BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Progress Energy Florida, Inc.	Docket No. 050078-EI Submitted for filing: April 29, 2005

DIRECT TESTIMONY OF

WILLIAM C. SLUSSER, JR.

On behalf of Progress Energy Florida

R. Alexander Glenn
James A. McGee
Progress Energy Service Company, LLC
Post Office Box 14042 (33733)
100 Central Avenue (33701)
St. Petersburg, Florida
Telephone: 727-820-5184
Facsimile: 727-820-5519

And

Gary L. Sasso
James Michael Walls
John T. Burnett
Carlton Fields
Post Office Box 3239
4221 West Boy Scout Bouelvard
Tampa, Florida 32607-5736

Attorneys for
PROGRESS ENERGY FLORIDA

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 in the state of Florida during my career until recently when I acquired a retired status. I retired from Florida Power Corporation in January 2001, after 36 years of service where I devoted most of my career to allocated cost of service and rate design matters. I have been retained by PEF since my retirement as a consultant on allocated cost of service and rate design matters in the Company's prior base rate proceeding, Docket No. 000824-EI, and now in this proceeding.

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 2006 test 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 present two retail Allocated Class Cost of Service and Rate of Return studies for the test period, each study differing primarily as to the method for allocating fixed production capacity costs among the Company's retail rate classes. The first study employs a method that allocates production capacity costs based on each class's 12 monthly coincident peak demands weighted by 12/13th and its average demand, or energy usage, weighted by 1/13th which is called the "12 CP and 1/13 AD" method. I have provided a study employing this method to satisfy the study specified by the Commission's Minimum Filing Requirements ("MFRs"). However, I am recommending that the Commission rely upon my second study, which allocates production capacity costs using what I call the "12 CP and 25% AD" method, for establishing each rate class's cost of service and, thus, the amount of revenues each class should produce as a result of this proceeding. 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 total retail revenue requirements.

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 Rates 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 schedules are true and accurate, subject to their being updated in the course of this proceeding.

Q. Are PEF's Jurisdictional Separation Study, Allocated Class Cost of Service Studies, and 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, however, that the Jurisdictional Separation Study and the two 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 wholesale business and its retail business. This separation of costs between the two businesses is based on accepted mathematical factors representing appropriate customer, capacity, and energy 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 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 a further allocation of the costs initially allocated to the retail jurisdiction among the individual retail rate classes. The results of this further retail allocation form the cost basis for establishing revenue requirements attributable to each rate class. One of the most important considerations in undertaking this type of study arises from the fact that the costs allocated to each rate class are heavily dependent upon the method employed by the study for the allocation of fixed production capacity costs. The production capacity cost allocation method recommended by PEF is called the "12 CP and 25% AD" method. Simply stated, this method allocates 75 percent of the Company's production capacity costs based on the 12 monthly coincident peak demands of a rate class and 25 percent of these costs based on the class's annual energy usage. As I explain later in my testimony, allocating 25 percent of production capacity costs on the basis of energy usage, instead of about 8 percent under the 12 CP and 1/13 AD method previously employed by the Commission, is intended to provide a better recognition of the enormous investment made in generation plant to achieve lower operating costs, *i.e.*, fuel savings. The Company's recommended method represents a reasonable middle ground between competing cost allocation approaches that allocates little or no production capacity based on energy responsibility at one extreme, and at the other extreme, that allocates the full amount of capacity investment made to achieve fuel savings on an energy basis, which in PEF's case is estimated to be approximately 50 percent.

With respect to rate design, PEF is not proposing any major rate structure or rate design changes. In keeping with Commission policy, the Company has proposed to limit the percentage revenue increase for a number of rate classes to 1-1/2 times the overall percentage increase. In addition, the Company has proposed the elimination of its Rate Schedules' IS-1 and IST-1, Interruptible General Service, and CS-1 and CST-1, Curtailable General Service, which have been closed to new customers since early 1996. The customers taking service under these rate schedules would be transferred to the Company's corresponding cost-effective interruptible or curtailable rate schedule, IS-2, IST-2, CS-2, or CST-2, which were established in the first place to accommodate new interruptible and curtailable customers when the grandfathered rates were closed to new customers almost 10 years ago.

III. <u>Jurisdictional Separation Study</u>

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 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 wholesale and retail jurisdictions. 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 been 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 Javier Portuondo provides the basic system cost of service information. This data is organized by primary FERC accounts and is classified or assigned into functional groupings for allocation purposes. The data represents the fully adjusted data for the test period. The factors developed for allocating system costs are predominately based on load data 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.

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. I consider it extremely important to utilize procedures and methodologies that are consistent with the regulatory practices of both this Commission and the FERC, and have endeavored to do so for each of the many separation studies I have prepared for the Company over the years. 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 in a comparable manner. Significantly, both commissions have relied upon 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 FERC staff provides a computerized cost allocation model which is intended to be utilized for rate filings before the FERC. The Company has elected to use this same model in this proceeding. The FERC model is somewhat limited in the number of line items it can accommodate, and therefore it is necessary to group certain FERC accounts for input into the model. This grouping process is referred to as "Cost Assignments to Allocation Categories" and is fully included in the MFR volume containing the Jurisdictional Separation Study.

Q. What type customers comprise the Company's separated wholesale business during the test period?

A. The Company provides full requirements service to the Cities of Bartow, Mt. Dora, Quincy, Chattahoochee, and Williston. Partial requirements service is provided to the Florida Municipal Power Agency, New Smyrna Beach Utilities Commission, and the City of Tallahassee. 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, and Reedy Creek Improvement District.

