BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Progress Energy Florida, Inc.

Docket No. 090079-EI

Submitted for filing:
March 20, 2009

DIRECT TESTIMONY OF

WILLIAM C. SLUSSER, JR.

On behalf of Progress Energy Florida

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DIRECT TESTIMONY OF
WILLIAM C. SLUSSER, JR.

I. Introduction

Q. Please state your name and business address.

A. My name is William C. Slusser, Jr. My business address is 16550 Gulf Boulevard, No. 342, North Redington Beach, Florida 33708.

Q. What is your occupation?

A. I am an electric utility rate consultant.

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

A. I am testifying on behalf of Progress Energy Florida ("PEF" or the "Company") on allocated cost of service and rate design issues.

Q. Please describe your educational background and professional experience.

A. I graduated in 1967 from the University of Florida with a Bachelor of Science Degree in Electrical Engineering and in 1970 from the University of South Florida with a Master's Degree in Engineering Administration. I have been a registered Professional Engineer employed by Florida Power Corporation for over 36 years until January 2001, after which time I became an independent rate consultant. I have devoted most of my career to preparing cost of service studies and performing rate analyses and rate design in the establishment of PEF's electric utility rate structure. I have testified on allocated class cost of service and rate design issues for

PEF for many years and most recently in their prior two base rate proceedings before this Commission in Docket No. 000824-EI and Docket No. 050078-EI.

II. Purpose and Summary of Testimony

Q. Mr. Slusser, what is the purpose of your testimony?

A. My testimony serves three main purposes.

First, I present a "Jurisdictional Separation Study" for the projected 2010 test year period. This study provides the basis for determining the Company's total costs and revenue requirements subject to the jurisdiction of this Commission.

Second, I have prepared and present three retail "Allocated Class Cost of Service and Rate of Return Studies" for the test year, each study differing only as to the weighting of demand and energy responsibilities in the allocator for fixed production capacity costs. The Company is recommending the study being referred to as the "12 CP and 50% AD" method be relied upon in this proceeding for establishing each rate class's allocated cost of service or revenue requirement.

Third, I present the Company's proposed tariff schedules of rates and charges which, when applied to test period billing determinants, produce the Company's class and total retail revenue requirements sought in this proceeding.

Q. Do you have an exhibit to your testimony?

A. Yes, I have prepared or supervised the preparation of the following exhibits which are attached to my direct testimony:

- Exhibit No. ___ (WCS-1), a list of the MFR schedules I sponsor or co-sponsor.
- Exhibit No. ___ (WCS-2), Summary Development of Functional Unit Costs with Proposed Revenue Credits.
- Exhibit No. ___ (WCS-3), Estimate of Alternative Resource Investment Required to Serve Peak Demand Only.
- Exhibit No. ___ (WCS-4), Comparison of Class Allocated Cost of Service Study Results.
- Exhibit No. ___ (WCS-5), Development of Target Revenue Increase by Rate Class.
- Exhibit No. ___ (WCS-6), Summary of Proposed Class Revenues and Class Rates of Return.

These exhibits are true and correct.

Q. What Minimum Filing Requirement (MFR) schedules do you sponsor?

A. I sponsor all or portions of the MFR schedules listed in my Exhibit ___ (WCS-1). These MFR schedules are true and correct, subject to their being updated in this proceeding.

Q. Are the "Jurisdictional Separation Study", the three "Allocated Class Cost of Service Studies", and PEF's proposed rate schedules provided as a part of the Company's MFRs?

A. Yes, they are provided within the portion of the MFRs designated Section E - Rate Schedules. I should mention that the "Jurisdictional Separation Study" and each of the three "Allocated Class Cost of Service Studies" are provided in separate bound volumes apart from the main volume of Section E because of the voluminous output reports included with these studies.

Q. Would you please provide a summary of your testimony?

A. Certainly. My role in this proceeding has been to develop, and to now support, the tariff rates and charges that produce sufficient revenues to (i) recover the Company's total retail jurisdictional cost of service from its rate classes as a whole and (ii) recover from each rate class, to the extent practicable, the portion of the Company's total retail cost of service properly and fairly allocated to that class. To accomplish this objective, I have prepared and sponsor two types of cost studies.

The first of these cost studies is entitled "Jurisdictional Separation Study." This type of study allocates the various items comprising the Company's total system costs between the Company's two jurisdictional businesses: its retail business and its wholesale business. This separation of costs between the two businesses is based on mathematical factors representing appropriate customer, capacity, or energy related cost responsibilities. The allocation of costs to the retail business that results from the application of these factors is the basis for determining the Company's revenue requirements in this proceeding subject to the jurisdiction of this Commission.

The second type of cost study is called an "Allocated Class Cost of Service and Rate of Return Study." This study is an extension of allocating the costs initially allocated to the retail jurisdiction to the individual rate classes comprising the retail business. The results of this study form the cost basis for establishing the revenue requirement attributable to each of the retail rate classes.

The most significant and noteworthy cost that must be allocated to rate classes is that of fixed production capacity costs. Production capacity related costs make up about 40% of the Company's base recoverable costs and over 80% of the costs recovered through the Capacity Cost Recovery, Energy Conservation Cost Recovery, and Environmental Cost Recovery clauses. PEF is recommending that production capacity costs be allocated using the method called the "12 CP and 50% AD" method. Simply stated, this method allocates 50 percent of the Company's production capacity costs on class demand responsibility and 50 percent of these costs based on class energy responsibility. As I explain later in my testimony, allocating 50 percent of production capacity costs on the basis of energy usage, instead of only about 8 percent under the "12 CP and 1/13 AD" method, a study method specified to be produced in accordance with the Commission's MFRs, is intended to provide a better matching of the allocation of costs and benefits to customer rate classes.

With respect to rate design, the Company is proposing to maintain its current rate structure and has generally revised its base rate charges to produce each class's revenue requirement and move the classes to parity to the extent practical. However, in keeping with past Commission practice, the Company has proposed to limit the percentage revenue increase for a number of rate classes to 1.5 times the overall percentage increase. In addition, the Company is proposing to complete the transition of its curtailable and interruptible general service customers being served for the last thirteen years under "closed" rate schedules and move these customers under the more up-to-date "open" curtailable and interruptible rate schedules.

III. Jurisdictional Separation Study

Q. What is a "Jurisdictional Separation Study"?

A. Most of the costs incurred by an electric utility to serve its customers are of a "joint" or "common use" nature. For example, a generating plant is ordinarily not constructed to serve any one customer or even one class of customers, but is part of a total generating system designed to serve the aggregate load requirements of all customers on the system. The investment in this plant is recorded on the Company's books and records as a "joint" cost for which all customers receiving electric service should share. A "Jurisdictional Separation Study" is an allocation of the Company's mostly "joint" costs between those customers served under the jurisdiction of the Federal Energy Regulatory Commission (FERC) and those customers served under the jurisdiction of this Commission, or, in other words, between the Company's retail and wholesale businesses. The study consists of allocations for all rate base and operating expense items comprising the Company's total system cost of service for the test period. Allocations are performed using mathematical formulas that best represent each jurisdiction's cost responsibility.

Q. What sources of information have you used to prepare the Company's "Jurisdictional Separation Study"?

A. The accounting data, particularly the data provided in MFR Schedules B, C, and D, sponsored by Company witness Peter Toomey, provide the basic system cost of service information. This data is organized by primary FERC account and is classified or assigned to functional groupings for allocation purposes. The data represents the fully adjusted data for the test period. The primary allocation factors are those used to allocate the fixed power supply capacity costs and are based on the jurisdictional loads occurring on the production and transmission systems at the time of the Company's projected system monthly peaks. This load data, which is sponsored by Company witness John B. Crisp, is projected for each individual wholesale customer and the total retail class for each month of the test period.

