BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase
by Tampa Electric Company
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DOCKET NO. 080317-EI

FILED: November 26, 2008

DIRECT TESTIMONY

OF

HUGH LARKIN, JR. CPA

On Behalf of the Citizens of the State of Florida

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TAMPA ELECTRIC COMPANY

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I INTRODUCTION

Q. WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?

A. My name is Hugh Larkin, Jr. I am a Certified Public Accountant licensed in the States of Michigan and Florida and the senior partner of the firm of Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES, PLLC.

A. Larkin & Associates, PLLC, is a Certified Public Accounting and Regulatory Consulting Firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorney general, etc.). Larkin & Associates, PLLC, has extensive experience in the utility regulatory field as expert witnesses in more than 800 regulatory proceedings including numerous electric, water and sewer, gas and telephone utilities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC COMMISSION?

A. Yes. I have testified before the Florida Public Service Commission on numerous occasions during the last 32 years.

Q. HAVE YOU PREPARED AN APPENDIX WHICH DESCRIBES YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. I have attached Appendix I which is a summary of my regulatory qualifications and experience.

Q. BY WHOM WERE YOU RETAINED?

A. Larkin & Associates, PLLC was retained by the Florida Office of Public Counsel ("OPC"). Accordingly, I am appearing on behalf of the Citizens of Florida ("Citizens").

II <u>PURPOSE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Our firm was asked by the Public Counsel to analyze the $228,167,000 rate increase requested by Tampa Electric and provide our analysis of what rate increase is justified. The increase requested amounts to a 26.4% increase in base rates over the projected 2009 base rate revenue. This increase would be in addition to the fuel cost increases already being passed on to ratepayers.

Q. WHAT ARE THE RESULTS OF YOUR ANALYSIS AND WHAT IS YOUR RECOMMENDED INCREASE FOR TAMPA ELECTRIC?

A. We are recommending that the Commission allow a rate increase no greater than $38,689,000 for the Tampa Electric. This recommendation is shown on my Exhibit HL-1, Schedule A, line 8. My Exhibit HL-1 incorporates the recommendations of Dr. J. Randall Woolridge and Helmuth W. Schultz, III. I am sponsoring Exhibits HL-1 and HL-2.

Q. HOW WOULD YOU CHARACTERIZE THE COMPANY'S REQUESTED INCREASE?

A. I would characterize the Company's filing as grossly overstated. The Company has included a number of gimmicks and cost over statements that have added significantly to the Company's revenue requirement request.

Q. WHAT PARTICULAR REQUESTS DO YOU VIEW AS THE MOST EGREGIOUS?

A. 1) The Company has made two adjustments to its capital structure which I would consider gimmicks or attempts to end run prior Commission policy. The first of these is to add $77 million to the Company's debt with a corresponding increase to equity. The Company states that this adjustment is necessary to account for additional risks associated with long-term purchased power agreements that are not accounted for as liabilities on the Company's balance sheet. Dr. Woolridge has addressed this in his testimony and has stated that such an adjustment is not reasonable or necessary.

2) The second adjustment to the capital structure was made to the Company's short-term debt and deferred income tax components to reduce those components for what the Company states are the debt and deferred income tax associated with financing under recoveries of fuel and purchased power costs. The effect of this adjustment is to raise the overall cost of capital and thereby allow the Company to earn a rate of return through the cost of capital in addition to the rate of return which the Commission allows when these under recoveries are passed on to ratepayers in subsequent fuel proceedings. This is an end run of the Commission's prior policy of not allowing receivables from customers for under recovered fuel in the working capital requirements. Also, as discussed by Dr. Woolridge, the Company's request for a 12% return on equity is well above current requirements.

3) In addition, Tampa Electric has included in the filing the annualization of certain costs for construction projects, which in my view, violates the projected test year principles and my understanding of past Commission policy. These annualizations have the effect of increasing the revenue

requirement by approximately $29 million. Even though the Company has been asked on two separate occasions to provide references to Commission orders which allow these types of annualizations, the Company has refused to do so.

4) The Company is also proposing certain changes to the rate structure to invert the energy and fuel charge, change service charges and consolidate lighting tariffs and changes to interruptible customer rates and time of day rates. Even though changes to rate schedules are common in the industry, particularly after changes in fuel costs or base rates, the Company proposes to increase plant in service by $2.4 million and amortization expenses by approximately $550,000 to account for estimated cost to change the Customer Information System for the above listed changes. The impact of the rate base addition and the amortization would increase rates by $630,000.

5) The Company is proposing a 400% increase in the storm damage accrual. The accrual would increase from $4 million to $20 million annually. This increase has been requested even though the Company has only experienced one year in which storms have struck its service territory, and the reserve was more then adequate to reimburse the Company for costs normally recognized by this Commission as recoverable as storm damage.

6) The Company is also asking for an automatic adjustment clause to recoup investments in transmission facilities referred to as a "Transmission Base Rate Adjustment Clause". I am unaware of this Commission or any other state utility commission in the country authorizing an automatic adjustment clause for the recovery of transmission facilities. As discussed in detail later in this testimony, base rates are designed to recoup this type of cost. With the lead time involved in a transmission project, if the Company were not earning within its authorized ROE it would have plenty of opportunity to seek a rate increase. However, customers will pay more for transmission if the Company is earning within its authorized ROE and the Company was also permitted to recoup transmission costs through an automatic adjustment clause.

7) The Company is proposing through an outside consultant a change in the amortization of investment tax credits which would increase rates by $3,365,000. The Company has been audited by the IRS for numerous years and the IRS has never challenged the amortization of the investment tax credit. This is a proposed change for a problem which does not exist and will increase rates. Mr. Schultz addresses this issue in his testimony.

8) The Company is proposing another tax change. Although it does not have a major impact on revenue requirements ($230,000), the Company is proposing, through the same outside consultant, a change in the calculation of deferred income taxes. This change, as testified to by Mr. Schultz, is not justified. It is based on private letter rulings to other utilities and not to Tampa Electric. Even if one were to apply those letter rulings to Tampa Electric, the factual situation set out in those letter rulings does not match this Commission's ratemaking methodology.

9) The Company is proposing to add to rate base a deferral for dredging costs for which there is no justification. The Company states that the dredging costs will amount to $6.9 million and occur every five years. However, the last time the Company incurred dredging costs was in 2002 and the net cost was $1,288,169.73, far less than the requested $6.9 million. Additionally, under the Company's purported five year schedule, dredging would have occurred in 2007, not 2009.

10) Finally, the Company wants to collect a bad debt provision on Sale for Resale. These are sales to municipalities and have not been subject to bad debt provisions in the past. It is unlikely that this type of customer would fail to pay their bill.

III TRANSMISSION BASE RATE ADJUSTMENT CLAUSE

Q. TAMPA ELECTRIC HAS REQUESTED THAT THE COMMISSION APPROVE WHAT IT TERMS A "TRANSMISSION BASE RATE ADJUSTMENT" ("TBRA"). IS AN AUTOMATIC ADJUSTMENT CLAUSE FOR TRANSMISSION INVESTMENT EITHER NECESSARY OR JUSTIFIED?

A. Definitely not. The justification for Tampa Electric requesting an automatic adjustment clause to recover transmission investment is contained in the testimony of Witness Regan B. Haines. Starting at page 40, Mr. Haines discusses the history of transmission planning in the state of Florida; this includes the failure of the implementation of a Regional Transmission Organization ("RTO") which would have been known as GridFlorida. He states that the Florida Public Service Commission is interested in promoting wholesale competition in peninsula Florida and to that end will monitor and promote areas where efficiencies may be gained in a cost-effective manner. One of the processes which the Commission quoted in its GridFlorida order was the initiative that regional transmission planning be reviewed and monitored by the Florida Reliability Coordinating Council, Inc. ("FRCC"). The FRCC is the regional reliability coordinator with the authority to act and direct actions in accordance with relevant North American Electric Reliability Council ("NERC") requirements. NERC sets reliability standards for most entities transmitting energy in the United States and Canada. The FRCC has specific procedures and guidelines to support and supplement NERC reliability standards that ensure reliability for the region is maintained by all operating entities which might affect the reliability of the bulk power transmission system in Florida.

Q. WHAT RELEVANCE DOES THE FRCC HAVE TO TAMPA ELECTRIC'S REQUEST FOR AN AUTOMATIC ADJUSTMENT CLAUSE FOR TRANSMISSION INVESTMENT?

A. Tampa Electric states that because the FRCC is reviewing regional transmission planning documents and that the Federal Energy Regulatory Commission ("FERC") has required the development of a cost allocation methodology for regional transmission expansion which the FRCC has developed to comply with the FERC requirements, this process might require Tampa Electric to incur transmission expansion costs. Tampa Electric implies that the FRCC review may somehow impose costs on Tampa Electric for transmission development over the next five years, which it states would be "... virtually impossible to predict Tampa Electric's share of expected expenditures accurately."[1] Presumably, this is the basis for Tampa Electric's request for an automatic adjustment clause for transmission investment.

Q. IS IT YOUR UNDERSTANDING THAT THE FRCC CAN IMPOSE CONSTRUCTIONAL REQUIREMENTS ON TAMPA ELECTRIC?

[1] Testimony of Regan B. Haines, p. 47.

A. No, it is not. The facilities which are constructed on the Tampa Electric system are fully under the control of the Company and the Florida Public Service Commission. While the FRCC may suggest that a particular construction project be undertaken by Tampa Electric, they cannot require them to do so. Tampa Electric states the following:

> However, given the regional planning process and the dynamic nature of generation and transmission needs for the next five years, it is virtually impossible to predict Tampa Electric's share of expected expenditures accurately.[2]

The fact that FRCC is reviewing regional transmission plans does not impose any additional financial requirements on Tampa Electric. Construction expenditures over lengthy periods of time have always been difficult to project. However, that does not require or support an automatic adjustment clause.

Q. THE COMMISSION HAS APPROVED OTHER AUTOMATIC ADJUSTMENT CLAUSES. CAN YOU DISCUSS THOSE CLAUSES AND HOW THEY DIFFER FROM TRANSMISSION COST EXPENDITURES?

A. Yes. The major automatic recovery clause which the Commission has authorized is the Fuel and Purchased Power Cost Recovery Clause. This clause is designed to compensate for day-to-day fluctuations in the cost of fuel which cannot be anticipated in base rates. Since fuel varies both as to price and the amount consumed almost on a daily basis, it is not

[2] Ibid.

possible to anticipate the actual level or cost of fuel for any length of time. The clause is necessary to ensure that there is a reasonable matching of fuel costs with fuel revenues. The fuel clause recovers both internally generated fuel costs, that is, fuel used in generators on the Company's own system, and also the fuel component of Purchased Power Cost.

The Commission has also authorized a Capacity Cost Recovery Clause. This clause is designed to recover the capacity component of Purchased Power Cost. This clause was designed in order to allocate capacity cost to customer classes based on demand rather than energy consumption. Like the fuel costs, capacity costs related to Purchased Power are difficult to predict and control on a long-term basis and cannot be accurately anticipated in order to be included in rate base.

The Commission has authorized a Generating Performance Incentive Factor ("GPIF"). The GPIF program is part of the Fuel Cost Recovery Clause. It was designed to promote the efficient operation of electric generating units. By promoting the efficient operation of the electric generating units, fuel costs are reduced and thus, a benefit is given to ratepayers through the reduction of fuel costs.

The Environmental Cost Recovery Clause ("ECRC") is designed to recover environmental costs. This clause was designed to allow investor-owned utilities the opportunity to recover costs incurred in complying with new environmental requirements. This clause allows the utility to recover incremental changes in environmental regulations that result in cost increases. Since environmental costs are not under the control of the utilities, but are mandated by regulatory agencies, the clause allows the company to recover environmental costs not under its control and not included in base rates.

The Energy Conservation Recovery Clause ("ECRC") allows the investor-owned utility the opportunity to recover costs associated with Demand Side Management Programs. Demand Side Management Programs are designed to effectively reduce electric consumption and/or lower peak demand. This is beneficial to ratepayers since lower demand and consumption will reduce the need for new generating facilities and purchased power.

In addition, recently enacted Florida law created clause recovery of certain nuclear construction costs and costs associated with coal gasification projects. This law provides that the recovery of these costs is necessary outside of base rates.

The above paragraphs briefly summarize the reason and purpose of the six adjustment clauses which are available for use by electric utilities in

Florida. Each of the clauses provides recovery of costs outside of base rates. Although each of these costs is under the control of the utility, the Commission or Legislature have decided to diminish the utilities exposure to the under-recovery of these costs. Some of the clauses provide a benefit to ratepayers through the reduction of costs. There is no need to remove transmission costs from base rates which will, in effect, reduce the Company's risk to plan and properly build transmission facilities. There is also no benefit to ratepayers to do so.

Transmission facilities are planned several years in advance. First, a cost benefit analysis must be made to determine whether the proposed transmission facility is really needed and necessary. After it is approved, the right-of-way for a transmission facility must be purchased and environmental concerns dealt with and then the utility can estimate the cost associated with constructing this facility. This takes several years and is not a cost which is unknown, or uncontrollable by a utility. If, in fact, base rates are not sufficient to provide a return on these facilities, then the utility has ample time to file a rate request which incorporates the projected cost of this construction and any operating expenses. There is no need for an automatic adjustment clause since the time frame in determining the need and construction of any facilities allows the utility ample time to request changes in base rates, if necessary.

The Company, at present, recovers almost 60% of its revenue requirements through adjustment clauses. Adding another clause will shift additional risk to ratepayers and add additional administrative costs to the Commission staff and the OPC. The timeframe for reviewing and auditing another clause would be relatively short and will place additional burdens on the Commission.

I am recommending that the Commission not allow the Company's requested Transmission Base Rate Adjustment ("TBRA"), because it is bad public policy for the reasons stated above and there is no justification for such a clause.

IV <u>RATE BASE</u>

<u>Annualization of Plant-In-Service</u>

Q. WOULD YOU PLEASE DESCRIBE WHAT THE COMPANY IS PROPOSING REGARDING CERTAIN PLANT ADDITIONS WHICH WOULD OCCUR IN THE MONTHS OF MAY, SEPTEMBER AND DECEMBER OF 2009?

A. The Company is proposing to annualize the costs of two combustion turbines ("CTs") that are currently scheduled to go into service in May of 2009, three combustion turbines, that are scheduled to go into service in September 2009, and a rail facility that is scheduled to be finished in

December of 2009. That is, the Company is stating that these facilities should be assumed to be in-service as of January 1, 2009, and not the actual in-service date. This has the effect of increasing the Company's rate request by approximately $29 million.

Q. HAS THE COMPANY BEEN ASKED TO PROVIDE REFERENCES TO COMMISSION ORDERS OR PRECEDENT WHICH ALLOWS FOR THE ANNUALIZATION OF PLANT AS IF IT HAD BEEN IN SERVICE FOR THE ENTIRE TEST YEAR?