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

A. Yes. It warrants mentioning, however, that the cost responsibilities for the wholesale full requirements and partial requirements sales, and for that of the retail business, are based on average, overall production embedded costs. By comparison, the cost responsibilities for stratified wholesale sales are based on the average embedded costs of the particular resource type or types of production resources, i.e. base, intermediate, or peaking, used to make these sales. The costing treatment that has been established in the Jurisdictional Separation Study is intended to be consistent with the treatment of stratified sales by the Company in its fuel cost recovery proceedings that establish the fuel charge on the bills of retail customers. That is, cost responsibilities are first determined and assigned to the stratified sales customers based on their respective type of production resource or resources. These costs are then subtracted from the Company's total costs to derive the average rate customers cost responsibility.

In addition, when developing the capacity portion of production costs to be assigned to the stratified rate customers, ratios for each stratification are calculated by dividing the average 12 CP load of stratified customers by the total average monthly system stratified resource capability adjusted for reserves. These ratios result in a specific capacity cost responsibility, expressed as a percentage for the type of generation resource required by each of the stratified customers. The remaining cost responsibility for the stratified resources is allocated to the average rate customer classes based on their 12 CP demands. This development is contained in the "Development of Input Allocation Factors" section of the separate MFR volume entitled "Jurisdictional Separation Study."

When developing the energy portion of production non-fuel costs to be assigned to stratified customers, direct assignments are calculated for stratified customers by applying per-unit energy costs by resources to stratified customer sales. These assignments are contained in the production O&M cost assignments section of the Jurisdictional Separation Study.

Similarly, all the various system production costs (plant-in-service, accumulated depreciation, fuel inventories, operation and maintenance expenses, and depreciation expenses) have been stratified within the separation study in order to appropriately assign the appropriate cost responsibility to the stratified customers.

Q. Have you applied any other different costing treatments 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 proportional requirements of 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 7.5% of the production, 28.6% of the transmission, 0.2% of the distribution, and 7.6% of the general plant investment of the Company. The wholesale business requires a proportionally higher investment in transmission plant relative to production plant due to the fact that (1) certain wholesale customers embedded in the system have acquired production resources from suppliers other than PEF which are delivered to these customers utilizing the Company's transmission system, and (2) certain wholesale transactions represent a transmission of power out of, into, or through the Company's system. The wholesale business requires very little distribution investment since most wholesale power is either received or delivered at points connected to the Company's transmission system.

IV. Class Allocated Cost of Service and Rate of Return Studies

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 within the retail jurisdiction. The study provides: (1) class realized rates of return at present and proposed rates, (2) class revenue surplus or deficiencies from full cost of service, and (3) functional unit cost information for rate design consideration. 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.

As with the separation study, the FERC cost model was utilized to perform the cost allocations to retail rate classes. To obtain the functional cost information required by the Commission's MFRs, additional model runs were 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. Rate schedules serving either, (i) optional time of use, (ii) load management service, or (iii) standby service, have 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 General Service (CS)

(6) Interruptible General Service (IS), and

(7) 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 classes' revenue requirements 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. I have provided a summary of the functional cost of service for each rate class and their respective unit costs in my Exhibit No. _____ (WCS-2). The production capacity costs in this exhibit are based on the 12 CP and 25% AD allocation method that I will describe below. 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 that I describe later in the rate design section of my testimony.

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 two allocated class cost of service studies were prepared for this proceeding which differ primarily by the method employed to allocate production capacity costs. Would you describe the two production capacity cost allocation methods that you have employed?

A. Yes. The Commission's MFRs require at least one cost of service study to be provided that allocates production and transmission 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 has been the method most often relied upon by the Commission in previous rate cases involving the four major investor-owned electric utilities in Florida. It allocates 12/13, or about 92 percent, of production capacity costs on the basis of class average monthly coincident peak demands, and 1/13, or about 8 percent of production capacity costs on the basis of class average hourly demands, which is the equivalent of class annual energy consumption. PEF believes that an energy weighted allocation of only 8 percent under this method gives too little recognition to the important role energy considerations play in determining production capacity costs. For this reason, I have prepared an additional study to recognize the greater extent that energy responsibility should bear in allocating the Company's total production capacity costs among the rate classes. I have chosen 25 percent as a reasonable allocation of these costs to be made on the basis of class energy responsibility in this additional study, which I refer to as the 12 CP and 25% AD method.

Q. Does your additional study utilizing the 12 CP and 25% AD method incorporate any other differences from the retail Class Allocated Cost of Service Study required by the MFRs?

A. Yes, there is one other allocation difference related to transmission costs. The study required by the MFRs allocates both production and transmission capacity costs using the 12 CP and 1/13 AD method. The Company's recommended study applies the 12 CP and 25% AD method only to the allocation of production capacity costs; transmission capacity costs are allocated fully on the average of the classes' 12 monthly coincident peaks, the 12 CP method. Unlike production costs, the Company does not believe that energy requirements are a significant consideration or factor in determining the costs of transmission plant. Furthermore, in the event a Regional Transmission Organization is developed for Florida participation, it is expected that the transmission users' cost responsibility will be assessed on a 12 CP basis. The Company believes and supports this method as an appropriate measure for transmission cost responsibility and therefore has employed this method in its recommended study in this proceeding.

Q. Mr. Slusser, would you explain why PEF believes that energy utilization should be given a greater weighting than 8 percent for allocating production capacity cost responsibility among its retail rate classes?