Q. Are the procedures and methodologies employed in the preparation of the "Jurisdictional Separation Study" in this proceeding consistent with those used in separation studies submitted in prior regulatory filings before both this Commission and the FERC?

A. Yes. It is important to utilize procedures and methodologies that are consistent with the regulatory practices of both this Commission and the FERC. The use or adoption of different costing procedures by either commission can result in an under- or over-recovery of costs by the Company on a total system basis. Both commissions employ similar embedded cost, ratemaking practices and develop rate base and rates of return to determine test year revenue requirements. And both commissions have specified the use of the "Average of the 12 Monthly Coincident Peak Demands," or the "12CP" methodology to allocate fixed power supply costs for jurisdictional separation purposes.

The Company is also employing the same computerized cost allocation program for preparing its studies in this proceeding as it has used in its previous rate filings before both the FERC and the FPSC. The computer program called ECOS was developed by the FERC staff and is obtainable from the FERC for a nominal fee. The program is designed to establish the rate groups to be allocated costs and requires the input of functionalized, system cost of service data and appropriate allocation factors. The preparation of the input system data is performed on Excel spread sheet tables described as "Cost Assignments to Allocation Categories." The input allocation factors are also prepared on Excel spread sheet tables and are described as "Development of Input Allocation Factors." These tables are included in the MFR volume containing the "Jurisdictional Separation Study."

Q. Who are the customers that comprise the Company's separated wholesale business?

A. Wholesale customers consist of municipals, rural electric cooperatives, and other electric utilities or entities that have the authority to generate into, or receive power from, PEF's transmission grid. PEF's rates and services to these types of entities are subject to the jurisdiction of the FERC. The Company currently provides wholesale full requirements sales to the Cities of Bartow, Winter Park, Mt. Dora, Quincy, Chattahoochee, and Williston. Wholesale partial requirements sales are provided to the Florida Municipal Power Agency, New Smyrna Beach Utilities Commission, Seminole Electric Cooperative, and the City of Tallahassee. Wholesale stratified production sales, which are sales specifically from a particular type of production resource, such as base, intermediate, or peaking, are made to Seminole Electric Cooperative, Inc., the City of Homestead, Gainesville Regional Utility, Tampa Electric Company, and Reedy Creek Improvement District. In addition to providing power sales to wholesale entities, the Company also provides firm transmission service to a number of other entities including the Cities of Fort Meade, Wauchula, and Tallahassee, the Georgia Power Company, and the co-generator Central Power & Lime.

Q. Have you developed a specific treatment in your "Jurisdictional Separation Study" for assigning production costs to those wholesale customers purchasing stratified production services?

A. Yes. First, it should be understood that production cost responsibilities for most of the Company's sales are based on average, overall production embedded costs. By comparison, the cost responsibilities for stratified wholesale sales are based on average, embedded costs for the particular type or types of production resources used to make these sales.

In order to assign the appropriate costs to stratified sales, it is necessary to present all the various system production costs, i.e. plant-in-service, accumulated depreciation, fuel inventories, operation and maintenance expenses and depreciation expenses, as separately stated stratified costs.

For the assignment of those production costs that are considered fixed, a demand allocator is developed for each stratum that represents the load responsibility of the stratum sales. This is determined by dividing the average 12 CP load of stratified customers by the total average monthly system stratified resource capability adjusted for reserves. Each stratum allocator results in a specific capacity cost responsibility, expressed as a percentage for the type of generation resource required. The remaining cost responsibility for the stratified resources is allocated to the average rate customer classes based on their 12 CP demands. This procedure insures that 100% of the costs have been assigned. This development is contained in the "Development of Input Allocation Factors" section of the separate MFR volume entitled "Jurisdictional Separation Study."

For the assignment of production costs that are considered variable, a stratified resource unit energy cost is calculated and applied to the appropriate stratified customer energy sales. These assignments are contained in the production O&M cost assignments section of the "Jurisdictional Separation Study."

Q. Have you applied any other different costing treatment to the wholesale jurisdiction?

A. Yes. In accordance with Commission Order No. PSC-99-1741-PPA-EI in Docket No. 990771-EI, specific amounts of plant and expense related to a sale to the City of Tallahassee have been assigned to the wholesale business. These costs, of course, have not been included in the balance of production costs assigned or allocated to any other customers.

Q. Would you summarize the wholesale business's cost responsibilities for the Company's investment in production, transmission, distribution, and general plant that result from the "Jurisdictional Separation Study"?

A. Yes. The wholesale business is responsible for 13.4% of the production, 32.7% of the transmission, 0.2% of the distribution, and 8.7% of the general plant investment of the Company. The wholesale business requires a higher investment in transmission plant due to other wholesale entities delivering power in, on, out, or through the Company's transmission system. The wholesale business requires very little distribution investment since most wholesale points of receipt or delivery are established on the Company's transmission system.

IV. <u>Class Allocated Cost of Service and Rate of Return Studies</u>

Q. What is a retail "Allocated Class Cost of Service and Rate of Return Study"?

A. This study is an extension of the "Jurisdictional Separation Study" in which the retail jurisdictional costs are further allocated to the various rate classes comprising the retail jurisdiction. Factors for allocating the jurisdictional costs to rate classes are based on billing determinants and class load characteristics derived from the Company's sales forecast and latest load research data. The study provides: (i) class realized rates of return at present and proposed rates, (ii) class revenue surplus or deficiencies from full cost of service, and (iii) functional unit cost information for rate design consideration.

As with the separation study, the FERC computer cost allocation program is utilized to perform the cost allocations to retail rate classes. To obtain the functional cost information required by the Commission's MFRs, additional program runs are made utilizing each class's cost results and allocating this data to functional categories.

Q. How did you establish the customer rate classes or rate groups that were used as costing entities in your "Allocated Class Cost of Service Studies"?

A. Each regular rate schedule in the Company's present tariff has been established as a rate group in the cost of service studies. The rate schedules for general service non-firm service, i.e. the curtailable and interruptible rate schedules are treated as one rate group since these customers only differ as to Company or customer control of their non-firm load capability. Each rate schedule serving either (i) optional time of use, (ii) load management service, or (iii) standby service, has been combined with its corresponding or related rate schedule. The resultant rate groups are described as:

(1) Residential Service (RS)

(2) General Service Non-Demand (GS-1)

(3) General Service 100% Load Factor (GS-2)

(4) General Service Demand (GSD)

(5) Curtailable/Interruptible General Service (CS/IS)

(6) Lighting Service (LS), consisting of sub-groups for the costs of

(a) Lighting Energy

(b) Lighting Facilities (Fixtures and Poles).

Q. You indicated that an "Allocated Class Cost of Service Study" provides functional cost information for rate design purposes. What functional components are provided in the cost of service studies?

A. The cost of service for each of the Company's rate classes, which ultimately translates into the class's revenue requirement for rate design purposes, is allocated or assigned to the following functional cost components:

(1) Production Capacity

(2) Production Energy

(3) Transmission Capacity

(4) Distribution Capacity - Primary

(5) Distribution Capacity - Secondary

(6) Distribution Services

(7) Metering

(8) Interruptible General Service Equipment

(9) Lighting Facilities (Fixtures & Poles) and

(10) Customer Billing, Information, etc.

Unit costs are developed in the allocated cost of service studies by dividing the class's component cost of service by the appropriate billing units, *i.e.*, the number of customer bills, energy sales, or billing demands. This type of information is then used as a consideration in rate design when establishing the level of customer charges, demand charges, energy charges, etc. A summary of the functional cost of service for each rate class and their respective unit costs is provided in my Exhibit No. _____ (WCS-2). The production capacity costs in this exhibit are based on the "12 CP and 50% AD" allocation method. All cost of service amounts shown have been reduced by an allocation of revenue credits from other operating revenues, including the additional revenue credits from proposed increases in service charges.

