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Florida Power
CORPORATION

JAMES A. MCGEE
SENIOR COUNSEL

February 17, 1995

Ms. Blanca S. Bayó, Director
Division of Records and Reporting
Florida Public Service Commission
101 East Gaines Street
Tallahassee, Florida 32399-0870

Re: Docket No. 941101-EQ

Dear Ms. Bayó:

Enclosed for filing in the subject docket are fifteen copies each of the Direct Testimony and Exhibits of the following Florida Power Corporation witnesses:

15 1. Robert D. Dolan - 01973-95
14 copies 2. Charles J. Harper 01974-95
13 copies 3. Henry I. Southwick, III - 01975-95
16 copies 4. Steven A. Lefton - 01976-95

Please acknowledge your receipt of the above filings on the enclosed copy of this letter and return to the undersigned. Also enclosed is a 3.5 inch diskette containing the above-referenced document in Word Perfect format. Thank you for your assistance in this matter.

Very truly yours,

James A. McGee

ACK
AFA
APP
CAF
CMU
CTR
EAG
LEG 1
LIN Orig & 6
OPC
RCH
SEC 1
WAS
OTH

JAM/jb
Enclosure

cc: Parties of Record

RECEIVED & FILED

FPSC-BUREAU OF RECORDS

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the Direct Testimony and Exhibits of Florida Power Corporation Witnesses Robert D. Dolan, Charles J. Harper, Henry I. Southwick, III and Steven A. Lefton have been provided by regular U.S. Mail on the 20th day of February, 1995 to the following:

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2005.

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Florida Power Corporation for determination that its plan for curtailing purchases from Qualifying Facilities in minimum load conditions is consistent with Rule 25-17.086, F.A.C.

Docket No. [redacted]

Submitted for filing: February 20, 1995

DIRECT TESTIMONY OF
HENRY I. SOUTHWICK, III

ON BEHALF OF

FLORIDA POWER CORPORATION

FLORIDA POWER CORPORATION

DOCKET NO. 941101-EQ

DIRECT TESTIMONY OF HENRY I. SOUTHWICK, III

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Henry I. Southwick, III. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

Q. By whom are you employed and in what capacity.

A. I am employed by Florida Power Corporation ("Florida Power" or "the Company") as the Director of Energy Control.

Q. Please describe your education and business experience.

A. I have a Bachelor of Science degree in Electrical Engineering from Clemson University and a Masters Degree in Engineering from the University of South Florida. I am a registered Professional Engineer in the State of Florida. I have held various positions at Florida Power Corporation in Industrial Development, Division Operations, and Economic Research. In 1983, I was promoted to Manager of System Planning with the responsibility for Florida Power's generation, transmission and distribution planning. In 1990, I was named Director of Engineering and Technical Services for the Fossil Operations area of Florida Power. I became Director of Energy Control in July, 1992.

Q. What are your responsibilities in your current position?

A. As Director of Energy Control I am responsible for the day-to-day operation of the Florida Power electric system. This includes the scheduling and dispatching of all power resources available to Florida Power to serve customer demand and the operation of the electric transmission system. I am also responsible for interchange operations between Florida Power and other utilities in Florida and the Southeast.

Q. Have you ever testified before the Florida Public Service Commission?

A. Yes, I have testified in several previous Florida Power rate and fuel cost recovery proceedings and in connection with Florida Power's acquisition of assets from Sebring Utilities Commission.

II. PURPOSES AND ORGANIZATION OF TESTIMONY

Q. What is the purpose of your testimony?

A. I will explain what is meant by the terms "minimum load conditions" and "minimum load emergency." I will show why those system conditions can create reliability and cost consequences that need to be addressed by any utility in a prudent and predictable manner. I will also outline the extent and nature of Florida Power's minimum load problem by reference to the Company's loads and resources. Having laid out the problem, I will then describe Florida Power's efforts to deal responsibly with the minimum load problem first by using all reasonable measures to reduce its own generation levels and ultimately by developing the October 12, 1994 Generation Curtailment Plan For Minimum Load Conditions ("the Curtailment Plan"). I will explain the basic principles incorporated into the Curtailment Plan in order to achieve equitable procedures that can be readily implemented by the Company's system operating personnel. Finally, I will discuss the Company's continuing desire to respond to legitimate Qualifying Facility ("QF") operating concerns if this can be done consistent with the objectives of the Curtailment Plan.

Q. Are you the Company's principal policy witness in this proceeding?

A. Yes. To the extent that the Curtailment Plan reflects judgment calls or Company policy decisions, I will be available to testify on those matters.

Q. Are you sponsoring any exhibits in this docket?

A. Yes. I am sponsoring Exhibit No. ___(HIS-1) which contains excerpts from several relevant publications of the North American Electric Reliability Council ("NERC"), the Southeastern Electric Reliability Council ("SERC") and the Florida Electric Power Coordinating Group, Inc. ("FCG"); Exhibit No. ___(HIS-2) which reproduces the Unit Power Sales Agreement between Florida Power and the Southern Companies; Exhibit No. _____ (HIS-3) which shows how QF purchases during minimum load conditions create negative avoided costs; and Exhibit No. ___(HIS-4) which includes examples of correspondence sent by Florida Power to its QF suppliers soliciting their involvement in dealing with the minimum load problem.

III. THE NATURE OF A MINIMUM LOAD EMERGENCY

Q. What is meant by the term "minimum load emergency"?

A. A minimum load emergency can be defined as a situation in which a utility's total system demand (or "load") falls to such a low level that the minimum generating input into the system exceeds that load level. In other words, such an emergency condition occurs when the utility can no longer match its generation and load levels because there is too much generation in relation to the system load.

Q. Please describe the components of a utility's load.

A. A utility's total system load consists of all purchases of electricity from the utility at a given point in time plus losses and station service. The load includes the electricity requirements of the utility's wholesale and retail customers as well as its off-system sales to other utilities. Typically, a distinction is drawn between "firm" loads (which include requirements services and assured capacity sales to others) and "non-firm" loads (which are interruptible either by rate schedule or contract). However, when measuring a utility's "minimum load" at any moment, one would normally include all of the demands being placed on the system at that moment.

Q. What are the components of a utility's available power supply?

A. Generally speaking, a utility's resources consist of (i) its own generating units; (ii) its purchases from QFs or other non-utility generators; (iii) its power purchases from other utilities; and (iv) its dispatchable demand-side management capability. A utility's generating units can have substantially different operating profiles, with some running virtually continuously as "baseload" units, some running intermittently as "intermediate" units, and still others operating only to satisfy "peak" demand periods. Likewise power purchase contracts -- with other utilities and with QFs -- may call for varying amounts of capacity availability.

When measuring a utility's minimum generation, one must consider the <u>lowest</u> levels to which the utility's resources can be reduced. The minimum generation usually will equal the sum of (i) the lowest prudent and economic operating levels for the utility's own units (typically baseload operation); (ii) the minimum purchases required under QF contracts or rate schedules; and (iii) the minimum purchase obligations under firm capacity purchase contracts with other utilities.

Q. Is it important for a utility to match its resources and loads at all times?

A. Yes, it is. In fact, this is a fundamental objective of any prudent utility. During peak load periods, it is imperative to have enough generation available to satisfy rising demands on the system, plus a reasonable margin of reserves to account for contingencies. It is equally important to have the capability during off-peak periods to dispatch or cycle off generating resources as the load drops. Both daily and seasonally, most utilities experience wide disparities between their minimum and maximum loads. Given the resources available to the utility, its system operating personnel strive to dispatch those resources in the most economically efficient and operationally reliable manner possible so as to follow the system's fluctuating loads. Obviously, careful attention must be given to how this is accomplished. For example, it would be inappropriate from both a reliability and a cost perspective to shut down a baseload resource to meet a temporary trough in the system load, where doing so prevents the unit from serving the load as it begins to rise again.

Q. It is easy to understand why a utility must have enough generation to meet its peak demands, but why do you conclude that it is equally important to be able to reduce generation in order to match minimum load levels?

A. I base this conclusion on both reliability and economic considerations. From a reliability standpoint, keeping loads and resources in balance is a fundamental matter of system integrity and reliability. Accepted industry-wide standards require that loads and resources be kept in balance to reliably serve customers and to protect the equipment of the utility, other interconnected systems, and the customers. A utility cannot maintain a practice of intentionally dumping excess generation onto the systems of other neighboring utilities. This unscheduled energy, commonly called "inadvertent interchange," must be held to a minimum in order to satisfy industry standards and the terms of inter-utility interchange contracts.

Given the heavily interconnected nature of the nation's electrical grid, generation excesses, like generation deficiencies, can create cascading adverse effects that place unacceptable burdens on other parties. Electricity must be used instantly, and excess generation creates frequency imbalances that can severely damage utility and customer equipment. In layman's terms, too much generation will cause motors to burn out. If neighboring utilities were to isolate Florida Power's system to avoid such impacts on their facilities, then the excess generation on Florida Power's own system would be even more detrimental.

Q. What are the economic considerations on which you base your conclusion?

A. The incurrence of uneconomic power supply costs during minimum load periods has an adverse impact on the utility and its ratepayers. Moreover, as the system is ramping-up to follow the rising load after a minimum load period, the utility will incur additional uneconomic costs if it has previously been required to operate its resources at levels less than normal minimums or to shut off units to balance generation and load. When the Company is compelled to make uneconomic purchases of energy from third parties, then in the words of this Commission's

Rule 25-17.086, those purchases "will result in costs greater than those which the utility would incur if it did not make such purchases" and will "otherwise place an undue burden on the utility."

The Federal Energy Regulatory Commission ("FERC") provided an excellent example of this problem when it issued its QF regulations in 1980. This example is cited in Mr. Robert D. Dolan's testimony. The FERC correctly observed that if a utility operating only its baseload units in minimum load conditions were forced to cut back output from those units in order to continue making a QF purchase, then the baseload units might not be able to ramp-up their output when needed again to follow the next increase in load. As a consequence, it would be necessary for the utility to meet that rising load by running less efficient, higher cost, intermediate or peaking units. As noted by the FERC, this would result in a negative avoided cost for the utility. The adverse cost impacts also are exacerbated by the fact that cycling of generating units causes a variety of other start-up and unit-related costs. I will briefly describe these impacts later in my testimony and I refer to the testimony of Mr. Steven A. Lefton for more detail.

Q. You have testified that it is necessary for a utility to keep its loads and resources in balance in order to satisfy accepted industry-wide standards. Please explain.

A. This basic operating tenet finds solid support in the industry standards published by NERC. The NERC standards, in turn, are endorsed and followed both by SERC and the FCG. Florida Power subscribes to the operating criteria published by each of these industry organizations. Following are representative statements from the NERC Operating Guides. I hasten to add, however, that the requirement for balancing resources and loads is such a basic concept that it literally permeates those Operating Guides. The text of the applicable NERC Operating Guides is reproduced for the Commission's reference in my Exhibit No. ___(HIS-1). In addition, that exhibit includes excerpts from the SERC and FCG manuals which confirm the intention of those organizations to carry out the objectives of the NERC Operating Guides.

1. <u>Representative excerpts from NERC Operating Guides:</u>

> Each control area shall operate sufficient generating capacity under automatic control to meet its obligation to continuously balance its generation and interchange schedules to its load.
>
> * * * * * *
>
> All generating units of consequential size, including jointly owned units capable of regulating, should be equipped with AGC to ensure that the control area can continuously balance its generation with its demand plus net scheduled interchange.

2. <u>Excerpt from SERC Agreement:</u>

> Membership in SERC is voluntary, but members recognize a commitment to comply with NERC and SERC guidelines for the planning and operating of the interconnected electric power system.

3. <u>Excerpt from FCG October 1994 Operating Committee Handbook:</u>

> The FCG Operating Committee accepts the NERC Operating Guides as a basis for operations. The Florida Specific Procedures contained in this Handbook were written to either clarify or enhance a

specific NERC Operating Guide for use within the Florida Subregion. The NERC Operating Guides are not included in this Handbook, but the Guides are referenced to the applicable Florida Specific Procedure in the Table of Contents. In cases where there is no Florida Specific Procedure associated with a NERC Guide, the Guide title and number is referenced in the Table of Contents to direct the reader to the NERC manual.