A. Yes. The primary reason is because PEF has made a considerable investment in production plant for reasons other than simply meeting peak demand. I have prepared Exhibit No.___(WCS-3) that provides an estimate of the additional investment expended by PEF in this regard for its existing generating fleet. 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. Allocating more than 8 percent of production capacity costs on an energy basis assigns more of this additional investment to classes with relatively high energy usage in recognition of the fact that these classes receive more of the benefit produced by the additional investment, in the form of lower fuel charges for each unit of energy consumed.

PEF also believes that this proceeding provides an especially timely opportunity to recognize the consideration that energy usage has had in the Company's generation decisions. The most recent capacity additions on the Company's system consist of two combined-cycle units at its Hines Energy Complex with a total capacity of approximately 1,000 MW. Another 500 MW combined-cycle unit is scheduled for commercial operation at the Hines site in December 2005. These combined-cycle units are complex, state-of-the-art technology types of generating plants which provide considerably more benefits, and require considerably more investment, than the capacity needed to simply meet the Company's reliability requirements; they provide tremendous improvements in generating efficiency and substantial fuel savings that result from this efficiency. These units were justified as the Company's next capacity additions by satisfying its reliability criteria while providing the lowest revenue requirements. PEF considers it to be both fair and consistent with sound allocation principles for its customers to pay for the higher capital costs invested in these units to achieve operating efficiencies in the same proportion that customers benefit from the fuel savings these efficiencies provide.

Q. Why is PEF proposing that average demand be weighted specifically by 25 percent?

A. Although PEF could justify an average demand weighting of as much as 50% based on the estimate of the additional investment shown in Exhibit No.__(WCS-3), the use of a 25 percent energy allocation factor is intended to represent a reasonable middle ground between the inadequate recognition of energy responsibility in the 12 CP and 1/13 AD method and a full recognition under capital substitution principles. As such, an increase in the weighting of energy usage to 25 percent is a significant improvement toward the allocation of energy-driven capacity costs to classes in closer proportion to the energy-based benefits the classes receive from those costs.

Q. Do you have an exhibit that compares the results of the two 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 between the two studies for each rate class. The exhibit also quantifies the effect on allocated costs of the two allocator differences employed in these studies, i.e. the production allocation factor difference and the transmission allocation factor difference.

Q. Has the Commission previously deviated from the 12 CP and 1/13 AD method for establishing class production capacity cost responsibility in a base rate proceeding?

A. Yes. The Commission relied upon the so called Equivalent Peaker method in Docket No. 850246-EI, a Tampa Electric Company base rate proceeding. This method is comparable to PEF employing a 50% average demand weighting in this proceeding.

In addition, when the allocation of costs for new nuclear units placed in service by PEF and Florida Power and Light Company were considered in Docket Nos. 770316-EU and 830465-EI, respectively, the Commission decided to allocate a portion of each unit's fixed costs equal to its fuel savings on an energy basis to recognize the magnitude of the savings afforded by the investment in such units. The Commission reasoned that since the fuel cost savings of a nuclear unit flow through to customers on an energy basis through the fuel clause, at least that amount of fixed costs should be recovered in base rates on a similar energy basis.

V. Development of Target Class Revenues

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.

A. The starting point 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 25% AD production capacity allocation method was 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. In this proceeding, several rate classes fall within the scope of the Commission's established policy of limiting the increase to any individual rate class to 150% of the overall percentage increase in the Company's total revenues.

The completion of this three-step procedure produces what we refer to as the target revenues for each rate class. These are the total class revenues the Company will attempt to produce through its revised base rate charges, which are determined by applying test year billing determinants to these total class revenues.

Q. How did the Company derive the projected billing determinants for the test year that were used in this procedure to determine the rate classes' current revenues and proposed rates?

A. The projected rate class billing determinants rely on the relationships between the actual number of bills, kWh sales, and kW billing demand recorded for each rate schedule during calendar year 2003. These actual relationships were applied to the Company's projected 2006 sales forecast by major rate class to derive the projected test year billing determinants for each rate schedule. The 2006 kWh sales forecast is described in the testimony of John B. Crisp. Billing determinants from 2003 were relied upon rather than those from 2004 due to the distorted and abnormal usage characteristics that resulted from the extraordinary hurricane season in 2004. The test year billing determinants derived from this process are included in MFR Schedule E-13c.

Q. Have you prepared an exhibit that sets out the procedure you have described to develop the target revenue increases for each of the Company's rate class?

A. Yes. My Exhibit No. _____(WCS-5) was prepared for this purpose.

Q. Would you explain this exhibit?

A. Certainly. The exhibit lays out the procedure I described numerically from left to right in columns (A) through (I). The rate classes' allocated cost of service developed in the 12 CP and 25% AD cost study is shown in column (A). This is compared to the classes' revenues under current rates in column (B), which yields the class revenue deficiency by difference in column (C). These revenue deficiencies are then reduced by crediting the additional revenues allocated to each class from the Company's proposed increases in service charges shown in column (D), resulting in the classes' net revenue deficiencies expressed monetarily in column (E) and as a percentage in column (F). This column also shows that the average of all class revenue deficiencies, *i.e.*, the overall revenue increase required, is 13.83%, with all rate classes exceeding the average revenue deficiency except residential and general service non-demand. The next two columns, (G) and (H), show the effect of the Commission's policy of limiting increases to individual rate classes to no more than 1½ times the system average increase. In the Company's case, this policy equates to a limitation of 20.74 percent (13.83% x 1.5). Column (H) shows that this limitation applies to all of the rate classes except for the Residential and General Service Non-Demand classes. For reasons I will discuss below, the Company has incorporated another constraint which further limits the class percentage revenue increase for the Lighting Facilities class. The target revenue increases for the Residential and General Service Non-Demand classes were raised above their stand-alone net revenue deficiencies to 10.71%. This was the result of allocating to these two classes, consistent with the Commission's increase limitation policy, the portion of the other classes' revenue deficiency that could not be targeted because of the policy. The final effect of the target increase procedure is the total revenue requirements to be collected from each rate class, which are shown in Column (I).

