ORIGINAL

McWHIRTER REEVES

ATTORNEYS AT LAW

TAMPA OFFICE:
400 NORTH TAMPA STREET, SUITE 2450
TAMPA, FLORIDA 33602
P. O. BOX 3350 TAMPA, FL 33601-3350
(813) 224-0866 (813) 221-1854 FAX

PLEASE REPLY TO:

TALLAHASSEE

TALLAHASSEE OFFICE:
117 SOUTH GADSDEN
TALLAHASSEE, FLORIDA 32301
(850) 222-2525
(850) 222-5606 FAX

RECEIVED-FPSC
02 JAN 18 PM 4:18
COMMISSION CLERK

January 18, 2002
VIA HAND DELIVERY

Blanca S. Bayo, Director
Division of Records and Reporting
Betty Easley Conference Center
4075 Esplanade Way
Tallahassee, Florida 32399-0870

Re: Docket No.: 000824-EI

Dear Ms. Bayo:

On behalf of the Florida Industrial Power Users Group (FIPUG), enclosed for filing and distribution are the original and 15 copies of the following:

- PUBLIC Intervenor Testimony of Thomas J. Regan on Behalf of the Florida Industrial Power Users Group; 00691-02
- Intervenor Testimony and Exhibits of Michael Gorman on Behalf of Florida Industrial Power Users Group, 00692-02
- Intervenor Testimony and Exhibits of Jeffry Pollock on Behalf of Florida Industrial Power Users Group. 00693-02

Please acknowledge receipt of the above on the extra copy and return the stamped copies to me. Thank you for your assistance.

Sincerely,

Vicki Gordon Kaufman

Vicki Gordon Kaufman

AUS ___
CAF ___
CMP ___
COM 5 orig
CTR ___
ECR ___
GCL VGK/bae
OPC Enclosure
MMS ___
SEC 1
OTH Shr pg

RECEIVED & FILED
FPSC-BUREAU OF RECORDS

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Florida Power Corporation's Earnings, Including Effects of Proposed Acquisition of Florida Power Corporation by Carolina Power & Light	**Docket No. 000824-EI**

Intervenor Testimony and Exhibits of

Jeffry Pollock

On behalf of

Florida Industrial Power Users Group

January 18, 2002
Project 7718

BRUBAKER & ASSOCIATES, INC.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Florida Power Corporation's Earnings, Including Effects of Proposed Acquisition of Florida Power Corporation by Carolina Power & Light	)	Docket No. 000824-EI

Intervenor Testimony and Exhibits of

Jeffry Pollock

On behalf of

Florida Industrial Power Users Group

January 18, 2002
Project 7718

BAI

BRUBAKER & ASSOCIATES, INC.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Florida Power Corporation's Earnings, Including Effects of Proposed Acquisition of Florida Power Corporation by Carolina Power & Light	)	**Docket No. 000824-EI**

Table Of Contents

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Florida Power Corporation's Earnings, Including Effects of Proposed Acquisition of Florida Power Corporation by Carolina Power & Light	**Docket No. 000824-EI**

Intervenor Testimony of Jeffry Pollock

1. INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock, 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri, 63141-2000.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and a principal in the firm of Brubaker & Associates, Inc. (BAI).

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University. Upon graduation, in June 1975, I joined the firm of Drazen-Brubaker & Associates, Inc. Drazen Brubaker & Associates, Inc. (DBA) was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. BAI was formed in April 1995 and is engaged in the economic, technical, accounting, and financial aspects of public utility rates and regulation and the acquisition of utility and energy services, through RFPs and negotiations, in both regulated and unregulated markets. In the last five years, BAI professionals have participated in numerous regulatory proceedings and in projects implementing customer choice in 40 states and Canada.

During my tenure at both DBA and BAI, I have also been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service, and rate design, and conducting site evaluation. Recent engagements have included advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing request for proposals (RFPs), evaluating RFP responses and contract negotiation. I am also responsible for developing and presenting seminars on electricity issues.

I have monitored, participated in, or submitted expert testimony before this Commission in numerous dockets since 1977. In addition to Florida, I have worked on various projects in over 20 states and in two Canadian provinces, and have testified before the regulatory commissions of Alabama, Arizona, Colorado, Delaware, Georgia, Illinois, Iowa, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, Ohio, Pennsylvania, Texas, Virginia, and Washington. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

Q ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS DOCKET?

A I am appearing on behalf of the Florida Industrial Power Users Group (FIPUG). The participating FIPUG members purchase substantial amounts of electric power and energy from Florida Power Corporation (FPC or the Company).

Q WHAT ISSUES ARE YOU ADDRESSING IN YOUR TESTIMONY?

A My testimony addresses the following issues:

- The proper method of allocating production plant costs to the customer classes.
- The Company's proposed revisions to the tariffs for interruptible service.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A My recommendations can be summarized as follows:

- FPC's proposal to allocate production plant costs to customer classes using the 12CP and 25% Average Demand (AD) method should be rejected. The sole reason offered by FPC for adopting this method is that it would be a first step toward full implementation of the Equivalent Peaker Method (EPM). Although FPC contends that the EPM is consistent with the economic theory underlying system planning decisions, a thorough analysis reveals that the EPM is a flawed and incomplete application of the theory of "capital substitution." This Commission specifically cited the flaw in the application of this theory when it rejected the EPM in 1990.

- Peak demands are the cost-causative factor in determining the amount of capacity resources required to enable a utility to provide reliable service to firm load customers. A summer and winter average coincident peak methodology would be most appropriate for FPC based on the Company's load characteristics. The Commission, however, has previously approved the 12CP and 1/13th AD method, citing factors other than peak demand drive production investment decisions. The 12CP and 1/13th AD method suffers from the same flaw as the EPM, but the flaw is not nearly as serious. Given a choice between 12CP and 1/13th AD or 12CP and 25% AD, the Commission should approve 12CP and 1/13th AD.

- FPC's proposal to eliminate the IS-1 and IST-1 rates would dramatically and adversely change the economics of interruptible service for existing IS-1/IST-1 customers, and it should be rejected. At a time when significant additional capacity is needed to maintain reliable service in this state, it is inappropriate to diminish the value of the interruptible resource. IS-1 and IST-1 should be retained with the existing level of demand credits since the existing credits are less than the avoided generation capacity costs attributable to interruptible service.

- The Company has provided no support for the cost-effectiveness test that was used to determine the value of the interruptible resource. Further, interruptible service is more valuable than other demand-side management (DSM) programs (both active and passive) for a variety of reasons. For example, interruptible load is available with little or no notice, without limitation, and it may also be used to fulfill FPC's operating reserve requirements. Recognizing its greater value, the interruptible demand credits should be set to achieve a benefit-to-cost ratio of 1.0 if a cost-effectiveness test is used.

- If the Commission nevertheless adopts FPC's recommendations with respect to interruptible service, existing IS-1/IST-1 customers should be grandfathered under their current rates for a period of two years, at which time they would be free to terminate interruptible service. This approach would give these customers the ability to evaluate other power supply options before they are forced to accept such a dramatic change in the rates, terms, and conditions of their electric service.

- The proposed load factor adjustment in the IS-1/IST-1 and IS-2/IST-2 demand charges should be rejected because load factor is not a reasonable proxy for measuring the amount of load available for interruption. FPC should directly measure the amount of load available for interruption by using the average of the customer's maximum demand on the day of, the day before, and the day after an interruption. In lieu of a direct measurement, the credit should apply to billing demand, as is currently the practice.

2. ALLOCATION OF PRODUCTION PLANT COSTS

Q WHAT IS FPC'S PROPOSAL FOR ALLOCATING PRODUCTION PLANT COSTS TO THE RETAIL CUSTOMER CLASSES?

