BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE:

PETITION FOR RATE INCREASE BY FLORIDA POWER AND LIGHT COMPANY	)))	**DOCKET NO. 120015-EI**

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 2012

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COMPANY	)	

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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, large consumers of electricity and other market participants. 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 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 2002, 2005 and 2009. 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 classes 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 revenue allocation to rate classes of its requested Step 1 (January 2013) base rate revenue increase of $516.5 million and its requested Step 2 (June 2013) increase of $173.9 million. FPL's class cost of service study is based on 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 development of rate class demand allocation factors, all of which bias the Company's study, overstating the cost of service attributed to large customers. I will correct FPL's class cost of service study so that it incorporates more accurate allocation factors.

I will also discuss the methodology used by the Company to classify distribution costs. As in prior cases, FPL classifies all distribution plant in FERC accounts 364 (poles), 365 (overhead conductors), 366 (underground conduit), 367 (underground conductors) and 368 (line transformers) as 100% demand related. FPL's methodology, which is inconsistent with the distribution cost allocation methodologies discussed in the NARUC Electric Utility Cost Allocation Manual (the "NARUC Manual"), ignores <u>any</u> cost consequences associated with simply connecting a customer to the Company's distribution system, regardless of the level of demand the customer imposes on the system or whether the customer premises are even occupied. I will present an alternative class cost of service study that illustrates the impact of utilizing a more reasonable minimum distribution system ("MDS") methodology. As I will discuss, in the recent Gulf Power Company ("GPC") rate case, GPC filed an MDS class cost of service study, which was adopted as part of a Commission approved stipulation of issues.

I have also developed an alternative class cost of service analysis using a summer coincident peak (1 CP) demand methodology. FPL's summer peak is the primary driver of capacity resource needs and it is therefore an appropriate basis to assign cost responsibility to rate classes for generation and transmission fixed costs. I will present the results of this analysis as an alternative to the Company's 12 CP and 1/13th demand methodology.

I will also discuss the Company's proposed methodology to allocate revenue increases to each rate class. FPL has proposed a two-part revenue allocation methodology for its requested \$516 million January 2013 increase. FPL adjusts rate class revenue to remove what FPL calculates under its methodology as rate of return parity differences at present rates. Then, the Company allocates the \$516 million revenue increase based on total revenue from each rate class (before the parity adjustment), including all clause revenues. The sum of these two parts becomes the target increase for each class, which FPL then adjusted in an effort to meet the Commission's practice of limiting the increase to any rate class to 1.5 times the retail average and insuring that no rate class receives a decrease. FPL also makes additional adjustments that are unexplained and disregard its own data, which distort the relationship between certain general service rate classes. I will address FPL's methodology and explain why it is inappropriate. While I agree with the use of a two-part framework generally, the \$516.5 million increase that is uniformly spread to each rate class should be spread on the basis of base revenues. Also, I will recommend an alternative mitigation approach that applies the "1.5 times" increase limit to individual rate class base revenue increases, rather than total revenues including clause revenues.

Finally, I will address two rate design issues affecting large general service rate classes. The first issue concerns FPL's proposed rate design for the CILC-1D rate schedule. FPL is proposing a 320% increase in the on-peak energy charge for this rate, which is not reasonable. I will propose and recommend an alternative rate design that more reasonably reflects cost of service and produces more stable increases to all customers taking service on this rate schedule. The second rate design issue concerns FPL's proposed Step 2 increases on large, demand metered, general service rate classes. FPL is proposing to recover 100% of the Canaveral revenue increase for Rates GSLDT-1, 2 and 3 and for CILC through the on-peak and off-peak energy charges, despite the fact that over 80% of the Canaveral revenue requirements are demand related. FPL's rate proposal is disconnected from the nature of the underlying costs. I will recommend an alternative recovery approach for these large general service rate classes that more accurately reflects the characteristics of the Canaveral cost of service 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 classes due to incorrect demand allocation factors, including the failure to use a Minimum Distribution System cost classification methodology to assign cost responsibility for FPL's primary and secondary distribution system. In addition, FPL's cost of service study should utilize a 1 CP methodology to allocate production and transmission demand related costs to rate classes.**

- **FPL has based its proposed rate class increases on the results of its 12 CP and 1/13th average demand cost of service study and a goal to bring each rate class to within parity of the system average rate of return as determined using FPL's cost of service methodology. However, FPL has ignored its own load research data for the month of January 2013, thus biasing its cost of**

service results. In addition, FPL's demand allocation factor "adjustment methodology" is unreasonable and distorts demands attributed to different classes of customers. These problems should be corrected. In addition, the Commission should adopt a Minimum Distribution System approach to the classification of 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 classes.

- **FPL has proposed increases to some rate classes that are substantially in excess of 1.5 times the average retail base rate increase requested by the Company. Some rate classes, such as CILC-D, GSLD-1, GSLDT-1, GSLDT-2, HLFT-2 and HLFT-3 will receive increases of 22% to 35% under the Company's proposals in this case, compared to the retail average base revenue increase of 12%. 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 class should receive an increase greater than 150% of the system average base rate increase.**

- **FPL's proposed rate CILC-1D rate design should be modified to provide a more reasonable balance between the proposed increase in the on-peak**

energy charge (320% proposed by FPL) and the various demand charges of the rate.

- **FPL's proposed Step 2 (Canaveral) rate design for large general service rate classes (CILC-1D, GSLDT 1, 2 and 3) should be modified so that both the demand and on-peak energy charges of these rates are increased, consistent with the classification of other production revenue requirements, which FPL uses to allocate the Step 2 increase to rate classes. FPL has proposed to apply 100% of the increase to the on-peak energy charges of these rates.**

II. COST ALLOCATION ISSUES

Q. Have you reviewed the class cost of service study filed by FPL in this case?

A. Yes. Consistent with the instructions for the MFR, FPL has prepared 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 (including Florida's Gulf Power Company) 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, the reasonableness of the Company's study is a significant issue. In particular, because FPL's revenue allocation methodology is an attempt to first eliminate any rate of return disparities (at present rates) and then allocate the overall revenue increase to rate classes, the issue of the reasonableness of the class cost of service study is of critical importance.

Q. Do you support the class cost of service study filed by FPL in this case?

A. No. I do not support the Company's study for a number of reasons, including FPL's use of a 12 CP and 1/13th average demand allocation methodology to allocate production/transmission demand related costs, discussed later in this section of my testimony.

I have specific concerns regarding FPL's cost of service analysis. First, I have identified a problem with the Company's calculation of the 12 CP and Group NCP ("GNCP") demand allocation factors developed for use in its cost of service study. Second, I do not agree with the methodology used to classify distribution plant and expenses. FPL has not considered any minimum distribution system costs in its cost classification analysis, which unreasonably overstates the cost responsibility for large general service rate classes. I address both of these issues below.

Q. Would you please discuss FPL's demand allocation factor development?

A. FPL calculates projected test year 2013 12 CP, Group NCP demand ("GNCP") and NCP demands by applying a 3-year historic load factor to projected 2013 mWh sales for each rate class. The historic 3-year period of data used in this case consists of sample load research data or, in the case of very large customers, actual metered data, for the years 2008, 2009 and 2010. FPL uses the LodeStar system to develop its monthly analyses. FPL witness Joseph Ender discusses this process beginning on page 11 of his testimony. He explains on page 12, beginning on line 19, how FPL actually performed its calculations in this case:

> Projected 2013 Test Year monthly CP, GNCP and NCP ratios for each rate class were then developed based on the average of their

respective historical ratios. The projected CP, GNCP and NCP ratios were then applied to the sales forecast by rate class to derive the projected CP, GNCP and NCP demands for each class.

This analysis forms the basis for the demand allocation factors used in the Company's filed class cost of service study.

Q. Does FPL actually use the monthly rate class demands, as calculated using the historic 3-year average load research results?

A. No. FPL does not use all 12 months of the data, as calculated. This point is not addressed in Mr. Ender's testimony.

Q. Please summarize how FPL departs from using actual historical data.

A. The first change that FPL made to the rate class demands was to make a substitution for the actual 3-year January CP and GNCP residential class load factors. This "adjustment" increased the January residential class CP and GNCP load factors, which has the effect of <u>reducing</u> the January 2013 CP and GNCP residential class demands. This "adjustment" reduces the residential class 12 CP and 1/13th average allocation factor (FPL 101) used to allocate production and transmission demand related costs and the GNCP allocation factor (FPL 104) used to allocate distribution plant and expenses to rate classes, and has the effect of increasing cost responsibility of other rate classes. Table 1 below compares the actual January CP load factors based on the results of FPL's load research to the January CP load factors that are instead imputed by FPL to develop its demand allocation factors. A similar adjustment was made to the residential class January GNCP load factor.

Table 1
Month of January 3-Year Average CP Load Factor
3-Year Average as Determined by LodeStar

	Per FPL LodeStar Data Base	Per FPL Filing (adjusted)	Difference
RETAIL:			
CILC-1D	1.3134	1.3134	-
CILC-1G	1.2988	1.2988	-
CILC-1T	1.2052	1.2052	-
GS(T)-1	0.9542	0.9542	-
GSCU-1	1.0253	1.0253	-
GSD(T)-1	0.9361	0.9361	-
GSLD(T)-1	0.9552	0.9552	-
GSLD(T)-2	1.0723	1.0723	-
GSLD(T)-3	0.9320	0.9320	-
METRO	0.6550	0.6550	-
OL-1	7.1486	7.1486	-
OS-2	1.9418	1.9418	-
RS(T)-1	0.4364	0.4839	(0.0475)
SL-1	7.0992	7.0992	-
SL-2	1.0000	1.0000	-
SST-D	9.2232	9.2232	-
SST-1T	0.4684	0.4684	-

Q. Is the residential class load factor substitution significant, in your opinion?

A. Yes. Moving the January CP demand load factor from 43.64% to 48.39% (a 9.8% difference) *increases* the share of costs borne by all other rate classes.

Q. What is the basis for FPL's substitution of load research data for the residential class?

A. There is no explanation or acknowledgement of this adjustment in the Company's testimony.

Q. Do you have additional concerns with the Company's demand allocation factor development?

A. Yes. Putting aside FPL's changes to the January CP and GNCP load factors described above, I have identified another methodological problem with FPL's calculation of its test year demand allocation factors. After the development of the 2013 rate class CP, GNCP and NCP demands, the Company performed a test to check whether the monthly GNCP demand is less than or equal to the monthly NCP demand. The NCP demand represents the sum of each customer's maximum hour of demand throughout a particular calendar month over all hours (e.g., customer 1's highest demand may occur in hour 300, while customer 2's highest demand may occur in hour 305 – these highest demands are summed for the month to calculate the NCP demand). The GNCP demand represents the highest aggregate demand in any single hour of the entire rate class during the month. If each individual customer had its highest hourly demand in the identical hour during the month, the GNCP would equal the NCP for the class. However, the GNCP could never exceed the NCP. Similarly, the rate class CP demand, which is the GNCP coincident with the monthly system peak hour, can never exceed the monthly GNCP (which is the maximum hourly GNCP during the month). Because the CP, GNCP and NCP demands are based on sample load research data, sampling errors can produce anomalies.

The problem that I identified with FPL's methodology is that it begins with the NCP and tests the GNCP and CP demands sequentially. If the GNCP exceeds the NCP in a month, the GNCP is set equal to the NCP and the excess is spread to all other rate classes. Similarly, if the CP exceeds the adjusted GNCP, the CP is set equal to the GNCP and the excess is spread to all other rate classes. Finally, after these adjustments, the "adjusted CP" demands are then summed across rate classes and compared to the FPL monthly system peak forecast. Any differences are spread only to the rate classes that were not adjusted in the NCP/GNCP/CP reconciliation process.

Q. Would you provide an example of the adjustments that the Company made in this case to the demand allocation factors?

A. Yes. Table 2 shows the Company's adjustment calculations for the residential class and for GSLDT-2, for the month of January 2013.[1] These adjustments do not include the effect of the Company's residential class CP load factor adjustment, which I discussed earlier; they only reflect the Company's reconciliation adjustments.

[1] This information was provided by FPL in response to OPC POD Number 2-12.

Table 2
Example of Residential and GSLDT-2 Class Load Data Adjustments
January 2013

I. Adjustment - "Pass 1"		
	Residential	**GSLDT-2**
KW Demands (January 2013)	@ Meter	@ Meter
CP	12,021,250	258,850
GNCP	12,495,859	371,089
NCP	32,753,098	450,328
[Residential class passes test, no adjustment in "Pass 1"]		
[CP forecasted peak reconciliation - 1,384,606, spread to all classes except SL-2]		
II. Adjustment - "Pass 2"		
KW Demands (January 2013) - w/share of CP forecast adjustment		
CP	12,883,684	277,420
GNCP	12,495,859	371,089
NCP	32,753,098	450,328
[Residential class fails "Pass 2" test, CP demand set equal to GNCP		
[CP forecasted peak reconciliation - 421,360 spread to all classes except GSCU-1, residential and SL-2]		
III. Final Adjusted Demands		
CP	12,495,859	294,921
GNCP	12,495,859	371,089
NCP	32,753,098	450,328
IV. Final Adjusted Demands - Percent Change From Load Data		
CP	3.95%	13.94%
GNCP	0.00%	0.00%
NCP	0.00%	0.00%

Part I of the table shows the kW demands at the meter (before adjustments) for both the residential and GSLDT-2 classes. In each case, the GNCP demands are less than the NCP demands and the CP demands are less than the GNCP demands. Both of these classes "pass" the first rounding of testing. After the first "pass," a reconciliation test is performed to compare the calculated January 2013 CP demands (summed over all classes) to the Company's independent 2013 peak forecast. The reconciliation shows that there is a shortfall of 1,384,606 kW (at generation voltage) that is then spread to all classes (other than SL-2, which is capped because its CP demand equals its GNCP demand already).

After this "peak forecast" reconciliation adjustment, the residential class January CP demand is now 12,883,684 and the GSLDT-2 CP demand is 277,420. At this point ("Pass 2"), the residential adjusted CP demand now exceeds the residential GNCP demand and therefore the residential class fails the CP/GNCP/NCP reconciliation test. As a result, the residential class January CP demand is now capped at 12,495,859, which is the GNCP demand for January 2013. With the residential capped demand (and the cap for GSCU-1, which also failed the "Pass 2" test and the cap for SL-2), the new "peak forecast" shortfall is 421,360 kW, which is spread to all classes except residential, GSCU-1 and SL-2. The final adjusted residential CP demand is 12,495,859 (equal to the residential GNCP demand due to the cap) and the GSLDT-2 CP demand is 294,921. For the residential class, this represents a 3.95% adjustment from the original load research based demand calculation. For the GSLDT-2 class, the adjusted CP demand is 13.94% higher than the original demand calculation. This obviously has resulted in a significant up-ward adjustment to the GSLDT-2 rate class demand allocation factor, and its cost responsibility as determined by the Company's cost of service study. This result is particularly problematic since the GSLDT-2 and other large general service classes have 100% actual hourly load data available, while the residential class and other smaller rate classes use sample load research data. In other words, the meter data for large general service classes needs no adjustment because they are already recorded and billed at a level of detail that does not require further statistical extrapolation, unlike some other rate schedules. Thus, FPL's adjustment for the large general service classes distorts actual recorded data and class cost responsibility.

Q. Is FPL's NCP/GNCP/CP reconciliation methodology reasonable?

A. No. The only reconciliation information available, beyond the load research sample data, is the independently developed FPL system peak forecast. It would be much more appropriate and valid to rely on the sample load research data (the 3-year load factors) to develop the rate class CP demands, which can then be uniformly adjusted to tie to FPL's system peak demand forecast. The resulting CP demands would then not be further adjusted in any reconciliation process; rather, the GNCP and NCP demands should be adjusted to insure that they are internally consistent.

FPL's methodology effectively reduces the quality of the statistically based random sample forming the load research data. As I showed in Table 2, the upward adjustment to large general service rate classes is substantial. There is simply no basis to perform the adjustments made by the Company. Particularly given that those adjustments distort actual metered data for certain rate classes. The rate class CP demands should be reconciled to the system peak forecast by FPL before the NCP/GNCP/CP reconciliation test is performed. It makes no sense to perform the adjustment process used by FPL; it once again has the effect in this case of improperly raising the large general service rate classes' cost responsibility.

Q. Have you revised FPL's demand allocation factors to correct the two problems that you have identified?

A. Yes. First, I used the correct residential class January CP and GNCP load factors, rather than FPL's substituted values. Second, I applied the reconciliation test by assuming that the rate class CP demands, which already have been reconciled with FPL's 2013 peak demand forecast, are reasonable. I made adjustments, if necessary, to the monthly GNCP demands if the GNCP was less than the CP demand by setting the GNCP equal to the CP for the month. Similarly, if the adjusted GNCP demand for the month (for each rate class) is greater than the NCP demand, I set the NCP demand equal to the GNCP demand.[2] Table 3 below shows a comparison of my corrected demand allocation factors for CP, GNCP and NCP to FPL's originally filed allocation factors.

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[2] Because there is no need to tie the sum of the rate class GNCP and NCP demands to another forecast (as is the case with the requirement to tie the CP demands to the Company's peak forecast), there is no requirement to "spread" the adjustment of GNCP and NCP demands to other rate classes.