A. Yes. However, the Company has refused to provide any references. When asked, the Company has stated on two occasions that:

> The company objected to this request on the grounds that it cannot respond to the request without disclosing materials prepared in anticipation of litigation and the mental impressions and trial strategies of its attorneys, all of which are privileged and beyond the scope of discovery.

Obviously, if the Company cannot provide documentation as to the basis of these adjustments, they should not be approved by the Commission.

Q. WHAT IS YOUR UNDERSTANDING OF THE COMMISSION'S POLICY REGARDING THE USE OF FUTURE TEST YEARS?

A. Up until the early part of 1981, this Commission used a historical test year to set rates in rate cases. Annualization adjustments, such as what the Company is proposing, were used to adjust an historical test period so that the test year was representative of the costs that would be incurred when the new rates were implemented. Additionally, corresponding changes in the number of customers and revenues were also annualized along with certain expenses. At one point before 1981, the Commission sought to use an end of test year rate base with historical average revenues and expenses. This methodology was rejected by the Florida Supreme Court because of the mismatching of investment and earnings. Subsequently, the Commission adopted a projected test year. This methodology, which uses forecasted data for a subsequent 12-month period, matched average rate base investment to average expenses and revenues. Thus, the projected test year is supposed to result in a matching of the Company's projected investment with its projected earnings during the future test period on a month-to-month basis and annual basis.

Generally, a Company brings on plant as new customer growth can support the additional kilowatts generated by the new plant plus meeting the required reserve margin. When the costs of new plant is included in rates without accounting for the new customer growth that would otherwise support the new plant, current customers end up paying more than they should for the additional plant. Under Tampa Electric's annualization proposal, the cost of the new plant would be put in rates without accounting for the new customer growth that would otherwise support those costs. As a result, the increased costs are spread over a smaller customer base and the current customers pay more than their fair share.

Thus, no annualizations of plant additions should be allowed when plant additions are revenue-producing or growth-related assets designed to increase the Company's ability to generate, transmit and deliver additional kilowatt hours of generation. If the Commission allows an adjustment for revenue-producing plant that increases capacity without an adjustment to recognize the increased customers and/or demand, this will overstate the revenue requirements used to create the rates charged to customers. This type of allowance will create a mismatch between the projected test year revenues and expenses and the projected investment related to assets (such as the CT's) that generated the test period revenues. The end result in setting rates should be an appropriate matching of the period used for forecasting generally coinciding with the period in which rates would become effective, there would be a matching of investment and operating revenues and expenses.

Q. WHAT DOES THE COMPANY STATE REGARDING THE PURPOSES OF ADDING THE COMBUSTION TURBINES AND THE RAIL FACILITY?

A. The Company states that the two combustion turbines to be added in May and the three to be added in September are necessary to maintain the Company's reserve at 20% as agreed to in a stipulation regarding Tampa

Electric, Florida Progress and FP&L. See Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 981890-EU. In order for the reserve margin to be in a state of decline, that is, the reserves decreasing below a 20% reserve margin there has to be growth in sales. In other words, if, in fact, these combustion turbines are necessary and used and useful, the Company must be projecting additional sales so that the utilization of the combustion turbines is a necessary addition to the Company's generation portfolio. The sales growth would be generating additional income as sales growth would require the CTs be in service to meet demand. By annualizing these plant additions and pretending that they went into service on January 1, 2009, any sales growth which the Company experiences because of the availability of the CT's in 2010 will not be reflected in the test year. Sales growth in the year 2010, when these units will provide a full year of service and beyond, will not be matched with the cost because that cost will have been already reflected in rates established for the test year 2009 when these assets would only be in service for part of the year. Revenues generated from these facilities in 2010 and beyond will be a windfall to the Company.

In addition, there are cost savings which the Company did not reflect in the annualization of these units. Company witness Mark J. Hornick states, at page 12 of his testimony:

> These machines offer a more economic option for meeting the company's operating reserve requirements than by spinning reserve, which requires keeping large units running.

Q. PLEASE ADDRESS THE RAIL PROJECT.

A. The rail project, which the Company states will be in-service December 2009, is designed to ". . . afford the company more options to procure coal from additional sources resulting in customer benefits."[3]

Also in response to OPC's Interrogatory No. 107, the Company stated the following:

> During Tampa Electric's solicitation for coal and solid fuel transportation in 2008 for services beginning in 2009, the company issued a request for proposals and determined, with the assistance of its third-party consultant, Energy Ventures Analysis, Inc., that bimodal sources of solid fuel transportation combined with certain coal mines yielded cost-effective alternatives. Upon final review, the company determined that the most cost effective delivered cost of coal varies by mine, with some coals being more cost-effective via a waterborne route while others are most cost-effective delivered by rail. <u>A bimodal solution broadens Tampa Electric's fuel source options and provides a stimulus for lower delivered cost of fuel.</u> The results of the 2008 solicitation for coal and solid fuel transportation services supports the conclusions reached in the Hill & Associates rail feasibility study. (Emphasis added.)

The benefits to customers can only be a reduction in fuel cost. Reduced fuel costs will stimulate additional sales and thus, provide a return on the Company's investment. The facility used to provide the lower cost coal is

[3] Testimony of Mark J. Hornick, pp. 15 and 16.

utilized to reduce fuel costs. By annualizing the rail facility for the entire year 2009 (when they have only been in service for one month or less), the Company earns a return as if the lower fuel costs would not exist in future periods. Moreover, the future increases in sales in the year 2010 and beyond when this rail facility will be fully in-service and utilized for an entire 12-month period will only fall to the benefit of the shareholders while the ratepayers have the burden of providing the carrying cost as if this facility had no productive benefit to the Company.

Q. DID YOU ASK FOR A COST BENEFIT ANALYSIS RELATED TO THE CONSTRUCTION OF THIS FACILITY?

A. Yes. The OPC's POD No. 103 required that the Company "Provide the documentation including contracts, cost benefit analysis, detailed project costs and any other supporting project documents which support the cost of $46,468,000 on a total Company basis of the rail project shown on Schedule B-2, page 2 of 4."

Q. DID YOU RECEIVE A COST BENEFIT ANALYSIS?

A. No, we did not. We received some documents which purport to be the cost analysis for the construction of the project which the Company says were preliminary and depended on inputs by the rail provider. In OPC Interrogatory No.107, the Company stated there was a cost benefit analysis, but it was not provided. I question the accuracy of what the

Company has provided as backup for this adjustment. Although the Company's testimony and descriptions describe this as an offloading facility, the cost documents indicate there is an Option Two which is a train loading structure. It is not clear why the Company would need a train loading facility in addition to an offloading facility. There would be substantial reductions in the costs the Company is projecting if only the offloading facility were included.

Q. ARE THERE OTHER CONCERNS WITH THE RAIL FACILITY COST?

A. Yes. The Company was requested in OPC Interrogatory No. 46 to explain whether the rail carrier was going to absorb some of the cost associated with this expansion and if not, explain why not. The response was that it was premature to address this matter. This is not an appropriate response. Since the Company is seeking recovery of the facilities in rates any cost reimbursed is significant. The rail carrier stands to benefit significantly from the movement of additional coal and it would be appropriate for the rail carrier to absorb at least some of the costs. This would not be uncommon.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE REQUESTED ANNUALIZATION ADJUSTMENTS?

A. I am of the opinion that the requested annualizations are a violation of the basic ratemaking principle of matching costs with benefits. The matching principle would not allow the annualization of production facilities which would have the impact of producing additional kilowatt hours, or facilities which have the affect of reducing costs or making a facility more productive, which the rail facility would have. I am recommending that the annualization of the five combustion turbines and the rail facility not be approved by the Commission. These costs should be reflected in rate base and the operating income statement as of the projected date that the assets are placed into service. Schedule B-2 shows the adjustments I am recommending to Plant-In-Service and O&M expense to remove these annualizations.

<u>Plant in Service Projections</u>

Q. WHAT ADJUSTMENTS ARE YOU PROPOSING TO THE COMPANY'S PLANT IN SERVICE?

A. The rate base requested by the Company utilizes a projected test year ending December 31, 2009. That means the Company must project by month each component of the rate base, i.e., plant in service, accumulated depreciation, plant held for future use and working capital. It is unlikely that the Company's projected balances almost two years into the future are without inaccuracies. The best method of testing the Company's projection methodologies is to compare actual results to projections and draw a conclusion regarding whether the projected amounts are overstated or understated based on comparisons of actual to projected amounts.

Q. HAVE YOU PERFORMED SUCH AN ANALYSIS?

A. Yes. I have been able to compare the Company's projections of plant in service balances for the months January through September of 2008 of the 13-month average for the year ending December 31, 2008, which is the year prior to the projected test year. The Company was only able to provide actual data through September 2008.

Q. HAVE YOU PREPARED A SCHEDULE THAT SHOWS THE RESULTS OF YOUR COMPARISON?

A. Yes, I have. On my Schedule B-3, attached to my prefiled testimony as Exhibit HL-1, I have compared the Tampa Electric projected plant in service balance to the actual plant in service balance as found in Tampa Electric's General Ledger, Trial Balance and Balance Sheet reports provided in response to OPC POD Nos. 5, 47 and 116 for the year 2008.

Q. WOULD YOU DISCUSS THOSE COMPARISONS AND YOUR PROPOSED ADJUSTMENT TO PLANT IN SERVICE?

A. On Exhibit HL-1, Schedule B-3, I have compared the actual balances of electric plant in service to the Company's projections on MFR Schedule B-3, page 4 of 9, for the projected prior year ended December 31, 2008.

This comparison of actual balances, as reported in the Company's accounting records, to the Company's projected balances will indicate whether there is a trend in the Company's projection methodology. In other words, if all of the projections exceed the actuals in months in which the Company only had to project expenditures and retirements for nine months into the future, then it is likely that the same trend of over projecting plant balances would continue into the future and would affect the test year 13-month average ending December 31, 2009.

Looking at the results shown on my Schedule B-3, each month (January 2008 through September 2008) shows that the Company's projected plant in service balance exceeded the actual in every month.

Q. WHAT RELEVANCE DOES THE YEAR 2008 HAVE TO THE PROJECTED TEST YEAR 2009?

A. The Company likely utilized the same projection methodology for both the prior year ended December 31, 2008, and the test year ended December 31, 2009. The 13-month average for the plant in service balance for the test year ended December 31, 2009, starts out with the same balance for December resulting from the projections for the prior year ended December 31, 2008. Any inaccuracies in 2008 are carried forward into the 2009 test year because the December 31, 2008, balance becomes the first month in the 13-month future test year average, and the same projection methodology is used.

Q. WHAT ADJUSTMENT ARE YOU PROPOSING?

A. I have calculated the difference between the actual plant in service balance and the projected plant in service balance for each of the actual months available. I have also calculated the percentage difference by which the projected balance exceeded the actual balance. I then took the average percentage overstatement of the balance of plant in service and applied it to the 13-month average plant in service balance projected by the Company on MFR Schedule B-3 for the 13-month average ending December 31, 2009. This results in a reduction to plant in service for the projected test year 2009 of $53,958,000 on a total Company basis. The jurisdictional adjustment is $51,969,000.

Q. DID YOU DO A SIMILAR STUDY RELATED TO THE ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION?

A. Yes, I did.

Q. WHAT WERE THE RESULTS OF THAT STUDY?

A. I found the average balance for the months January through July of 2008[4] to be overstated as well. Accordingly, I have made a similar adjustment to

[4] The information provided by the Company for August 2008 and September 2008 did not show the actual accumulated provisions for depreciation.

Accumulated Provision for Depreciation and Amortization. This results in a reduction to Accumulated Provision for Depreciation and Amortization in the amount of $8,500,000 on a total Company basis and $8,187,000 on a jurisdictional Company basis. Additionally, Depreciation expense should also be adjusted since any overstatement of the Accumulated Provision resulted from the overstatement of Depreciation expense.

CIS Upgrades

Q. TAMPA ELECTRIC HAS ADDED TO JURISDICTIONAL RATE BASE AN AMOUNT OF $2,445,000 WHICH IS LABELED AS CIS UPGRADE. IN ADDITION, OPERATING EXPENSES HAVE BEEN INCREASED BY $558,000 RELATED TO THE AMORTIZATION OF THIS UPGRADE. DO YOU AGREE THAT SUCH AN ADJUSTMENT SHOULD BE MADE?

A. No. The Company's justification for this increase in rate base and depreciation expense is that the Company will be requesting changes in customer rates and that the implementation of these changes will necessitate the Company making changes to the customer rate schedules included within the customer information system ("CIS"). Included as Exhibit HL-2, Schedule 1, is the Company's response to OPC's POD No. 98. This document is a Tampa Electric internal document which summarizes program costs. This document only discusses in generalities the changes proposed to customer information system. None of the items are unusual changes to a customer information system and would be done routinely when rates are changed. Additionally, the changes which the Company anticipates may never be approved by the Commission. There is no cost benefit analysis provided nor is there any detailed calculation of how the proposed dollars would be used. It is my opinion that these costs, if they are incurred, would be incurred in the normal course of business in any year base rates or fuel rate changes are made and does not justify separate adjustment. I am therefore recommending that the Company's request for an increase in rate base of $2,445,000 for the supposedly extraordinary CIS upgrade not be approved and that depreciation expenses be decreased by $558,000.

Amortize Dredging O&M

Q. TAMPA ELECTRIC IS REQUESTING A RATE BASE ADJUSTMENT TO INCLUDE THE UNAMORTIZED PORTION OF $6.9 MILLION DREDGING COSTS AT ITS BIG BEND FACILITY. WOULD YOU PLEASE DISCUSS THAT ADJUSTMENT?

A. Tampa Electric claims that it incurs costs to dredge out the channel at the Big Bend generating station. The Company claims that these costs are incurred every five years and that dredging costs will be incurred in the year 2009. Tampa Electric witness Hornick states that Tampa Electric has included "roughly" $6.9 million (total Company) in its 2009 production O&M budget for channel dredging expense. Tampa Electric has removed from operating expenses $5,320,000 (jurisdictional) of the $6.9 million (total Company), which leaves an expense of $1,330,000 (jurisdictional). Tampa Electric has added to the rate base an amount of $2,657,000 which it states represents the 13-month average of the unamortized jurisdictional balance.

Q. DO YOU AGREE WITH WHAT THE COMPANY IS PROPOSING?

A. No, I do not. We asked the Company to provide the costs associated with the last two dredgings which took place at the Big Bend generating station. In response to OPC POD No. 100, we were able to determine that in the year 2002 the Company incurred total dredging costs of $2,346,105.81, with $1,288,169.73 allocated to Tampa Electric and the remainder of $1,057,936.08 allocated to an organization designated as IMC. Prior to the 2002 dredging, the Company incurred dredging costs which started in 1997 and finished in 1998. The total cost of the 1997 dredging was $1,329,989.47 with $228,400 allocated to IMC. This left dredging costs expensed by Tampa Electric of $1,101,589.47. Based on the history of allocating dredging costs between Tampa Electric and IMC, at most only half the requested dredging cost should have been included in the request or $665,000 (jurisdictional expense $1,330,000 / 2 = $665,000). Additionally, this should be amortized over five years and only $133,000 included in the test year.