Q. What were the service charge increases that provided the additional revenue credits to the target revenue increases for the rate classes?

A. The Company has identified the need for an increase in three of its service charges, which would produce additional revenues of $8.2 million. These additional revenues will serve as a credit to offset a corresponding revenue requirement that would otherwise increase the Company's base rates.

The first increase relates to charges for providing temporary service connections. Currently, a customer is assessed a service charge of $104.00 for the cost of installing and removing a temporary service extension where such extension is requested and can be provided by a service drop or connection point to the Company's existing distribution system. The Company's analysis has determined that the actual cost to provide such an extension is currently $227.00. The Company has therefore proposed that the temporary service charge be adjusted to this amount, which will produce an additional annual revenue credit estimated to be $1.9 million.

The second concerns the returned check service charge. The proposed increase is based on the same level of increase for returned checks in other circumstances provided by a recent revision to Section 68.065, Florida Statutes. The Company estimates this increase will result in an additional annual revenue credit of approximately $300,000.

The third service charge which the Company proposes to revise is its late payment charge. The Company currently assesses a 1.5% charge on past due unpaid account balances, except on the accounts of governmental entities. The Company's proposal would include a minimum charge of $5.00 to provide a more meaningful deterrent to late payments, which the Commission has previously authorized for other utilities. This revision will increase the annual revenue credit by an estimated $6.0 million.

The Company believes its other service charges, which were adjusted in the 2002 rate settlement approved by the Commission in Docket No. 000824-EI, remain at a reasonable and compensatory level.

VI. Rate Design

Q. What were PEF's rate design objectives in developing the proposed rates and charges submitted in this proceeding?

A. The first objective, of course, is to establish proposed charges for each rate schedule such that their application to the test year billing determinants produces the target class revenues. Second, the Company does not intend to make any major rate design or rate structure changes to its tariff. The Company believes its rate structure is reasonable, equitable, and generally acceptable by its customers. Third, the Company seeks to continue the historically developed methodologies of establishing the charges for affiliate and optional rate schedules consisting of Time-of-Use and Stand-by Rate Schedules. Fourth, the Company finds that it is appropriate in this proceeding to propose the elimination of particular "closed" and "grandfathered" General Service Interruptible and Curtailable rate schedules and transfer the customers under these schedules to an applicable "open" Interruptible or Curtailable rate schedule. Lastly, the Company is pursuing some changes in the offerings and terms and conditions of its Lighting Service Rate Schedule and limiting the magnitude of the proposed increases of certain facility offerings.

Q. What changes are being proposed for the Company's residential rate schedules, RS-1, RST-1, RSL-1, RSL-2, and RSS-1?

A. The changes being proposed for residential service are simply increases to the per kWh energy and demand charges in order to derive the residential class's proposed target revenues. These changes are consistent with the

Company's objective to make no major rate design revisions. That is, the Company is proposing to maintain for its regular rate the same two-step inverted rate design with the 1000 kWh inversion point and one cent price differential. In addition, the Time of Use (TOU) rate design is intended to be the same design as historically developed.

The customer charges in the residential rate schedules remain at the existing level with two exceptions. First, regarding the TOU customer charge in Rate Schedule RST-1, with on-going changes and capabilities of electronic metering, the Company finds it is no longer necessary to distinguish the cost of single-phase and three-phase TOU metering in the charge. This distinction has been eliminated for the secondary delivery customer charges with the existing single-phase charge now applying to both single and three-phase secondary delivery.

The second proposed change relates to the customer charge for optional seasonal service Rate Schedule, RSS-1. The customer charge for this service is intended to provide an incentive for a seasonal customer to maintain active service during their absence by setting the accumlated customer charges at a level below the cost of the reconnection charge the customer would otherwise incur upon return. The desired relationship between the cost of this customer charge and the cost of the Company's reconnect charge was not maintained when the Company increased its reconnection charge from $15 to $28 in Docket No. 000824-EI. To re-establish the intended relationship with the reconnection charge, the monthly seasonal customer charge has been set at $4.20.

Q. What changes are proposed for Rate Schedules GS-1 and GST-1, the Company's General Service Non-Demand rates?

A. Since the kWh energy charges in these rate schedules are intended to be equivalent to the levelized energy kWh charges for residential service, the revisions proposed in this proceeding track those of the residential class.

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 an increase in the energy and demand charge 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. The energy and demand charges for these rate schedules were 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. The existing customer charges and equipment rental charges were determined to be adequate compared with cost of service.

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, about 2,000 General Service Demand (GSD) customers would receive lower billings under the General Service Non-Demand (GSND) rates. This is because the proposed GSND rates will receive a lower percentage increase than the proposed GSD rates. Currently, GSD rates are advantageous compared to GSND rates at load factors of 22% or greater. With the GSND rate's lower percentage increase, this break-point has risen to 25%, which means that the approximately 2,000 GSD customers with a load factor between 22% and 25% will benefit from service under the GSND rate. Since the Company will automatically transfer these customers to the lower GSND rate, this transfer has been simulated in the revenue billing calculations included in the MFRs.