TABLE 3
Comparison of Demand Allocation Factors: SFHHA Corrected vs. FPL's
(mW)

	SFHHA Corrected Allocators			FPL Allocators		
	FPL101 12CP	FPL104 GNCP	FPL109 NCP	FPL101 12CP	FPL104 GNCP	FPL109 NCP
CILC-1D	364	451	347	367	451	347
CILC-1G	23	30	36	24	30	36
CILC-1T	159	-	-	161	-	-
GS(T)-1	1,064	1,369	2,487	1,070	1,351	2,487
GSCU-1	5	5	5	5	5	5
GSD(T)-1	4,034	4,915	6,955	4,074	4,915	6,955
GSLD(T)-1	1,793	2,221	2,405	1,817	2,221	2,405
GSLD(T)-2	332	396	333	336	396	333
GSLD(T)-3	26	-	-	26	-	-
MET	16	21	-	17	21	-
OL-1	2	29	29	2	29	29
OS-2	2	13	12	2	13	12
RS(T)-1	10,927	14,988	35,395	10,848	13,504	35,395
SL-1	10	154	154	10	154	154
SL-2	4	4	4	4	4	4
SST-DST	1	30	-	1	6	-
SST-TST	13	-	-	13	-	-

Q. **Why is your methodology more reasonable than FPL's methodology?**

A. FPL's methodology distorts each of the demand allocation factors calculated in this case because of the sequence of the Company's reconciliation adjustments. Of the three demand allocation factors (CP, GNCP and NCP), only the CP demands can be reconciled with a separate forecasted peak. To the extent that the sum of the class CP demand for each month developed using FPL's three-year load factor analysis does not match the 2013 monthly FPL system peak forecast, it is appropriate to perform a reconciliation on a uniform basis so that the adjustments to each rate class are consistent – this is the methodology that I have used in this case. FPL's methodology distorts these rate class CP demands, which is particularly problematic for rate classes, such as larger general service classes, that have actual historic hourly data rather than estimated data from a load research sample. Also, the Company's method distorts rate class GNCP demands, as I have shown.

Q. Have you revised FPL's class cost of service study to incorporate your corrected demand allocation factors?

A. Yes. Baron Exhibit__(SJB-2) presents a summary of this corrected cost of service study. The only changes that I made to the Company's filed cost of service study are the demand allocation factors (FPL 101, 104, 105 and 109) to reflect the corrections that I have just discussed. Table 4 compares the rate parity results from my corrected cost of service study to FPL's originally filed study. As can be seen, the correction to the demand allocation factors shows that FPL's flawed methodology understates the rate parity results for numerous rate schedules.[3]

[3] It should be noted that rate Class SST-DST has a negative rate of return when corrected allocation factors are used. This occurs because FPL made a significant adjustment to the SST-DST December GNCP and NCP load factors in its analysis, which had the effect of reducing test year GNCP and NCP demand for this rate class. This FPL adjustment had little effect on other rate classes (unlike the residential class adjustment) because of the small size of rate class SST-DST (only 0.02% of retail mWh). This adjustment is not made in the SFHHA corrected analysis.

Table 4
Comparison of ROR Parities
SFHHA w/Corrected Demand Allocation Factors
vs. FPL COS Study

	SFHHA Corrected	FPL As-Filed
CILC-1D	0.95	0.91
CILC-1G	1.19	1.14
CILC-1T	0.81	0.78
GS(T)-1	1.38	1.35
GSCU-1	1.22	1.21
GSD(T)-1	1.09	1.05
GSLD(T)-1	0.75	0.70
GSLD(T)-2	0.71	0.67
GSLD(T)-3	0.99	0.96
MET	0.86	0.81
OL-1	0.98	0.98
OS-2	0.78	0.73
RS(T)-1	0.98	1.00
SL-1	0.97	0.97
SL-2	2.08	2.08
SST-DST	(0.18)	1.15
SST-TST	3.02	2.99

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.[4] The Company's approach does not give any recognition to a customer component of any primary or

[4] Primary pull-offs are also specifically assigned to rate classes.

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. FPL places significant weight on the "parity" results from its cost of service study when assigning increases to rate classes. In particular, the proposed increases to its general service rate classes 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 classes. 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 materially increase rates to a number of rate classes. Therefore, 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 classes in this case, it is reasonable for the Commission to consider evidence on alternative methods of classifying distribution costs in this case.

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.[5] The amount of distribution cost that is a function of the requirement to interconnect the customer, regardless of the customer's size, is appropriately assigned to rate classes 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?

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

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

(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 should not 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, which is not related to customer usage levels, 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. For example, new distribution investment in poles, or underground conductors, for a new subdivision may be associated with unsold, or unoccupied homes that have "0" kW demand – yet the cost for these facilities is still incurred. Similarly, distribution facilities must be installed to meet the needs of part time residents that may have little or no demand during a portion of the year – yet the cost of such distribution facilities still must be incurred and does not vary as a result of the fact that such facilities serve part-time residents. The MDS methodology gives recognition to this circumstance by assigning a portion of the cost of these facilities based on the existence of a "customer," and not just the level of the customer's kW demand. This is in contrast to FPL's analysis that assumes 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 a specific example that illustrates this point?

A. Yes. In FPL's prior base rate case (Docket No. 080677-EI), I presented an analysis of account No. 364 secondary poles allocated by the Company using its "100% demand" methodology. This analysis clearly demonstrated that the Company's refusal to acknowledge <u>any</u> customer component of distribution cost (other than for services and meters) is not justified.

Q. Have you performed a similar analysis of account No. 364 data in this case?

A. Yes. FPL has classified all costs in account No. 364, poles, towers and fixtures, as demand related and allocated these costs to rate classes 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 classes using rate class NCP demand. Table 5 summarizes FPL's implicit allocation of these secondary poles to major general service rate classes 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 on average more than 35 residential customers are served from a single pole, while it takes about 14 poles to serve a single GSLDT-2 customer. This obviously is not realistic; yet, this is the cost allocation underlying FPL's proposed rate class increases in this case.

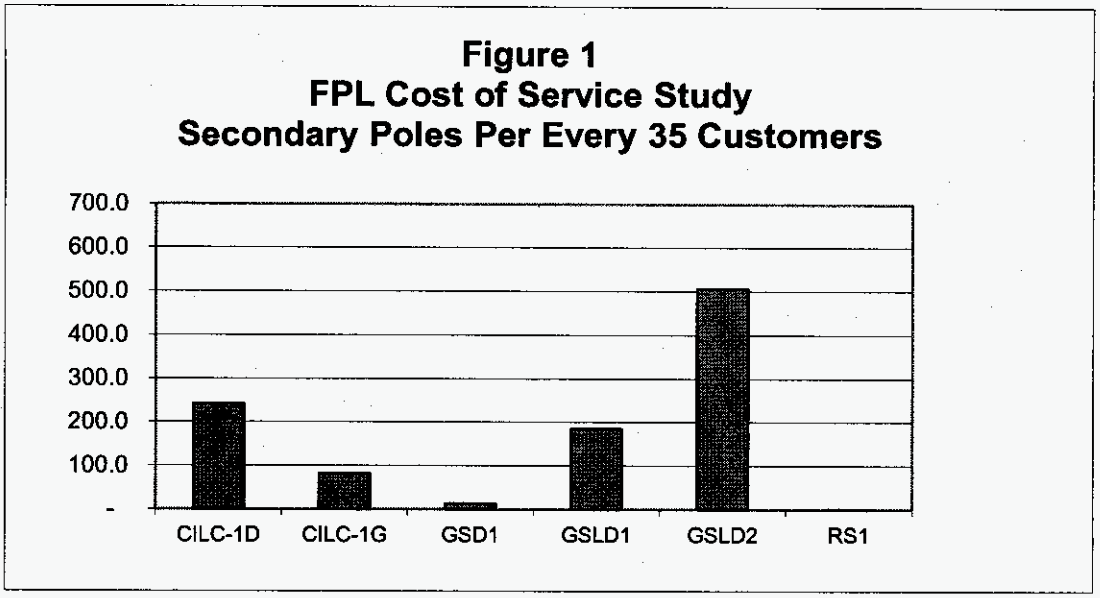
Table 5
FPL's Assignment of Secondary Poles Per Customer

Total Secondary Poles: **182,304**

Rate Class	Allocation Factor*	Poles Allocated to Rate	Poles Per Customer	Poles Per Every 35 Customers
CILC-1D	1.254%	2,287	6.91	241.8
CILC-1G	0.132%	241	2.32	81.2
GSD1	21.605%	39,387	0.37	13.1
GSLD1	9.441%	17,211	5.26	184.1
GSLD2	1.198%	2,183	14.45	505.8
RS1	59.525%	108,517	0.03	0.9

* FPL105

Figure 1 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 classes.



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

A. Yes. As discussed by FPL witness Rosemary Morley on page 20 of her testimony, at the end of 2011, the ratio of inactive meters to total customers on the FPL system was 6.1%. According to Dr. Morley, this ratio is "a proxy for empty homes" on the FPL system (testimony at page 20, line 7). The Company's test year cost of service study would tend to systematically understate the actual cost responsibility of such customers for distribution plant and expenses. "Empty homes" nonetheless have distribution facilities (*e.g.*, poles, overhead and underground lines, transformers) installed to allow connection to such customers, despite the fact that they are empty. These distribution facilities are installed to serve these homes, even if there is no or de minimus usage because the homes are empty. These vacant homes required investments by FPL in primary and secondary lines, poles, conduit and transformers. Yet, because kW demand, which FPL uses to allocate the cost of these distribution facilities to rate schedules, approaches zero for unoccupied homes, the costs of these distribution facilities are essentially allocated to other rate classes, not the cost-causers. While a minimum distribution system methodology may still not fully remedy this problem, it would provide a more reasonable allocation of cost.

Q. **Do other major electric utility operations in Florida incorporate minimum distribution system classifications in class cost of service studies?**

A. Yes. In a recent Gulf Power Company ("GPC") rate case (Docket No. 110138-EI), GPC presented and strongly supported the use of an MDS methodology to develop its class cost of service study. GPC's cost of service witness in that case, Michael O'Sheasy, testified in support of an MDS methodology as follows:

> Q. Please explain why the Minimum Distribution System methodology is important to Gulf and its customers?
>
> A. As I discuss in more detail later, some costs of the distribution system beyond the customer meter and service drop do not vary with customers' use of electricity. The Minimum Distribution System (MDS) methodology is necessary to accurately determine and allocate these customer-related distribution costs. The misclassification of costs that results from not using the MDS methodology sends misleading price signals to customers. This misclassification also results in different customer rate

> classes bearing more or less costs than their cost-causative share of distribution costs. It is therefore important to examine these customer-related costs and classify them appropriately, which the MDS methodology enable us to do. [O'Sheasy Direct Testimony at pages 16 -17, Gulf Power Company Docket No. 110138-EI].

Q. Do you agree with Mr. O'Sheasy's quoted testimony on the MDS issue?

A. Yes. There is no question that some portion of each of FPL's distribution accounts 364 to 368 is customer related. FPL of course assumes that each of these accounts is 100% demand related – that is, if a customer were to decrease its usage to 0 kW, all of the poles, overhead conductors, underground conductors and transformers would somehow disappear or be used to supply customers in other parts of FPL's system. This is obviously not the case. With the FPL system having over **285,000** inactive accounts, this problem is exacerbated.[6] It is simply not credible to argue, as FPL does, that 100% of its primary and secondary distribution system (other than services and meters) is cost-causally related to kW demand and none to the number of customers served on the distribution system.

Q. What were the results of GPC's MDS classification analysis?

A. Baron Exhibit__(SJB-4) contains a copy of Mr. O'Sheasy's MDS results for each

[6] Number of inactive accounts on the FPL system in July 2011(Source: response to SFHHA POD No. 77).

FERC distribution account.

Q. Did the Commission adopt GPC's MDS methodology in Docket No. 110138-EI?

A. It is my understanding, based on a review of the Commission's Order in that case, that the Commission approved a Stipulation adopting the methodology "solely for use in designing rates in this case." At least for that GPC case, the conceptual framework that some portion of distribution accounts 364 through 368 is customer related has been accepted, even if it is only for "use in designing rates" in that case.

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

A. Yes. Given the importance of the cost of service results (parities) in this case, it is appropriate for the Commission to adopt an alternative methodology, particularly given clear evidence that FPL's methodology produces results that over-estimate cost responsibility of some classes. The conceptual basis for the MDS 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. Have you performed any analysis to evaluate the reasonableness of using the

GPC MDS results as a measure of minimum distribution costs on the FPL system?

A. Yes. As described by GPC witness O'Sheasy in Docket No. 110138-EI on page 25 at line 24 of his Direct Testimony, GPC used a minimum size methodology for Account 364 data based on the "the average of the smallest, most frequently used poles since the unit cost of different sized poles did not lend itself to regression analysis."[7] In the GPC analysis, the Company used the cost of wooden poles that were 35 feet and smaller. Using FPL Account No. 364 data provided by the Company in response to OPC POD 2-12 (used to support FPL's primary-secondary distribution plant split in its cost of service study), I performed a similar analysis of the cost of smaller wooden poles on the FPL system. Baron Exhibit__(SJB-5), pages 1 and 2 presents the analysis that I performed.

Page 1 of the exhibit includes an extract from FPL's file "2010 Primary Secondary Split-Final.xlsx," Tab "2009 Surviving Balance Report," which was provided in response to OPC POD 2-12. This file extract shows the installed cost of various pole categories in the FPL Account No. 364 inventory. Based on the Company's own data, there were 1,011,357 wooden poles on the FPL system in the two smallest categories used by FPL ("23/30 FT" and "35/40/45 FT"). As shown on the exhibit, the average cost of these smaller wooden poles is $616.57 per pole. The entire inventory of FPL poles (1,297,659) is then re-priced in my analysis at this minimum

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[7] For all other distribution plan accounts, GPC used a zero intercept, regression methodology.

unit cost. Based on this analysis, using the GPC methodology, 82% of FPL's Account No. 364 costs are customer related. This compares to GPC's Account No. 364 classification (page 2 of the exhibit) that assigns 65% of these cost as customer related. The higher FPL customer classification appears to be consistent with the fact that FPL's 35 foot category also included large 40 foot and 45 foot poles. Nonetheless, my conclusion from this analysis is that the GPC classification results are a reasonable proxy for the FPL system.

Q. Have you developed an alternative class cost of service study reflecting a minimum distribution system methodology?

A. Yes. In order to provide indicative rate of return parity impacts from the use of an MDS methodology, I have rerun the corrected FPL class cost of service study that I presented in Baron Exhibit__(SJB-2) using the customer/demand classifications for FERC Account Nos. 364 through 368 developed by Gulf Power Company in its recent rate case before the Commission [see Baron Exhibit__(SJB-4)]. These results illustrate the bias in the Company's study as a result of the classification of 100% of distribution plant accounts 364 through 368 as demand related and 0% as customer related. Baron Exhibit__(SJB-6) presents the results of this study of FPL's cost of service. This analysis also includes the correction to the residential class 12 CP, GNCP and NCP demands that I previously discussed.

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

A. Table 6 shows the comparison. I have highlighted the large general service rate classes in Table 6 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 differences in the rate of return parities for most large general service rate classes using an MDS methodology.

Table 6
Comparison of ROR Parities
SFHHA Minimum Distribution System COS Study
w/Corrected Demand Allocation Factors
vs. FPL COS Study

	SFHHA Corrected	FPL As-Filed
CILC-1D	1.01	0.91
CILC-1G	1.27	1.14
CILC-1T	0.81	0.78
GS(T)-1	1.32	1.35
GSCU-1	1.00	1.21
GSD(T)-1	1.16	1.05
GSLD(T)-1	0.81	0.70
GSLD(T)-2	0.77	0.67
GSLD(T)-3	0.99	0.96
MET	0.91	0.81
OL-1	1.01	0.98
OS-2	0.89	0.73
RS(T)-1	0.95	1.00
SL-1	0.99	0.97
SL-2	2.18	2.08
SST-DST	(0.12)	1.15
SST-TST	3.02	2.99

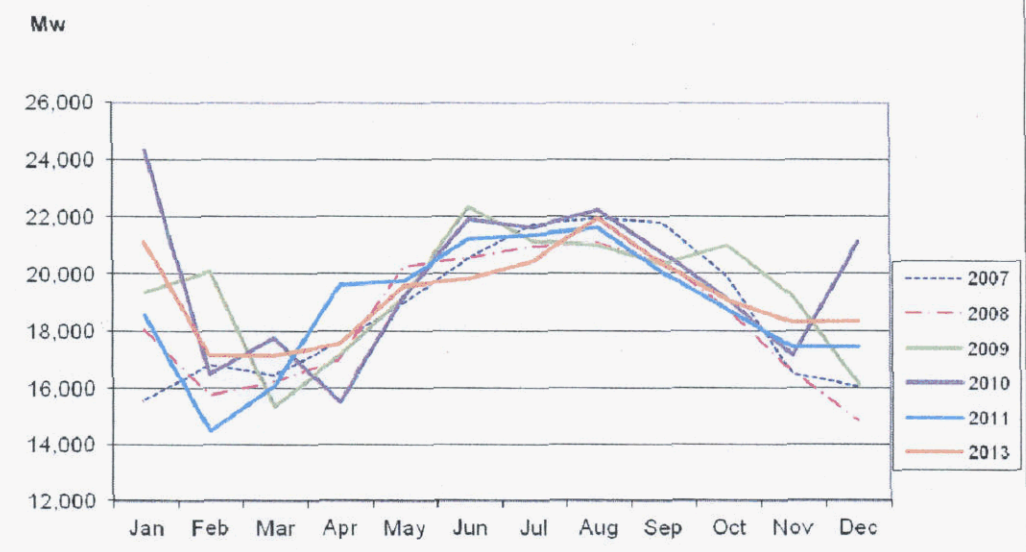
Q. What is the implication of these results from your MDS cost of service study?

A. Using an alternative methodology that recognizes a minimum level of distribution cost associated with connecting customers to the system produces a more accurate measure of rate class revenue increases. I believe that the Commission should require FPL to file an MDS cost of service study in a compliance filing in this case and use these results to allocate any Commission approved revenue increases. Further, I recommend that the Commission require FPL to perform and file an MDS cost of service study with the appropriate supporting data in its next base rate case.

Q. You indicated previously that you believe that a summer coincident peak demand ("1 CP") methodology to allocate production and transmission demand costs is more appropriate than FPL's proposal to use a 12 CP and 1/13th average demand method. What is the basis for your opinion on this issue?

A. As in prior FPL rate cases, I continue to support the use of a 1 CP methodology based on the significance of customer demands during the summer months as a driver of new generation capacity on the system. Figure 2 below shows FPL's actual monthly system peaks for the last five years (2007 to 2011) and the Company's forecasted 2013 test year monthly peaks.