A FPC proposes to allocate these costs using the 12 coincident peak (CP) and 25% average demand (AD) method. This method classifies 75% of production plant costs as demand-related and 25% as energy-related. The 12CP method is then used to allocate those capacity costs classified to demand, while annual energy usage, or average demand, is used to allocate those capacity costs classified to energy.

Q WHAT REASON DOES FPC OFFER FOR USING THE 12CP AND 25% AD METHOD TO SET RATES IN THIS PROCEEDING?

A FPC argues that the optimal method of allocating production capacity costs is the Equivalent Peaker Method (EPM). FPC further asserts that application of EPM would result in a 12CP and 50% AD allocation of production plant costs. This is in contrast to the 12CP and 1/13th AD allocation method that the Company is required to submit under the Minimum Filing Requirements (MFR). The Company characterizes the 12CP and 25% AD method as a reasonable compromise between the results of applying EPM and the allocation method specified in the MFR.

Q WHY DOES FPC BELIEVE THAT EPM IS THE OPTIMAL METHOD FOR ALLOCATING PRODUCTION CAPACITY COSTS?

A FPC witness, William C. Slusser, Jr., states that application of EPM is consistent with the Company's generation expansion planning process because annual *energy utilization* is a major consideration in determining the type of plant that the Company considers to be built. He further argues that FPC has significant production plant investment related to environmental concerns, which he asserts is incurred more as a function of the *energy utilization* of a production facility than its peak capability.

Q HOW DOES THE EPM ATTEMPT TO EMULATE THE GENERATION EXPANSION PLANNING PROCESS?

A The EPM is based on "capital substitution" theory. Under this theory, a utility is said to "substitute" capital investment for fuel savings. In other words, system planners are said to justify the extra investment to install base load generation solely because it will save fuel costs relative to building combustion turbine peaking capacity. The fuel cost savings would more than offset the higher plant costs. Thus, according to the EPM, the extra investment is energy-related, rather than demand-related.

EPM classifies production plant investment between demand and energy. The demand component is represented by the equivalent cost of peaking capacity. All production plant investment that is above the investment of equivalent peaking capacity costs are considered to be energy-related because they, allegedly, are incurred as a trade-off for lower operating costs.

Q ARE THERE ANY CONSIDERATIONS OTHER THAN THESE ECONOMIC TRADE-OFFS THAT CAN AFFECT A UTILITY'S DECISION TO INVEST IN BASE LOAD CAPACITY?

A Yes. An investment decision in a generating plant can be affected by the existing generation mix, the availability of a suitable site, environmental restrictions, system stability, licensing, governmental and other regulatory restrictions, fuel diversification, etc. I would also add that since fuel costs are extremely volatile and with the advent of competitive electricity markets, it would not be prudent to rely solely on projected fuel cost savings to justify a larger investment in plant.

Q IS THE EPM CONSISTENT WITH CAPITAL SUBSTITUTION THEORY?

A No. The EPM is a flawed and incomplete representation of capital substitution theory.

Q HOW IS THE EPM A FLAWED APPLICATION OF CAPITAL SUBSTITUTION THEORY?

A The EPM assumes that *energy utilization in all hours of the year* causes the utility to incur the extra plant investment of installing base load capacity. This is clearly at odds with the planning process. All production from the plant is not a critical factor in deciding which type of capacity to install. Once a plant is expected to run beyond the "break-even point," all additional hours of generation are irrelevant to the investment.

Q PLEASE EXPLAIN WHAT YOU MEAN BY A "BREAK-EVEN POINT."

A The concept of a break-even point is illustrated in Exhibit ____ (JP-1). This Exhibit compares the total cost of base/intermediate capacity and peaking capacity as a function of operating hours. The base/intermediate cost curve is shown in gold, while the cost curve associated with peaking capacity is shown in blue. As can be seen, base/intermediate capacity is more expensive than peaking capacity for the initial operating hours. This is because base/intermediate units require more investment per kW of capacity than do peaking units. However, the corresponding operating expense of base/intermediate units is lower than the cost to operate peaking units on a per MWh basis. As a consequence, the base/intermediate cost curve inclines more gradually than does the cost curve of peaking capacity.

The break-even point is the number of operating hours in which the total cost of base/intermediate and peaking capacity is the same. The illustration is based on a break-even point of 1,500 hours. Based on my experience, this is representative of the break-even point of operating peaking capacity.

Q WHAT IS THE SIGNIFICANCE OF THE BREAK-EVEN POINT?

A Once a utility decides that additional production capacity is needed to meet peak demand, if that new capacity is expected to run only a limited number of hours, total costs are minimized by the choice of a peaker. On the other hand, if it is projected that a unit will run for a sufficient number of hours, then the intermediate or base load unit will be more economical.

Therefore, *annual energy utilization* does not cause plant investment. However, *load duration* up to the break-even point may influence plant investment decisions. Beyond the break-even point, energy utilization is no longer a factor in the decision to select base load capacity or peaking capacity.

Q COULD YOU PLEASE GIVE AN EXAMPLE TO ILLUSTRATE THIS POINT?

A To provide an analogy, suppose two different customers are required to rent cars from a fleet that contains only two types of cars: "Type B" and "Type P." The Type B car has a high fixed charge per day and gets high mileage (a base load plant) while the Type P car has a low fixed charge per day but gets poor mileage (a peaking unit). Suppose that the break-even point between the total cost of the two cars were 100 miles. That is, the higher mileage Type B car has a lower total cost per mile than the

Type P car if it operated more than 100 miles. If one customer needed to drive 200 miles and a second customer needed to drive a car 400 miles, both customers would choose the same car, Type B. The EPM, however, would charge the second customer about twice as much of the additional fixed charge of the Type B car solely because that customer needed to drive twice as many miles. This result is arbitrary and inequitable because the Type B car was the more economical choice for both customers.

Q DOES THE EPM REFLECT COST-CAUSATION CONSISTENT WITH THE BREAK-EVEN POINT CONCEPT?

A No. Under the EPM, all production plant costs in excess of the equivalent peaker are allocated on *annual energy utilization*. As stated previously, investment decisions are not caused by *annual energy utilization*. Thus, the EPM is totally contrary to capital substitution theory. The Commission should not endorse a cost allocation method which, on its face, is inconsistent with system planning principles and the underlying theory of capital substitution.

Q HAS THE COMMISSION PREVIOUSLY RECOGNIZED THE FLAW OF ALLOCATING PRODUCTION INVESTMENT PAST THE BREAK-EVEN POINT?

A Yes, it has. In a Gulf Power rate case, the Commission specifically rejected EPM because "[it] implies a refined knowledge of costs which is misleading, particularly as to the allocation of plant costs to hours past the break-even point."[1]

[1] Order No. 23573, page 48.

Q IS THERE A SIMILAR PROBLEM WITH THE 12CP AND 1/13TH AD METHOD?

A Yes. Exhibit ____ (JP-2) shows the occurrence of FPC's monthly system peak demands as a function of load duration for the year 2000. The monthly coincident peaks are shown in red. The load duration curve is shown in blue up to the break-even point and in green beyond the break-even point. As can be seen, some of FPC's monthly CP demands occur beyond the 1,500 hour break-even point.

Average demand is depicted in Exhibit ____ (JP-3). As can be seen, using average demand to allocate costs also results in assigning costs beyond the break-even point. However, since average demand is only weighted by 1/13th, or 8%, the problem is not nearly as serious as with the EPM.

Q WHY DO YOU CONTEND THAT THE EPM IS AN INCOMPLETE REPRESENTATION OF CAPITAL SUBSTITUTION THEORY?

