ORIGINAL

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY) DOCKET NO. 080677-EI
FLORIDA POWER & LIGHT COMPANY)

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

July 2009

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INRCEASE BY) DOCKET NO. 080677-EI
FLORIDA POWER & LIGHT COMPANY)

TABLE OF CONTENTS

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY) DOCKET NO. 080677-EI
FLORIDA POWER & LIGHT COMPANY)

DIRECT TESTIMONY OF STEPHEN J. BARON

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. Please state your educational background.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to numerous industrial, commercial, Public Service Commission and utility clients, including international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of

1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, before the Federal Energy Regulatory Commission ("FERC"), and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Baron Exhibit ____ (SJB-1).

Q. **Do you have previous experience in FPL regulatory proceedings?**

A. Yes. I have been involved in a number of FPL rate proceedings during my career. This includes participation as a Florida Public Service Commission Staff member in a 1975 FPL rate case, a generic DSM proceeding in 1993 and FPL rate cases in 2001 and 2005. I have also testified before the Commission in other proceedings on a number of occasions.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the South Florida Hospital and Healthcare Association, Inc. ("SFHHA" or the "hospitals"). SFHHA members take service on FPL General Service, High load factor-Time of Use and CILC rate schedules throughout the Company's service area.

Q. What is the purpose of your testimony?

A. I will address issues associated with FPL's class cost of service study and its proposed allocation of its requested base rate revenue increase of $1,044 million in 2010 ($969 million in rate schedule increases, $75 million in "other revenue" increases).[1] FPL has filed and supports a 12 CP and 1/13th average demand methodology that does not classify any distribution plant and expense as customer related, other than services and meters. Initially, I will discuss the Company's study and identify what appear to be anomalies in the projections that the Company has made for some rate schedules in the 2010 test year analysis.

[1] Since FPL's 2011 cost of service study uses an identical methodology, my comments, findings and recommendations apply to 2011 as well.

I will present the results of alternative cost of service analyses using other production demand allocation methods that correct for FPL's unreasonable proposals. In addition, I will address the Company's classification of distribution costs and present an analysis that reflects a more reasonable classification of these costs on the basis of the number of customers in each rate schedule, consistent with methodologies addressed in the National Association of Regulatory Utility Commissions ("NARUC") Electric Utility Cost Allocation Manual.

I will also discuss the Company's proposed increases to each rate schedule. FPL has argued that, because of prior settlements, projected 2010 and 2011 rate disparities are excessive and the Company is proposing to eliminate these disparities in this case. This position would produce excessive increases to large general service customers in this case. For example, the Company is proposing a base rate increase for the CILC-D rate schedule, on which many members of SFHHA take service, of 58.8% in 2010, compared to the system average rate schedule increase of 25%. My primary position is that FPL's cost of service allocation methodology is unreasonable. While I recognize that FPL's methodology is consistent with Commission precedent, I will show that the Company's cost of service study does not produce fair, just and reasonable rates under the current circumstances and that the Commission therefore should adopt a different allocation methodology that more appropriately recognizes the cost drivers on FPL's system. I will also discuss anomalies in the Company's projected parity results that I have identified.

I will also address the concept of gradualism in ratemaking and propose an alternative set of rate schedule revenue increases consistent with the Florida Commission's prior precedent of limiting the increase to any rate schedule to 150% of the average increase. Irrespective of the class cost of service study methodology that is approved by the Commission (i.e., FPL's filed 12 CP and 1/13th average demand study, the SFHHA study or any alternative cost of service study approved by the Commission), the increase to any rate schedule be limited to 150% of the system average increase.

Q. Would you summarize your conclusions and recommendations?

A. Yes.

- **FPL has used cost of service methodologies in this case that unreasonably attribute cost responsibility to large general service rate schedules and ignore key cost drivers that have the effect of promoting on-peak consumption, which leads to increased costs on the system.**

- **FPL has based its proposed rate schedule increases on the results of its 12 CP and 1/13th average demand cost of service study and a goal to bring each rate schedule to within parity of the system average rate of return. A more reasonable cost of service study for FPL is a method based on a summer CP methodology, coupled with consideration of a "minimum distribution system" approach to the classification of secondary distribution facilities. FPL's failure to reasonably allocate costs in this case has resulted in an over-allocation of cost of service to large customers, which FPL then relies on to support significantly above average increases to these rate schedules.**

- **FPL has proposed increases to some rate schedules that are substantially in excess of 1.5 times the average retail base rate increase requested by the Company. Some rate schedules, such as CILC-D, GSLD-1, GSLDT-1, GSLDT-2, HLFT-2 and HLFT-3 will receive increases of 50% to 60% under the Company's proposals in this case. Putting aside for the moment the issue of whether FPL's cost responsibility calculations are correct; in consideration of the impact and the potential for "rate shock" with such large increases, no rate schedule should receive an increase greater than 150% of the system average base rate increase, consistent with the regulatory concept of "gradualism" and the Commission's precedents in other cases.**

II. COST ALLOCATION ISSUES

Q. Would you please discuss the issue of the allocation of demand related production costs?

A. Yes. As required by the MFR, FPL has filed a 12 CP and 1/13th average demand based cost of service study in this case. Another important methodological feature of the Company's cost study (beyond the allocation method for production and transmission demand costs) is the Company's classification of all distribution costs (except meters and services) as demand related. As I will discuss, the Company's methodology ignores any "customer related" cost responsibility for hundreds of millions of dollars of distribution plant and expenses, contrary to the approaches used by many other utilities throughout the country and the NARUC cost allocation manual, which recognizes a "customer component" of distribution cost based on a minimum system concept.

Given the significance placed on the rate of return parities produced by the Company's class cost of service study, these issues (the production demand allocation method and the consideration of a customer component of distribution costs) are highly significant. In particular, the Company's rejection of gradualism in its rate schedule increases places even more importance on these methodological issues. While I agree that parties can, and typically do, reasonably disagree about cost allocation methodologies, the Company's insistence on setting rates at parity in this case places a higher level of significance on the cost of service study issue. Given that general service customers will face increases in excess of twice the average increase in this case under the Company's proposal, it is all the more important to address the reasonableness of the cost of service study relied on by FPL for its recommendations.

Q. What is your understanding of the underpinning for the use of the 12 CP and 1/13th average demand method?

A. This methodology, which is primarily a 12 CP method, allocates production demand costs under the assumption that customer (and ultimately rate schedule) kW demand contributions to each of the 12 monthly coincident peaks have equal "cost responsibility" for the Company's generating units and power purchases (the capacity portion thereof). Thus, for example, the 12 CP method presumes that a residential or general service customer's incremental demand at the time of the August or January system coincident peak is no more "costly" to the system than the same amount of incremental demand at the time of the October or April FPL peak. This method sends price signals to customers that adding demand during any of the monthly peaks throughout the year costs the same to the Company. Correspondingly, if residential loads are being added more rapidly in the summer and winter peak months than in the off-peak months, the impact on class revenue requirements is much less (under FPL's cost methodology) than if a group of general service customers added the identical load during the summer and winter peaks, but also added a like amount of load in the off-peak months. In that case, general service class cost responsibility would increase much more under the Company's cost of service study allocation approach, even though such responsibility was spread throughout the year and not concentrated during the summer and winter peak months. As I will discuss subsequently, the driving factor in the addition of new generating capacity on the FPL system is the peak demand during the summer months. A review of FPL monthly reserve margins clearly demonstrates that it is customer demand during the peak summer months that is the primary cause of new capacity and its associated cost. While annual energy use influences the economics of generation selection, it is the level of customer demand in the summer months that influences the need for the capacity itself. As a result, a methodology, such as 12 CP that attributes the same impact to peak demand during off-peak months such as October or April as it does during peak summer months, does not recognize the actual causation of the need for capacity additions on the system

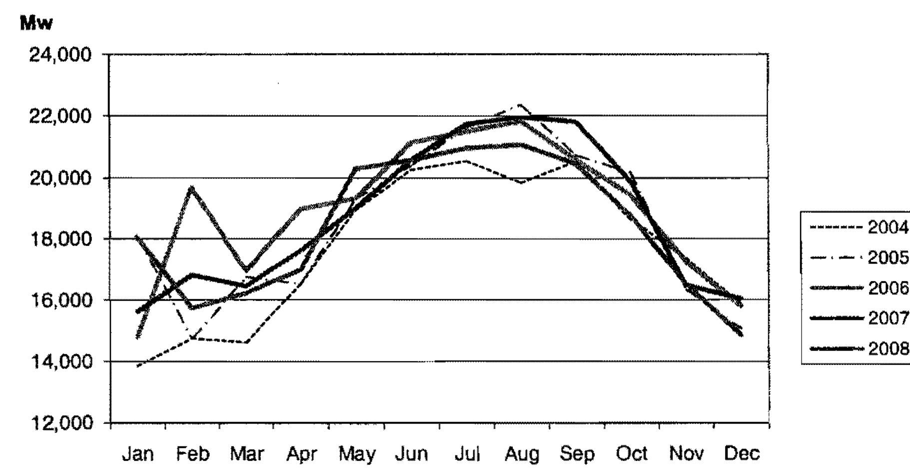
Q. Does FPL plan capacity additions to meet minimum reserve requirements during the summer peak?

A. Yes. Based on the Company's most recent 10 year site plan document, FPL utilizes a 20% minimum planning reserve margin criterion that it applies to both the summer and winter peak load requirements. However, based on expected peak loads on the system over the next 10 years, the summer month reserve margin is the binding constraint for planning. Baron Exhibit__(SJB-2) contains an excerpt from FPL's April 2009 "Ten Year Power Plant Site Plan" covering the period 2009 to 2018. A comparison of Schedule 7.1 of the planning document, which shows summer peak reserve margins to Schedule 7.2, which shows winter peak reserves, clearly demonstrates that FPL summer peak loads drive the need for future capacity additions.

Q. Are peak demands in other months binding constraints on the need for capacity and reserves on the system?

A. No, not based on the relative loads in non-summer months. Figure 1 below shows a chart of actual monthly system peak demands for the five year period 2004 to 2008. This chart clearly demonstrates that summer peak demands are significantly greater than non-summer month demands.

Figure 1
Florida Power & Light
Monthly System Peak Demands (2004 - 2008 Actual)

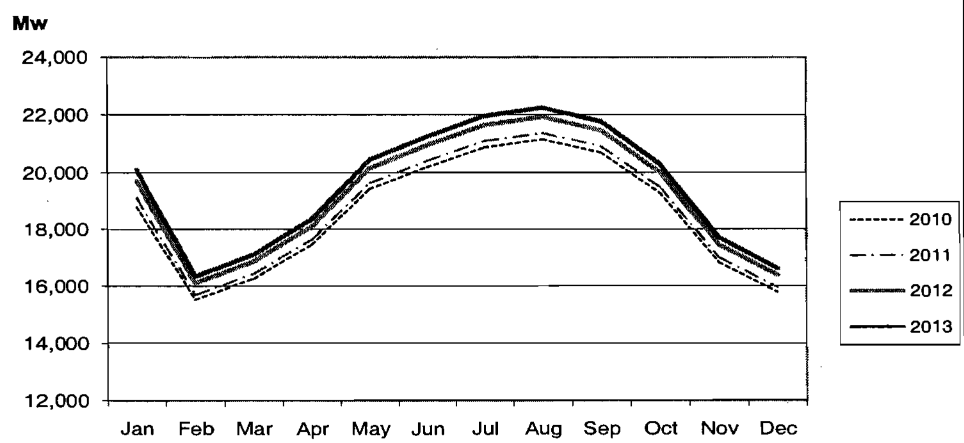


Customer on-peak usage during the summer is driving the need for capacity on the system and should be the basis for assigning production demand cost responsibility to rate schedules.

Q. Is this pattern expected to continue during in the future?

A. Yes. Figure 2 below shows a chart of forecasted monthly peaks for the period 2010 through 2013. FPL continues to expect a pronounced summer peak in future years.

Figure 2
Florida Power & Light
Monthly Peak Demands (2010 - 2013 Forecasted)



Q. What are the implications of this for pricing using the Company's proposed 12 CP and 1/13th average demand methodology?