IV. FLORIDA POWER's LOADS

Q. Do Florida Power's system loads fluctuate significantly?

A. Yes, the Company's total system demand can vary by as much as 1,000 MW per hour and can range from a low of about 1,850 MW up to almost 8,000 MW. It is crucial to match generation with these quickly fluctuating loads as they rise and as they fall.

Q. Please describe the fluctuation patterns in the Company's loads.

A. Florida Power's loads vary both daily and seasonally based primarily on prevailing weather conditions. This is because the Company's largest loads are related to heating and cooling requirements. The Company generally experiences its lowest customer demands late at night and early in the morning -- between 11:00 p.m. and 7:00 a.m. on weekdays, and between 11:00 p.m. and 8:00 a.m. on weekends and holidays.

Florida Power is a winter peaking utility because its service area occasionally experiences winter cold snaps which temporarily drive up demand to very high levels. However, the Company's lowest load periods also tend to occur during the fall, winter and spring months, when the weather is often very mild.

Loads lower than 2,500 MW are considered to be the Company's "minimum load" conditions. The minimum load conditions typically occur during the October through May time frame, although the load may fall below 2,500 MW during other months as well. The example provided on page 3 of the Curtailment Plan (Exhibit No. ___(RDD-1)) provides a good illustration of the lowest load conditions experienced in the fall-winter-spring of 1993-1994. That example shows that the lowest load day per month for the eight-month period (October, 1993 - May, 1994) and the corresponding minimum gross loads for each day were as follows:

October 31, 1993	2,009 MW
November 26, 1993	1,859 MW
December 5, 1993	1,954 MW
January 3, 1994	1,917 MW
February 7, 1994	1,893 MW
March 14, 1994	1,931 MW
April 4, 1994	1,963 MW
May 22, 1994	1,902 MW

Q. What are the comparable data for the period between October 1, 1994 and January 31, 1995.

A. The comparable data for that period are as follows:

October 16, 1994	2,015 MW
November 27, 1994	1,926 MW
December 30, 1994	2,041 MW
January 2, 1995	1,935 MW

V. FLORIDA POWER's RESOURCES

Q. Turning now to the Company's available resources, how many generating units does Florida Power own and operate?

A. Florida Power has 56 generating units located at 14 stations, and one combustion turbine cogeneration unit. The total installed net winter generating capability is about 7,335 MW.

Q. Please describe the Company's baseload generation.

A. Florida Power owns five baseload units representing 3,031 MW of net winter generating capability. This consists of (i) Crystal River Units 1, 2, 4 and 5, which are fueled by coal; and (ii) Crystal River No. 3 (755 MW net) which is a nuclear unit.

Q. Next, please describe Florida Power's intermediate units.

A. Florida Power owns eight oil- and gas-fired steam intermediate units as follows: Anclote Units 1 and 2; Bartow Units 1, 2 and 3; and Suwannee Units 1, 2 and 3. The intermediate units account for a total of 1,630 MW of net winter generating capability.

Q. How many peaking units does the Company own?

A. The Company owns 43 peakers totaling 2,634 MW of net winter generating capability. These are: DeBary Units P1-P10; Intercession City Units P1-P10; Suwannee River Units P1-P3; Bartow Units P1-P4;

Turner Units P1-P4; Bayboro Units P1-P4; Higgins Units P1-P4; Avon Park Units P1-P2; Rio Pinar; and Port St. Joe.

Q. Where is the Company's cogeneration unit located?

A. Florida Power owns a 40 MW cogeneration unit at the University of Florida in Gainesville.

Q. Does the Company have other capacity resources?

A. Yes. In addition to its substantial demand-side management activities, the Company purchases capacity from two other utilities and from a number of QFs. Mr. Dolan's testimony describes the QF purchases, which accounted for roughly 1,000 MW as of January 1, 1995 and will exceed 1,100 MW later this year. The utility purchases are from (i) the Southern Companies (approximately 400 MW); and (ii) Tampa Electric Company (50 MW).

Q. Please summarize Florida Power's total net generating capability, including purchases.

A. Chart 1 at page 6 of the Curtailment Plan which is Mr. Dolan's Exhibit No. ___(RDD-1) showed a total system net generating capability of approximately 8,707 MW. As explained in Mr. Dolan's testimony, that figure should now be increased to 8,817 MW to reflect additional QF capacity and energy available to the Company.

Q. Does the Company require all of this generation for peak load purposes?

A. Yes. The Company requires this generating capability to meet its peak load needs, when taking into account unit outages, reserve requirements and other contingencies.

Q. Does the Company need all of this generation under minimum load conditions?

A. Obviously not. The 8,817 MW total far exceeds the minimum load levels of 2,500 MW and below. Indeed, for the reasons I explained previously, the Company must reduce a significant amount of its total available generation to match its minimum load levels.

VI. FLORIDA POWER's ABILITY TO RESPOND TO FALLING CUSTOMER LOADS

Q. What measures can the Company take with respect to its own resources to follow the load as it declines toward minimum load conditions?

A. First, I should note that the Company's system operating personnel plan ahead, to the maximum extent practicable, to have resources available when needed and off-line when not needed. For example, plant maintenance typically is scheduled during anticipated low load periods. Similarly, power purchases and sales may be scheduled so as to minimize capacity resources when they are not required. In other words, there are long-term and intermediate-term measures which are routinely taken in anticipation of the need to reduce generation when loads are low.

The system operators also have the ability, as shorter-term measures, to take the following steps aimed at matching generation and load: (i) reducing inter-utility capacity purchases to minimum levels permitted by the applicable purchase contracts; (ii) maximizing economic off-system sales to other utilities; (iii) reducing the Company's generating units to their minimum generation levels consistent with reliability constraints and operating conditions at the time; and (iv) exercising voluntary unit output reductions agreed to by certain of the Company's QF suppliers. The QF output reductions are discussed in Mr. Dolan's testimony. I will describe the other three measures available to the system operating personnel.

Q. Would you please elaborate on the first of these measures -- reducing inter-utility capacity purchases?

A. As I noted previously, Florida Power currently is buying 50 MW of capacity from Tampa Electric and about 400 MW from the Southern Companies. The contract with Tampa Electric permits Florida Power to reduce the 50 MW purchase to zero each day. This is a measure which the system operating personnel routinely take under minimum load conditions.

Q. What about the 400 MW purchase from the Southern Companies?

A. Through 1994, half of the 400 MW from the Southern Companies was purchased under Schedule E of an Interchange Agreement between the parties, and the other half was purchased under a separate Unit Power

Sales Agreement. Under those arrangements, Florida Power could be required to purchase a minimum of 84 MW depending upon conditions on the Southern Companies' system. Since the beginning of 1995, all of the 400 MW purchase is occurring under the Unit Power Sales Agreement. The minimum that the Southern Companies can now require the Company to buy and take is 168 MW

Q. What provisions in the Unit Power Sales Agreemen* impose this minimum take requirement?

A. The minimum purchase obligation is set forth in Section 3.6 of the Unit Power Sales Agreement which is entitled "Minimum Operation Capacity Obligation." For the Commission's convenience, I am including a copy of the entire Unit Power Sales Agreement as Exhibit No.___(HIS-2).

Section 3.6 requires Florida Power to take a proportionate share of the energy produced by the Southern Companies' Miller generating units and Scherer Unit No. 3 whenever those units are operating at "Minimum Operating Conditions." It is possible that the Minimum Operating Conditions at one or more of the Southern Companies' units will not coincide with Florida Power's minimum load conditions. In that case, the minimum purchases associated with that unit would not apply.

Q. Does the Curtailment Plan assume that the Southern Companies' system conditions will be such as to compel the Company to take the minimum 168 MW?

A. The background discussion in the Curtailment Plan states that Florida Power may be compelled to take the full 168 MW under the Unit Power Sales Agreement, and the minimum generation levels shown, for example, on Chart 2 at page 16 of the Plan (Exhibit No. ___(RDD-1) assume that the minimum take requirement will be applicable. However, I want to emphasize that this minimum take will affect the actual implementation of the Curtailment Plan only if Minimum Operating Conditions on the Southern Companies' units coincide with Florida Power's minimum load conditions so that Florida Power is compelled to accept the minimum takes during its minimum load period. The instructions to the system operating personnel (Appendix C to Exhibit No. ___(RDD-1)) make clear that the purchases from the Southern Companies are to be reduced as much as possible before any curtailments take place.

Q. Is there reason to believe that the minimum take requirement will not always be applicable?

A. As noted, the minimum takes depend upon conditions on the Southern Companies' system. The purchases are not always required. In fact, the minimum take requirement was not applicable on October 19, 1994, when the Company first implemented the Curtailment Plan. Therefore, the need for QF curtailments was reduced on that occasion by 84 MW (recall that the 1994 minimum was only 84 MW, as compared to the current 168 MW). Similarly, during later curtailment experiences: no purchases were made from the Southern Companies on January 1, 1995; only 23 MW from Scherer Unit No. 3 was purchased on January 2, 1995; the amounts purchased on January 7 and 8, 1995 ranged from 109 MW to 132 MW; the amounts purchased on January 14, 1995 were 96 MW or less; and the purchase amounts ranged from 8 MW to 95 MW during the curtailments on January 30, 1995.

Q. You stated that, in response to an impending minimum load condition, the Company's operating personnel also can reduce the likelihood of having excess generation by maximizing economic off-system sales. Please explain.

A. An increase in off-system sales to third parties has the same net effect as a corresponding increase in load. The Company often makes inter-utility sales under its various interchange contracts for long and intermediate time frames. In addition, the system operating personnel also engage in short-term sales when the system has available generation. Many such energy sales are made on the Florida Energy Broker System. Florida Power has direct electrical interconnections with 13 other generating utilities and makes every reasonable effort to sell economy energy to others.

Q. Are there limitations on the Company's ability to sell power off-system in anticipation of or during a minimum load condition?

A. Yes, there are. For example, the off-system sales must be made at a price that at least recovers the incremental cost of producing the energy. It is my understanding that the governing FERC pricing policies mandate that the price for off-system opportunity sales be no lower than the seller's incremental cost.

Another factor limiting the Company's ability to market energy during minimum load conditions is the relative state of its neighboring utilities' power supply needs at the time. Florida Power cannot sell power unless it has a willing buyer, and it is quite likely that other interconnected utilities, whose loads also are weather-related, will be facing low load conditions coincident with Florida Power's incurrence of minimum load conditions. In other words, when Florida Power's loads are very low, it may have difficulty finding a willing purchaser for its available generation.

Q. How does the ability to sell power off-system affect the Company's implementation of the Curtailment Plan?

A. Just as the Plan instructs the Company's system operating personnel to minimize the power purchases, it also instructs them to maximize off-system sales as a means of mitigating the need for QF curtailments. In fact, the Plan directs that this will be done, not once, but throughout the minimum load period. The more successful the Company is in making these sales on a given occasion, the less impact QFs will feel from the Curtailment Plan.

Q. You previously mentioned a third step that the system operations personnel can take as the system load declines -- reducing the output from Florida Power's own units. Please explain how this occurs.

A. Actually, managing the generation levels of the Company's units is not a single "step," but rather a series of "steps" which is ongoing as a normal part of the system operating and dispatch functions. Each of the Company's units has distinctive operating characteristics. As a class and under normal conditions, peaking units are capable of being cycled on and off regularly to meet peak energy needs. Intermediate units likewise are capable of being cycled on and off, but generally are operated more constantly than peakers because of their lower running costs. Baseload units, which are the least expensive units to run, typically operate more or less on a must-run basis as the system's work-horses to meet the lower end of the load curve.

In addition to the general operational limits of the types of units, individual units also have their own individual operating profiles. The Company's system dispatchers routinely interact with the plant operators when evaluating the most reliable and economic mix of resources to use to meet the system's changing conditions.

Q. Can you be more specific about Florida Power's intentions for running its own units in anticipation of and during minimum load periods?

A. The Company's objective, whenever possible given the current condition of its various units and other system constraints, is to minimize the need for QF curtailments by maximizing its own unit output reductions in a manner that is consistent with sound operating practices. Florida Power has been engaged in efforts since at least 1993 to investigate the true minimum operating levels of its various generating units because we envisioned that potential minimum load problems would occur in the fall of 1994 with the addition of large new increments of QF capacity. As a consequence of these efforts, the Company is running its own units today at much lower levels of output than it did several years ago. I should note that the Curtailment Plan anticipates that Florida Power will substantially curtail its own generating units before asking any QF to reduce its output. Given these commitments by the Company, I believe that the Curtailment Plan represents a conservative, rather than an aggressive, approach to QF curtailment.