A Mr. Slusser implements capital substitution theory by altering the method in which production plant-related costs are allocated among the retail customer classes. The result of applying capital substitution in this fashion is to allocate above-average plant investment to high load factor customer classes and below-average investment to lower load factor customers. This is shown in Exhibit ____ (JP-4). As can be seen, FPC's average production investment is $194 per 12CP kW. All of the non-residential customer classes (e.g., GS-1, GS-2, GSD, CS and IS) have been allocated net investment ranging from $200 per kW to $230 per kW, which are above the average.

However, Mr. Slusser fails to apply capital substitution theory to allocate production operating expense. That is, the EPM erroneously uses a "slice of the system" approach to allocate production operating costs based on class energy usage. A slice of the system means that each class is served from the same mix of base load and peaking capacity. Similarly, Mr. Slusser made no attempt to recognize that fuel and purchased power costs are also recovered on a "slice of the system" basis.

Q WHY IS THIS INCONSISTENT WITH CAPITAL SUBSTITUTION THEORY?

A There is a symmetrical relationship between plant investment and operating expense. This relationship is shown in Exhibit ____ (JP-5). On average, FPC's net production investment is $192 per kW of capacity. The average operating expense (fuel and variable O&M) associated with this investment is $27.35 per MWh. As can be seen, the capacity that FPC classifies as base load (line 1) has a net plant investment of $272 per kW and associated operating expense of $21.41 per MWh. The base load capacity, thus, has a higher plant investment but a lower operating expense, on a per unit basis. The opposite is true for FPC's peaking capacity (line 3).

Given the symmetrical relationship, the application of capital substitution theory would not be complete unless the allocation of operating expense were consistent (symmetrical) with the corresponding allocation of plant investment. This means that a class that is allocated a larger share of production plant investment should also receive more of the associated benefits of the lower operating costs of base/intermediate capacity. Stated differently, if a class is allocated above-average plant investment per kW, then consistency demands that this same class be allocated below average operating expense (fuel and variable O&M) per MWh. This would explicitly recognize the symmetrical relationship between plant investment and operating expense.

Consider again the analogy of the two cars (Type B and Type P) with different fuel efficiencies and fixed costs. The customer who drives the car only a few miles a day (low load factor) would incur a higher average mileage charge than the customer that drives many miles per day (high load factor). This symmetrical relationship is consistent with capital substitution theory.

Although the EPM asserts that the operating cost savings are the only reason to rent the more capital-intensive car and would assign more of the daily fixed charge to the high load factor customer, both customers would be assessed the same mileage charge. This result is contrary to capital substitution theory and is yet another reason for rejecting the EPM and methodologies designed to reflect, in part, the EPM (e.g., 12CP and 25% AD).

Q DOES FPC RECOGNIZE THE SYMMETRY BETWEEN PLANT INVESTMENTS AND OPERATING COSTS ELSEWHERE IN ITS COST OF SERVICE STUDY?

A Yes. FPC's jurisdictional separation study provides a symmetrical allocation of base, intermediate and peaking investment and the corresponding operating costs to its wholesale "stratified" customers. Further, it is my understanding that fuel costs are similarly differentiated based on the amount of base, intermediate, and peaking capacity.

Q WOULD YOU PLEASE SUMMARIZE YOUR OBJECTIONS TO USING THE EPM TO ALLOCATE PRODUCTION CAPITAL COSTS TO THE VARIOUS RATE CLASSES?

A Yes. First, the assumption that year-round energy usage causes higher production capital investment is flawed. As discussed above, investment decisions are not caused by *energy utilization*. At most, they are influenced by *load duration* but only up to the break-even point between different types of capacity. Therefore, allocating production investment on *energy utilization*, as is the case under the EPM, is a flawed application of capital substitution theory.

Second, there is no symmetrical allocation of operating costs. Each class is allocated average operating expense, which is the same allocation as under methodologies that do not explicitly recognize system planning principles. Absent a symmetrical allocation of investment and operating costs, which would result in below-average operating costs per kWh being assigned to those classes that are also assigned above-average investment per kW, the EPM is an incomplete representation of capital substitution theory.

Q **MR. SLUSSER ARGUES THAT THE CLASSIFICATION OF SOME PRODUCTION CAPITAL COSTS TO THE ENERGY FUNCTION IS JUSTIFIED BY THE NOTION THAT PRODUCTION PLANT COSTS THAT RELATE TO ENVIRONMENTAL CONCERNS ARE GENERALLY A FUNCTION OF ENERGY USAGE. HOW DO YOU RESPOND?**

A I do not believe this argument is consistent with cost-causation. The proper application of cost-causation is to identify the specific usage characteristics that cause the utility to incur production plant and related expenses. While environmental concerns may be reflected in the investment in production investment and may influence production operating expenses, they are a prerequisite to plant operation. In other words, a plant could not be legally operated to provide either capacity or energy unless it was in full compliance with all applicable environmental regulations. Thus, environmental concerns do not alter the fundamental reasons that cause electric utilities to install generation capacity: namely, the projected peak demand for electricity and load duration up to the break-even point.

In addition to being directly related to production plant, pollution control investments are primarily fixed. They vary directly in proportion to the size (i.e., the capacity) of a generating unit. More importantly, other than some operation and maintenance expenses, these costs do not vary with energy usage. Therefore, the cost characteristics of pollution control equipment do not support the classification of production plant costs to the energy function.

Q **IN YOUR VIEW, WHAT IS THE BEST ALLOCATION METHOD FOR PRODUCTION CAPITAL COSTS?**

A As I previously stated, projected peak demands are the cost-causative factor in the construction of production plant. Therefore, FPC's production plant-related costs should be allocated to customer classes based on a measure of the peak demands imposed by such customers on the utility's system at the time of system peak demand. Specifically, I believe that the Summer/Winter Coincident Peak (SWCP) method would be most appropriate for FPC based on an analysis of FPC's load characteristics.

Q **HAVE YOU ANALYZED FPC'S LOAD CHARACTERISTICS?**

A Yes. FPC is primarily a winter peaking utility with a secondary summer peak, as illustrated in Exhibit ____ (JP-6), page 1. This schedule shows the monthly firm peak demands as a percent of the annual system peak for the years 1996 through 2000. The system peaks have typically occurred during the winter months of January and February. A secondary summer peak period typically occurs in the months of June through August. The peak demands in the other months are typically well below the winter and summer peak demands.

These characteristics are summarized in Exhibit ____ (JP-6), page 2. Column 1 shows the firm system peak demand. Columns 2 and 3 show the ratios of the firm system peak demand to the minimum and average monthly firm peak demands, respectively. If the demands were not seasonal, then these ratios would be relatively close to 1.0. For FPC, however, the maximum-to-minimum monthly peak is varied from 1.49 to 1.70 times, and the maximum-to-average monthly peak is varied from 1.15 to 1.28 times. These ratios confirm the seasonal load characteristics of the FPC system and support the application of the SWCP method for allocating the Company's production plant costs. Specifically, the SWCP allocator should be calculated using the system peak months of December through February and June through August.

Q **WHAT METHOD HAS THE COMMISSION PREVIOUSLY APPROVED FOR FPC?**

A The Commission has previously approved the 12CP and 13th AD method in FPC's most recent base rate case. In addition, the Commission has most often relied on this method in recent rate cases involving other investor-owned utilities in Florida.

Q **IF THE COMMISSION SHOULD PREFER A METHODOLOGY REFLECTING THE ECONOMIC THEORY SUPPORTED BY MR. SLUSSER, THEN WHAT METHOD SHOULD BE ADOPTED?**

A It is my understanding that the 12CP and 1/13th AD method was originally adopted by the Commission to recognize the same economic theory as Mr. Slusser associates with the EPM. Although the 12CP and 1/13th AD allocates production investment beyond the break-even point, it does so only minimally, and it also recognizes that load duration is a driver that determines utility investment decisions. Assuming that the choices are limited to the 12CP and 1/13th AD method, the 12CP and 25% AD or the EPM, the 12CP and 1/13th AD comes closer to recognizing cost-causation and the economic theory underlying generation expansion planning (i.e., capital substitution) than the other two methods. Therefore, the Commission should, once again, reject the EPM and it should also reject allocation methods derived from the EPM (e.g., FPC's "compromise" 12CP and 25% AD method) in this proceeding.