A. The main implication is that customers are being provided price signals through rates that FPL is indifferent as to whether customers use demand in say March or in August. Even with moderated growth, FPL expects that installed capacity will grow by close to 6,000 mW over the next 10 years, according to Schedule 7.1 of the Company's 10 Year Site Plan [see Baron Exhibit__(SJB-2)]. Based on the Company's planning criteria and its seasonal load shape (pronounced summer peak), it would appear highly unlikely that changes in monthly peak demands in the non-summer months would have a material impact on the need for new capacity. Yet, FPL's 12 CP and 1/13th method assumes that production demand costs are equally driven by customer load coincident with these non-summer months as by customer loads in the summer. FPL continues to argue in its rate filing that customer behavior during any of the 12 months during the year is equally responsible for the Company's need to acquire new generating facilities to meet demand. However, FPL's own data do not support that conclusion. Rather, the data support the conclusion that much of the new generating capacity that FPL is planning would not be required, but for the need to meet summer peak requirements.

Q. What about the argument that the fuel savings associated with base load generating units support an allocation method that recognizes customer usage in non-peak months or even in the off-peak period?

A. Though it is certainly true that a base load nuclear unit produces energy at a lower fuel cost than a gas fired combined cycle unit, this does not change the fact that the Company is proposing to add thousands of mW of additional generating capacity to meet its summer peak demand. At the same time, FPL is "telegraphing" its customers through cost allocation and rate design that the "cost" of customer decisions associated with the next unit of consumption during March or October is equally responsible for this new capacity cost as the next unit of consumption during August at the time of the system peak.

Q. What conclusions do you draw from this analysis?

A. I believe that it is appropriate for the Commission to depart from its traditional approved 12 CP and $1/13^{th}$ methodology because that methodology is inconsistent with the factors that cause FPL to incur costs associated with new capacity additions. I recommend a summer coincident peak method because it recognizes the factors that actually are driving capital expenditures on FPL's system.

Q. Would you please discuss the methodology used by FPL to allocate distribution plant investment and expenses to retail rate classes?

A. Yes. As discussed in FPL witness Joseph Ender's testimony, the Company has classified all distribution plant as demand related except account 369 Services and account 370 meters, which are classified as customer related. The Company's approach does not give any recognition to a customer component of any primary or secondary line, pole or transformer. All of these costs are assigned on the basis of kW demand.

Q. Do you agree with the Company's classification of these distribution costs?

A. No. Despite the Commission's prior decision's rejecting a customer component for these distribution facilities, I believe that there is credible evidence to support a classification of some portion of these facilities as customer related. Given the significant reliance that the Company has placed on the results of its cost of service study in assigning its requested revenue increase to rate schedules in this case, it is reasonable for the Commission to consider evidence on alternative methods of classifying distribution costs in this case. FPL has, to a very significant degree, relied on the "parity" results from its cost of service study to assign increases to rate schedules. In particular, the proposed increases to its general service rate schedules are substantially higher than the system average increase due to the parity results. These parity results are driven to a large extent by the methodology used by FPL to classify and allocate costs to rate schedules. This is not purely an argument of academic interest. To the extent that the cost of service study is used to allocate the approved increase in this case, the underlying methodology used in the study will have a material impact on customer rates.

Q. What is the central argument underlying a classification of some portion of distribution costs (other than services, meters and "primary pull-offs") as customer related?

A. As described in the NARUC Electric Utility Cost Allocation Manual, the underlying argument in support of a customer component is that there is a minimal level of distribution investment necessary to connect a customer to the distribution system (lines, poles, transformers) that is independent of the level of demand of the customer.[2] To the extent that this component of distribution cost is a function of the requirement to interconnect the customer, regardless of the customer's size, it is appropriate to assign the cost of these facilities to rate schedules on the basis of the number of customers, rather than on the kW demand of the class. As stated on page 90 of the NARUC cost allocation manual:

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

Q. Has FPL offered evidence disputing that conclusion?

A. No.

Q. Would you briefly explain the conceptual basis for a minimum distribution cost methodology?

---

[2] An excerpt from the NARUC manual that discusses the classification of distribution costs is contained in Baron Exhibit__(SJB-3).

A. As discussed in the NARUC cost allocation manual, there are two approaches that are typically used to develop a customer component of distribution plant and expenses. Each of the two approaches ("zero-intercept" and "minimum size") is designed to measure a "zero load cost" associated with serving customers. Each methodology attempts to measure the customer component of various distribution plant accounts (e.g., poles, primary lines, secondary lines, line transformers, etc.). Each of the two methods (the zero-intercept method, for example) is designed to estimate the component of distribution plant cost that is incurred by a utility to effectively interconnect a customer to the system, as opposed to providing a specific level of power (kW demand) to the customer. Though arithmetically the zero-intercept method does produce the cost of say "line transformers" associated with "0" kW demand, the more appropriate interpretation of the zero-intercept is that it represents the portion of cost that does not vary with a change in size or kW demand and thus <u>should not</u> be allocated on NCP demand (as FPL has done). Essentially, the "zero-intercept" represents the cost that would be incurred, irrespective of differences in the kW demand of a distribution customer. It is this cost-invariant component that is used in the zero-intercept method to identify the portion of distribution costs that should be allocated to rate classes based on the number of primary and secondary distribution customers taking service in the class.

Conceptually, this analysis is designed to estimate the behavior of costs statistically, as the Company meets growth in both the number of distribution customers and the loads of these customers. This is in contrast to FPL's analysis that is premised on an assumption that all distribution costs (except services and meters) vary directly with kW demand, without any fixed component that should be allocated on the basis of the number of customers in each class.

Q. Do you have any specific examples that could illustrate this point?

A. Yes. In this rate case, FPL has classified all costs in account No. 364, poles, towers and fixtures, as demand related and allocated these costs to rate schedules on the basis of rate class NCP demand. This account mainly consists of primary and secondary poles. Based on the Company's workpapers in this case, there were approximately 185,000 secondary poles in the account that have been allocated to rate schedules using rate class

NCP demand. Table 1 summarizes FPL's implicit allocation of these secondary poles to major general service rate schedules and the residential rate class on the basis of demand. As can be seen in the table, FPL's cost of service study assumes that about 30 residential customers are served from each pole, while it takes about 19 poles to serve a single GSLDT-2 customer. This obviously does not seem realistic; yet, this is the cost allocation underlying FPL's proposed rate schedule increases in this case.

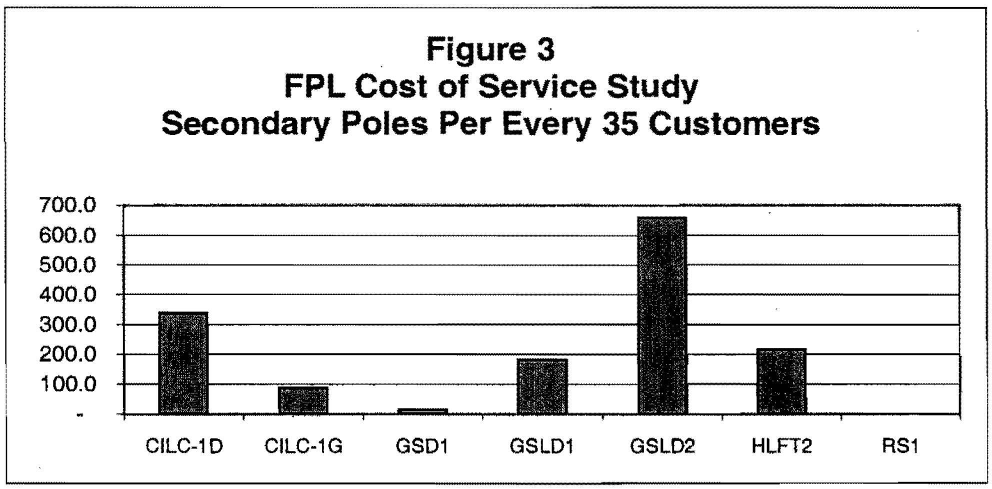
Table 1
FPL's Assignment of Secondary Poles Per Customer

Total Secondary Poles: 185,256

Rate Class	Allocation Factor*	Poles Allocated to Rate	Poles Per Customer	Poles Per Every 35 Customers
CILC-1D	1.444%	2,675	9.62	336.6
CILC-1G	0.145%	269	2.47	86.6
GSD1	21.398%	39,641	0.39	13.5
GSLD1	4.767%	8,831	5.18	181.3
GSLD2	0.526%	974	18.79	657.7
HLFT2	3.965%	7,346	6.18	216.3
RS1	57.231%	106,024	0.03	0.9

* FPL105

Figure 3 below illustrates this in graphic form. This result suggests that the Company's study, which ignores any measure of a customer component for distribution facilities (other than meters and services), overstates cost responsibility for large general service rate schedules.



Q. Does FPL acknowledge that the cost of poles is not fully dictated by customer kW demands, as is assumed in the Company's cost of service study?

A. Yes, I believe that they do acknowledge this fact. In response to SFHHA Interrogatory No. 137, the Company stated that there are numerous factors that determine the type, size and number (and by implication cost) of secondary poles on the system. Baron Exhibit__(SJB-4) contains a copy of this interrogatory response.

Q. Have you reviewed minimum distribution system classification results from cost studies developed by other utilities?

A. Yes. I have developed a summary of distribution classification results from five electric utilities, based on class cost of service studies filed by these Companies in regulatory proceedings during the past few years. While these results are not designed to be a comprehensive, random survey of electric utilities, the classification ratios (customer, demand) represent a cross-section of utilities that incorporate a minimum system distribution methodology in class cost of service studies. The summary results are presented in Baron Exhibit__(SJB-5). Based on these results, most distribution accounts are substantially classified as customer related (nearly 50% of most accounts). These customer classified costs are allocated to rate schedule on the basis of the number of customers in the class, not on demand. The remaining costs in each account are allocated on demand.

Q. Do you believe that a minimum distribution system is appropriate for FPL?

A. Yes. At a minimum, given the importance of the cost of service results (parities) in this case, it is appropriate for the Commission to analyze alternative methodologies. The conceptual basis for the zero-intercept method is that it reflects a classification of the distribution facilities that would be required to simply interconnect a customer to the system, irrespective of the kW load of the customer. From a cost causation standpoint, the argument supporting this approach is that all of these minimal facilities are needed to interconnect a customer to the FPL system, including meeting minimum safety standards set forth in the National Electric Safety Code ("NESC"), which the FPSC requires be adhered to for all Florida electric utilities.

Q. Are there other reasons why a customer classification of some portion of distribution plant is appropriate for FPL's system?

A. Yes. In response to the Commission Staff's Third Set of Interrogatories, Interrogatory No. 19, which asked FPL about adjustments that it made to its forecasts in this docket, the Company stated that it made "[A]n adjustment for the increase in the number of minimal usage customers FPL has experienced coincident with the housing crisis." FPL goes on to state that it adjusted its residential net energy for load forecast to reflect an increase in minimal use residential customers due to vacant homes. Since this would also affect residential kW demand, which is used to allocate distribution costs, the Company's test year cost of service study would tend to systematically understate the actual cost responsibility of the residential class for distribution plant and expenses. These distribution facilities are installed to serve these vacant homes, even if there is no usage. As noted, FPL is experiencing a substantial increase in the number of unoccupied residential dwellings. These vacant homes required investments by FPL in primary and secondary lines, poles, conduit and transformers. Yet, because the homes are vacant, the kW demand, which FPL's cost allocation method uses to allocate these distribution facilities to rate schedules are essentially allocated to other rate classes and not the residential rate class. The cost is not allocated to the residential class because there is little or no kW demand associated with a vacant home. While a minimum distribution system methodology may still not fully remedy this problem, it would provide a more reasonable allocation of cost. Baron Exhibit__(SJB-6) contains a copy of the interrogatory response.