Figure 2
Florida Power & Light
Monthly Peak Demands (2007 - 2011 Actual + 2013 TY)



As is clear from this chart, FPL summer peak demands predominate on the FPL system. While winter peaks on rare occasions have exceeded the summer peak under certain weather conditions, the summer peak drives the need for capacity on the system. Clearly, customer usage during lower load months such as March, April, May, October and November does not drive the need for additional generation resources on the system. This is confirmed in the Company's 10 Year Site Plans repeatedly over time. For example, in the 2011 Site Plan, FPL states that the Company uses a dual planning criterion of maintaining a 20% reserve margin based on the summer and winter peaks, as well as a loss of load probability criterion.[8] Since FPL forecasts that the summer peak will exceed the winter peak, the Company's

[8] FPL's "Ten Year Power Plant Site Plan 2012-2021" (April 2012) at page 55.

generating capacity needs are clearly being driven by summer peak load.

Q. Is the 12 CP and 1/13th average demand methodology consistent with this planning criterion?

A. No. The 12 CP and 1/13th average demand methodology assumes that the peak day usage in any one month contributes equally to the need for FPL to add new capacity as the peak day usage in every other month. I do not believe that it is consistent or reasonably reflects the significance of customer demands during the summer peak months in driving the need for capacity additions on the FPL system. As a result, the price signals from the Company's rates, which are based on the 12 CP and 1/13th average cost of service analysis, do not reasonably reflect cost causation.

Q. Have you developed a 1 CP class cost of service analysis in this case?

A. Yes. Baron Exhibit__(SJB-7) presents the results of a revised FPL cost of service study using a 1 CP methodology, as well as the corrections to the Company's demand allocation factors and the MDS classification of distribution costs. I believe that this cost of service study would be the most appropriate basis to assign cost responsibility in this case and to use in developing the allocation of the Commission approved increase to rate classes. Table 7 summarizes the rate parities for each rate class based on a 1 CP/MDS cost of service study, compared to the rate parities in FPL's filed cost of service study.

Table 7
Comparison of ROR Parities
SFHHA MDS - 1 CP COS Study
w/Corrected Demand Allocation Factors
vs. FPL COS Study

	SFHHA MDS - 1 CP	FPL As-Filed
CILC-1D	1.03	0.91
CILC-1G	1.30	1.14
CILC-1T	0.83	0.78
GS(T)-1	1.23	1.35
GSCU-1	1.06	1.21
GSD(T)-1	1.14	1.05
GSLD(T)-1	0.82	0.70
GSLD(T)-2	0.78	0.67
GSLD(T)-3	1.05	0.96
MET	0.94	0.81
OL-1	1.05	0.98
OS-2	1.00	0.73
RS(T)-1	0.96	1.00
SL-1	1.03	0.97
SL-2	2.33	2.08
SST-DST	(0.13)	1.15
SST-TST	2.09	2.99

III. ALLOCATION OF THE AUTHORIZED REVENUE INCREASE

Q. What does this issue involve?

A. FPL is seeking to increase *base rates* by $516.5 million in Step 1 and $173.9 million in Step 2. This portion of my testimony concerns how increases in base rates should be spread across customer classes.

Q. What is the single most important goal in this exercise in your opinion?

A. I believe it is critically important to use revenue related to base rates -- not other revenues (*e.g.*, fuel or other costs subject to trackers that are triggered in ways independent of base rate cost responsibility) to allocate these step increases.

Q. Would you please briefly describe the methodology that FPL is proposing to use to allocate its requested base rate Step 1 increase of $516.5 million and its base rate Step 2 increase of $173.9 million to rate classes?

A. Based on the testimony of FPL witness Renae Deaton and an analysis of FPL's workpapers in this case, the Company uses two factors to develop the initial "target revenue increases" for base rates in each rate class. The first component of the target revenue increase for base rates is an adjustment to each rate class to remove any rate of return parity differences as calculated by FPL. This adjustment is intended to remove any dollar subsidies paid or received by each rate class based on the results of FPL's class cost of service study at present rates. Effectively, rate classes receive revenue increases or decreases necessary to move towards an equal rate of return.

The second component of the target revenue increase is a uniform percentage increase to each rate class on a *total revenue* basis (including all clause revenues and unbilled revenues) sufficient to recover the Step 1, $516 million revenue increase. Based on FPL's filing, this uniform percentage factor is 5.86%. The sum of these two parts becomes the target increase for each class.

Q. You indicated that the uniform percentage increase portion of the "target revenue" increase is based on total rate class revenues. What is included in FPL's "total revenue" for each rate class that is used in the revenue allocation calculations?

A. Total revenue includes the following categories in addition to base revenues:

a. miscellaneous revenues

b. other allocated operating revenue credits

c. unbilled revenues

d. an add-back of any CILC or CDR incentives included in base revenues

e. All Clause Revenues

Table 8 below shows the composition of "total revenues" used by FPL for rate GSLDT-1. The only revenues actually at issue in this case are base revenues and miscellaneous revenues. These constitute 41% of the "total revenues" used in FPL's calculations; the remaining 59% revenues used by FPL to allocate its requested increase *are not at issue in this case.*

Table 8
Example of Total Revenues - GSLDT-1

Rate Class		GSLD(T)-1
2013 Base Rate Revenue	$	306,793,721
Misc. Sevice Revenue	$	805,007
Other Operating Revenue	$	6,612,648
CILC Incentive offset.	$	5,959,107
Unbilled	$	(917,546)
Clause Revenue	$	433,061,467
2013 Operating Revenue	$	752,314,404

In other words, the base rate increase is being allocated primarily, in the instance of GSLDT-1, *not* on the basis of base rate revenues, but instead on other revenue.

Q. **Does the Company make any adjustments to this "target revenue" increase?**

A. Yes. There are three sets of adjustments made to the initial target increases. First, any revenue decreases are eliminated, following the Commission's prior decisions that no rate class should receive a rate decrease. The excess revenue produced in this step is credited (a reduction) to all rate classes receiving an increase on the basis of the dollars of target revenue increases. The next adjustment is the application of the Commission's "1.5 times average increase" rule that limits the increase to any rate class to a maximum of 1.5 times the retail average increase. FPL has applied this "1.5 times" limitation to the "total revenue" increase of each rate class (based on all revenues, from whatever the source), rather than the base revenues at issue in this case. These "total revenues" for each rate class are the same amounts used in developing the uniform increase portion of the "target revenue" increase that I discussed above.

Q. **What is the final set of adjustments that FPL makes to its "target revenue"**

increases?

A. The Company made a number of adjustments to the revenue increases for large general service rate classes that have the effect of preserving relationships ("cross-over points") between similar rates across rate classes.

Q. **Do you agree with FPL's revenue allocation methodology for its Step 1, $516 million revenue increase?**

A. No. I have two separate objections to the Company's methodology. First, I believe that the development of the rate class "target increases" is inappropriate because it uses "total revenues" to allocate the Step 1 $516 million increase instead of the base revenues and miscellaneous revenues that are at issue in this case. There is no justification to assign the "target" increase for each rate class based on total rate class revenues that include such extraneous items as the rate class share of pole attachment revenues (a component of "other revenues" that are allocated by FPL to each rate class and included in the calculation of total revenues). The second objection that I have concerns the use of "total revenues" in the application of the Commission's "1.5 times" maximum increase rule. While it is true that the Commission required FPL to include all clause revenues in the application of the "1.5 times" adjustment in the 2009 FPL rate case, I will recommend that this mitigation adjustment apply only to the base revenue and miscellaneous revenues at issue in this case.

Q. **Has the Commission previously found that the "target revenue" increase for each rate class should be based on "total revenues" rather than base revenues?**

A. No, I am not aware that the Commission has ever adopted such a policy. As I indicated, the Commission did require that the "1.5 times" maximum increase be based on base revenues plus clause revenues, but this did not address the computation of "target revenue" increases. These two issues, the computation of the "target revenue" increase and the application of the "1.5 times" maximum increase rule, are separate issues, though as I indicated I am recommending that both calculations use base plus miscellaneous revenues, rather than total revenues, as FPL has done in this case.

Q. Is FPL's use of "total revenues" in the development of target rate class increases reasonable?

A. No. The only revenue categories at issue in this case are base revenues and miscellaneous revenues. While the Commission has included "clause revenues" in the calculation of the "1.5 times" maximum increase in prior cases, there is no basis to include any of these other categories of "revenue" in the computation of rate class target increases. In particular, including "other operating revenues," which has nothing to do with rate class "rates" (it represents an allocated credit of "other" FPL revenues for such items as late payment charges, initial connection and reconnection charges, pole attachment rent revenues, transmission revenues, other rents) or clause revenues, in the development of the target rate class increase makes no sense. Effectively, higher load factor rate classes that have a higher proportion of fuel charges (which they already have paid for in their fuel clause charges) receive a larger share of the "target increase" in base rates, all else being equal. Based on FPL's methodology, as fuel costs increase, high load factor general service customers will receive a larger share of the non-fuel base revenue increase, even though they may not be causing more costs reflected in the derivation of base rates. FPL in fact suggests that fuel costs (recovered in the fuel charge) will decline as a result of the Canaveral capital costs (included in base rates).[9] Thus, it is fundamentally illogical to use one to allocate the other. Also, FPL adds-back CILC and CDR incentives to base revenues before applying the uniform percentage increase. This means that CILC and other large general service rate classes are allocated target revenue increases on the basis of "hypothetical revenues." In fact, in FPL's 2009 rate case, the Company did not add-back incentive revenues before computing target rate class revenue increases.

Q. Is FPL's use of "total revenues" in the application of the "1.5 times" maximum rate class increase rule reasonable?

A. No. For the same reasons that I discussed above, it is not reasonable to use total rate class revenues in the application of the "1.5 times" maximum increase rule. The "1.5 times" maximum increase rule should only apply to base and miscellaneous revenues because of the significant increases being proposed by the Company for some large general service rate classes. Table 9 shows the base rate increases proposed by the Company for major rate classes and the relative increase for that rate class compared to the retail average. The Company is proposing increases for some general service rate classes of 21% to 35%, which is 1.8 to 2.9 times the retail average increase.

[9] Kennedy Direct Testimony at 9:11-13 (noting that fuel cost savings will increase as new and modernized generating units are placed into service); 11:1-5 (noting that the Canaveral Modernization Project will, *inter alia*, reduce fuel costs); and 14:18-21 (stating that "FPL is a leader in converting older power plants to modern combined cycle technology . . . providing significant fuel cost savings to customers . . . .").

Table 9
FPL Proposed Rate Class Increases
Step 1 - January 2013

	Increase ($000)	% Base Revenue*
CILC-1D	$ 13,032,796	23.0%
CILC-1G	$ 336,645	7.5%
CILC-1T	$ 5,678,789	35.2%
GS(T)-1	$ 3,469,333	1.1%
GSCU-1	$ 38,612	2.3%
GSD(T)-1	$ 97,175,710	11.2%
GSLD(T)-1	$ 66,062,257	21.5%
GSLD(T)-2	$ 13,077,926	23.1%
GSLD(T)-3	$ 593,583	14.6%
MET	$ 553,338	19.1%
OL-1	$ 1,303,193	11.3%
OS-2	$ 123,450	14.5%
RS(T)-1	$ 306,503,369	11.8%
SL-1	$ 7,990,149	11.3%
SL-2	$ (225,732)	-17.1%
SST-DST	$ 58,320	15.8%
SST-TST	$ 749,557	17.5%
TOTAL RETAIL	$ 516,521,295	12.0%

* Base revenue plus miscellaneous revenue

Q. Do the increases proposed by the Company give reasonable weight to the regulatory concept of "gradualism?"

A. No. Based on the proposed increases shown in Table 9, FPL has not reasonably applied gradualism or mitigation in assigning increases to rate classes.

Q. Do you agree with the Company's methodology to allocate the proposed $516 million Step 1 increase to rate classes?

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. Also, for the reasons that I discussed above, I disagree with the Company's proposed allocation of the revenue increase in this case to rate classes. I am recommending a modification to FPL's revenue allocation methodology to use "base plus miscellaneous" revenues instead of total revenues for both the development of the target revenue increases for each rate class and for use in applying the Commission's "1.5 times" maximum increase rule.

Q. Have you developed rate class revenue allocations using your modified FPL methodology?

A. Yes. I have developed four revenue allocation analyses using my recommended methodology that utilizes base plus miscellaneous revenues, rather that FPL's calculation of "total revenues" for both the initial target increase and the application of the "1.5 times" maximum increase rule. The three alternative revenue allocations are as follows:

1. FPL's As-Filed cost of service study.

2. FPL's cost of service study with SFHHA's recommended correction to the demand allocation factors.

3. FPL's cost of service study with both SFHHA's demand allocation factor correction and the incorporation of a minimum distribution system methodology.

4. FPL's cost of service study with SFHHA's demand allocation factor correction, the incorporation of a minimum distribution system methodology and the use of a 1 CP production/transmission demand allocation methodology.

Baron Exhibit__(SJB-8), Schedules A through D present the results of this analysis. Table 10 summarizes these revenue allocation results for each rate class.

Table 10
Alternative Rate Class Increases Using SFHHA Revenue Allocation Methodology
Step 1 - January 2013*

	FPL COS Study		FPL COS - Corrected Demand		FPL COS - MDS-Corrected Dem		FPL COS - MDS-Corr Dem-1 CP	
	Increase ($000)	% Increase Base Rev**	Increase ($000)	% Increase Base Rev**	Increase ($000)	% Increase Base Rev**	Increase ($000)	% Increase Base Rev**
CILC-1D	$ 10,371,750	18.3%	$ 8,890,529	15.7%	$ 6,655,892	11.7%	$ 5,951,649	10.5%
CILC-1G	$ 246,127	5.5%	$ 143,634	3.2%	$ 15,876	0.4%	$ 12,958	0.3%
CILC-1T	$ 2,904,845	18.0%	$ 2,904,845	18.0%	$ 2,904,845	18.0%	$ 2,904,845	18.0%
GS(T)-1	$ 2,646,185	0.9%	$ 1,996,915	0.6%	$ 2,509,755	0.8%	$ 10,758,309	3.5%
GSCU-1	$ 101,711	6.1%	$ 90,964	5.4%	$ 204,307	12.2%	$ 169,940	10.2%
GSD(T)-1	$ 91,860,043	10.6%	$ 74,329,106	8.6%	$ 48,245,710	5.6%	$ 55,145,807	6.4%
GSLD(T)-1	$ 55,336,918	18.0%	$ 55,336,918	18.0%	$ 55,336,918	18.0%	$ 55,336,918	18.0%
GSLD(T)-2	$ 10,188,255	18.0%	$ 10,188,255	18.0%	$ 10,188,255	18.0%	$ 10,188,255	18.0%
GSLD(T)-3	$ 585,412	14.4%	$ 534,568	13.2%	$ 525,116	12.9%	$ 419,656	10.3%
MET	$ 520,275	18.0%	$ 520,275	18.0%	$ 484,358	16.7%	$ 429,827	14.9%
OL-1	$ 1,668,942	14.4%	$ 1,567,464	13.6%	$ 1,391,830	12.0%	$ 1,185,428	10.2%
OS-2	$ 153,638	18.0%	$ 153,638	18.0%	$ 152,070	17.8%	$ 105,933	12.4%
RS(T)-1	$ 329,323,337	12.7%	$ 349,787,725	13.5%	$ 378,796,816	14.6%	$ 365,887,605	14.1%
SL-1	$ 10,555,452	14.9%	$ 9,984,111	14.1%	$ 9,028,876	12.7%	$ 7,944,529	11.2%
SL-2	$ 9,242	0.7%	$ 7,016	0.5%	$ 3,777	0.3%	$ 3,030	0.2%
SST-DST	$ 24,228	6.6%	$ 66,451	18.0%	$ 66,451	18.0%	$ 66,451	18.0%
SST-TST	$ 24,796	0.6%	$ 18,741	0.4%	$ 10,302	0.2%	$ 10,014	0.2%
TOTAL	$ 516,521,155	12.0%	$ 516,521,155	12.0%	$ 516,521,155	12.0%	$ 516,521,155	12.0%

* This table is based on FPL's requested revenue increase. It does not reflect SFHHA's recommended reduction to FPL's proposed increase.

** Base revenue plus miscellaneous revenue

Q. What is your recommendation in this case regarding revenue allocation?

A. I recommend that the Commission adopt my proposed modified revenue allocation methodology based on base revenues and miscellaneous revenues. Consistent with my recommendation on class cost of service, I also recommend that the Commission utilize the results of my revenue allocation methodology reflecting a minimum distribution system methodology, a 1 CP production/transmission demand methodology and incorporate my correction to FPL's demand allocation factors.

Q. Have you reviewed FPL's proposed allocation of its requested Step 2, Canaveral increase of $173.9 million?

A. Yes. FPL is proposing to allocate the Canaveral increase on the basis of "other production revenue requirements" developed at proposed, equal rates of return. I recommend that the application of the "1.5 times" maximum increase rule be based on the same base revenues plus miscellaneous revenues that I recommend for the Step 1, $516 million increase. Table 11 below summarizes my recommended allocation of the Total Step 1 plus Step 2 (Canaveral) increases to each rate class using FPL's cost of service study and the two alternative studies that I have discussed.[10] As I previously indicated, I am recommending the revenue allocation based on the minimum distribution system study.

[10] Baron Exhibit__(SJB-8), Schedule A through D contains the support for Table 11.