Q. Please describe the sequence in which Florida Power will dispatch its own units in a minimum load condition.

A. To the extent we can do so in light of unit and system conditions at the time, the Company will first respond to minimum load conditions by cycling off its peaking and intermediate units.

Next, the Company will reduce its coal-fired baseload units to their normal minimum operating levels while maintaining enough margin for load control and system security. Again, this assumes that such reductions are practical at the time. Florida Power has determined that it would incur unacceptable operational risk and costs if it cycled these units off entirely. These units are needed on the system for Automatic Generation Control ("AGC") and load following purposes. Finally, the Company will cycle off its University of Florida combustion turbine. It is worth noting that, under normal operating conditions, this treats the Company's own cogeneration plant as fully curtailable before any curtailments are required for unaffiliated QFs.

Q. What do you mean when you refer to "normal minimum operating levels" for the coal units?

A. As I have noted, baseload units normally are operated at a high capacity factor to satisfy the low end of the utility's load curve. Nonetheless, preliminary evaluation of the Crystal River 1, 2, 4 and 5 units suggests that under normal operating conditions, they can be dispatched down to lower operating levels in order to respond to minimum load conditions. Specifically, the Company is estimating that these units generally will be able to achieve the following normal minimum gross operating levels consistent with emissions restrictions, AGC requirements and other system conditions:

	MINIMUM GENERATION	ADDITIONAL AGC/SYSTEM SECURITY REQUIREMENT
Crystal River 1	120 MW	0 MW
Crystal River 2	140 MW	0 MW
Crystal River 4	150 MW	150 MW
Crystal River 5	150 MW	150 MW
SUBTOTALS	560 MW	300 MW
TOTAL	860 MW	

Let me briefly explain the column showing the AGC/system security requirements for Crystal River Units 4 and 5. Generally, those units are not operated below the normal 250 MW lower limit of their control range (i.e., the normal level at which they can remain on AGC). The additional 50 MW represents a system security requirement which is maintained in order to provide necessary load following capability. Unit 5 also provides an additional system security function whenever Florida Power's Crystal River 3 nuclear unit also is on-line. Because of constraints on the 500 kV transmission system, Unit 5 must maintain an optimal output level of between 300 and 350 MW to supply needed transmission voltage stabilization in case Unit 3 should trip off-line.

Q. Is it possible that the Crystal River coal units could achieve greater than normal output reductions without creating unreasonable risk and costs?

A. It is possible that they may not achieve as much reduction as anticipated and it is conceivable that they could achieve slightly more. I emphasize that these are estimates only. Again, in the interest of minimizing QF curtailments, the Curtailment Plan contemplates that the system operating personnel will communicate with the Crystal River plant operators and reduce the coal-fired units even more than the amounts noted above (*i.e.*, to temporary "emergency minimum operating levels") if the circumstances permit at the time.

Q. Will the Crystal River 3 nuclear unit be cycled in response to minimum load conditions?

A. No. The Company has determined that safety, reliability and cost considerations all make it impractical to dispatch the Crystal River 3 unit for load following purposes. In addition to the adverse impacts on Crystal River 3 itself and the impacts on system reliability if Crystal River 3 cannot be returned immediately to full power, it is my understanding that running the unit at reduced capacity levels also can have undesirable side effects such as producing xenon imbalances, excessive amounts of radioactive waste water and unused fuel at the end of an operating cycle. Mr. Lefton elaborates on these concerns in his testimony.

Q. Assuming that all units are available for reduced operation in the manner you have described, please summarize the Company's normal minimum gross generation levels.

A. In 1995, the normal minimum gross generation level (before QF purchases) is about 1,823 MW. This is made up of 860 MW from coal units, 795 MW from Crystal River 3, and 168 MW from the Southern Companies.

Q. Based on these minimum generation levels, can you provide some indication of the magnitude of the need for QF curtailments under minimum load conditions?

A. The actual extent of any curtailments will depend upon numerous factors which are difficult to predict. For example: QF units or Company units may happen to be out of service in a low load period; some units may have to remain on-line for AGC or other reliability reasons; some units may elect to cycle off entirely rather than reduce their output; the minimum take requirements from the Southern Companies may or may not be applicable; off-system sales may be at relatively high levels or relatively light; and the list goes on. All that I can say with any real confidence is that the extent of required QF curtailments will be measured by the difference between (i) total system generation after all available measures have been taken short of curtailments; and (ii) the system load at the time.

The Curtailment Plan offered an example of a minimum load curtailment (Exhibit No. ___(RDD-1) at page 15). Perhaps it would be useful for me to update that example now that the Company has negotiated several additional voluntary output reduction plans with QFs. The example included in the Curtailment Plan assumed 792 MW of total available QF generation after the negotiated QF reductions. As Mr. Dolan explains in his testimony, two additional QFs have since negotiated output reduction plans. When these additional reductions are realized, the total QF generation is reduced from 792 MW to about 745 MW, yielding a corrasponding reduction in the amount of required QF curtailments. Thus, the example in the Curtailment Plan should be modified as follows:

EXAMPLE OF MINIMUM LOAD CURTAILMENT:

Coal	860 MW	
Nuclear	795 MW	
Southern	168 MW	
	1,823 MW	FPC generation and firm purchases
plus	~~792~~ 745 MW	QF generation after negotiated reductions
	~~2,615~~ 2,568 MW	
minus	2,400 MW	Assumed minimum load
	~~215~~ 168 MW	Additional QF generation to curtail

Q. Can you provide an estimate of the likely frequency of QF curtailments under the Curtailment Plan?

A. For the reasons I have just given, any estimate would be highly speculative. Moreover, it would likely be misleading since a "curtailment" event might mean that only 1 MW was curtailed from only the as-available suppliers, or alternatively, it might mean that many more megawatts were curtailed from all categories of QF suppliers.

It bears emphasizing, however, that the initial fear of very frequent curtailments expressed to the Company by several QFs has not proven to be justified. I am pleased to say that Florida Power was forced to implement involuntary curtailments only once during 1994. Thus far, only a handful of curtailments have been required in 1995. In all other cases where system loads were below the 2,500 MW threshold and the potential need for curtailments was imminent, circumstances within and outside the Company's control came together in such a way as to forestall that need. It is significant to note that there were 2,952 hours in the low load months of October 1994 through January 1995, while curtailments occurred in a total of only 31.25 hours, or one percent of the time. Moreover, for those QFs who have entered into voluntary output reduction plans, the impact of curtailments was even less frequent, since these QFs were able to avoid more than half of the involuntary curtailments. I refer to Mr. Harper's testimony for more information on this subject. Granted, we would prefer to have no curtailments, but the experience to date should help to alleviate any concern that the Company is attempting to trigger frequent curtailmnnts in an irresponsible or haphazard way.

Q. You have testified that the decision to operate Florida Power's baseload coal units at minimum operating levels, rather than cycling them off, is based upon both reliability and economic considerations. Please elaborate on the economic considerations.

A. Even if reliability coniderations allow turning coal units off, this is not desirable on an economic basis. So long as the total cost to take a unit off-line ("cycling cost") exceeds the fuel savings that result from not running the unit, the net economic effect of cycling the unit off must be an increase in net system cost, or a negative avoided cost. Cycling off a baseload coal unit in order to continue purchasing QF energy can be expected to cause a negative avoided cost. As I have noted, when system load declines prior to a minimum load period, Florida Power maintains a balance of generation and load by first cycling off its peaking units, then reducing generation from all of its steam units and finally cycling off its oil-fired units. At this point, only the largest, most economical units remain on-line (coal and nuclear units). The only remaining operational option to further reduce generation from Florida Power's own facilities would be to cycle off one or more of these baseload units. However, there is a substantial cost incurred if any of these units is cycled off.

Q. What types of costs are incurred when the baseload units are cycled off?

A. Mr. Lefton explains that a wide variety of cycling costs occur each time a baseload unit is cycled off. For convenience, I will refer to the costs described by Mr. Lefton as "unit impact costs" since they all are related directly to the specific unit being cycled. In addition to the unit impact costs, there is another significant cost component of cycling activity that relates to the replacement power costs incurred whenever more expensive energy must be generated or purchased in lieu of energy that otherwise would be available from the cycled unit.

Q. Please summarize the kinds of cycling costs that you have referred to as unit impact costs.

A. Simply stated, cycling a unit on and off makes the unit and its components wear out faster and cost more to operate than in the case of steady state operation. Related unit impact costs include, among other things: higher periodic maintenance and capital expenses as components require repair and replacement earlier than they otherwise would; higher forced outage costs; and a reduction in the operating life expectancy of the unit. Each time a unit is cycled off and on, transients in temperatures, pressures and flow rates result in significantly increased stress and wear on many of its component parts.

In addition, unit impact costs of cycling include the effect of increasing the frequency of unit start-ups. A coal-fired unit includes many large mechanical components and systems that operate at high temperatures. When the unit is turned off, these components and systems begin to cool and will eventually reach ambient temperatures. When the unit is restarted, critical components must be slowly and evenly reheated to operating temperatures before the unit can resume operation. For example, if the turbine rotor (a very large, very expensive, integral component of the generating unit) is heated unevenly or too rapidly, it will warp, resulting in severe damage to the turbine and extended unit unavailability. Upon restart, supplemental firing is required until the unit reaches a stable operating level. The start-up fuel required to preheat and supplemental fire the unit to achieve stable operation is a primary component of the unit start-up cost. In addition, cycling and transient operation of the unit disrupts the chemical balance of the water in the boiler and cooling system, resulting in an increase in water treatment costs and related equipment problems.

Mr. Lefton discusses such unit impacts in his testimony and concludes that these costs should be expected to range from at least $30,000 to well over $100,000 each time an older unit like Florida Power's Crystal River Unit 2 is cycled. The start-up fuel cost alone accounts for roughly $13,000 per start.

Q. Please describe your second general category of cycling costs -- replacement power costs.

A. The $30,000-$100,000+ range provided by Mr. Lefton does not include the short-term replacement power costs which are incurred during the period immediately after a minimum load condition whenever it becomes necessary to replace the power that would have been available from the cycled-off baseload unit with other, more expensive power. Generally, because the baseload units supply the Company's lowest cost energy, these units are dispatched at full capacity as the system load rapidly increases each day. Cycling off a baseload unit during the overnight minimum load period creates a substantial risk that the unit will not be available as needed for this load following purpose. This is true for at least three reasons.

First, under normal operating conditions, each unit has a "minimum down time" that limits how soon it can be restarted after being turned off. For planning purposes, the minimum down time for each of Florida Power's coal units is at least six hours. This period often is longer than six hours, as for example, in the situation where Crystal River Units 1 and 2 or Units 4 and 5 are returned to service simultaneously. In that case, it is more common for one unit to return to service approximately two hours prior to the return of the second unit.

Second, once a unit is cycled off-line, that unit can only be returned to full capacity gradually. The normal ramp periods can extend for several hours during which time the on-line units may be unable to meet the rising system demand, thus requiring that alternative resources be utilized for this purpose.

Third, there is always a significant risk that a critical component mav not operate properly or may fail during the shut-down/start-up sequence, resulting in a forced outage. The maintenance and repairs required by the component failure can make the unit unavailable for hours or even weeks. Although it is difficult to predict when any particular unit will trip off-line, it is reasonable to expect that this will happen from time to time.

During each period when the baseload unit is unavailable to follow load, its generation must be replaced with other, more expensive resources -- typically the capacity and energy would be provided from oil-fired intermediate units or peaking units. The differential in power supply costs to the system is a direct result of the cycling event and is the major component of the short-term replacement power cost. Another significant, but smaller, impact is the potential start-up cost associated with the replacement power resource.

Q. In what circumstances would these short-term replacement power costs result in a negative avoided cost for a block of energy?

A. As I have already noted, the replacement power expenses are only a component of the total cost of cycling a baseload generating unit. Nonetheless, short-term replacement power costs alone will result in a negative avoided cost whenever they exceed the Company's avoided fuel cost from not generating that block of energy. Using plausible assumptions, it is reasonable to expect that replacement power costs incurred as a result of cycling a Crystal River unit would make a csignificant contribution to negative avoided cost.