3. REVISIONS TO THE INTERRUPTIBLE RATES

Q PLEASE SUMMARIZE FPC'S PROPOSED REVISIONS TO ITS INTERRUPTIBLE SERVICE TARIFFS.

A FPC proposes to eliminate the IS-1 and IST-1 rate schedules. The Company argues that, under the stipulation in Docket No. 910890-EI, the existing demand credits for these rate schedules were to remain in effect until the next rate case. FPC asserts that the current proceeding is the next rate case intended under that stipulation. Therefore, the Company contends that the existing demand credits for all interruptible customers should be reviewed in this proceeding and revised to cost-effective levels. If the credits are revised to cost-effective levels for all customers, FPC argues that it is reasonable to consolidate all interruptible customers under the applicable IS-2 or IST-2 rate schedule with a unified level of demand credits.

The Company treats interruptible service as a demand-side management (DSM) program, and FPC proposes to continue recovering the cost of the demand credits as a conservation program cost. Accordingly, the Company has allocated costs to interruptible customers as if they were firm customers under its proposed cost of service study. FPC proposes to pay demand credits to interruptible customers to recognize the value of their load as a DSM program.

Consistent with this approach, FPC asserts that the credits should be established using the same benefit-to-cost ratio of 1.2 that is applied in evaluating other DSM programs. Using this criterion, FPC calculates a demand credit of $2.82 per monthly coincident peak (CP) kW as being cost-justified for interruptible customers. To calculate a customer's monthly CP kW for the purpose of establishing each customer's demand credit, the Company proposes to multiply the customer's maximum demand by the customer's billing load factor. This approach would use the billing load factor as a proxy for the customer's coincidence factor. This contrasts with the current assessment of the demand credit, which is based on a customer's maximum demand. FPC's proposals would reduce the demand credit for IS-1 customers from $3.37 per maximum kW to $2.82 per monthly CP kW. This would result in a rate increase of up to 13.5% for some interruptible customers and an overall increase of 3.5% for the class.

In addition to the foregoing changes, the Company proposes to apply a minimum billing demand of 500 kW to all interruptible and curtailable rate schedules. FPC argues that it is not cost-effective to administer these rates for customers whose minimum demands fall below this threshold. However, the Company proposes to exempt existing interruptible and curtailable customers from this new requirement.

By consolidating Rates IS-1 and IS-2, the Company would also reduce the notice requirement for transferring from interruptible to firm service from 60 months to 36 months for IS-1 customers.

Q **IN ADDITION TO THE POINTS YOU HAVE ALREADY RAISED, DO YOU HAVE ANY GENERAL POLICY CONCERNS REGARDING FPC'S PROPOSED REVISIONS TO ITS INTERRUPTIBLE SERVICE RATES?**

A Yes. FPC's proposal to eliminate the IS-1 rate schedule and significantly reduce the demand credits for existing IS-1 customers would not only be a drastic measure, it would also ignore the facts that interruptible service is: (1) an important resource that has been and will continue to be relied upon by electric utilities to provide reliable service to customers, and (2) a long-term proposition for interruptible customers.

The interruptible tariffs have been in place for decades. It has been and remains a valuable resource. When capacity is needed to serve firm load customers, interruptible customers, statewide, may be called upon (with or without notice and without limitation as to the frequency and duration of curtailments) to discontinue service so that the lights will stay on. At a time when system reliability has taken center stage in restructuring debates and recognizing that utilities in Florida will be required to add over 14,000 MW of new resources by 2010 to provide the reliability judged necessary by this Commission, such drastic changes in the rates, terms and conditions of interruptible service are not only untimely, but unwarranted. The Commission should not approve any changes that would discourage the continued use of this valuable resource.

Reducing the benefits of interruptible service would also make it less cost-effective for the customer for two reasons. First, for some customers, interruptible service is the only viable option. This is particularly the case for firms that produce commodity products such as phosphate and industrial gases. Electricity is a significant operating cost in producing these products. Firms operating in these industries continue to face increasing global and domestic competition. An arbitrary change in cost allocation policy and drastic rate design changes would further raise their manufacturing costs and seriously hamper the continued operation of these firms.

Second, interruptible power is not cost free for the participating customer. It requires substantial investment in equipment and modifications to manufacturing operations, the cost of which interruptible customers expect to recover over a period of time through lower rates. Thus, rate stability is an important consideration in the design of interruptible rates. Significant increases in interruptible rates that reduce a customer's savings are therefore inequitable to existing customers as a matter of policy, because such increases reduce the rate benefits that these customers expected when they decided to accept the risks of interruptible service.

Q DO YOU BELIEVE IT IS APPROPRIATE TO TREAT INTERRUPTIBLE SERVICE AS A DSM PROGRAM FOR THE PURPOSE OF DESIGNING INTERRUPTIBLE RATES?

A No. There are significant differences between interruptible service and traditional DSM programs.

Q PLEASE EXPLAIN.

A Interruptible service and traditional DSM programs are distinguishable by the obligation to serve. A utility that funds a traditional DSM program, such as home insulation, continues to provide a firm service to its customers. The capacity and energy savings associated with such programs are merely a substitute for the power and energy sales that have been the traditional services provided by a regulated utility. Thus, DSM programs maintain or enhance the quality of service that customers receive.

By contrast, interruptible power is a lower quality of service. The utility does not have an obligation to serve interruptible customers when capacity is needed to maintain service to firm load customers. Non-firm customers are therefore relinquishing their entitlement to use power and energy upon demand in exchange for a lower rate.

Q DOESN'T FPC'S RESIDENTIAL LOAD MANAGEMENT PROGRAM ALSO PERMIT FPC TO REMOTELY DISCONNECT CERTAIN CUSTOMER LOADS?

A Yes. However, interruptible service under the IS schedules is unique in that it provides a substantial amount of capacity savings with only a relatively few number of participants. In addition, interruptions are not limited in either frequency, duration or time of day, and they may be called with or without notice. Interruptible customers cannot become firm customers unless they give three to five years' notice. By contrast, residential load management customers can discontinue participation in this non-firm service by providing only 45 days notice. Further, interruptible load may be used to satisfy FPC's operating reserve requirements as determined by the Florida Reliability Coordinating Counsel (FRCC).

These characteristics, in my opinion, make interruptible service more valuable than other active and passive DSM programs.

Q HAS FPC CALCULATED THE LEVEL OF INTERRUPTIBLE SERVICE CREDIT?

A Yes. FPC filed a cost-effectiveness test which shows that the resulting credit for interruptible customers should be \$3.46 per coincident peak (CP) kW based on a benefit-to-cost ratio of 1.0 and \$2.82 per CP kW based on a 1.2 benefit-to-cost ratio.

Q DO YOU BELIEVE THE COMPANY HAS ADEQUATELY SUPPORTED ITS COST-EFFECTIVENESS CALCULATIONS FOR INTERRUPTIBLE SERVICE?

A No. In his January 11, 2002 deposition in this case, Company witness Slusser testified that he was not familiar with the assumptions underlying the Company's cost-effectiveness calculations. This is the case despite the fact that FPC is proposing drastic changes to its interruptible rates. In fact, it does not appear that the Company has presented any witness in this proceeding that is familiar with the details behind the cost-effectiveness calculations. In my view, this lack of supporting evidence is a sufficient basis for rejecting FPC's proposed reduction in the demand credit for interruptible service.