Q. WHAT DOES THE HISTORICAL INFORMATION INDICATE?

A. The historical information indicates that the Company has never incurred dredging costs which approach $6.9 million. Additionally, the historical information indicates that if dredging costs were incurred in the year 1997/1998 and 2002, the next five year period should have been in the year 2007 and not 2009. Thus, dredging costs would not occur in the year 2009.

Q. DID YOU ASK TAMPA ELECTRIC TO SUPPORT OR PROVIDE DOCUMENTATION OF THE $6,900,000 OF DREDGING COSTS?

A. Yes, we did. We asked Tampa Electric to provide in the same OPC POD No. 100 "Documentation regarding the bid the Company received for dredging costs for 2009."

Q. DID THE COMPANY PROVIDE ANY DOCUMENTATION?

A. No, it did not. The Company has stated verbally that the information contained in OPC POD No. 100 contained all the information they had regarding dredging costs. The Company, in OPC POD No. 100, did not provide any information to support that 2009 would be the year in which the dredging cost would occur, or the $6.9 million amount they state will be the cost of the dredging.

Q. WHAT ADJUSTMENT HAVE YOU MADE REGARDING DREDGING COSTS?

A. I have removed from the rate base the Company's deferred dredging cost balance of $2,657,000 (jurisdictional) and I have also removed from operating expenses the remaining amount which the Company did not remove of $1,330,000. The Company has failed to provide any documentation to meet its burden of proof that 1) dredging costs will reach $6.9 million and 2) that the dredging cost will occur in the year 2009.

Plant Held for Future Use ("PHFU")

Q. DOES IT APPEAR THAT THE PROJECTIONS FOR PLANT HELD FOR FUTURE USE ARE CORRECT?

A. No. In response to OPC Interrogatory No. 89, which requested the basis on which the Company projected Plant Held for Future Use, the Company responded as follows:

> The projected balance in the property held for future use account was based on the budgeted land acquisition requirements for each respective year. The company forecasts what the future growth rate of the population may be and ensures that it is more than able to supply the needs of its current and future customers.

Q. DOES IT APPEAR THAT THE COMPANY ACTUALLY FOLLOWED THEIR RESPONSE AND ATTEMPTED TO BUDGET THE ACTUAL ADDITIONS AND REDUCTIONS TO PLANT HELD FOR FUTURE USE TEST YEAR AND THE PROJECTED 2008 AND 2009 YEARS?

A. No, it did not. For the year 2008, the Company utilized the ending balance at December 31, 2007 for each month of the 2008 year with exception of December 2008 when the balance was increased by $2,713,000. In the test year 2009, the Company used the December 2008 balance for property held for future use for each month of the test year except December 2009 where the balance was increased by $1,326,000. Therefore, it is obvious that the Company did not project monthly additions and uses during either the projected prior year ending December 31, 2008 or the projected test year ended December 31, 2009. If it had projected monthly, the PHFU balance would not have remained the same for each month except for December of each of the years.

Q. WHY IS IT NOT POSSIBLE FOR THE PROPERTY HELD FOR FUTURE USE TO HAVE THE SAME BALANCE IN EACH MONTH OF 2008 EXCEPT FOR DECEMBER AND HAVE THE SAME BALANCE IN 2009 FOR EACH MONTH EXCEPT DECEMBER?

A. In OPC Interrogatory No. 87, we asked the Company to provide for the historical year ended December 31, 2007 a list of each property held for future use. We asked if the Company to state the date it was acquired, its original cost and the projected use date. In that response, the following projects were projected to go into service in 2008:

Acct.	Name	2007 Number of Months	Originally Acquired Date	Projected Use Date	Cost ($)
105.05	Dale Mabry Sub	12	3/30/1973	2008	368,966.60
105.09	Silver Dollar Sub	12	10/30/2001	In Service 2008	546,940.43
105.27	Palm River Operating Center - Add'l Lan	12	6/30/1987	In Service 2008	618,703.87
	Total				1,534,610.90

As can be seen in the above schedule, projects of $1,534,610.90 were projected to go into service in 2008. Additionally, that same interrogatory shows the projects that were projected to go into service in the year 2009. In fact, the major component of property held for future use was projected to go into service in 2009. Inclusion of this major property component in the 2009 plant in service would have reduced the plant held for future use substantially. The following data shows the projects listed as of December 31, 2007, which was scheduled to go into service in 2009:

Acct.	Name	2007 Number of Months	Originally Acquired Date	Projected Use Date	Cost ($)
105.19	Handcart Sub	12	1/18/2006	2009	634,360.91
105.03	River to S. Hillsborough Trans R/W	12	6/30/1973	2009	23,752,289.05
105.11	New Tampa Transmission Easement	12	12/4/2004	2009	778,124.83
	Total				25,164,774.79

In OPC Interrogatory No.118, we asked why the amounts were still in Plant Held for Future Use when they show in service dates from 2008 and 2009. The Company responded by changing the in service dates on major PHFU amounts and removing others from the balance.

The Company stated in response to OPC Interrogatory No. 118:

> These adjustments do not change the total system rate base since the reduction in Plant Held For Future Use would be offset by a corresponding increase in Electric Plant In Service.

The Company has also stated that its projection of plant in service is accurate and reflects the cost of plant to be placed in service. Both statements cannot be true. Since the Company claims to have adjusted plant in service to reflect all plant placed in service in 2009, I have adjusted (decreased) the Company PHFU by $2,328,354 on a jurisdictional basis to reflect the change which the Company made.

<u>Construction Work In Progress ("CWIP")</u>

Q. ARE YOU PROPOSING ANY ADJUSTMENTS TO THE COMPANY'S PROJECTED CONSTRUCTION WORK IN PROGRESS?

A. Yes. Similar to my analysis of Plant In Service and Accumulated Provision for Depreciation, I have compared the actual Construction Work in Progress ("CWIP") balance for the first nine months of 2008 with the Company's projected balance. On average the Company's projected balance was understated by 1.90%. I have adjusted the Company's jurisdictional CWIP balance by 1.90% for 2009. I also have adjusted the Company's calculation of the Commission adjustment to remove from the CWIP balance which earns a rate of return through the Allowance for Funds Used During Construction ("AFUDC"). I have deducted the Company's adjustment to remove the current balance of CWIP reflected in rates of $36,171,000. This results in a higher construction work in progress balance than the Company has used in its filing. I am recommending a balance of $103,679,000 which is greater then the Company's balance by $2,608,000 on a jurisdictional basis.

<u>Working Capital Adjustment</u>

Q. ARE YOU PROPOSING ANY ADJUSTMENTS TO THE COMPANY'S WORKING CAPITAL REQUEST?

A. Yes. The Company has included Account 143 - Other Accounts Receivable in its working capital requirement. The Company has made an adjustment to remove job orders receivable in the amount of $1,717,000 that it attributes to adjustments the Commission has made in prior cases. The Uniform System of Accounts states that this account shall include amounts due the utility upon opening accounts other than amounts due from associated companies and from current customers for utility service. The utility should be required to show that all of the accounts receivable in Account 143 - Other Accounts Receivable are related to utility services and that the cost or revenue associated with these accounts receivable have been included in jurisdictional operating income. The Company has yet to show that these accounts are all related to utility service, thus the exclusion I have made of the entire account is justified. I have removed the remainder of Other Accounts Receivable in the amount of $10,959,000 on a jurisdictional basis

I have also excluded the entire balance in Account 146 - Accounts Receivable from Associated Companies. Again, the utility should be required to show that this entire balance of $6,309,000 is a necessary working capital requirement for ratepayers to bear and is directly related to the provision of utility services. The Company should be required to document that such receivables are on the Company's books as a result of providing service to jurisdictional ratepayers. They have not done so.

Q. IS THERE ANY OTHER ADJUSTMENT YOU ARE PROPOSING?
A. Yes. There has been a recent reduction in the price of fuel. I have reduced the Company's fuel stock by 10% to reflect current reductions which might have occurred in coal, oil and gas prices. The Company should be required to re-price its fuel stock inventory to accurately reflect the current price of fuel. The adjustment I have made does not accurately reflect an estimate of the decline in fuel prices because I do not have all necessary information available to me. Therefore, it is necessary for the

Company to make an accurate reassessment of fuel inventory costs based on current prices.

Q. ARE THERE ANY OTHER ADJUSTMENTS TO WORKING CAPITAL THAT YOU HAVE MADE?

A. Yes, there are other adjustments to working capital that have been discussed in other parts of my testimony.

V OPERATING EXPENSES

Storm Damage Accrual

Q. TAMPA ELECTRIC IS REQUESTING THAT THE STORM DAMAGE ACCRUAL BE INCREASED FROM THE CURRENT LEVEL OF $4 MILLION ANNUALLY TO $20 MILLION ANNUALLY. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No, I do not. I believe that the current level of $4 million of storm damage accrual is adequate given the Company's past history and the current guarantee by the Commission that costs incurred over the storm damage accrual would be reimbursed to the Company through future surcharges on ratepayers.

The Commission has allowed companies to recover excesses incurred in storm damage costs over storm damage reserves on a regular basis. Most of the Florida electric companies incurred substantial storm damage costs in 2004 and 2005, and several incurred damage that exceeded the amounts included in the storm damage reserve in 2004 and/or 2005. The Commission expeditiously authorized several companies to collect surcharges to recover any costs in excess of storm damage accruals and held hearings to determine the appropriate mechanism for cost recovery and level of cost recovery. Based on the storm recovery that the Commission has approved, there is no likelihood that Tampa Electric, or for that matter any other utility in the State of Florida, would not fully recover any prudently incurred storm damage costs which have not been recovered from the storm damage reserve.

Q. HAVE YOU EXAMINED THE HISTORICAL ADEQUACY OF THE STORM DAMAGE RESERVE FOR TAMPA ELECTRIC?

A. Yes. On Schedule C-2, attached to my testimony, I have shown the historical accumulation of the storm reserve and charges against that reserve through December 31, 2008, assuming that there will be no hurricane damage or storm damage in the final month of the year 2008. The storm reserve at the end of 2008 should be $24,310,365 as shown on my Schedule C-2. The only year that the Company incurred storm damage costs since the inception of the accrual for storm damage was 2004. My Schedule C-2, shows the total of these costs as provided by the Company in response to OPC Interrogatory No. 24. I have shown the total costs in the year 2004, although the Company charged the reserve from some of these costs in 2005, and subsequently made corrections to the 2004 storm cost in the years 2006 and 2007. The $74,567,219 in storm costs charged to the reserve including $38,877,284 in costs which the Company stipulated, should have been capitalized. See Order No. PSC-05-0675-PAA-EI, issued June 20, 2005, in Docket No. 050225-EI. As shown on Schedule C-2, I have increased the reserve in 2004 by the $38,877,284 that the Company eventually capitalized, or charged the reserve for depreciation in the year 2005. The net amount of storm costs charged to the reserve for depreciation was $35,689,935. When this amount is netted against the storm reserve in 2004 there was a balance left in the storm reserve of $8,310,065. Obviously, the accrual approved by the Commission and the accumulated reserve which were accumulated was more than sufficient to handle the costs the Company incurred when hurricanes hit the Company's system in 2004.

Q. WOULD THE COMPANY HAVE BEEN ENTITLED TO RECOVER THE FULL $74.5 MILLION BY CHARGING IT TO THE RESERVE FOR STORM DAMAGE?

A. In my opinion, it would not. Every storm recovery case that I have been involved with, which includes cases in the states of Florida, Louisiana, Mississippi and Hawaii requires that the Company only recover incremental costs of operating and maintenance expense and construction costs for replacement assets that are capitalized. The capitalized costs are not considered storm damage costs recoverable through the reserve for storm damage loss, but are considered assets which the Company will receive a rate of return on and recovery of through depreciation. Even though the Company implies that it was only as a result of the stipulation that there were capitalized costs, I believe that the Commission would not have allowed the full charging of these costs against the reserve for storm losses. In fact, the Commission has codified the incremental cost approach by rule.

Q. HAS THE COMMISSION APPROVED THE FULL COST RECOVERY METHOD FOR UTILITIES THAT INCURRED STORM DAMAGE SINCE 2004?

A. No, it has not. Either as a result of litigated (Progress Energy Florida and Florida Power and Light) or stipulated cases (Gulf Power, Tampa Electric and several others), the Commission has allowed the incremental cost recovery method for storm costs. To codify this policy, the Commission modified Rule 25-6.0143, Florida Administrative Code, to address specifically what types of costs can be charged to the storm reserve and how those costs should be accounted.

Q. IN YOUR OPINION IS THE LEVEL OF TAMPA ELECTRIC'S STORM RESERVE SUFFICIENT?

A. Yes. The relevant point that I am trying to make is that the level of accrual that the Commission authorized and the reserve which was accumulated were more than adequate to cover storm damage costs which the Company incurred in the year 2004.

Q. ONE OF THE ARGUMENTS WHICH THE COMPANY MAKES FOR INCREASING THE RESERVE IS THAT THE VALUE OF THE COMPANY'S TRANSMISSION AND DISTRIBUTION SYSTEM HAS INCREASED SINCE 1994 WHEN THE INITIAL ACCRUAL WAS ESTABLISHED AND THEREFORE, THE HIGHER VALUE OF THE ASSETS JUSTIFIES AN INCREASE IN THE ACCRUAL. DO YOU AGREE WITH THAT?

A. No. While I do agree that the value of the Company's transmission and distribution system has increased since 1994, it is clear that the reserve was adequate in the year 2004 to cover the higher value of assets damaged by the storms which struck in that year. Historically, Tampa Electric's reserve has functioned exactly as the Commission thought it would and how it was designed to operate. At the end of 2008, the reserve will have reached the level of approximately $24 million. Further, the Company's estimate of possible future storm damage was based on a full cost recovery basis, not the incremental recovery basis required under Rule 25-6.0143, Florida Administrative Code. As shown above, in the Company's actual 2004 storm costs, more than 50 percent of the costs did not flow through the reserve and instead were accounted for in base rate recovery.

Q. ANOTHER ARGUMENT THAT THE COMPANY HAS ADVANCED IS THAT THERE COULD BE STORM DAMAGE OF A CATASTROPHIC NATURE, WHICH COULD OVERWHELM WHATEVER RESERVE THE COMPANY HAS ACCUMULATED. DO YOU AGREE THAT COULD BE A LIKELIHOOD?