Q. Can you provide an example of the impact of replacement power on the avoided cost of a block of energy?

A. Yes. It is impossible to precisely quantify this cost in advance of its incurrence. However, a simple example should serve to illustrate that this cost impact can be substantial. First, note that there is an upper limit to the benefit that can be derived from cycling off a unit during any minimum load period. If a unit such as Crystal River 2 is cycled off, it will provide at most 140 MW of relief, assuming that it has been previously operated at its normal minimum generation level of 140 MW. Assuming further that the duration of the minimum load emergency lasted for six hours, then cycling off Crystal River 2 could enable Florida

Power to accept a maximum of 840 MWH of QF energy (140 MW for six hours). If Crystal River 2 thereby became unavailable at its full capacity of 500 MW for a single hour and this power were replaced by peakers at an average cost of $60/MWH, the resulting cost differential would be $21,000 (500 MW for one hour at $42/MWH, which is the difference between the Crystal River 2 fuel cost of approximately $18/MWH and the $60/MWH replacement cost). The resulting avoided cost of the 840 MWH block of energy not generated by Crystal River 2 is equal to the avoided cost of generation ($15,120 based on 840 MWH at $18/MWH) less the replacement power cost of $21,000 -- in other words, a negative avoided cost component of $5,880 or $7.00/MWH. Of course, where a unit is cycled-off and remains off-line for longer than one hour after it was scheduled to return to service the magnitude of this negative cost will be far greater than shown in my example.

Q. Can you supply a similar example showing the effect of the unit impact costs on the calculation of avoided cost?

A. Yes. First, let me repeat that the unit impact costs also are only a subset of the total cost of cycling. And, like the replacement power costs, they will produce negative avoided costs whenever, separately or in combination with other cycling costs, they exceed the fuel savings from not generating the avoided block of energy. To illustrate the effect of these costs, I have used assumptions similar to those described earlier. The resulting avoided cost is as follows:

	CR #2
Minimum capacity - MW	140
Hours off	6
Block size - MWH	840
Fuel cost - $/MWH	18.00
Avoided Fuel Cost - $	15,120
Unit Impact Cost - $	(65,000)
Net Avoided Cost - $	(49,880)
Net Avoided Cost - $/MWH	($59.38)

For convenience, I have used a per-event unit-impact cycling cost half-way between the low and high ends of the cost-estimate range offered by Mr. Lefton. I would, however, draw the same conclusion even using the low-end estimate. My conclusion is that the unit-related costs of cycling are material and of sufficient magnitude to create a negative avoided cost (separate and apart from the short-term replacement power costs) whenever a Crystal River coal unit has to be cycled off in order to continue purchasing QF power.

Q. Do you have significant confidence in your conclusion?

A. Yes, this example clearly shows that, using plausible assumptions, the cycling cost of a coal unit results in a negative avoided cost even without considering the replacement power subset of costs. Again, the exact magnitude may be difficult to predict, but the direction of the impact necessarily will be negative. In this example, the cycling cost for Crystal River 2 exceeds the avoided fuel cost by a factor of five. It would be necessary for that unit to be cycled off for more than 30 hours in order for the avoided energy cost to approach the cycling costs attributable to a coal unit hot-start, but it is obviously not plausible to expect the minimum load conditions to persist for such an extended period of time.

Q. Can you demonstrate the negative avoided cost impacts of cycling a coal unit in lieu of curtailments by looking at actual minimum load experience?

A. Yes. For each of the days on which curtailments have been required, we performed system operating simulations using the Unit Commit computer model which is utilized routinely to plan the daily dispatch of Florida Power's system. In each instance, we find that negative avoided costs would have been incurred if we had not called for curtailments.

Q. Please describe these simulations.

A. First, we selected as a "Base Case" the Company's after-the-fact avoided cost billing runs for each of the days in question. This case shows actual loads and costs as they were incurred <u>with</u> the required QF curtailments. Next, we developed a "Change Case" which varied the Base Case in one discrete way to simulate what reasonably might have happened if Florida Power had not curtailed the QFs, but instead cycled off one or more of the Crystal River coal units. The discrete change was to add back the curtailed QF volumes thereby reducing the amount of load served by the Company's own generation. In other words, the Change Case simulates Florida Power's system operation without curtailments.

Q. What did the Unit Commit simulations show?

A. The results of the simulations are summarized on page 1 of my Exhibit No. _____ (HIS-3). For every curtailment event, the Change Case shows that Florida Power would have incurred negative avoided costs had it not curtailed the QFs in accordance with the Curtailment Plan. The negative impacts ranged from over $2,000 to more than $40,000.

Q. Do the Unit Commit simulations include all of the cycling costs you described earlier?

A. No, they do not reflect all of the unit impact costs discussed by Mr. Lefton, and because they do not, they understate the magnitude of the negative avoided cost impacts. The simulations only reflect the effects of unit start-ups, short-term replacement power costs and a fixed charge for unit maintenance.

Q. Are there still other costs that may not be reflected in the Unit Commit simulations?

A. Yes. One good example is the lost opportunity to make Broker sales of energy during the day following a minimum load period whenever a coal unit that is cycled off to match the falling load thereby becomes unavailable later in the day. It is difficult to quantify such costs in advance, but it is not hard to understand how this can occur. When a coal unit is cycled off, the remaining units are forced to operate at higher capacity factors, thereby reducing or eliminating the option to market available coal capacity.

Q. Have you examined the actual curtailment events using any other method to verify that negative avoided costs would have been incurred if curtailments had not been ordered?

A. Yes. As additional confirmation of the existence of negative avoided costs, we examined each of the first seven curtailment events using manual cost calculations.

Q. What were the results of this analysis?

A. The results corroborate the conclusions drawn from Unit Commit. Based strictly on coal unit start-up costs, negative avoided costs would have existed for each of the seven events. The negative avoided cost attributable to atart-ups ranged from approximately $2/MWH to $85/MWH and averaged $13/MWH for the seven events. The derivation of these costs is shown in Part A on page 2 of my Exhibit No. _____ (HIS-3). Supporting information for these results is included on page 3 of Exhibit No. _____ (HIS-3).

Q. Did you examine the likely effect of replacement power costs?

A. Yes. Even though the avoided costs would have been negative without considering replacement power costs, we went on to assess the potential exposure to replacement power costs in addition to unit start-up costs. The resulting estimates of negative avoided cost including both unit start-up costs and an expected value of replacement power cost as shown in Part B ranged from $6/MWH to $122/MWH and averaged $22/MWH for the seven events. On average for the seven events, the incremental effect of replacement power cost drives the avoided cost negative by an additional $9/MWH.

Q. Why do you refer to the negative avoided cost impacts of replacement power as "expected values"?

A. We know that start-up costs are incurred every time that a unit is cycled off. On the other hand, the incurrence and extent of any replacement power cost would depend upon the particular circumstances that would have been encountered if the curtailments were not made. The major uncertainty is the length of time that a baseload unit would have been unavailable to follow load because it had been cycled off. In order to account for this uncertainty, we constructed a set of proxy restart scenarios which assigned a cost and probability to each alternative to determine when a coal unit would be expected to return to service. Summing the product of cost and probability for all alternatives produces an expected value for this event that captures the effect of uncertainty.

Q. What was the basis for your assumptions as to how long it may take a coal unit to return to service after being cycled off?

A. The assumptions regarding coal unit performance are based on actual operating experience with Crystal River Units 1 and 2 during 1994, which included 38 events where one of these units was returned to service after being cycled off. It has been assumed in this analysis that the coal units would return to service after being cycled off during a minimum load period with performance and reliability equivalent to that experienced for these units during 1994.

Q. Did your manual calculations also estimate the effect of unit impact costs other than start-up costs?

A. Yes. As a final step in this analysis, unit impact costs were included using the lower end estimate of $30,000 for a cycling event. Recognizing that start-up costs were included in Part A, only the balance of unit impact costs were included in Part C to arrive at a total unit impact cost of $30,000 for each cycling event. When these costs were included, the total negative avoided cost ranged from $29/MWH to $257/MWH and averaged $60/MWH for the seven events.

Q. What conclusions do you draw from the studies discussed in this section of your testimony?

A. The studies conclusively demonstrate that negative avoided costs would have been incurred if curtailments had not been ordered for each of the seven curtailment events studied. These results have been validated by using different methodologies (Unit Commit and manual cost calculations) as well as by analyzing the components of negative avoided cost separately and in combination. Although the magnitude of negative avoided cost will depend upon a variety of variables which cannot be measured precisely in advance, the Company can predict with a high degree of confidence that negative avoided costs will be incurred whenever it is compelled to cycle off one of the Crystal River coal units in order to continue purchasing power from QFs.

The FERC rules and this Commission's rules contemplate this kind of forward looking method of reasonably predicting the incurrence of negative avoided costs. Based upon such reasonable expectations, QFs are to be given notice in advance of the event that they should cease deliveries in order to avoid the conditions that would give rise to the predicted negative avoided cost. Therefore, the Curtailment Plan appropriately calls for QF curtailments before the Crystal River coal units are forced to shut down. If curtailments occur as anticipated, then an after-the-fact analysis should show that the Curtailment Plan operated successfully to avoid the predicted negative cost impact. The studies discussed above demonstrate that the Curtailment Plan has met this criterion for each and every actual event subjected to after-the-fact analysis.

VII. THE OBJECTIVES OF FLORIDA POWER's CURTAILMENT PLAN

Q. Having characterized the nature and estimated scope of the minimum load problem, please explain how the Curtailment Plan strives to address that problem.

A. Perhaps I can do that best by restating the purposes and goals articulated in the Plan itself. The Curtailment Plan is a document designed primarily to provide instruction and guidance to the Company's operating personnel when the need to address minimum load conditions arises. In the process, it affords notice to this Commission and to the affected QFs of the measures which the Company intends to take in these circumstances. It is an operating tool -- not a rigid set of irrevocable rules meant to hamper sound operator discretion.

The Curtailment Plan was intended to establish a set of working guidelines and priorities which:

- address minimum load conditions in an efficient, operationally sound and cost-effective manner;
- comply with outstanding contracts and regulatory requirements;
- are compatible with applicable NERC, SERC and FCG criteria;
- operate in an equitable manner to Florida Power and all QFs from whom the Company purchases power;
- will be known in advance and readily understood by system operating personnel and by affected QFs;
- will be relatively uncomplicated to implement whenever the need arises; and

- contain sufficient detail to provide meaningful operational guidance while remaining flexible enough to accommodate changing generation and load conditions over time.

VIII. THE PRINCIPLES UNDERLYING THE PLAN's CURTAILMENT PRIORITIES

Q. Mr. Charles J. Harper's testimony describes how the Curtailment Plan works, but would you please explain the basic principles which the Company applied in determining the Plan's curtailment priorities.

A. An overriding principle is that the Curtailment Plan should achieve equity and fairness while being capable of efficient administration by the system operating personnel. In addition, there are at least four more key principles.

First, the Plan recognizes the principle that the Company will, as I have already testified, exercise efforts on an ongoing basis to limit exposure to minimum load emergencies and thereby attempt to minimize the QFs' exposure to curtailments.

Second, when curtailments nonetheless become necessary, the Plan calls for the Company to first curtail its "as-available" energy purchases, including amounts in excess of QF Committed Capacities and other amounts purchased on an as-available basis. This Commission's rules recognize the principle that as-available energy sales carry no "assurances as to the quantity, time, or reliability of delivery." Rule 25-

17.0825 F.A.C. Likewise the Curtailment Plan recognizes the lack of firmness of as-available energy.

Third, the Plan operates from the principle that certain QFs who have voluntarily agreed in writing to follow specific output reduction plans already have assisted greatly in Florida Power's overall efforts to address a significant operational problem. As a result, it would be unfair to require still greater interruption of deliveries from these QFs until after the remaining QFs have been called upon to bear their fair share in solving this problem. Based on this principle, the Plan directs the Company's system operating personnel to look to the remaining QFs to curtail a specified portion of their firm Committed Capacity amounts before returning to the QFs with pre-arranged output reduction plans for more interruption of energy deliveries than initially made pursuant to those plans.