Q DESPITE THIS LACK OF SUPPORTING EVIDENCE, HAVE YOU BEEN ABLE TO IDENTIFY ANY FLAWS IN FPC'S COST-EFFECTIVENESS CALCULATIONS?

A Yes. First, it appears that FPC's model relies on a single point estimate of avoided fuel costs associated with each avoided generating unit. Because fuel (particularly natural gas) costs are very volatile, it would be more appropriate to calculate a range of reasonable interruptible demand credits using a range of potential fuel costs. This type of scenario analysis is an accepted approach when dealing with volatile model inputs.

Second, it appears that FPC has understated the amount of generating capacity deferred by the presence of interruptible and curtailable service. Specifically, FPC appears to have modeled the amount of deferred capacity based on the amount of existing interruptible and curtailable load, with no reserve margin adjustment. However, FPC currently maintains a generation reserve margin of 15%, and this reserve margin will increase to 20% beginning in the summer of 2004. (See Florida Public Service Commission, Review of 2000 Ten-Year Site Plans, page 37, December 2000.) Thus, the model should reflect the fact that each MW of interruptible load will in fact defer 1.15 or 1.2 MW of generation capacity.

Third, FPC's cost-effectiveness model appears to contain a timing mismatch between the costs and benefits of interruptible service. Specifically, the model assigns costs to interruptible service in the form of incentive payments in the first year of the model's 30-year time horizon, without assigning any avoided generation capacity benefits to that same year in the model. Since the incentive payments are principally made to recognize the avoided capacity cost benefits of interruptible service, the model should include avoided generation capacity costs for each year of the model's time horizon. This approach specifically ignores the capacity benefits provided by interruptible loads in the past, which is unfair.

Finally, the model assigns some costs to interruptible service in the form of increased fuel and O&M costs in certain years. In effect, the model appears to assume that FPC would have to operate less fuel-efficient generating units if it avoids the construction of additional generation. This assumption appears overly pessimistic.

Q ARE THERE ANY OTHER BENEFITS OF INTERRUPTIBLE SERVICE THAT ARE NOT CAPTURED IN FPC'S COST-EFFECTIVENESS ANALYSIS?

A Yes. Interruptible service provides mining and manufacturing operations with the ability to reduce their power costs by locating and expanding their operations in FPC's service territory. As previously stated, these firms operate in very competitive, global industries, and the cost of power is often a major component of their cost structures. Significant increases in the cost of interruptible service of the magnitude proposed by FPC in this case could lead such companies to shut down their operations or relocate them to other states or countries. Studies have shown that every manufacturing job typically creates between three and four additional jobs and generate significant economic benefits in other sectors of the state and local economies. Thus, the net impact of interruptible customers that shut down their operations would be a significant loss of jobs, tax revenues, and associated economic activity for the state of Florida. The substantial economic benefits provided by interruptible service in FPC's service territory should not be ignored in evaluating the proper rate levels for this service.

Q IS INTERRUPTIBLE SERVICE COST-EFFECTIVE?

A Yes. To measure the cost-effectiveness of interruptible service, I have quantified the avoided capacity costs associated with peaking capacity on the FPC system. The analysis is shown in Exhibit ____ (JP-7). It is based on publicly available data regarding the investment and fixed O&M costs of a new conventional combustion turbine. The calculation also relies on the capital structure and return on equity recommendations sponsored by my colleague, Michael Gorman.

As can be seen, the Exhibit shows that the FPC system avoids $75 per kW per year in capacity costs by providing interruptible service. This translates into a savings of $6.25 per CP kW-month, a figure that more than justifies the existing level of interruptible demand credits for IS-1 customers.

Q EVEN IF THE COMMISSION WERE TO ADOPT FPC'S PROPOSED COST-EFFECTIVENESS TEST, IS IT APPROPRIATE TO SET THE BENEFIT-TO-COST RATIO AT 1.2?

A No. Other ratepayers would be no worse off if the credit were set at full avoided cost, provided that the interruptible service rates are recovering all of the out-of-pocket costs to serve interruptible customers, plus an appropriate margin. The ratepayers would be better off even at a 1.0 benefit-to-cost ratio because the presence of interruptible customers on FPC's system provides measurable economic benefits to the state and local economies, as discussed above.

Q **FPC ASSERTS THAT A BENEFIT-TO-COST RATIO OF 1.2 SHOULD BE APPLIED TO GUARD AGAINST THE RISK THAT ACTUAL INTERRUPTIONS MAY PROVE TO BE INFREQUENT. HOW DO YOU RESPOND?**

A This argument mischaracterizes the benefits of interruptible service. The presence of this service provides important benefits to all ratepayers, irrespective of the level of actual interruptions.

First, in the long run, this service will offset the need for additional generating capacity, thereby reducing total capacity costs from what they would have otherwise been without the presence of interruptible service. Second, this service helps to defray some of the fixed costs and, therefore, reduces the cost to serve the remaining firm customers. These are in addition to the other benefits of interruptible service previously cited in my testimony.

Whether or not interruptions actually occur at an assumed frequency is irrelevant in measuring the benefits of interruptible service. The fact that interruptions can occur whenever FPC experiences a capacity shortfall warrants a continuation of this service. In some years, interruptions will be heavy. In other years, they may be relatively light. Since interruptions are not a function of any one factor, attempting to "guess" at the frequency of interruptions during any particular time period would be pure speculation.

The obviously analogy is with a fire insurance policy. Even though many years may pass without incident, the homeowner will continue to pay the insurance company in order to maintain the appropriate coverage. At a minimum, the cost that the system pays for this insurance coverage (in the form of interruptible demand credits) should reflect the avoided cost associated with deferring the installation of new peaking generation capacity on the FPC system. This is the case because peaking capacity is the type of generation that is most likely to be avoided through the continued presence of interruptible load on the utility's system.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS WITH RESPECT TO FPC'S PROPOSALS TO ELIMINATE THE IS-1 RATE SCHEDULE AND REDUCE THE LEVEL OF INTERRUPTIBLE DEMAND CREDIT FOR THIS SERVICE.

A I recommend that the Commission reject these proposals. Instead, the Commission should retain the existing IS-1 rate schedule at the current level of demand credits. FPC has not met its burden of proof to justify a reduction in the existing level of credits for IS-1 customers.

Q IF, DESPITE YOUR RECOMMENDATIONS, FPC'S PROPOSALS ARE ACCEPTED, THEN WHAT OTHER STEPS SHOULD THE COMMISSION TAKE?

A If the Company's interruptible rate proposals are accepted, I recommend that the Commission grandfather IS-1 customers under their existing rates for a period of two years, and allow these customers to terminate service from the Company within that time frame. This approach would give these customers a reasonable opportunity to evaluate and exercise other power supply options before imposing a dramatic and unexpected rate increase on them. In light of the significant investments made by IS-1 customers to take interruptible service, equity demands that such an option be made available to them.

Load Factor Adjustment of the Interruptible Demand Credits

Q UNDER FPC'S PROPOSAL, WOULD ALL INTERRUPTIBLE CUSTOMERS RECEIVE THE $2.82 PER CP KW CREDIT YOU PREVIOUSLY REFERENCED IN YOUR TESTIMONY?

A No. Under FPC's proposal, the $2.82 per kW credit would be reduced in proportion to the customer's billing load factor. These credits would, in turn, be further reduced by any applicable metering voltage adjustment. For example, a primary distribution level customer having a maximum kW demand of 5,000 kW at an 80% load factor would have an effective interruptible credit of only $2.23 per kW ($2.82 per CP kW X 80% X 99% to account for the metering voltage adjustment.)

By contrast, under FPC's existing interruptible rates, IS-1 customers receive an interruptible credit that is applied to the customer's monthly maximum demand. No load factor adjustment is applied to the IS-1 demand credit.