If further rate revisions to the general service rates are given consideration in this proceeding, I would request that the Company be allowed to test any such revisions for similar migration effects. Where migration is likely to occur, the billing determinants for the affected rate schedules should be revised to reflect the post-migration effect. This can sometimes involve a laborious iterative process, but it is nonetheless essential to undertake this effort before the final general service rate charges are established in order to avoid potentially serious unintended consequences.

Q. What changes are proposed by the Company for its General Service Interruptible and Curtailable rate schedules?

A. In general, the Company revised the charges in these schedules in the same manner as it has proposed for its General Service Demand rate schedules. The major change to the tariff for these rate classes is the proposed elimination of the curtailable and interruptible rate schedules that have been closed to new customers since April 1996. Also, as a housecleaning item, the Company proposes to revise the language of the following items to achieve consistency with the wording of comparable provisions contained in other of the Company's rate schedules: (1) Special Provision No. 4 of Rate Schedules IS-2 and IST-2, and (2) the Metering Voltage Adjustment and Power Factor clauses of Rate Schedules CS-3 and CST-3.

Q. Please elaborate on your reference to the Company's proposal for eliminating certain curtailable and interruptible rate schedules.

A. The Company has proposed to complete the closure and withdrawal of its general service interruptible and curtailable Rate Schedules IS-1, IST-1, CS-1, and CST-1, and transfer the remaining customers served under these rate schedules to the applicable IS-2, IST-2, CS-2, or CST-2 rate schedule. These rate schedules were closed by the Commission in April 1996 to all but existing customers 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 affected customers will continue to have the same quality of service and subject to the same base rates as they would have otherwise.

The primary difference is that they will be subject to a lesser value of interruptible or curtailable demand credit provided for under their transferred rate schedule. The Company believes that those customers under the closed tariff have had ample notice that the demand credits they have been receiving are not justified and that it is now time for their grace period to finally be ended.

There are some differences and possible modifications required to the applicable schedule which the affected customers will be transferred to accommodate them. 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 withdrawn rate schedule which requires 60 months. The Company proposes to permit these customers 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 affected customer that has a demand less than the desired minimum would not be subject to the billing demand minimum in the event that the customer exercises the 36-month notice provision to transfer to a firm rate. This is the same mitigating offer that was adopted by the Commission in Docket

No. 000824-EI when the Company sought to incorporate the 500 kW billing demand minimum in the Rate Schedules IS-2, IST-2, CS-2, and CST-2.

A third difference relates to a limitation incorporated in the Applicability Clause of the IS-2, IST-2, CS-2, and CST-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, not interfere with functions performed for the protection of public health or safety. The Company is aware that certain of those customers proposed to be transferred to one of these schedules may not satisfy this limitation and proposes that the limitation not apply.

A final difference relates to the 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. Has the Company revised the Interruptible and Curtailable Capacity Credits contained in Rate Schedule SS-2, Interruptible Standby Service, and Rate Schedule SS-3, Curtailable Standby Service?

A. Yes. The credits provided under these existing tariffs correspond with the credits provided for under the grandfathered IS-1, IST-1, CS-1 and CST-1 rate schedules. With the proposed elimination of these rate schedules, the credits should be revised to correspond with the credits provided for under the "open" IS-2, IST-2, CS-2, and CST-2 rate schedules.

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

A. The Company has proposed that the energy and demand charges be revised to the level which produces the proposed target revenues for this rate class.

Q. You indicated earlier that the Company placed a further constraint on the total revenue increases for the Lighting Facilities rate class. Why did the Company choose to do this?

A. The Company would like to have individual lighting charges reflect their current embedded cost. However, this would require substantial increases in a number of commonly utilized facilities. As was done in the Stipulation approved by the Commission in Docket No. 000824-EI, the Company has proposed in this proceeding to take another significant step toward correcting these deficiencies by setting the fixture and pole charges to reflect their current embedded cost, but limiting any particular fixture charge to a 15 percent maximum increase and limiting any particular pole charge to a maximum of a 20% increase.

Q. Has the Company proposed any other changes to lighting service provided under Rate Schedule LS-1?

A. Yes. In addition to revising the facility charges, PEF is proposing the following revisions to this schedule and its related standard contract forms.

1. PEF is proposing to increase its maintenance charges for light fixtures to a level reflective of current maintenance cost.

2. In the form of housecleaning, certain facility offerings have been proposed to be added, deleted, or restricted, and certain format changes are being proposed. Format changes include: (a) the elimination of what is considered a not fully inclusive "Total" column for the indicated component charges for a fixture; (b) the re-sequencing of "Poles" offerings by billing type number; and (c) a more descriptive header and footnote regarding the description for "Lumens" and "Watts" for a fixture type.

3. Due to the increasing capital nature of many facilities, PEF is proposing to increase the minimum term of service from six years to ten years.

4. Clarifications and additions were made in the Special Provisions regarding reference to appropriate sections of the Company's Rules which apply.

5. The special provision in the rate schedule and its related standard contract form regarding an option for an up-front lump sum payment for lighting facilities has been proposed to be eliminated due to the non-use of any customer for this option.

6. The standard contract form for service application of the metal halide pilot program is proposed to be eliminated. Metal halide lighting service is no longer a pilot program and the standard contract form for application of lighting service is proposed to be modified and used for any application for lighting service.

VII. Other Tariff Revisions

Q. Is the Company seeking revisions to any riders to its rate schedules?

A. Yes. The Company asks that Rate Schedule CISR-1, its Commercial/Industrial Service Rider pilot program be made permanent. The pilot program's tariff provides for its termination forty-eight months from the initial effective date, which will occur in August 2005. Renewed interest in the Rider has led the Company to conclude that the program should remain in effect.