Fourth, the Plan endeavors to fairly apply the additional principle that the percentage reduction initially applicable to QFs who have not negotiated a specific output reduction plan should be high enough to make a meaningful contribution to the excess generation "solution," but not so high as to unduly penalize or burden these QFs. The Plan uses a 50 percent reduction from the Committed Capacity amount for this purpose. The across-the-board reduction of up to 50 percent was selected as an amount which (i) shares the burden of curtailments in a roughly proportionate manner; (ii) is compatible with existing contracts and this Commission's rules; (iii) is consistent among the affected QFs; (iv) is administratively convenient to administer when system dispatchers are called upon to make immediate operating decisions; and (v) appeared as if it would avoid unintended problems relating to emission standards, thermal host requirements for cogenerators or other regulatory conditions. I should add that the Plan invited any QFs who might have unique operational problems from the 50 percent reduction level to bring those problems to the Company's attention so that an alternative load reduction plan could be considered.

Q. Are these principles reflected in the curtailment priority classifications set forth in Appendix B of the Curtailment Plan (Exhibit No. ___(RDD-1)?

A. Yes. Applying these principles, the Company developed three curtailment classifications as shown on Appendix B. Group A includes all QFs that have agreed in writing to follow specific output reduction plans. Group B consists of those of the Company's firm QF suppliers that have not specified particular output reduction plans in writing. Group C includes the Company's as-available energy purchases which (i) are made under the Company's Rate Schedule COG-1; or (ii) exceed the firm Committed Capacity under a negotiated power purchase contract. Mr. Dolan has updated the Appendix B groupings in his Exhibit No. ___(RDD-4) to reflect the current status of the negotiated output reduction plans.

Q. Before leaving your discussion of the Curtailment Plan, would you please comment on the principles underlying the Plan's compliance procedures?

A. Certainly. I will start by saying emphatically that I hope no compliance measures ever will have to be invoked. Throughout our efforts to deal with the minimum load problem, the Company's goal has been to achieve cooperative assistance from our QF suppliers. This has been evidenced by the Company's significant efforts to negotiate voluntary output reduction plans, the repeated attempts to solicit input from QFs, and the very substantial generation reductions which the Company itself will accept in order to mitigate QF curtailments. Moreover, I agree wholeheartedly with the statement in the Curtailment Plan (Exhibit No. ___(RDD-1) at page 28) that:

> The Company anticipates that its NUG suppliers will appreciate the need for a coordinated curtailment program, and that all of the affected NUGs will follow the instructions issued by the system operating personnel pursuant to this Generation Curtailment Plan. Such cooperation should be expected as a matter of prudent operating practice....

Q. In the event that your expectations are not entirely correct, how does the Curtailment Plan deal with the compliance issue?

A. The Curtailment Plan recognizes that perfect compliance at all times may be unattainable. Even the Company cannot always achieve a precise targeted megawatt output level for all its units. The Plan acknowledges that there will be small errors and that marginal non-compliance will be tolerated. In most cases, the small errors will be remedied by making small adjustments to the curtailments required of other QFs. The expectation is that this kind of marginal non-compliance will be transitory and should balance out over time.

A different situation exists, of course, if a particular QF significantly or repeatedly fails to comply with the Curtailment Plan. In this instance, that QF is unfairly leaning on other QFs to accept the curtailment shortfall. The Plan seeks to avoid inequitable effects, but it cannot anticipate and protect in advance against intentional or material non-compliance.

The Company expressly reserves the right to withhold payments for energy delivered in amounts not in compliance with the Curtailment Plan, to assess additional Company costs against the QF and to pursue any other legal or equitable remedies in the event of non-compliance. In addition, in the event of material or repeated instances of non-compliance, the Company reserves the option to physically interrupt deliveries from the QF or to refuse schedules from intervening utilities if the QF is not directly interconnected with Florida Power.

Q. Will physical interruption of deliveries be used as a remedy without further notice to the Commission?

A. No. Although any non-compliance may adversely affect the Company and/or other QF suppliers, Florida Power would prefer to give any non-complying QF a reasonable opportunity to cure its non-compliance. I will repeat again that the Curtailment Plan attempts to resolve difficult problems as equitably as possible. Therefore, before the Company initiates any physical disconnection, it will first provide written notice to the QF and to the Commission and will provide for a reasonable cure period.

IX. QF INPUT INTO THE CURTAILMENT PLAN AND RELATED ISSUES

Q. Did the Company solicit input into the Curtailment Plan from affected QFs?

A. Yes, it did. Early in 1993 Florida Power began discussions with its QF suppliers explaining that minimum load problems were anticipated, that curtailments might be required under Rule 25-17.086, and that the QFs' assistance in working toward mutually acceptable procedures would be appreciated. As evidenced by the various negotiated output reduction plans described by Mr. Dolan, the Company's efforts to approach the problem cooperatively continued with some success up to and even after the filing of the Curtailment Plan.

The Plan itself took considerable time and effort to develop and was not completed until shortly before the October 12, 1994 filing date with the Commission. It was, nevertheless, imperative to distribute and file the Plan in a timely manner so that it could be implemented as soon as October 15, 1994, when the Company expected to begin experiencing its first minimum load emergencies. The Company distributed the

Appendix C curtailment procedures to all affected QFs on October 3, 1994, and invited interested persons to an open-house discussion of the Plan on October 7, 1994 (a copy of the Company's invitation letter is included in Exhibit No. ___(HIS-3)). Approximately 30 QF representatives attended that meeting and many questions and concerns were aired. In addition, the Company invited and received further written comments on the Plan and mailed out additional explanatory materials after the October 7th meeting.

Following the meeting, the Company continued to discuss output reduction plans with a number of interested QFs. As Mr. Dolan's testimony makes clear, those efforts succeeded in moving two more QFs from curtailment Group B into Group A. Also, the Company carefully reviewed the written follow-up comments and considered whether responsive changes to the plan could be made. One such change was the addition of footnote 6 at page 29 of the Plan to acknowledge that individual QFs might prefer to arrange different outage sharing agreements among themselves and that the Company generally would not object to such alternative arrangements as long as the Company can depend upon assured output reductions and the arrangements are otherwise feasible to implement.

The Company was and still is willing to work cooperatively with its QF suppliers to achieve equitable and effective procedures for operating the system in minimum load periods.

Q. Mr. Harper's description of the events that occurred on October 18-19, 1994 indicates that several of the Company's units -- specifically Anclote 2, Bartow 2 and the University of Florida unit -- were not cycled off during that minimum load emergency because of temporary equipment problems. How can those decisions be reconciled with the instructions provided in the Curtailment Plan?

A. As I have explained, the Curtailment Plan is designed to achieve fairness and equity, while simultaneously ensuring safe, reliable and economic operation of the electric system. While the Plan attempted to narrow the need for dispatcher discretion, it is neither possible nor prudent to remove all elements of judgment and still ensure that the system is operated soundly. Thus, while the Plan lays out specific procedures and expresses the Company's expectations of how the system will be run under normal conditions, it also recognizes in very clear terms that the stated procedures will not be construed as hampering the day-to-day decisions of the Company's system operating personnel. Ultimately, the system operates reliably and economically because of the informed judgment of our highly experienced operating personnel.

The decisions not to cycle off Anclote 2, Bartow 2 and the University of Florida unit on October 19, 1994 for sound operational reasons therefore were consistent with and in the furtherance of the Curtailment Plan's objectives. As the procedures specified in Appendix C to the Plan acknowledge, the Plan itself allows for necessary exceptions to be made from time to time, so long as they are fully documented at the time.

It is significant to note the temporary nature of these equipment problems. These problems at Anclote, Bartow, and the University of Florida unit have been corrected.

Q. Mr. Harper's testimony also notes that several QFs who were asked to curtail their output on October 19, 1994 stated that they were unwilling or unable to do so. How do you respond to these concerns?

A. I believe that Florida Power should attempt to be responsive to the QF's legitimate operational problems, just as it is with respect to its own units. If a QF is experiencing a temporary, uncontrollable equipment problem that prevents it from reducing output without tripping off-line or causing other physical damage, then I would expect the system operating personnel to consider excusing that unit from the Curtailment Plan on that particular occasion if they would do so with respect to a similar problem on a Florida Power unit. This judgment should be made on a non-discriminatory basis.

This does not mean that all QF requests to be excluded from curtailments will be accepted. I am referring to non-chronic, mechanical problems of the type that would prevent cycling of a Company-owned unit. Moreover, if the problem is reoccurring, it will have to be addressed in other ways, since one QF's non-compliance with the

Curtailment Plan means that other QFs must share the impact of the non-compliance. As I testified earlier, the Company remains willing to discuss these other types of problems with any affected QF in an effort to achieve a mutually satisfactory solution.

Q. In order to accommodate a limited measure of flexibility to handle temporary QF operating problems, are any changes to the Curtailment Plan required?

A. No. Although the Curtailment Plan does not specifically carve out any exceptions, it does, as I previously explained, contemplate a measured degree of discretion by the system operating personnel. I view temporary but significant QF operating problems of the type I described as falling within that band of discretion. As I have also stated, equity and fairness are fundamental objectives of the Curtailment Plan. Therefore, after evaluating the events that occurred on October 18-19, 1994, I instructed the appropriate personnel at Florida Power's Energy Control Center to consider these kinds of temporary QF operating problems as if they were problems on the Company's own equipment and to act accordingly. They also have been instructed to document any resulting exception to the normal curtailment practices that otherwise would have been followed under the Plan. Any persistent problems will have to be handled on a case-by-case basis.

Q. Does that conclude your testimony, Mr. Southwick?

A. Yes.

EXHIBITS

FPSC DOCKET NO. 941101-EQ
FPC WITNESS: **SOUTHWICK**
EXHIBIT NO. _____ (HIS-1)
CONSISTING OF 35 PAGES

FLORIDA ELECTRIC POWER COORDINATING GROUP

FCG
OPERATING COMMITTEE
HANDBOOK

INTRODUCTION

REVISED: October 1994

This Handbook of the FCG Operating Committee contains the Florida Specific Procedures for both normal and emergency operations under which member systems are currently operating. This Handbook is intended as a reference source for use by operating personnel and Committee members.

The FCG Operating Committee accepts the NERC Operating Guides as a basis for operations. The Florida Specific Procedures contained in this Handbook were written to either clarify or enhance a specific NERC Operating Guide for use within the Florida Subregion. The NERC Operating Guides are not included in this Handbook, but the Guides are referenced to the applicable Florida Specific Procedure in the Table of Contents. In cases where there is no Florida Specific Procedure associated with a NERC Guide, the Guide title and number is referenced in the Table of Contents to direct the reader to the NERC manual.

This issue of the Handbook has been restructured into three sections: Operations, Master Contact List and Administrative. The Operations section contains the procedures and other information the System Operators routinely reference, while the Administrative section contains procedures and other information generally referenced by the Operating Committee. Between the Operations and Administrative sections is the Master Contact List that provides contact information for operation centers, committee/subcommittee members and emergency contact personnel. The list is in alphabetical order by Company name.

A Table of Contents is located in the front of the Operations and Administrative Sections. Each Table of Contents is divided into major sections (i.e. GENERATION/INTERCHANGE and TRANSMISSION), with a Main Topic column containing key words to assist the reader in quickly locating information. The Handbook pages are consecutively numbered to further assist the reader in locating information.

Revisions to this Handbook will be identified by the use of a vertical bar in the left margin to indicate lines on the page that have been changed.

INTRODUCTION

This Handbook of the FCG Operating Committee contains the guidelines for both normal and emergency procedures, practices and reports under which member systems are currently operating. Through these operating procedures, practices, and reports, member systems attain coordination of their interconnected operation. This Handbook is intended as a reference source for use by operating personnel and Committee members.

The FCG Operating Committee has accepted the NERC Operating Guide as the basis for this Handbook. All future revisions to this handbook will be identified by use of a vertical bar in the left margin to indicate lines on the page that have been changed. Section III of this Handbook contains the NERC GUIDES followed by a FLORIDA SPECIFIC PROCEDURE, if one currently exists. The FLORIDA SPECIFIC PROCEDURES have evolved from the coordination of activities of the Florida Operating Committee, now the FCG Operating Committee, since its formation in 1959. These Florida Specific Procedures clarify and add to the NERC Guidelines for the Florida subregion.