Q. What costing treatment is utilized in the class cost of service studies for those rate groups that contain non-firm service provisions?

A. PEF's residential service and general service rate groups include optional load management provisions that permit the interruption of certain specified customer equipment, while the interruptible service and curtailable service rate groups require that all, or a significant portion of the customer's load, be subject to interruption or curtailment as a condition for service. However, the development of costs for these rate groups is based on the premise that all of the groups' load requirements are firm. This is because the Company's various forms of non-firm service are elements of its demand side management (DSM) program and, therefore, the value of each rate group's load subject to interruption or curtailment is not a consideration in setting base rates, but instead is recognized separately by the payment of billing credits that are established in and recovered through PEF's Energy Conservation Cost Recovery clause.

Q. Mr. Slusser, you indicated that three "Allocated Class Cost of Service and Rate of Return Studies" have been prepared for this proceeding which differ only by the method employed to allocate production capacity costs. Would you describe the three production capacity cost allocation methods that you have employed?

A. Yes. The Commission's MFRs require, at a minimum, a cost of service study be provided that allocates production plant using the average of the twelve monthly coincident peaks and 1/13 weighted average demand (the "12 CP and 1/13th AD" method). This method allocates 12/13, or about 92 percent, of production capacity costs on the basis of class monthly coincident peak demands, thus the term "12 CP"; and 1/13, or about 8 percent, of production capacity costs on the basis of class average hourly demands, thus the term "AD". It should be noted that average demand and annual energy usage are mathematically the same allocation basis since average demand is simply total energy use divided by number of hours of use.

PEF believes that an energy weighted allocation of only 8 percent under this study method gives too little recognition to the role energy is given in generation facility planning. For this reason, the Company has prepared two additional studies that recognize the greater extent that energy considerations bear in the incurrence of production capacity costs.

The Company has prepared and presented studies that weight energy responsibility by 25 percent and 50 percent respectively as being more appropriate weightings. These studies are referred to as the "12 CP and 25% AD" study and the "12 CP and 50% AD" study.

Q. Mr. Slusser, do you know the origin of the Commission MFR's prescribed "12CP and 1/13 AD" study methodology?

A. Yes, this methodology became crystallized by the Commission in a series of rate cases being conducted for each of the four major Florida investor owned electric utilities in the early 1980's. These cases followed the Commission's adoption of a Cost of Service standard stating "Rates charged by any electric utility for each class of customer shall be designed to reflect the costs of providing electric service, to the maximum extent practicable and with due consideration of the other rate making elements specified in Section 366.06(1), Florida Statutes." The adoption of this standard placed a greater emphasis on relying on a specific cost of service study in rate cases thereafter.

At that time the focus was on 12 CP demand responsibility, but there was difficulty in determining the appropriate 12 CP demands to be used in particular for interruptible load. Interruptible customers were, as they are now, significant rate classes for Tampa Electric Company (TECO) and PEF's predecessor company Florida Power Corporation. Since interruptible load is not included in capacity planning, interruptible load would have no cost responsibility under the 12 CP methodology. A consideration of injecting an amount for average demand in the allocator in TECO's rate case, Docket No. 820007-EU, gave rise to the method called "12 CP and 1/13 AD." This was justified on the premise that each class will pay for some portion of the production plant it uses, even if the usage is not coincident with the system peak. It also recognized for TECO, that some of the production plant costs, such as coal handling equipment, varied more with the amount of kWh produced than with the demand placed on the system.

Even with this introduction of average demand into the allocator, there were differences of opinion as to the appropriate mathematical inclusion of average demand in the allocator. At first with TECO, average demand was inserted as a thirteenth number for each class along with the other 12 coincident peak numbers. For a company with a 50% load factor, this resulted in only about 1/26 of production plant costs being allocated on an average demand basis. The "12 CP and 1/13 AD" method was soon thereafter interpreted to mean that 12/13 of production capacity costs be allocated on a 12 CP basis and 1/13 of costs on an average demand basis.

Q. Why does PEF believe now that energy responsibility should be given a much greater weighting for production cost responsibility?

A. Generation investment strategies are different today than that reflected in the Company's generation fleet nearly thirty years ago. The emphasis years ago was to build conventional power plants that met accepted reliability criteria. Today, due to the relatively greater cost of fuel and stricter emissions requirements, the emphasis is on providing clean and efficient generation as well as satisfying reliability criteria. In recent years, PEF has applied state-of-the-art technologies in the construction of more efficient generation including the Hines Energy Complex, the repowering of Bartow power plant, and uprates to the Crystal River nuclear unit. Its future plans to install new, advanced nuclear generation in Florida will provide a clean, low-cost and less volatile fuel source. All of these investment strategies have a higher up-front capital cost. However, the benefits to the customers are primarily related to the costs for fuel which is apportioned on an energy basis. There should be no question that a significant portion of the Company's production capacity costs being incurred should be apportioned in the same manner as the customer realizes the benefits, i.e. on an energy basis.

Q. Have you performed any type of analysis that quantifies how much weighting energy should be given for production capacity cost responsibility?

A. Yes. I had prepared an exhibit in the Company's last base rate proceeding, in Docket No. 050078-EI, which resulted in the determination of an energy weighting of about 50 percent for PEF. I have updated this exhibit for this proceeding with nearly the same results and have included it as Exhibit No. ____ (WCS-3). The exhibit is intended to provide an estimate of the additional investment expended by PEF in production plant for reasons other than meeting peak demand. The theory being employed therein is that if meeting peak demand had been the sole consideration, the Company would have installed less expensive, simple-cycle combustion turbine units. Instead, as can be seen from this exhibit, PEF has invested approximately twice the cost of peaking units in order to incur lower operating costs for those generating units that will need to remain online well beyond peak demand periods.

Q. Is a weighting for energy responsibility of 50% an unusually high weighting by a utility for production capacity cost responsibility?

A. No, not at all. There are a number of utilities of which I am aware that employ a method called the "Average and Excess". This method effectively weights energy responsibility by the utility's load factor which is generally in the 50% to 60% range. The Commission also approved the "Equivalent Peaker" method applied inTampa Electric Company's Docket No. 850246-EI, which resulted in an energy weighting of 70%. There are a number of other recognized allocation methods such as "Probability of Dispatch" and "Base-Intermediate-Peaking" that effectively result in a similar weighting of energy responsibility. These latter methods require significant efforts to develop from hourly cost and load data and as a result are not often used. A 50/50 weighting is a good representation of the dual function that generating resources perform: (1) providing the demand capability to meet the Company's system peak loads, and (2) generating the energy needs of its customers throughout all hours of the year.

Q. Why did you prepare the "12 CP and 25 AD%" cost study method for inclusion in this filing?

A. I have included the "12 CP and 25% AD" study in this proceeding because it has been recommended by both PEF and TECO in recent years and is a worthy study method to include in this proceeding. First, this study method was recommended by PEF in each of the Company's prior two base rate proceedings in Docket No. 000824-EI and Docket No. 050078-EI. Second, this is the study method being proposed by TECO in their pending rate case in Docket No. 080317-EI. Although both PEF and TECO have recommended this method, it was viewed as a compromise between that of the Commission prescribed 1/13th energy weighting and that of the "Equivalent Peaker" resultant energy weightings of 50% for PEF and 70% for TECO.

Q. Do you have an exhibit that compares the results of the three allocated class cost of service studies which you have prepared?

A. Yes. My Exhibit No. ____ (WCS-4) provides a summary comparison that shows the allocated class cost of service resulting from each study and calculates the difference in base cost responsibility of the two additional studies to that of the Commission MFR's prescribed study method. The base cost of service differences are shown in dollars as well as the base rate effect on a dollars per thousand kWh basis for each rate class.

Q. Would the production capacity cost allocation method that the Commission chooses to rely on in this proceeding for base rate costs also apply to the allocation of capacity costs in any of the Company's cost recovery clauses?