Table 11
Alternative Rate Class Increases Using SFHHA Revenue Allocation Methodology
Total Proposed FPL Step 1 + Step 2 Increases*

	FPL COS Study		FPL COS - Corrected Demand		FPL COS - MDS-Corrected Dem		FPL COS - MDS-Corr Dem-1 CP	
	Increase ($000)	% Base Rev**	Increase ($000)	% Base Rev**	Increase ($000)	% Base Rev**	Increase ($000)	% Base Rev**
CILC-1D	13,629,362	24.0%	12,523,861	22.1%	10,287,196	18.1%	9,582,314	16.9%
CILC-1G	479,829	10.8%	376,974	8.5%	249,101	5.6%	246,179	5.5%
CILC-1T	3,882,554	24.0%	3,882,554	24.0%	3,882,554	24.0%	3,882,554	24.0%
GS(T)-1	12,668,704	4.1%	12,011,746	3.9%	12,525,051	4.0%	20,781,089	6.7%
GSCU-1	148,929	8.9%	138,089	8.3%	251,535	15.1%	217,137	13.0%
GSD(T)-1	130,555,261	15.1%	112,935,257	13.1%	86,828,196	10.0%	93,734,553	10.8%
GSLD(T)-1	72,451,059	23.6%	72,410,458	23.5%	72,410,458	23.5%	72,410,458	23.5%
GSLD(T)-2	13,451,962	23.8%	13,444,424	23.7%	13,444,424	23.7%	13,444,424	23.7%
GSLD(T)-3	841,645	20.7%	790,283	19.5%	780,822	19.2%	675,267	16.6%
MET	673,261	23.3%	672,884	23.3%	636,934	22.0%	582,354	20.1%
OL-1	1,715,457	14.8%	1,612,926	13.9%	1,437,132	12.4%	1,230,543	10.6%
OS-2	169,887	19.9%	169,791	19.9%	168,223	19.7%	122,043	14.3%
RS(T)-1	428,654,328	16.5%	448,897,070	17.3%	477,932,480	18.4%	465,011,557	17.9%
SL-1	10,804,293	15.2%	10,226,380	14.4%	9,270,278	13.1%	8,184,947	11.5%
SL-2	50,316	3.8%	48,059	3.6%	44,818	3.4%	44,070	3.3%
SST-DST	32,275	8.7%	74,518	20.2%	74,518	20.2%	74,518	20.2%
SST-TST	162,033	3.8%	155,881	3.6%	147,435	3.4%	147,146	3.4%
TOTAL	$ 690,371,155	16.0%	$ 690,371,155	16.0%	$ 690,371,155	16.0%	690,371,155	16.0%

* This table is based on FPL's requested revenue increase. It does not reflect SFHHA's recommended revenue increase.

** Base revenue plus miscellaneous revenue

IV. RATE DESIGN ISSUES

Q. Have you reviewed FPL's proposed CILC-1D rate design in this case?

A. Yes. The Company is proposing an increase to the on-peak energy charge of CILC-1D <u>in excess of 320% in this case</u>. This outcome occurs because of the protocols that FPL has adopted for CILC-1D rate design. Specifically, the Firm On-peak demand charge, the Load Control On-peak demand charge, the Max Demand charge and off-peak non-fuel energy charge are all set at unit cost based on proposed revenue levels at equal rate of return. All additional revenue is recovered from the On-peak energy charge. In this case, this protocol results in a 320% increase to this charge.

Q. Is there a valid rate design rationale to justify imposing the residual revenue requirement for CILC-1D only on the on-peak non-fuel energy charge?

A. No. In fact, to the extent that customers are more likely to be price responsive to energy charges than demand charges, it would be more appropriate to impose the "residual revenue requirement" on the demand charges of the rate. All else being equal, this would impose the largest deviations from unit cost on the least price sensitive portion of the rate, thus preserving cost of service to the extent possible in the CILC-1D rate design. Moreover, imposing an extreme (320%) increase to one of the rate elements of the rate will produce unreasonable increases to some customers, relative to the CILC-1D increase overall.

Q. Do you have an alternative CILC-1D rate design proposal that is revenue neutral

to this rate class?

A. Yes. Baron Exhibit__(SJB-9) presents a revenue neutral alternative CILC-1D rate design that produces the same revenue level (and therefore revenue increase) as FPL's proposed rate. The protocol that I am recommending is to set the non-fuel energy charges of CILC-1D at unit cost, which is $0.00700/kWh and then uniformly increase all three of the CILC-1D demand charges by an equal percentage to meet the revenue target. Based on FPL's proposed overall 22.2% increase for CILC-1D, this would result in a 29.5% increase in the Max Demand, Load Control On-Peak and Firm On-Peak demand charges.

Q. Does your proposed alternative CILC-1D rate design have any impact on other rate classes in this case?

A. No. Because it produces the identical CILC-1D revenues at proposed rates as FPL's rate design, there is no impact on other rate classes or schedules.

Q. Would you please address FPL's proposal to recover the Canaveral Step 2 rate increase from large general service rate classes?

A. FPL is proposing to recover 100% of the Canaveral revenue increase for Rates GSLDT-1, 2 and 3 and for CILC through the on-peak and off-peak energy charges, despite the fact that over 80% of the Canaveral revenue requirements are demand related. As I will discuss, FPL has allocated the $173.9 million Canaveral revenue increase to rate classes following the allocation of "Other Production Revenue Requirements," as developed in its class cost of service study [see FPL's response to FIPUG's Third Set of

Interrogatories, Interrogatory No. 14 attached as Baron Exhibit__(SJB-10)]. The rate design, to the extent feasible, should follow the same cost allocation basis.

Q. How are "Other Production Revenue Requirements," which is used to allocate the Canaveral revenue increase, classified in FPL's class cost of service study?

A. Baron Exhibit__(SJB-11) contains an excerpt from MFR No. E-6b, Attachment No. 2 of 2. This is the workpaper supporting the cost classification and allocation of Other Production Revenue Requirements, which is the basis for the Canaveral revenue allocation. Line 5 of this schedule shows that the demand portion of "Production – Other Production" revenue requirements is $886,456 (Total Retail, column 2). On page 2, the energy portion of "Production – Other Production" revenue requirements (Line 17) is shown to be $187,728 (Total Retail, column 2). These two amounts total to $1,074,184, of which 82.5% is demand related, 17.5% is energy related.

Q. Has FPL provided any reasonable basis for its proposal to assign 100% of the Canaveral revenue increase to large general service energy charges?

A. No. Baron Exhibit__(SJB-12) contains FPL's response to SFHHA's First Set of Interrogatories, Interrogatory No. 56 requesting an explanation for FPL's proposed rate design. FPL states that the Canaveral increase should not be recovered through the customer charge (which I agree with) and then goes on to state that it is administratively efficient, follows fuel savings and benefits low load factor customers. The Company does not state that its proposal is consistent with cost of service, which it is not as I have demonstrated. None of the reasons cited by FPL support its proposal. FPL has allocated the Canaveral increase to rate classes on the basis of other production revenue requirements and the allocation of this same Canaveral revenue increase within each large general service rate class should follow the same protocol, which means that 82.5% of the increase should be recovered from demand charges and 17.5% from non-fuel energy charges.

Q. What is your recommendation on this issue?

A. I recommend that 82.5% of the Canaveral revenue increase for Rates GSLDT-1, 2 and 3 and for CILC be assigned to the on-peak demand charge and 17.5 of the Canaveral increase be assigned to the on and off-peak energy charges. For non-time of day general service rate classes, the Canaveral increase should be assigned 82.5% to the demand charge and 17.5% to the non-fuel energy charge of each such rate.

Q. Does your Canaveral rate design proposal affect any other rate classes besides the large, demand metered general service rates?

A. No.

Q. Have you identified any additional issues associated with the Company's rate design analyses?

A. Yes. As discussed by FPL witness Morley in her Direct Testimony at page 11, FPL's test year 2013 forecast "relies on a twenty year history in order to determine normal weather patterns." This normal weather forecast assumption thus forms the basis for FPL's projected billing determinants and rate class revenues in this case. I have performed an analysis that compares the Company's normal weather assumption to actual weather history in the FPL service territory for the past 10 years. The comparison that I made uses cooling degree hours ("CDH") as the weather metric, which is the principal weather variable used by FPL in its net energy for load (mWh) forecast in this case.

Baron Exhibit__(SJB-13) presents the results of this analysis. As shown on page 1 of the exhibit, I calculated the actual 10 year average annual CDH value for the FPL service area using the data supplied by the Company in response to SFHHA POD 1-5, which requested the forecast model inputs. The 10 year average annual FPL CDH is 1,990.5. This is compared to the Company's assumed normal CDH, based on a 20 year history of 1,958.3. The comparison shows that the actual 10 year CDH is 1.64% greater than the 20 year normal value assumed by the Company for its test year projections in this case.

Q. **What is the impact on mWh energy from a 1.64% increase in CDH, based on the NEL forecast model relied on by FPL in this case?**

A. Using the sensitivity factor calculated by the Company and presented in MFR Schedule F-6 in the Company's filing, a 1.64% increase in CDH results in a 0.38% increase in NEL mWh. This calculation is shown on page 2 of the exhibit.

Q. **What do you conclude from your analysis?**

A. During the past 10 years, weather conditions in the FPL service area have been 1.64%

hotter than during the 20 year period assumed by FPL for normal weather. Using a 10 year "normal" in this rate case would have produced a higher level of mWh sales and revenues than assumed by the Company in its rate filing. These additional revenues would, all else being equal, have offset some of the Company's revenue deficiency in this case.

Q. Does that complete your prepared testimony?

A. Yes.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER AND LIGHT COMPANY	)))	**DOCKET NO. 120015-EI**

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE:	**PETITION FOR RATE INCREASE BY FLORIDA POWER AND LIGHT COMPANY**	**)))**	**DOCKET NO. 120015-EI**

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 2012

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	Chamber of	Santa Clara	Cost-of-service, rate design.

**Expert Testimony Appearances
of
Stephen J. Baron
As of June 2012**

Date	Case	Jurisdict.	Party	Utility	Subject
		Santa Clara	Commerce	Municipal	
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	Indiana & Michigan	Interruptible rates.

Expert Testimony Appearances of Stephen J. Baron As of June 2012

Date	Case	Jurisdict.	Party	Utility	Subject
			Consumers	Power Co.	
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.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.
10/87	E-015/ GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and 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.,	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.

Expert Testimony Appearances
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As of June 2012

Date	Case	Jurisdict.	Party	Utility	Subject
			Allegheny Ludlum Corp.		
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
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.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2012

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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 Note: No testimony was prefiled on this.	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
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.

Expert Testimony Appearances
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As of June 2012

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.
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		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues

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Date	Case	Jurisdict.	Party	Utility	Subject
	P-00062214		Alliance		
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
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 Rev 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

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Date	Case	Jurisdict.	Party	Utility	Subject
2/08	ER07-956	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Rate Schedules 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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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
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
6/09	PUE-2009 -00016	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider
6/09	PUE-2009 -00038	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider
7/09	080677-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
8/09	U-20925 (RRF 2004)	LA	Louisiana Public Service Commission Staff	Entergy Louisiana LLC	Interruptible Rate Refund Settlement
9/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Energy Cost Rate issues
9/09	Doc. No. 05-UR-104	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
9/09	Doc. No. 6680-UR-117	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
10/09	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Allocation of Rev Increase
10/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
11/09	PUE-2009 -00019	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service, Rate Design
11/09	09-1485 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
12/09	Case No. 09-906-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan

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12/09	ER09-1224	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
12/09	Case No. PUE-2009-00030	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Increase, Rate Design
2/10	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Rate Design
3/10	Case No. 09-1352-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
3/10	E015/ GR-09-1151	MN	Large Power Intervenors	Minnesota Power Co.	Cost of Service, rate design
4/10	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales
4/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.
4/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
7/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Cost of Service, Rate Design
09/10	2010-00167	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design
09/10	10M-245E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Economic Impact of Clean Air Act
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design, Transmission Rider
11/10	Doc. No. 4220-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Northern States Power Co. Wisconsin	Cost of Service, rate design
12/10	10A-554EG	CO	CF&I Steel Company Climax Molybdenum	Public Service Company	Demand Side Management Issues
12/10	10-2586-EL-SSO	OH	Ohio Energy Group	Duke Energy Ohio	Provider of Last Resort Rate Plan Electric Security Plan
3/11	20000-384-ER-10	WY	Wyoming Industrial Energy Consumers	Rocky Mountain Power Wyoming	Electric Cost of Service, Revenue Apportionment, Rate Design

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Date	Case	Jurisdict.	Party	Utility	Subject
5/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
6/11	Docket No. 10-035-124	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/11	PUE-2011 -00045	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider
07/11	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Entergy System Agreement - Successor Agreement, Revisions, RTO Day 2 Market Issues
07/11	Case Nos. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Provider of Last Resort Issues
08/11	PUE-2011-00034	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Rate Recovery of RPS Costs
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co. Kentucky Utilities Company	Environmental Cost Recovery
09/11	Case Nos. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Stipulation Support Testimony
10/11	11-0452 E-P-T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Energy Efficiency/Demand Reduction Cost Recovery
11/11	11-1274 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
11/11	E-01345A-11-0224	AZ	Kroger Company	Arizona Public Service Co.	Decoupling
12/11	E-01345A-11-0224	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
3/12	Case No. 2011-00401	KY	Kentucky Industrial Utility Consumers	Kentucky Power Company	Environmental Cost Recovery
4/12	2011-00036 Rehearing Case	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
5/12	2011-346 2011-348	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
6/12	PUE-2012 -00051	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider

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of
Stephen J. Baron
As of June 2012

Date	Case	Jurisdict.	Party	Utility	Subject
6/12	12-00012 12-00026	TN	Eastman Chemical Co. Air Products and Chemicals, Inc.	Kingsport Power Company	Demand Response Programs
6/12	Docket No. 11-035-200	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/12	12-0275-E-GI-EE	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Rider
6/12	12-0399-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER AND LIGHT COMPANY	**)))**	**DOCKET NO. 120015-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

SFHHA CORRECTED CLASS COST OF SERVICE STUDY
CORRECTED DEMAND ALLOCATORS

MFR E-1 - COST OF SERVICE STUDY
2013 AT PRESENT RATES
($000 WHERE APPLICABLE)

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET
RATE BASE -											
Electric Plant In Service	30,424,227	525,540	35,414	163,440	1,740,323	8,336	5,937,601	2,587,419	471,897	26,637	22,621
Accum Depreciation & Amortization	(11,901,711)	(205,882)	(13,848)	(66,733)	(681,588)	(3,266)	(2,328,425)	(1,014,477)	(185,143)	(10,880)	(8,808)
Net Plant In Service	18,522,516	319,658	21,566	96,707	1,058,734	5,071	3,609,176	1,572,942	286,754	15,757	13,813
Plant Held For Future Use	230,192	4,442	288	1,618	13,354	64	48,237	21,400	3,995	266	193
Construction Work in Progress	501,676	9,282	608	3,531	29,251	147	102,172	44,960	8,361	575	395
Net Nuclear Fuel	565,229	15,541	974	7,084	32,052	208	137,514	61,965	13,313	1,053	495
Total Utility Plant	19,819,614	348,923	23,435	108,941	1,133,392	5,490	3,897,099	1,701,267	312,423	17,651	14,895
Working Capital - Assets	3,593,422	69,429	4,524	26,961	231,519	1,566	712,633	308,204	60,851	4,142	2,610
Working Capital - Liabilities	(2,376,213)	(44,258)	(2,893)	(16,832)	(154,219)	(1,038)	(461,911)	(199,007)	(38,929)	(2,598)	(1,694)
Working Capital - Net	1,217,209	25,171	1,631	10,129	77,300	528	250,722	109,197	21,923	1,545	916
Total Rate Base	21,036,823	374,094	25,067	119,070	1,210,692	6,018	4,147,821	1,810,464	334,346	19,196	15,811
REVENUES -											
Sales of Electricity	4,266,616	73,145	5,467	23,403	304,655	1,665	860,849	311,835	57,388	4,043	2,884
Other Operating Revenues	140,637	1,417	93	265	8,680	25	19,138	7,137	1,280	43	60
Total Operating Revenues	4,407,253	74,562	5,560	23,668	313,335	1,690	879,986	318,972	58,668	4,086	2,944
EXPENSES -											
Operating & Maintenance Expense	(1,565,789)	(27,202)	(1,792)	(9,904)	(104,780)	(729)	(291,197)	(124,087)	(23,995)	(1,535)	(1,061)
Depreciation Expense	(803,912)	(13,162)	(899)	(4,461)	(46,783)	(243)	(150,745)	(64,362)	(11,793)	(723)	(570)
Taxes Other Than Income Tax	(371,710)	(6,383)	(430)	(1,981)	(21,833)	(112)	(71,933)	(31,182)	(5,720)	(322)	(274)
Amortization of Property Losses	1,151	21	1	5	48	(0)	247	112	19	1	1
Gain or Loss on Sale of Plant	2,641	48	3		147	1	527	238	43		2
Total Operating Expenses	(2,737,619)	(46,678)	(3,116)	(16,341)	(173,202)	(1,084)	(513,100)	(219,281)	(41,446)	(2,578)	(1,901)
Net Operating Income Before Taxes	1,669,634	27,884	2,443	7,328	140,133	606	366,886	99,691	17,222	1,508	1,043
Income Taxes	(513,276)	(8,391)	(808)	(2,031)	(48,399)	(202)	(117,542)	(25,439)	(4,195)	(466)	(296)
NOI Before Curtailment Adjustment	1,156,359	19,493	1,636	5,296	91,735	404	249,344	74,252	13,027	1,041	747
Curtailment Credit Revenue	618							460	158		
Reassign Curtailment Credit Revenue	(618)	(12)	(1)	(5)	(35)	(0)	(133)	(59)	(11)	(1)	(1)
Net Curtailment Credit Revenue		(12)	(1)	(5)	(35)	(0)	(133)	401	147	(1)	(1)
Net Curtailment NOI Adjustment		(7)	(0)	(3)	(21)	(0)	(81)	246	90	(1)	(0)
Net Operating Income (NOI)	1,156,359	19,486	1,635	5,293	91,713	404	249,262	74,498	13,117	1,041	746

Docket No. 120015-EI
SFHHA Corrected Class Cost of Service Study
Exhibit SJB-2, Page 1 of 4

