred either for reliability or as a substitute for higher capital costs. Thus, they should be allocated to classes on a peak demand basis.

Q **WHAT ARE VARIABLE COSTS?**

A Variable costs are those that are primarily related to producing energy. The most obvious examples of variable costs are fuel and purchased energy expenses.

Q **HOW ARE FUEL AND PURCHASED ENERGY COSTS ALLOCATED AND COLLECTED?**

A Fuel and purchased energy costs are allocated and collected on an energy basis.

Q **IF SOME PORTION OF PRODUCTION FIXED COSTS IS ASSUMED TO BE ENERGY-RELATED, IS IT REASONABLE TO ASSUME THAT ALL FUEL AND PURCHASED ENERGY COSTS ARE ALSO ENERGY-RELATED?**

A No. TECO's assumption that all fuel and purchased energy costs are energy-related ignores several fundamental principles. First, TECO must commit its generating units in advance of actual demand. This requires fuel to be consumed for unit start-up and stabilization.

Second, certain generating units cannot be cycled completely down once they have been committed to serving load. These units must operate at minimum load levels to provide spinning and supplementary reserves. This is particularly necessary during low load periods.

In both instances (*i.e.* start up and operating units at minimum load), there is no direct link between fuel costs and kWh generated.

Q DOES TECO INCUR FUEL COSTS THAT DO NOT DIRECTLY RESULT IN GENERATING KILOWATT HOURS?

A Yes. As with other utilities, TECO incurs fuel costs both during start-up to commit units to daily operation and to allow units to operate at their economic minimums during low load periods. TECO estimates that about $8.3 million of costs are incurred for start-up. TECO could not quantify the fuel costs incurred to maintain units at minimal operating levels.[25] Arguably, both start-up costs and the fuel costs to maintain a unit in service should be allocated on a demand basis because they are being incurred to maintain system reliability.

Distribution Cost Classification

Q HOW HAS TECO CLASSIFIED DISTRIBUTION INVESTMENT?

A TECO has classified a portion of its distribution network investment as customer-related. This is consistent with the purpose of the distribution system, which is to deliver power from the transmission grid to the customer, where it is eventually consumed. Certain investments (*e.g.*, meters, service drops) must be made just to attach a customer to the system. These investments are customer-related.

Q WHAT DO YOU MEAN BY THE DISTRIBUTION NETWORK?

A The distribution "network" consists of TECO's investment in poles, towers, fixtures, overhead lines and line transformers. These investments are booked to FERC Accounts 364, 365, 366, 367, and 368.

Q **HOW DID TECO DETERMINE THE CUSTOMER-RELATED PORTION OF THE DISTRIBUTION NETWORK INVESTMENT?**

A TECO used a minimum distribution study (MDS). Under MDS, the customer-related portion is representative of the investment in the minimum size equipment required to attach customers to the system and provide the necessary voltage support.

Q **WHY IS IT APPROPRIATE TO CLASSIFY A PORTION OF THE DISTRIBUTION NETWORK INVESTMENTS AS A CUSTOMER-RELATED COST?**

A Classifying a portion of the distribution network as a customer-related cost recognizes the reality that every utility must provide a path through which electricity can be delivered to each and every customer regardless of the peak demand or energy consumed. Further, that path must be in place if the utility is to meet its obligation to provide service upon demand.

Absent a connection to the system, a customer cannot take power. Further, the connecting facilities must be sized to provide voltage support before any power or energy can be consumed. These prerequisites (*i.e.*, a grid connection with facilities sized to provide voltage support) are clearly related to the existence of the customer.

Q **DO ANY OTHER FACTORS JUSTIFY CLASSIFYING A PORTION OF THE DISTRIBUTION NETWORK AS CUSTOMER-RELATED?**

A Yes. The distribution network must comply with this Commission's standards of construction. Specifically, Rule 25-6.034 requires that:

> (1) The facilities of each utility shall be constructed, installed, maintained and operated in accordance with generally accepted

> engineering practices to assure, as far as is reasonably possible, continuity of service and uniformity in the quality of service furnished.
>
> (2) Each utility shall, at a minimum, comply with the National Electrical Safety Code [ANSI C-2) [NESC], incorporated by reference in Rule 25-6.0345, F.A.C.

Rule 25-6.0342, Florida Administrative Code, was more recently enacted. It requires utilities to cost-effectively strengthen critical electric infrastructure to increase the ability of transmission and distribution facilities to withstand extreme weather conditions and reduce restoration costs and outage times to end-use customers associated with extreme weather conditions. The costs to comply with these Commission rules are not required because of the amount of electric power and energy demanded. They are required because of the existence of each customer and TECO's obligation to provide a reliable connection to the grid.

Q IS IT A RECOGNIZED PRACTICE TO CLASSIFY A PORTION OF THE DISTRIBUTION NETWORK AS CUSTOMER-RELATED?

A Yes. For example, the NARUC Electric Utility Cost Allocation Manual states that:

> Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system.[26]

An excerpt from the Manual pertaining to distribution cost classification is provided in **Exhibit___ (JP-6)**.

Q IS THIS PRACTICE FOLLOWED BY OTHER UTILITIES?

A Yes. **Exhibit___ (JP-7)** is a partial list of the utilities that classify some portion of their distribution network investment as customer-related. This is not intended to be an exhaustive survey.

Q **WHAT PORTION OF THE DISTRIBUTION NETWORK IS TECO PROPOSING TO CLASSIFY AS CUSTOMER-RELATED?**

A TECO's MDS study resulted in classifying about 25% of its distribution network investment (FERC Accounts 364 through 368) as customer-related. This is shown in **Exhibit___ (JP-8)**, line 44, column 4.

Q **HOW DOES TECO'S CLASSIFICATION OF DISTRIBUTION NETWORK COSTS COMPARE WITH THE UTILITIES SHOWN IN EXHIBIT___ (JP-8)?**

A As previously stated, TECO classifies about 25% of the investment in FERC Accounts 364 through 368 as customer-related. The corresponding composite percentage for the other listed utilities ranges from 19% to 69%. Some variation is to be expected because of differences between each utility's distribution construction practices and the methodologies used to determine the customer-related component.

Q **PLEASE SUMMARIZE YOUR RECOMMENDATION.**

A TECO's proposed classification of distribution network costs comports with accepted practice and is modest relative to other utilities. Accordingly, TECO's proposed distribution customer classification should be adopted in this case.

4. REVENUE REQUIREMENT

Q WHAT REVENUE REQUIREMENT ISSUES ARE YOU ADDRESSING?

A I am addressing the test year planned outage expense and the storm reserve.

<u>**Planned Outage Expense**</u>

Q WHAT ARE PLANNED OUTAGE EXPENSES?

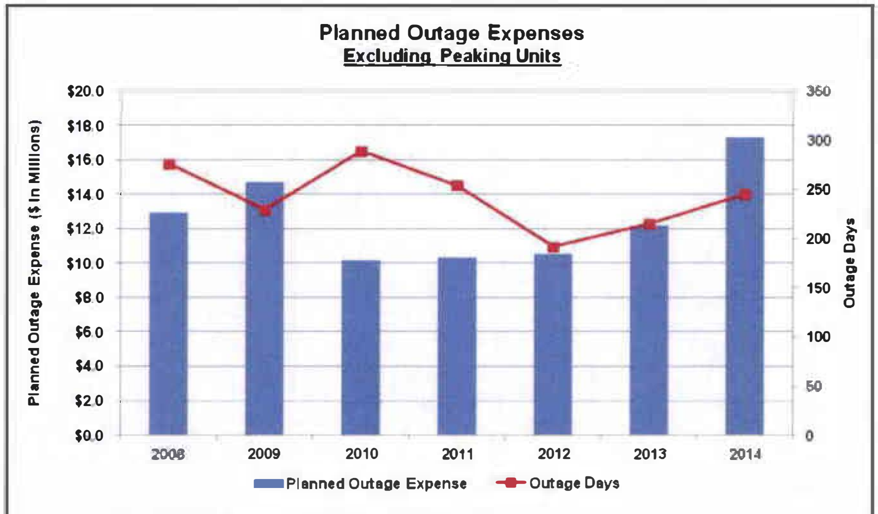
A Planned outage expenses are incurred to conduct major overhauls of generating units. They are a subset of production O&M expense.

Q IS TECO PROPOSING TO INCLUDE PLANNED OUTAGE EXPENSES IN BASE RATE IN THIS CASE?

A Yes. TECO is proposing to include about $17.6 million (Total Company) of planned outage expenses in base rates. This includes all generating units.

Q IS TECO'S PROPOSAL REASONABLE?

A No. As can be seen in the chart below, Test Year planned outage expenses are abnormally high. For my analysis I have included generating units other than peakers that will have been in-service for the entire 2008 – 2014 timeframe.



Source: TECO Response to FIPUG Interrogatory No. 37.

A further analysis of these expenses is provided in **Exhibit___ (JP-9)**. Specifically, I have compared the planned outage expenses during the Test Year (column 1) versus the average outage expenses from the previous six years and Test Year (column 2).

As can be seen, the proposed Test Year expense of $17.3 million is nearly 26% higher than the corresponding average period expense of $12.9 million. Particularly noteworthy is the substantial increase in Test Year overhaul costs incurred at Big Bend Unit 1 (line 1) and Big Bend Unit 4 (line 4) plants. The corresponding Test Year costs are 72% and 66% higher than over the previous six years.