A. Yes. The Commission's practice has been to use the same production capacity cost allocation method approved in a utility's last base rate case as the method to be employed for allocating any demand related costs in a utility's cost recovery clauses. For PEF, the production capacity allocation method is employed for (i) all recoverable costs of the Capacity Cost Recovery (CCR) clause (including Nuclear Cost Recovery), (ii) the demand classified recoverable costs of the Energy Conservation Cost Recovery (ECCR) clause, and (iii) the demand classified recoverable costs of the Environmental Cost Recovery Clause (ECRC). Therefore, any change in production cost allocation methodology resulting from this proceeding would be the method employed in these clause calculations effective on or after the institution of the Company's revised base rates. For purposes of determining the appropriate CCR, ECCR, and ECRC billing adjustments for inclusion in the billing comparisons contained in the MFRs of this filing, the billing adjustment factors for these clauses reflect the "12 CP and 1/13" method for present rate calculations and the "12 CP and 50% AD" method for proposed rate calculations.

V. Billing Determinants

Q. Would you explain the term "Billing Determinants" as it is used in ratemaking?

A. Yes. Billing determinants are those rate parameters or units of measurement of electric service by customers that, by application of the rate charges under the applicable rate schedules, produce the Company's billed revenue. Billing determinants include at a minimum a count of active customers and their kWh usage under each rate schedule. Additional billing determinants may be required in particular rate schedules that include measurements of kW demand, time of use, power factor, metering and delivery voltage, or other unique units of measurement for the services being rendered under the rate schedule.

Q. How did the Company derive the projected billing determinants for the test year that forms the basis for calculating the present revenues and proposed revenues being presented in this proceeding?

A. First, the starting point for deriving the billing determinants in this proceeding is the Company's Customer and MWH Sales Forecast for the 2010 calendar year test period. This forecast is described in the testimony of witness John B. Crisp. The forecast provides numbers of customers and MWH sales by revenue reporting classifications of residential, commercial, industrial, and sales to public authorities. From that forecast, the Company then develops a customer and sales forecast consisting of the Company's major rate schedules RS, GS, GSD, CS, IS, and LS. Next, actual billing determinants based on historic calendar year 2007 are summarized for each rate schedule to identify lines of billing, sales by delivery voltage, kW to kWh ratios, Time of Use rate relationships, and other rate parameters utilized in calculating customer billings. Lastly, these historic billing relationships are applied to the Company's projected 2010 customer and sales forecast by major rate class to derive the projected billing determinants for each rate schedule that correspond with the test year. These resultant calculations are the billing determinants being employed in

MFR Schedule E-13c and applied to present and proposed charges to produce the revenues attributable to each rate class as shown thereon.

VI. <u>Development of Target Class Revenues</u>

Q. Please describe generally the procedure used to determine the portion of the Company's total proposed base rate revenue increase assigned to each rate class.

The focus in determining the portion, or percentage, of the Company's proposed base rate revenue increase to be assigned to each rate class is the class cost of service study. For this purpose, the cost of service study utilizing the "12 CP and 50% AD" production capacity allocation method is relied upon. Ideally, the rates developed in a proceeding such as this will produce revenues from each of the rate classes that equal the costs allocated to that class by the cost of service study.

Therefore, the first step in determining how much each rate class should share in the Company's total revenue increase, *i.e.*, the shortfall between total revenue requirements and total revenues under current rates, is to determine for each rate class the shortfall between the costs allocated to that class and the revenues produced by applying current rates to the class's test year billing determinants. The next step is to determine how much of each class's revenue shortfall will be offset by additional revenues from any increase in other operating revenues, such as the increase in certain service charges proposed by the Company in this proceeding. Once the net revenue deficiency of each rate class has been determined, the final step is to identify whether any ratemaking policy considerations should limit the amount of any rate class's revenue increase. Where an increase limit is imposed on a rate class, the other rate classes must make up the deficiency. This deficiency resulting from limiting class increases is spread to the other rate classes in proportion to each of their deficiencies to the extent that their resultant increase does not exceed an imposed limit.

The completion of this three-step procedure produces what we refer to as the target revenues for each rate class. This is the sum for each class of its present revenues and its apportioned increase. These are the total class revenues the Company will attempt to produce through its design of proposed rate charges and their application to test year billing determinants.

Q. Have you prepared an exhibit that develops the proposed class target revenues from the procedure you have described?

A. Yes. My Exhibit No. ______ (WCS-5) was prepared for this purpose. In this proceeding, three of the rate class's revenue increases were limited as a result of recognizing the Commission's prior practice of limiting any individual class's increase to 150% of the overall percentage increase in the Company's total revenues. Increases for two of the classes, the CS/IS rate class and the Lighting – Energy sub-group rate class, are significantly limited by this practice. The third rate class, GSD, is being limited a very minor amount. In other words, the customers in the Curtailable and Interruptible class and the Lighting- Energy class actually should be bearing a larger percentage of the increase than that being proposed, but because of the practice established by this Commission, the customers in the Residential and General Service non-demand classes must bear a larger percentage of the increase.

VI. Rate Design

Q. Would you summarize the more significant rate design changes or revisions the Company is proposing to make to its Tariff in this proceeding?

A. Yes. The noteworthy proposed changes are as follows:

a. Most all base rate charges contained in the Company's rate schedules have been revised in order to produce the target class and total revenue requirements being sought in this proceeding.

b. The Customer Charge for Residential Service is designed to include the customer's transformer cost in addition to other normally included costs.

c. The Residential Time of Use Rate Schedule, RST-1, is being closed to existing customers.

d. The base rates and billing adjustment charges for general service interruptible service and curtailable service are being set the same.

e. The "closed" IS-1/CS-1 rate schedules are being eliminated and the affected customers transferred to their applicable "open" IS-2/CS-2 rate schedules.

f. The higher voltage delivery credits applicable in the general service demand metered rate schedules reflect the full avoided distribution costs rather than only the avoided transformation cost.

g. The Company is updating its service charges and adding the service charge for "Investigation of Unauthorized Use" to its Tariff.

Q. Why is the Company proposing to include the cost of a customer's transformer in the Residential Service's Customer Charge?

A. The Customer Charge is intended to recover those fixed costs that are independent of the level of a customer's usage. The transformer, like the residential customer's meter and service wire tap, are considered necessary facilities to be installed to make a customer electrically active and should more appropriately be recovered in a Customer Charge than in a usage charge.

Q. Is the Company making any other rate design changes to its Residential Service rate offerings?

A. The only rate design change the Company is seeking for residential service is to close its Residential Time of Use Rate Schedule, RST-1, to new customers. The Company has had little interest in this particular rate schedule and only 38 customers currently take service under this option. The Company plans to introduce in the near future a critical peak pricing rate schedule that is expected to attract more interest and be more effective than the current TOU rate. The Company does not feel it is worthwhile to offer the current TOU rate to any additional customers at this time.

Q. Is the Company making any rate design changes to its General Service Non-Demand Rate Schedules, GS-1 and GST-1?

A. No. As has been the practice since 1982, the base rate energy charges of these schedules are being set equal to that of the effective residential service rate to circumvent any potential administrative problem of residential customers claiming entitlement to the non-residential rate based on commercial activities in a residence.

Q. What changes are proposed for Rate Schedule GS-2, the Company's General Service 100% Load Factor rate?

A. The only change in this rate schedule is the revision of the Customer Charge and Energy and Demand Charge in order to produce the proposed target class revenues.

Q. What changes are proposed for Rate Schedules GSD-1 and GSDT-1, the Company's General Service Demand Rates?

A. As for most all the Company's rate schedules, the Customer Charge and the Energy and Demand Charges are being revised to produce the class's target revenues determined after taking into account (1) the amount of revenues from the proposed Firm Standby Service charges established by the cost of service study, and (2) the effect on revenues from proposed cost of service based changes in delivery voltage credits, power factor credits and charges, and premium distribution charges.