A. Yes, of course. No one knows when or if a hurricane will strike any particular area in the State of Florida. However, that could occur even if the Commission were to increase the accrual by the $16 million per year which the company is requesting. That would not avoid having the ratepayers pay for the storm damage in excess of the reserve. It only means that instead of paying up front by giving up the use of their funds currently, the ratepayer will pay when the damage actually exceeds the storm reserve. From a financial point of view, this is more beneficial to the ratepayer then having the Company collect huge amounts of reserves prior to the occurrence of a storm.

Q. WOULDN'T IT BE BETTER FOR THE COMPANY TO HAVE THESE FUNDS ON HAND WHEN THE STORM OCCURS RATHER THEN TO COLLECT THEM LATER FROM THE RATEPAYERS THROUGH A SURCHARGE?

A. The Company will not have these funds on hand. Tampa Electric does not have a funded storm reserve. If the Commission were to increase the storm reserve accrual from $4 million to $20 million, the total funds that the Company collects, that is, the $20 million will not be set aside and be available in the form of cash or cash equivalents to fund storm damage restoration. Since Tampa Electric does not have a funded reserve, the funds that the Company will (and has collected) will be treated as normal cash flow to the Company, funds that they will use in their operations, to fund plant additions, operating expense, or to pay dividends or interest on bonds. If the Commission were to authorize a higher accrual only means that ratepayers will pay a smaller surcharge when and if a storm does overwhelm the reserve for storm damage.

It should be kept in mind that this is not a self-insurance reserve that the Company is funding through stockholder funds. This is a ratepayer provided insurance plan which is funded through charges included in rates charged to retail customers. Since the ratepayer is in fact the insurer and not the Company, the ratepayer should have the final say on how and when storm costs should be funded. Ratepayers always have a higher cost of capital than utilities. It is in the best interest of ratepayers to fund the reserve at the level which has historically proven to be adequate and to fund any excess over the storm reserve, should one occur, through surcharges when and if such an event occurs.

Q. DOES TAMPA ELECTRIC HAVE ADDITIONAL PROTECTION FROM EXCESS STORM DAMAGE COST?

A. Yes. Florida law has authorized Securitization financing for storm recovery which is another vehicle which the Commission has at its disposal to deal with excessive storm damage cost. Section 366.8260, Florida Statutes, would allow for the securitization of storm damage in the form of bonds. This guarantees that all prudent storm damage losses would be recovered on a current basis by any utility which had storm damage losses.

Q. WHAT IS YOUR RECOMMENDATION?

A. My recommendation is that the current level of accrual of $4 million annually has proven adequate when a storm has actually hit the Tampa Electric system. The Commission should continue with that level of storm accrual and when, and if, a storm occurs which is in excess of the reserve the Commission should then deal with that through a surcharge on rates if necessary or securitization. I have adjusted operating expense to reduce them by the $16 million increase requested by the Company. I have also increased the working capital by $8 million to remove the effect of increasing the storm reserve on Tampa Electric's rate base.

Uncollectible Expense

Q. WHAT AMOUNT OF UNCOLLECTIBLE EXPENSE HAS THE COMPANY INCLUDED IN THE TEST YEAR?

A. The Company has projected uncollectible expense of $7,971,000 in the test year compared to $5,527,000 actually expensed in 2007. This is an increase of 44% over 2007 levels.

Q. HAS THE COMPANY OFFERED AN EXPLANATION FOR THE SIGNIFICANT INCREASE TO UNCOLLECTIBLE EXPENSE?

A. Yes. The Company indicated in response to OPC Interrogatory No. 43 that:

> Due to deterioration in the economic conditions in the Tampa Bay area a significant increase in the net writeoffs is projected for 2009. The 2008 budget was developed during Q3 2007 which was before the significant increase to net write-offs was being experienced.

However, it is not clear from the Company's filing how the Company derived the bad debt factor of 3.49% in its determination of uncollectible expense for the test year ended December 31, 2009.

Q. PLEASE DESCRIBE THE COMPANY'S PRESENTATION OF HISTORICAL AND PROJECTED UNCOLLECTIBLE EXPENSE SHOWN ON MFR SCHEDULE C-11.

A. MFP Schedule C-11 shows write offs (retail), gross revenues from sales of electricity (retail) and the resulting bad debt factor for the years 2004 through 2009. The bad debt factor is derived by dividing the write-offs by the gross revenues from sales of electricity. For the years 2004 through 2007, the gross revenues from sales of electricity is comprised of accounts 440 - 446 Retail Billed Sales and account 451 Miscellaneous Service Revenue.

Q. HOW DID THE COMPANY PROJECT THE BAD DEBT WRITE-OFFS FOR THE YEARS 2008 AND 2009?

A. As I have previously stated, the Company used Accounts 440 through 446-Retail Billed Sales and Account 451 - Miscellaneous Service Revenue in the years 2004 through 2007. However, for the years 2008 and 2009, the Company also included as sales subject to bad debt write-off Account 447 - Sales for Resale, Account 456 - Unbilled Revenue and Accounts 407.3 and 407.4 - Deferred Clause Revenues. Sales for Resale Account 447 would include those sales to municipalities and other wholesale customers who resale the electricity. It is unlikely that any of these customers would actually result in a bad debt write-off. Unbilled and deferred clause revenues have been included in retail billed sales for accruals and deferrals made in prior periods. They are not actually billed in the current period and should not be included for bad debt write-off calculations.

Q. WHAT LEVEL OF UNCOLLECTIBLE EXPENSE DO YOU PROPOSE?

A. Taking a five year average (2003 through 2007) of the Company's Bad Debt Factor and applying that to the company's projected gross revenues from sales of electricity (Accounts 440-446 and 451) would yield a more consistent and representative level of uncollectible expense for the test year.

Using a historical period will give an average of the Company's bad debt write-offs over a longer period of time and reflect a reasonable estimate of what the Company's write-offs will be in future periods.

Q. WHAT ABOUT THE COMPANY'S CONTENTION THAT DETERIORATING ECONOMIC CONDITIONS IN THE TAMPA BAY AREA MAY INCREASE BAD DEBT IN 2009?

A. The Commission should not build into rates charged to ratepayers economic downturns. This would protect Tampa Electric from the effects of the economy and pass onto ratepayers in economic bad times increased bad debt expense during economic bad times. Historical data will reflect ongoing bad debt expense not influenced by unusual temporary effects of economic downturns.

Q. WHAT ADJUSTMENT SHOULD BE MADE TO THE COMPANY'S PROPOSED UNCOLLECTIBLE EXPENSE TO REFLECT A MORE REPRESENTATIVE LEVEL OF THIS EXPENSE?

A. As shown on Schedule C-3, I have reduced uncollectible expense by $2,409,000 and the jurisdictional adjustment is $2,342,000. I have also adjusted the revenue conversion factor to reflect the Bad Debt Factor I am proposing.

Capital Structure

Q. WOULD YOU PLEASE EXPLAIN THE ADJUSTMENTS YOU HAVE MADE TO THE CAPITAL STRUCTURE TO REFLECT YOUR RATE BASE ADJUSTMENTS?

A. Dr. Woolridge has recommended a capital structure which utilizes the average of the 2007 and 2008 capital structure components. By utilizing the 2007 and 2008 capital structure components, Dr. Woolridge has, in effect, removed the specific adjustments which the Company has made to the equity component and short-term debt component. This is because the actual capital structure for those periods does not include the rate case adjustment to the capital structure which the Company is proposing. On my Schedule D, in the second column, I have adjusted the Company's rate base to comport with Dr. Woolridge's capital structure. The adjusted amount shown in Column 3 is the Company's beginning rate base allocated based on Dr. Woolridge's capital structure. In the next column,

Column 4, I have allocated the rate base adjustments we are recommending based on Dr. Woolridge's capital structure. The next column, Column 5, is the OPC's recommended capital structure based on Dr. Woolridge's recommended capital structure. The final three columns calculate OPC weighted cost of capital based on Dr. Woolridge's recommendation.

Q DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does at this time. However, there are still outstanding discovery requests which may affect my adjustments or require additional adjustments.

CERTIFICATE OF SERVICE
DOCKET NO. 080317-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing Direct Testimony of Hugh Larkin, Jr. has been furnished by hand delivery or U.S. Mail to the following parties on this 26th day of November, 2008.

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APPENDIX 1

QUALIFICTIONS OF HUGH LARKIN, JR. CPA

APPENDIX I

Q. WHAT IS YOUR OCCUPATION?

A. I am a certified public accountant and a partner in the firm of Larkin & Associates, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. I graduated from Michigan State University in 1960. During 1961 and 1962, I fulfilled my military obligations as an officer in the United States Army.

In 1963 I was employed by the certified public accounting firm of Peat, Marwick, Mitchell & Co., as a junior accountant. I became a certified public accountant in 1966.

In 1968 I was promoted to the supervisory level at Peat, Marwick, Mitchell & Co. As such, my duties included the direction and review of audits of various types of business organizations, including manufacturing, service, sales and regulated companies.

Through my education and auditing experience of manufacturing operations, I obtained an extensive background of theoretical and practical cost accounting.

I have audited companies having job cost systems and those having process cost systems, utilizing both historical and standard costs.

I have a working knowledge of cost control, budgets and reports, the accumulation of overheads and the application of same to products on the various recognized methods.

Additionally, I designed and installed a job cost system for an automotive parts manufacturer.

I gained experience in the audit of regulated companies as the supervisor in charge of all railroad audits for the Detroit office of Peat, Marwick, including audits of the Detroit, Toledo and Ironton Railroad, the Ann Arbor Railroad, and portions of the Penn Central Railroad Company. In 1967, I was the supervisory senior accountant in charge of the audit of the Michigan State Highway Department, for which Peat, Marwick was employed by the State Auditor General and the Attorney General.

In October of 1969, I left Peat, Marwick to become a partner in the public accounting firm of Tischler & Lipson of Detroit. In April of 1970, I left the latter firm to form the certified public accounting firm of Larkin, Chapski & Company. In September 1982 I re-organized the firm into Larkin & Associates, a certified public accounting firm. The firm of Larkin & Associates performs a wide variety of auditing and accounting services, but concentrates in the area of utility regulation and ratemaking. I am a member of the Michigan Association of Certified Public Accountants and the American Institute of Certified Public Accountants. I testified before the Michigan Public Service Commission and in other states in the following cases:

U-3749	Consumers Power Company - Electric Michigan Public Service Commission
U-391	Detroit Edison Company Michigan Public Service Commission
U-4331	Consumers Power Company - Gas Michigan Public Service Commission
U-4332	Consumers Power Company - Electric Michigan Public Service Commission
U-4293	Michigan Bell Telephone Company Michigan Public Service Commission
U-4498	Michigan Consolidated Gas sale to Consumers Power Company Michigan Public Service Commission
U-4576	Consumers Power Company - Electric Michigan Public Service Commission
U-4575	Michigan Bell Telephone Company Michigan Public Service Commission
U-4331R	Consumers Power Company - Gas - Rehearing Michigan Public Service Commission
6813	Chesapeake and Potomac Telephone Company of Maryland, Public Service Commission, State of Maryland

Formal Case No. 2090	New England Telephone and Telegraph Co. State of Maine Public Utilities Commission
Dockets 574, 575, 576	Sierra Pacific Power Company, Public Service Commission, State of Nevada
U-5131	Michigan Power Company Michigan Public Service Commission
U-5125	Michigan Bell Telephone Company Michigan Public Service Commission
R-4840 & U-4621	Consumers Power Company Michigan Public Service Commission
U-4835	Hickory Telephone Company Michigan Public Service Commission
36626	Sierra Pacific Power Company v. Public Service Commission, et al, First Judicial District Court of the State of Nevada
American Arbitration Association	City of Wyoming v. General Electric Cable TV
760842-TP	Southern Bell Telephone and Telegraph Company, Florida Public Service Commission
U-5331	Consumers Power Company Michigan Public Service Commission
U-5125R	Michigan Bell Telephone Company Michigan Public Service Commission
770491-TP	Winter Park Telephone Company, Florida Public Service Commission
77-554-EL-AIR	Ohio Edison Co., Public Utility Commission of Ohio
78-284-EL-AEM	Dayton Power and Light Co., Public Utility Commission of Ohio
0R78-1	Trans Alaska Pipeline, Federal Energy Regulatory Commission (FERC)

78-622-EL-FAC	Ohio Edison Co., Public Utility Commission of Ohio
U-5732	Consumers Power Company - Gas, Michigan Public Service Commission
77-1249-EL-AIR, et al	Ohio Edison Co., Public Utility Commission of Ohio
78-677-EL-AIR	Cleveland Electric Illuminating Co., Public Utility Commission of Ohio
U-5979	Consumers Power Company, Michigan Public Service Commission
790084-TP	General Telephone Company of Florida, Florida Public Service Commission
79-11-EL-AIR	Cincinnati Gas and Electric Co., Public Utilities Commission of Ohio
790316-WS	Jacksonville Suburban Utilities Corp., Florida Public Service Commission
790317-WS	Southern Utility Company, Florida Public Service Commission
U-1345	Arizona Public Service Company, Arizona Corporation Commission
79-537-EL-AIR	Cleveland Electric Illuminating Co., Public Utilities Commission of Ohio
800011-EU	Tampa Electric Company, Florida Public Service Commission
800001-EU	Gulf Power Company, Florida Public Service Commission
U-5979-R	Consumers Power Company, Michigan Public Service Commission
800119-EU	Florida Power Corporation, Florida Public Service Commission

810035-TP	Southern Bell Telephone and Telegraph Company, Florida Public Service Commission
800367-WS	General Development Utilities, Inc., Port Malabar, Florida Public Service Commission
TR-81-208**	Southwestern Bell Telephone Company, Missouri Public Service Commission
810095-TP	General Telephone Company of Florida, Florida Public Service Commission
U-6794	Michigan Consolidated Gas Company, 16 refunds Michigan Public Service Commission
U-6798	Cogeneration and Small Power Production -PURPA, Michigan Public Service Commission
0136-EU	Gulf Power Company, Florida Public Service Commission
E-002/GR-81-342	Northern State Power Company Minnesota Public Utilities Commission
820001-EU	General Investigation of Fuel Cost Recovery Clauses, Florida Public Service Commission
810210-TP	Florida Telephone Corporation, Florida Public Service Commission
810211-TP	United Telephone Co. of Florida, Florida Public Service Commission
810251-TP	Quincy Telephone Company, Florida Public Service Commission
810252-TP	Orange City Telephone Company, Florida Public Service Commission
8400	East Kentucky Power Cooperative, Inc., Kentucky Public Service Commission
U-6949	Detroit Edison Company - Partial and Immediate Rate Increase Michigan Public Service Commission