Q. **Beyond the two methodological concerns that you have identified (production demand allocation method and distribution cost classification method), are there other issues with the Company's class cost of service study?**

A. Yes. As I indicated, the Company is proposing to allocate its requested $969 million 2010 rate schedule increase (and its 2011 increase) such that rate parities among rate schedules are equalized (i.e., set to 1.0).[3] These increases are based on the Company's projected test year cost of service study, which requires multiple forecasts of costs, billing determinants and cost allocation factors. Based on a comparison of cost of service results for the recent historical period, compared to the forecasted results for 2010 and 2011, there is reason to question whether the Company's forecast is reasonable. As I will discuss, this is a particular concern for certain large general service rate schedules, such as rates HLFT-2 and HLFT-3. Given the strict adherence FPL makes on its projected cost of service results in allocating the revenues

[3] The remaining $75 million in increased revenue in 2010 (total base revenue increase of $1,044 million) is being recovered from miscellaneous charges.

increase to rate schedules in this case, these concerns with the reasonableness of the Company's forecast should support a more reasoned application of the cost of service parity results – principally, the use of the Commission's gradualism precedent applied to rate schedule increases, such that no rate class receives and increase greater than 1.5 times the average increase.

Table 2 below shows the <u>actual</u> rate of return parities developed by FPL (using its cost of service methodology) for rates HLFT-2 and HLFT-3 for the most recent two years (2006 and 2007), compared to the parities that FPL <u>projects</u> for these two rate schedules for the years 2010 and 2011 if no adjustment is made to current rates.

Table 2
Rate of Return Parity Analysis
2006 to 2007 Actual, 2010 to 2011 Projected

	Actual 2006	Actual 2007	Projected 2010	Projected 2011
HLFT-2	0.62	0.61	0.34	0.35
HLFT-3	0.66	0.60	0.36	0.36

As can be seen from the table, for 2006 and 2007, using actual cost of service results, FPL reports that the rate of return parities for rates HLFT-2 and HLFT-3 were in the range of 0.60 to 0.66. For the forecast period, absent an adjustment to current rates, (2010 and 2011), FPL projects that the rate of return parities for rates HLFT-2 and HLFT-3 will be in the range of only 0.34 to 0.36, only about half the parity level in the recent actual period. This substantial reduction in parities projected by FPL in 2010 and 2011 raises a legitimate question as to the accuracy of the Company's projections. Since FPL is basing its proposed increases to rate schedules on these projected 2010 and 2011 cost of service parity results, without any mitigation or gradualism, this issue is not merely academic – it will impact the electric bills paid by FPL's large customers if the Company's proposals are adopted as filed.

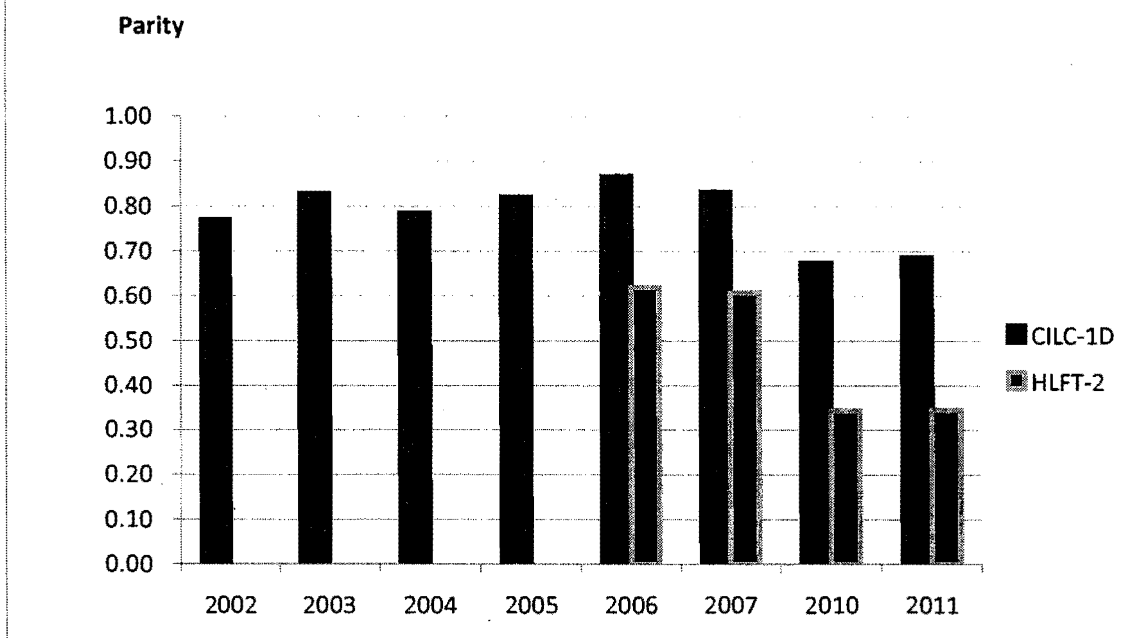
Q. Do the projected rate of return parity results for other large general service rate schedules exhibit similar anomalies?

A. Yes, to some extent. Table 3 below shows a comparison of rate of return parities for a group of large general service rate schedules and the residential class for the actual period 2002 through 2007 and the projected periods 2010 and 2011 filed in this case, including rates HLFT-2 and HLFT-3.

Table 3 Rate of Return Parity Analysis 2002 to 2007 Actual, 2010 to 2011 Projected	Actual 2002	Actual 2003	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Projected 2010	Projected 2011
CILC-1D	0.77	0.83	0.78	0.82	0.87	0.83	0.68	0.69
GSLD(T)-1	0.61	0.69	0.64	0.59	0.65	0.76	0.58	0.58
GSLD(T)-2	0.59	0.67	0.70	0.71	0.90	0.84	0.67	0.66
GSLD(T)-3	1.06	0.96	1.10	1.07	1.08	1.01	0.85	0.88
HLFT-1					0.82	0.89	0.79	0.79
HLFT-2					0.62	0.61	0.34	0.35
HLFT-3					0.66	0.60	0.36	0.36
RS(T)-1	1.13	1.05	1.08	1.06	1.04	1.05	1.07	1.06

While not as striking as the substantial reductions in parities in the projected period for rate schedules HLFT-2 and HLFT-3, FPL is projecting similar large reductions in parities for rate schedules CILC-1D, GSLD(T)-1, GSLD(T)-2 and GSLD(T)-3, absent a change in current rates. This anomaly is easier to see in Figure 4 below, which only depicts the results for CILC-1D and HLFT-2. Given the significance that these projected rate parities play in FPL's recommended increases, I have concern that the Company's projections are accurate.

Figure 4
Parity Comparison
2002-2007 Actual vs. 2010-2011 Projected



Q. **Have you identified any specific reasons why the CILC-D and HLFT-2 (and HLFT-3) rate of return results have changed so dramatically in the Company's projections, compare to actual results for the past six years for CILC-D and the past two years for HLFT-2 and HLFT-3?**

A. No. However, as shown on Table 4 below, FPL is projecting significant reductions from 2007 actual to 2010 in both 12 CP demand and kWh sales for the system and most rate schedules, though by varying amounts. In particular, the Company is showing increases in HLFT-2 demand and energy, while most other schedules are showing decreases.

Table 4
Comparison of 2007 Actual to Projected 2010 12 CP and kWh Sales
Percent Change 2010 vs. 2007

	Total FPSC	CILC-1D	GSLD1	GSLD2	HLFT2	RS1
fpl101 -12 CP	-1.66%	-2.70%	-6.55%	-6.25%	7.62%	-3.03%
fpl201 - MWH Sales	-3.73%	-5.05%	-13.19%	-12.57%	6.56%	-6.93%

Given the significant change that the Company is projecting for the rate of return parity for HLFT-2, these results call into question whether the forecasted test year class cost of service results are accurate. Though FPL has not proposed to increase HLFT-2 and HLFT-3 by the full amount necessary to achieve parity, the increases are still substantial (58% and 51% respectively). The great weight that the Company has placed on the forecasted rate parity results from its cost of service study (i.e., rejection of any mitigation or gradualism) means that any anomaly should raise a serious red flag as to the reasonableness of the Company's proposals in this case.

Q. You have discussed your recommendation to use a summer CP production demand allocation methodology and a minimum distribution system classification approach in developing the test year class cost of service study for FPL. Have you developed a revised class cost of service study reflecting these two changes to the Company's study?

A. Yes. Baron Exhibit__(SJB-7) presents the summary results of my recommended 2010 class cost of service study that incorporates a summer CP/minimum distribution methodology. This analysis, which reflects the same overall revenue requirement as the Company's MFR cost of service study, reflects the Company's analysis, modified for the two changes that I have discussed. I have not made changes to any other assumptions or methodology in the Company's study beyond the changes made to the production demand allocator and the distribution cost classifications.

Q. With regard to the minimum distribution system classifications, did you perform an independent analysis of FPL's distribution plant accounts to develop the customer and kW demand portion of each account?

A. No. For the purposes of this analysis, I utilized the average customer/demand classification values for each plant account, based on the data contained in Baron Exhibit__(SJB-5).

Q. How do the rate of return parities in your cost of service study compare to the Company's filed MFR cost study?

A. Table 5, which follows, shows the comparison. I have highlighted the large general service rate schedules in Table 5 to show the impact of these changes to the Company's cost of service study. As can be seen from the table, there are significant corrections in the rate of return parities for most large general service rate schedules using my alternative study.

Table 5
Comparison of ROR Parities
FPL COSS vs. Summer CP/Minimum System

	FPL COSS	Summer CP/ Min Sys
CILC-1D	0.67	1.16
CILC-1G	1.21	1.81
CILC-1T	0.64	0.94
CS1	0.91	1.35
CS2	0.90	1.24
GS1	1.50	1.25
GSCU-1	1.81	0.96
GSD1	0.96	1.23
GSLD1	0.58	0.86
GSLD2	0.66	1.06
GSLD3	0.85	1.16
HLFT1	0.79	1.18
HLFT2	0.34	0.65
HLFT3	0.35	0.65
MET	0.88	1.35
OL-1	1.59	0.34
OS-2	0.47	1.27
RS1	1.07	0.91
SDTR-1	0.90	1.67
SDTR-2	0.53	1.06
SDTR-3	0.32	0.72
SL-1	1.02	1.36
SL-2	2.25	3.12
SST-DST	0.74	0.99
SST-TST	3.70	2.62

Q. What is the implication of these results from your alternative cost of service study?

A. Using an alternative methodology that recognizes the importance of summer peak demands and reflects a minimum level of distribution cost associated with connecting customers to the system produces a materially different set of rate schedule revenue increases. I believe that the Commission should adopt my recommendation to use an alternative methodology for cost allocation using a summer CP/minimum distribution system approach.

Q. Have you prepared separate, independent impacts of rate of return parities for each of your two recommended changes to the Company's cost of service study?

A. Yes. Though I am recommending both changes, Table 6 below shows the rate of return parities using a summer CP method (with no change in FPL's distribution cost classifications) and FPL's 12 CP and 1/13th average demand method with a minimum distribution system classification method.

Table 6
ROR Parities - SFHHA Summer CP COSS
and 12 CP & 1/13th/Minimum System COSS

	Summer CP COSS	12 CP & 1/13th Min Sys COSS
CILC-1D	0.92	0.91
CILC-1G	1.47	1.53
CILC-1T	0.98	0.64
CS1	1.03	1.21
CS2	0.93	1.19
GS1	1.38	1.35
GSCU-1	2.02	0.86
GSD1	0.96	1.24
GSLD1	0.60	0.84
GSLD2	0.78	0.93
GSLD3	1.20	0.85
HLFT1	0.91	1.04
HLFT2	0.42	0.55
HLFT3	0.43	0.56
MET	1.10	1.11
OL-1	2.00	0.19
OS-2	0.80	0.85
RS1	1.04	0.94
SDTR-1	1.29	1.23
SDTR-2	0.74	0.82
SDTR-3	0.41	0.61
SL-1	1.22	1.16
SL-2	2.64	2.69
SST-DST	0.67	1.07
SST-TST	2.51	3.74

Q. Does your recommendation for the Commission to adopt an alternative cost of service study and use these results to allocate the revenue increases in this case result in "cost shifting"?

A. No. FPL is proposing substantial increases in this proceeding based on the assumption that certain rate classes have under-contributed to their share of the system's costs (e.g., rate schedule CILC-1D, for which FPL is proposing a 58% increase). However, using a more reasonable measure of cost responsibility, these same classes are actually over-contributing to their share of costs. Likewise, some rate schedules (RS-1, for example) are shown to be over-contributing to their share of costs under FPL's cost study, while under a more reasonable measure, these same classes are under-contributing to their share of costs (i.e., producing a parity less than 100%).