VIII. Summary of Class Proposed Rates of Return

Q. Do you have an exhibit that summarizes the amount and change in class revenues, as a result of the Company's proposed rates, and the class rates of return which would be realized under the proposed rates?

A. Yes. My Exhibit No. _____(WCS-6) shows this information. The classes' proposed rates of return, of course, vary from parity primarily due to the limitations placed by the Company on the proposed class increases.

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-1	Full Revenue Requirements Increase Requested
A-2	Full Revenue Requirements Bill Comparison - Typical Monthly Bills
A-3	Summary of Tariffs
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

FPSC Docket No. 050078-EI
PEF Witness: Slusser
Exhibit No.: (WCS-2)

PROGRESS ENERGY FLORIDA
SUMMARY DEVELOPMENT OF FUNCTIONAL UNIT COSTS WITH PROPOSED REVENUE CREDITS
PROJECTED CALENDAR YEAR 2006 DATA: FULLY ADJUSTED
ALLOCATION METHOD: PRODUCTION CAPACITY - 12CP & 25% AD; TRANSMISSION CAPACITY - 12 CP

Line				(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-ABLE (CS, SS-3)	(7) INTERRUPT-IBLE (IS, SS-2)	(8) LIGHTING (LS) ENERGY	(9) LIGHTING (LS) FACILITIES
	I.		COST OF SERVICE - (000'S)									
1		A	Production Capacity									
2			a. 12 CP Component	$ 435,979	$ 247,539	$ 15,095	$ 584	$ 151,302	$ 2,260	$ 18,723	$ 476	$
3			b. AD Component	145,326	72,373	4,904	308	56,381	933	9,251	1,178	
4			Total Prod Capacity	581,306	319,912	19,999	892	207,683	3,193	27,974	1,654	
5		B	Production Energy	163,303	81,323	5,510	347	63,362	1,044	10,401	1,318	
6		C	Transmission	142,159	80,722	4,923	191	49,337	733	6,102	155	
7		D	Distribution Primary	296,032	171,394	10,954	300	97,051	2,162	11,788	2,385	
8		E	Distribution Secondary	192,112	149,356	8,158	106	33,248	2	407	833	
9		F	Distribution Services	80,074	70,965	5,806	575	2,714	-	2	16	
10		G	Metering	51,505	43,079	4,167	306	3,645	17	282	11	
11		H	Interruptible Equipment	429	-	-	-	-	-	429	-	
12		I	Lighting Facilities	59,322	-	-	-	-	-	-	-	59,322
13		J	Customer Billing, Info, etc.	58,302	50,729	4,142	411	1,981	2	18	1,017	
14			Rounding Adjustment (Tie to Juris & Class)	15	(4)	5	(1)	(4)	5	3	4	(1)
15			Total	$ 1,624,560	$ 967,477	$ 63,665	$ 3,127	$ 459,017	$ 7,158	$ 57,407	$ 7,392	$ 59,321
16	II		BILLING UNITS									
17		A	Number of Monthly Bills									
18			1. Metered Bills	19,086,497	16,931,340	1,378,198	119,480	651,422	121	1,938	3,998	
19			2. Unmetered Bills	809,115	-	7,812	17,509	-	-	-	783,794	
20			3. Total Bills	19,895,612	16,931,340	1,386,010	136,989	651,422	121	1,938	787,792	
21			4. Total Bills with Secondary Service Tap	19,094,726	16,931,340	1,375,520	136,989	646,245	9	625	3,998	
22			5. Total Bills with IS Equipment	1,938	-	-	-	-	-	1,938	-	
23		B	Annual Effective MWH Sales									
24			1. Production and Transmission Services	41,487,690	20,597,768	1,396,004	88,600	16,110,868	270,232	2,689,522	334,696	
25			2. Distribution Primary Service	40,836,959	20,597,768	1,393,760	88,600	16,093,033	270,232	2,058,870	334,696	
26			3. Distribution Secondary Service	35,909,480	20,597,768	1,384,262	88,600	13,345,899	382	157,873	334,696	
27		C	Sum of Monthly Effective Billing KW									
28			1. Production and Transmission Services	-	-	-	-	41,290,568	637,416	6,518,794	-	
29			2. Distribution Primary Service	-	-	-	-	41,187,887	637,416	5,163,190	-	
30			3. Distribution Secondary Service	-	-	-	-	35,486,265	1,120	384,647	-	
31		E	12 CP - Allocator per Alloctor No. 1B	100.000%	56.778%	3.462%	0.134%	34.704%	0.518%	4.294%	0.109%	0.000%
32			Avg Demand - Allocator per Alloctor No. 1B	100.000%	49.795%	3.374%	0.214%	38.800%	0.639%	6.369%	0.810%	0.000%
			12 CP & 25% AD Allocator per Alloctor No. 1B	100.000%	55.032%	3.440%	0.154%	35.728%	0.549%	4.813%	0.284%	0.000%
33	III		UNIT COSTS									
34		A	**Customer Related Costs - $/Bill**									
35			1. Metering (L. 8/L.17)	-	$ 2.54	$ 3.02	$ 2.56	$ 5.60	$ 140.28	$ 145.26	$ 2.74	
36			2. Customer Billing, Info, etc. (L. 13/L. 19)	-	$ 3.00	$ 2.99	$ 3.00	$ 3.04	$ -	$ 9.29	$ 1.29	
37			3. Secondary Service Tap (L. 9/L. 20)	-	$ 4.19	$ 4.22	$ 4.20	$ 4.20	$ -	$ -	$ 3.98	
38			4. Interruptible Equipment (L. 11/L. 21)	-	-	-	-	-	-	$ 221.39	-	
39		B	**Energy Related Costs - $/MWH**									
40			1. Production Energy (L. 5/ L. 23)	-	$ 3.95	$ 3.95	$ 3.92	$ 3.93	$ 3.86	$ 3.87	$ 3.94	
41		C	**Capacity Related Costs**									
42			a. Based on MWH Sales - $/MWH									
43			1. Production Capacity 12CP (L. 2/L. 23)	-	$ 12.02	$ 10.81	$ 6.59	$ 9.39	$ 8.36	$ 6.96	$ 1.42	
44			2. Production Capacity 25% AD(L. 3/L. 23)	-	$ 3.51	$ 3.51	$ 3.48	$ 3.50	$ 3.45	$ 3.44	$ 3.52	
45			3. Transmission (L. 6/L. 23)	-	$ 3.92	$ 3.53	$ 2.16	$ 3.06	$ 2.71	$ 2.27	$ 0.46	
46			4. Distribution Primary (L. 7/L. 24)	-	$ 8.32	$ 7.86	$ 3.38	$ 6.03	$ 8.00	$ 5.73	$ 7.13	
47			5. Distribution Secondary (L. 8/L. 25)	-	$ 7.25	$ 5.89	$ 1.19	$ 2.49	$ 5.21	$ 2.58	$ 2.49	
48			Or									
49			b. Based on Billing KW Demand - $/KW/Month									
50			1. Production Capacity 12CP (L. 2/L. 27)				-	$ 3.66	$ 3.55	$ 2.87		
51			2. Production Capacity 25% AD (L. 3/L. 27)				-	$ 1.37	$ 1.46	$ 1.42		
52			3. Transmission (L. 6/L. 27)				-	$ 1.19	$ 1.15	$ 0.94		
53			4. Distribution Primary (L. 7/L. 28)				-	$ 2.36	$ 3.39	$ 2.28		
54			5. Distribution Secondary (L. 8/L. 29)				-	$ 0.94	$ -	$ 1.06		