18328	Alabama Gas Corporation, Alabama Public Service Commission
U-6949	Detroit Edison Company - Final Rate Recommendation Michigan Public Service Commission
820007-EU	Tampa Electric Company, Florida Public Service Commission
820097-EU	Florida Power & Light Company, Florida Public Service Commission
820150-EU	Gulf Power Company, Florida Public Service Commission
18416	Alabama Power Company, Public Service Commission of Alabama
820100-EU	Florida Power Corporation, Florida Public Service Commission
U-7236	Detroit Edison-Burlington Northern Refund Michigan Public Service Commission
U-6633-R	Detroit Edison - MRCS Program, Michigan Public Service Commission
U-6797-R	Consumers Power Company - MRCS Program, Michigan Public Service Commission
82-267-EFC	Dayton Power & Light Company, Public Utility Commission of Ohio
U-5510-R	Consumers Power Company - Energy Conservation Finance Program, Michigan Public Service Commission
82-240-E	South Carolina Electric & Gas Company, South Carolina Public Service Commission
8624 8625	Kentucky Utilities, Kentucky Public Service Commission
8648	East Kentucky Power Cooperative, Inc., Kentucky Public Service Commission

U-7065	The Detroit Edison Company (Fermi II) Michigan Public Service Commission
U-7350	Generic Working Capital Requirements, Michigan Public Service Commission
820294-TP	Southern Bell Telephone Company, Florida Public Service Commission
Order RH-1-83	Westcoast Gas Transmission Company,Ltd., Canadian National Energy Board
8738	Columbia Gas of Kentucky, Inc., Kentucky Public Service Commission
82-168-EL-EFC	Cleveland Electric Illuminating Company, Public Utility Commission of Ohio
6714	Michigan Consolidated Gas Company Phase II, Michigan Public Service Commission
82-165-EL-EFC	Toledo Edison Company, Public Utility Commission of Ohio
830012-EU	Tampa Electric Company, Florida Public Service Commission
ER-83-206**	Arkansas Power & Light Company, Missouri Public Service Commission
U-4758	The Detroit Edison Company (Refunds), Michigan Public Service Commission
8836	Kentucky American Water Company, Kentucky Public Service Commission
8839	Western Kentucky Gas Company, Kentucky Public Service Commission
83-07-15	Connecticut Light & Power Company, Department of Utility Control State of Connecticut
81-0485-WS	Palm Coast Utility Corporation, Florida Public Service Commission

U-7650	Consumers Power Company - (Partial and Immediate), Michigan Public Service Commission
83-662**	Continental Telephone Company, Nevada Public Service Commission
U-7650	Consumers Power Company – Final Michigan Public Service Commission
U-6488-R	Detroit Edison Co. (FAC & PIPAC Reconciliation), Michigan Public Service Commission
Docket No. 15684	Louisiana Power & Light Company, Public Service Commission of the State of Louisiana
U-7650	Consumers Power Company (Reopened Reopened Hearings) Michigan Public Service Commission
38-1039**	CP National Telephone Corporation Nevada Public Service Commission
83-1226	Sierra Pacific Power Company (Re application to form holding company) Nevada Public Service Commission
U-7395 & U-7397	Campaign Ballot Proposals Michigan Public Service Commission
820013-WS	Seacoast Utilities Florida Public Service Commission
U-7660	Detroit Edison Company Michigan Public Service Commission
U-7802	Michigan Gas Utilities Company Michigan Public Service Commission
830465-EI	Florida Power & Light Company Florida Public Service Commission
U-7777	Michigan Consolidated Gas Company Michigan Public Service Commission

U-7779	Consumers Power Company Michigan Public Service Commission
U-7480-R	Michigan Consolidated Gas Company Michigan Public Service Commission
U-7488-R	Consumers Power Company – Gas Michigan Public Service Commission
U-7484-R	Michigan Gas Utilities Company Michigan Public Service Commission
U-7550-R	Detroit Edison Company Michigan Public Service Commission
U-7477-R	Indiana & Michigan Electric Company Michigan Public Service Commission
U-7512-R	Consumers Power Company – Electric Michigan Public Service Commission
18978	Continental Telephone Company of the South - Alabama, Alabama Public Service Commission
9003	Columbia Gas of Kentucky, Inc. Kentucky Public Service Commission
R-842583	Duquesne Light Company Pennsylvania Public Utility Commission
9006*	Big Rivers Electric Corporation Kentucky Public Service Commission *Company withdrew filing
U-7830	Consumers Power Company - Electric (Partial and Immediate) Michigan Public Service Commission
7675	Consumers Power Company - Customer Refunds Michigan Public Service Commission
5779	Houston Lighting & Power Company Texas Public Utility Commission

U-7830	Consumers Power Company - Electric – "Financial Stabilization" Michigan Public Service Commission
U-4620	Mississippi Power & Light Company (Interim) Mississippi Public Service Commission
U-16091	Louisiana Power & Light Company Louisiana Public Service Commission
9163	Big Rivers Electric Corporation Kentucky Public Service Commission
U-7830	Consumers Power Company - Electric - (Final) Michigan Public Service Commission
U-4620	Mississippi Power & Light Company - (Final) Mississippi Public Service Commission
76-18788AA & 76-18788AA	Detroit Edison (Refund - Appeal of U-4807) Ingham County Circuit Court Michigan Public Service Commission
U-6633-R	Detroit Edison (MRCS Program Reconciliation) Michigan Public Service Commission
19297	Continental Telephone Company of the South - Alabama, Alabama Public Service Commission
9283	Kentucky American Water Company Kentucky Public Service Commission
850050-EI	Tampa Electric Company Florida Public Service Commission
R-850021	Duquesne Light Company Pennsylvania Public Service Commission
TR-85-179**	United Telephone Company of Missouri Missouri Public Service Commission
6350	El Paso Electric Company The Public Utility Board of the City of El Paso

6350	El Paso Electric Company Public Utility Commission of Texas
85-53476AA & 85-534855AA	Detroit Edison-refund-Appeal of U-4758 Ingham County Circuit Court Michigan Public Service Commission
U-8091/ U-8239	Consumers Power Company-Gas Michigan Public Service Commission
9230	Leslie County Telephone Company, Inc. Kentucky Public Service Commission
85-212	Central Maine Power Company Maine Public Service Commission
850782-EI & 850783-EI	Florida Power & Light Company Florida Public Service Commission
ER-85646001 & ER-85647001	New England Power Company Federal Energy Regulatory Commission
Civil Action * No. 2:85-0652	Allegheny & Western Energy Corporation, Plaintiff, - against – The Columbia Gas System, Inc. Defendant
Docket No. 850031-WS	Orange Osceola Utilities, Inc. Before the Florida Public Service Commission
Docket No. 840419-SU	Florida Cities Water Company South Ft. Myers Sewer Operations Before the Florida Public Service Commission
R-860378	Duquesne Light Company Pennsylvania Public Service Commission
R-850267	Pennsylvania Power Company Pennsylvania Public Service Commission
R-860378	Duquesne Light Company - Surrebuttal Testimony - OCA Statement No. 2D Pennsylvania Public Service Commission
Docket No. 850151	Marco Island Utility Company Before the Florida Public Service Commission

Docket No. 7195 (Interim)	Gulf States Utilities Company Public Utility Commission of Texas
R-850267 Reopened	Pennsylvania Power Company Pennsylvania Public Service Commission
Docket No. 87-01-03	Connecticut Natural Gas Corporation Connecticut Department of Public Utility Control
Docket No. 5740	Hawaiian Electric Company Hawaii Public Utilities Commission
1345-85-367	Arizona Public Service Company Arizona Corporation Commission
Docket 011	Tax Reform Act of 1986 - California No. 86-11-019 California Public Utilities Commission
Case No. 29484	Long Island Lighting Company New York Department of Public Service
Docket No. 7460	El Paso Electric Company Public Utility Commission of Texas
Docket No. 870092-WS*	Citrus Springs Utilities Before the Florida Public Service Commission
Case No. 9892	Dickerson Lumber EP Company - Complainant vs. Farmers Rural Electric Cooperative and East Kentucky Power Cooperative – Defendants Before the Kentucky Public Service Commission
Docket No. 3673-U	Georgia Power Company Before the Georgia Public Service Commission
Docket No. U-8747	Anchorage Water and Wastewater Utility Report on Management Audit
Docket No. 861564-WS	Century Utilities Before the Florida Public Service Commission
Docket No. FA86-19-001	Systems Energy Resources, Inc. Federal Energy Regulatory Commission

Docket No. 870347-TI	AT&T Communications of the Southern States, Inc. Florida Public Service Commission
Docket No. 870980-WS	St. Augustine Shores Utilities Inc. Florida Public Service Commission
Docket No. 870654-WS*	North Naples Utilities, Inc. Florida Public Service Commission
Docket No. 870853	Pennsylvania Gas & Water Company Pennsylvania Public Utility Commission
Civil Action* No. 87-0446-R	Reynolds Metals Company, Plaintiff, v. The Columbia Gas System, Inc., Commonwealth Gas Services, Inc., Commonwealth Gas Pipeline Corporation, Columbia Gas Transmission Corporation, Columbia Gulf Transmission Company, Defendants - In the United States District Court for the Eastern District of Virginia - Richmond Division
Docket No. E-2, Sub 537	Carolina Power & Light Company North Carolina Utilities Commission
Case No. U-7830	Consumers Power Company - Step 2 Reopened Michigan Public Service Commission
Docket No. 880069-TL	Southern Bell Telephone & Telegraph Florida Public Service Commission
Case No. U-7830	Consumers Power Company - Step 3B Michigan Public Service Commission
Docket No. 880355-EI	Florida Power & Light Company Florida Public Service Commission
Docket No. 880360-EI	Gulf Power Company Florida Public Service Commission
Docket No. FA86-19-002	System Energy Resources, Inc. Federal Energy Regulatory Commission
Docket Nos. 83-0537-Remand & 84-0555-Remand	Commonwealth Edison Company Illinois Commerce Commission

Docket Nos. 83-0537 Remand & 84-0555 Remand	Commonwealth Edison Company Surrebuttal Illinois Commerce Commission
Docket No. 880537-SU	Key Haven Utility Corporation Florida Public Service Commission
Docket No. 881167-EI***	Gulf Power Company Florida Public Service Commission
Docket No. 881503-WS	Poinciana Utilities, Inc. Florida Public Service Commission
Cause No. U-89-2688-T	Puget Sound Power & Light Company Washington Utilities & Transportation Committee
Docket No. 89-68	Central Maine Power Company Maine Public Utilities Commission
Docket No. 861190-PU	Proposal to Amend Rule 25-14.003, F.A.C. Florida Public Service Commission
Docket No. 89-08-11 Control	The United Illuminating Company State of Connecticut, Department of Public Utility
Docket No. R-891364	The Philadelphia Electric Company Pennsylvania Public Utility Commission
Formal Case No. 889	Potomac Electric Power Company Public Service Company of the District of Columbia
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (In the Supreme Court County of Onondaga, State of New York)
Case No. 87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf + Western, Inc. et al, defendants (In the Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
Case No. 89-640-G-42T*	Mountaineer Gas Company West Virginia Public Service Commission

Docket No. 890319-EI	Florida Power & Light Company Florida Public Service Commission
Docket No. EM-89110888	Jersey Central Power & Light Company Board of Public Utilities Commissioners
Docket No. 891345-EI	Gulf Power Company Florida Public Service Commission
BPU Docket No. ER 8911 0912J	Jersey Central Power & Light Company Board of Public Utilities Commissioners
Docket No. 6531	Hawaiian Electric Company Hawaii Public Utilities Commissioners
Docket No. 890509-WU	Florida Cities Water Company, Golden Gate Division Florida Public Service Commission
Docket No. 880069-TL	Southern Bell Telephone Company Florida Public Service Commission
Docket Nos. F-3848, F-3849, and F-3850	Northwestern Bell Telephone Company South Dakota Public Utilities Commission
Docket Nos. ER89-* 678-000 & EL90-16-000	System Energy Resources, Inc. Federal Energy Regulatory Commission
Docket No. 5428	Green Mountain Power Corporation Vermont Department of Public Service
Docket No. 90-10	Artesian Water Company, Inc. Delaware Public Service Commission
Case No. 90-243-E-42T*	Wheeling Power Company West Virginia Public Service Commission
Docket No. 900329-WS	Southern States Utilities, Inc. Florida Public Service Commission
Docket Nos. ER89-* 678-000 & EL90-16-000	System Energy Resources, Inc. (Surrebuttal) Federal Energy Regulatory Commission
Application No. 90-12-018	Southern California Edison Company California Public Utilities Commission

Docket No. 90-0127	Central Illinois Lighting Company Illinois Commerce Commission
Docket No. FA-89-28-000	System Energy Resources, Inc. Federal Energy Regulatory Commission
Docket No. U-1551-90-322	Southwest Gas Corporation Before the Arizona Corporation Commission
Docket No. R-911966	Pennsylvania Gas & Water Company The Pennsylvania Public Utility Commission
Docket No. 176-717-U	United Cities Gas Company Kansas Corporation Commission
Docket No. 860001-EI-G	Florida Power Corporation Florida Public Service Commission
Docket No. 6720-TI-102	Wisconsin Bell, Inc. Wisconsin Citizens' Utility Board
(No Docket No.)	Southern Union Gas Company Before the Public Utility Regulation Board of the City of El Paso
Docket No. 6998	Hawaiian Electric Company, Inc. Before the Public Utilities Commission of the State of Hawaii
Docket No. TC91-040A	In the Matter of the Investigation into the Adoption of a Uniform Access Methodology Before the Public Utilities Commission of the State of South Dakota
Docket Nos. 911030-WS & 911067-WS	General Development Utilities, Inc. Before the Florida Public Service Commission
Docket No. 910890-EI	Florida Power Corporation Before the Florida Public Service Commission
Docket No. 910890-EI	Florida Power Corporation, Supplemental Before the Florida Public Service Commission

Case No. 3L-74159	Idaho Power Company, an Idaho corporation In the District Court of the Fourth Judicial District of the State of Idaho, In and For the County of Ada - Magistrate Division
Cause No. 39353*	Indiana Gas Company Before the Indiana Utility Regulatory Commission
Docket No. 90-0169 (Remand)	Commonwealth Edison Company Before the Illinois Commerce Commission
Docket No. 92-06-05	The United Illuminating Company State of Connecticut, Department of Public Utility Control
Cause No. 39498	PSI Energy, Inc. Before the State of Indiana - Indiana Utility Regulatory Commission
Cause No. 39498	PSI Energy, Inc. - Surrebuttal testimony Before the State of Indiana - Indiana Utility Regulatory Commission
Docket No. 7287	Public Utilities Commission - Instituting a Proceeding to Examine the Gross-up of CIAC Before the Public Utilities Commission of the State of Hawaii
Docket No. 92-227-TC	US West Communications, Inc. Before the State Corporation Commission of the State of New Mexico
Docket No. 92-47	Diamond State Telephone Company Before the Public Service Commission of the State of Delaware
Docket Nos. 920733-WS & 920734-WS	General Development Utilities, Inc. Before the Florida Public Service Commission
Docket No. 92-11-11	Connecticut Light & Power Company State of Connecticut, Department of Public Utility Control
Docket Nos.EC92-21-000 & ER92-806-000	Entergy Corporation Before the Federal Energy Regulatory Commission