III. ALLOCATION OF THE AUTHORIZED REVENUE INCREASE - GRADUALISM

Q. Would you please briefly describe the methodology that FPL is proposing to use to allocate its requested $969 million increase to rate schedules?

A. Based on the testimony of FPL witness Renae Deaton, the Company has used the results of its cost of service study to assign the increase to rate schedules such that each rate schedule produces a rate of return on rate base (premised upon the Company's recommended cost allocation study) equal to the system average rate of return (100% parity) "to the greatest extent possible."[4] Table 7 shows the base rate increases proposed by the Company for major rate schedules and the relative increase for that rate schedule compared to the retail average. The Company is proposing increases for some general service rate schedules of as much as 58%, which is 235% of the retail average increase.

Q. **Has the Company given any weight to the regulatory concept of "gradualism" in developing its proposed increases in this case?**

[4] Deaton Direct Testimony at page 13, line 5.

A. No. Based on the proposed increases shown in Table 7 and the Company's own statements, FPL has not implemented any material measure of gradualism or mitigation in assigning increases to rate schedules.

Table 7
FPL Proposed Base Rate Increases

	Percent Increase	Relative Increase *
CILC-1D	58.8%	2.35
CILC-1G	24.3%	0.97
CILC-1T	63.2%	2.53
GS-1	6.3%	0.25
GSD-1	30.7%	1.23
GSLD-1	50.7%	2.03
GSLD-2	46.5%	1.86
GSLD-3	29.4%	1.18
GSLDT-1	50.7%	2.03
GSLDT-2	49.5%	1.98
GSLDT-3	33.6%	1.34
GST-1	16.0%	0.64
HLFT-1	26.6%	1.07
HLFT-2	58.1%	2.33
HLFT-3	50.8%	2.03
MET	33.3%	1.33
RS-1	20.8%	0.83
RST-1	33.2%	1.33
Total Retail	25.0%	1.00

* Relative to average retail percentage increase

Baron Exhibit__(SJB-8) contains a copy of the Company's response to SFHHA's First Set of Interrogatories, Interrogatory No. 19, which clearly states that FPL did not give any weight to gradualism or mitigation in developing its proposed rate schedule increases. In response to SFHHA's First Set of Interrogatories, Interrogatory No. 26, the Company stated that it considered limiting the increase to any specific rate schedule to "1.5 times" the average increase, but decided not to use such a measure of mitigation because "it has been 24 years since parity was last addressed."

Q. Do you agree with the Company's proposed increases and its position ignoring gradualism or other measures of mitigation?

A. No. First, as discussed by SFHHA witnesses Lane Kollen and Richard Baudino, SFHHA does not agree with the overall level of proposed revenue requirements reflected in the Company's filing. I also disagree with the Company's proposed allocation of the revenue increase in this case to rate schedules. As I have discussed in the previous section of my testimony, there are legitimate concerns regarding the Company's projection that form the basis for the test year cost of service study results (parities). Also, as I discussed, I believe that the Company's cost of service methodology overstates the allocated costs to general service rate schedules and understates the cost to serve the residential class. Putting aside all of these issues (level of the required revenue increase, concerns with the Company's projections and the cost of service study methodology itself), I also believe that it is appropriate to incorporate a measure of gradualism in the allocation of the approved revenue increase in this case, contrary to FPL's approach that ignore gradualism. As I will discuss, it is reasonable and appropriate for the Commission to continue its past practice of limiting the increase to any rate schedule to 1.5 times the average percentage increase. This Commission policy of incorporating gradualism in the allocation of the approved rate increase to rate classes is appropriate, regardless of the cost of service methodology approved by the Commission – in fact, it is independent of cost of service and focuses instead on the impacts and potential hardships created by the approved rate increase. In this case, in particular, given the very substantial proposed base rate increase requested of 25% and the current economic environment in the State of Florida, the Company's insistence on ignoring mitigation is unreasonable and should be rejected.

Q. Is there any basis for the Company's position that because of prior rate case settlements and other factors that have limited a full litigated

consideration of cost of service and rate parities by the Commission, it is proper to ignore gradualism in this case?

A. No. All of the Company's rate schedules at issue in this case have been approved by the Commission and were thus just and reasonable for each of the past 24 years "since parity was addressed" by the Commission. To the extent that past increases for various rate schedules were developed as part of a settlement of a rate case (such as the 2005 FPL case), these rates were agreed to by virtue of a settlement that was agreed to by FPL as being just and reasonable. FPL's position seems to be that the prior settlements produced unjust rates and therefore in this current case it is necessary to fix the problem and address these past mistakes. There is no basis for the Company's position. Each case rests on its own merits and the application of reasonable ratemaking principles, such as gradualism should not be influenced by the Company's apparent complaint now about the outcome of prior settlements that FPL voluntarily entered into and prospered from. It is especially important for the Commission to continue its past practice of applying gradualism in the development of increases, given the level of the Company's proposed request and the general economic environment that all of the Company's customers are facing. Finally, the Company's test year cost of service results do not provide any basis to draw the conclusion, as FPL does, that the test year rate disparities have existed for 24 years. As shown in Table 3, the rate disparities for a number of the large general service rate schedules (e.g., CILC-D, HLFT-2 and HLFT-3) are projected to change materially in the 2010 and 2011 projected period, compared to actual results. Even if the FPL projected test year cost of service results are assumed to be correct, these results do not mean that the same rate parities have been in effect for 24 years.

Q. Would you explain the regulatory concept of gradualism and how it has been addressed by the Florida Public Service Commission in past rate cases?

A. Gradualism is a ratemaking concept that has been used by the Florida Public Service Commission and other regulatory commissions that incorporates a measure of mitigation into the increases that would otherwise be dictated by the results of an approved cost of service study. Most regulatory commissions, including the FPSC, base their decisions on the allocation of an approved rate increase to rate schedules on the results of a cost of service study. The FPSC has generally allocated increases to rate schedules in a manner that would move rates towards cost of service (i.e., rate parity of 1.0). However, to the extent that such an increase would be excessive, relative to the average increases approved for all rate schedules, regulators have incorporated the concept of rate gradualism into their decisions. The FPSC has traditionally limited the increase to any rate schedule to no more than 1.5 times the average increase, with no rate schedule receiving a decrease. In its recent TECO rate order in Docket No. 080317-EI (Order No. PSC-09-0281-FOF-EI), the Commission affirmed this past practice. The Commission should limit the increase in base rates that is approved in this case to 1.5 times the system average for each rate schedule.

Q. Have you developed a set of proposed increases using a "1.5 times" limitation, based on your recommended cost of service study parity results?

A. Yes. Baron Exhibit__(SJB-9) shows the development of a set of rate schedule increases based on my recommended summer CP/minimum distribution system cost of service study results.[5] The methodology reflects an

[5] Though this recommendation is based on the Company's level of revenue requirements for comparison purposes it should not be construed as a support for the Company's filed requested increase, which SFHHA opposes.

initial set of increases necessary to achieve parity, adjusted to meet the "1.5 times" limitation, consistent with the Commission's recent TECO Order in Docket No. 080317-EI.

Q. In the event that the Commission adopts FPL's cost of service study results and the Company's proposed increases, have you developed a set of increases that reflects the application of the "1.5 times" limitation?

A. Yes. Baron Exhibit__(SJB-10) shows the adjusted increases using the Company's proposed rate schedule increases, as adjusted to limit the base rate increase to 1.5 times the average increase.

Q. Would you summarize your recommendation with regard to the allocation of the Commission approved revenue increase in this case?

A. SFHHA recommends that the Commission adopt a summer CP allocation methodology in conjunction with a minimum distribution system classification method and that rate schedule increases be developed such that rates are set at cost of service, subject to a constraint that no rate schedule should receive an increase greater than 1.5 times the system average increase and that no rate schedule receives a rate decrease, consistent with past Commission practices. Table 8 summarizes the increases that SFHHA recommends using a summer CP/minimum distribution system cost of service study and the increases using FPL's MFR filed cost of service study.[6] Both sets of increases reflect an application of the "1.5 times system average increase" mitigation.

[6] As noted earlier, SFHHA is recommending substantial adjustments in FPL's requested revenue increases. The increases shown in Table 8 are based on FPL's requested revenue requirements so as to facilitate comparisons to the Company's filing.

Table 8
Comparison of Increases with "1.5x" Cap

	SFHHA Cost of Service		FPL Increases with Cap	
	Increase	%	Increase	%
CILC-1D	13,926,584	26.9%	19,362,722	37.5%
CILC-1G	61,307	1.4%	1,174,681	26.2%
CILC-1T	5,885,579	37.4%	5,895,320	37.5%
CS1-CST1	740,480	14.9%	1,856,227	37.5%
CS2-CST2	360,577	19.3%	698,034	37.5%
GS1-GST1-WIES	45,139,788	15.6%	23,213,707	8.0%
GSCU-1	319,853	22.3%	22,058	1.5%
GSD1-GSDT1	131,884,413	17.8%	242,282,889	32.7%
GSLD1-GSLDT1	45,954,798	32.7%	52,617,291	37.5%
GSLD2-GSLDT2	4,998,825	25.5%	7,340,722	37.5%
GSLD3-GSLDT3	838,340	18.9%	1,556,204	35.0%
HLFT1	6,641,136	20.3%	9,362,521	28.6%
HLFT2	41,236,053	37.4%	41,304,298	37.5%
HLFT3	8,721,923	37.4%	8,736,357	37.5%
MET	392,530	14.0%	992,205	35.3%
OL-1	3,835,668	32.7%	435,458	3.7%
OS-2	140,663	16.8%	313,913	37.5%
RS1-RST1	644,394,329	27.8%	524,910,244	22.7%
SDTR-1	672,221	4.4%	5,928,711	38.6%
SDTR-2	3,714,534	23.9%	5,815,715	37.5%
SDTR-3	625,136	37.4%	626,171	37.5%
SL-1	6,888,634	10.0%	14,488,490	21.0%
SL-2	0	0.0%	17,049	1.5%
SST-DST	72,397	28.3%	95,878	37.5%
SST-TST	0	0.0%	0	0.0%
Total Retail	967,445,767	24.9%	969,046,862	25.0%

* Differences between FPL and SFHHA totals due to rounding

Q. Does that complete your testimony at this time?

A. Yes.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY) DOCKET NO. 080677-EI
FLORIDA POWER & LIGHT COMPANY)

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY) DOCKET NO. 080677-EI
FLORIDA POWER & LIGHT COMPANY)

EXHIBIT__(SJB-1)

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2009

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa Clara	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2009

Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768-E-42T	WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2009

Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.
10/87	E-015/	MN	Taconite	Minnesota Power	Excess capacity, power and

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2009

Date	Case	Jurisdict.	Party	Utility	Subject
	GR-87-223		Intervenors	& Light Co.	cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludium Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2009

Date	Case	Jurisdict.	Party	Utility	Subject
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load forecasting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2009

Date	Case	Jurisdict.	Party	Utility	Subject
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.