SFHHA CORRECTED CLASS COST OF SERVICE STUDY
CORRECTED DEMAND ALLOCATORS

MFR E-1 - COST OF SERVICE STUDY
2013 AT PRESENT RATES
($000 WHERE APPLICABLE)

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET
Rate of Return (ROR)	5.50%	5.21%	6.52%	4.45%	7.58%	6.72%	6.01%	4.11%	3.92%	5.42%	4.72%
Parity At Present Rates	1.00	0.95	1.19	0.81	1.38	1.22	1.09	0.75	0.71	0.99	0.86
EQUALIZED RATE OF RETURN (ROR) -											
Equalized Base Revenue Requirements	4,266,616	74,903	5,047	25,447	263,591	1,545	826,149	352,666	65,973	4,067	3,085
Other Operating Revenues (Equalized)	140,637	1,417	93	265	8,680	25	19,138	7,137	1,280	43	60
Total Equalized Revenue Requirements	4,407,253	76,320	5,140	25,711	272,271	1,570	845,287	359,803	67,253	4,109	3,144
Revenue Requirements Deficiency (Excess)	0	1,758	(420)	2,043	(41,064)	(120)	(34,700)	40,830	8,586	23	200
Revenue Requirements Index [1]	100.0%	97.7%	108.2%	92.1%	115.1%	107.6%	104.1%	88.7%	87.2%	99.4%	93.6%

[1] (Total Revenues / Total Equalized Revenue Requirements)

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SFHHA CORRECTED CLASS COST OF SERVICE STUDY
CORRECTED DEMAND ALLOCATORS

MFR E-1 - COST OF SERVICE STUDY
2013 AT PRESENT RATES
($000 WHERE APPLICABLE)

	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
RATE BASE -							
Electric Plant In Service	84,933	7,651	18,277,114	504,529	5,886	9,855	15,033
Accum Depreciation & Amortization	(33,721)	(2,877)	(7,158,278)	(175,915)	(2,313)	(3,423)	(6,134)
Net Plant In Service	51,211	4,774	11,118,837	328,613	3,573	6,432	8,899
Plant Held For Future Use	129	41	135,165	734	49	63	153
Construction Work in Progress	795	85	296,261	4,728	106	96	324
Net Nuclear Fuel	545	67	290,767	2,915	179	41	515
Total Utility Plant	52,680	4,967	11,841,031	336,990	3,908	6,631	9,891
Working Capital - Assets	6,538	648	2,121,023	39,119	840	700	2,114
Working Capital - Liabilities	(4,523)	(432)	(1,418,497)	(27,027)	(539)	(486)	(1,329)
Working Capital - Net	2,016	216	702,525	12,091	301	214	784
Total Rate Base	54,695	5,183	12,543,556	349,081	4,209	6,845	10,675
REVENUES -							
Sales of Electricity	11,479	853	2,532,394	70,674	1,252	369	4,262
Other Operating Revenues	200	36	101,247	852	83	48	34
Total Operating Revenues	11,679	889	2,633,642	71,526	1,334	417	4,297
EXPENSES -							
Operating & Maintenance Expense	(3,328)	(296)	(954,631)	(19,773)	(339)	(352)	(789)
Depreciation Expense	(3,196)	(203)	(486,851)	(19,176)	(151)	(186)	(407)
Taxes Other Than Income Tax	(983)	(93)	(223,800)	(6,288)	(73)	(122)	(181)
Amortization of Property Losses	4	0	662	26	0	1	1
Gain or Loss on Sale of Plant	3	1	1,607	17	0	3	
Total Operating Expenses	(7,500)	(590)	(1,663,012)	(45,195)	(563)	(656)	(1,377)
Net Operating Income Before Taxes	4,179	298	970,629	26,331	772	(239)	2,920
Income Taxes	(1,240)	(77)	(295,127)	(7,792)	(290)	170	(1,150)
NOI Before Curtailment Adjustment	2,939	222	675,503	18,539	481	(69)	1,770
Curtailment Credit Revenue							
Reassign Curtailment Credit Revenue	(0)	(0)	(360)	(0)	(0)	(0)	(0)
Net Curtailment Credit Revenue	(0)	(0)	(360)	(0)	(0)	(0)	(0)
Net Curtailment NOI Adjustment	(0)	(0)	(221)	(0)	(0)	(0)	(0)
Net Operating Income (NOI)	2,939	222	675,282	18,538	481	(69)	1,769

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SFHHA Corrected Class Cost of Service Study
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SFHHA CORRECTED CLASS COST OF SERVICE STUDY
CORRECTED DEMAND ALLOCATORS

MFR E-1 - COST OF SERVICE STUDY
2013 AT PRESENT RATES
($000 WHERE APPLICABLE)

	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
Rate of Return (ROR)	5.37%	4.28%	5.38%	5.31%	11.43%	(1.00%)	16.57%
Parity At Present Rates	0.98	0.78	0.98	0.97	2.08	(0.18)	3.02
EQUALIZED RATE OF RETURN (ROR) -							
Equalized Base Revenue Requirements	11,589	956	2,555,593	71,734	844	1,095	2,333
Other Operating Revenues (Equalized)	200	36	101,247	852	83	48	34
Total Equalized Revenue Requirements	11,789	992	2,656,840	72,586	927	1,143	2,367
Revenue Requirements Deficiency (Excess)	111	103	23,199	1,061	(408)	726	(1,930)
Revenue Requirements Index [1]	99.1%	89.6%	99.1%	98.5%	144.0%	36.5%	181.5%

[1] (Total Revenues / Total Equalized Revenue Requiremer

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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER AND LIGHT COMPANY	)))	DOCKET NO. 120015-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 I/c cable. Since there are generally many types and sizes of I/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 I/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 (I/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 AND LIGHT COMPANY	)))	DOCKET NO. 120015-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

MDS Customer/Demand Percentages by FERC Account

Account	%Customer	%Demand
364	65.2%	34.8%
365	13.2%	86.8%
366	3.9%	96.1%
367	4.8%	95.2%
368	25.4%	74.6%
369	100%	0%
370	100%	0%

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE:	**PETITION FOR RATE INCREASE BY FLORIDA POWER AND LIGHT COMPANY**	**)))**	**DOCKET NO. 120015-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

Analysis of FPL Account 364 Minimum Size Poles

Retirement Unit	Quantity	Cost	Unit Cost
36400 - Poles, Towers & Fixtures			
400.130 :POLE, WOOD 25/30 FT	179,524	56,153,723.31	312.79
400.135 :POLE, WOOD 35/40/45 FT	831,833	567,414,395.47	682.13
400.150 :POLE, WOOD 50/55/60 FT	63,210	87,536,977.29	1,384.86
400.165 :POLE, WOOD 65 FT and >	1,615	3,966,858.37	2,456.26
400.230 : POLE,CONCRETE 30'	2,780	1,726,255.64	620.96
400.235 :POLE, CONCRETE 35/40/45 F	51,213	71,128,190.26	1,388.87
400.251 :POLE, CONCRETE 50/55/60 F	25,121	127,496,717.64	5,075.30
400.263 :POLE, CONCRETE 65 FT and	785	6,831,161.25	8,702.12
Totals	**1,297,659**	**970,222,265.21**	**747.67**
Cost of 35 FT and Smaller Poles	**1,011,357**	**623,568,119**	**616.57**
Repricing of All Poles at Minimum	**1,297,659**	**800,092,135**	**616.57**
Customer Component Percent		**82%**	
Demand Component Percent		**18%**	

Source: File "2010 Primary Secondary Split-Final.xlsx," OPC POD 2-12
"2009 SURVIVING BALANCE REPORT"

Docket No. 120015-EI
Analysis of FPL Account 364 Minimum Size Poles
Exhibit SJB-5, Page 1 of 2

GULF POWER COMPANY
TWELVE MONTHS ENDED 12/31/10
MINIMUM DISTRIBUTION SYSTEM
ACCOUNT 364 - POLES, TOWERS AND FIXTURES ANALYSIS (MASS ACCOUNT)
SCHEDULE 6.3

	PRIMARY LEVEL 4 12-31-10 TOTAL LEVEL 4 COSTS	PRIMARY LEVEL 4 CUSTOMER-RELATED COMPONENT	PRIMARY LEVEL 4 DEMAND-RELATED COMPONENT	NOTES
COMPONENT SPLIT ANALYSIS OF				
MASS ACCOUNT RECORDS				(A)
				(B)
1. AVERAGE UNIT COST OF MFUS POLES		206.05		(C)
2. TOTAL NUMBER OF POLES		255,703		
3. TOTAL COST OF POLES	80,795,233	52,695,426	28,099,807	
4. PERCENTAGE OF TOTAL COST OF POLES		65.22%	34.78%	

	12-31-10 TOTAL ALL COSTS	PRIMARY LEVEL 4 12-31-10 TOTAL LEVEL 4 COSTS	PRIMARY LEVEL 4 CUSTOMER-RELATED COMPONENT	PRIMARY LEVEL 4 DEMAND-RELATED COMPONENT	SECONDARY LEVEL 5 12-31-10 TOTAL LEVEL 5 COSTS	SECONDARY LEVEL 5 CUSTOMER-RELATED COMPONENT	SECONDARY LEVEL 5 DEMAND-RELATED COMPONENT	NOTES
5. *PRIMARY / SECONDARY SPLIT OF OVERHEAD LINES FROM ACCOUNT 365*	107,066,574	83,237,343			23,829,231			(D)
ANALYSIS OF ACCOUNT 364								
6. POLES (WOOD, CONCRETE)	79,450,041	61,767,273	40,285,208	21,482,065	17,682,768	11,532,871	6,149,897	(E)
7. STEEL-REINFORCED POLE TRUSS	1,345,192	1,345,192	877,347	467,845	-	-	-	(F)
8. TOTAL POLES	80,795,233	63,112,465	41,162,555	21,949,910	17,682,768	11,532,871	6,149,897	
9. FIXTURE SETS	42,553,065	33,239,936	21,679,405	11,560,531	9,313,122	6,074,108	3,239,014	(G)
10. OTHER ACCOUNT 364	1,971,847	1,540,134	1,004,490	535,644	431,513	281,437	150,076	(H)
11. TOTAL ACCOUNT 364	125,319,936	97,892,535	63,846,400	34,046,065	27,427,403	17,888,416	9,538,987	
12. PERCENTAGES AT LEVEL			65.22%	34.78%		65.22%	34.78%	
13. PERCENTAGES OF TOTAL		78.11%	50.95%	27.17%	21.89%	14.27%	7.61%	

NOTES:

(A) MFUS INCLUDES 35-FOOT WOODEN POLES--MOST FREQUENTLY USED--AND SMALLER.
(B) INCLUDES ALL POLE SIZES.
(C) TOTAL AMOUNT FOR ALL POLES. CUSTOMER COMPONENT EQUAL TOTAL NUMBER OF POLES (LINE 2) TIMES AVERAGE UNIT COST OF MFUS POLES (LINE 1). DEMAND COMPONENT IS TOTAL MINUS CUSTOMER COMPONENT.
(D) FROM ACCOUNT 365, LINE 7, TOTAL OVERHEAD LINES.
(E) TOTAL AMOUNT ALLOCATED TO LEVEL PER PRIMARY / SECONDARY SPLIT OF OVERHEAD LINES FROM ACCOUNT 365 (LINE 5). WITHIN LEVEL, ALLOCATED TO COMPONENT PER TOTAL COST OF POLES (LINE 3).
(F) TOTAL AMOUNT ASSIGNED TO PRIMARY LEVEL. ALLOCATED TO COMPONENT PER TOTAL COST OF POLES (LINE 3).
(G) ALLOCATED PER TOTAL POLES (LINE 8).
(H) INCLUDES ADJUSTMENTS, INTERIM RUCs, AND NON-UNITIZED. ALLOCATED PER TOTAL POLES (LINE 8).

Florida Public Service Commission
Docket No. 110138-EI
GULF POWER COMPANY
Witness: Michael T. O'Sheasy
Exhibit No. ___ (MTO-2)
Schedule 6.3
Page 1 of 1

Docket No. 120015-EI
Analysis of FPL Account 364 Minimum Size Poles
Exhibit SJB-5, Page 2 of 2

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER AND LIGHT COMPANY	)))	**DOCKET NO. 120015-EI**

EXHIBIT__(SJB-6)

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.

ROSWELL, GEORGIA

SFHHA MDS CLASS COST OF SERVICE STUDY
MINIMUM DISTRIBUTION SYSTEM
CORRECTED DEMAND ALLOCATORS

MFR E-1 - COST OF SERVICE STUDY
2013 AT PRESENT RATES
($000 WHERE APPLICABLE)

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET
RATE BASE -											
Electric Plant In Service	30,424,227	502,968	33,736	163,440	1,797,238	9,591	5,683,767	2,465,856	451,591	26,637	21,824
Accum Depreciation & Amortization	(11,901,711)	(195,883)	(13,104)	(66,733)	(706,880)	(3,823)	(2,215,792)	(960,569)	(176,145)	(10,880)	(8,456)
Net Plant In Service	18,522,516	307,086	20,633	96,707	1,090,358	5,768	3,467,975	1,505,287	275,446	15,757	13,368
Plant Held For Future Use	230,192	4,432	287	1,618	13,377	65	48,127	21,347	3,986	266	192
Construction Work in Progress	501,676	9,090	593	3,531	29,729	157	100,025	43,929	8,189	575	388
Net Nuclear Fuel	565,229	15,541	974	7,084	32,052	208	137,514	61,965	13,313	1,053	495
Total Utility Plant	19,819,614	336,149	22,487	108,941	1,165,517	6,198	3,753,642	1,632,528	300,934	17,651	14,443
Working Capital - Assets	3,593,422	68,308	4,443	26,961	234,082	1,623	700,489	302,265	59,848	4,142	2,568
Working Capital - Liabilities	(2,376,213)	(43,471)	(2,836)	(16,832)	(155,973)	(1,077)	(453,471)	(194,859)	(38,226)	(2,598)	(1,664)
Working Capital - Net	1,217,209	24,837	1,607	10,129	78,109	546	247,018	107,406	21,623	1,545	904
Total Rate Base	21,036,823	360,985	24,094	119,070	1,243,625	6,744	4,000,660	1,739,934	322,556	19,196	15,347
REVENUES -											
Sales of Electricity	4,266,616	73,145	5,467	23,403	304,655	1,665	860,849	311,835	57,388	4,043	2,884
Other Operating Revenues	140,637	1,055	68	265	9,382	41	15,532	5,320	960	43	44
Total Operating Revenues	4,407,253	74,200	5,535	23,668	314,037	1,706	876,380	317,155	58,348	4,086	2,929
EXPENSES -											
Operating & Maintenance Expense	(1,565,789)	(26,629)	(1,750)	(9,904)	(106,029)	(756)	(285,092)	(121,072)	(23,483)	(1,535)	(1,039)
Depreciation Expense	(803,912)	(12,377)	(841)	(4,461)	(48,807)	(288)	(141,835)	(60,115)	(11,086)	(723)	(543)
Taxes Other Than Income Tax	(371,710)	(6,149)	(413)	(1,981)	(22,419)	(125)	(69,309)	(29,923)	(5,509)	(322)	(265)
Amortization of Property Losses	1,151	20	1	5	51	0	235	106	18	1	1
Gain or Loss on Sale of Plant	2,641	48	3		147	1	527	238	43		2
Total Operating Expenses	(2,737,619)	(45,087)	(2,999)	(16,341)	(177,057)	(1,169)	(495,474)	(210,766)	(40,017)	(2,578)	(1,844)
Net Operating Income Before Taxes	1,669,634	29,114	2,536	7,328	136,980	537	380,906	106,389	18,331	1,508	1,085
Income Taxes	(513,276)	(9,051)	(857)	(2,031)	(46,714)	(165)	(125,041)	(29,024)	(4,790)	(466)	(319)
NOI Before Curtailment Adjustment	1,156,359	20,063	1,679	5,296	90,266	372	255,865	77,365	13,541	1,041	766
Curtailment Credit Revenue	618							460	158		
Reassign Curtailment Credit Revenue	(618)	(12)	(1)	(5)	(35)	(0)	(133)	(59)	(11)	(1)	(1)
Net Curtailment Credit Revenue		(12)	(1)	(5)	(35)	(0)	(133)	401	147	(1)	(1)
Net Curtailment NOI Adjustment		(7)	(0)	(3)	(21)	(0)	(81)	246	90	(1)	(0)
Net Operating Income (NOI)	1,156,359	20,056	1,678	5,293	90,245	372	255,783	77,611	13,632	1,041	766

Docket No. 120015-EI
Minimum Distribution System
Exhibit SJB-6, Page 1 of 4

SFHHA MDS CLASS COST OF SERVICE STUDY
MINIMUM DISTRIBUTION SYSTEM
CORRECTED DEMAND ALLOCATORS

MFR E-1 - COST OF SERVICE STUDY
2013 AT PRESENT RATES
($000 WHERE APPLICABLE)

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET
Rate of Return (ROR)	5.50%	5.56%	6.96%	4.45%	7.26%	5.52%	6.39%	4.46%	4.23%	5.42%	4.99%
Parity At Present Rates	1.00	1.01	1.27	0.81	1.32	1.00	1.16	0.81	0.77	0.99	0.91
EQUALIZED RATE OF RETURN (ROR) -											
Equalized Base Revenue Requirements	4,266,616	72,797	4,890	25,447	268,942	1,663	802,307	341,259	64,076	4,067	3,011
Other Operating Revenues (Equalized)	140,637	1,055	68	265	9,382	41	15,532	5,320	960	43	44
Total Equalized Revenue Requirements	4,407,253	73,853	4,958	25,711	278,324	1,703	817,839	346,578	65,037	4,109	3,056
Revenue Requirements Deficiency (Excess)	0	(348)	(577)	2,043	(35,713)	(2)	(58,542)	29,424	6,689	23	127
Revenue Requirements Index [1]	100.0%	100.5%	111.6%	92.1%	112.8%	100.1%	107.2%	91.5%	89.7%	99.4%	95.8%

[1] (Total Revenues / Total Equalized Revenue Requirements)

Note: Totals may not add due to rounding.