Q **HOW DO TECO'S PROPOSED TEST YEAR PLANNED OUTAGE EXPENSES FOR THE BIG BEND UNITS COMPARE WITH PAST YEARS OUTAGE EXPENSES?**

A In past years major outage expenses have been limited to one unit or no units. The following table lists the Big Bend Units that experienced outage expenses of over $5 million in a year.

Big Bend Units with Yearly Outage Expenses Greater than $5 Million		
Unit	**Year**	**Expense**
Big Bend 3	2008	$5,219,128
Big Bend 2	2009	$6,105,000
Big Bend 3	2013	$5,300,000
Source: TECO Response to FIPUG Interrogatory No. 37.		

The proposed Test Year expenses include major outage expenses of $5.4 million for Big Bend Unit 1 and $5.7 million for Big Bend Unit 4. Therefore, the proposed Test Year planned outage expenses are clearly abnormal. For this reason, TECO's proposal should be rejected.

Q WOULD IT BE APPROPRIATE TO NORMALIZE PLANNED OUTAGE EXPENSES IN SETTING RATES TO BE APPROVED IN THIS CASE?

A Yes. TECO's proposed Test Year planned outage expenses are clearly abnormal and overstated. Thus, it would be appropriate to normalize these expenses so that the base rates approved in this proceeding are more representative of the costs that TECO will actually incur for planned maintenance outages.

Q WHAT IS YOUR RECOMMENDED NORMALIZATION ADJUSTMENT?

A I recommend a $3.7 million reduction in TECO's proposed Test Year expense. The $3.7 million adjustment is shown in column 5. It was derived by reducing Test Year expenses for Big Bend Unit 4 to within 5% of the 2008-2014 average expense (column 7).

<u>**Storm Reserve**</u>

Q WHAT IS A STORM RESERVE?

A Rule 25-6.0143, Florida Administrative Code, states: "A separate subaccount shall be established for that portion of Account No. 228.1 which is designated to cover storm-related damages to the utility's own property or property leased from others that is not covered by insurance."

Q WHAT IS TECO'S CURRENT STORM RESERVE LEVEL?

A The balance in TECO's storm reserve as of December 31, 2012 was $50.2 million. Considering the current annual storm damage accrual of $8 million, the balance will grow to $57.3 million assuming no further property damage is charged to the reserve in 2013. [27] If TECO experiences low storm activity similar to the 2005 – 2012 period, the reserve level could reach the target level of $64 million in 2014.

Q **HOW IS THE STORM RESERVE FUNDED?**

A The storm reserve is funded through customer contributions that the Commission authorizes when it sets base rates. Customers currently contribute $8 million per year to the storm reserve.

Q **DOES THE COMMISSION HAVE A FRAMEWORK FOR STORM RESTORATION COST RECOVERY?**

A Yes. According to the order in the last Tampa Electric Company rate case, the Commission addresses the storm restoration cost issue in the following manner:

> We have established a regulatory framework consisting of three major components: (1) an annual storm accrual, adjusted over time as circumstances change; (2) a storm reserve adequate to accommodate most, but not all storm years; and, (3) a provision for utilities to seek recovery of costs that go beyond the storm reserve.[28]

Q **WHO ULTIMATELY ASSUMES THE RISK OF LOSS FROM STORM DAMAGE UNDER THE EXISTING COMMISSION FRAMEWORK?**

A As the Commission stated, TECO's customers ultimately bear all of the risk of losses due to hurricanes and other storms:

> . . . under the current approach to the recovery of storm restoration costs, the risk associated with a lower reserve level (i.e., the possibility of storm restoration costs exceeding the Reserve, leading to subsequent customer charges) and the risk associated with a higher reserve level (i.e., paying charges now for storm restoration costs that do not materialize) is completely borne by FPL's customers. The customers represented in this proceeding have made clear that they would rather pay to fund the Reserve to a lower level now and risk future rate volatility than pay to fund the Reserve to a higher level before future storm restoration costs have been incurred.[29]

As such, TECO is at little or no risk that it will not recover its legitimate storm restoration costs regardless of the amount in the storm reserve. Put simply, from a customer perspective, the question is when to pay for the cost of restoration – before or after the damage occurs. It is clear that customers prefer to pay when the damage occurs, rather than have the utility hold their money for them. And, the Commission has made it clear through its past actions that when a documented case for such recovery is made, it will permit the utility to recover these costs.

Q IS TECO PROPOSING AN INCREASE IN THE ANNUAL ACCRUALS FOR ITS STORM RESERVE?

A No. TECO proposes to continue the $8 annual accrual it collects for storm reserve.

Q HAS TECO PROPOSED CHANGES TO THE TARGET STORM RESERVE BALANCE?

A Yes. The current target level is $64 million, approved by the Commission in Docket No. 080317-EI, Order No. PSC-09-0283-FOF-EI. In this case, TECO is proposing the targeted reserve balance to increase from $64 to $100 million.[30]

Q SHOULD TECO'S PROPOSED $36 MILLION INCREASE TO THE TARGETED STORM RESERVE BE APPROVED?

A No. TECO has not supported the need for a $36 million increase. Further, since the $50.2 million storm reserve balance as of 12/31/12 is sufficient to cover all but the severest storms, accruals should cease. Put simply, this increase is not warranted. As explained below, funds in the storm reserve are sufficient even if the accrual is stopped altogether. Therefore, I recommend that the Commission maintain the targeted reserve at its current level of $64 million.

Q WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A Under the Commission's framework described above, the storm reserve accrual and reserve balance are designed to provide coverage for some, but not all, storms. However, the Expected Annual Damage (EAD) presented by TECO witness, Steven Harris, takes into account all manner and strength of storms.[31] In other words, it assumes that the storm reserve should be adequate to cover damage from hurricanes up to Category 4. The current $50.2 million reserve balance covers all Category 1 hurricanes.[32] Considering $17.6 expected annual charges to the storm reserve, it is sufficient to cover almost three consecutive years.[33]

Q WHY IS TECO SEEKING A $36 MILLION INCREASE IN STORM DAMAGE RESERVE?

A The proposed increase is based on an increase in asset value from the previous study and to cover the expected average annual storm loss to be charged to the reserve derived in the TECO Storm Loss and Reserve Performance Analysis.

Q DOES THE EAD PRESENTED IN THE STUDY PROPERLY REFLECT THE ANNUAL COSTS THAT ARE COVERED WITH THE STORM RESERVE?

A No. I believe the EAD is overstated because it ignores the Commission's directive that the storm reserve should be adequate to accommodate most, but not all storm years.

Q WHAT TYPE OF STORMS ARE INCLUDED IN THE STUDY PRESENTED BY MR. HARRIS?

A The EAD is the average damage of thousands of simulated hurricane seasons in the EQECAT model. The EAD of $21.9 million presented by TECO represents the average of all these simulations. The analysis includes all storm categories in the EAD. The EAD for all levels of storms is $21.9 million per year, with a $17.6 million average expected charge to the reserve. Over the 2000-2012 time frame, TECO has charged $79 million (in total) to the reserve, as shown in **Exhibit___ (JP-10)**. This equates to an annual average charge to the reserve of less than $6.1 million. The 2004 Hurricanes (Charley, Francis, and Jeanne) account for $74 million of this total. The average annual charges to the storm reserve excluding the 2004 hurricanes have been $0.4 million. The 2000 – 2012 period falls in a timeframe with increased hurricane activity as recognized by the National Oceanic and Atmospheric Administration (NOAA).[34]

Q IS THERE ANY OTHER ISSUE WITH HOW THE EAD WAS CALCULATED?

A Yes. TECO has indicated that the EAD calculation did not include consideration for storm hardening since no major storm has occurred since the storm hardening program was implemented in 2004.[35] One would expect the expenditures dedicated to this program to reduce storm damage. However, the EAD calculation omits these benefits and made no assumptions that the result of TECO's storm hardening efforts should result in less damage when a major storm strikes TECO's service territory, all things being equal, as compared to the damage that could be expected before the storm hardening efforts were undertaken. This is an assumption that I believe is a reasonable one to make, and is supported by a factual predicate as described below.

Q WHAT IS THE SOURCE OF THE EXPECTATIONS THAT THE STORM HARDENING PROGRAM WOULD REDUCE STORM DAMAGE?

A The Direct Testimony of Beth Young (page 27) includes the following:

> **Q** You have discussed the reliability of the T&D system and steps you have taken to improve reliability and strengthen the system. What impact do these steps have on restoration after a major storm event?
>
> **A** These steps reduce the amount of damage, reduce the number of outages and reduce the overall restoration time for Tampa Electric's system for a major storm event.

TECO has projected spending $54 million in 2014 on storm hardening initiatives so one would expect reduced storm damages as a benefit of these initiatives.[36]

Q WHAT IS THE LIKELIHOOD THAT TECO WOULD INCUR DAMAGE IN EXCESS OF THE CURRENT $64 MILLION TARGET RESERVE?

A TECO analyzed the Aggregate Damage Exceedance Probabilities for various damage levels up to and in excess of $360 million.[37] According to TECO's study, there is an 8.68% probability that there will be damage in any one year that exceeds $60 million. In other words, a storm inflicting damage in an amount of approximately $60 million is likely to occur only once every 11.5 years.