Q. Will the Company's proposed rate changes to its general service rate schedules result in any customers being transferred from one general service rate schedule to another?

A. Yes. Under the Company's proposed rates in this proceeding, it has been determined that approximately 7,500 general service customers, presently taking service under the General Service Demand (GSD) rates, would receive lower billings under the proposed General Service Non-Demand (GS) rates. This is due to the change in the pricing relationship between these rates resulting from different proposed percentage increases being applied. Under current rates and pricing relationships, the GSD rate is more advantageous for customers having average monthly load factors greater than 19%. Under the proposed rates, customers must have average monthly load factors greater than 28% to find the GSD rate to be more economically advantageous. Thus, the Company has recognized that current GSD customers having load factors between 19% and 28% need be transferred to the GS rate as being more economical under the Company's proposed rates.

If further rate revisions to the general service rates are given consideration in this proceeding, a similar analysis must be performed again to determine any change in the pricing relationship between these rates and the resulting change in billing determinants under each rate that would occur as a result of general service customers transferring to the most economic rate.

Q. Why are you treating the curtailable customers and interruptible customers as a combined rate class for establishing cost of service, base rates, and billing adjustments?

A. These customers are simply subsets of customers normally taking service under the Company's general service demand rate schedules. They differ only in that they are willing to subject their load to curtailment or interruption. However, the Commission has had a practice of recognizing these customers as separate rate classes from that of the general service demand rate class. Accepting that, the Company finds no reason to differentiate the curtailable customers from the interruptible customers for ratemaking other than provisions related to their non-firm service. Both groups possess non-firm load capability and only differ as to allowing the Company to control their non-firm load when needed or for the customer to adhere to a Company request to control their non-firm load. For this difference, the curtailable customers are provided a smaller credit than that provided for interruptible customers. In all other respects, the Company has set the base rate charges and billing adjustments the same in the curtailable and interruptible rate schedules and they are treated as one rate class in establishing their cost of service.

Q. Why is the Company proposing to eliminate its "closed" General Service Curtailable and Interruptible rate schedules?

A. The Company is proposing to bring an interim measure to final closure by the elimination of the curtailable and interruptible rate schedules that have been "closed" to new customers since April 1996. The Company will eliminate Rate Schedules CS-1, CST-1, IS-1, and IST-1and transfer the customers served under these rate schedules to the applicable CS-2, CST-2, IS-2, or IST-2 rate schedule. These rate schedules were previously "closed" by the Commission because they were no longer cost-effective. The Commission allowed the customers then served under the rate schedules to be grandfathered to avoid the possibility of hardship from their immediate transfer to comparable, but cost-effective rate schedules.

The customers affected by this elimination will continue to have the same quality of service and be subject to the same base rates and recovery clauses as they would have otherwise, and with some modifications, the same terms and conditions as they would have otherwise. The primary difference is that they will be subject to the application of the curtailable and interruptible demand credits established for the "open" schedule to which each will be transferred.

There are some differences and modifications required to the applicable "open" schedules to accommodate the transferred customers. The first relates to the time period of a required notice provision by a customer who may desire to transfer to a firm rate schedule. The new notice for the customer is actually less restrictive, that being 36 months, than the eliminated rate schedule which requires 60 months. The Company proposes to permit these transferred customers to use the less restrictive provision that is in the open rate schedules.

The second difference relates to the requirement of a minimum billing demand of 500 kW under the applicable rate to which the customer is being transferred. The Company has found that loads of less than 500 kW posed administrative problems and, in many instances, required customized interruptible equipment and metering installations which were not practical or cost effective. The Company is proposing that any transferred customer that has a demand less than the desired minimum be exempt from application of the proposed minimum monthly billing demand. This seems appropriate since the Company has already installed its interruptible equipment and metering for these customers.

A third difference relates to a limitation incorporated in the Applicability Clause of the CS-2, CST-2, IS-2, and IST-2 rate schedules for customer accounts established under any of these schedules after June 3, 2003. The customers establishing service after this date are limited to those premises at which an interruption or curtailment will not significantly affect members of the general public, nor interfere with functions performed for the protection of public health or safety. The Company is aware that certain of the customers proposed to be transferred to one of these schedules may not satisfy this limitation and proposes that the limitation not apply to them.

A final difference relates to the closed tariff's exclusion of curtailment or interruption of an affected customer's facility during periods of use as a public shelter. This exclusion is proposed to be added to the open tariffs as it applies only to these transferred customers.

Q. How were the charges for the "open" Curtailable and Interruptible rate schedules modified to produce the target revenue requirements for this class?

A. Similar to the GSD rate design, Customer Charges and Energy and Demand Charges are revised to produce the class's target revenues after taking into account (1) the amount of revenues from the proposed Curtailable and Interruptible Standby Service charges established by the cost of service study and (2) the effect on revenues from proposed cost of service based changes in delivery voltage credits, power factor credits and charges, and premium distribution charges. It was intended to increase Energy Charges and Demand Charges proportionally to provide a uniform percentage increase to customers within the class regardless of load factor. This appears to have been effectively accomplished as evidenced by the resultant similar percentage increases in revenues from Demand Charges as compared to increases in revenues from Energy Charges as shown in MFR E-13c for these rate schedules. However, the proposed Demand Charges as stated for secondary voltage service has the appearance of being increased at a much greater percentage. This development is necessary to recognize the large proportion of service being provided under these schedules at higher voltages. As was previously mentioned and will be discussed further in my testimony, the proposed delivery voltage credits afforded the higher voltage customers are much greater than the present delivery voltage credits. This revenue effect necessitates that the stated charge for secondary service reflect a much larger inclusion of distribution primary and secondary costs in the stated demand charge.

Q. By the elimination of the "closed" curtailable and interruptible rate schedules, all curtailable and interruptible customers are being

transferred to the corresponding "open" rate schedules and are subject to the credits provided for under these schedules. Has the Company reviewed the credits being provided for under the "open" rate schedules?

A. Yes. The credits provided for under the "open" rate schedules differ in two respects from those under the "closed" rate schedules. First, the level of the credit is lower, and second, the application of the credit to the customer's billing demand is different. The Company established both the level and application of the credits provided for in the "open" tariff as being cost effective in Docket No. 000824-EI. Some slight changes have been made to the level of the credits in more recent years when adjustments to the credits were included in base rate adjustments approved by the Commission. The Company believes the level of the credits under these "open" schedules continues to be cost effective, i.e. they do not exceed avoided capacity costs, and therefore are appropriate. The Company also believes that the application of the credits to a load factor adjusted billing demand under the "open" rate schedules more appropriately recognizes the expected demand capability of the customer at peak times than the rate design under the "closed" schedule which applies the credit to a customer's maximum billing demand whenever it occurs.

Q. Is the Company proposing to make any changes in the design and derivation of any of the optional Time of Use rate schedules or its Standby Service rate schedules?

A. No. The Company has designed these rate schedules in the same manner as has been prescribed by the Commission since their inception.

Q. You indicated that the development of delivery voltage credits to customers taking service at higher voltages under demand metered rate schedules is being changed. Would you describe the reason for this change?

A. Yes. This change is being made to provide a consistent treatment in rates with the allocation of costs in the cost of service study. Loads that take delivery at higher voltages, i.e. transmission or distribution primary, are not allocated any cost responsibility in the cost of service study for the lower voltage facilities for which they do not impose their loads on. Since rates are designed for application at the Company's lowest service voltage, i.e. distribution secondary, any customer taking higher voltage service should be credited with the lower voltage costs embodied in the rates for secondary service. This avoidance of lower voltage costs has previously been only partially recognized in the design of delivery credits. The previous design only recognized the avoidance of transformation costs included in the lower voltage costs and was remiss in not recognizing the avoidance of poles, lines, etc. that are also a part of lower voltage costs.