Q IS THIS LOAD FACTOR ADJUSTMENT A VALID APPROACH FOR ALLOCATING THE INTERRUPTIBLE CREDITS WITHIN THE IS CLASS?

A No. First, FPC's proposal uses a customer's billing load factor as a proxy for the customer's coincidence factor. This approach assumes that there is a linear relationship between load factor and coincidence factor. However, FPC has provided no evidence of such a linear relationship using current data for the Company's system.

Second, I would add that even if such a relationship could be demonstrated, since the amount of interruptible load is based on the average 12CP demand of the IS class, the adjustment should be made relative to the class average load factor, not a 100% load factor. The IS coincident load factor is 98%.

Also, recall that the definition of coincidence factor is the ratio of the customer's coincident peak demand (that is, the demand coincident with the one-hour monthly system peak) to the customer's non-coincident peak demand. Thus, the load factor adjustment erroneously implies that the amount of interruptible load is strictly a function of the demand coincident with FPC's one-hour monthly system peak. In reality, interruptions can occur at any time, not just coincident with the system peak or with the on-peak hours. For example, a customer could be planning to operate at his maximum demand but be unable to do so because of a curtailment. If this same customer only operated at a 50% load factor during the month, he would only get credit for half of the interruptible capacity that he is providing to FPC.

If a customer's load factor is sufficiently low in a given month, FPC's proposed adjustment could effectively cause the customer to pay a firm rate level for an interruptible service of lower quality. This result could cause interruptible customers to reduce their operations in FPC's service territory or to relocate those operations to other parts of the country.

Q HOW SHOULD THE INTERRUPTIBLE CREDIT BE STRUCTURED?

A The interruptible credit should reasonably measure the amount of load that the Company is not obligated to serve during an interruption event. When an interruption event occurs, an interruptible customer's operating demand may immediately be reduced to zero. However, reducing existing operating demand to zero is not the only benefit of an interruption. In lieu of an interruption, a customer may have anticipated operating at a higher level of demand. The fact that the customer was prevented from imposing a higher level of demand during an interruption period is providing a benefit to the system.

To measure this benefit, it is my recommendation that the amount of interruptible demand subject to credit be determined by quantifying each customer's maximum demand on the day of, the day before, and the day after an interruption. This should provide a more reasonable estimate of the amount of interruptible load that was not served during an interruption event.

In lieu of this approach, however, the credit should be applied as a reduction to the maximum demand charge. In other words, each customer should receive the same credit per kW of billing demand. In no event should load factor be used to adjust the amount of the credit unless the load factor is based on the class average, not the 100% load factor that the Company proposes to use.

Notice Requirement

Q **FPC PROPOSES TO APPLY A THREE-YEAR NOTICE PERIOD FOR TRANSFERRING FROM INTERRUPTIBLE TO FIRM SERVICE. DO YOU BELIEVE THIS NOTICE PERIOD IS APPROPRIATE?**

A No. This notice period is designed to give FPC adequate time to "firm up" the power it provides to the interruptible customer that switches to firm service. Under today's market conditions, FPC could either construct a combustion turbine or purchase firm power from an off-system source in less than three years. In my judgment, a shorter notice period of two years would be appropriate.

Q **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

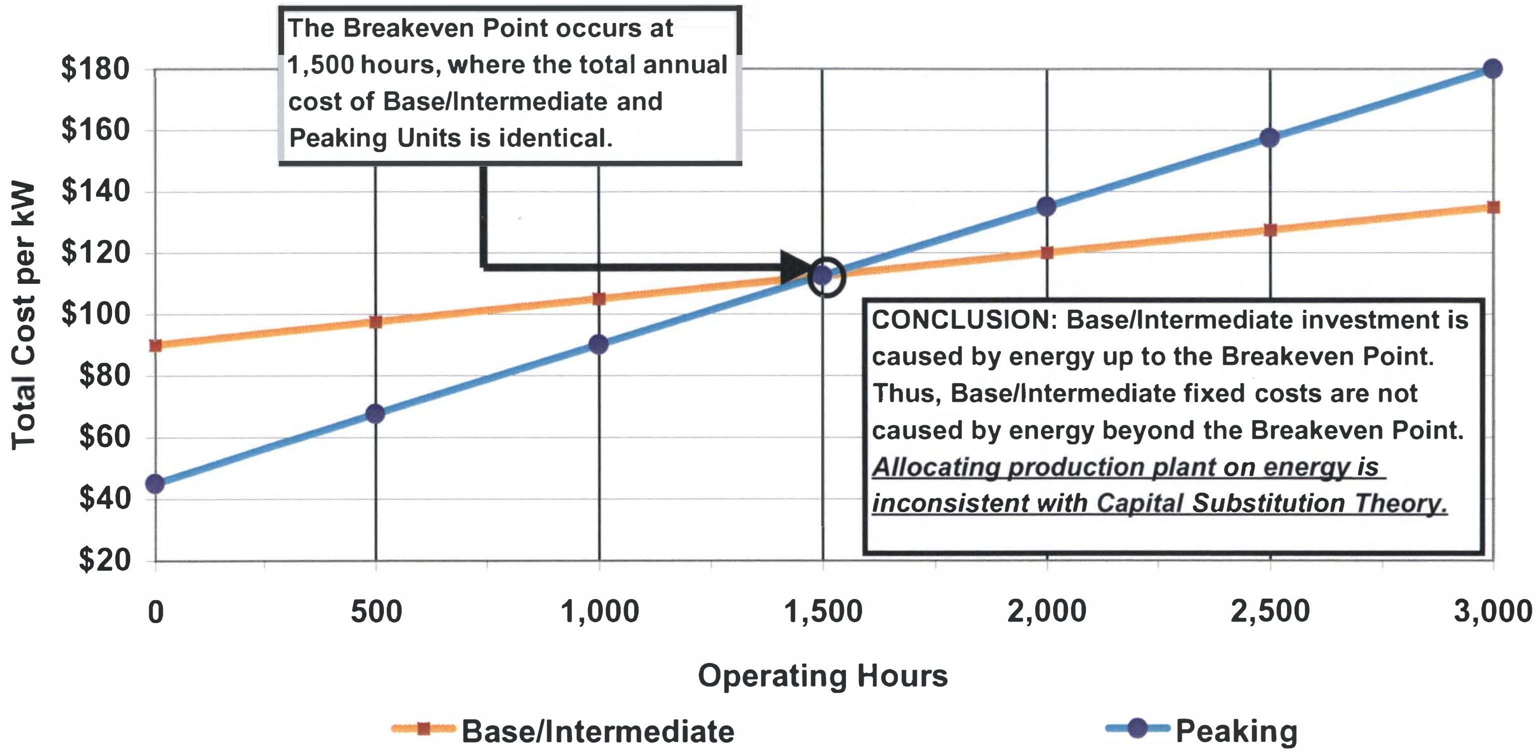
A Yes, it does.