Q WHAT RESULTS DOES THE STUDY SHOW FOR CATEGORY 1 AND 2 HURRICANES?

A On average, the most destructive Category 1 storm would cause mean damage of slightly less than $45 million.[38] The damage from the most severe Category 2 storm would cause mean damage of less than $120 million.[39]

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Q IS IT NECESSARY TO SET THE STORM RESERVE TO COVER THE COSTS OF ALL TROPICAL STORMS OR HURRICANES REGARDLESS OF THE LEVEL OF SUCH STORMS?

A No. The storm reserve and associated accrual are only part of the framework for recovering storm restoration costs. The Commission has demonstrated its ability and willingness to promptly consider and act upon a utility's request to recover storm costs. As such, the storm reserve need not cover all storms. To do so would impose an unnecessary added burden on customers.

Rather, what is needed is a reasonable accrual and a reasonable reserve designed to cover the expected damage from the more common (but not all) storm events. In this instance, TECO is seeking to establish the reserve at a level designed to provide for coverage for all storm damage. Such a "worst case" approach is only necessary if the storm reserve and associated accrual are the only means by which a utility is able to obtain coverage for damages from storms.

Q DO TECO'S CUSTOMERS BENEFIT FROM A HIGHER RESERVE TARGET?

A No. As explained above, the current $8 million contribution and the current storm reserve target of $64 million are more than sufficient to cover all but the most severe storms. Finally, the risk of non-recovery for storm damage restoration costs will remain with customers because if a catastrophic storm or storms strike TECO's service territory, customers will be surcharged to allow TECO to recover restoration in excess of the storm reserve balance.

Q IS AN INCREASE IN THE RESERVE NECESSARY TO MAINTAIN THE STATUS QUO?

A No. The current reserve balance is sufficient to cover all Category 1 hurricanes, as well as all but the most severe Category 2 hurricanes. In fact, at the EAD chargeable to the reserve each year, the reserve balance is sufficient to provide coverage for almost three years. Thus, it is not necessary to increase the current target level, and in fact, it would be sufficient for some years even if the accruals were stopped.

Q WHAT WOULD BE THE IMPACT ON THE STORM RESERVE IF ACCRUALS WERE STOPPED ENTIRELY?

A Over time, the level of the reserve will decline. However, absent a direct strike in the most populated portion of TECO's service territory, the current reserve balance may be sufficient to cover the EAD funded from the reserve for a number of years. If losses remain at the levels experienced over the 2005-2012 period, the current reserve is more than capable of supporting storm recovery for several years, without any further customer contributions.

Q SHOULD THE COMPANY REVISE ITS STORM RESERVE ANALYSIS IN THE NEXT RATE CASE?

A Yes. Since the present analysis addresses all manner and strength of storms up to and including the most severe and damaging storms and excludes any benefits of the storm hardening program, the Commission should require that any subsequent study consider alternative levels of storm damage. Any subsequent study should evaluate the reserve performance taking into account only Category 1 (and potentially Category 2) storms. This approach gives recognition to the framework for addressing storm restoration costs – which recognizes that the annual accrual and reserve balance are not intended to cover the most destructive storms. A future analysis should also expressly consider in detail how storm hardening efforts have reduced the risk of damage from hurricane or tropical storm events and the need to accrue monies for storm reserves.

Q PLEASE SUMMARIZE YOUR RECOMMENDATION.

A The storm reserve target should not be increased. The current reserve balance is sufficient to provide for coverage of the EAD funding from the reserve and also provides coverage for all Category 1 storms. Thus, TECO should stop accruing to the storm reserve. A revised study should be submitted when TECO next files a rate case or seeks to re-institute the storm reserve accrual and collection that shows what an appropriate reserve target is assuming coverage of *most* (Category 1 and 2) storms instead of *all* levels of storms.

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 12647 Olive Blvd., Suite 585, 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. I have also completed a Utility Finance and Accounting course.

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 requests 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 several Canadian provinces, and have testified before the Federal Energy Regulatory Commission and the state regulatory commissions of Alabama, Arizona, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, Ohio, Pennsylvania, Texas, Virginia, Washington, and Wyoming. 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 partial list of my appearances is provided in **Appendix B**.

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. J.Pollock is a registered Class I aggregator in the State of Texas.

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Supplemental	KS	Testimony in Support of Nonunanimous Settlement	6/28/2013
121203	JERSEY CENTRAL POWER & LIGHT COMPANY	Gerdau Ameristeel Sayreville, Inc.	ER1211105	Direct	NJ	Cost of Service Study for GT-230 KV Customers; AREP Rider	6/14/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Direct	KS	Wholesale Requirements Agreement; Process for Excemption From Regulation; Conditions Required for Public Interest Finding on CCN spin-down	5/14/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Cross	KS	Formula Rate Plan for Distribution Utility	5/10/2013
10090	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Direct	KS	Formula Rate Plan for Distribution Utility	5/3/2013
121001	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41223	Direct	TX	Public Interest of Proposed Divestiture of ETI's Transmission Business to an ITC Holdings	4/30/2013
121101	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Surrebuttal	MN	Depreciation; Used and Useful; Cost Allocation; Revenue Allocation	4/12/2013
121101	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Rebuttal	MN	Class Revenue Allocation.	3/25/2013
121101	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Direct	MN	Depreciation; Used and Useful; Property Tax; Cost Allocation; Revenue Allocation; Competitive Rate & Property Tax Riders	2/28/2013
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Second Supplemental Rebuttal	TX	Competitive Generation Service Tariff	2/1/2013
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Second Supplemental Direct	TX	Competitive Generation Service Tariff	1/11/2013
110202	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	40443	Cross Rebuttal	TX	Cost Allocation and Rate Design	1/10/2013
110202	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	40443	Direct	TX	Application of the Turk Plant Cost-Cap; Revenue Requirements; Class Cost-of-Service Study; Class Revenue Allocation; Industrial Rate Design	12/10/2012
120301	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Corrected Supplemental Rebuttal	FL	Support for Non-Unanimous Settlement	11/13/2012
120301	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Corrected Supplemental Direct	FL	Support for Non-Unanimous Settlement	11/13/2012
1 0602	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	12-E-0201/12-G-0202	Rebuttal	NY	Electric and Gas Class Cost-of-Service Studies.	9/25/2012
120602	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	12-E-0201/12-G-0202	Direct	NY	Electric and Gas Class Cost-of-Service Study; Revenue Allocation; Rate Design; Historic Demand	8/31/2012
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	12-MKEE-650-TAR	Direct	KS	Transmission Formula Rate Plan	7/31/2012
120502	WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	12-WSEE-651-TAR	Direct	KS	TDC Tariff	7/30/2012
120301	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Direct	FL	Class Cost-of-Service Study, Revenue Allocation, and Rate Design	7/2/2012

APPENDIX B
Testimony Filed in Regulatory Proceedings
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PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
120101	LONE STAR TRANSMISSION, LLC	Texas Industrial Energy Consumers	40020	Direct	TX	Revenue Requirement, Rider AVT	6/21/2012
111102	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39896	Cross	TX	Class Cost-of-Service Study, Revenue Allocation, and Rate Design	4/13/2012
111102	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39896	Direct	TX	Revenue Requirements, Class Cost-of-Service Study, Revenue Allocation, and Rate Design	3/27/2012
91023	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39851	Supplemental Rebuttal	TX	Competitive Generation Service Issues	2/24/2012
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39851	Supplemental Direct	TX	Competitive Generation Service Issues	2/10/2012
101101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	39722	Direct	TX	Carrying Charge Rate Applicable to the Additional True-Up Balance and Tax Balances	11/4/2011
110703	GULF POWER COMPANY	Florida Industrial Power Users Group	110138-EI	Direct	FL	Cost Allocation and Storm Reserve	10/14/2011
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39504	Direct	TX	Carrying Charge Rate Applicable to the Additional True-Up Balance and Taxes	9/12/2011
101101	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
101101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	39360	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
100503	ONCOR ELECTRIC DELIVERY COMPANY, LLC	Texas Industrial Energy Consumers	39375	Direct	TX	Energy Efficiency Cost Recovery Factor	8/2/2011
90103	ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	31653	Direct	AL	Renewable Purchased Power Agreement	7/28/2011
101101	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Direct	TX	Energy Efficiency Cost Recovery Factor	7/26/2011
101101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	36360	Direct	TX	Energy Efficiency Cost Recovery Factor	7/20/2011
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39366	Direct	TX	Energy Efficiency Cost Recovery Factor	7/19/2011
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39363	Direct	TX	Energy Efficiency Cost Recovery Factor	7/15/2011
101201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Direct	MN	Surplus Depreciation Reserve, Incentive Compensation, Non-Asset Trading Margin Sharing, Cost Allocation, Class Revenue Allocation, Rate Design	4/5/2011
101202	ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-381-EA-10	Direct	WY	2010 Protocols	2/11/2011
100802	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	38480	Direct	TX	Cost Allocation, TCRF	11/8/2010
90402	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	31958	Direct	GA	Alternate Rate Plan, Return on Equity, Riders, Cost-of-Service Study, Revenue Allocation, Economic Development	10/22/2010
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	38339	Cross-Rebuttal	TX	Cost Allocation, Class Revenue Allocation	9/24/2010
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	38339	Direct	TX	Pension Expense, Surplus Depreciation Reserve, Cost Allocation, Rate Design, Riders	9/10/2010