Docket No. 930405-EI	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. UE-92-1262	Puget Sound Power & Light Company Before the Washington Utilities & Transportation Commission
Docket No. 93-02-04	Connecticut Natural Gas Corporation State of Connecticut, Department of Public Utility Control
Docket No. 93-02-04	Connecticut Natural Gas Corporation, Supplemental State of Connecticut, Department of Public Utility Control
Docket No. 93-057-01	Mountain Fuel Supply Company Before the Utah Public Service Commission
Cause No. 39353 (Phase II)	Indiana Gas Company Before the Indiana Utility Regulatory Commission
PU-314-92-1060	US West Communications, Inc. Before the North Dakota Public Service Commission
Cause No. 39713	Indianapolis Water Company Before the Indiana Utility Regulatory Commission
93-UA-0301*	Mississippi Power & Light Company Before the Mississippi Public Service Commission
Docket No. 93-08-06	SNET America, Inc. State of Connecticut, Department of Public Utility Control
Docket No. 93-057-01	Mountain Fuel Supply Company - Rehearing on Unbilled Revenues - Before the Utah Public Service Commission
Case No. 78-T119-0013-94	Guam Power Authority vs. U.S. Navy Public Works Center, Guam - Assisting the Department of Defense in the investigation of a billing dispute. Before the American Arbitration Association
Application No. 93-12-025 - Phase I	Southern California Edison Company Before the California Public Utilities Commission

Case No. 94-0027-E-42T	Potomac Edison Company Before the Public Service Commission of West Virginia
Case No. 94-0035-E-42T	Monongahela Power Company Before the Public Service Commission of West Virginia
Docket No. 930204-WS**	Jacksonville Suburban Utilities Corporation Before the Florida Public Service Commission
Docket No. 5258-U	Southern Bell Telephone and Telegraph Company Before the Georgia Public Service Commission
Case No. 95-0011-G-42T*	Mountaineer Gas Company Before the West Virginia Public Service Commission
Case No. 95-0003-G-42T*	Hope Gas, Inc. Before the West Virginia Public Service Commission
Docket No. 95-02-07	Connecticut Natural Gas Corporation State of Connecticut, Department of Public Utility Control
Docket No. 95-057-02*	Mountain Fuel Supply Before the Utah Public Service Commission
Docket No. 95-03-01	Southern New England Telephone Company State of Connecticut, Department of Public Utility Control
BRC Docket No. EX93060255 OAL Docket PUC96734-94	Generic Proceeding Regarding Recovery of Capacity Costs Associated with Electric Utility Power Purchases from Cogenerators and Small Power Producers Before the New Jersey Board of Public Utilities
Docket No. U-1933-95-317	Tucson Electric Power Before the Arizona Corporation Commission
Docket No. 950495-WS	Southern States Utilities Before the Florida Public Service Commission
Docket No. 960409-EI	Prudence Review to Determine Regulatory Treatment of Tampa Electric Company's Polk Unit 1

Docket No. 960451-WS	United Water Florida Before the Florida Public Service Commission
Docket No. 94-10-05	Southern New England Telephone Company State of Connecticut Department of Public Utility Control
Docket No. 96-UA-389	Generic Docket to Consider Competition in the Provision of Retail Electric Service Before the Public Service Commission of the State of Mississippi
Docket No. 970171-EU	Determination of appropriate cost allocation and regulatory treatment of total revenues associated with wholesale sales to Florida Municipal Power Agency and City of Lakeland by Tampa Electric Company Before the Florida Public Service Commission
Case No. PUE960296 *	Virginia Electric and Power Company Before the Commonwealth of Virginia State Corporation Commission
Docket No. 97-035-01	PacifiCorp, dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. G-03493A-98-0705*	Black Mountain Gas Division of Northern States Power Company, Page Operations Before the Arizona Corporation Commission
Docket No. 98-10-07	United Illuminating Company State of Connecticut Department of Public Utility Control
Docket No. 98-10-07	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket NO. 99-02-05	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket No. 99-03-36	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control

Docket No. 99-03-35	United Illuminating Company State of Connecticut Department of Public Utility Control
Docket No. 99-03-04	United Illuminating Company State of Connecticut Department of Public Utility Control
Docket No. 99-08-02	Yankee Energy System, Inc. State of Connecticut Department of Public Utility Control
Docket No. 99-08-09	CTG Resources, Inc. State of Connecticut Department of Public Utility Control
Docket No. 99-07-20	Connecticut Energy Corporation / Energy East State of Connecticut Department of Public Utility Control
Docket No. 99-09-03 Phase II	Connecticut Natural Gas State of Connecticut Department of Public Utility Control
Docket No. 99-09-03 Phase III	Connecticut Natural Gas State of Connecticut Department of Public Utility Control
Docket No. 99-04-18 Phase II	Southern Connecticut Gas Company State of Connecticut Department of Public Utility Control
Docket No. 99-057-20*	Questar Gas Company Public Service Commission of Utah
Docket No. 99-035-10	PacifiCorp dba Utah Power & Light Company Public Service Commission of Utah
Docket No. T-1051B-99-105	U.S. West Communications, Inc. Arizona Corporation Commission
Docket No. 01-035-10*	PacifiCorp dba Utah Power & Light Company Public Service Commission of Utah
Docket No. 991437-WU	Wedgefield Utilities, Inc. Before the Florida Public Service Commission

Docket No. 991643-SU	Seven Springs Before the Florida Public Service Commission
Docket No. 98P55045	General Telephone and Electronics of California California Public Utilities Commission
Docket No. 00-01-11	Consolidated Edison, Inc. and Northeast Utilities Merger State of Connecticut Before the Department of Public Utility Control
Docket No. 00-12-01	Connecticut Light & Power Company State of Connecticut Before the Department of Public Utility Control
Docket No. 000737-WS	Aloha Utilities/Seven Springs Utilities Before the Florida Public Service Commission
Consolidated Docket Nos. EL00-66-000 ER00-2854-000 EL95-33-000	Entergy Services, Inc. Before the Federal Energy Regulatory Commission
Docket No. 950379-EI	Tampa Electric Company Before the Florida Public Service Commission
Docket No. 010503-WU	Aloha Utilities, Inc. – Seven Springs Water Division Before the Florida Public Service Commission
Docket No. 01-07-06*	The Towns of Durham and Middlefield State of Connecticut Before the Department of Public Utility Control
Docket No. 99-09-12-RE-02	Connecticut Light & Power/Millstone State of Connecticut Before the Department of Public Utility Control
Civil Action No. C2-99-1181	The United States et al v. Ohio Edison et al U.S. District Court, S.D. Ohio
Docket No. 001148-ET****	Florida Power & Light Company Before the Florida Public Service Commission
Civil Action No. 99-833-Per *	The United States et al v. Illinois Power Company U.S. District Court, S.D. Illinois

Civil Action No. IP99-1692-C-M/s *	The United States et al v. Southern Indiana Gas and Electric Company U.S. District Court, S.D. Indiana
Docket No. 02-057-02*	Questar Gas Company Public Service Commission of Utah
Docket No. EL01-88-000	Entergy Services, Inc. et. al. Mississippi Public Service Commission
Docket No. 9355-U	Georgia Power Company Before the Georgia Public Service Commission
Case No. 1016	Washington Gas Light Company Before the Public Service Commission of the District of Columbia
Civil Action Nos. C2 99-1182 C2 99-1250 (Consolidated)	The United States et al v. American Electric Power Company, ET, AL
Docket No. 030438-EI *	Florida Public Utilities Company Before the Florida Public Service Commission
Docket No. EL01-88-000	Entergy Services, Inc., et al Before the Federal Energy Regulatory Commission
Application No. 02-12-028	San Diego Gas & Electric Company Before the California Public Utilities Commission
Civil Action No. 1:00 CV1262	The United States et al v. Duke Energy Company
Docket No. 050045-EI *	Florida Power & Light Corporation Before the Florida Public Service Commission
Docket No. 050078-EI *	Progress Energy Florida, Inc. Before the Florida Public Service Commission
Civil Action No. 1P99-1693 C-M/S	The United States et al. v. Cinergy Corporation, ET AL.
Civil Action No. 04-34-KSF	The United States et al. v. East Kentucky Power Cooperative, Inc. ET AL.

Case No. 05-0304-G-42T *	Hope Gas, Inc. d/b/a Dominion Hope Consumer Advocate Division of the Public Service Commission of West Virginia
Case No. 05-E-1222	New York State Electric & Gas Corporation Before the New York Public Service Commission
Case Nos. 05-E-0934 05-G-0935	Central Hudson Gas & Electric Corporation Before the New York Public Service Commission
Case No. 05-G-1494	Orange and Rockland Utilities, Inc. Before the New York Public Service Commission
Docket No. 060038-EI	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. 060154-EI*	Gulf Power Company Before the Florida Public Service Commission
Docket No. 060300-TL	GTC, Inc. d/b/a GT Com Before the Florida Public Service Commission
Case Nos. 06-G-1185 06-G-1186	KeySpan Gas East Corporation Before the New York Public Service Commission
Docket No. U-29203 (Phase II)	Gulf States, Inc. and Entergy Louisiana, Inc. Before the Louisiana Public Service Commission
Formal Case No. 1053	Potomac Electric Power Company Before the Public Service Commission of the District of Columbia
Application No. 06-12-009	San Diego Gas & Electric Company Before the California Public Utilities Commission
Formal Case No. 1054*	Washington Gas Light Company Before the Public Service Commission of the District of Columbia
Civil Action No. 2:05cv0885	Commonwealth of Pennsylvania et al vs Allegheny Energy Inc. et al
Docket Nos. 070304-EI & 070300-EI	Florida Public Utilities Company Before the Florida Public Service Commission

Docket No. ER07-956-001	Entergy Service, Inc. Before the Federal Energy Regulatory Commission
Docket No. 080001-EI	Florida Power & Light Company Before the Florida Public Service Commission

*Case Settled
**Issues Stipulated
***Testimony Withdrawn
****Case Settled, Testimony Not Filed

TAMPA ELECTRIC COMPANY
DOCKET NO. 080317-EI

SCHEDULES OF HUGH LARKIN, JR.
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Schedules C-4 to C-12 are sponsored by OPC Witness Helmuth Schultz

Tampa Electric Company
Projected Test Year Ended December 31, 2009

Revenue Requirement
(Thousands of Dollars)

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Exhibit No.__ HL-1
Schedule A
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Line No.	Description	Per Company Amount (A)	Per OPC Amount (B)	Col. (B) Reference
1	Jurisdictional Adjusted Rate Base	$ 3,656,800	$ 3,413,382	Schedule B-1, p. 1
2	Required Rate of Return	8.82%	7.33%	Schedule D-1
3	Jurisdictional Income Required	$ 322,530	$ 250,280	Line 1 x Line 2
4	Jurisdictional Adj. Net Operating Income	$ 182,970	$ 226,591	Schedule C-1, p. 1
5	Income Deficiency (Sufficiency)	$ 139,560	$ 23,689	Line 3 - Line 4
6	Earned Rate of Return	5.00%	6.64%	Line 4 / Line 1
7	Net Operating Income Multiplier	1.634900	1.633202	Schedule A-1
8	Revenue Deficiency (Sufficiency)	$ 228,166	$ 38,689	Line 5 x Line 7
9	Percentage Revenue Increase	26.37%	4.47%	Line 8 /Line 4, Sch C-1

Tampa Electric Company
Projected Test Year Ended December 31, 2009

Net Operating Income Multiplier
(Thousands of Dollars)

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Exhibit No.__ HL-1
Schedule A-1
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Line No.	Description	Percent	
1	Revenue Requirement	100.0000%	
2	Gross Receipts Tax Rate	0.0000%	
3	Regulatory Assessment Rate	0.0720%	
4	Bad Debt Rate, per OPC	0.2464%	Schedule C-3
5	Net Before Income Taxes	99.6816%	
6	State Income Tax Rate (Effective)	5.5000%	
7	State Income Tax	5.4825%	
8	Net Before Federal Income Tax	94.1991%	
9	Federal Income Tax Rate (Effective)	35.0000%	
10	Federal Income Tax	32.9697%	
11	Revenue Expansion Factor	61.2294%	
12	Net Operating Income Multiplier	1.633202	

Source:
MFR Schedule C-44

Tampa Electric Company
Projected Test Year Ended December 31, 2009

Adjusted Rate Base
(Thousands of Dollars)

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Exhibit No.__ HL-1
Schedule B-1
Page 1 of 2

Line No.	Rate Base Components	Adjusted Juris. Total Amount per Company (A)	Citizens Adjustments (B)	Adjusted Juris. Total Amount per Citizens (C)
1	Plant in Service	$ 5,483,474	$ (229,855)	$ 5,253,619
2	Accumulated Depreciation & Amortization	(1,934,489)	8,187	$ (1,926,302)
3	Net Plant in Service	3,548,985	(221,668)	3,327,317
4	Construction Work in Progress	101,071	2,608	103,679
5	Plant Held for Future Use	37,330	(2,328)	35,002
6	Nuclear Fuel	-		-
7	Accumulated Amortization of Nuclear Fuel	-		-
8	Total Net Plant	3,687,386	(221,388)	3,465,998
9	Total Working Capital	(30,586)	(22,030)	(52,616)
10	Other Rate Base Adjustments	-		-
11	Total Rate Base	$ 3,656,800	$ (243,418)	$ 3,413,382

Source/Notes
Col. A: Company MFR Schedule B-1, p. 1
Col. B: See Schedule B-1, page 2

Tampa Electric Company
Projected Test Year Ended December 31, 2009

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Exhibit No.__ HL-1
Schedule B-1
Page 2 of 2

Adjusted Rate Base-Summary of Adjustments
(Thousands of Dollars)

Line No.	Adjustment Title	Witness Reference	Total Adjustment	Jurisdictional Separation Factor	Jurisdictional Amount
	Plant in Service Adjustments				
1	Remove Annualization 2 CTs	Schedule B-2			$ (36,125)
2	Remove Annualization 3 CTs	Schedule B-2			$ (94,562)
3	Remove Annualization Rail Project	Schedule B-2			$ (44,754)
4	Adjustments to Plant in Service (Accounts 101 and 106)	Schedule B-3	$ (53,958)	0.963137	$ (51,969)
5	Remove CIS Upgrade	Testimony			$ (2,445)
6					
7					
8					
9	*Total Plant in Service*		$ (53,958)		$ (229,855)
10					
11					
12	**Accumlated Depreciation Adjustments**				
13	Reduction to Accumulated Depreciation	Schedule B-4	$ 8,500	0.963137	$ 8,187
14					-
15					-
16	*Total Accumulated Depreciation*		$ 8,500		$ 8,187
17					
18					
19	**Construction Work in Progress**				
20	Increase to CWIP	Schedule B-6			2,608
21	*Total Construction Work in Progress*				$ 2,608
22					
23					
24	**Plant Held for Future Use**				
25	Decrease to PHFFU				$ (2,328)
26	*Total Plant Held for Future Use*				$ (2,328)
27					
28					
29	**Working Capital Adjustments**				
30	Adjustment to Working Capital	Schedule B-5			$ (22,030)
31	*Total Working Capital*				$ (22,030)

Tampa Electric Company
Projected Test Year Ended December 31, 2009

Annualization Adjustments
(Thousands of Dollars)

Docket No. 080317-EI
Exhibit No. ___ HL-1
Schedule B-2
Page 1 of 1

Line No.	Description	Jurisdictional 2 CTs	Jurisdictional 3 CTs	Jurisdictional Rail Project
	Capital Costs			
1	Annualized Amount [1]	$ 36,125	$ 94,562	$ 44,754
	O&M Expenses, Depreciation and Taxes Other Than Income Tax			
2	O&M Expenses [2]	$ 212	$ 658	$ -
3	Depreciation Expense [2]	$ 1,391	$ 4,034	$ 906
4	Taxes Other Than Income [2]	$ 2,226	$ 3,227	$ 1,039

Source:
[1] MFR Schedule B-2 page 2 of 4.
[2] MFR Schedule C-2, page 3 of 7.