Progress Energy Florida
Estimate of Alternative Resource Investment Required to Serve Peak Demand Only
as of 12/31/04

Line	Plant Name	(A) In Service Year	(B) Nameplate Capacity MW	(C) Actual EPIS Balance $000's	(D) Estimated Alternative EPIS Balance $000's	(E) Determination of Alternative Peaking Resource Cost
1	Steam					
2	Anclote Unit 1	1974	556.2			
3	Anclote Unit 2	1978	556.2	265,892	116,328	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	123,894	123,894	No Viable Peaking Resource for In-Service Year
8						
9	Crystal River Unit 1	1966	440.5			
10	Crystal River Unit 2	1969	523.8	406,315	127,289	Per KW Capacity Cost Equivalent to Avon Park Peakers
11						
12	Crystal River Unit 3	1977	817.4	797,088	144,769	Per KW Capacity Cost Equivalent to DeBary Peakers
13						
14	Crystal River Unit 4	1982	739.3			
15	Crystal River Unit 5	1984	739.3	901,512	230,948	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	33,351	33,351	No Viable Peaking Resource for In-Service Year
20						
21	Combined Cycle					
22	Hines Power Block 1	1999	546.6	285,118	167,897	2004 Peaker Cost at $329/KW times H/W Index Ratio of .93
23	Hines Power Block 2	2003	598.0	238,772	199,338	2004 Peaker Cost at $329/KW times H/W Index Ratio of 1.01
24	Hines Power Block 3 (Projected)	2005	598.0	260,471	201,490	2004 Peaker Cost at $329/KW escalated @ 2.5%
25	Tiger Bay	1997	278.2	78,800	79,243	2004 Peaker Cost at $329/KW times H/W Index Ratio of .87
26	University of Florida	1994	43.0	22,987	11,652	2004 Peaker Cost at $329/KW times H/W Index Ratio of .82
27						
28	Combustion Turbine					
29	Avon Park Peakers 1-2	1968	67.6	8,921	8,921	Actual Peaking Resource
30	Bartow Peakers 1-4	1972	222.8	24,263	24,263	Actual Peaking Resource
31	Bayboro Peakers 1-4	1973	226.8	23,717	23,717	Actual Peaking Resource
32	DeBary Peakers 1-10	1975-76, 92	861.2	152,518	152,518	Actual Peaking Resource
33	Higgins Peakers 1-4	1969-1971	153.4	17,793	17,793	Actual Peaking Resource
34	Intercession City Pkrs 1-14	1974,93,97,00	1,255.3	239,727	239,727	Actual Peaking Resource
35	Rio Pinar Peaker 1	1970	19.3	3,124	3,124	Actual Peaking Resource
36	Suwannee Peakers 1-3	1980	183.6	28,677	28,677	Actual Peaking Resource
37	Turner Peakers 1-4	1970-74	181.0	22,737	22,737	Actual Peaking Resource
38						
39	Total Production Plant			3,935,676	1,957,676	
40						
41						
42	**Percentage of Actual Resource Investment Made to Serve Peak Demand Only**			=	**49.7%**	(1,957,676 / 3,935,676) x 100%
43	**Percentage of Actual Resource Investment Made For Other Reasons**			=	**50.3%**	((3,935,676 - 1,957,676) / 3,935,676) x 100%

PROGRESS ENERGY FLORIDA
COMPARISON OF CLASS ALLOCATED COST OF SERVICE STUDY RESULTS
TEST PERIOD: PROJECTED TEST YEAR 2006
$000's