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100303	NIAGARA MOHAWK POWER CORP.	Multiple Interveno s	10-E-0050	Rebuttal	NY	Multi-Year Rate Plan, Cost Allocation, Revenue Allocation, Reconciliation Mechanisms, Rate Design	8/6/2010
100303	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	10-E-0050	Direct	NY	Multi-Year Rate Plan, Cost Allocation, Revenue Allocation, Reconciliation Mechanisms, Rate Design	0714/2010
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37744	Cross Rebuttal	TX	Cost Allocation, Revenue Allocation, CGS Rate Design, Interruptible Service	6/30/2010
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37744	Direct	TX	Class Cost of Service Study, Revenue Allocation, Rate Design, Competitive Generation Services, Line Extension Policy	6/9/2010
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37482	Cross Rebuttal	TX	Allocation of Purchased Power Capacity Costs	2/3/2010
90402	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	28945	Direct	GA	Fuel Cost Recovery	1/29/2010
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consum rs	37482	Direct	TX	Purchased Power Capacity Cost Factor	1/22/2010
90403	VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00081	Direct	VA	Allocation of DSM Costs	1/13/2010
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37580	Di ect	TX	Fuel refund	12/4/2009
90403	VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00019	Direct	VA	Standby rate design; dynamic pricing	11/9/2009
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consum rs	37135	Direct	TX	Transmission cost recovery factor	10/22/2009
80703	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	09-MKEE-969-RTS	Direct	KS	Revenue requirements, TIER, rate design	10/19/2009
90601	VARIOUS UTILITIES	Florida Industrial Power Users Group	090002-EG	Direct	FL	Interruptible Credits	10/2/2009
80505	ONCOR ELECTRIC DELIVERY COMPANY	Texas Industrial Energy Consumers	36958	Cross Rebuttal	TX	2010 Energy efficiency cost recovery factor	8/18/2009
81001	PROGRESS ENERGY FLORIDA	Florida Industrial Power Users Group	90079	Direct	FL	Cost-of-service study, evenue allocation, ate design, depreciation expense, capital structure	8/10/2009
90404	CENTERPOINT	Texas Industrial Energy Consumers	36918	Cross Rebuttal	TX	Allocation of System Restoration Costs	7/17/2009
90301	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	080677	Direct	FL	Depreciation; class revenue allocation; rate design; cost allocation; and capital structu e	7/16/2009
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	36956	Direct	TX	Approval to revise energy efficiency cost recovery factor	7/16/2009
90601	VARIOUS UTILITIES	Florida Industrial Power Users Group	VARIOUS DOCKETS	Direct	FL	Conservation goals	7/6/2009
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	36931	Direct	TX	System restoration costs under Senate Bill 769	6/30/2009
90502	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	36966	Direct	TX	Authority to revise fixed fuel factors	6/18/2009
80805	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	36025	Cross-Rebuttal	TX	Cost allocatiion, evenue allocation and rate design	6/10/2009
80805	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	36025	Direct	TX	Cost allocation, revenue allocation, rate design	5/27/2009

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81201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Surrebuttal	MN	Cost allocation, revenue allocation, rate design	5/27/2009
90403	VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00018	Direct	VA	Transmission cost allocation and rate design	5/20/2009
90101	NORTHERN INDIANA PUBLIC SERVICE COMPANY	Beta Steel Corporation	43526	Direct	IN	Cost allocation and rate design	5/8/2009
81203	ENTERGY SERVICES, INC	Texas Industrial Energy Consumers	ER008-1056	Rebuttal	FERC	Rough Production Cost Equalization payments	5/7/2009
81201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Rebuttal	MN	Class revenue allocation and the classification of renewable energy costs	5/5/2009
81201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Direct	MN	Cost-of-service study, class revenue allocation, and rate design	4/7/2009
81203	ENTERGY SERVICES, INC	Texas Industrial Energy Consumers	ER08-1056	Answer	FERC	Rough Production Cost Equalization payments	3/6/2009
80901	ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-333-ER-08	Direct	WY	Cost of service study; revenue allocation; inverted rates; revenue requirements	1/30/2009
81203	ENTERGY SERVICES	Texas Industrial Energy Consumers	ER08-1056	Direct	FERC	Entergy's proposal seeking Commission approval to allocate Rough Production Cost Equalization payments	1/9/2009
80505	ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	35717	Cross Rebuttal	TX	Retail transformation; cost allocation, demand ratchet waivers, transmission cost allocation factor	12/24/2008
70101	GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Traditional Manufacturers Association	27800	Direct	GA	Cash Return on CWIP associated with the Plant Vogtle Expansion	12/19/2008
80505	ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	35717	Direct	TX	Revenue Requirement, class cost of service study, class revenue allocation and rate design	11/26/2008
80802	TAMPA ELECTRIC COMPANY	The Florida Industrial Power Users Group and Mosaic Company	080317-EI	Direct	FL	Revenue Requirements, retail class cost of service study, class revenue allocation, firm and non firm rate design and the Transmission Base Rate Adjustment	11/26/2008
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	10/13/2008
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

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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
60303	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	26794	Direct	GA	Fuel Cost Recovery	4/15/2008
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
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

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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 NORTH 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,	12/15/2006
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Fuel Reconcilation	12/15/2006
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	08/23/06
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	32672	Direct	TX	ME-SPP Transfer of Certificate to SWEPCO	8/23/2006
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/
60301	P BLIC 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

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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
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

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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
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

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
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
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
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

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
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
6181	GULF STATES UTILITIES COMPANY	Texas Industrial Energy Consumers	12852	Direct	TX	Competitive Alignment Proposal	11/1/1994
6061	HOUSTON LIGHTING & POWER COMPANY	Texas Industrial Energy Consumers	12065	Direct	TX	Rate Design	11/1/1994
5929	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	12820	Direct	TX	Rate Design	10/1/1994
6107	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	12855	Direct	TX	Fuel Reconciliation	8/1/1994
6112	HOUSTON LIGHTING & POWER COMPANY	Texas Industrial Energy Consumers	12957	Direct	TX	Standby Rates	7/1/1994
5698	GULF POWER COMPANY	Misc. Group	931044-EI	Direct	FL	Standby Rates	7/1/1994
5698	GULF POWER COMPANY	Misc. Group	931044-EI	Rebuttal	FL	Competition	7/1/1994
6043	EL PASO ELECTRIC COMPANY	Phelps Dodge Corporation	12700	Direct	TX	Revenue Requirement	6/1/1994
6082	GEORGIA PUBLIC SERVICE COMMISSION	Georgia Industrial Group	4822-U	Direct	GA	Avoided Costs	5/1/1994
6075	GEORGIA POWER COMPANY	Georgia Industrial Group	4895-U	Direct	GA	FPC Certification Filing	4/1/1994
6025	MISSISSIPPI POWER & LIGHT COMPANY	MIEG	93-UA-0301	Comments	MS	Environmental Cost Recovery Clause	1/1/1994
5971	FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	940042-EI	Direct	FL	Section 712 Standards of 1992 EPACT	1/1/1994

APPENDIX C

<u>Flaws with TECO's Application of Capital Substitution Theory</u>

TECO is proposing to allocate over 50% of production plant costs on an energy basis on the theory that the "extra" investment is associated with certain types of generation (*i.e.*, units that are operated as base load and/or load following) provides fuel cost savings. Since fuel costs are typically allocated on an energy (or kWh) basis, the assumption is that this investment is also driven by kWh sales. This theory is referred to as "Capital Substitution" (or CAPSUB). TECO's application of CAPSUB overlooks four realities:

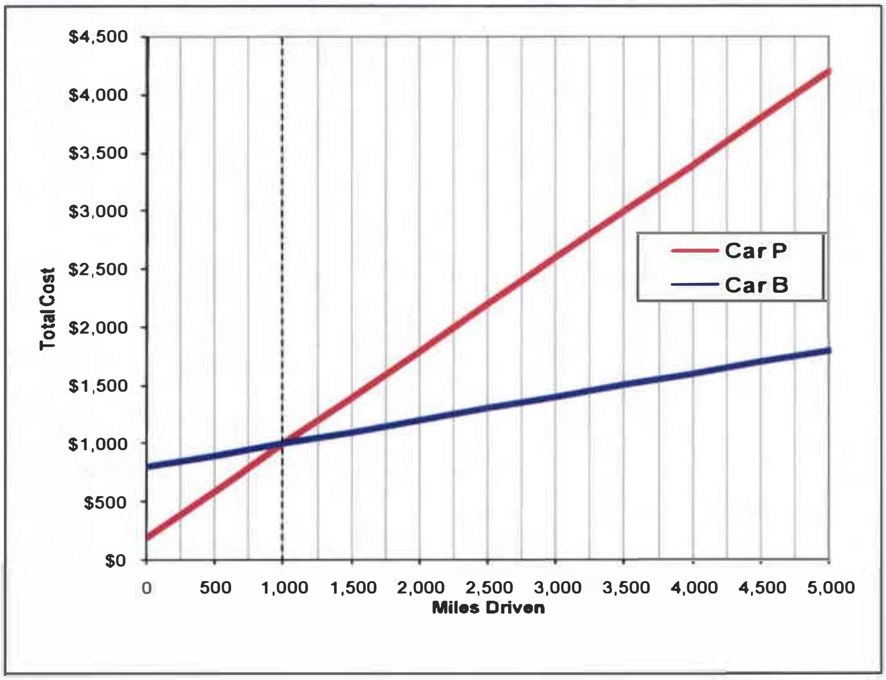
- The need for new capacity is driven by both projected peak demands and reserve requirements to ensure that electricity is reliable. Using 12CP to allocate the portion of production plant that TECO considers demand-related does not recognize the peak demands that drive capacity needs: **See Exhibits ___ (JP-4) and ___ (JP-5)**.
- Fuel savings is not a cost driver. All new plants save fuel costs because of improvements in generation technology, not because they are more capital intensive. Although the choice of plant technology is determined by economics, the objective is to provide reliable service at the lowest *overall* cost and not solely to lower fuel costs.
- Combined cycle gas turbines (CCGTs) have become the technology of choice not because they have lower fuel costs but because they can provide flexible load following capabilities needed to balance loads and resources in real time and meet operating reserve requirements.
- An energy allocation assumes all hours are critical to the choice of generation. However, not all production from a specific plant determines the type of capacity to install. ***Thus, allocating investment to all hours is contrary to cost causation***.