Docket No. 120015-EI
Minimum Distribution System
Exhibit SJB-6, Page 2 of 4

SFHHA MDS CLASS COST OF SERVICE STUDY
MINIMUM DISTRIBUTION SYSTEM
CORRECTED DEMAND ALLOCATORS

MFR E-1 - COST OF SERVICE STUDY
2013 AT PRESENT RATES
($000 WHERE APPLICABLE)

	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
RATE BASE -							
Electric Plant In Service	83,358	7,044	18,651,694	496,123	5,647	8,680	15,033
Accum Depreciation & Amortization	(33,023)	(2,608)	(7,324,382)	(172,188)	(2,207)	(2,905)	(6,134)
Net Plant In Service	50,335	4,436	11,327,312	323,934	3,440	5,776	8,899
Plant Held For Future Use	129	41	135,330	730	49	62	153
Construction Work in Progress	781	80	299,437	4,657	104	86	324
Net Nuclear Fuel	545	67	290,767	2,915	179	41	515
Total Utility Plant	51,789	4,624	12,052,847	332,236	3,772	5,965	9,891
Working Capital - Assets	6,461	619	2,139,329	38,705	828	638	2,114
Working Capital - Liabilities	(4,468)	(412)	(1,431,286)	(26,738)	(531)	(442)	(1,329)
Working Capital - Net	1,992	207	708,043	11,967	298	196	784
Total Rate Base	53,782	4,831	12,760,890	344,203	4,070	6,161	10,675
REVENUES -							
Sales of Electricity	11,479	853	2,532,394	70,674	1,252	369	4,262
Other Operating Revenues	176	27	106,862	724	79	25	34
Total Operating Revenues	11,655	879	2,639,257	71,398	1,331	394	4,297
EXPENSES -							
Operating & Maintenance Expense	(3,288)	(281)	(963,927)	(19,562)	(333)	(319)	(789)
Depreciation Expense	(3,141)	(182)	(499,934)	(18,883)	(143)	(146)	(407)
Taxes Other Than Income Tax	(967)	(86)	(227,680)	(6,201)	(70)	(109)	(181)
Amortization of Property Losses	4	0	681	26	0	0	1
Gain or Loss on Sale of Plant	3	1	1,607	17	0	3	
Total Operating Expenses	(7,389)	(548)	(1,689,253)	(44,604)	(546)	(571)	(1,377)
Net Operating Income Before Taxes	4,266	332	950,004	26,794	785	(177)	2,920
Income Taxes	(1,287)	(94)	(284,087)	(8,040)	(298)	137	(1,150)
NOI Before Curtailment Adjustment	2,979	237	665,917	18,754	487	(40)	1,770
Curtailment Credit Revenue							
Reassign Curtailment Credit Revenue	(0)	(0)	(360)	(0)	(0)	(0)	(0)
Net Curtailment Credit Revenue	(0)	(0)	(360)	(0)	(0)	(0)	(0)
Net Curtailment NOI Adjustment	(0)	(0)	(221)	(0)	(0)	(0)	(0)
Net Operating Income (NOI)	2,979	237	665,697	18,754	487	(40)	1,769

Docket No. 120015-EI
Minimum Distribution System
Exhibit SJB-6, Page 3 of 4

SFHHA MDS CLASS COST OF SERVICE STUDY
MINIMUM DISTRIBUTION SYSTEM
CORRECTED DEMAND ALLOCATORS

MFR E-1 - COST OF SERVICE STUDY
2013 AT PRESENT RATES
($000 WHERE APPLICABLE)

	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
Rate of Return (ROR)	5.54%	4.91%	5.22%	5.45%	11.97%	(0.65%)	16.57%
Parity At Present Rates	1.01	0.89	0.95	0.99	2.18	(0.12)	3.02
EQUALIZED RATE OF RETURN (ROR) -							
Equalized Base Revenue Requirements	11,442	899	2,590,731	70,945	822	987	2,333
Other Operating Revenues (Equalized)	176	27	106,862	724	79	25	34
Total Equalized Revenue Requirements	11,618	926	2,697,593	71,670	901	1,012	2,367
Revenue Requirements Deficiency (Excess)	(37)	47	58,336	272	(430)	618	(1,930)
Revenue Requirements Index (1)	100.3%	95.0%	97.8%	99.6%	147.8%	38.9%	181.5%

(1) (Total Revenues / Total Equalized Revenue Requireme

Note: Totals may not add due to rounding.

Docket No. 120015-EI
Minimum Distribution System
Exhibit SJB-6, Page 4 of 4

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER AND LIGHT COMPANY	)))	**DOCKET NO. 120015-EI**

EXHIBIT__(SJB-7)

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.

ROSWELL, GEORGIA

SFHHA MDS CLASS COST OF SERVICE STUDY
MIN DIST SYSTEM- 1 CP PROD/TRANS DEMAND
CORRECTED DEMAND ALLOCATORS

MFR E-1 - COST OF SERVICE STUDY
2013 AT PRESENT RATES
($000 WHERE APPLICABLE)

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET
RATE BASE -											
Electric Plant In Service	30,424,227	494,845	33,125	160,344	1,899,597	9,186	5,773,888	2,438,809	447,506	25,388	21,184
Accum Depreciation & Amortization	(11,901,711)	(192,596)	(12,856)	(65,480)	(748,290)	(3,659)	(2,252,251)	(949,627)	(174,493)	(10,375)	(8,197)
Net Plant In Service	18,522,516	302,249	20,268	94,864	1,151,306	5,527	3,521,637	1,489,182	273,014	15,013	12,987
Plant Held For Future Use	230,192	4,366	282	1,593	14,219	62	48,868	21,124	3,952	255	187
Construction Work in Progress	501,676	8,936	582	3,473	31,666	150	101,730	43,418	8,112	552	376
Net Nuclear Fuel	565,229	15,541	974	7,084	32,052	208	137,514	61,965	13,313	1,053	495
Total Utility Plant	19,819,614	331,091	22,106	107,013	1,229,242	5,946	3,809,749	1,615,690	298,390	16,874	14,045
Working Capital - Assets	3,593,422	68,164	4,432	26,906	235,898	1,616	702,088	301,785	59,776	4,120	2,557
Working Capital - Liabilities	(2,376,213)	(43,351)	(2,827)	(16,786)	(157,494)	(1,071)	(454,810)	(194,457)	(38,165)	(2,579)	(1,655)
Working Capital - Net	1,217,209	24,813	1,605	10,121	78,404	545	247,278	107,328	21,611	1,541	902
Total Rate Base	21,036,823	355,905	23,711	117,134	1,307,646	6,491	4,057,027	1,723,018	320,001	18,415	14,946
REVENUES -											
Sales of Electricity	4,266,616	73,145	5,467	23,403	304,655	1,665	860,849	311,835	57,388	4,043	2,884
Other Operating Revenues	140,637	1,049	68	262	9,467	40	15,607	5,297	957	42	44
Total Operating Revenues	4,407,253	74,194	5,535	23,665	314,122	1,705	876,455	317,132	58,344	4,085	2,928
EXPENSES -											
Operating & Maintenance Expense	(1,565,789)	(26,603)	(1,749)	(9,894)	(106,352)	(755)	(285,377)	(120,986)	(23,470)	(1,531)	(1,037)
Depreciation Expense	(803,912)	(12,169)	(825)	(4,382)	(51,427)	(278)	(144,142)	(59,423)	(10,982)	(691)	(526)
Taxes Other Than Income Tax	(371,710)	(6,064)	(407)	(1,949)	(23,483)	(121)	(70,246)	(29,642)	(5,467)	(309)	(259)
Amortization of Property Losses	1,151	19	1	5	60	(0)	243	103	18	1	1
Gain or Loss on Sale of Plant	2,641	48	3		147	1	527	238	43		2
Total Operating Expenses	(2,737,619)	(44,769)	(2,975)	(16,220)	(181,054)	(1,153)	(498,994)	(209,710)	(39,858)	(2,530)	(1,819)
Net Operating Income Before Taxes	1,669,634	29,424	2,559	7,446	133,068	552	377,461	107,423	18,487	1,556	1,109
Income Taxes	(513,276)	(9,230)	(871)	(2,100)	(44,453)	(174)	(123,051)	(29,621)	(4,880)	(494)	(333)
NOI Before Curtailment Adjustment	1,156,359	20,194	1,688	5,346	88,614	379	254,410	77,802	13,607	1,062	776
Curtailment Credit Revenue	618							460	158		
Reassign Curtailment Credit Revenue	(618)	(12)	(1)	(5)	(35)	(0)	(133)	(59)	(11)	(1)	(1)
Net Curtailment Credit Revenue		(12)	(1)	(5)	(35)	(0)	(133)	401	147	(1)	(1)
Net Curtailment NOI Adjustment		(7)	(0)	(3)	(21)	(0)	(81)	246	90	(1)	(0)
Net Operating Income (NOI)	1,156,359	20,187	1,688	5,343	88,593	379	254,329	78,047	13,697	1,061	776

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Min Dist System-1 CP Prod/Trans Demand
Exhibit SJB-7, Page 1 of 4

SFHHA MDS CLASS COST OF SERVICE STUDY
MIN DIST SYSTEM- 1 CP PROD/TRANS DEMAND
CORRECTED DEMAND ALLOCATORS

MFR E-1 - COST OF SERVICE STUDY
2013 AT PRESENT RATES
($000 WHERE APPLICABLE)

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET
Rate of Return (ROR)	5.50%	5.67%	7.12%	4.56%	6.77%	5.83%	6.27%	4.53%	4.28%	5.76%	5.19%
Parity At Present Rates	1.00	1.03	1.30	0.83	1.23	1.06	1.14	0.82	0.78	1.05	0.94
EQUALIZED RATE OF RETURN (ROR) -											
Equalized Base Revenue Requirements	4,266,616	72,128	4,839	25,191	277,380	1,630	809,736	339,029	63,740	3,964	2,959
Other Operating Revenues (Equalized)	140,637	1,049	68	262	9,467	40	15,607	5,297	957	42	44
Total Equalized Revenue Requirements	4,407,253	73,176	4,907	25,453	286,847	1,670	825,343	344,326	64,697	4,005	3,002
Revenue Requirements Deficiency (Excess)	0	(1,017)	(628)	1,788	(27,275)	(35)	(51,112)	27,194	6,352	(80)	74
Revenue Requirements Index (1)	100.0%	101.4%	112.8%	93.0%	109.5%	102.1%	106.2%	92.1%	90.2%	102.0%	97.5%

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Min Dist System-1 CP Prod/Trans Demand
Exhibit SJB-7, Page 2 of 4

SFHHA MDS CLASS COST OF SERVICE STUDY
MIN DIST SYSTEM- 1 CP PROD/TRANS DEMAND
CORRECTED DEMAND ALLOCATORS

MFR E-1 - COST OF SERVICE STUDY
2013 AT PRESENT RATES
($000 WHERE APPLICABLE)

	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
RATE BASE -							
Electric Plant In Service	80,940	6,491	18,513,999	483,493	5,287	8,944	21,202
Accum Depreciation & Amortization	(32,045)	(2,384)	(7,268,676)	(167,079)	(2,061)	(3,011)	(8,630)
Net Plant In Service	48,895	4,106	11,245,323	316,414	3,226	5,933	12,572
Plant Held For Future Use	109	36	134,199	626	46	65	204
Construction Work in Progress	735	69	296,832	4,418	97	91	440
Net Nuclear Fuel	545	67	290,767	2,915	179	41	515
Total Utility Plant	50,284	4,279	11,967,121	324,373	3,548	6,129	13,732
Working Capital - Assets	6,418	609	2,136,886	38,481	822	643	2,223
Working Capital - Liabilities	(4,432)	(403)	(1,429,240)	(26,550)	(525)	(446)	(1,421)
Working Capital - Net	1,985	206	707,646	11,930	297	196	802
Total Rate Base	52,269	4,485	12,674,767	336,304	3,845	6,325	14,534
REVENUES -							
Sales of Electricity	11,479	853	2,532,394	70,674	1,252	369	4,262
Other Operating Revenues	174	26	106,747	714	79	25	39
Total Operating Revenues	11,653	879	2,639,142	71,387	1,330	394	4,302
EXPENSES -							
Operating & Maintenance Expense	(3,281)	(279)	(963,492)	(19,522)	(332)	(320)	(809)
Depreciation Expense	(3,079)	(168)	(496,410)	(18,559)	(134)	(152)	(565)
Taxes Other Than Income Tax	(942)	(81)	(226,249)	(6,070)	(67)	(112)	(245)
Amortization of Property Losses	4	0	668	24	0	1	1
Gain or Loss on Sale of Plant	3	1	1,607	17	0	3	
Total Operating Expenses	(7,294)	(526)	(1,683,875)	(44,111)	(532)	(581)	(1,618)
Net Operating Income Before Taxes	4,358	353	955,267	27,277	799	(187)	2,684
Income Taxes	(1,340)	(107)	(287,127)	(8,319)	(305)	143	(1,014)
NOI Before Curtailment Adjustment	3,018	246	668,139	18,958	493	(44)	1,670
Curtailment Credit Revenue							
Reassign Curtailment Credit Revenue	(0)	(0)	(360)	(0)	(0)	(0)	(0)
Net Curtailment Credit Revenue	(0)	(0)	(360)	(0)	(0)	(0)	(0)
Net Curtailment NOI Adjustment	(0)	(0)	(221)	(0)	(0)	(0)	(0)
Net Operating Income (NOI)	3,018	246	667,919	18,958	493	(44)	1,670

Docket No. 120015-EI
Min Dist System-1 CP Prod/Trans Demand
Exhibit SJB-7, Page 3 of 4

SFHHA MDS CLASS COST OF SERVICE STUDY
MIN DIST SYSTEM- 1 CP PROD/TRANS DEMAND
CORRECTED DEMAND ALLOCATORS

MFR E-1 - COST OF SERVICE STUDY
2013 AT PRESENT RATES
($000 WHERE APPLICABLE)

	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
Rate of Return (ROR)	5.77%	5.48%	5.27%	5.64%	12.82%	(0.70%)	11.49%
Parity At Present Rates	1.05	1.00	0.96	1.03	2.33	(0.13)	2.09
EQUALIZED RATE OF RETURN (ROR) -							
Equalized Base Revenue Requirements	11,242	854	2,579,379	69,904	792	1,009	2,841
Other Operating Revenues (Equalized)	174	26	106,747	714	79	25	39
Total Equalized Revenue Requirements	11,416	880	2,686,126	70,618	871	1,034	2,880
Revenue Requirements Deficiency (Excess)	(237)	1	46,985	(769)	(460)	640	(1,421)
Revenue Requirements Index [1]	102.1%	99.9%	98.3%	101.1%	152.8%	38.1%	149.3%

Docket No. 120015-EI
Min Dist System-1 CP Prod/Trans Demand
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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER AND LIGHT COMPANY	)))	DOCKET NO. 120015-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

SFHHA Recommended Revenue Allocation Methodolgy
(FPL COS As-Filed)

	2013								
Rate Class	2013 Base Rate Revenue	Misc. Sevice Revenue (Preliminary Allocations)	Other Operating Revenue (Preliminary Allocations)	CILC Incentive offset.	Unbilled	Base + Misc. Revenue	Clause Revenue	2013 Sales Revenue (2/6/12 Fuel Curves)	2013 Operating Revenue
CILC-1D	56,579,600	103,104	$ 1,367,404	$ 16,797,415	$ (232,167)	$ 56,682,704	111,513,448	184,658,296	186,128,804
CILC-1G	4,455,382	5,110	$ 91,224	$ 1,026,132	$ (14,409)	$ 4,460,492	6,920,689	12,387,794	12,484,129
CILC-1T	16,138,417	8,609	$ 256,895	$ 7,373,838	$ (108,824)	$ 16,147,026	51,544,110	74,947,542	75,213,045
GS(T)-1	305,128,929	4,298,709	$ 4,480,823		$ (474,146)	$ 309,427,638	229,546,046	534,200,830	542,980,362
GSCU-1	1,668,152	2,626	$ 22,680		$ (3,072)	$ 1,670,778	1,678,197	3,343,277	3,368,582
GSD(T)-1	859,613,370	4,783,506	$ 14,958,747	$ 3,269,592	$ (2,034,427)	$ 864,396,876	990,377,867	1,851,226,402	1,870,968,654
GSLD(T)-1	306,793,721	805,007	$ 6,612,648	$ 5,959,107	$ (917,546)	$ 307,598,728	433,061,467	744,896,749	752,314,404
GSLD(T)-2	56,513,977	118,999	$ 1,209,869	$ 1,072,436	$ (198,806)	$ 56,632,976	89,185,696	146,573,304	147,902,172
GSLD(T)-3	4,059,551	2,460	$ 40,625		$ (16,182)	$ 4,062,011	8,600,954	12,644,323	12,687,408
MET	2,892,011	15	$ 62,160		$ (7,520)	$ 2,892,026	3,348,575	6,233,066	6,295,241
OL-1	11,486,837	79,468	$ 126,083		$ (8,060)	$ 11,566,305	3,920,034	15,398,811	15,604,361
OS-2	853,710	308	$ 37,253		$ (1,020)	$ 854,018	518,651	1,371,341	1,408,901
RS(T)-1	2,536,695,749	56,805,961	$ 43,342,537		$ (4,301,361)	$ 2,593,501,710	2,454,591,404	4,986,985,793	5,087,134,290
SL-1	70,716,672	157,735	$ 727,661		$ (43,126)	$ 70,874,407	20,974,023	91,647,569	92,532,966
SL-2	1,254,377	68,273	$ 14,693		$ (2,655)	$ 1,322,650	1,450,265	2,701,987	2,784,953
SST-DST	369,261	115	$ 11,325		$ (618)	$ 369,376	285,845	654,488	665,928
SST-TST	4,270,312	12,823	$ 21,450		$ (7,918)	$ 4,283,135	4,228,689	8,491,083	8,525,356
Total	4,239,490,028	67,252,829	73,384,077	35,498,520	-8,371,857	4,306,742,857	4,411,745,961	8,678,362,653	8,818,999,559