Line	Rate Class		(A) Cost of Service	(B) Cost of Service	(C) Total Difference	(D) Total Difference	Difference Due To	
1	Residential							
2								
3	General Service							
4	Non-Demand							
5								
6	General Service	GS-2, GSLM-2	3,079	3,153	74	2.4%	82	(8)
7	100% Load Factor							
8								
9	General Service	GSD-1, GSDT-1, SS-1	457,184	460,868	3,684	0.8%	4,129	(445)
10	Demand							
11								
12	Curtailable	CS-1, CST-1, CS-2,	7,075	7,185	110	1.6%	132	(22)
13		CST-2, SS-3, CS-3, CST-3						
14								
15	Interruptible	IS-1, IST-1, IS-2, IST-2	55,762	57,624	1,862	3.3%	2,091	(229)
16		SS-2						
17								
18	Lighting							
19	Energy	LS-1	6,786	7,416	630	9.3%	710	(80)
20	Facilities	LS-1	59,515	59,515		0.0%		
21								
22								
23	Rounding Adj (tie to Jurisdictional Study)			(2)	(2)		(1)	(1)
24								
25	Total Retail		$ 1,632,755	$ 1,632,755	$ -	0.0%	$ -	$

PROGRESS ENERGY FLORIDA
TEST PERIOD: PROJECTED CALENDAR YEAR 2006
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 & 25% AD	Present Class Revenue	Revenue Defiiciency (A) - (B)	Additional Revenue Credits	$ (C) - (D)	% (E) / (B)	$	%	(B) + (G)
1	I. Residential (RS)	$ 972,948	$ 887,640	$ 85,308	$ 5,469	$ 79,839	8.99%	$ 95,093	10.71%	$ 982,733
2										
3	II. General Service	64,048	65,410	(1,362)	383	(1,745)	-2.67%	7,007	10.71%	72,417
4	Non-Demand (GS-1)									
5										
8	III. General Service 100%	3,153	2,587	566	25	541	20.91%	537	20.74%	3,124
9	Load Factor (GS-2)									
10										
11	IV. General Service	460,868	369,178	91,690	1,851	89,839	24.33%	76,580	20.74%	445,758
12	Demand (GSD, SS-1)									
13										
14	V. Curtailable (CS, SS-3)	7,185	5,395	1,790	28	1,762	32.66%	1,119	20.74%	6,514
15	General Service									
16										
17	VI. Interruptible (IS, SS-2)	57,624	45,709	11,915	218	11,697	25.59%	9,482	20.74%	55,191
18	General Service									
19										
20	VII. Lighting (LS)									
21	A. - Energy	7,416	5,707	1,709	24	1,685	29.52%	1,184	20.74%	6,891
22	B. - Facilities	59,515	45,572	13,943	196	13,747	30.17%	6,364	13.96%	51,936
23										
24	Total	$ 1,632,757	$ 1,427,198	$ 205,559	$ 8,194	$ 197,365	13.83%	$ 197,365	13.83%	$ 1,624,563

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

- For Rate Classes III, IV, V, VI and VIIA - Percentage increase set at one and one half times system average.
- For Rate Classes VIIB, Lighting Facilities - Revenues established from setting fixture, pole, and maintenance charges at cost with no fixture charge increase greater than 15% and no pole charge increase greater than 20%.
- For Rate Classes I and II - Percentage increase is resultant increase required for recovery of remaining revenue deficiency after increases established in all other rate classes.

PROGRESS ENERGY FLORIDA
TEST PERIOD: PROJECTED CALENDAR YEAR 2006
SUMMARY OF PROPOSED RATES AND CLASS RATES OF RETURN
Dollars in 000's

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
		Present Revenues			Proposed Incr / (Decr)		Proposed Revenues						
Line	Rate Class	Total Revenue	Allocated Revenue Credits	Class Revenue (A) - (B)	Allocated Revenue Credits	Class Revenue	Total Revenue (G) + (H)	Allocated Revenue Credits (B) + (D)	Class Revenue (C) + (E)	Cost of Service 12CP and 25% AD with Proposed Rev Credtis	Class Revenue Requirement Index (H) / (I)	Rate of Return at Proposed Rates	Rate of Return Index (K) / total (K)
1	Residential (RS)	927,927	40,287	887,640	5,469	95,460	1,028,856	45,756	983,100	967,477	1.02	9.84%	1.04
2													
3	General Service	68,316	2,906	65,410	383	6,615	75,314	3,289	72,025	63,665	1.13	12.33%	1.30
4	Non-Demand (GS-1)												
5													
6	General Service 100%	2,792	205	2,587	25	540	3,357	230	3,127	3,127	1.00	9.49%	1.00
7	Load Factor (GS-2)												
8													
9	General Service	379,128	9,950	369,178	1,851	76,567	457,546	11,801	445,745	459,017	0.97	8.88%	0.93
10	Demand (GSD)												
11													
12	Curtailable (CS)	5,542	147	5,395	28	1,122	6,692	175	6,517	7,158	0.91	7.58%	0.80
13	General Service												
14													
15	Interruptible (IS)	46,730	1,021	45,709	218	9,516	56,464	1,239	55,225	57,407	0.96	8.67%	0.91
16	General Service												
17													
18	Lighting (LS)												
19	- Energy	5,881	174	5,707	24	1,192	7,097	198	6,899	7,392	0.93	7.77%	0.82
20	- Facilities	45,907	335	45,572	196	6,364	52,467	531	51,936	59,321	0.88	6.36%	0.67
21													
22													
23	Total Retail Revenue	1,482,223	55,025	1,427,198	8,194	197,376	1,687,793	63,219	1,624,574	1,624,564	1.00	9.502%	1.00