How 12CP-50%AD is Contrary to Cost Causation

The following simplified example demonstrates how TECO's energy allocation is contrary to cost causation. Let's suppose two drivers are required to rent cars from a fleet that contains only two types of cars, "Car P" and "Car B":

	Car P	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 Car P has a low fixed charge but gets poor mileage (like a peaker). 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. As can be seen, the *break-even point* between Car P and Car B is 1,000 miles.

Miles Driven	Total Cost			Best Choice
	Car P		Car B	
0	$200		$800	P
500	$600		$900	P
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

That is, the higher mileage **Car B** has a lower total cost per mile than **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 to drive **Car B**. In other words, the decision to drive **Car B** was based on whether the car would be driven 1,000 miles. It didn't matter that it would be driven more than 1,000 miles.

The same break-even construct applies to electric utilities. For example, assuming the break-even point between Base Load and Peaking capacity is 1,000 hours per year, it doesn't matter whether the Base Load plant will operate 5,000 hours, 6,000 hours, or 8,000 hours per year. Thus, ***load duration*** can affect the decision of whether to install Base Load or Peaking capacity. However, once the decision is made, duration beyond the break-even point is irrelevant.

TECO's allocation proposal ignores this fundamental planning construct because investment would be allocated to all kWh usage. *This is at odds with CAPSUB because the extra investment in base load generation can be justified* *by load duration up to the economic break-even point between Base Load and Peaking capacity*. That is, 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 a load following 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.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Tampa Electric Company	DOCKET NO. 130040-EI Filed: July 15, 2013

AFFIDAVIT OF JEFFRY POLLOCK

State of Missouri)
) SS
County of St. Louis)

Jeffry Pollock, being first duly sworn, on his oath states:

1. My name is Jeffry Pollock. I am President of J. Pollock, Incorporated, 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141. We have been retained by Florida Industrial Power Users Group to testify in this proceeding on its behalf;

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony and Exhibits, which have been prepared in written form for introduction into evidence in Florida Public Service Commission Docket No. 130040-EI; and,

3. I hereby swear and affirm that the answers contained in my testimony and the information in my exhibits are true and correct.

Jeffry Pollock

Subscribed and sworn to before me this 12 day of July, 2013.

Kitty Turner, Notary Public
Commission #: 11390610

My Commission expires on April 25, 2015.

KITTY TURNER
Notary Public - Notary Seal
State of Missouri
Commissioned for Lincoln County
My Commission Expires: April 25, 2015
Commission Number: 11390610

ENDNOTES

[1] Direct Testimony and Exhibit of William R. Ashburn at 43

[2] *Id.* at 50

[3] *Id.*

[4] *Id.* at 49.

[5] *Id.* at 51.

[6] MFR Schedule E, Volume II, at 1 and 76.

[7] MFR Schedule E, E-13a at 52.

[8] National Association of Regulatory Utility Commissioners (NARUC), *Electric Utility Cost Allocation Manual* (Jan. 1992) *at* 22.

[9] American Gas Association Rate Committee, *Gas Rate Fundamentals*, Third Edition at 268 (1978).

[10] Direct Testimony and Exhibit of William R. Ashburn at 19.

[11] *Id.* at 31.

[12] *Id.* at 32.

[13] *Id.*

[14] *Id.* at 34.

[15] Average Demand = Energy ÷ 8760 hours.

[16] *NARUC, Electric Utility Cost Allocation Manual* at 50.

[17] Deposition of William R. Ashburn at 19.

[18] *Id.* at 73.

[19] *Petition for Rate Increase by Florida Power & Light Company*, Docket No. 120015- EI, Testimony and Exhibits of Joseph A. Ender at 21.

[20] Tampa Electric Company's *Ten-Year Site Plan for Electrical Generating Facilities and Associated Transmission Lines* (January 2012 to December 2021) at 55.

[21] Florida Reliability Coordinating Council, Inc. *FRCC Handbook*, FRCC Contingency (Operating Reserve) Policy (July 7, 2011) at 1.

[22] Tampa Electric Company, *Ten-Year Site Plan for Electrical Generating Facilities and Associated Transmission Lines* (January 2013 to December 2022) at 55.

[23] *Petition of Gulf Power Company for an increase in its rates and charges*; Docket No. 891345-EI, Order No. 23573 (10/3/90) at 48.

[24] Deposition of William R. Ashburn at 89-90.

[25] TECO's Response to FIPUG's POD No. 13c.

[26] NARUC, *Electric Utility Cost Allocation Manual* at 90.

[27] TECO's Response to FIPUG Interrogatory No. 35.

[28] *In re Petition for rate increase by Tampa Electric Company*, Docket No. 080317-EI, Order (Apr. 30, 2009) at 17.

[29] *In re Petition for Issuance of a Storm Recovery Financing Order, by Florida Power & Light Company*, Order (May 30, 2006) at 25.

[30] Direct Testimony and Exhibit of Edsel Carlson at 3.

[31] Direct Testimony and Exhibit of Steven Harris at 9-10.

[32] Exhibit No.___ (SPH-1) at 19.

[33] *Id.* at 22.

[34] *Id.* at 12.

[35] TECO's Response to FIPUG's Interrogatory Set 2, No. 33.

[36] Exhibit No. ____SBY-1, Document No. 6 at 47.

[37] Exhibit No.___ (SPH-1), Table 3-1 at 15.

[38] *Id.* at 18.

[39] *Id.* at 19.

TAMPA ELECTRIC COMPANY

GSD and IS Class Load, Usage and Service Characteristics
Projected Test Year Ending December 31, 2014

Line	Description	GSD	IS
		(1)	(2)
	Size		
1	Energy (kWh/Customer/Month)	45,674	1,684,336
2	Billing Demand (kW/Customer/Month)	119	6,672
	Percent of Sales		
3	Secondary	84%	0%
4	Sub-Transmission	0.1%	72%
	Load Factor		
5	12CP	70%	110%
6	Winter CP	80%	105%
7	Summer CP	62%	132%
8	NCP	61%	67%
9	Billing Demand	52%	35%
	Coincidence Factor		
10	12CP to NCP	87%	61%
11	12CP to Billing Demand	75%	32%