\\Larry\Docs\TSK\7718\testimony\26913.doc

CAPITAL SUBSTITUTION THEORY

Total Cost Versus Operating Hours

By Investment Type

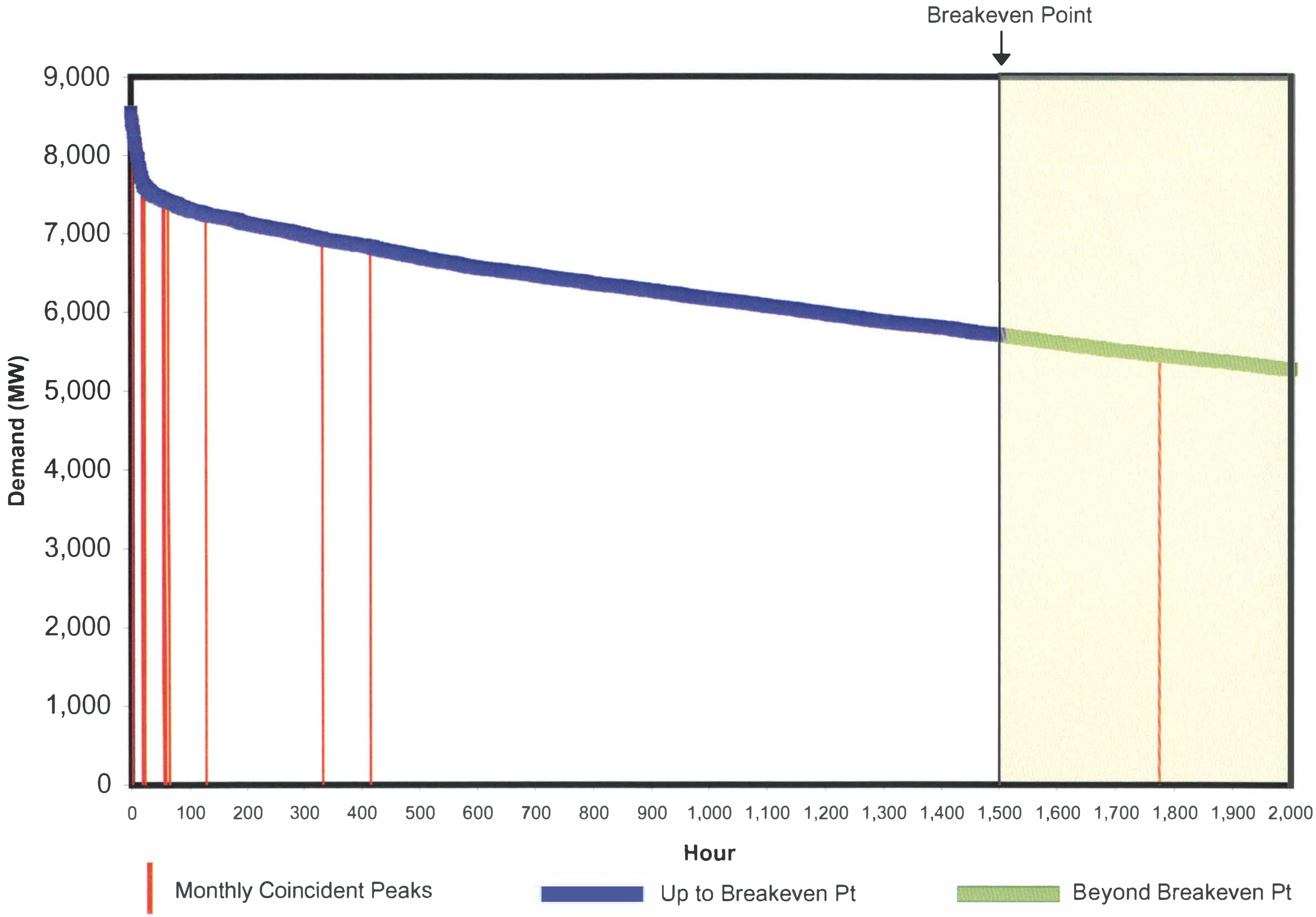


ASSUMPTIONS

Capacity Type	Fixed Cost/kW	Variable Cost/MWh
Base/Intermediate	$90	$15
Peaking	$45	$45

FLORIDA POWER CORPORATION

Cost Allocation Using The 12CP Method



Monthly Coincident Peaks

Hour	MW
0	8,548
2	8,421
19	7,717
24	7,607
56	7,442
59	7,430
65	7,409
129	7,247
333	6,926
416	6,828
1774	5,451
1775	5,451

FLORIDA POWER CORPORATION

Cost Allocation Using Average Demand

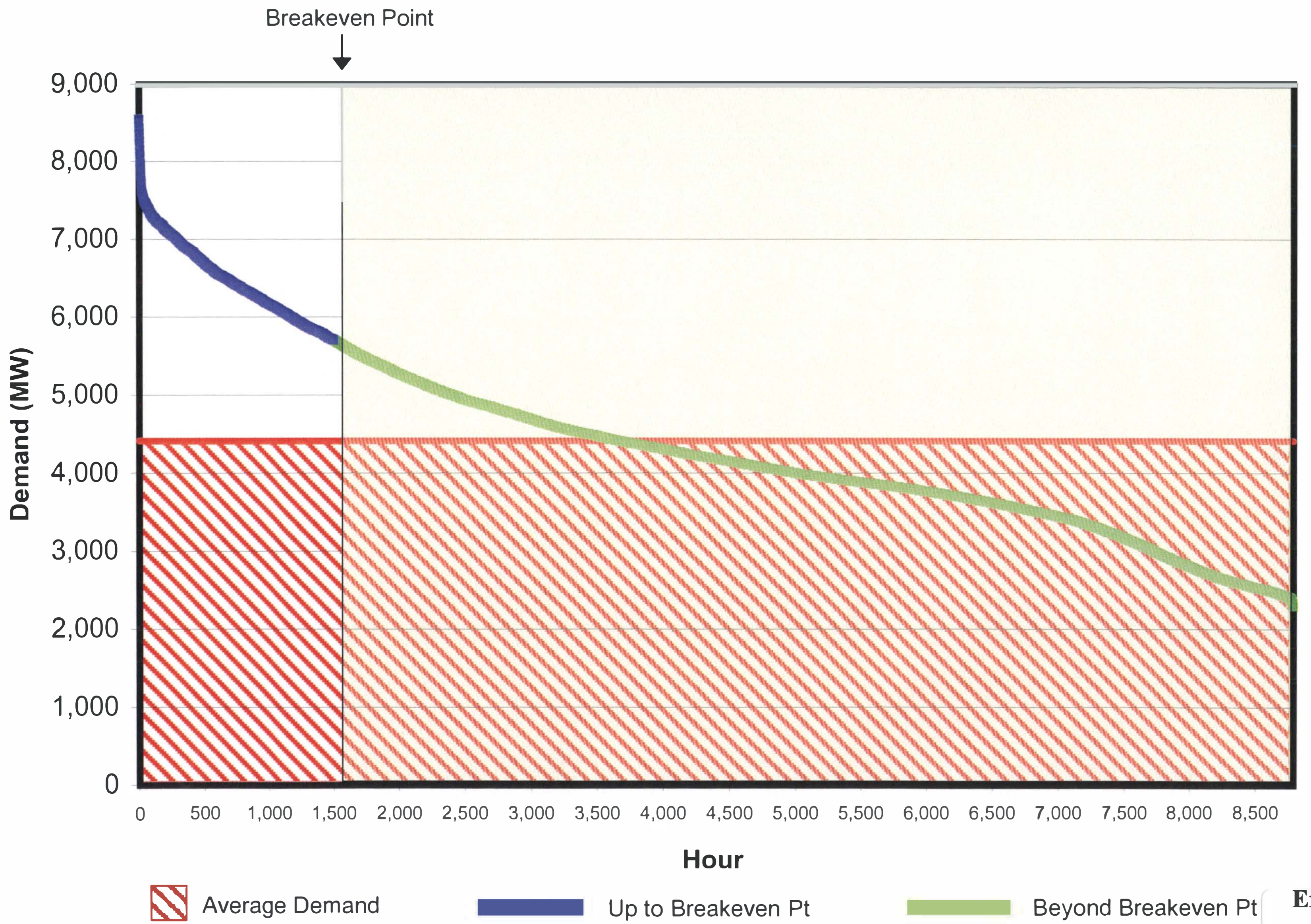


Exhibit ____ (JP-3)