Expert Testimony Appearances of Stephen J. Baron As of June 2009

Date	Case	Jurisdict.	Party	Utility	Subject
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2009

Date	Case	Jurisdict.	Party	Utility	Subject
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2009

Date	Case	Jurisdict.	Party	Utility	Subject
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2009

Date	Case	Jurisdict.	Party	Utility	Subject
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and Millennium Inorganic Chemicals Inc.	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2009

Date	Case	Jurisdict.	Party	Utility	Subject
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2009

Date	Case	Jurisdict.	Party	Utility	Subject
08/00	98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER00-2854 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic .	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2009

Date	Case	Jurisdict.	Party	Utility	Subject
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

**Expert Testimony Appearances
of
Stephen J. Baron
As of June 2009**

Date	Case	Jurisdict.	Party	Utility	Subject
04/04	2003-00433 2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses, Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213 P-00062214		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2009

Date	Case	Jurisdict.	Party	Utility	Subject
07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Revenue Incr, Off-System Sales margin rate treatment
09/06	E-01345A-05-0816	AZ	Kroger Company	Arizona Public Service Co.	Revenue alllocation, cost of service, rate design.
11/06	Doc. No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
06/07	R-00072155	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues.
07/07	Doc. No. 07F-037E	CO	Gateway Canyons LLC	Grand Valley Power Coop.	Distribution Line Cost Allocation
09/07	Doc. No. 05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
11/07	ER07-682-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues.
1/08	Doc. No. 20000-277-ER-07	WY	Cimarex Energy Company	Rocky Mountain Power (PacifiCorp)	Vintage Pricing, Marginal Cost Pricing Projected Test Year
1/08	Case No. 07-551	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to Rate Schedules
2/08	ER07-956	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
2/08	Doc No. P-00072342	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Default Service Plan issues.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2009

Date	Case	Jurisdict.	Party	Utility	Subject
3/08	Doc No. E-01933A-05-0650	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
05/08	08-0278 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Power Co.	Expanded Net Energy Cost "ENEC" Analysis.
6/08	Case No. 08-124-EL-ATA	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Recovery of Deferred Fuel Cost
7/08	Docket No. 07-035-93	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Rate Design
08/08	Doc. No. 6680-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Doc. No. 6690-UR-119	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Case No. 08-936-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Competitive Solicitation
09/08	Case No. 08-935-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
09/08	Case No. 08-917-EL-SSO 08-918-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Provider of Last Resort Rate Plan
10/08	2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/08	08-1511 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
11/08	M-2008-2036188, M-2008-2036197	PA	Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Transmission Service Charge
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
01/09	E-01345A-08-0172	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
02/09	2008-00409	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2009

Date	Case	Jurisdict.	Party	Utility	Subject
5/09	PUE-2009 -00018	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Transmission Cost Recovery Rider
5/09	09-0177-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost "ENEC" Analysis

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	) DOCKET NO. 080677-EI)

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

Ten Year Power Plant Site Plan

2009-2018

Submitted To:

Florida Public
Service Commission

Miami, Florida
April 2009

DOCUMENT NUMBER-DATE

02906 APR-1 8

FPSC-COMMISSION CLERK

However, FPL is scheduled to present its new projections of cost-effective DSM to the FPSC in June 2009. These new projections will be used to determine FPL's new DSM Goals for the years 2010 through 2019. The analyses to develop these new projections of cost-effective DSM for the new DSM Goals are currently a work in progress at the time the 2009 Site Plan is being filed. The final order from the FPSC establishing FPL's new DSM Goals is expected in the 4th Quarter of 2009. The subsequent development and approval of FPL's DSM Plan (with which FPL will meet the new Goals) will likely be made in early 2010. Therefore, the impact of FPL's new DSM Goals and DSM Plan will be reflected next year in FPL's 2010 Site Plan.

These key assumptions, plus the other updated information, are then applied in the first fundamental step: the determination of the magnitude and the timing of FPL's resource needs. This determination is accomplished by system reliability analyses which are typically based on a dual planning criteria of a minimum peak period reserve margin of 20% (FPL applies this to both Summer and Winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 day per year. Both of these criteria are commonly used throughout the utility industry.

Historically, two types of methodologies, deterministic and probabilistic, have been employed in system reliability analysis. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. It provides an indication of the adequacy of a generating system's capacity resources compared to its load during peak periods. However, deterministic methods do not take into account probabilistic-related elements such as the impact of individual unit failures. For example: two 50 MW units which can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit which can also be counted on to run 90% of the time. Probabilistic methods also recognize the value of being part of an interconnected system with access to multiple capacity sources.

For this reason, probabilistic methodologies have been used to provide an additional perspective on the reliability of a generating system. There are a number of probabilistic methods that are being used to perform system reliability analyses. Of these, the most widely used is loss-of-load probability or LOLP. Simply stated, LOLP is an index of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of through 2008 have resulted in a cumulative Summer peak reduction of approximately 4,109 MW at the generator and an estimated cumulative energy saving of approximately 46,646 Gigawatt Hour (GWh) at the generator. Accounting for reserve margin requirements, FPL's DSM efforts through 2008 have eliminated the need to construct more than 12 new 400 MW generating units.

FPL has consistently been among the leading utilities nationally in DSM achievement. For example, according to the U.S. Department of Energy's 2006 data (the last year for which the DOE data was available at the time this Site Plan was being developed), FPL ranked # 1 nationally in energy efficiency demand reduction and # 3 nationally in load management demand reduction.

In June 2009, FPL will be submitting its proposed DSM Goals for the 2010 – 2019 time period to the FPSC for its approval. At the time the 2009 Site Plan is being finalized, FPL's analyses to determine what its proposed DSM Goals for 2010 – 2019 are a work in progress. Consequently, FPL's 2009 Site Plan is retaining essentially the same level of projected DSM additions as was presented in its 2008 Site Plan. However, this level of projected DSM additions is likely to change due to the DSM Goals work.

Once FPL's DSM Goals are established, FPL will then send its proposed DSM Plan, with which it plans to meet these DSM Goals, to the FPSC for approval. FPL currently anticipates that both its DSM Goals and DSM Plan for the 2010 – 2019 time period will be approved by the first Quarter of 2010. Therefore, FPL expects that both its new DSM Goals and DSM Plan will be addressed in FPL's 2010 Site Plan.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled
Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
August of Year	Total Installed Capacity 1/ MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	Reserve Margin Before Maintenance 5/ % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	Reserve Margin After Maintenance 6/ % of Peak
2009	21,985	1,824	0	690	24,499	21,124	1,997	19,127	5,372	28.1	0	5,372	28.1
2010	20,809	1,467	0	640	22,916	21,147	2,119	19,028	3,888	20.4	0	3,888	20.4
2011	21,946	1,467	0	595	24,008	21,368	2,236	19,132	4,876	25.5	0	4,876	25.5
2012	22,230	1,311	0	650	24,191	21,933	2,357	19,576	4,614	23.6	0	4,614	23.6
2013	23,553	1,311	0	650	25,514	22,249	2,483	19,766	5,748	29.1	0	5,748	29.1
2014	24,760	1,361	0	650	26,771	23,533	2,615	20,918	5,853	28.0	0	5,853	28.0
2015	24,760	1,361	0	650	26,771	24,142	2,749	21,393	5,377	25.1	0	5,377	25.1
2016	25,574	50	0	650	26,274	24,772	2,884	21,888	4,386	20.0	0	4,386	20.0
2017	26,396	50	0	650	27,096	25,401	3,019	22,383	4,713	21.1	0	4,713	21.1
2018	27,496	50	0	650	28,196	26,143	3,064	23,079	5,116	22.2	0	5,116	22.2

1/ Capacity additions and changes projected to be in-service by June 1st are generally considered to be available to meet Summer peak loads are forecasted to occur during August of the year indicated. All values are Summer net MW.
2/ Total Capacity Available = Col.(2) + Col.(3) - Col.(4) + Col.(5).
3/ These forecasted values reflect the 2009 load forecast without incremental DSM or cumulative load management.
4/ The DSM MW shown represent cumulative load management capability plus incremental conservation from 1/2008-on designed for use with the 2008 load forecast. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.
5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)
6/ Margin (%) After Maintenance = Col.(13) / Col.(9)

Schedule 7.2
Forecast of Capacity , Demand, and Scheduled
Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
January of Year	Total Installed Capability [1] MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available [2] MW	Total Peak [3] Demand MW	DSM [4] MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance [5] MW	Reserve Margin Before Maintenance [5] % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance [6] MW	Reserve Margin After Maintenance [6] % of Peak
2009	23,280	1,962	0	740	25,982	18,697	1,730	16,968	9,014	53.1	0	9,014	53.1
2010	24,661	1,501	0	690	26,852	18,790	1,819	16,971	9,880	58.2	0	9,880	58.2
2011	22,338	1,500	0	595	24,433	19,120	1,888	17,231	7,201	41.8	0	7,201	41.8
2012	23,765	1,500	0	595	25,860	19,710	1,960	17,749	8,110	45.7	0	8,110	45.7
2013	24,061	1,320	0	650	26,031	20,098	2,035	18,063	7,967	44.1	0	7,967	44.1
2014	25,404	1,370	0	650	27,424	21,154	2,113	19,041	8,382	44.0	0	8,382	44.0
2015	26,714	1,370	0	650	28,734	21,882	2,196	19,687	9,047	46.0	0	9,047	46.0
2016	27,539	440	0	650	28,629	22,396	2,278	20,118	8,510	42.3	0	8,510	42.3
2017	28,373	50	0	650	29,073	22,912	2,361	20,551	8,521	41.5	0	8,521	41.5
2018	28,373	50	0	650	29,073	23,466	2,436	21,030	8,043	38.2	0	8,043	38.2

1/ Capacity additions and changes projected to be in-service by January 1st are considered to be available to meet Winter peak loads which are forecast to occur during January of the "second" year indicated. All values are Winter net MW.
2/ Total Capacity Available = Col.(2) + Col.(3) - Col.(4) + Col.(5).
3/ These forecasted values reflect the 2009 load forecast without incremental DSM or cumulative load management.
4/ The DSM MW shown represent cumulative load management capability plus incremental conservation from 1/2008-on desinged for use with the 2008 load forecast. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.
5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)
6/ Margin (%) After Maintenance = Col.(13) / Col.(9)

FPL 068952

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	) DOCKET NO. 080677-EI)

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

ELECTRIC UTILITY COST ALLOCATION MANUAL

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

January, 1992

PREFACE

This project was jointly assigned to the NARUC Staff Subcommittees on Electricity and Economics in February, 1985. Jack Doran, at the California PUC had led a task force in 1969 that wrote the original **Cost Allocation Manual**; the famous "Green Book". I was asked to put together a task force to revise it and include a Marginal Cost section.

I knew little about the subject and was not sure what I was getting into so I asked Jack how he had gone about drafting the first book. "Oh" he said, "There wasn't much to it. We each wrote a chapter and then exchanged them and rewrote them." What Jack did not tell me was that like most NARUC projects, the work was done after five o'clock and on weekends because the regular work always takes precedence. It is a good thing we did not realize how big a task we were tackling or we might never have started.

There was great interest in the project so when I asked for volunteers, I got plenty. We split into two working groups; embedded cost and marginal cost. Joe Jenkins from the Florida PSC headed up the Embedded Cost Working Group and Sarah Voll from the New Hampshire PUC took the Marginal Cost Working Group. We followed Jack's suggestions but, right from the beginning, we realized that once the chapters were technically correct, we would need a single editor to cast them all "into one hand" as Joe Jenkins put it. Steven Mintz from the Department of Energy volunteered for this task and has devoted tremendous effort to polishing the book into the final product you hold in your hands. Victoria Jow at the California PUC took Steven's final draft and desktop published the entire document using Ventura Publisher.

We set the following objectives for the manual:

- It should be simple enough to be used as a primer on the subject for new employees yet offer enough substance for experienced witnesses.
- It must be comprehensive yet fit in one volume.
- The writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons.

It is with extreme gratitude that I acknowledge the energy and dedication contributed by the following task force members over the last five years.

Steven Mintz, Department of Energy, Editor; Joe Jenkins, Florida PSC, Leader, Embedded Cost Working Group; Sarah Voll, New Hampshire PUC, Leader, Marginal Cost Working Group; Victoria Jow, California PUC; John A. Anderson, ELCON; Jess Galura, Sacramento MUD; Chris Danforth, California PUC; Alfred Escamilla, Southern California Edison; Byron Harris, West Virginia CAD; Steve Houle, Texas Utility Electric Co.; Kevin Kelly, formally NRRI; Larry Klapow California PUC; Jim Ketter P.E., Missouri PSC; Ed Lucero, Price Waterhouse; J. Robert Malko, Utah State University; George McCluskey, New Hampshire PUC; Marge Meeter, Florida PSC; Gordon Murdock, The FERC; Dennis Nightingale, North Carolina UC; John Orecchio, The FERC; Carl Silsbee, Southern California Edison; Ben Turner, North Carolina UC; Dr. George Parkins, Colorado PUC; Warren Wendling, Colorado PUC; Schef Wright, formally Florida PSC; **IN MEMORIAL** Bob Kennedy Jr., Arkansas PSC.