This Handbook is ordered into four major sections. Each section is divided into several subsections. Each major section has a tab printed with the section's title and number. Section III, which contains the Operating Guides, has a printed tab for subsections A through I. The first page of each of the four major sections and the first page of subsections D through I of the Operating Guides (Section III) is a colored sheet which provides a table of contents for that section or subsection. The top right corner of each page lists the Section and subsection (i.e. I-B). A subsection may be broken into several parts and subparts. When this occurs, an extension (i.e. III-E.6a) is added. Page numbers of the major sections are located in the center bottom of each page. Each section is numbered sequentially beginning with page 1.

FCG MEMBERSHIP

The following is the membership list of the Florida Electric Power Coordinating Group. Members of the Operating Committee are shown with an asterisk preceding the utility's name.

FCG GUIDELINES FOR MEMBERSHIP TO THE OPERATING COMMITTEE

Any FCG member that employs automatic generation control, and which owns and controls generating units whose capacity, in conjunction with any purchase of firm capacity, is sufficient to serve its own load and provide an adequate operating reserve, and whose electrical system is normally operated directly interconnected with other such systems may be a member of the Operating Committee by request to the Executive Committee of the FCG. In addition, the Operating Committee will consist of one (1) respresentative selected by the municipal and other government-owned electric systems not otherwise qualified and one (1) representative selected by the rural electric cooperative systems not otherwise qualified and such other representatives selected by the Executive Committee not otherwise qualified.

INVESTOR-OWNED UTILITIES

*Florida Power Corporation, St. Petersburg
*FPL, Miami
Florida Public Utilities Company, Fernandina Beach
*Gulf Power Company, Pensacola
*Tampa Electric Company, Tampa

MUNICIPAL UTILITIES

*Florida Municipal Power Agency, Orlando
*Fort Pierce Utilities Authority, Fort Pierce
*Gainesville Regional Utilities, Gainesville
*City of Homestead, Homestead
*Jacksonville Electric Authority, Jacksonville
*Utility Board of the City of Key West, Key West
*Kissimmee Utility Authority, Kissimmee
*City of Lake Worth Utilities, Lake Worth
*City of Lakeland, Lakeland
*Utilities Commission of New Smyrna Beach, New Smyrna Beach
City of Ocala, Ocala
*Orlando Utilities Commission, Orlando
*Reedy Creek , Lake Buena Vista
*City of St. Cloud, St. Cloud
Sebring Utilities Commission, Sebring
*City of Starke, Starke
*City of Tallahassee, Tallahassee
*City of Vero Beach, Vero Beach

* Denotes FCG Operating Committee Members

COOPERATIVE UTILITIES

Alabama Electric Cooperative, Inc., Andalusia, Alabama
Central Florida Electric Cooperative, Inc., Chiefland
Choctawhatchee Electric Cooperative, Inc., DeFuniak Springs
Clay Electric Cooperative, Inc., Keystone Heights
Escambia River Electric Cooperative, Inc., Jay
Glades Electric Cooperative, Inc., Moore Haven
Lee Country Electric Cooperative, Inc., North Fort Meyers
Okefenoke Rural Electric Cooperative, Inc., Nahunta, Georgia
Peace River Electric Cooperative, Inc., Wauchula
*Seminole Electric Cooperative, Inc., Tampa
Sumter Electric Cooperative, Inc., Sumterville
Suwannee Valley Electric Cooperative, Inc., Live Oak
Talquin Electric Cooperative, Inc., Quincy
Tri-County Electric Cooperative, Inc., Madison
Withlacoochee River Electric Cooperative, Inc., Dade City

*Denotes FCG Operating Committee Members

DESCRIPTION OF THE FCG

The FCG is a non-profit corporation funded by membership dues. Thirty-eight electric utilities, consisting of five investor-owned, eighteen municipal and fifteen rural electric cooperative, make up the organization. The members account for nearly 100 percent of the electric generation and transmission capabilities within Florida.

The FCG is the product of the willingness and ability of Florida's electric utilities to work together toward a common goal of providing a reliable, adequate supply of electric power at the lowest possible cost consistent with environmental standards. Voluntary cooperation has led to improvements in procedures, production, and service activities.

A basic philosophy of the FCG is sharing ideas and maintaining open lines of communication to all interested parties. This extends to government agencies, regulatory bodies, environmental groups, media and the public. Member utilities benefit through open communication by keeping each other up-to-date on new technology, key issues or emerging concerns.

Each utility volunteers specialists in various areas of expertise to serve on FCG committees. The committees have regularly scheduled meetings on a one to two month basis to enable exploration of ideas and create solutions to the varied problems and challenges that face the utility industry.

Changes in the economic, social, political, and technical arenas put different pressures on the electric utility industry. Through the FCG, members continually meet and together assess and plan for tomorrow's energy needs.

FLORIDA SPECIFIC PROCEDURE DEFINITION OF TERMS

A1 Criteria - The ACE must return to zero within ten minutes of previously reaching zero. Violations of this criteria count for each subsequent ten-minute period that the ACE fails to return to zero.

A2 Criteria - The average ACE for each of the 6 ten-minute periods during the hour (i.e., for the ten-minute periods ending at 10, 20, 30, 40, 50 and 60 minutes past the hour) must be within specific limits, referred to as Ld, that are determined from the control area's rate of change of demand characteristics.

Control Surveys - These surveys serve the purpose of revealing control equipment malfunctions, telemetering errors, improper frequency bias settings, scheduling errors, inadequate generation under automatic generation control, general control performance deficiencies, or other factors contributing to inadequate control performance.

Florida Economy Broker - The system used to match the least cost seller with the highest avoided cost buyer for hourly economic energy transactions.

Inadvertent Payback - The scheduling of energy between two or more control areas with inadvertent interchange balances of opposite signs. The cooperating areas' operators have to enter offsetting schedules into their AGC controllers but not into the accounting sheets.

Manual Load Shedding - The reduction of Electrical load due to actions taken by the System Operator.

Volt-Amperes Reactive (VAR) - Volt amperes that provide the electric fields needed to make equipment work.

Economic Dispatch - The optimal generator loadings to minimize the total production cost to meet load and interchange requirements.

Time Error - The difference between local time and the National Bureau of Standards time

Underfrequency Load Shedding - Automatic reduction of electrical load based on predetermined set points on underfrequency relays.

FLORIDA SPECIFIC PROCEDURE

RESERVE CAPABILITY

I. OPERATING RESERVE REQUIREMENTS

A. Operating Reserves should be maintained by the combined systems at a value equal to or greater than the loss of generation that would result from the most severe single contingency.

B. The combined systems should provide an amount of Spinning Reserve equal to or greater than 25% of the amount of Operating Reserves provided by the combined systems. This Spinning Reserve should be automatically responsive to a frequency deviation from normal.

C. Each system should provide an amount of Spinning Reserve, responsive to automatic generation control, which is sufficient to provide normal regulating margin.

D. Operating Reserves must be fully applicable within ten minutes.

E. Each system's Operating Reserve allocation should be available to the other systems and not be restricted by transformer, line, or other limitations.

II. ALLOCATION OF STATE OPERATING RESERVES

The Operating Reserve and the Spinning Reserve requirements, (the minimum values specified in Paragraph 1), are allocated among the participants in proportion to each participant's maximum demand for the preceding year and the summer Gross SERC Capability of its largest unit or ownership share of a joint unit, whichever is greater. Fifty percent is allocated on the basis of demand and fifty percent on the basis of the summer Gross SERC Capability of the largest unit.

A. Operating Reserve should be maintained by the combined systems at a value equal to or greater than the summer Gross SERC Capability rating of the largest generating unit in service.

B. At least 25% of the Operating Reserves shall be Spinning Reserve which is automatically responsive to a frequency deviation from normal.

Example: If a system's Operating Reserve allocation is 100 MW:

Operating Reserve = 100 MW
Actual Spinning Reserve = 30 MW
Required Minimum Nonspinning Reserve = 100 MW -30 MW = 70 MW

C. A system may arrange with other systems to carry its Operating Reserve allocation so long as that reserve meets the FCG definitions and is not restricted by transmission or other constraints.

D. FCG shall compute the Operating Reserve allocations. Each system shall transmit to the FCG office the following information by February 15th of each year:

- the previous year's peak hour Net Energy for Load
- the current partial requirements contract obligation with systems that schedule partial requirements, if the partial requirements contract requires that the provider supply operating reserves.
- the summer Gross Capability of its largest unit or ownership share of a joint unit, whichever is greater

The allocations will be calculated annually and published by March 1st of each year.

A change in the capability of the largest unit in peninsular Florida, that will last for 7 days or longer, should be reported immediately and the Operating Reserves recalculated.

When a system's largest unit is expected to be out of service or its capability limited significantly for 7 days or longer, it should be reported immediately along with the estimated return date. Operating Reserves will be recalculated upon receipt of this information. A recalculation of the Operating Reserves will be performed on the estimated return date unless the utility notifies FCG of a revised return to service date.

Recalculated values shall be transmitted by Message System for immediate use and confirming copy shall be mailed to each system.

See the following page for sample calculations.

E. If a utility's total reserve allocation changes by 5% the operating reserve allocation methodology will be readdressed if the utility makes the request.

III. USE AND RESTORATION OF STATE OPERATING RESERVES

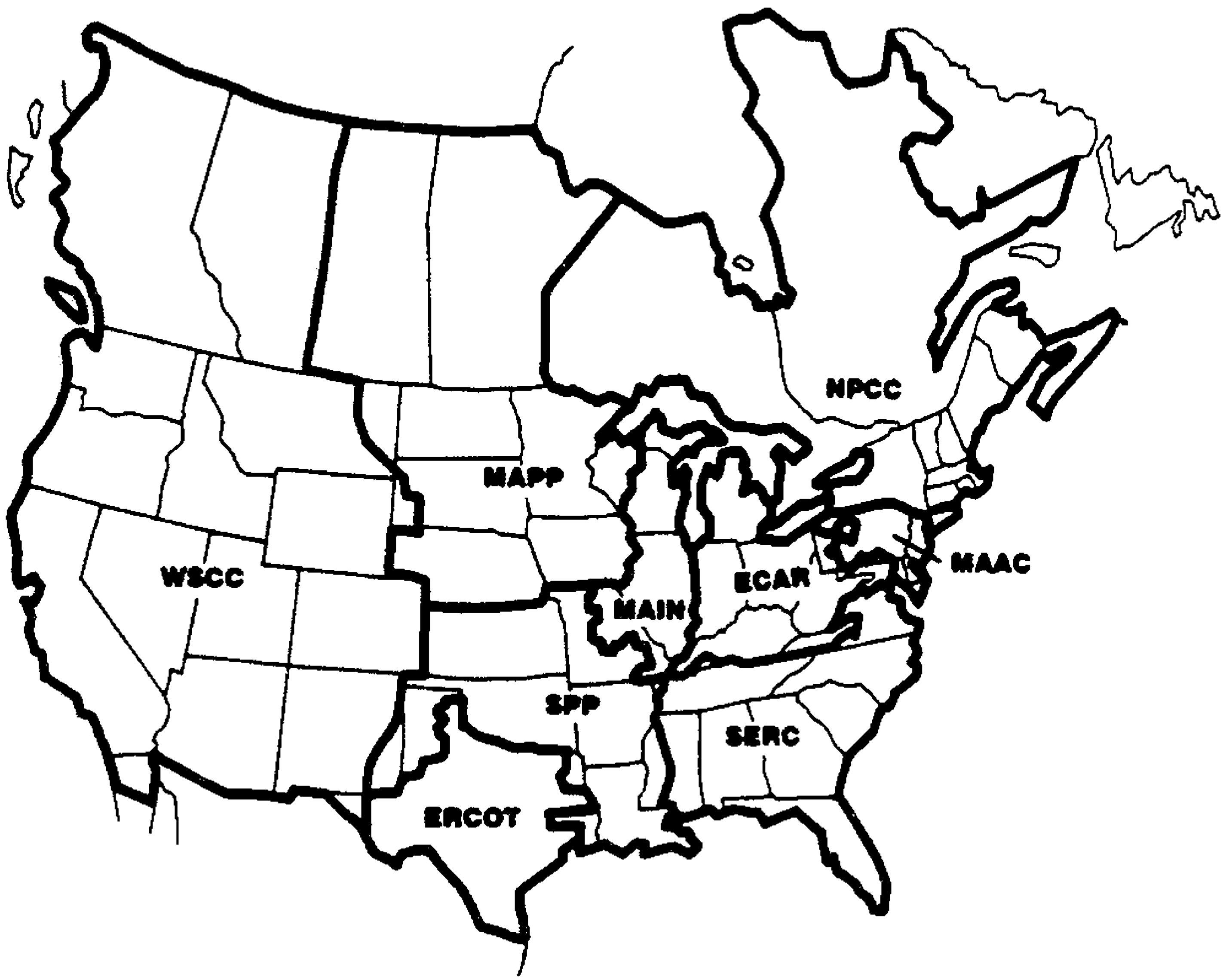
Operating reserves shall be made available for up to 30 minutes following a disturbance. Within 30 minutes after the disturbance, the deficient utility shall either replace the generation loss with its own resources or purchase sufficient capacity, if needed, to serve its own system requirements plus State Operating Reserve allocation. If sufficient capacity is not available to re-establish such reserves, then the deficient utility should re-establish its share of the State Operating Reserves as soon as practical. All interchange schedules should be fully implemented prior to the end of the 30 minute period such that State Operating Reserves will be fully restored after 30 minutes. All energy flows associated with the utilization of Operating Reserves shall be treated as inadvertent energy, and no transmission service charges shall be applicable to this inadvertent energy, unless otherwise specified in bilateral contracts.