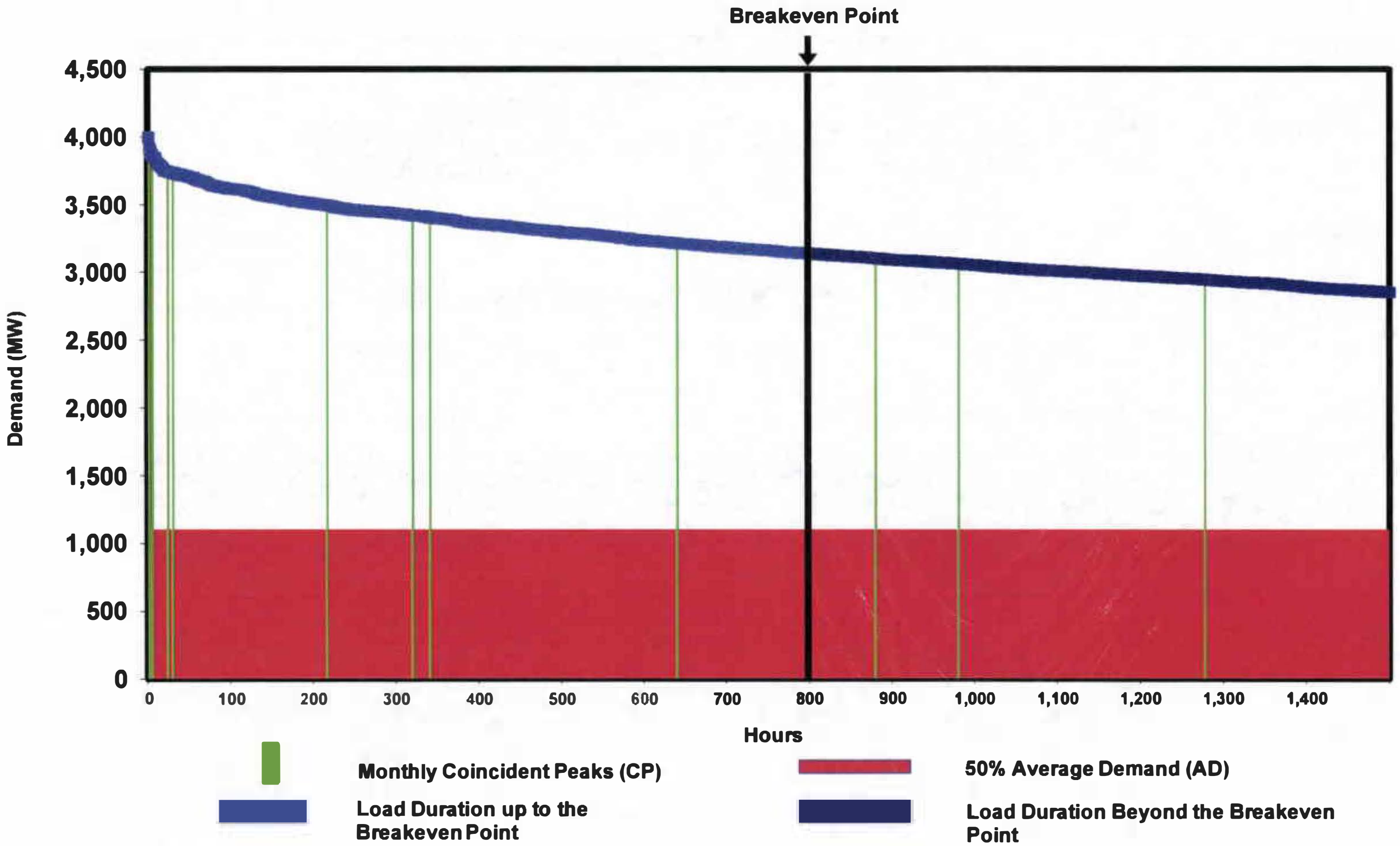
TAMPA ELECTRIC COMPANY

GSD and IS Class Load, Usage and Service Characteristics
Projected Test Year Ending December 31, 2014

Line	Description	GSD Secondary	GSD Primary	GSD SubTrans	IS Primary	IS SubTrans
		(1)	(2)	(3)	(4)	(5)
	Size					
1	Energy (kWh/Customer/Month)	38,481	788,811	94,249	690,142	3,743,737
2	Billing Demand (kW/Customer/Month)	103	1,689	2,658	1,735	16,898
	Percent of Sales					
3	Billing Demand	85.5%	13.5%	1.0%	17.5%	82.5%
4	Energy	83.7%	16.2%	0.1%	28.0%	72.0%
	Load Factor					
5	12CP	68%	81%	425%	121%	106%
6	Billing Demand	51%	64%	5%	54%	30%
	Coincidence Factor					
7	12CP to Billing Demand	75%	79%	1%	45%	29%

TAMPA ELECTRIC COMPANY

Cost Allocation Using The 12CP-50%AD Method

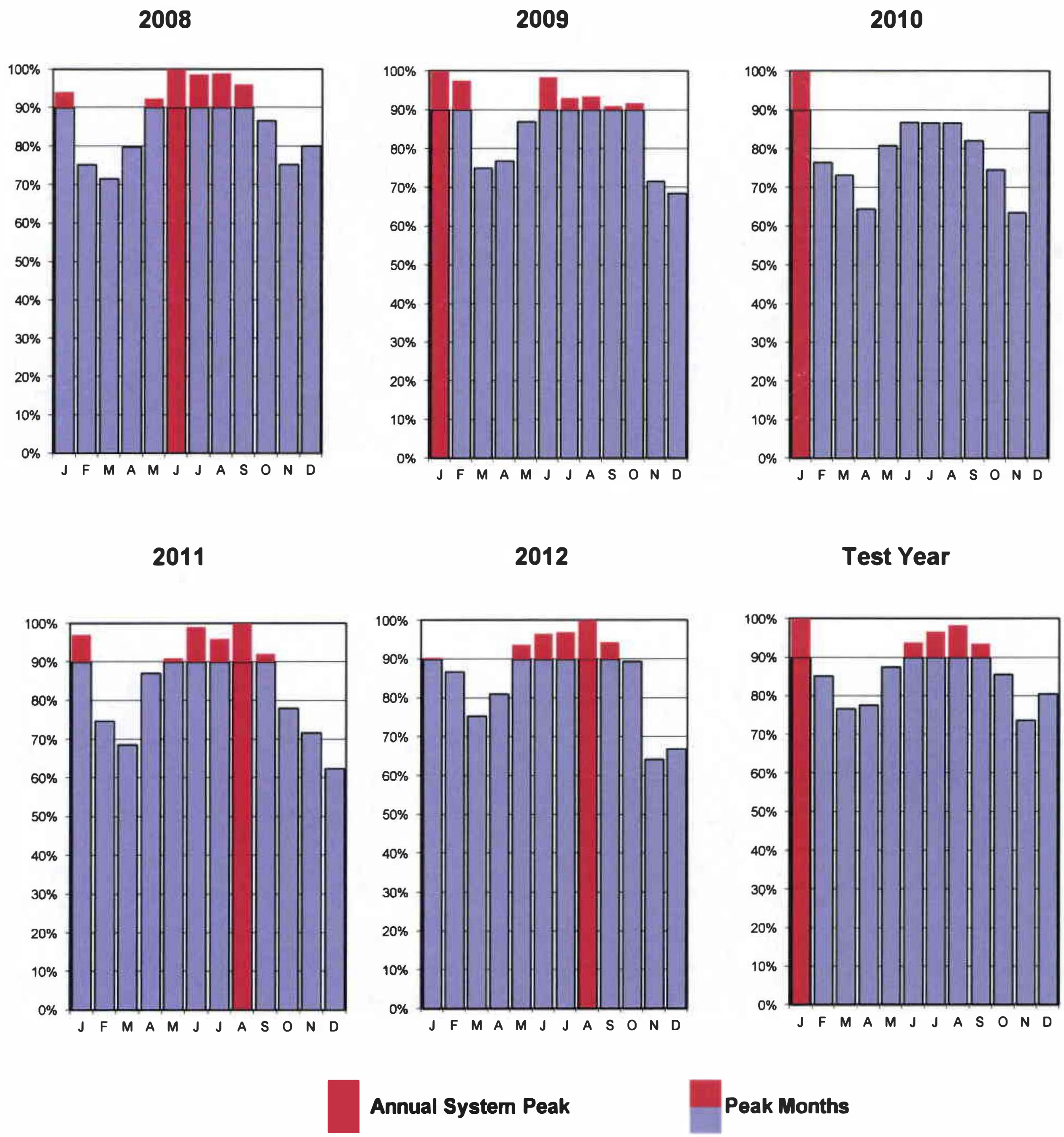


TAMPA ELECTRIC COMPANY
Operating Hours of TECO's Peaker Units

Line	Plant	Unit	2010	2011	2012	Average
			(1)	(2)	(3)	(4)
	Bayside					
1		3	1,644	482	504	877
2		4	1,501	553	517	857
3		5	1,299	565	537	800
4		6	1,184	331	522	679
	Polk					
5		2	280	525	849	551
6		3	228	1,003	1,047	759
7		4	228	1,386	1,079	898
8		5	531	1,441	1,139	1,037
	Big Bend					
9		4	1,170	255	326	584
10	Average		896	727	724	782

Source: SNL Financial

TAMPA ELECTRIC COMPANY
Analysis of Monthly System Peak Demands
As a Percentage of the Annual System Peak
for the Years 2008-2012 and Test Year



Source: TECO's Response to FIPUG's First Request for PODs No. 4

TAMPA ELECTRIC COMPANY
Analysis of System Peak Load Characteristics
2008-2012 (Actual) and Test Year

Line	Year	Peak Demand	Minimum Demand	Average Demand	Average Summer Demand	Average Non-Summer Demand	Winter Peak Demand
		(1)	(2)	(3)	(4)	(5)	(6)
		Peak Demand (MW)					
1	2008	3,952	2,829	3,452	3,887	3,235	3,709
2	2009	4,080	2,795	3,548	3,832	3,406	4,080
3	2010	4,512	2,869	3,628	3,860	3,512	4,512
4	2011	3,931	2,455	3,332	3,802	3,098	3,812
5	2012	3,892	2,500	3,359	3,774	3,151	3,517
6	2013	3,970	2,917	3,464	3,786	3,303	3,970
7	Test Year	3,999	2,948	3,494	3,820	3,331	3,999

		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
8	2008	72%	87%	20%	98%	82%	60%
9	2009	69%	87%	13%	94%	83%	57%
10	2010	64%	80%	10%	86%	78%	53%
11	2011	62%	85%	23%	97%	79%	57%
12	2012	64%	86%	20%	97%	81%	56%
13	Average (Actual)	66%	85%	17%	94%	81%	57%
14	2013	73%	87%	15%	96%	83%	55%
15	Test Year	74%	87%	15%	95%	83%	55%

Source: TECO's Response to FIPUG's First Request for PODs No. 4

Docket No. 130040-EI
Reserve Margin
Exhibit ___(JP-5)

TAMPA ELECTRIC COMPANY

Reserve Margins as a Percent of Firm Peak Demand

Line	Year	Data	Average Peak Months	Average Non-Peak Months	Difference of Non-Peak to Peak Margins
			(1)	(2)	(3)
1	2008	Actual	46%	63%	18%
2	2009	Actual	40%	66%	27%
3	2010	Actual	40%	55%	16%
4	2011	Actual	53%	72%	19%
5	2012	Actual	45%	63%	18%
6	2013	Projected	38%	63%	25%
7	2014	Test Year	37%	62%	25%

CHAPTER 6

CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT

Distribution plant equipment reduces high-voltage energy from the transmission system to lower voltages, delivers it to the customer and monitors the amounts of energy used by the customer.