Julian Ajello
California PUC

CHAPTER 6

CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT

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

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

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

I. COST ACCOUNTING FOR DISTRIBUTION PLANT AND EXPENSES

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

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

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

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

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

TABLE 6-2

CLASSIFICATION OF DISTRIBUTION EXPENSES[1]

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

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

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

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

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

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

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

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

II. DEMAND AND CUSTOMER CLASSIFICATIONS OF DISTRIBUTION PLANT ACCOUNTS

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

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

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

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

A. The Minimum-Size Method

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

1. Account 364 - Poles, Towers, and Fixtures

- Determine the average installed book cost of the minimum height pole currently being installed.
- Multiply the average book cost by the number of poles to find the customer component. Balance of plant account is the demand component.

2. Account 365 - Overhead Conductors and Devices

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

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

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

4. Account 368 - Line Transformers

- Determine minimum size transformer currently being installed.

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

5. **Account 369 - Services**

- Determine minimum size and average length of services currently being installed.

- Estimate cost of minimum size service and multiply by number of services to get customer component.

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

B. The Minimum-Intercept Method

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

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

- Determine the number, investment, and average installed book cost of distribution poles by height and class of pole. (Exclude stubs for guying.)

- Determine minimum intercept of pole cost by creating a regression equation, relating classes and heights of poles, and using the Class 7 cost intercept for each pole of equal height weighted by the number of poles in each height category.

- Multiply minimum intercept cost by total number of distribution poles to get customer component.

- Balance of pole investment is assigned to demand component.

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

2. Account 365 - Overhead Conductors and Devices

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

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

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

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

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

  - Balance of conductor investment is assigned to demand.

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

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

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

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

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

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

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

  - Balance of cable investment is assigned to demand.

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

4. Account 368 - Line Transformers

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

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

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

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

  - Balance of transformer investment is assigned to demand component.

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

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

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

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

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

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

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

D. Other Accounts

The preceding discussion of the merits of minimum-system versus the zero-intercept classification schemes will affect the major distribution-plant accounts for FERC Accounts 364 through 368. Several other plant accounts remain to be classified. While the classification of the following distribution-plant accounts is an important step, it is not as controversial as the classification of substations, poles, transformers, and conductors.

1. Account 369 - Services

This account is generally classified as customer-related. Classification of services may also include a demand component to reflect the fact that larger customers will require more costly service drops.

2. Account 370 - Meters

Meters are generally classified on a customer basis. However, they may also be classified using a demand component to show that larger-usage customers require more expensive metering equipment.

3. Account 371 - Installations on Customer Premises

This account is generally classified as customer-related and is often directly assigned. The kind of equipment in this account often influences how this account is treated. The equipment in this account is owned by the utility, but is located on the customer's side of the meter. A utility will often include area lighting equipment in this account and assign the investment directly to the lighting customer class.

4. Account 373 - Street Lighting and Signal Systems

This account is generally customer-related and is directly assigned to the street customer class.

III. ALLOCATION OF THE DEMAND AND CUSTOMER COMPONENTS OF DISTRIBUTION PLANT

After completing the classification of distribution plant accounts, the next major step in the cost of service process is to allocate the classified costs. Generally, determining the distribution-demand allocator will require more data and analysis than determining the customer allocators. Following are procedures used to calculate the demand and customer allocation factors.

A. Development of the Distribution Demand Allocators

There are several factors to consider when allocating the demand components of distribution plant. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation.

Similarly, when designing primary and secondary distribution feeders, the distribution engineer ensures that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary- and secondary-distribution service levels. Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class noncoincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities. The customer-class load characteristic used to allocate the demand component of distribution plant (whether customer class NCPs or the summation of individual customer maximum demands) depends on the load diversity that is present at the equipment to be allocated. The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities. The facilities nearer the customer, such as secondary feeders and line transformers, have much lower load diversity. They are normally allocated according to the individual customer's maximum demands. Although these are the methods normally used for the allocation of distribution demand costs, some exceptions exist.

The load diversity differences for some utilities at the transmission and distribution substation levels may not be large. Consequently, some large distribution substations may be allocated using the same method as the transmission system. Before the cost analyst selects a method to allocate the different levels of distribution facilities, he must know the design and operational characteristics of the distribution system, as well as the demand losses at each level of the distribution system.

As previously indicated, the distribution system consists of several levels. The first level starts at the distribution substation, and the last level ends at the customer's meters. Power losses occur at each level and should be included in the demand allocators. Power losses are incorporated into the demand allocators by showing different demand loss factors at each predominant voltage level. The demand loss factor used to develop the primary-distribution demand allocator will be slightly larger than the demand loss factor used to develop the secondary demand allocator. When developing the distribution demand allocator, be aware that some customers take service at different voltage levels.

Cost analysts developing the allocator for distribution of substations or primary demand facilities must ensure that only the loads of those customers who benefit from these facilities are included in the allocator. For example, the loads of customers who take service at transmission level should not be reflected in the distribution substation or primary demand allocator. Similarly, when analysts develop the allocator for secondary demand facilities, the loads for customers served by the primary distribution system should not be included.

Utilities can gather load data to develop demand allocators, either through their load research program or their transformer load management program. In most cases, the load research program gathers data from meters on the customers' premises. A more complex procedure is to use the transformer load management program.

This procedure involves simulating load profiles for the various classes of equipment on the distribution system. This provides information on the nature of the load diversity between the customer and the substation, and its effect on equipment cost. Determining demand allocators through simulation provides a first-order load approximation, which represents the peak load for each type of distribution equipment.

The concept of peak load or "equipment peak" for each piece of distribution equipment can be understood by considering line transformers. If a given transformer's loading for each hour of a month can be calculated, a transformer load curve can be developed. By knowing the types of customers connected to each load management transformer, a simulated transformer load profile curve can be developed for the system. This can provide each customer's class demand at the time of the transformer's peak load. Similarly, an equipment peak can be defined for equipment at each level of the distribution system. Although the equipment peak obtained by this method may not be ideal, it will closely approximate the actual peak. Thus, this method should reflect the different load diversities among customers at each level of the distribution system. An illustration of the simulation procedure is provided in Appendix 6-A.

B. Allocation of Customer-Related Costs

When the demand-customer classification has been completed, most of the assumptions will have been made that affect the results of the completed cost of service study.

The allocation of the customer-related portion of the various plant accounts is based on the number of customers by classes of service, with appropriate weightings and adjustments. Weighting factors reflect differences in characteristics of customers within a given class, or between classes. Within a class, for instance, we may want to give more weighting of a certain plant account to rural customers, as compared to urban customers. The metering account is a clear example of an account requiring weighting for differences between classes. A metering arrangement for a single industrial customer may be 20 to 80 times as costly as the metering for one residential customer.

While customer allocation factors should be weighted to offset differences among various types of customers, highly refined weighting factors or detailed and time consuming studies may not seem worthwhile. Such factors applied in this final step of the cost study may affect the final results much less than such basic assumptions as the demand-allocation method or the technique for determining demand-customer classifications.

Expense allocations generally are based on the comparable plant allocator of the various classes. For instance, maintenance of overhead lines is generally assumed to be directly related to plant in overhead conductors and devices. Exceptions to this rule will occur in some accounts. Meter expenses, for example, are often a function of maintenance and testing schedules related more to revenue per customer than to the cost of the meters themselves.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	) DOCKET NO. 080677-EI)

EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

Q.

Interrogatories Directed to Mr. Joseph Ender (or such others as FPL deems appropriate):

Please provide an explanation of the relationship between customer kW demands and the number and cost of secondary poles, include specific documentation from FPL's distribution planning organization supporting the provisioning of poles on the system and the level of customer kW demand, and identify the name, title and organization of the respondent to this request, including a copy of the respondent's resume (if not already a witness in the proceeding).

A.

As stated in FPL's response to SFHHA's Second Set of Interrogatories No. 130, distribution poles installed throughout FPL's distribution system consist of feeder poles, lateral poles, service poles and streetlight poles, all of which can and do carry secondary voltage. KW demand/load, which affects the size/weight of the overhead wire and equipment to be used, is just one of many factors considered when FPL is determining the type, sizing and number of distribution poles to install. Other considerations include clearance requirements, wind loading requirements, the number of attaching entities, as well as other equipment to be installed on the pole. The size and type of poles for FPL's distribution system are determined and installed consistent with FPL's distribution engineering/construction standards and guidelines which have been provided in FPL's responses to SFHHA's Second Request for Production of Documents Nos. 41 and 42. Regarding the cost of poles, generally, larger poles are more costly than smaller poles and concrete poles are more expensive than wood poles. See also installed costs provided in FPL's response to SFHHA's Second Set of Interrogatories No. 130.

Respondent - Michael G. Spoor, Distribution, Director, Business Services

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	) DOCKET NO. 080677-EI)

EXHIBIT__(SJB-5)

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

Selected Rate Case Application of Distribution Minimum System
Classification of Non-lighting Distribution Plant

Voltage	Classification	Wisconsin Public Service	Ohio Edison	Kentucky Utilities	Louisville Gas & Electric	Virginia Electric & Power	Average
Account 364 - Poles, Towers, & Fixtures							
Primary	Demand	53.8%	100.0%	21.1%	39.4%	41.7%	51.2%
	Customer	46.2%	0.0%	78.9%	60.6%	58.3%	48.8%
Secondary	Demand	28.6%	100.0%	21.1%	39.4%	52.7%	48.4%
	Customer	71.4%	0.0%	78.9%	60.6%	47.3%	51.6%
Account 365 - Overhead Conductors & Devices							
Primary	Demand	30.2%	100.0%	21.1%	39.4%	66.8%	51.5%
	Customer	69.8%	0.0%	78.9%	60.6%	33.2%	48.5%
Secondary	Demand	18.4%	100.0%	21.1%	39.4%	81.4%	52.1%
	Customer	81.6%	0.0%	78.9%	60.6%	18.6%	47.9%
Account 366 - Underground Conduit							
Primary	Demand	100.0%	100.0%	27.9%	37.4%	73.7%	67.8%
	Customer	0.0%	0.0%	72.1%	62.6%	26.3%	32.2%
Secondary	Demand	100.0%	100.0%	27.9%	37.4%	73.7%	67.8%
	Customer	0.0%	0.0%	72.1%	62.6%	26.3%	32.2%
Undesignated	Demand	100.0%				73.7%	
	Customer	0.0%				26.3%	
Account 367 - Underground Conductors							
Primary	Demand	27.0%	100.0%	27.9%	37.4%	73.7%	53.2%
	Customer	73.0%	0.0%	72.1%	62.6%	26.3%	46.8%
Secondary	Demand	37.0%	100.0%	27.9%	37.4%	73.7%	55.2%
	Customer	63.0%	0.0%	72.1%	62.6%	26.3%	44.8%
Undesignated	Demand					73.7%	
	Customer					26.3%	
Account 368 - Distribution Transformers							
	Demand	33.2%	30.3%	52.1%	51.2%	87.3%	50.8%
	Customer	66.8%	69.7%	47.9%	48.8%	12.7%	49.2%

WPSC Docket No. 6690-UR-119 Test Year Ended December 31, 2009
Ohio Edison Docket No. 07-551-EL-AIR Test Year Ended 02/08
KU Case No. 2008-00251 Test Year Ended April 30, 2008
  364 & 366 classified same as 365 & 367, respectively
  366/367 based on workpapers; filed study was erroneously used 364/365 factors
LG&E Case No. 2008-00252 Test Year Ended April 30, 2008
  364 & 366 classified same as 365 & 367, respectively
VEPCO Case No. PUE-2009-00019 Test Year Ended 12/08

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY) DOCKET NO. 080677-EI
FLORIDA POWER & LIGHT COMPANY)

EXHIBIT__(SJB-6)

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

Q.

This interrogatory relates to FPL's forecasts in this docket. Please identify any adjustments that were made to either the forecast data, or made during the course of executing the programs used to develop the Company's forecasting models.

A.