FLORIDA POWER CORPORATION

Allocated Net Production Investment by Class

Allocation Method: 12CP and 25% AD

Line	Class	Net Production Investment	12CP Demand	Unit Cost ($/12CP kW)
		(1)	(2)	(3)
1	Residential	$ 763,890,000	4,116,900	$186
2	GS Non-Demand	37,983,000	190,100	$200
3	GS 100% LF	1,942,000	8,800	$221
4	GS Demand	414,284,000	1,995,800	$208
5	Curtailable	4,088,000	17,800	$230
6	Interruptible	60,319,000	280,000	$215
7	Lighting	3,330,000	6,300	$529
8	Total	$1,285,836,000	6,615,700	$194

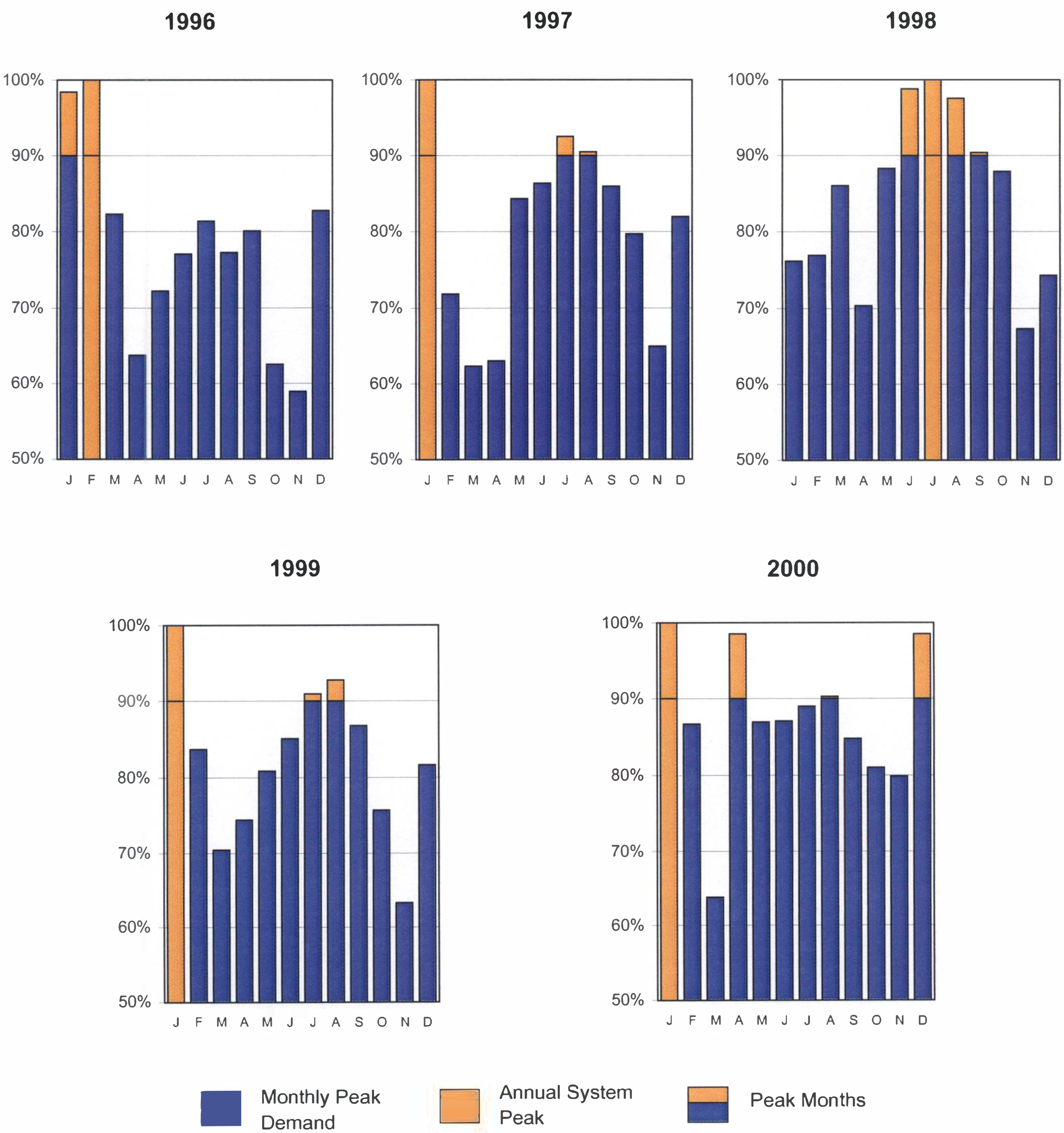
FLORIDA POWER CORPORATION

Comparison of Net Plant Investment and Operating Expense By Capacity Type
Forecast Year Ending December 31, 2002

Line	Capacity Type	Net Investment ($/kW) (1)	Operating Expense ($/MWh) (2)
1	Base Load	$272	$21.41
2	Intermediate	$33	$37.08
3	Peaking	$176	$67.51
4	System Average	$192	$27.35

FLORIDA POWER CORPORATION

Analysis of Monthly Peak Demands
as a Percent of the Annual System Peak
<u>for the Fiscal Years 1996 through 2000</u>



FLORIDA POWER CORPORATION

Summary of Load Characteristics

Line	Year	System Peak (MW) (1)	Maximum-to-Minimum Monthly Peak (2)	Maximum-to-Average Monthly Peak (3)	Annual Load Factor (4)
1	1996	8,807	1.70	1.28	59%
2	1997	8,066	1.60	1.25	62%
3	1998	8,004	1.49	1.18	66%
4	1999	8,318	1.58	1.22	68%
5	2000	8,548	1.57	1.15	65%

Source: FERC Form No. 1, Report Years 1996 - 2000.

FLORIDA POWER CORPORATION

Value of Interruptibility

Line	Description	Amount ($/kW-Yr) (1)
1	Avoided Capacity Cost	$58.80
2	Reserve Margin	20%
3	Demand Loss Factor	0.94
4	Value of Interruptible Resource	$75.06
5	Round to	$75.00

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Intervenor Testimony and Exhibits of Jeffry Pollock on Behalf of the Florida Industrial Power Users Group has been furnished by (*) hand delivery and U.S. Mail to the following this 18th day of January, 2002:

(*)Mary Anne Helton
Adrienne Vining
Division of Legal Services
Public Service Commission 2540
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

James McGee
Florida Power Corporation
One Progress Plaza, Suite 1500
Post Office Box 14042
St. Petersburg, Florida 33701

(*)Gary L. Sasso
James Michael Walls
Jill H. Bowman
W. Douglas Hall
c/o Kim Pullen
Carlton Fields, P.A.
Post Office Box 2861
St. Petersburg, Florida 33731

Daniel E. Frank
Sutherland Asbill & Brennan LLP
1275 Pennsylvania Avenue, NW
Washington, DC 20004-2415

Thomas A. Cloud
Gray, Harris & Robinson, P.A.
301 East Pine Street, Suite 1400
Post Office Box 3068
Orlando, Florida 32801

Charles J. Beck
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, Florida 32399-1400

Michael B. Twomey
8903 Crawfordville Road
Post Office Box 5256
Tallahassee, Florida 32314-5256

Lee Schmudde
Vice President, Legal
Walt Disney World Co.
1375 Lake Buena Drive
Fourth Floor North
Lake Buena Vista, Florida 32830

Vicki Gordon Kaufman

John W. McWhirter, Jr.
McWhirter, Reeves, McGlothlin, Davidson
Decker, Kaufman, Arnold & Steen, P.A.
400 North Tampa Street, Suite 2450
Tampa, Florida 33601-3350
(813) 224-0866 telephone
(813) 221-1854 telefax

Vicki Gordon Kaufman
McWhirter, Reeves, McGlothlin, Davidson
Decker, Kaufman, Arnold & Steen, P.A.
117 South Gadsden Street
Tallahassee, Florida 32301
(850) 222-2525 telephone
(850) 222-5606 telefax

Attorneys for the Florida Industrial
Power Users Group