Q. What changes are being made to the Lighting Service Rate Schedule, LS-1?

A. The Company has revised the Customer Charge and the Energy and Demand Charge in order to produce the proposed target revenues for the

Energy sub-group of the Lighting Service rate class. Because the cost of service study shows the revenues from the Facilities sub-group adequately recover its cost of service, no change is being made to any of the fixture, pole, or maintenance charges.

VIII. Other Tariff Revisions

Q. What are the changes being made in the Company's Service Charges that resulted in additional revenue credits to the target class revenue requirements?

A. The Company has updated its service charges, which will produce additional revenues of approximately $4.1 million. PEF has also recognized specifically a service charge for "Investigation of Unauthorized Use" to be described in Rate Schedule SC-1, Service Charges. Revenues from service charges serve as a credit to offset a corresponding revenue requirement that would otherwise increase the Company's base rate charges.

IX. Summary of Class Proposed Rates of Return

Q. Do you have an exhibit that summarizes the Company's proposed class revenues and the class rates of return which would be realized by the Company's proposed rates and charges?

A. Yes. My Exhibit No. _____ (WCS-6) shows this information. The classes are at parity under the proposed rates to the extent the Company was able to accomplish this, considering the limitation recognized by the Company of not increasing any rate class by more than 150% of the total average percentage increase.

Q. Does this conclude your testimony?

A. Yes, it does.

MINIMUM FILING REQUIREMENT SCHEDULES
Sponsored, All or In Part, by William C. Slusser, Jr.

Schedule	Schedule Title
A-2	Full Revenue Requirements Bill Comparison - Typical Monthly Bills
A-3	Summary of Tariffs
A-5	Interim Revenue Requirements Bill Comparison - Typical Monthly Bills
B-1	Adjusted Rate Base
B-2	Rate Base Adjustments
B-6	Jurisdictional Separation Factors - Rate Base
B-13	Construction Work in Progress
B-15	Property Held for Future Use - 13 Month Average
B-17	Working Capital - 13 Month Average
C-1	Adjusted Jurisdictional Net Operating Income
C-2	Net Operating Income Adjustments
C-3	Jurisdictional Net Operating Income Adjustments
C-4	Jurisdictional Separation Factors - Net Operating Income
C-5	Operating Revenues Detail
C-13	Miscellaneous General Expenses
C-14	Advertising Expenses
C-15	Industry Association Dues
C-20	Taxes Other Than Income Taxes
E-1	Cost of Service Studies
E-2	Explanation of Variations From Cost of Service Study Approved in Company's Last Rate Case
E-3a	Cost of Service Study - Allocation of Rate Base Components to Rate Schedule
E-3b	Cost of Service Study - Allocation of Expense Components to Rate Schedule

MINIMUM FILING REQUIREMENT SCHEDULES
Sponsored, All or In Part, by William C. Slusser, Jr.

Schedule	Schedule Title
E-4a	Cost of Service Study - Functionalization and Classification of Rate Base
E-4b	Cost of Service Study - Functionalization and Classification of Expenses
E-5	Source and Amount of Revenues - at Present and Proposed Rates
E-6a	Cost of Service Study - Unit Costs, Present Rates
E-6b	Cost of Service Study - Unit Costs, Proposed Rates
E-7	Development of Service Charges
E-8	Company - Proposed Allocation of the Rate Increase by Rate Class
E-9	Cost of Service - Load Data
E-10	Cost of Service Study - Development of Allocation Factors
E-11	Development of Conincident and Noncoincident Demands for Cost Study
E-12	Adjustment to Test Year Revenue
E-13a	Revenue from Sale of Electricity by Rate Schedule
E-13b	Revenues by Rate Schedule - Service Charges (Account 451)
E-13c	Base Revenue by Rate Schedule - Calculations
E-13d	Revenue by Rate Schedule - Lighting Schedule Calculation
E-14	Proposed Tariff Sheets and Support for Charges
E-15	Projected Billing Determinants - Derivation
E-16	Customers by Voltage Level
E-17	Load Research Data
E-18	Monthly Peaks
E-19a	Demand and Energy Losses
E-19b	Energy Losses
E-19c	Demand Losses

MINIMUM FILING REQUIREMENT SCHEDULES
Sponsored, All or In Part, by William C. Slusser, Jr.

Schedule	Schedule Title
G-2	Interim Adjusted Rate Base
G-3	Interim Rate Base Adjustments
G-4	Interim Jurisdictional Separation Factors - Rate Base
G-5	Interim Working Capital - 13 Month Average
G-7	Interim Adjusted Jurisdictional Net Operating Income
G-8	Interim Net Operating Income Adjustments
G-9	Interim Jurisdictional Net Operating Income Adjustments
G-10	Interim Jurisdictional Separation Factors - Net Operating Income
G-20	Interim - Revenue from Sales of Electric by Rate Schedule
G-21	Interim - Revenue from Service Charges (Account 451)
G-22	Interim - Base Revenue by Rate Schedule Calculations
G-23	Interim Revenue by Lighting Schedule Calculation

PROGRESS ENERGY FLORIDA, INC
SUMMARY DEVELOPMENT OF FUNCTIONAL UNIT COSTS WITH PROPOSED REVENUE CREDITS
PROJECTED CALENDAR YEAR 2010 DATA: FULLY ADJUSTED
PRODUCTION CAPACITY ALLOCATION METHOD: 12CP & 50% AD