IV. PERFORMANCE REVIEW

Following the occurrence of generation loss, a review is made by the State Coordinator of the combined systems' response to determine compliance with established Control Performance Criteria. If poor performance is observed, it is brought to the attention of the Operating Committee for review and analysis. Where warranted, the Performance Subcommittee is assigned to make a full investigation.

NERC OPERATING MANUAL

North American Electric Reliability Council



ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

ML102075

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
OPERATING GUIDES

INTRODUCTION

| The NERC Operating Guides (Guides) are designed to promote coordinated operation among interconnected systems and to achieve high levels of interconnected systems reliability and control. The Guides specify how the basic operating policy of the NERC Operating Committee, contained in the Reliability Criteria for Interconnected Systems Operation (Criteria), is to be implemented. The Criteria and Guides are based on established technical rationale and mature operating experience and judgment. System operator input is vital to the establishment and maintenance of good operating policy. The Criteria and Guides are reviewed and updated by the Operating Committee as necessary with present and future Interconnection and system requirements in mind.

In practice, certain Guide statements are more essential to reliable Interconnection operation than others. Therefore, the Guide statements have been classified as either Operating Requirements or Operating Recommendations.

A NERC Operating Requirement is a written statement, adopted under the NERC Operating Committee voting procedures, that describes the obligations of a control area and systems functioning as a part of a control area. An Operating Requirement may also specify whether there will be monitoring for compliance.

A NERC Operating Recommendation is a written informational statement, adopted under the NERC Operating Committee voting procedures, describing good operating practices that should be followed by a control area and systems functioning as part of a control area. The application of recommendations may vary among control areas to cover local conditions and individual system characteristics.

The Guides are organized the same as the Criteria. A Criteria reference statement, extracted from the Reliability Criteria for Interconnected Systems Operation, is found at the beginning of each Guide subsection. Requirements, Recommendations, and Background categories are also included in each Guide subsection. A glossary of terms precedes the Guides; an appendix and revision procedure follow the Guides.

Refer to the Reliability Criteria for Interconnected Systems Operation for the complete set of Criteria statements.

TERMS USED IN THE GUIDES

Anti-Aliasing Filter An analog filter installed at a metering point to remove aliasing errors from the data acquisition process. The filter is designed to remove the high frequency components of the signal over the AGC sample period

Adequate Regulating Margin The minimum on-line capacity that can be increased or decreased to allow the system to respond to all reasonable demand changes in order to be in compliance with the Control Performance Criteria.

Adjacent System or Adjacent Control Area Any system or control area either directly interconnected with or electrically close to (so as to be significantly affected by the existence of) another system or control area.

Area Control Error (ACE) The instantaneous difference between actual and scheduled interchange, taking into account the effects of frequency bias (and time error or unilateral inadvertent if automatic correction for either is part of the system's AGC).

Automatic Generation Control (AGC) Equipment which automatically adjusts a control area's generation from a central location to maintain its interchange schedule plus frequency bias.

Bulk Electric System The aggregate of electric generating plants, transmission lines, and related equipment. The term may refer to those facilities within one electric utility, or within a group of utilities in which the transmission lines are interconnected.

Capacity Emergency A capacity emergency exists when a system's or pool's operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.

Commonly or Jointly Owned Units (COU/JOU) These terms may be used interchangeably to refer to a unit in which two or more control areas share ownership.

Contract Intermediary Control Area A NERC control area that has connecting facilities in the scheduling path between the sending and receiving control areas and operating agreements which establish the conditions for the use of such facilities.

Control Area A system which regulates its generation in order to maintain its interchange schedule with other systems and contributes its frequency bias obligation to the Interconnection

Demand The rate at which energy is being used by the customer.

Disturbance 1. Any perturbation to the electric system. 2. The unexpected change in ACE that exceeds 3 times L_d which is caused by the sudden loss of generation or interruption of load.

Dynamic Schedule A telemetered reading or value which is updated in real time and which is used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for "scheduling" jointly owned generation to or from another control area.

TERMS USED IN THE GUIDES

Energy Emergency An energy emergency exists when a system or pool does not have an adequate fuel supply (including water for hydro units) to provide its customers' expected energy requirement over a given period.

Frequency Bias Setting A value, in MW/0.1 Hz, set into a control area's AGC equipment to represent a control area's response to deviation from scheduled frequency.

Host Control Area The control areas(s) within whose metered boundaries a jointly owned unit is physically located.

Hourly Value Data measured on a clock-hour basis.

Inadvertent Interchange The difference between the control area's net actual interchange and net scheduled interchange.

Interconnection When capitalized, any one of the four bulk electric system networks in North America: Eastern, Western, ERCOT, and Québec. When not capitalized, the facilities that connect two systems or control areas.

Interruptible Load Demand that can be interrupted by direct action of the supplying system's system operator in accordance with contractual provisions.

Leap Second A second of time added occasionally by the National Bureau of Standards to correct for the offset between the clock-hour day and the solar day.

Load The amount of electric power delivered or required at any specified point or points on a system.

Joint Control Automatic generation control of jointly owned units by two or more control areas.

Metered Value A measured electrical quantity that may be collected by telemetering, SCADA, or other means.

Neighboring System See Adjacent System

Net Energy for Load Net system generation plus interchange received minus interchange delivered.

Non-spinning Reserve That operating reserve not connected to the system but capable of serving demand within a specified time, or interruptible load that can be removed from the system in a specified time.

Operating Reserve That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.

Operating Security The ability of a power system to withstand or limit the adverse effects of any credible contingency to the system including overloads beyond emergency ratings, excessive or inadequate voltage, loss of stability or abnormal frequency deviations.

TERMS USED IN THE GUIDES

Overlap Regulation Service A method of providing regulation service in which the control area providing the regulation service incorporates all of the other control area's tie lines and schedules into its own AGC ACE equation.

Pseudo-Tie A telemetered reading or value which is updated in real time and which is used as a tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actual exists. The integrated value is used as a metered MWh value for interchange accounting purposes.

Region One of the NERC Regional Reliability Councils.

Regulation Service The process whereby one control area contracts to provide corrective response to all or a portion of the ACE of another control area. The controlling utility assumes the obligation of meeting all applicable control criteria as specified by NERC. Adjustments to control parameters shall be per applicable NERC Operating Guides. Control may be transferred by transmittal of an ACE quantity or the transmittal of the actual tie flows and corresponding schedules (see Overlap Regulation Service and Supplemental Regulation Service).

Subregion A portion of a Region.

Supervisory Control and Data Acquisition (SCADA) A system of remote control and telemetry used to monitor and control the transmission system.

Special Protection System A protection system designed to perform functions other than the isolation of electrical faults. Also called "remedial action scheme."

Spinning Reserve Unloaded generation which is synchronized and ready to serve additional demand

Station Service The electric supply for the ancillary equipment used to operate a generating station or substation.

Station Service Generator A generator (usually found in hydro plants) used to supply electric energy for station service equipment.

Supplemental Regulation Service A method of providing regulation service in which the control area providing the regulation service receives a signal representing all or a portion of the other control area's ACE.

System A combination of generation, transmission, and distribution components comprising an electric utility, or group of utilities.

System Operator A person who operates the electric system.

GUIDE I. SYSTEMS CONTROL

A. GENERATION CONTROL

Criteria Reference

Each control area shall operate sufficient generating capacity under automatic control to meet its obligation to continuously balance its generation and interchange schedules to its load. It shall also provide its proper contribution to interconnection frequency regulation.

Requirements

1. All load, generation, and transmission operating in an Interconnection must be included within the metered boundaries of a control area.

2. Automatic Generation Control (AGC) shall compare total net actual interchange to total net scheduled interchange plus frequency bias contribution to determine the control area's Area Control Error (ACE), and respond to return the ACE to zero.

3. Each control area shall maintain generating regulating capability, synchronized to the Interconnection, that can be increased or decreased by AGC to provide for adequate system regulation and Control Performance.

4. Each control area shall operate its AGC on tie-line frequency bias, unless such operation is adverse to system or Interconnection reliability. The requirements for tie-line bias control follow:

    4.1. The control area shall set its frequency bias (expressed in MW/0.1 Hz) as close as practical to the control area's frequency response characteristic. Frequency bias may be calculated several ways:

        4.1.1. A fixed frequency bias value may be used which is based on a fixed, straight-line function of tie-line deviation versus frequency deviation. The fixed value shall be determined by observing and averaging the frequency response characteristic for several disturbances during on-peak hours.

        4.1.2. A variable (linear or non-linear) bias value may be used which is based on a variable function of tie-line deviation to frequency deviation. The variable frequency bias value shall be determined by analyzing frequency response as it varies with factors such as load, generation, governor characteristics, and frequency.

        4.1.3. Control areas that use dynamic scheduling and/or pseudo-ties for jointly owned units must reflect their respective share of the unit governor droop response into their respective frequency bias setting. Fixed schedules for jointly owned units mandates that the control area that contains the jointly owned unit must incorporate the respective share of the unit governor droop response for any control area(s) that has a fixed schedule. The control area(s) that have a fixed schedule but do not contain the jointly owned unit should not include their share of the governor droop response in their frequency bias setting.

4.2 The Performance Subcommittee shall set demonstration and performance standards for whichever frequency bias method is used.

4.2.1. In no case shall the monthly average frequency bias be less than 1% of the control area's estimated yearly peak demand per 0.1 Hz change as described in the Control Performance Criteria Training Document

4.2.2. A control area that is performing overlap regulation service will increase its frequency bias setting to match the frequency response of the entire area being controlled. A control area that is performing supplemental regulation service shall not change its frequency bias setting.

4.3. Each control area must be able to demonstrate and verify to the Performance Subcommittee that its frequency bias setting closely matches its system response.

4.4. Each control area shall review its frequency bias settings by January 1 of each year and recalculate its setting to reflect any change in area frequency response characteristic.

4.4.1. The bias setting, and the method used to determine the setting, may be changed whenever any of the factors used to determine the current bias value change.

4.4.2. Each control area shall report its frequency bias setting, and method for determining that setting, to the Performance Subcommittee.

4.5 It is the responsibility of the control area providing regulation service to notify the entity for whom it is controlling if it is unable to provide the service.

Recommendations

1. AGC should remain in operation as much of the time as possible.

2. AGC may be suspended at frequencies above 60.2 Hz or below 59.8 Hz if continued control would result in generation changes that could endanger system reliability.

3. Turbine governors and control systems, including AGC, and HVDC control systems should be checked periodically to verify their correct operation.

4. Turbine governors and HVDC controls, where applicable, should be allowed to respond to system frequency deviation, unless there is a temporary operating problem.

5. The utility should establish normal and emergency rates of response for each generator and HVDC terminal.

6. Load-limiting devices should be applied only to restrict the extent of load change which might have an adverse effect on the generator or jeopardize transmission security.

7. Regulating margin should be distributed over as many units as possible.

8. Each control area should plan for future adequate control performance to meet expected changes in load characteristics and daily load patterns.