								Parity Increase - Commission Guidelines		
Rate Class	parity at present rates	E1 deficiency at present rates 000s	Target Increase	Adjusted 1/1/13 Increase	1/1/13 Increase% Base Op Rev	Est 6/1/13 Increase	Adj Canaveral Increase	Total Step 1 + Step 2 Increase	Total w/ clauses %	Total w/o clauses%
CILC-1D	91%	3,051	$ 9,849,075	$ 10,371,750	18.30%	$ 3,621,979	3,257,612	13,629,362	7.3%	24.0%
CILC-1G	114%	(328)	$ 207,103	$ 246,127	5.52%	$ 232,999	233,702	479,829	3.8%	10.8%
CILC-1T	78%	2,249	$ 4,185,262	$ 2,904,845	17.99%	$ 1,599,991	977,709	3,882,554	5.2%	24.0%
GS(T)-1	135%	(38,000)	$ (889,283)	$ 2,646,185	0.86%	$ 10,003,942	10,022,519	12,668,704	2.3%	4.1%
GSCU-1	121%	(113)	$ 87,059	$ 101,711	6.09%	$ 47,000	47,218	148,929	4.4%	8.9%
GSD(T)-1	105%	(19,535)	$ 84,134,438	$ 91,860,043	10.63%	$ 38,503,779	38,695,219	130,555,261	7.0%	15.1%
GSLD(T)-1	70%	48,200	$ 85,091,384	$ 55,336,918	17.99%	$ 17,007,902	17,114,141	72,451,059	9.6%	23.6%
GSLD(T)-2	67%	9,863	$ 16,655,291	$ 10,188,255	17.99%	$ 3,243,981	3,263,707	13,451,962	9.1%	23.8%
GSLD(T)-3	96%	61	$ 548,540	$ 585,412	14.41%	$ 254,999	256,233	841,645	6.6%	20.7%
MET	81%	267	$ 613,586	$ 520,275	17.99%	$ 151,999	152,986	673,261	10.7%	23.3%
OL-1	98%	177	$ 1,563,942	$ 1,668,942	14.43%	$ 44,000	46,515	1,715,457	11.0%	14.8%
OS-2	73%	132	$ 234,670	$ 153,638	17.99%	$ 16,000	16,249	169,887	12.1%	19.9%
RS(T)-1	100%	(5,102)	$ 305,945,246	$ 329,323,337	12.70%	$ 98,702,432	99,330,991	428,654,328	8.4%	16.5%
SL-1	97%	1,411	$ 9,910,833	$ 10,555,452	14.89%	$ 232,999	248,842	10,804,293	11.7%	15.2%
SL-2	208%	(404)	$ (245,003)	$ 9,242	0.70%	$ 41,000	41,074	50,316	1.8%	3.8%
SST-DST	115%	(23)	$ 20,982	$ 24,228	6.56%	$ 8,000	8,047	32,275	4.8%	8.7%
SST-TST	299%	(1,906)	$ (1,391,968)	$ 24,796	0.58%	$ 136,999	137,237	162,033	1.9%	3.8%
Total		0	$ 516,521,155	$ 516,521,155	11.99%	$ 173,850,000	173,850,000	690,371,155	7.8%	16.0%

Docket No. 120015-EI
SFHHA Recommended Revenue Allocation Methodology
Exhibit SJB-8, Page 1 of 4
Schedule A

SFHHA Recommended Revenue Allocation Methodolgy
(FPL COS With Corrected Demand Allocation Factors)

Rate Class	2013 Base Rate Revenue (2013)	Misc. Sevice Revenue (Preliminary Allocations) (2013)	Other Operating Revenue (Preliminary Allocations) (2013)	CILC Incentive offset. (2013)	Unbilled (2013)	Base + Misc. Revenue (2013)	Clause Revenue (2013)	2013 Sales Revenue (2/6/12 Fuel Curves) (2013)	2013 Operating Revenue (2013)
CILC-1D	56,579,600	103,104	$ 1,367,404	$ 16,797,415	$ (232,167)	$ 56,682,704	111,513,448	184,658,296	186,128,804
CILC-1G	4,455,382	5,110	$ 91,224	$ 1,026,132	$ (14,409)	$ 4,460,492	6,920,689	12,387,794	12,484,129
CILC-1T	16,138,417	8,609	$ 256,895	$ 7,373,838	$ (108,824)	$ 16,147,026	51,544,110	74,947,542	75,213,045
GS(T)-1	305,128,929	4,298,709	$ 4,480,823		$ (474,146)	$ 309,427,638	229,546,046	534,200,830	542,980,362
GSCU-1	1,668,152	2,626	$ 22,680		$ (3,072)	$ 1,670,778	1,678,197	3,343,277	3,368,582
GSD(T)-1	859,613,370	4,783,506	$ 14,958,747	$ 3,269,592	$ (2,034,427)	$ 864,396,876	990,377,867	1,851,226,402	1,870,968,654
GSLD(T)-1	306,793,721	805,007	$ 6,612,648	$ 5,959,107	$ (917,546)	$ 307,598,728	433,061,467	744,896,749	752,314,404
GSLD(T)-2	56,513,977	118,999	$ 1,209,869	$ 1,072,436	$ (198,806)	$ 56,632,976	89,185,696	146,573,304	147,902,172
GSLD(T)-3	4,059,551	2,460	$ 40,625		$ (16,182)	$ 4,062,011	8,600,954	12,644,323	12,687,408
MET	2,892,011	15	$ 62,160		$ (7,520)	$ 2,892,026	3,348,575	6,233,066	6,295,241
OL-1	11,486,837	79,468	$ 126,083		$ (8,060)	$ 11,566,305	3,920,034	15,398,811	15,604,361
OS-2	853,710	308	$ 37,253		$ (1,020)	$ 854,018	518,651	1,371,341	1,408,901
RS(T)-1	2,536,695,749	56,805,961	$ 43,342,537		$ (4,301,361)	$ 2,593,501,710	2,454,591,404	4,986,985,793	5,087,134,290
SL-1	70,716,672	157,735	$ 727,661		$ (43,126)	$ 70,874,407	20,974,023	91,647,569	92,532,966
SL-2	1,254,377	68,273	$ 14,693		$ (2,655)	$ 1,322,650	1,450,265	2,701,987	2,784,953
SST-DST	369,261	115	$ 11,325		$ (618)	$ 369,376	285,845	654,488	665,928
SST-TST	4,270,312	12,823	$ 21,450		$ (7,918)	$ 4,283,135	4,228,689	8,491,083	8,525,356
Total	4,239,490,028	67,252,829	73,384,077	35,498,520	-8,371,857	4,306,742,857	4,411,745,961	8,678,362,653	8,818,999,559

Rate Class	parity at present rates	E1 deficiency at present rates	Target increase	Adjusted 1/1/13 Increase	1/1/13 increase% Base Op Rev	Target 6/1/13 Increase	Adj Canaveral Increase	Total Step 1 + Step 2 Adjusted Increase	Total w/ clauses %	Total w/o clauses%
		000s								
CILC-1D	95%	1,758	$ 8,556,134	$ 8,890,529	15.7%	$ 3,621,979	3,633,332	12,523,861	6.7%	22.1%
CILC-1G	119%	(420)	$ 114,961	$ 143,634	3.2%	$ 232,999	233,340	376,974	3.0%	8.5%
CILC-1T	81%	2,043	$ 3,979,563	$ 2,904,845	18.0%	$ 1,599,991	977,709	3,882,554	5.2%	24.0%
GS(T)-1	138%	(41,064)	$ (3,953,375)	$ 1,996,915	0.6%	$ 10,003,942	10,014,831	12,011,746	2.2%	3.9%
GSCU-1	122%	(120)	$ 80,382	$ 90,964	5.4%	$ 47,000	47,125	138,089	4.1%	8.3%
GSD(T)-1	109%	(34,700)	$ 68,969,824	$ 74,329,106	8.6%	$ 38,503,779	38,606,151	112,935,257	6.0%	13.1%
GSLD(T)-1	75%	40,830	$ 77,721,278	$ 55,336,918	18.0%	$ 17,007,902	17,073,540	72,410,458	9.6%	23.5%
GSLD(T)-2	71%	8,586	$ 15,378,170	$ 10,188,255	18.0%	$ 3,243,981	3,256,168	13,444,424	9.1%	23.7%
GSLD(T)-3	99%	23	$ 510,170	$ 534,568	13.2%	$ 254,999	255,715	790,283	6.2%	19.5%
MET	86%	200	$ 546,850	$ 520,275	18.0%	$ 151,999	152,609	672,884	10.7%	23.3%
OL-1	98%	111	$ 1,498,183	$ 1,567,464	13.6%	$ 44,000	45,462	1,612,926	10.3%	13.9%
OS-2	78%	103	$ 205,425	$ 153,638	18.0%	$ 16,000	16,154	169,791	12.1%	19.9%
RS(T)-1	98%	23,199	$ 334,245,780	$ 349,787,725	13.5%	$ 98,702,432	99,109,344	448,897,070	8.8%	17.3%
SL-1	97%	1,061	$ 9,561,190	$ 9,984,111	14.1%	$ 232,999	242,269	10,226,380	11.1%	14.4%
SL-2	208%	(408)	$ (249,370)	$ 7,016	0.5%	$ 41,000	41,043	48,059	1.7%	3.6%
SST-DST	-18%	726	$ 770,300	$ 66,451	18.0%	$ 8,000	8,068	74,518	11.2%	20.2%
SST-TST	302%	(1,930)	$ (1,416,310)	$ 18,741	0.4%	$ 136,999	137,141	155,881	1.8%	3.6%
Total		(2)	$ 516,519,155	$ 516,521,155	12.0%	$ 173,850,000	173,850,000	690,371,155	7.8%	16.0%

Docket No. 120015-EI
SFHHA Recommended Revenue Allocation Methodology
Exhibit SJB-8, Page 2 of 4
Schedule B

SFHHA Recommended Revenue Allocation Methodolgy
(FPL COS With MDS and Corrected Demand Allocation Factors)

	2013								
Rate Class	2013 Base Rate Revenue	Misc. Sevice Revenue (Preliminary Allocations)	Other Operating Revenue (Preliminary Allocations)	CILC Incentive offset.	Unbilled	Base + Misc. Revenue	Clause Revenue	2013 Sales Revenue (2/6/12 Fuel Curves)	2013 Operating Revenue
CILC-1D	56,579,600	103,104	$ 1,367,404	$ 16,797,415	$ (232,167)	$ 56,682,704	111,513,448	184,658,296	186,128,804
CILC-1G	4,455,382	5,110	$ 91,224	$ 1,026,132	$ (14,409)	$ 4,460,492	6,920,689	12,387,794	12,484,129
CILC-1T	16,138,417	8,609	$ 256,695	$ 7,373,838	$ (108,624)	$ 16,147,026	51,544,110	74,947,542	75,213,045
GS(T)-1	305,128,929	4,298,709	$ 4,480,823		$ (474,146)	$ 309,427,638	229,546,046	534,200,830	542,980,362
GSCU-1	1,668,152	2,626	$ 22,680		$ (3,072)	$ 1,670,778	1,678,197	3,343,277	3,368,582
GSD(T)-1	859,613,370	4,783,506	$ 14,958,747	$ 3,269,592	$ (2,034,427)	$ 864,396,876	990,377,667	1,851,226,402	1,870,968,654
GSLD(T)-1	306,793,721	805,007	$ 6,612,646	$ 5,959,107	$ (917,546)	$ 307,598,728	433,061,467	744,896,749	752,314,404
GSLD(T)-2	56,513,977	118,999	$ 1,209,869	$ 1,072,436	$ (198,806)	$ 56,632,976	89,185,696	146,573,304	147,902,172
GSLD(T)-3	4,059,551	2,460	$ 40,625		$ (16,182)	$ 4,062,011	8,600,954	12,644,323	12,687,408
MET	2,892,011	15	$ 62,160		$ (7,520)	$ 2,892,026	3,348,575	6,233,066	6,295,241
OL-1	11,486,837	79,468	$ 126,083		$ (8,060)	$ 11,566,305	3,920,034	15,398,811	15,604,361
OS-2	853,710	308	$ 37,253		$ (1,020)	$ 854,018	518,651	1,371,341	1,408,901
RS(T)-1	2,536,695,749	56,805,961	$ 43,342,537		$ (4,301,361)	$ 2,593,501,710	2,454,591,404	4,986,985,793	5,087,134,290
SL-1	70,716,672	157,735	$ 727,661		$ (43,126)	$ 70,874,407	20,974,023	91,647,569	92,532,966
SL-2	1,254,377	68,273	$ 14,693		$ (2,655)	$ 1,322,650	1,450,265	2,701,967	2,784,953
SST-DST	369,261	115	$ 11,325		$ (618)	$ 369,376	285,645	654,488	665,928
SST-TST	4,270,312	12,823	$ 21,450		$ (7,918)	$ 4,283,135	4,228,689	8,491,083	8,525,356
Total	4,239,490,028	67,252,829	73,384,077	35,498,520	-8,371,857	4,306,742,857	4,411,745,961	8,678,362,653	8,818,999,559

	Parity Increase - Commission Guidelines									
Rate Class	parity at present rates	E1 deficiency at present rates 000s	Target Increase	Adjusted 1/1/13 Increase	1/1/13 Increase% Base Op Rev	Target 6/1/13 Increase	Adj Canaveral Increase	Total Step 1 + Step 2 Increase	Total w/ clauses %	Total w/o clauses%
CILC-1D	101%	(348)	$ 6,450,561	$ 6,655,892	11.7%	$ 3,621,979	3,631,304	10,287,196	5.5%	18.1%
CILC-1G	127%	(577)	$ (42,269)	$ 15,876	0.4%	$ 232,999	233,224	249,101	2.0%	5.6%
CILC-1T	81%	2,043	$ 3,979,761	$ 2,904,845	18.0%	$ 1,599,991	977,709	3,882,554	5.2%	24.0%
GS(T)-1	132%	(35,713)	$ 1,397,501	$ 2,509,755	0.8%	$ 10,003,942	10,015,296	12,525,051	2.3%	4.0%
GSCU-1	100%	(2)	$ 198,253	$ 204,307	12.2%	$ 47,000	47,228	251,535	7.5%	15.1%
GSD(T)-1	116%	(58,542)	$ 45,128,065	$ 48,245,710	5.6%	$ 38,503,779	38,582,486	86,828,196	4.6%	10.0%
GSLD(T)-1	81%	29,424	$ 66,314,807	$ 55,336,918	18.0%	$ 17,007,902	17,073,540	72,410,458	9.6%	23.5%
GSLD(T)-2	77%	6,689	$ 13,481,008	$ 10,188,255	18.0%	$ 3,243,981	3,256,168	13,444,424	9.1%	23.7%
GSLD(T)-3	99%	23	$ 510,389	$ 525,116	12.9%	$ 254,999	255,706	780,822	6.2%	19.2%
MET	91%	127	$ 473,844	$ 484,358	16.7%	$ 151,999	152,576	636,934	10.1%	22.0%
OL-1	101%	(37)	$ 1,349,923	$ 1,391,830	12.0%	$ 44,000	45,302	1,437,132	9.2%	12.4%
OS-2	89%	47	$ 148,963	$ 152,070	17.8%	$ 16,000	16,152	168,223	11.9%	19.7%
RS(T)-1	95%	58,336	$ 369,383,015	$ 378,796,816	14.6%	$ 98,702,432	99,135,664	477,932,480	9.4%	18.4%
SL-1	99%	272	$ 8,771,956	$ 9,028,876	12.7%	$ 232,999	241,402	9,270,278	10.0%	13.1%
SL-2	218%	(430)	$ (271,495)	$ 3,777	0.3%	$ 41,000	41,040	44,818	1.6%	3.4%
SST-DST	-12%	618	$ 662,526	$ 66,451	18.0%	$ 8,000	8,068	74,518	11.2%	20.2%
SST-TST	302%	(1,930)	$ (1,416,191)	$ 10,302	0.2%	$ 136,999	137,133	147,435	1.7%	3.4%
Total		(1)	$ 516,520,618	$ 516,521,155	11.99%	$ 173,850,000	173,850,000	690,371,155	7.8%	16.0%

Docket No. 120015-EI
SFHHA Recommended Revenue Allocation Methodology
Exhibit SJB-8, Page 3 of 4
Schedule C

SFHHA Recommended Revenue Allocation Methodolgy
(FPL COS With: Corrected Demd Alloc Factors, MDS, 1 CP)