Line No.			-1 TOTAL RETAIL	-2 RESIDENTIAL (RS)	-3 GEN SERV NON DEM (GS-1)	-4 GEN SERV 100% LF (GS-2)	-5 GEN SERV DEMAND (GSD, SS-1)	-6 CURTAIL/ INTERR (CS, SS-3, IS, SS-2)	-7 LIGHTING (LS) ENERGY	-8 LIGHTING (LS) FACILITIES
	I.	COST OF SERVICE - (000'S)								
1	A	Production Capacity								
2		a. 12 CP Component	$ 389,047	$ 233,523	$ 12,742	$ 561	$ 122,938	$ 18,808	$ 475	$ -
3		b. AD Component	389,047	196,616	12,823	857	148,619	26,686	3,485	-
4		Total Prod Capacity	778,094	430,139	25,565	1,418	271,557	45,494	3,960	-
5	B	Production Energy	197,290	99,713	6,510	433	75,351	13,531	1,762	-
6	C	Transmission	198,540	119,167	6,500	285	62,753	9,600	244	-
7	D	Distribution Primary	317,760	198,192	11,254	346	93,219	11,875	2,892	-
8	E	Distribution Secondary	204,189	160,772	9,521	112	33,379	306	95	-
9	F	Distribution Services	73,984	65,748	5,240	511	2,445	2	28	-
10	G	Metering	37,407	25,205	3,989	179	7,654	354	24	-
11	H	Interruptible Equipment	408	-	-	-	-	409	-	-
12	I	Lighting Facilities	60,592	-	-	-	-	-	-	60,547
13	J	Customer Billing, Info, etc.	76,143	65,776	5,239	514	2,463	4	2,147	-
14		Rounding Adjustment (Tie to Juris & Class)	(4)	(13)	(1)	3	(10)	4	(7)	-
15		Total	$ 1,944,403	$ 1,164,699	$ 73,817	$ 3,801	$ 548,811	$ 81,579	$ 11,145	$ 60,547
16	II.	BILLING UNITS								
17	A	Number of Monthly Bills								
18		1. Metered Bills	19,640,980	17,467,887	1,387,218	122,394	654,400	1,862	7,219	-
19		2. Unmetered Bills	776,684	-	5,972	14,046	-	-	756,666	-
20		3. Total Bills	20,417,664	17,467,887	1,393,190	136,440	654,400	1,862	763,885	-
21		4. Total Bills with Secondary Service Tap	19,654,824	17,467,887	1,392,684	136,440	650,065	529	7,219	-
22		5. Total Bills with IS Equipment	1,778	-	-	-	-	1,778	-	-
23	B	Annual Effective MWH Sales		-	-	-	-	-	-	-
24		1. Production and Transmission Services	38,792,214	19,542,753	1,277,281	85,224	14,828,507	2,712,612	345,836	-
25		2. Distribution Primary Service	38,036,341	19,542,753	1,274,148	85,224	14,802,923	1,985,457	345,836	-
26		3. Distribution Secondary Service	33,869,817	19,542,753	1,265,675	85,224	12,499,183	131,146	345,836	-
27	C	Sum of Monthly Effective Billing KW		-	-	-	-	-	-	-
28		1. Production and Transmission Services	-	-	-	-	37,884,686	6,182,964	-	-
29		2. Distribution Primary Service	-	-	-	-	37,824,914	4,940,959	-	-
30		3. Distribution Secondary Service	-	-	-	-	33,141,848	340,723	-	-
31	E	12 CP - Allocator per Alloctor No. 1B	100.000%	60.02%	3.28%	0.14%	31.60%	4.83%	0.12%	-
32		Avg Demand - Allocator per Alloctor No. 1B	100.000%	50.54%	3.30%	0.22%	38.19%	6.86%	0.89%	-
		12 CP & 50% AD Allocator per Alloctor No. 1B	100.000%	55.29%	3.29%	0.18%	34.89%	5.85%	0.51%	-
33	III.	UNIT COSTS								
34	A	Customer Related Costs - $/Bill								
35		1. Metering (L. 8/L.17)	-	$ 1.44	$ 2.88	$ 1.46	$ 11.70	$ 190.12	$ 3.32	-
36		2. Customer Billing, Info, etc. (L. 13/L. 19)	-	$ 3.77	$ 3.76	$ 3.77	$ 3.76	$ -	$ 2.81	-
37		3. Secondary Service Tap (L. 9/L. 20)	-	$ 3.76	$ 3.76	$ 3.75	$ 3.76	$ 3.78	$ 3.88	-
38		4. Interruptible Equipment (L. 11/L. 21)	-	-	-	-	-	$ 230.03	-	-
39	B	Energy Related Costs - $/MWH								
40		1. Production Energy (L. 5/ L. 23)	-	$ 5.10	$ 5.10	$ 5.08	$ 5.08	$ 4.99	$ 5.09	-
41	C	Capacity Related Costs								
42		a. Based on MWH Sales - $/MWH								
43		1. Production Capacity 12CP (L. 2/L. 23)	-	$ 11.95	$ 9.98	$ 6.58	$ 8.29	$ 6.93	$ 1.37	-
44		2. Production Capacity 50% AD(L. 3/L. 23)	-	$ 10.06	$ 10.04	$ 10.06	$ 10.02	$ 9.84	$ 10.08	-
45		3. Transmission (L. 6/L. 23)	-	$ 6.10	$ 5.09	$ 3.34	$ 4.23	$ 3.54	$ 0.71	-
46		4. Distribution Primary (L. 7/L. 24)	-	$ 10.14	$ 8.83	$ 4.06	$ 6.30	$ 5.98	$ 8.36	-
47		5. Distribution Secondary (L. 8/L. 25)	-	$ 8.23	$ 7.52	$ 1.31	$ 2.67	$ 2.33	$ 0.27	-
48		Or								
49		b. Based on Billing KW Demand - $/KW/Month								
50		1. Production Capacity 12CP (L. 2/L. 27)	-	-	-	-	$ 3.25	$ 3.04	-	-
51		2. Production Capacity 50% AD (L. 3/L. 27)	-	-	-	-	$ 3.92	$ 4.32	-	-
52		3. Transmission (L. 6/L. 27)	-	-	-	-	$ 1.66	$ 1.55	-	-
53		4. Distribution Primary (L. 7/L. 28)	-	-	-	-	$ 2.46	$ 2.40	-	-
54		5. Distribution Secondary (L. 8/L. 29)	-	-	-	-	$ 1.01	$ -	-	-

Progress Energy Florida
Docket No. 090079-EI
Exhibit No.: _____(WCS-3)

Progress Energy Florida
Estimate of Alternative Resource Investment Required to Serve Peak Demand Only
as of 12/31/08

Line	Plant Name	(A) In Service Year	(B) Nameplate Capacity MW	(C) Actual EPIS Balance $0	(D) Estimated Alternative EPIS Balance $0	(E) Determination of Alternative Peaking Resource Cost
1	Steam					
2	Anclote Unit 1	1974	556.2		59,643	
3	Anclote Unit 2	1978	556.2	314,035	59,643	Per KW Capacity Cost Equivalent to Bayboro Peakers
4						
5	Bartow Unit 1	1958	127.5			
6	Bartow Unit 2	1961	127.5			
7	Bartow Unit 3	1963	239.4	125,654	125,654	No Viable Peaking Resource for In-Service Year
8						
9	Crystal River Unit 1	1966	440.5		65,717	
10	Crystal River Unit 2	1969	523.8	448,607	78,145	Per KW Capacity Cost Equivalent to Avon Park Peakers
11						
12	Crystal River Unit 3	1977	817.4	831,468	146,507	Per KW Capacity Cost Equivalent to DeBary Peakers
13						
14	Crystal River Unit 4	1982	739.3		130,601	
15	Crystal River Unit 5	1984	739.3	932,514	130,601	Per KW Capacity Cost Equivalent to Suwannee Peakers
16						
17	Suwannee Unit 1	1953	34.5			
18	Suwannee Unit 2	1954	37.5			
19	Suwannee Unit 3	1956	75.0	36,538	36,538	No Viable Peaking Resource for In-Service Year
20						
21	Combined Cycle					
22	Hines Energy Complex 1	1999	546.6		167,897	2004 Peaker Cost at $329/KW times H/W Index Ratio of .93
23	Hines Energy Complex 2	2003	548.2		182,738	2004 Peaker Cost at $329/KW times H/W Index Ratio of 1.01
24	Hines Energy Complex 3	2005	561.0		180,958	2004 Peaker Cost at $329/KW times H/W Index Ratio of .98
25	Hines Energy Complex 4	2007	610.0	1,076,008	241,845	2004 Peaker Cost at $329/KW times H/W Index Ratio of 1.21
26	Tiger Bay	1997	278.1	82,413	79,857	2004 Peaker Cost at $329/KW times H/W Index Ratio of .87
27	University of Florida	1994	43.0	23,387	11,685	2004 Peaker Cost at $329/KW times H/W Index Ratio of .83
28						
29	Combustion Turbine					
30	Avon Park Peakers 1-2	1968	67.6	10,082	10,082	Actual Peaking Resource
31	Bartow Peakers 1-4	1972	222.8	27,368	27,368	Actual Peaking Resource
32	Bayboro Peakers 1-4	1973	226.8	24,321	24,321	Actual Peaking Resource
33	DeBary Peakers 1-10	1975-76, 92	861.2	154,350	154,350	Actual Peaking Resource
34	Higgins Peakers 1-4	1969-1971	153.4	19,015	19,015	Actual Peaking Resource
35	Intercession City Pkrs 1-14	1974,93,97,00	1,255.3	254,103	254,103	Actual Peaking Resource
36	Rio Pinar Peaker 1	1970	19.3	3,567	3,567	Actual Peaking Resource
37	Suwannee Peakers 1-3	1980	183.6	32,434	32,434	Actual Peaking Resource
38	Turner Peakers 1-4	1970-74	181.0	25,809	25,809	Actual Peaking Resource
39						
40	Total Production Plant			4,421,674	2,249,078	
41						
42						
43	**Percentage of Actual Resource Investment Made to Serve Peak Demand Only**			=	**50.9%**	(2,249,078 / 4,421,674) x 100%
44	**Percentage of Actual Resource Investment Made For Other Reasons**			=	**49.1%**	((4,421,674 - 2,249,078) / 4,421,674) x 100%