Tampa Electric Company
Projected Test Year Ended December 31, 2009

Docket No. 080317-EI
Exhibit No. ___ HL-1
Schedule B-3
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Adjustments to Plant in Service (Accounts 101 and 106)
(Thousands of Dollars)

Line No.	Month and Year	TECO Projected Plant in Service Balance [1]	TECO Actual Plant in Service Balance [2]	Amount of Difference Over Actual	Percentage Difference Over Actual
1	January 2008	$ 5,240,558	$ 5,234,001	$ 6,557	0.125%
2	February 2008	$ 5,253,164	$ 5,237,428	$ 15,736	0.300%
3	March 2008	$ 5,261,874	$ 5,239,405	$ 22,469	0.429%
4	April 2008	$ 5,343,301	$ 5,236,769	$ 106,532	2.034%
5	May 2008	$ 5,449,327	$ 5,300,477	$ 148,850	2.808%
6	June 2008	$ 5,462,230	$ 5,370,865	$ 91,365	1.701%
7	July 2008	$ 5,473,391	$ 5,454,357	$ 19,034	0.349%
8	August 2008	$ 5,492,413	$ 5,463,621	$ 28,792	0.527%
9	September 2008	$ 5,472,308	$ 5,471,683	$ 625	0.011%
10	Total	$ 48,448,566	$ 48,008,606	$ 439,960	8.286%
11	Average Percentage Overstated				0.921%
12	13-Month Average Projected Utility Plant in Service				$5,860,981 [3]
13	Adjustment to Utility Plant in Service (Line 11 x Line 12)				$ (53,958)
14	Jurisdictional Factor				0.963137 [4]
15	Jurisdictional Adjustment (Line 13 x Line 14)				$ (51,969)

[1] MFR Schedule B-3 page 4 of 9.
[2] POD #5, 47, 116
[3] MFR Schedule B-1 page 1.
[4] MFR Schedule B-1 page 1.

Tampa Electric Company
Projected Test Year Ended December 31, 2009

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Exhibit No. ___ HL-1
Schedule B-4
Page 1 of 1

Adjustments to Accumulated Depreciation & Amortization
(Accounts 108 and 111)
(Thousands of Dollars)

Line No.	Month and Year	TECO Projected Accumulated Depreciation	TECO Actual Accumulated Depreciation	Amount of Difference Over Actual	Percentage Difference Over Actual
1	January 2008	$ (1,955,055)	$ (1,956,136)	$ 1,081	-0.055%
2	February 2008	$ (1,962,744)	$ (1,955,483)	$ (7,261)	0.371%
3	March 2008	$ (1,970,118)	$ (1,958,221)	$ (11,897)	0.608%
4	April 2008	$ (1,967,282)	$ (1,954,812)	$ (12,470)	0.638%
5	May 2008	$ (1,976,618)	$ (1,964,835)	$ (11,783)	0.600%
6	June 2008	$ (1,982,501)	$ (1,975,190)	$ (7,311)	0.370%
7	July 2008 [5]	$ (1,989,068)	$ (1,981,647)	$ (7,421)	0.374%
8	Total	$ (13,803,386)	$ (13,746,324)	$ (57,062)	2.906%
9	Average Percentage Overstated				0.415%
10	13-Month Average Projected Accumulated Depreciation				$ (2,047,696) [3]
11	Adjustment to Accumulated Depreciation (Line 9 x Line 10)				$ 8,500
12	Jurisdictional Factor				0.963137 [4]
13	Jurisdictional Adjustment (Line 11 x Line 12)				$ 8,187

[1] Schedule B-3 page 4 of 9.
[2] POD #5 & POD 47
[3] Schedule B-1 page 1.
[4] Schedule B-1 page 1.
[5] We were not able to update the accumulated depreciation and amortization through September 2008 as we did for Plant In Service because the Financial Statements provided by the Company did not contain enough detail to determine the respective amounts.

Tampa Electric Company
Projected Test Year Ended December 31, 2009

Working Capital
(Thousands of Dollars)

Line No.	Account No.	Component	Reference	Test Year Jurisdictional Amount	Commission Adjustment	OPC Adjustment	Adjusted Test Year Amount
1							
2		**Current and Accrued Assets:**					
3	131	Cash		$ -			$ -
4	134	Other Special Deposits		$ 83			$ 83
5	135	Working Funds		$ 81			$ 81
6	136	Temporary Cash Investments		$ 2,093	$ (2,093)		$ -
7	142	Customer Accounts Receivable		$ 158,046			$ 158,046
8	143	Other Accounts Receivable		$ 12,676	$ (1,717)	$ (10,959)	$ -
9	144	Accum Provision for Uncoll. Accounts		$ (672)			$ (672)
10	146	Accounts Receivable from Associated		$ 6,309		$ (6,309)	$ -
11	151	Fuel Stock		$ 94,926		$ (9,493)	$ 85,433
12	152&153	Residuals		$ -			$ -
13	154	Plant Materials and Operating Supplies		$ 55,678			$ 55,678
14	158	CAAA Allowances		$ 4			$ 4
15	163	Stores Expense Undistributed		$ -			$ -
16	165	Prepayments		$ 12,610			$ 12,610
17	171	Interest and Dividends Receivable		$ -			$ -
18	173	Unbilled Revenue Receivable		$ 33,979			$ 33,979
19	176	Derivatives		$ 5,235			$ 5,235
20		**Total Current and Accrued Assets**		$ 381,048	$ (3,810)	$ (26,761)	$ 350,477
21							
22		**Deferred Debits:**					
22	182	Regulatory Assets		$ 153,100	$ (61,489)		$ 91,611
22	183	Preliminary Survey & Investigation Charges		$ 5,569			$ 5,569
23	184	Clearing Accounts		$ -			$ -
24	186	Deferred Debits		$ 1,411			$ 1,411
25	188	Research & Development Expenditures		$ -			$ -
26	189	Unamortized Loss		$ -			$ -

Tampa Electric Company
Projected Test Year Ended December 31, 2009

Working Capital
(Thousands of Dollars)

Line No.	Account No.	Component	Reference	Test Year Jurisdictional Amount	Commission Adjustment	OPC Adjustment	Adjusted Test Year Amount
27		**Total Deferred Debits**		$ 160,080	$ (61,489)	$ -	$ 98,591
28							
29		**Adjusted Current and Accrued Assets & Deferred Debits**		$ 541,128	$ (65,299)	$ (26,761)	$ 449,068
30							
31		**Other Noncurrent Liabilities**					
32	228	Miscellaneous Current Liabilities		$ 191,720			$ 191,720
33	229	Provision for Refund		$ -			$ -
34	230	ARO		$ 26,095			$ 26,095
35		**Total Other Noncurrent Liabilities**		$ 217,815	$ -	$ -	$ 217,815
36							
37		**Current and Accrued Liabilities**					
38	232	Accounts Payable		$ 159,958	$ (350)		$ 159,608
39	234	Accounts Payable to Associated Companies		$ 7,848			$ 7,848
40	236	Taxes Accrued		$ 38,741			$ 38,741
41	237	Interest Accrued		$ 29,709			$ 29,709
42	238	Dividends Declared - Common Equity		$ 7,372	$ (7,372)		$ -
43	241	Tax Collections Payable		$ 5,292			$ 5,292
44	242	Current & Accrued Liabilities		$ 23,721			$ 23,721
45		**Total Current & Accrued Liabilities**		$ 272,641	$ (7,722)	$ -	$ 264,919
46							
47		**Deferred Credits**					
48	245	Derivatives		$ 5,222			$ 5,222
49	253	Other Deferred Credits		$ 10,601			$ 10,601
50	254	Regulatory Liabilities		$ 4,147			$ 4,147
51	256	Deferred Credit - Property Held For Future Use		$ 998			$ 998
52		**Total Deferred Credits**		$ 20,968	$ -	$ -	$ 20,968
53							

Tampa Electric Company
Projected Test Year Ended December 31, 2009

Working Capital
(Thousands of Dollars)

Line No.	Account No.	Component	Reference	Test Year Jurisdictional Amount	Commission Adjustment	OPC Adjustment	Adjusted Test Year Amount
54		**Adjusted NonCurrent, Current and Accrued Liabilities/Deferred Credits**		$ 511,424	$ (7,722)	$ -	$ 503,702
55							
56		**Working Capital Allowance**		$ 29,704	$ (57,577)	$ (26,761)	$ (54,634)
57							
58		**Company Adjustments**					
59		Amortize Rate Case Expense		$ 2,628		$ (612)	$ 2,016
60		Amortize Dredging O&M		$ 2,657		$ (2,657)	$ -
61		Storm Reserve Accrual	Testimony	$ (8,000)		$ 8,000	$ -
62		Subtotal		$ (2,715)	$ -	$ 4,731	$ 2,016
63							
64		**Adjusted Working Capital Allowance**		$ 26,989	$ (57,577)	$ (22,030)	$ (52,618)

Tampa Electric Company
Projected Test Year Ended December 31, 2009

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Exhibit No. ___ HL-1
Schedule B-6
Page 1 of 1

Adjustments to Construction Work In Progress (Account 107)
(Thousands of Dollars)

Line No.	Month and Year	TECO Projected CWIP Balance [1]		TECO Actual CWIP Balance [2]		Amount of Difference Over Actual		Percentage Difference Over Actual
1	January 2008	$	329,528	$	331,120	$	1,592	0.481%
2	February 2008	$	349,455	$	346,680	$	(2,775)	-0.800%
3	March 2008	$	378,303	$	364,202	$	(14,101)	-3.872%
4	April 2008	$	313,144	$	378,107	$	64,963	17.181%
5	May 2008	$	240,196	$	342,803	$	102,607	29.932%
6	June 2008	$	254,194	$	298,076	$	43,882	14.722%
7	July 2008	$	274,936	$	240,080	$	(34,856)	-14.518%
8	August 2008	$	297,353	$	266,386	$	(30,967)	-11.625%
9	September 2008	$	334,745	$	292,566	$	(42,179)	-14.417%
10	Average Percentage Understated							1.898%
		(a) TECO		(b) Average % Understated		(c) Col (a) x Col. (b)		
11	Jurisdictional Utility	$	394,109	1.0190		$	401,597	
12	Commission Adjustments	$	(256,867)	1.0190		$	(261,747)	
13	Company Adjustments	$	(36,171)			$	(36,171)	
14	Total	$	101,071			$	103,679	
15	Jurisdictional Adjusted utility per TECO					$	101,071	
16	Adjustment to CWIP					$	2,608	

[1] MFR Schedule B-3 page 4 of 9.
[2] POD #5, 47, 116

[3] Calculation of CWIP for Aug & Sep 2008	$	306,618	$	332,798
CWIP Per Balance Sheet OCC POD 116	$	40,232	$	40,232
Less PHFFU per General Ledger 7/08 OCC POD 47	$	266,386	$	292,566

Tampa Electric Company
Projected Test Year Ended December 31, 2009

Adjusted Net Operating Income
(Thousands of Dollars)

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Exhibit No.__ HL-1
Schedule C-1
Page 1 of 2

Line No.	Description	Adjusted Jurisdictional Total per Company (A)	Citizens Adjustments (B)	Adjusted Jurisdictional Total per Citizens (C)
1	Revenues from Sales	837,851	-	837,851
2	Other Operating Revenues	27,508	-	27,508
3				
4	**Total Operating Revenues**	865,359	-	865,359
5				
6	**Operating Expenses**			
7	Fuel	6,652		6,652
8	Purchased Power	962		962
9	Deferred Costs	-		-
10	Other Operation & Maintenance	370,934	(54,963)	315,971
11	Depreciation & Amortization	194,608	(15,076)	179,532
12	Taxes Other Than Income	62,275	(6,492)	55,783
13	Income Taxes	48,492	32,910	81,402
14	Gain/Loss on Disposition of Utility Plant	(1,534)		(1,534)
15				
16	Total Operating Expenses	682,389	(43,621)	638,768
17				
18	Net Operating Income	182,970		226,591

Source/Notes
Col. A: MFR Schedule C-1, p. 1
Col. B: See Schedule C-1, Page 2

Tampa Electric Company
Projected Test Year Ended December 31, 2009.

Net Operating Income-Summary of Adjustments
(Thousands of Dollars)

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Exhibit No.__ HL-1
Schedule C-1
Page 2 of 2

Line No.	Adjustment Title	Witness/Reference	Total Adjustment	Separation Factor	Jurisdictional Amount
	Operating Revenue Adjustments				
1					
2					
3	subtotal				$ -
4					
5	**Operating Expense Adjustments**				
6	Other O & M				
7	Remove Annualization 2 CTs	Schedule B-2			$ (212)
8	Remove Annualization 3 CTs	Schedule B-2			(658)
9	Remove increase in storm reserve	Testimony			(16,000)
10	Uncollectible Expense	Schedule C-3	(2,409)	0.972497	(2,342)
11	Dredging O&M	Testimony	(1,380)	0.963880	(1,330)
12	Payroll	H. Schultz Testimony	(3,677)	0.970549	(3,569)
13	Benefits	H. Schultz Testimony	(1,462)	0.971647	(1,421)
14	Incentive Compensation	H. Schultz Testimony	(11,575)	0.970549	(11,234)
15	D&O Liability Insurance	H. Schultz Testimony	(1,701)	0.970549	(1,651)
16	Tree trimming	H. Schultz Testimony			(3,989)
17	Pole Inspections	H. Schultz Testimony			(236)
18	Transmission Inspections	H. Schultz Testimony	(319)	0.841260	(268)
19	Substation Preventative Maintenance	H. Schultz Testimony	(1,058)	0.920559	(974)
20	Generation Maintenance	H. Schultz Testimony	(8,480)	0.963733	(8,172)
21	Rate Case Expense	H. Schultz Testimony			(612)
22	Office Supplies & Expense	H. Schultz Testimony	(2,363)	0.971140	(2,295)
23					-
24					-
25					-
26					-
27					
28	subtotal				$ (54,963)
29					
30	Depreciation & Amortization				
31	Remove Annualization 2 CTs	Schedule B-2			(1,391)
32	Remove Annualization 3 CTs	Schedule B-2			(4,034)
33	Remove Annualization Rail Project	Schedule B-2			(906)
34	Overstatement of Reserve for Depreciation	Testimony			(8,187)
35	Remove CIS Upgrade	Testimony			(558)
36					-
37	subtotal				$ (15,076)
38					
39	Taxes Other Than Income				
40	Remove Annualization 2 CTs	Schedule B-2			$ (2,226)
41	Remove Annualization 3 CTs	Schedule B-2			$ (3,227)
42	Remove Annualization Rail Project	Schedule B-2			$ (1,039)
43					-
44	subtotal				$ (6,492)
45					
46	Income Taxes				
47		Schedule C-13			$ 29,522
48					
49	subtotal				$ 29,522
50					
51	Interest Synchronization				
52	subtotal	Schedule C-14			$ 3,388
53					$ 3,388
54					
55	Total Income Taxes including interst interest synchronization				$ 32,910

Notes
Jurisdictional Separation Factors from MFR Schedule C-4 or other schedules within the Company's filing.