Distribution facilities provide service at two voltage levels: primary and secondary. Primary voltages exist between the substation power transformer and smaller line transformers at the customer's points of service. These voltages vary from system to system and usually range between 480 volts to 35 KV. In the last few years, advances in equipment and cable technology have permitted the use of higher primary distribution voltages. Primary voltages are reduced to more usable secondary voltages by smaller line transformers installed at customer locations along the primary distribution circuit. However, some large industrial customers may choose to install their own line transformers and take service at primary voltages because of their large electrical requirements.

In some cases, the utility may choose to install a transformer for the exclusive use of a single commercial or industrial customer. On the other hand, in service areas with high customer density, such as housing tracts, a line transformer will be installed to serve many customers. In this case, secondary voltage lines run from pole-to-pole or from handhole-to-handhole, and each customer is served by a drop tapped off the secondary line leading directly to the customer's premise.

I. COST ACCOUNTING FOR DISTRIBUTION PLANT AND EXPENSES

The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts requires separate accounts for distribution investment and expenses. Distribution plant accounts are summarized and classified in Table 6-1. Distribution expense accounts are summarized and classified in Table 6-2. Some utilities may choose to establish subaccounts for more detailed cost reporting.

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant [2]		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems [1]	-	-

[1]Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

TABLE 6-2

CLASSIFICATION OF DISTRIBUTION EXPENSES[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Operation [2]		
580	Operation Supervision & Engineering	X	X
581	Load Dispatching	X	-
582	Station Expenses	X	-
583	Overhead Line Expenses	X	X
584	Underground Line Expenses	X	X
585	Street Lighting & Signal System Expenses [1]	-	-
586	Meter Expenses	-	X
587	Customer Installation Expenses	-	X
588	Miscellaneous Distribution Expenses	X	X
589	Rents	X	X
	Maintenance [2]		
590	Maintenance Supervision & Engineering	X	X
591	Maintenance of Structures	X	X
592	Maintenance of Station Equipment	X	-
593	Maintenance of Overhead Lines	X	X
594	Maintenance of Underground Lines	X	X
595	Maintenance of Line Transformers	X	X
596	Maint. of Street Lighting & Signal Systems [1]	-	-
597	Maintenance of Meters	-	X
598	Maint. of Miscellaneous Distribution Plants	X	X

[1]Direct assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classifications may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.

Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. This will ensure that costs are assigned to the correct functional groups for classification and allocation. As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related, or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.

To recognize voltage level and use of facilities in the functionalization of distribution costs, distribution line costs must be separated into overhead and underground, and primary and secondary voltage classifications. A typical functionalization and classification of distribution plant would appear as follows:

Substations:	Demand
Distribution:	Overhead Primary
	Demand
	Customer
	Overhead Secondary
	Demand
	Customer
	Underground Primary
	Demand
	Customer
	Underground Secondary
	Demand
	Customer
	Line Transformers
	Demand
	Customer
Services:	Overhead
	Demand
	Customer
	Underground
	Demand
	Customer
Meters:	Customer
Street Lighting:	Customer
Customer Accounting:	Customer
Sales:	Customer

From this breakdown it can be seen that each distribution account must be analyzed before it can be assigned to the appropriate functional category. Also, these accounts must be classified as demand-related, customer-related, or both. Some utilities assign distribution to customer-related expenses. Variations in the demands of various customer groups are used to develop the weighting factors for allocating costs to the appropriate group.

II. DEMAND AND CUSTOMER CLASSIFICATIONS OF DISTRIBUTION PLANT ACCOUNTS

When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. The reason is that costs are incurred to serve area load, rather than a specific number of customers.

Distribution substations costs (which include Accounts 360 -Land and Land Rights, 361 - Structures and Improvements, and 362 -Station Equipment), are normally classified as demand-related. This classification is adopted because substations are normally built to serve a particular load and their size is not affected by the number of customers to be served.

Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

A. The Minimum-Size Method

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method (to be discussed). The following describes the methodologies for determining the minimum size for distribution plant Accounts 364, 365, 366, 367, 368, and 369.

1. **Account 364 - Poles, Towers, and Fixtures**

   - Determine the average installed book cost of the minimum height pole currently being installed.

   - Multiply the average book cost by the number of poles to find the customer component. Balance of plant account is the demand component.

2. **Account 365 - Overhead Conductors and Devices**

   - Determine minimum size conductor currently being installed.

   - Multiply average installed book cost per mile of minimum size conductor by the number of circuit miles to determine the customer component. Balance of plant account is demand component. (Note: two conductors in minimum system.)

3. **Accounts 366 and 367 - Underground Conduits, Conductors, and Devices**

   - Determine minimum size cable currently being installed.

   - Multiply average installed book cost per mile of minimum size cable by the circuit miles to determine the customer component. Balance of plant Account 367 is demand component. (Note: one cable with ground sheath is minimum system.) Account 366 conduit is assigned, basedon ratio of cable account.

   - Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component. Balance of plant account is demand component.

4. **Account 368 - Line Transformers**

   - Determine minimum size transformer currently being installed.

- Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component.

5. **Account 369 - Services**

- Determine minimum size and average length of services currently being installed.
- Estimate cost of minimum size service and multiply by number of services to get customer component.
- If overhead and underground services are booked separately, they should be handled separately. Most companies do not book service by size. This requires an engineering estimate of the cost of the minimum size, average length service. The resultant estimate is usually higher than the average book cost. In addition, the estimate should be adjusted for the average age of service, using a trend factor.

B. The Minimum-Intercept Method

The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. This requires considerably more data and calculation than the minimum-size method. In most instances, it is more accurate, although the differences may be relatively small. The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component. The following describes the methodologies for determining the minimum intercept for distribution-plant Accounts 364, 365, 366, 367, and 368.

1. **Account 364 - Poles, Towers, and Fixtures**

- Determine the number, investment, and average installed book cost of distribution poles by height and class of pole. (Exclude stubs for guying.)
- Determine minimum intercept of pole cost by creating a regression equation, relating classes and heights of poles, and using the Class 7 cost intercept for each pole of equal height weighted by the number of poles in each height category.
- Multiply minimum intercept cost by total number of distribution poles to get customer component.

- Balance of pole investment is assigned to demand component.

- Total account dollars are assigned based on ratio of pole investment. (Transformer platforms in Account 364 are all demand-related. They should be removed before determining the account ratio of customer- and demand-related costs, and then they should be added to the demand portion of Account 364.)

2. Account 365 - Overhead Conductors and Devices

- If accounts are divided between primary and secondary voltages, develop a customer component separately for each. The total investment is assigned to primary and secondary; then the customer component is developed for each. Since conductors generally are of many types and sizes, select those sizes and types which represent the bulk of the investment in this account, if appropriate.

- When developing the customer component, consider only the investment in conductors, and not such devices as circuit breakers, insulators, switches, etc. The investment in these devices will be assigned later between the customer and demand component, based on the conductor assignment.

  - Determine the feet, investment, and average installed book cost per foot for distribution conductors by size and type.

  - Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor weighted by feet or investment in each category, and developing a cost for the utility's minimum size conductor.

  - Multiply minimum intercept cost by the total number of circuit feet times 2. (Note that circuit feet, not conductor feet, are used to get customer component.)

  - Balance of conductor investment is assigned to demand.

  - Total primary or secondary dollars in the account, including devices, are assigned to customer and demand components based on conductor investment ratio.

3. Accounts 366 and 367 - Underground Conduits, Conductors, and Devices

- The customer demand component ratio is developed for conductors and applied to conduits. Underground conductors are generally booked by type and size of conductor for both one-conductor (1/c) cable and three-conductor (3/c) cables. If conductors are booked by voltage, as between primary and secondary, a customer component is developed for each. If network and URD investments are segregated, a customer component must be developed for each.

- The conductor sizes and types for the customer component derivation are restricted to l/c cable. Since there are generally many types and sizes of l/c cable, select those sizes and types which represent the bulk of the investment, when appropriate.

  - Determine the feet, investment, and average installed book cost per foot for l/c cables by size and type of cable.

  - Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable weighted by feet of investment in each category.

  - Multiply minimum intercept cost by the total number of circuit feet (l/c cable with sheath is considered a circuit) to get customer component.

  - Balance of cable investment is assigned to demand.

  - Total dollars in Accounts 366 and 367 are assigned to customer and demand components based on conductor investment ratio.

4. Account 368 - Line Transformers

- The line transformer account covers all sizes and voltages for single- and three-phase transformers. Only single-phase sizes up to and including 50 KVA should be used in developing the customer components. Where more than one primary distribution voltage is used, it may be appropriate to use the transformer price from one or two predominant, selected voltages.

  - Determine the number, investment, and average installed book cost per transformer by size and type (voltage).