PROGRESS ENERGY FLORIDA
COMPARISON OF CLASS ALLOCATED COST OF SERVICE STUDY RESULTS
TEST PERIOD: PROJECTED CALENDAR YEAR 2010
$000's

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
						Difference 25% to 1/13th AD			Difference 50% to 1/13th AD		
Line No.	Rate Class	Rate Schedules	Base Rate Cost of Service 12 CP and 1/13th AD	Base Rate Cost of Service 12 CP and 25% AD	Base Rate Cost of Service 12 CP and 50% AD	$ (B) - (A)	% (D) / (A)	Base Rate Effect $/MWH	$ (C) - (A)	% (G) / (A)	Base Rate Effect $/MWH
1	Residential	RS-1, RSL-1, RST-1	$ 1,199,578	$ 1,186,769	$ 1,168,308	$ (12,809)	-1.1%	$ (0.66)	$ (31,270)	-2.6%	$ (1.60)
2											
3	General Service	GS-1, GST-1, GSLM-1	74,030	74,060	74,105	30	0.0%	$ 0.02	75	0.1%	$ 0.06
4	Non-Demand										
5											
6	General Service	GS-2, GSLM-2	3,580	3,682	3,829	102	2.8%	$ 1.20	249	7.0%	$ 2.92
7	100% Load Factor										
8											
9	General Service	GSD-1, GSDT-1, SS-1	527,219	536,106	548,945	8,887	1.7%	$ 0.60	21,726	4.1%	$ 1.47
10	Demand										
11											
12	Curtailable/Interruptible	CS-1, CST-1, CS-2,	74,912	77,644	81,579	2,732	3.6%	$ 1.01	6,667	8.9%	$ 2.46
13		CST-2, SS-3, CS-3, CST-3									
14		IS-1, IST-1, IS-2, IST-2									
15		SS-2									
16											
17											
18	Lighting										
19	Energy	LS-1	8,594	9,637	11,146	1,043	12.1%	$ 3.02	2,552	29.7%	$ 7.38
20	Facilities	LS-1	60,547	60,547	60,547	-	0.0%		-	0.0%	
21											
22											
23	Rounding Adj (tie to Jurisdictional Study)		3	18	4	15			1		
24											
25	Total Retail		$ 1,948,463	$ 1,948,463	$ 1,948,463	$ -	0.0%		$ -	0.0%	

Progress Energy Florida
FPSC Docket No. 090079-EI
Exhibit No.: ______ (WCS-5)

PROGRESS ENERGY FLORIDA
TEST PERIOD: PROJECTED CALENDAR YEAR 2010
DEVELOPMENT OF TARGET PROPOSED REVENUE INCREASE BY RATE CLASS
Dollars in 000's

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
						Net Revenue Deficiency		Target Proposed Revenue Increase *		Target Proposed Class Revenue
Line	Rate Class	Cost of Service 12 CP & 50% AD	Present Class Revenue	Revenue Deficiency (A) - (B)	Additional Revenue Credits	$ (C) - (D)	% (E) / (B)	$	%	(B) + (G)
1	I. Residential (RS)	$ 1,168,308	$ 900,586	$ 267,722	$ 3,609					
2										
3	II. General Service	74,105	64,691	9,414	288					
4	Non-Demand (GS-1)									
5										
8	Sub-Total: I. + II.	$ 1,242,413	$ 965,277	$ 277,136	$ 3,896	$ 273,240	28.31%	$ 279,146	28.92%	$ 1,244,423
9										
10										
11	III. General Service 100%	3,829	2,639	1,190	28	1,162	44.01%	1,187	44.96%	3,826
12	Load Factor (GS-2)									
13										
14										
15	IV. General Service	548,945	365,172	183,773	134	183,638	50.29%	187,544	51.36%	552,716
16	Demand (GSD, SS-1)									
17										
18										
19	V. Curtailable/Interruptible	81,579	48,403	33,176	0	33,176	68.54%	24,859	51.36%	73,261
20	General Service (CS/IS)									
21										
22										
23	VI. Lighting (LS)									
24	A. - Energy	11,146	6,225	4,921	1	4,919	79.03%	3,197	51.36%	9,422
25	B. - Facilities	60,547	60,750	(203)	0	(203)	-0.33%	0	0.00%	60,750
26										
27										
28	Total	$ 1,948,459	$ 1,448,466	$ 499,993	$ 4,060	$ 495,932	34.24%	$ 495,932	34.24%	$ 1,944,399
	Rounding Adj to Juris	4								
	Total COS	$ 1,948,463								

(*) Allocation of proposed revenue increase to rate classes:

- For Rate Classes I. and II. - Rate Classes have been combined due to application of same rate charges to each class.
- For Rate Classes V. and VI.A. - Percentage increase set at one and one half times system average per Commission Policy.
- For Rate Class IV., - Percentage increase limited to one and one half times system average per Commission Policy.
- For Rate Class VI.b. - in accordance with Commission Policy, class revenue not reduced in a rate increase proceeding.
- For Rate Classes (i) Combined Classes I and II and (ii) Class III - Remaining revenue deficiency allocated in proportion to each class's revenue deficiency.

Progress Energy Florida
FPSC Docket No. 090079-EI
Exhibit No.: _____ (WCS-6)
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PROGRESS ENERGY FLORIDA
TEST PERIOD: PROJECTED CALENDAR YEAR 2010
SUMMARY OF PROPOSED CLASS REVENUES AND CLASS RATES OF RETURN
Dollars in 000's

Line	Rate Class	(A) Present Revenues: Sales Revenue	(B) Present Revenues: Revenue Credits	(C) Present Revenues: Total Class Revenue (A) + (B)	(D) Proposed Incr / (Decr): Sales Revenue	(E) Proposed Incr / (Decr): Revenue Credits	(F) Proposed Revenues: Sales Revenue (A) + (D)	(G) Proposed Revenues: Revenue Credits (B) + (E)	(H) Proposed Revenues: Total Class Revenue (F)+(G)	(I) Cost of Service 12CP & 50% AD with Proposed Rev Credits	(J) Class Revenue Requirement Index (H) / (I)	(K) Rate of Return at Proposed Rates	(L) Rate of Return Index (K) / total (K)
1	Residential (RS)	$ 900,586	$ 50,978	$ 951,564	$ 258,575	$ 3,609	$ 1,159,161	$ 54,587	$ 1,213,748	$ 1,164,699	1.04	9.12%	0.99
2													
3	General Service	64,691	3,498	68,189	20,600	288	85,291	3,786	89,077	73,817	1.21	12.27%	1.33
4	Non-Demand (GS-1)												
5													
6	General Service 100%	2,639	243	2,882	1,186	28	3,826	271	4,097	3,801	1.08	9.35%	1.01
7	Load Factor (GS-2)												
8													
9	General Service	365,172	12,543	377,715	187,492	134	552,665	12,677	565,342	548,811	1.03	9.34%	1.01
10	Demand (GSD)												
11													
12	Interruptible(IS)/Curtailable (CS)	48,403	1,490	49,893	24,872	-	73,275	1,490	74,765	81,579	0.92	7.28%	0.79
13	General Service												
14													
18	Lighting (LS)												
19	- Energy	6,225	233	6,458	3,198	1	9,423	234	9,657	11,145	0.87	5.40%	0.59
20	- Facilities	60,750	470	61,220	-	-	60,750	470	61,220	60,547	1.01	9.30%	1.01
21													
22													
23	Total	$ 1,448,466	$ 69,455	$ 1,517,921	$ 495,924	$ 4,060	$ 1,944,390	$ 73,515	$ 2,017,905	$ 1,944,399	1.04	9.21%	1.00