The output of the econometric model used to forecast net energy for load per customer was adjusted for changes in usage not embedded in the historical data. The specific adjustments are as follows:

1. The addition of two new wholesale contracts (Lee County and Seminole Electric Cooperative).

2. Incremental energy efficiency reductions resulting from mandated changes in appliance efficiency (e.g., higher energy efficiency standards for air-conditioners) and compact fluorescent bulbs. This adjustment reflects only increases in energy efficiency not reflected in the historical usage. This adjustment is consistent with adjustments for mandated energy efficiency standards incorporated in FPL's recent Need Determination filings.

3. An adjustment for the increase in the number of minimal usage customers FPL has experienced coincident with the housing crisis. Historically, 6.8% to 7% of FPL's residential customers have been minimal usage customers, defined as those using 1 to 200 kWH per month. However, this percentage has risen with the increase in vacancy rates resulting from the housing crisis. As of the end of 2008, the percentage of residential customers using minimal amounts of electricity had increased to 8.7% and recent actuals show the percentage has since risen to 8.9%. Based on the increase in this percentage relative to its long-term average, FPL estimates that the increase in minimal usage customers is reducing net energy for load by approximately 1%.

4. An anchoring adjustment is made to calibrate the model to the average level of 2008 usage.

In combination, the above adjustments have substantially reduced the year-to-date weather normalized variance in net energy for load and are needed to accurately reflect the expected level of sales in the test year.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY) DOCKET NO. 080677-EI
FLORIDA POWER & LIGHT COMPANY)

EXHIBIT__(SJB-7)

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

Florida Power Light Company
Docket No. 080677-EI
Summary of Cost of Service Results
Single CP Production and Distribution Minimum System

Description	Total	CILC-1D	CILC-1G	CILC-1T	CS1	CS2	GS1	GSCU-1	GSD1	GSLD1	GSLD2	GSLD3	HLFT1
RATE BASE													
Electric Plant in Service	28,288,080	461,131	31,857	162,701	33,539	13,325	1,933,674	9,682	4,971,800	1,085,112	145,053	27,611	226,979
Accumulated Depreciation and Amortization	(12,590,521)	(205,058)	(14,161)	(78,335)	(14,945)	(5,938)	(850,960)	(4,088)	(2,233,901)	(487,850)	(64,649)	(13,232)	(101,870)
Net Plant In Service	15,697,559	256,073	17,696	84,366	18,594	7,386	1,082,713	5,594	2,737,899	597,262	80,404	14,379	125,109
Plant Held for Future Use	74,502	1,613	108	563	112	44	4,725	17	15,427	3,503	489	100	751
Construction Work In Progress	707,530	13,180	896	5,304	924	366	46,933	220	132,787	29,397	4,017	905	6,352
Net Nuclear Fuel	374,733	11,162	727	5,439	686	298	21,734	118	84,839	18,496	2,980	846	5,159
Total Utility Plant	16,854,324	282,026	19,427	95,671	20,315	8,095	1,156,106	5,949	2,970,952	648,658	87,890	16,230	137,371
Working Capital - Assets	3,393,188	72,122	4,885	31,235	4,706	1,948	223,575	1,329	634,881	136,492	20,360	4,973	33,940
Working Capital - Liabilities	(3,183,926)	(63,293)	(4,320)	(27,017)	(4,182)	(1,728)	(213,889)	(1,286)	(574,827)	(122,935)	(18,076)	(4,317)	(30,016)
Working Capital - Net	209,262	8,829	566	4,218	523	220	9,686	43	60,054	13,558	2,284	656	3,924
Total Rate Base	**17,063,586**	**290,855**	**19,992**	**99,890**	**20,839**	**8,315**	**1,165,792**	**5,992**	**3,031,006**	**662,216**	**90,174**	**16,885**	**141,296**
REVENUES													
Sales of Electricity	3,920,872	71,354	5,913	25,240	4,955	1,863	289,878	1,432	741,464	141,683	20,940	4,444	34,823
Other Operating Revenues	193,855	1,897	130	615	137	55	15,228	133	21,302	4,271	585	101	932
Total Operating Revenues	4,114,727	73,251	6,043	25,855	5,091	1,918	305,106	1,564	762,766	145,954	21,524	4,546	35,755
EXPENSES													
Operating & Maintenance	(1,721,872)	(30,175)	(2,094)	(12,291)	(2,039)	(832)	(119,679)	(753)	(289,309)	(61,257)	(8,790)	(1,981)	(14,451)
Depreciation & Amortization	(1,075,373)	(17,109)	(1,188)	(6,311)	(1,250)	(496)	(72,857)	(362)	(186,967)	(40,637)	(5,396)	(1,063)	(8,495)
Taxes Other Than Income	(350,370)	(5,844)	(405)	(1,995)	(419)	(166)	(24,137)	(128)	(61,170)	(13,283)	(1,811)	(338)	(2,841)
Income Taxes	(243,338)	(5,791)	(822)	(1,284)	(389)	(99)	(26,342)	(77)	(66,956)	(6,590)	(1,482)	(336)	(2,895)
Amortization of Property Losses	1,108	62	4	41	4	1	20	(1)	440	111	16	7	26
Gain or Loss on Sale of Plant	1,002	22	1	0	2	1	66	0	211	49	7	0	10
Total Operating Expense	(3,388,844)	(58,836)	(4,504)	(21,840)	(4,091)	(1,592)	(242,929)	(1,319)	(603,750)	(121,608)	(17,456)	(3,712)	(28,645)
NOI Before Curtailment Adjustment	725,883	14,415	1,540	4,015	1,000	327	62,178	245	159,016	24,346	4,069	834	7,110
Curtailment Credit Revenue	497	0	0	0	316	181	0	0	0	0	0	0	0
Reassign Curtailment Credit Revenue	(497)	(11)	(1)	(5)	(1)	(0)	(30)	(0)	(104)	(24)	(3)	(1)	(5)
Net Curtailment Credit Revenue	0	(11)	(1)	(5)	316	181	(30)	(0)	(104)	(24)	(3)	(1)	(5)
Net Curtailment NOI Adjustment	0	(7)	(0)	(3)	193	111	(19)	(0)	(64)	(15)	(2)	(1)	(3)
Net Operating Income	**725,883**	**14,408**	**1,539**	**4,012**	**1,194**	**437**	**62,159**	**245**	**158,952**	**24,331**	**4,067**	**833**	**7,106**
Rate of Return	**4.25%**	**4.95%**	**7.70%**	**4.02%**	**5.73%**	**5.26%**	**5.33%**	**4.09%**	**5.24%**	**3.67%**	**4.51%**	**4.93%**	**5.03%**
Parity	**1.00**	**1.16**	**1.81**	**0.94**	**1.35**	**1.24**	**1.25**	**0.96**	**1.23**	**0.86**	**1.06**	**1.16**	**1.18**
Increase to Proposed Equal Rate of Return	1,043,534	14,463	98	6,497	773	372	50,769	383	136,339	46,770	5,138	845	6,851
Total Revenues at Proposed Rate of Return	5,158,261	87,714	6,141	32,352	5,864	2,290	355,875	1,947	899,105	192,724	26,662	5,391	42,606
Proposed Other Operating Revenues	269,183	2,517	173	698	176	69	21,283	198	26,871	5,328	755	115	1,193
Revenue from Sales at Prop Rate of Return	4,889,078	85,197	5,969	31,653	5,688	2,221	334,591	1,749	872,234	187,396	25,907	5,276	41,414

Florida Power Light Company
Docket No. 080677-EI
Summary of Cost of Service Results
Single CP Production and Distribution Minimum System

Description	HLFT2	HLFT3	MET	OL-1	OS-2	RS1	SDTR-1	SDTR-2	SDTR-3	SL-1	SL-2	SST-DST	SST-TST
RATE BASE													
Electric Plant in Service	911,726	183,930	17,969	105,786	5,655	17,290,435	86,997	107,328	13,146	438,877	4,362	1,935	17,473
Accumulated Depreciation and Amortization	(409,415)	(82,440)	(7,944)	(73,610)	(2,177)	(7,583,750)	(37,397)	(46,631)	(5,642)	(255,279)	(1,956)	(840)	(8,452)
Net Plant In Service	502,311	101,490	10,025	32,175	3,478	9,706,684	49,600	60,698	7,504	183,598	2,406	1,095	9,022
Plant Held for Future Use	3,020	616	63	59	18	42,149	315	380	46	306	15	6	58
Construction Work In Progress	25,406	5,145	501	2,062	123	417,384	2,414	2,951	348	9,210	127	49	529
Net Nuclear Fuel	19,758	4,161	332	382	48	190,868	1,776	2,144	254	1,926	113	26	461
Total Utility Plant	550,494	111,412	10,921	34,677	3,667	10,357,085	54,105	66,172	8,152	195,041	2,662	1,177	10,069
Working Capital - Assets	131,848	27,211	2,425	8,823	624	1,977,505	12,669	15,024	1,786	41,204	755	219	2,647
Working Capital - Liabilities	(116,899)	(24,074)	(2,156)	(8,970)	(563)	(1,897,499)	(11,158)	(13,293)	(1,589)	(38,596)	(670)	(200)	(2,373)
Working Capital - Net	14,949	3,137	269	(146)	61	80,005	1,510	1,731	197	2,609	85	19	274
Total Rate Base	**565,443**	**114,549**	**11,190**	**34,531**	**3,728**	**10,437,090**	**55,615**	**67,902**	**8,349**	**197,649**	**2,747**	**1,196**	**10,343**
REVENUES													
Sales of Electricity	115,444	23,478	2,808	11,731	838	2,315,944	15,359	15,524	1,671	68,935	1,112	256	3,782
Other Operating Revenues	3,673	748	76	529	41	141,427	377	443	56	995	33	9	62
Total Operating Revenues	119,117	24,226	2,884	12,260	879	2,457,371	15,736	15,967	1,727	69,930	1,145	265	3,844
EXPENSES													
Operating & Maintenance	(56,501)	(11,563)	(1,065)	(5,962)	(315)	(1,064,509)	(5,480)	(6,501)	(781)	(24,004)	(329)	(103)	(1,109)
Depreciation & Amortization	(34,103)	(6,862)	(662)	(5,395)	(199)	(652,234)	(3,175)	(3,931)	(478)	(25,290)	(164)	(71)	(678)
Taxes Other Than Income	(11,337)	(2,295)	(226)	(759)	(78)	(215,884)	(1,132)	(1,369)	(168)	(4,302)	(57)	(24)	(202)
Income Taxes	(1,671)	(351)	(291)	359	(86)	(119,242)	(2,021)	(1,116)	(44)	(4,860)	(231)	(17)	(703)
Amortization of Property Losses	105	21	2	(10)	(0)	292	11	11	1	(57)	1	0	1
Gain or Loss on Sale of Plant	40	9	1	1	1	562	5	6	1	7	0	0	0
Total Operating Expense	(103,467)	(21,041)	(2,241)	(11,765)	(677)	(2,051,015)	(11,793)	(12,900)	(1,470)	(58,507)	(780)	(214)	(2,691)
NOI Before Curtailment Adjustment	15,650	3,185	643	495	202	406,357	3,943	3,067	257	11,423	364	50	1,153
Curtailment Credit Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
Reassign Curtailment Credit Revenue	(21)	(4)	(0)	(0)	(0)	(279)	(2)	(2)	(0)	(1)	(0)	(0)	(0)
Net Curtailment Credit Revenue	(21)	(4)	(0)	(0)	(0)	(279)	(2)	(2)	(0)	(1)	(0)	(0)	(0)
Net Curtailment NOI Adjustment	(13)	(3)	(0)	(0)	(0)	(171)	(1)	(1)	(0)	(1)	(0)	(0)	(0)
Net Operating Income	**15,637**	**3,183**	**643**	**495**	**202**	**406,186**	**3,942**	**3,066**	**257**	**11,422**	**364**	**50**	**1,153**
Rate of Return	**2.77%**	**2.78%**	**5.74%**	**1.43%**	**5.42%**	**3.89%**	**7.09%**	**4.52%**	**3.08%**	**5.78%**	**13.26%**	**4.20%**	**11.14%**
Parity	**0.65**	**0.65**	**1.35**	**0.34**	**1.27**	**0.91**	**1.67**	**1.06**	**0.72**	**1.36**	**3.12**	**0.99**	**2.62**
Increase to Proposed Equal Rate of Return	48,328	9,766	412	3,703	157	700,041	827	3,863	670	7,163	(236)	74	(532)
Total Revenues at Proposed Rate of Return	167,445	33,993	3,296	15,963	1,036	3,157,413	16,563	19,830	2,398	77,093	909	339	3,313
Proposed Other Operating Revenues	4,669	949	100	416	59	200,892	552	616	76	1,365	52	11	48
Revenue from Sales at Prop Rate of Return	162,776	33,044	3,196	15,547	977	2,956,521	16,011	19,214	2,321	75,728	856	328	3,265

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	) DOCKET NO. 080677-EI)

EXHIBIT__(SJB-8)

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

Q.
Interrogatories to Renae Deaton

Regarding page 5:1-8. Please explain the manner in which FPL considered the ratemaking concept of "gradualism" in its proposed increase to each rate schedule and the movement towards parity.