  - Determine zero intercept of transformer cost using cost per transformer by type, weighted by number for each category.

  - Multiply zero intercept cost by total number of line transformers to get customer component.

  - Balance of transformer investment is assigned to demand component.

  - Total dollars in the account are assigned to customer and demand components based on transformer investment ratio from customer and demand components.

C. The Minimum-System vs. Minimum-Intercept Approach

When selecting a method to classify distribution costs into demand and customer costs, the analyst must consider several factors. The minimum-intercept method can sometimes produce statistically unreliable results. The extension of the regression equation beyond the boundaries of the data normally will intercept the Y axis at a positive value. In some cases, because of incorrect accounting data or some other abnormality in the data, the regression equation will intercept the Y axis at a negative value. When this happens, a review of the accounting data must be made, and suspect data deleted.

The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.

Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.

When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus, the customer cost of a particular piece of equipment has no demand cost in it whatsoever.

D. Other Accounts

The preceding discussion of the merits of minimum-system versus the zero-intercept classification schemes will affect the major distribution-plant accounts for FERC Accounts 364 through 368. Several other plant accounts remain to be classified. While the classification of the following distribution-plant accounts is an important step,

TAMPA ELECTRIC COMPANY

Utilities that Classify a Portion of their Distribution Network Investment as Customer-Related

			FERC Account No.					
Line	Utility	Docket/Case No.	364	365	366	367	368	Total
			(1)	(2)	(3)	(4)	(5)	(6)
1	Alabama Power Company	18117 & 18416	100%	50%	100%	50%	28%	57%
2	Ameren Missouri	ER-2011-0028	22%	41%	68%	68%	57%	50%
3	Central Hudson Gas & Electric Company	09-E-0588	70%	71%	77%	75%	53%	67%
4	Georgia Power Company	D-31958	74%	29%	7%	8%	15%	26%
5	Gulf Power Company	110138-EI	65%	13%	4%	5%	25%	27%
6	Minnesota Power	D-E-015/GR-09-1151	35%	35%	26%	26%	22%	29%
7	Mississippi Power Company	N/A	50%	53%	46%	59%	51%	52%
8	Niagara Mohawk	10-E-0050	50%	50%	54%	53%	0%	39%
9	Northern States Power Company	E002/GR-10-971	45%	45%	71%	71%	46%	61%
10	Progress Energy Carolina	E-2,Sub 537A	56%	56%	0%	0%	30%	32%
11	South Carolina Electric & Gas Company	2009-489-E	40%	40%	41%	41%	27%	37%
12	Kentucky Utilities	2008-00251	79%	79%	79%	79%	48%	69%
13	Louisville Gas and Electric Company	2008-00252	61%	61%	63%	63%	49%	59%
14	Virginia Electric Power Company	07551-EL-AIR	45%	20%	17%	17%	10%	19%
15	Wisconsin Public Service Corporation	6690-UR-119	49%	71%	0%	72%	64%	59%

TAMPA ELECTRIC COMPANY
Minimum Distribution System (MDS) Customer Classification

Docket No. 130040-EI
Customer Classification
Exhibit ___(JP-8)

LINE	DESCRIPTION	FUNCTION	TOTAL	Acct. 360 Line Land	Acct. 360 Sub Land	Acct. 361 Structures	Acct. 362 Station Equipment	Acct. 364 Poles	Acct. 365 OH Conductors	Acct. 366 367 UG Lines	Acct. 368 Line Xformers	Acct. 369.01 OH Services	Acct. 369.02 UG Services	Acct. 370 Meters	Acct. 373 Street Lighting
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
1	DISTRIBUTION PLANT														
2	SUBSTATIONS DIRECT	DEM	-		-	-	-								
3	SUBSTATIONS COMMON	DEM	220,498		8,772	3,862	207,864								
4	SUBSTATIONS	TOTAL	220,498		8,772	3,862	207,864								
5															
6															
7	POLES DIRECT (SL)	CUST	23,228					23,228							
8	POLES PRIMARY	DEM	78,138					78,138							
9	POLES PRIMARY (MDS)	CUST	138,912					138,912							
10	POLES SECONDARY	DEM	3,401					3,401							
11	POLES SECONDARY (MDS)	CUST	6,046					6,046							
12	POLES	TOTAL	249,726					249,726							
13															
14	OH LINES DIRECT (SL)	CUST	5,804						5,804						
15	OH LINES PRIMARY	DEM	177,357						177,357						
16	OH LINES PRIMARY (MDS)	CUST	17,541						17,541						
17	OH LINES SECONDARY	DEM	30,335						30,335						
18	OH LINES SECONDARY (MDS)	CUST	3,000						3,000						
19	OH LINES	TOTAL	234,037						234,037						
20															
21	UG LINES DIRECT	CUST	-							-					
22	UG LINES PRIMARY	DEM	257,685							257,685					
23	UG LINES PRIMARY (MDS)	CUST	25,485							25,485					
24	UG LINES SECONDARY	DEM	112,959							112,959					
25	UG LINES SECONDARY (MDS)	CUST	11,172							11,172					
26	UG LINES	TOTAL	407,301							407,301					
27															
28	TRANSFORMERS DIRECT	CUST	-								-				
29	TRANSFORMERS	DEM	377,975								377,975				
30	TRANSFORMERS (MDS)	CUST	119,360								119,360				
31	TRANSFORMERS	TOTAL	497,335								497,335				
32															
33	SERVICES	CUST	194,385									78,858	115,527		
34	METERS	CUST	80,375											80,375	
35	INTERRUPTIBLE EQUIPMENT	CUST	1,643				966		678						
36	STREET LIGHTING	CUST	176,898												176,898
37															
38	DISTRIBUTION PLANT	DEM	1,258,348	-	8,772	3,862	207,864	81,539	207,692	370,644	377,975	-	-	-	-
39	DISTRIBUTION PLANT	CUST	803,851	-	-	-	966	168,187	27,023	36,657	119,360	78,858	115,527	80,375	176,898
40															
41	DISTRIBUTION PLANT	TOTAL	2,062,199	-	8,772	3,862	208,830	249,726	234,715	407,301	497,335	78,858	115,527	80,375	176,898
42	CUSTOMER RELATED (ACCTS 364-368)	TOTAL	350,550					168,187	26,345	36,657	119,360				
43	ACCTS. 364-368	TOTAL	1,388,399					249,726	234,037	407,301	497,335				
44	PERCENT CUSTOMER RELATED		25%												

Docket No. 130040-EI
TECO Outage Expense
Exhibit___(JP-9)

TAMPA ELECTRIC COMPANY

Adjustment to Test Year Production Operation and Maintenance Expense
For Abnormal Planned Outage Expenses
Excluding Peaking Units
Year Ended December 31, 2014

		Planned Outage Expense		Test Year Vs. Historical Period Average			Test Year	
Line	Unit	Test Year	Average 2008-2014	Amount	Percent	Adjustment	Adjusted Expense	Percent Difference
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Big Bend 1	$5,400,000	$1,521,222	$3,878,778	72%	$0	$5,400,000	255%
2	Big Bend 2	$950,000	$1,635,232	($685,232)	-72%	$0	$950,000	-42%
3	Big Bend 3	$950,000	$2,084,174	($1,134,174)	-119%	$0	$950,000	-54%
4	Big Bend 4	$5,700,000	$1,937,926	$3,762,074	66%	($3,665,178)	$2,034,822	5%
5	Bayside 1	$600,000	$787,596	($187,596)	-31%	$0	$600,000	-24%
6	Bayside 2	$600,000	$1,323,031	($723,031)	-121%	$0	$600,000	-55%
7	Polk 1	$3,100,000	$3,563,571	($463,571)	-15%	$0	$3,100,000	-13%
8	Total	$17,300,000	$12,852,752	$4,447,248	26%	**($3,665,178)**	$13,634,822	
9	Florida Retail Allocation Factor					**100.00%**		
10	Adjustment					**($3,665,178)**		

Source: TECO Response to FIPUG Interrogatory No. 37.

Docket No. 130040-EI
TECO Storm Damage
Exhibit ___(JP-10)

TAMPA ELECTRIC COMPANY
Historical Storm Damage Expense
Year Ended December 31, 2014

Line	Year	Storm	Storm Recovery Expense ($000)
		(1)	(2)
1	**2000**	**No Charges**	**$0**
2	**2001**	**No Charges**	**$0**
3	**2002**	**No Charges**	**$0**
4	**2003**	**No Charges**	**$0**
5	2004	Charley	$14,017
6	2004	Frances	$25,102
7	2004	Jeanne	$32,846
8	**2004**	**Total**	**$71,965**
9	2005	Charley	$372
10	2005	Frances	$1
11	2005	Jeanne	$2,139
12	2005	Storm Cost Adjustment	($118)
13	**2005**	**Total**	**$2,394**
14	**2006**	**Storm Cost Adjustment**	**$220**
15	**2007**	**Storm Cost Adjustment**	**($12)**
16	**2008**	**Fay**	**$1,658**
17	**2009**	**No Charges**	**$0**
18	**2010**	**No Charges**	**$0**
19	**2011**	**Tornado Storm**	**$1,925**
20	**2012**	**Debby**	**$1,185**
21		**Annual Average**	**$6,103**
22		**Annual Average Excluding 2004**	**$405**

Source: Response to FIPUG Interrogatory No. 35