	2013								
Rate Class	2013 Base Rate Revenue	Misc. Sevice Revenue (Preliminary Allocations)	Other Operating Revenue (Preliminary Allocations)	CILC Incentive offset.	Unbilled	Base + Misc. Revenue	Clause Revenue	2013 Sales Revenue (2/6/12 Fuel Curves)	2013 Operating Revenue
CILC-1D	56,579,600	103,104	$ 1,367,404	$ 16,797,415	$ (232,167)	$ 56,682,704	111,513,446	184,658,296	186,128,804
CILC-1G	4,455,382	5,110	$ 91,224	$ 1,026,132	$ (14,409)	$ 4,460,492	6,920,689	12,387,794	12,484,129
CILC-1T	16,138,417	8,609	$ 256,895	$ 7,373,838	$ (108,824)	$ 16,147,026	51,544,110	74,947,542	75,213,045
GS(T)-1	305,128,929	4,298,709	$ 4,480,823		$ (474,146)	$ 309,427,638	229,546,046	534,200,830	542,980,362
GSCU-1	1,668,152	2,626	$ 22,680		$ (3,072)	$ 1,670,778	1,676,197	3,343,277	3,368,582
GSD(T)-1	859,613,370	4,783,506	$ 14,958,747	$ 3,269,592	$ (2,034,427)	$ 864,396,876	990,377,867	1,851,226,402	1,870,968,654
GSLD(T)-1	306,793,721	805,007	$ 6,612,648	$ 5,959,107	$ (917,546)	$ 307,598,728	433,061,467	744,896,749	752,314,404
GSLD(T)-2	56,513,977	118,999	$ 1,209,869	$ 1,072,436	$ (198,806)	$ 56,632,976	89,185,696	146,573,304	147,902,172
GSLD(T)-3	4,059,551	2,460	$ 40,625		$ (16,162)	$ 4,062,011	8,600,954	12,644,323	12,687,408
MET	2,892,011	15	$ 62,160		$ (7,520)	$ 2,892,026	3,348,575	6,233,066	6,295,241
OL-1	11,486,837	79,468	$ 126,083		$ (8,060)	$ 11,566,305	3,920,034	15,398,811	15,604,361
OS-2	853,710	308	$ 37,253		$ (1,020)	$ 854,018	518,651	1,371,341	1,406,901
RS(T)-1	2,536,695,749	56,805,961	$ 43,342,537		$ (4,301,361)	$ 2,593,501,710	2,454,591,404	4,986,985,793	5,087,134,290
SL-1	70,716,672	157,735	$ 727,661		$ (43,126)	$ 70,874,407	20,974,023	91,647,569	92,532,966
SL-2	1,254,377	68,273	$ 14,693		$ (2,655)	$ 1,322,650	1,450,265	2,701,987	2,784,953
SST-DST	369,261	115	$ 11,325		$ (618)	$ 369,376	285,845	654,488	665,928
SST-TST	4,270,312	12,823	$ 21,450		$ (7,918)	$ 4,283,135	4,226,689	8,491,083	8,525,356
Total	4,239,490,028	67,252,829	73,384,077	35,498,520	-8,371,857	4,306,742,857	4,411,745,961	8,678,362,653	8,818,999,559

Rate Class	parity at present rates	E1 deficiency at present rates 000s	Target Increase	Adjusted 1/1/13 Increase	1/1/13 increase% Base Op Rev	Target 6/1/13 Increase	Adj Canaveral Increase	Total Step 1 + Step 2 Adjusted Increase	Total w/ clauses %	Total w/o clauses%
CILC-1D	1.03	(1,017)	$ 5,780,873	$ 5,951,649	10.5%	$ 3,621,979	3,630,665	9,582,314	5.1%	16.9%
CILC-1G	1.30	(628)	$ (92,684)	$ 12,958	0.3%	$ 232,999	233,222	246,179	2.0%	5.5%
CILC-1T	0.83	1,788	$ 3,724,492	$ 2,904,845	18.0%	$ 1,599,991	977,709	3,882,554	5.2%	24.0%
GS(T)-1	1.23	(27,275)	$ 9,835,900	$ 10,758,309	3.5%	$ 10,003,942	10,022,780	20,781,089	3.8%	6.7%
GSCU-1	1.06	(35)	$ 164,909	$ 169,940	10.2%	$ 47,000	47,197	217,137	6.4%	13.0%
GSD(T)-1	1.14	(51,112)	$ 52,557,666	$ 55,145,807	6.4%	$ 38,503,779	38,588,746	93,734,553	5.0%	10.8%
GSLD(T)-1	0.82	27,194	$ 64,085,108	$ 55,336,918	18.0%	$ 17,007,902	17,073,540	72,410,458	9.6%	23.5%
GSLD(T)-2	0.78	6,352	$ 13,144,252	$ 10,188,255	18.0%	$ 3,243,981	3,256,168	13,444,424	9.1%	23.7%
GSLD(T)-3	1.05	(80)	$ 407,421	$ 419,656	10.3%	$ 254,999	255,611	675,267	5.3%	16.6%
MET	0.94	74	$ 421,057	$ 429,827	14.9%	$ 151,999	152,527	582,354	9.3%	20.1%
OL-1	1.05	(237)	$ 1,150,593	$ 1,185,428	10.2%	$ 44,000	45,115	1,230,543	7.9%	10.6%
OS-2	1.00	1	$ 103,352	$ 105,933	12.4%	$ 16,000	16,111	122,043	8.7%	14.3%
RS(T)-1	0.96	46,985	$ 358,031,401	$ 365,887,605	14.1%	$ 98,702,432	99,123,952	465,011,557	9.1%	17.9%
SL-1	1.03	(769)	$ 7,730,768	$ 7,944,529	11.2%	$ 232,999	240,418	8,184,947	8.8%	11.5%
SL-2	2.33	(460)	$ (301,144)	$ 3,030	0.2%	$ 41,000	41,040	44,070	1.6%	3.3%
SST-DST	(0.13)	640	$ 684,270	$ 66,451	18.0%	$ 8,000	8,068	74,518	11.2%	20.2%
SST-TST	2.09	(1,421)	$ (907,606)	$ 10,014	0.2%	$ 136,999	137,133	147,146	1.7%	3.4%
Total		(1)	$ 516,520,618	$ 516,521,155	12.0%	$ 173,850,000	173,850,000	690,371,155	7.8%	16.0%

Docket No. 120015-EI
SFHHA Recommended Revenue Allocation Methodology
Exhibit SJB-8, Page 4 of 4
Schedule D

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER AND LIGHT COMPANY	)))	DOCKET NO. 120015-EI

EXHIBIT__(SJB-9)

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.

ROSWELL, GEORGIA

Rate Class CIILC-1D
SFHHA Recommended Rate Design

Line No.	(1) Type of Charges	(2) Present Revenue Calculation: Units	(3) Present Revenue Calculation: Charge/Unit	(4) Present Revenue Calculation: $ Revenue	(5) FPL Proposed Charge/Unit	(6) Percent Increase	(7) SFHHA Proposed: Units	(8) SFHHA Proposed: Charge/Unit	(9) SFHHA Proposed: $ Revenue	(10) Percent Increase
1	**RATE SCHEDULE CILC-1D - 54**									
2										
3	Customer	3,972	$ 175.00	$ 695,100	$ 150.00	-14.3%	3,972	$ 150.00	$ 595,800	-14.3%
4	Non-Fuel Energy									
5	On Peak	754,148,919	$ 0.00646	$ 4,871,802	**$ 0.02719**	**320.9%**	754,148,919	$ 0.00700	$ 5,279,042	8.4%
6	Off Peak	2,107,793,706	$ 0.00646	$ 13,616,347	$ 0.00700	8.4%	2,107,793,706	$ 0.00700	$ 14,754,556	8.4%
7	Demand									
8	Max Demand	6,864,611	$ 3.17	$ 21,760,817	$ 3.10	-2.2%	6,864,611	$ 4.11	$ 28,187,235	29.5%
9	Load Control On-Peak	4,807,458	$ 2.04	$ 9,807,214	$ 1.30	-36.3%	4,807,458	$ 2.64	$ 12,703,487	29.5%
10	Firm On-Peak	805,340	$ 7.81	$ 6,289,705	$ 7.80	-0.1%	805,340	$ 10.12	$ 8,147,185	29.5%
11	Transformation Credit	1,922,442	$ (0.24)	$ (461,386)	$ (0.28)	16.7%	1,922,442	$ (0.28)	$ (538,284)	16.7%
12										
13	**TOTAL**			**$ 56,579,600**		22.2%			**$ 69,129,022**	22.2%
14										
15							Increase		$ 12,549,422	
16							Target revenues		$ 12,549,423	
17							Difference		(0)	

Docket No. 120015-EI
Rate Class CILC-1D - SFHHA Recommended Rate Design
Exhibit SJB-9, Page 1 of 1

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER AND LIGHT COMPANY	)))	DOCKET NO. 120015-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

Q.
Referring to MFR E-13a CC WP, please explain how the 2013 Cape Canaveral Energy Factor was calculated.

A.
The derivation of the Cape Canaveral energy rate is shown in Cape Canaveral Schedule E8. The Cape Canaveral revenue requirements are allocated to the classes based on the allocation of Other Production demand and energy revenue requirements in MFR E6b. The allocated revenue requirements are divided by the classes' total sales, including unbilled sales, to derive the Cape Canaveral energy rate.

As discussed in FPL's response to SFHHA's First Set of Interrogatories No. 55, and in FPL's April 27 informational filing, a cell reference error was made in calculating the allocation of the Cape Canaveral revenue requirements. The corrected allocation and resulting rates are shown below.

Revised Revenue Requirement Allocation and Rates for Cape Canaveral Step Increase

Rate Class	Other Production Demand & Energy Revenue Requirements per E-6b ($000s)	Allocation %	Canaveral Allocated Revenue Requirements ($000s)	Sales kWh	Canaveral Step Increase ¢/kWh
CILC-1D	22,378	2.1%	3,622	2,865,110,154	0.126
CILC-1G	1,442	0.1%	233	177,812,951	0.131
CILC-1T	9,888	0.9%	1,600	1,342,962,457	0.119
GS(T)-1	61,812	5.8%	10,004	5,851,293,153	0.171
GSCU-1	288	0.0%	47	37,911,020	0.123
GSD(T)-1	237,906	22.1%	38,504	25,106,278,915	0.153
GSLD(T)-1	105,089	9.8%	17,008	11,323,169,609	0.150
GSLD(T)-2	20,042	1.9%	3,244	2,453,405,165	0.132
GSLD(T)-3	1,575	0.1%	255	199,703,548	0.128
MET	936	0.1%	152	92,800,603	0.163
OL-1	274	0.0%	44	99,468,089	0.045
OS-2	101	0.0%	16	12,592,879	0.130
RS(T)-1	609,861	56.8%	98,703	53,081,851,668	0.186
SL-1	1,438	0.1%	233	532,201,007	0.044
SL-2	256	0.0%	41	32,761,953	0.126
SST-DST	49	0.0%	8	7,621,954	0.103
SST-TST	849	0.1%	137	97,718,947	0.141
Total Retail	1,074,183	100.0%	173,851	103,314,664,074	0.168

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE:	**PETITION FOR RATE INCREASE BY FLORIDA POWER AND LIGHT COMPANY**	**)))**	**DOCKET NO. 120015-EI**

EXHIBIT__(SJB-11)

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.

ROSWELL, GEORGIA

OPC 000247
FPL RC-12
MFR E-6B, Attachment 2

MFR E-6b - COST OF SERVICE STUDY - UNIT COSTS
2013 PROPOSED RATES - EQUALIZED - DETAIL
($000 WHERE APPLICABLE)

	(1)	(2)
Line No.		Total Retail
1	**Demand**	
2	**Revenue Requirements**	
3	Production - Steam	196,235
4	Production - Nuclear	778,017
5	Production - Other Production	886,456
6	Production - Other Power Supply	11,240
7	Production - Curtailment Credit	547
8	Transmission	363,241
9	Distribution - Land & Land Rights	13,841
10	Distribution - Structures & Improvements	23,630
11	Distribution - Station Equipment	203,038
12	Distribution - Poles, Towers & Fixtures	92,910
13	Distribution - Overhead Conductors & Devices	366,270
14	Distribution - Underground Conduit	189,154
15	Distribution - Underground Conductors & Devices	147,355
16	Distribution - Primary Capacitors and Regulators	25,511
17	Distribution - Secondary Transformers	212,815
18	**Sub-Total Revenue Requirements**	3,510,262
19		
20	**Billing Units (Annual)**	
21	KW for Demand Classes	110,857,944
22	KWH for All Other Classes	59,582,135,691
23	**Sub-Total Billing Units (Annual)**	59,692,993,635
24		
25	**Unit Costs ($/Unit)**	
26	Production - Steam	0.000000
27	Production - Nuclear	0.000000
28	Production - Other Production	0.000000
29	Production - Other Power Supply	0.000000
30	Production - Curtailment Credit	0.000000
1	Transmission	0.000000
2	Distribution - Land & Land Rights	0.000000
3	Distribution - Structures & Improvements	0.000000
4	Distribution - Station Equipment	0.000000
5	Distribution - Poles, Towers & Fixtures	0.000000
6	Distribution - Overhead Conductors & Devices	0.000000
7	Distribution - Underground Conduit	0.000000
8	Distribution - Underground Conductors & Devices	0.000000
9	Distribution - Primary Capacitors and Regulators	0.000000
10	Distribution - Secondary Transformers	0.000000
11	**Sub-Total Unit Costs ($/Unit)**	0.000000
12		
13	**Energy**	
14	**Revenue Requirements**	
15	Production - Steam	130,181
16	Production - Nuclear	383,982
17	Production - Other Production	187,728
18	Transmission	30,256
19	Customer - Uncollectible Accounts	(190)
20	**Sub-Total Revenue Requirements**	731,956
21		

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER AND LIGHT COMPANY	)))	DOCKET NO. 120015-EI

EXHIBIT__(SJB-12)

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. 120015-EI
SFHHA's First Set of Interrogatories
Interrogatory No. 56
Page 1 of 1

Q.
Regarding Deaton at Schedule A-2, page 4-6, lines 12-13, 15: Please explain why only the Energy Charge regarding the Canaveral Modernization project for rate classes GSLD-1, GSLD-2, and GSLD-3 increases for the proposed 2013 Test Year, as opposed to the customer, demand, fuel, conservation, capacity, environmental, and storm charges.

A.
First, the Canaveral Modernization project is not the type of project that FPL would normally be allowed to recover through the fuel, conservation, capacity, environmental, or storm charges. As such, Canaveral is properly recoverable through base rates.

Regarding a rate design methodology, i.e., recovery through energy, demand or customer charge, under accepted rate design principles, production costs should not be recovered through the customer charge. Applying the step increase to energy charges rather than demand charges is administratively efficient, matches the cost with the benefit in fuel savings, and helps to mitigate the bill impacts to low load factor customers.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE:	**PETITION FOR RATE INCREASE BY FLORIDA POWER AND LIGHT COMPANY**	)))	**DOCKET NO. 120015-EI**

EXHIBIT__(SJB-13)

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.

ROSWELL, GEORGIA

Comparison of FPL Normal Cooling Degree Hours to 10 Year Historical Average

(Cooling Degree Hours with Base=72)

	Year	Month	CDH	Year	Month	CDH	Year	Month	CDH	Month	FPL Normal CDH
1	2001	8	323.9	2005	4	68.1	2008	12	37.6	1	325.1
2	2001	9	215.6	2005	5	168.4	2009	1	22.7	2	278.1
3	2001	10	170.1	2005	6	237.6	2009	2	19.4	3	196.9
4	2001	11	65.9	2005	7	364.9	2009	3	58.1	4	81.0
5	2001	12	58.8	2005	8	365.7	2009	4	123.1	5	39.3
6	2002	1	38.7	2005	9	295.9	2009	5	205.6	6	25.2
7	2002	2	19.4	2005	10	202.3	2009	6	286.3	7	32.3
8	2002	3	92.5	2005	11	83.1	2009	7	333.2	8	64.7
9	2002	4	146.8	2005	12	19.1	2009	8	358.9	9	109.6
10	2002	5	224.0	2006	1	28.8	2009	9	293.3	10	207.7
11	2002	6	222.2	2006	2	21.5	2009	10	264.4	11	272.4
12	2002	7	299.7	2006	3	53.9	2009	11	100.3	12	326.1
13	2002	8	312.6	2006	4	129.4	2009	12	63.3		
14	2002	9	306.5	2006	5	196.5	2010	1	19.0	**Total**	**1958.3**
15	2002	10	245.0	2006	6	277.0	2010	2	7.2		
16	2002	11	78.3	2006	7	300.4	2010	3	15.4		
17	2002	12	31.4	2006	8	324.0	2010	4	89.1		
18	2003	1	5.7	2006	9	267.9	2010	5	255.2		
19	2003	2	42.3	2006	10	196.8	2010	6	357.5		
20	2003	3	124.0	2006	11	67.1	2010	7	367.3		
21	2003	4	101.8	2006	12	63.6	2010	8	354.6		
22	2003	5	243.6	2007	1	45.6	2010	9	310.2		
23	2003	6	257.2	2007	2	30.4	2010	10	181.6		
24	2003	7	328.3	2007	3	62.9	2010	11	78.0		
25	2003	8	293.6	2007	4	102.0	2010	12	3.7		
26	2003	9	261.3	2007	5	167.2	2011	1	13.5		
27	2003	10	222.2	2007	6	252.1	2011	2	42.2		
28	2003	11	112.8	2007	7	317.7	2011	3	79.0		
29	2003	12	18.3	2007	8	364.0	2011	4	190.4		
30	2004	1	15.8	2007	9	282.7	2011	5	242.3		
31	2004	2	31.7	2007	10	252.3	2011	6	304.6		
32	2004	3	51.5	2007	11	75.0	2011	7	355.8		
33	2004	4	77.5	2007	12	77.1					
34	2004	5	160.6	2008	1	29.2					
35	2004	6	309.2	2008	2	59.3					
36	2004	7	317.9	2008	3	65.7					
37	2004	8	306.5	2008	4	109.1					
38	2004	9	280.1	2008	5	237.1					
39	2004	10	177.9	2008	6	279.2					
40	2004	11	78.6	2008	7	286.6					
41	2004	12	25.9	2008	8	325.2					
42	2005	1	23.5	2008	9	294.6					
43	2005	2	18.7	2008	10	173.3					
44	2005	3	59.8	2008	11	54.1					

Total (10 Years)	**19,905**
Average Annual	**1,990.5**

Source: FPL Response to SFHHA POD 1-5

Comparison of FPL Normal Cooling Degree Hours to 10 Year Historical Average
(Cooling Degree Hours with Base=72)

FPL Normal CDH	**1,958.3**
Actual 10 Year Average CDH	**1,990.5**
10 Year Average vs. FPL Normal (% Difference)	**1.64%**

FPL Westher Sensitivity	
10% Increase in CDH produces a 2.29% Increase in Net Energy for Load (NEL)	
Increase in CDH using 10 Year Averge	**1.64%**
Increase in Test Year NEL MWH	**0.38%**

Source: FPL Response to SFHHA POD 1-5

CERTIFICATE OF SERVICE
DOCKET NO. 120015-EI

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, U.S. Mail or Federal Express, this 2nd day of July, 2012 to the following:

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