A.
FPL did not consider the concept of "gradualism" in its proposed increase to each rate schedule and the movement towards parity as it has been 24 years since parity was addressed. It was determined that the inequities between the rate classes should be corrected at this time in order to eliminate the subsidization of some classes by other classes to the greatest extent practical.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY) DOCKET NO. 080677-EI
FLORIDA POWER & LIGHT COMPANY)

EXHIBIT__(SJB-9)

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

INCREASES TO EQUAL RATE OF RETURN WITH "1.5 TIMES" LIMITATION

Single CP Production Allocation and Distribution Minimum System Class Cost of Service Study

				Increase						
Line No.	(1) Rate	(2) Base Revenue at Present Rates*	(3) Base Revenue at Proposed Equal ROR	(4) Dollars (3) - (2)	(5) Percent (4) / (2)	(6) Percent in Excess of 150%	(7) Dollar Increase at 150% Cap	(8) Allocation of Shortfall $6,687,783	(9) Adjusted Increase	(10) Percent Increase
1	CILC-1D	$51,694,388	$65,526,304	$13,831,916	26.8%	0.0%	$13,831,916	$94,667	$13,926,584	26.9%
2	CILC-1G	$4,487,872	$4,542,617	$54,745	1.2%	0.0%	$54,745	$6,563	$61,307	1.4%
3	CILC-1T	$15,739,262	$22,149,220	$6,409,958	40.7%	3.3%	$5,885,579	$0	$5,885,579	37.4%
4	CS1-CST1	$4,955,735	$5,687,998	$732,263	14.8%	0.0%	$732,263	$8,218	$740,480	14.9%
5	CS2-CST2	$1,863,603	$2,220,972	$357,369	19.2%	0.0%	$357,369	$3,209	$360,577	19.3%
6	GS1-GST1-WIES	$289,935,102	$334,591,498	$44,656,396	15.4%	0.0%	$44,656,396	$483,392	$45,139,788	15.6%
7	GSCU-1	$1,432,040	$1,749,365	$317,325	22.2%	0.0%	$317,325	$2,527	$319,853	22.3%
8	GSD1-GSDT1	$741,276,781	$871,901,538	$130,624,757	17.6%	0.0%	$130,624,757	$1,259,656	$131,884,413	17.8%
9	GSLD1-GSLDT1	$140,477,085	$186,162,929	$45,685,844	32.5%	0.0%	$45,685,844	$268,954	$45,954,798	32.7%
10	GSLD2-GSLDT2	$19,598,181	$24,561,521	$4,963,340	25.3%	0.0%	$4,963,340	$35,485	$4,998,825	25.5%
11	GSLD3-GSLDT3	$4,445,355	$5,276,073	$830,718	18.7%	0.0%	$830,718	$7,622	$838,340	18.9%
12	HLFT1	$32,785,838	$39,370,095	$6,584,257	20.1%	0.0%	$6,584,257	$56,879	$6,641,136	20.3%
13	HLFT2	$110,273,775	$157,583,831	$47,310,056	42.9%	5.5%	$41,236,053	$0	$41,236,053	37.4%
14	HLFT3	$23,324,234	$32,885,230	$9,560,996	41.0%	3.6%	$8,721,923	$0	$8,721,923	37.4%
15	MET	$2,808,275	$3,196,187	$387,912	13.8%	0.0%	$387,912	$4,618	$392,530	14.0%
16	OL-1	$11,733,403	$15,546,610	$3,813,207	32.5%	0.0%	$3,813,207	$22,461	$3,835,668	32.7%
17	OS-2	$838,081	$977,332	$139,251	16.6%	0.0%	$139,251	$1,412	$140,663	16.8%
18	RS1-RST1	$2,316,397,918	$2,956,520,894	$640,122,976	27.6%	0.0%	$640,122,976	$4,271,353	$644,394,329	27.8%
19	SDTR-1	$15,361,533	$16,010,623	$649,090	4.2%	0.0%	$649,090	$23,131	$672,221	4.4%
20	SDTR-2	$15,526,733	$19,213,509	$3,686,776	23.7%	0.0%	$3,686,776	$27,758	$3,714,534	23.9%
21	SDTR-3	$1,671,744	$2,321,359	$649,615	38.9%	1.5%	$625,136	$0	$625,136	37.4%
22	SL-1	$68,948,389	$75,727,617	$6,779,228	9.8%	0.0%	$6,779,228	$109,405	$6,888,634	10.0%
23	SL-2	$1,112,458	$856,214	($256,244)	-23.0%	0.0%	$0	$0	$0	0.0%
24	SST-DST	$255,974	$327,897	$71,923	28.1%	0.0%	$71,923	$474	$72,397	28.3%
25	SST-TST	$3,782,762	$3,264,855	($517,907)	-13.7%	0.0%	$0	$0	$0	0.0%
26										
27	Total Retail Adjusted Base Re	$3,880,726,521	$4,848,172,288	$967,445,767	24.9%		$960,757,984		$967,445,767	24.9%
28										

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	**) DOCKET NO. 080677-EI)**

EXHIBIT__(SJB-10)

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

FPL PROPOSED RATE SCHEDULE INCREASES WITH "1.5 TIMES" LIMITATION

Line No.	(1) Rate	(2) Base Revenue at Present Rates*	(3) Base Revenue at Proposed Rates	Increase (4) Dollars (3) - (2)	Increase (5) Percent (4) / (2)	(6) Percent in Excess of 150%	(7) Dollar Increase at 150% Cap	(8) Allocation of Shortfall $65,132,058	(9) Adjusted Increase	(10) Percent Increase
1	CILC-1D	$51,694,388	$82,079,174	$30,384,786	58.8%	21.3%	$19,362,722	$0	$19,362,722	37.5%
2	CILC-1G	$4,487,872	$5,577,083	$1,089,211	24.3%	0.0%	$1,089,211	$85,470	$1,174,681	26.2%
3	CILC-1T	$15,739,262	$25,693,881	$9,954,619	63.2%	25.8%	$5,895,320	$0	$5,895,320	37.5%
4	CS1-CST1	$4,955,735	$7,573,359	$2,617,625	52.8%	15.4%	$1,856,227	$0	$1,856,227	37.5%
5	CS2-CST2	$1,863,603	$2,782,773	$919,170	49.3%	11.9%	$698,034	$0	$698,034	37.5%
6	GS1-GST1-WIES	$289,935,102	$308,422,156	$18,487,053	6.4%	0.0%	$18,487,053	$4,726,654	$23,213,707	8.0%
7	GSCU-1	$1,432,040	$1,432,151	$110	0.0%	0.0%	$110	$21,948	$22,058	1.5%
8	GSD1-GSDT1	$741,276,781	$968,713,866	$227,437,085	30.7%	0.0%	$227,437,085	$14,845,804	$242,282,889	32.7%
9	GSLD1-GSLDT1	$140,477,085	$211,742,952	$71,265,867	50.7%	13.3%	$52,617,291	$0	$52,617,291	37.5%
10	GSLD2-GSLDT2	$19,598,181	$28,944,082	$9,345,901	47.7%	10.2%	$7,340,722	$0	$7,340,722	37.5%
11	GSLD3-GSLDT3	$4,445,355	$5,910,972	$1,465,617	33.0%	0.0%	$1,465,617	$90,587	$1,556,204	35.0%
12	HLFT1	$32,785,838	$41,512,173	$8,726,335	26.6%	0.0%	$8,726,335	$636,185	$9,362,521	28.6%
13	HLFT2	$110,273,775	$174,336,415	$64,062,641	58.1%	20.6%	$41,304,298	$0	$41,304,298	37.5%
14	HLFT3	$23,324,234	$35,165,313	$11,841,079	50.8%	13.3%	$8,736,357	$0	$8,736,357	37.5%
15	MET	$2,808,275	$3,743,115	$934,841	33.3%	0.0%	$934,841	$57,364	$992,205	35.3%
16	OL-1	$11,733,403	$11,985,185	$251,782	2.1%	0.0%	$251,782	$183,676	$435,458	3.7%
17	OS-2	$838,081	$1,361,440	$523,360	62.4%	25.0%	$313,913	$0	$313,913	37.5%
18	RS1-RST1	$2,316,397,918	$2,798,421,588	$482,023,670	20.8%	0.0%	$482,023,670	$42,886,574	$524,910,244	22.7%
19	SDTR-1	$15,361,533	$20,968,889	$5,607,357	36.5%	0.0%	$5,607,357	$321,354	$5,928,711	38.6%
20	SDTR-2	$15,526,733	$23,542,544	$8,015,811	51.6%	14.2%	$5,815,715	$0	$5,815,715	37.5%
21	SDTR-3	$1,671,744	$2,455,303	$783,558	46.9%	9.4%	$626,171	$0	$626,171	37.5%
22	SL-1	$68,948,389	$82,177,487	$13,229,097	19.2%	0.0%	$13,229,097	$1,259,392	$14,488,490	21.0%
23	SL-2	$1,112,458	$1,112,458	$0	0.0%	0.0%	$0	$17,049	$17,049	1.5%
24	SST-DST	$255,974	$363,351	$107,377	41.9%	4.5%	$95,878	$0	$95,878	37.5%
25	SST-TST	$3,782,762	$3,755,673	($27,089)	-0.7%	0.0%	$0	$0	$0	0.0%
26										
27	Total Retail Adjusted Base Re	$3,880,726,521	$4,849,773,383	$969,046,862	25.0%		$903,914,804		$969,046,862	25.0%
28										

CERTIFICATE OF SERVICE
<u>DOCKET NO. 080677-EI</u>

I HEREBY CERTIFY that a copy of the **PREFILED TESTIMONY AND EXHIBITS OF THE SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION** has been furnished by electronic mail and U.S. mail to the following parties on this 16th day of July, 2009 to the following:

Robert A. Sugarman
I.B.E.W. System Council U-4
c/o Sugarman Law Firm
100 Miracle Mile, Suite 300
Coral Gables, FL 33134

Jean Hartman
Lisa Bennett
Martha Brown
Anna Williams
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Jack Leon, Natalie Smith
Senior Attorney
Florida Power & Light Company
9250 W. Flagler Street, Suite 6514
Miami, Florida 33174

John T. Butler
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420

Robert Scheffel Wright
John T. LaVia
c/o Florida Retail Federation
225 South Adams Street, Suite 200
Tallahassee, FL 32301

Jon C. Moyle, Jr
Vicki Gordon Kaufman
Keefe Anchors Gordon & Moyle
118 North Gadsden Street
Tallahassee, Fl 32301

J.R. Kelly
Office of Public Counsel
c/o The Florida Legislature
111 W. Madison Street, Room 812
Tallahassee, FL 32399-1400

Thomas Saporito
Saporito Energy Consultants
Post Office Box 8413
Jupiter, FL 33468-8413

Brian P. Armstrong
Nabors, Giblin & Nickerson, PA
1500 Mahan Drive, Suite 200
Tallahassee, FL 32308

Mr. Wade Litchfield
Florida Power & Light Company
215 South Monroe Street, Suite 810
Tallahassee, FL 32301-1859

Cecilia Bradley
Office of the Attorney General
The Capitol – PL01
Tallahassee, Fl 32399-1050

John W. McWhirter, Jr
c/o McWhirter Law Firm
PO Box 3350
Tampa, FL 33601

<u>*/s/ Kenneth L. Wiseman*</u>
Kenneth L. Wiseman, Esq.