Tampa Electric Company
Projected Test Year Ended December 31, 2009

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Exhibit No. ___ HL-1
Schedule C-2
Page 1 of 1

Storm Damage Reserve
(Thousands of Dollars)

	Accrual	Storm Charges	Balance December 31 Year End
1994	$ 4,000,000		$ 4,000,000
1995	$ 4,000,000		$ 8,000,000
1996	$ 4,000,000		$ 12,000,000
1997	$ 4,000,000		$ 16,000,000
1998	$ 4,000,000		$ 20,000,000
1999	$ 3,999,950		$ 23,999,950
2000	$ 4,000,050		$ 28,000,000
2001	$ 4,000,000		$ 32,000,000
2002	$ 4,000,000		$ 36,000,000
2003	$ 4,000,000		$ 40,000,000
2004	$ 4,000,000		$ 44,000,000
Cost charged to reserve including costs which should have been capitalized. [1]		$ 74,567,219	
Costs included in reserve which should have been capitalized or charged to the reserve for depreciation. [2]		$ (38,877,284)	$ 8,310,065
2005	$ 4,000,000		$ 12,310,065
2006	$ 4,000,000		$ 16,310,065
2007	$ 4,000,000		$ 20,310,065
2008	$ 4,000,000		$ 24,310,065

[1] Reflects total costs charged in all years.
[2] Reflects capitalized cost recorded in 2005.

Tampa Electric Company
Projected Test Year Ended December 31, 2009

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Exhibit No.__ HL-1
Schedule C-3
Page 1 of 1

Uncollectible Expense
(Thousands of Dollars)

Line No.	Year	Write-Offs (Retail) [1]	Gross Revenues From Sales of Electricity [2]	Bad Debt Factor	
1	2003	3,296	1,518,920	0.217%	
2	2004	3,261	1,642,008	0.199%	
3	2005	4,761	1,666,119	0.286%	
4	2006	4,812	1,908,413	0.252%	
5	2007	5,527	2,053,228	0.269%	
6	Total 2001 - 2004	21,657	8,788,688	0.246%	
7	2009 Adjusted Gross Revenues, per Tampa Electric			2,257,289	[3]
8	OPC Recommended Bad Debt Rate			0.246%	
9	OPC Recommended Bad Debt Expense			5,562	Line 7 x Line 8
10	Bad Debt Expense (Net Write-Offs), per Tampa Electric			7,971	[4]
11	Reduction to Bad Debt Expense			(2,409)	
12	Separation Factor			0.972497	[5]
13	Jurisdictional Adjustment (Line 11 x Line 12)			$ (2,342)	

Source:
[1] MFR Sch. C-6 (Line 1), Schedule C-11 (Lines 2- 5)
[2] MFR Sch. C-6 (Line 1), Schedule C-11 (Lines 2- 5)
[3] MFR Schedule C-6, Accounts 440-446 and 451
[4] MFR Schedule C-11
[5] MFR Schedule C-1

Tampa Electric Company
Projected Test Year Ended December 31, 2009

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Exhibit No.__ HL-1
Schedule C-13
Page 1 of 1

Income Tax Expense
(Thousands of Dollars)

Line No.	Description	Amount
1	Jurisdictional Operating Income Adjustments (1)	$ 76,531
2	Composite Income Tax Rate (2)	38.575%
3	Adjustment to Income Expense	$ 29,522

Source:
(1) Schedule C-1, Page 2
(2) Calculated using Florida state income tax rate of 5.50% and federal income tax rate of 35%.

Tampa Electric Company
Projected Test Year Ended December 31, 2009

Docket No. 080317-EI
Exhibit No.__ HL-1
Schedule C-14
Page 1 of 1

Interest Synchronization Adjustment
(Thousands of Dollars)

Line No.	Description	Amount	Reference
1	Adjusted Jurisdictional Rate Base, per Citizens	$ 3,413,382	Schedule B-1
2	Weighted Cost of Debt	3.16%	Note (1)
3	Interest Deduction for Income Taxes	$ 107,988	
4	Interest Deduction, per Company	$ 116,770	MFR Sch. C-23
5	Increase in Deductible Interest	$ (8,782)	
6	Consolidated Income Tax Rate	38.575%	
7	(Reduction) Increase to Income Tax Expense	$ 3,388	

Source:
(1) Based on weighted cost of debt and weighted cost of customer deposits, as shown on Schedule D.

Tampa Electric Company
Projected Test Year Ended December 31, 2009

Docket No. 080317-EI
Exhibit No.__ HL-1
Schedule D-1
Page 1 of 1

Cost of Capital
(Thousands of Dollars)

		Per Company	Adjs. To Reflect OPC Cap. Struct.	Adjusted Amounts	OPC Rate Base Adjustments	Per Citizens Adjusted Amounts	Ratio	Cost Rate*	Weighted Cost Rate
		(1)	(2) (col. (e), below)	(3)	(4)	(5)	(6)	(7)	(8)
1	Long Term Debt	1,397,565	204,105	1,601,670	(106,617)	1,495,053	43.80%	6.80%	2.98%
2	Preferred Stock	-				-			
3	Customer Deposits	103,724	(532)	103,192	(6,869)	96,323	2.82%	6.07%	0.17%
4	Common Equity	1,835,985	(282,732)	1,553,253	(103,394)	1,449,859	42.48%	9.75%	4.14%
5	Short Term Debt	8,002	13,971	21,973	(1,463)	20,511	0.60%	2.33%	0.01%
6	Deferred Income Tax	302,744	61,827	364,571	(24,268)	340,303	9.97%	0.00%	0.00%
7	Investment Tax Credits	8,780	3,361	12,141	(808)	11,332	0.33%	8.21%	0.03%
8									
9	Total	3,656,800	(0)	3,656,800	(243,418)	3,413,382	100.00%		7.33%
10									
11									

		Per TECO Amounts	Effective TECO Ratio	Capitalization Ratio Per OPC*	Revised Allocations	Adjs. To Reflect OPC Cap. Struct.
12						
13						
14	Ratio of Debt & Equity Components					
15		(a)	(b)	(c)	(d)	(e) = (d - a)
16	Long Term Debt	1,397,565	38.22%	43.80%	$ 1,601,670	204,105
17	Preferred Stock	-				-
18	Customer Deposits	103,724	2.84%	2.82%	$ 103,192	(532)
19	Common Equity	1,835,985	50.21%	42.48%	$ 1,553,253	(282,732)
20	Short Term Debt	8,002	0.22%	0.60%	$ 21,973	13,971
	Deferred Income Tax	302,744	8.28%	9.97%	$ 364,571	61,827
	Investment Tax Credits	8,780	0.24%	0.33%	$ 12,141	3,361
		3,656,800	100.00%	100.00%	$ 3,656,800	(0)

The per Company amounts are from MFR Sch. D-1a.
* The Capitalization Ratio and cost rates are sponsored by Citizens Witness Dr. J. Randall Woolridge.

3,656,800
$ (243,418)

204,105.02	1,397,565	$ 1,601,670	Long Term Debt	43.80%	$ (106,617)
	-		Preferred Stock		
(531.61)	103,724	$ 103,192	Customer Deposits	2.82%	$ (6,869)
(282,731.93)	1,835,985	$ 1,553,253	Common Equity	42.48%	$ (103,394)
13,971.30	8,002	$ 21,973	Short Term Debt	0.60%	$ (1,463)
61,826.64	302,744	$ 364,571	Deferred Income Tax	9.97%	$ (24,268)
3,360.59	8,780	$ 12,141	Investment Tax Credits	0.33%	$ (808)
		$ 3,656,800			$ (243,418)
(0.00)	3,656,800				

TECO
TAMPA ELECTRIC

SUMMARY OF PROGRAM SCOPE APPROVAL

COMPANY: TAMPA ELECTRIC COMPANY

OPERATION UNIT: Customer Service

PROJECT TITLE:
Rate Case Software Changes

PROJECT LOCATION: Customer Service

[ ] BUDGETED [X] UNBUDGETED

[ ] DEFERRABLE [ ] NON-DEFERRABLE

ESTIMATED PROJECT DATES

START	IN SERVICE
03/24/08	04/05/0~~8~~9

TYPE/AMOUNT OF REQUEST	($x1000)
LAND	$
FIXED ASSETS	$ 2655
DISPOSITION FIXED ASSET	
MAJOR MAINTENANCE	
LEASE	
CIAC / REIMBURSEMENT	
EXPENSE	$ 137
OTHER	
TOTAL REQUEST	$ 2792
CAPITALIZED INTEREST	$

TOTAL COST BY YEAR

	2008	2009	2010	2011	TOTAL
IMPROVEMENT # E2589	$1,951	$704			$2,655
RETIREMENT #					
TOTAL CAPITAL COST					
[X] EXPENSE [ ] VEHICLE	$ 71	$ 66			$137
TOTAL REQUEST	$2,022	$770			$2,792

APPROVALS AND ENDORSEMENTS

TITLE	NAME	INITIALS	DATE
INITIATOR & PROJECT RESPONSIBILITY	Sharon Ogle / Project Lead	Sharon Ogle	05/05/08
ORIGINATING DIRECTOR	Barb Powers	BAP	05/05/08
DIRECTOR - FINANCIAL SERVICES	Sean Hillary	SH	5/5/08
VICE PRESIDENT	Deirdre Brown	Deirdre A Brown	5/6/08
COMPANY PRESIDENT	Chuck Black	C Black	5/8/08

PROGRAM TITLE: Rate Case Software Changes IMPROVEMENT NO. # E2589

- **Job Description (Describe Major Highlights or Action Contemplated)**
  - **Spare Parts Required (No____) (Yes____)**

The anticipated 2008 rate case filing in May 2008 is expected to include proposed changes to many of the customer rate schedules, which ultimately must be programmed into the Customer Information System (CIS) and its subsystems for accurate billing. This PSA includes the man hours necessary to code and test to prepare for implementation as early as cycle 01, April 2009. The following areas impacted and included in this PSA:

- Inverted Energy and Fuel Rates for Residential (RS) customers
- Service Charges
- Lighting
- Interruptible customers (IS, SBI)
- TOD Residential (RST)

Due to the extensiveness of the changes, the project plan began in April 2008 with testing expected to begin October 2008 through March 2009, with code drops throughout this testing timeline. Additionally, this project includes the development and revision of Training Manuals for the Customer Contact Center and others users in Customer Service and Energy Delivery.

Tampa Electric may explore recoverability of the project costs as a Recoverable Rate Case Expenditure as we move through the Rate Case proceedings.

- **Consequences of Not Implementing (Year 1 and Long-Term)**

Tampa Electric would not be able to implement the FPSC approved changes by April 2009, Cycle 01, and would be out of compliance with our Tariff's effective date, if not implemented

- **Justification (Expected Gains in Service, Economics & Reliability and Intangible Benefits)**

Tampa Electric is seeking changes in rates and rate structure, with the Florida Public Service Commission as early as May of 2008. This work is directly the result of this filing.

- **Discussion of Business Risk**

- Unexpected Regulatory changes, significant in size, required to be implemented in the CIS system prior to April 2009 may have a significant impact on the project timeline and impede TEC's ability to meet the proposed implementation date of April 2009, Cycle 01.
- Unexpected event causing billing and/or workforce interruptions, such as hurricanes or other natural disasters, requiring the implementation of our Business Continuity plans may have a significant impact on the Rate Case project timeline and impede TEC's ability to meet the proposed implementation date as early as April 2009, Cycle 01.
- Workforce capacity to do strategic projects may be significantly reduced or eliminated.
- Unknown requirements and/or significant changes to requirements late in the project timeline, may delay TEC's ability to automatically implement changes and/or cause significant manual work.

- Lack of availability of developers in the market place for CIS, or lengthy contract negotiations with third party providers responsible for making the enhancements to iCON (Graphical Interface for CIS), GIS (Geographical Information System), Workpro (New Construction Work Management System), and OMS (Outage Management System).

♦ Detailed Description (Describe Units of Property) Additions

Permanent and automated methods of billing our customers according to the proposed tariff scheduled for approval in the spring of 2009 will change or enhance functionality to the following including:

- Inverted Energy and Fuel Rates for Residential (RS) customers
  - Includes storing several new data fields, screen changes, calculation changes for billing, bill print changes, numerous report modifications, and changes to iCON.
- Service Charges
  - Includes adding three to six new charges to the billing calc program, automating the passage to the customer, reporting, and transaction edits.
- Lighting
  - Includes the closure of three existing rate schedules and replacing with one new Schedule, thereby reducing the number of rates billed; transaction edits; changes to bill calculation programs, reporting, and bill print.
  - Impacts CIS interfaces with WorkPro, GIS and OMS.
- Interruptible customers (IS, SBI)
  - Includes Rate Calculation Redesign
  - Affects several transaction edits, new screens, billing, storing history, reporting, and bill print.
- TOD Residential (RST)
  - Includes the closure of the RST customers either to new business or permanently, which affects several transactions

- Training Manuals for the Customer Contact Center, all of Customer Service and Energy Delivery.

Detailed Description (Describe Units of Property) Removals

♦ Alternatives Considered

No other more cost effective and timely alternative is available considering the magnitude of the changes and the project timeline. Once approved by the Florida Public Service Commission, TEC must implement and make available to all applicable customers by the earliest expected date of cycle 01, April 2009.

♦ Cost Effective Measures Considered

- A holistic approach to the design is being considered in order to take advantage of similar changes to avoid duplicate effort in programming and in testing.
- Significant efforts and controls will be put into practice to control the scope of changes.