9. All generating units of consequential size, including jointly owned units capable of regulating should be equipped with AGC to ensure that the control area can continuously balance its generation with its demand plus net scheduled interchange

10. Data acquisition for and calculation of ACE should occur at least every four seconds

11. Generating units with nameplate ratings of 10 MW or greater should be equipped with governors operational for frequency response unless restricted by regulatory mandates.

12. All turbine-generators equipped with governors should be capable of providing immediate and sustained response to abnormal frequency excursions. Governors should provide a 5% droop characteristic. Governors should, as a minimum, be fully responsive to frequency deviations exceeding $\pm$ 0.036 Hz.

13. Turbine control systems that provide adjustable limits to governor valve movement (valve position limit or equivalent) should not restrict travel more than necessary to coordinate boiler and turbine response characteristics.

Background

Accurate and adequate generator control helps reduce time error, frequency deviations, and inadvertent interchange within the Interconnection.

Each control area will respond to frequency deviations according to its system response characteristic. Most of this response will be reflected in the control area's net tie flow to the Interconnection. By monitoring the interchange deviation from schedule, the frequency deviation from schedule, and by using the control area's frequency response characteristic, the control area, through its AGC, can determine whether the imbalance in load and generation is internal or external to its control area. If internal, the AGC will adjust the generation to correct the imbalance. If external, no AGC action should occur; however, the system frequency response to the deviation should be allowed to continue until the external system with the generation surplus or deficiency corrects its imbalance and returns the frequency to schedule. Until actual system response can be continuously measured, it must be estimated This estimate is the tie-line frequency bias setting. The closer the tie-line frequency bias matches the actual system frequency response, the better the AGC will be able to distinguish internal and external imbalances and reduce the number of unnecessary control actions. Therefore, the basic requirement of tie-line frequency bias is that it match the actual system response as closely as practicable.

B. VOLTAGE CONTROL

Criteria Reference

Each system and control area shall operate capacitive and inductive reactive resources at proper levels to maintain system and interconnection voltages within established high and low limits. Reactive generation scheduling, transmission switching and load shedding, if necessary, shall be implemented to maintain these levels. Each system and control area shall maintain adequate Mvar reserve resources to support its voltage under credible contingency conditions.

Requirements

1. Devices used to regulate transmission voltage and reactive flow shall be available for use by the system operator.

2. System operators shall monitor transmission system voltage for deviation from prearranged voltage levels and take corrective action to keep voltages within allowable limits.

   2.1. Prearranged voltage levels, reactive control equipment settings, and changes in transmission configuration shall be coordinated with neighboring systems.

   2.2. Transfer or interchange limits shall reflect voltage or reactive restrictions.

   2.3. System operators shall monitor and keep reactive power flow within established limits on tie-lines.

Recommendations

1. Important transmission lines should be kept in service during light-load periods as much as possible. They should be removed from service for voltage control measure only after all reactive control measures are fully implemented and appropriate studies indicate that system reliability will not be degraded below acceptable levels.

2. Automatic voltage regulators and power system stabilizers on generators and synchronous condensers should be kept in service as much of the time as possible.

3. Devices used to regulate transmission voltage and reactive flow should be switchable without deenergizing other facilities.

4. When a generator's automatic voltage regulator is out of service, field excitation should be maintained at a level adequate for stable operation.

5. Systems with dc transmission facilities should utilize reactive capabilities of converter terminal equipment for voltage control.

C. TIME AND FREQUENCY CONTROL

Criteria Reference

Interconnection frequency shall be scheduled at 60 Hz and controlled to that value except for those periods in which frequency deviations are scheduled to correct time error

Operating limits for frequency deviation and time error shall be established with interconnection reliability as first priority.

Each control area shall participate in interconnection time error correction.

Control areas which are operating in parallel shall select one control area to monitor time error for the interconnection and to issue time error correction orders.

Requirements

1. Each Interconnection shall designate an Interconnection Monitor who shall monitor time error and shall initiate or terminate corrective action orders when time error reaches predetermined limits as shown in Appendix I.C.

2. Time error corrections shall start and end on the hour or half-hour, and notice shall be given at least twenty minutes before the time error correction is to start or stop.

3. Time error correction notifications shall be serialized alphabetically on a monthly basis.

4. The time error correction offset shall be applied by either of the following two methods:

   4.1. The frequency schedule may be offset by 0.02 Hz, leaving the bias setting normal, or

   4.2. If the control frequency base setting cannot be offset, the Net Interchange schedule (MW) may be offset by an amount equal to the computed bias contribution during a 0.02 Hz frequency deviation (i.e., 20% of the frequency bias setting).

5. A Regional Monitor shall be designated through which time error correction notifications originating with the Interconnection Monitor will be routed to each system in the Region by way of established Time Notification Channels.

6. The Interconnection Monitor shall periodically issue a notification of time error, accurate to within 0.1 second, to the Regional Monitors to assure uniform calibration of time standards.

7. Using the Time Notification Channels, the Regional Monitors shall, each hour, on the hour, notify all systems within their respective Regions of the accumulated time error within 0.1 second. Time error notification shall be accompanied by the alphabetic designator if a time error correction is in progress.

8. Each control area shall at least annually check and calibrate its time error and frequency devices against a common reference.

9. When one or more control areas has been separated from the Interconnection, upon reconnection, they shall adjust their time error devices to coincide with the Interconnection by one of the following methods:

9.1 Before connection, the separated area may institute a Time Error Correction Procedure to correct its accumulated time error to coincide with the indicated time error of the Interconnection Monitor, or

9.2. After interconnection, the time error devices of the previously separated area may be recalibrated to coincide with the indicated time error of the Interconnection Monitor. A notification of adjusted time error shall be passed through Time Notification Channels as soon as possible after interconnection.

10. Standards of allowable time error are found in Appendix I.C.

Recommendations

1. The control areas of an Interconnection may implement automatic time error control as a part of their AGC scheme.

   1.1. If automatic time error correction is used, all control areas of the Interconnection should participate.

   1.2. Automatic time error control should be suspended whenever an announced time correction is in progress.

2. Systems using time error devices that are not capable of automatically adjusting for leap-seconds should arrange to receive advance notice of the leap-second and make the necessary manual adjustment in a manner that will not introduce a disturbance into their control system.

Background

The difference between load and generation results in frequency deviations from 60 Hz, and the integrated deviation appears as a departure from correct time.

The satisfactory operation of the Interconnected systems is dependent, in part, upon accurate frequency transducers and recorders and time error devices associated with AGC equipment.

D. INTERCHANGE SCHEDULING

Criteria Reference

Scheduling power between control areas shall be done through transmission paths established by contract or ownership

The net amount of interchange scheduled between control areas shall not exceed the mutually established transfer limits of the common interconnections and alternate paths which have been arranged for between the parties When establishing normal and emergency transfer limits, the sending, contract intermediary, and receiving control areas shall consider the effect of power flow through their own and other parallel systems or control areas based on mutually acceptable reliability criteria. In no case shall the scheduled power between two control areas exceed the total installed capacity of owned or arranged-for transmission facilities between the two control areas.

Schedule changes shall be made at a time and rate agreeable to both the supplier and receiver and within the capability of each to control the change.

Requirements

1. Interchange shall be scheduled only between control areas having directly connecting facilities in service unless there is a contract or mutual agreement with other control areas to provide connecting facilities.

2. Interchange schedules or schedule changes shall not cause any other system to violate established reliability criteria.

   2.1. When control areas are connected so that parallel flows present reliability issues, the combinations of control areas shall develop multi-control area interchange monitoring techniques and pre-determined corrective actions to mitigate or alleviate potential or actual transmission system overloads.

   2.2. Transfer limits shall be reevaluated and interchange schedules adjusted as soon as practicable if transmission facilities become overloaded or are out of service, or when changes are made to the bulk system which can affect these limits.

3. The maximum net scheduled interchange between two control areas shall not exceed the lesser of two values.

   3.1 The total capacity of the transmission facilities in service between the two control areas owned by them or available to them under specific arrangements, contracts, or mutual agreements, or

3.2 The mutually established First Contingency Total Transfer Capability of the two control areas considering other transmission facilities available to them under specific arrangements. First Contingency Total Transfer Capability is defined in Appendix I D., *Transfer Capability A Reference Document*, NERC October 1980

4 The sending, contract intermediary, and receiving control areas that are parties to a interchange transaction shall agree on the following:

4.1 The schedule's magnitude, starting and ending times

4.2. The schedule's magnitude and rate of change shall be equal and opposite and not exceed the ability of the systems to effect the change.

4.3. The scheduled generation in one control area that is delivered to another control area must be scheduled with all intermediate control areas unless there is a contract or mutual agreement among the sending, contract intermediary, and receiving control areas to do otherwise.

5. Control areas shall develop procedures to disseminate information on interchange schedules and facilities out of service which may have an adverse effect on other control areas not involved in the scheduled interchange and the involved parties shall predetermine schedule priorities, which will be used if a schedule reduction becomes necessary.

Background

Scheduled interchange must be coordinated between control areas to prevent frequency deviations and accumulations of inadvertent interchange, and prevent exceeding mutually established transfer limits

E. CONTROL PERFORMANCE CRITERIA

Criteria Reference

The Control Performance Criteria define a standard of minimum control performance. Each control area is to have the best operation above this minimum that can be achieved within the bounds of reasonable economic and physical limitations.

Requirements

1. Two criteria shall be used to continually monitor control performance during normal conditions (See the "Control Performance Criteria Training Document," Section 2.1)

1.1. A1 Criteria - The ACE must return to zero within ten minutes of previously reaching zero. Violations of this criteria count for each subsequent ten-minute period that the ACE fails to return to zero.

1.2. A2 Criteria - The average ACE for each of the 6 ten-minute periods during the hour (i.e., for the ten-minute periods ending at 10, 20, 30, 40, 50, and 60 minutes past the hour) must be within specific limits, referred to as L_d, that are determined from the control area's rate of change of demand characteristics. See the "Control Performance Criteria Training Document," Section 2.1.2.1 for the methods for calculating L_d.

2. Two criteria shall be used to continually monitor control performance during disturbance conditions (See the "Control Performance Criteria Training Document," Section 2.2)

2.1 B1 Criteria — The ACE must return to zero within ten minutes following the start of the disturbance.

2.2 B2 Criteria — The ACE must start to return to zero within one minute following the start of the disturbance.

3. The ACE used to determine compliance to the Control Performance Criteria shall reflect its actual value, and exclude short excursions due to transient telemetering problems or other influences such as control algorithm action.

4. All control areas shall respond to control performance surveys that are requested by the Performance Subcommittee.

Recommendations

1. Each control area should be in compliance with the A1 and A2 Criteria at least 90% of the time.

Background

Control performance is the degree to which a control area matches its generation to its demand plus scheduled interchange taking into account the effects of frequency bias. The NERC Operating Committee has established the Control Performance Criteria (CPC) which include standards of acceptable control performance. The CPC establish minimum standards for control performance and provide a means for measuring the relative control performance of each control area. While these standards define the minimum acceptable performance, each control area shall meet and strive to exceed these standards.

F. INADVERTENT INTERCHANGE MANAGEMENT

Criteria Reference

Each control area shall, through daily schedule verification and the use of reliable metering equipment, accurately account for inadvertent interchange. Recognizing generation and load patterns, each control area shall be active in preventing unintentional inadvertent interchange accumulation. Each control area shall also be diligent in reducing accumulated inadvertent balances in accordance with Operating Committee procedures.

Each control area interconnection point shall be equipped with a common MWh meter, with readings provided hourly at the control center of both areas.

Requirements

1. Inadvertent interchange shall be calculated and recorded hourly and may accumulate as a credit or debit to the control area. (See the Inadvertent Interchange Accounting Training Document.)

2. All interconnections shall be included in the inadvertent interchange account. Interchange served through jointly owned facilities and interchange with borderline customers must be properly taken into account.

3. Inadvertent interchange accumulations shall be paid back by one or both of the following methods.

   3.1. Method 1 — Inadvertent interchange accumulations may be paid back by scheduling interchange with another control area.

      3.1.1. The other control area must have an inadvertent accumulation in the opposite direction.

      3.1.2. The amount of inadvertent payback scheduled shall be agreed upon by all involved systems.

   3.2. Method 2 — Inadvertent interchange accumulations may be paid back unilaterally by offsetting tie-line schedule when such action will aid in correcting the existing time error.

      3.2.1. If time is slow and there is a negative accumulation (undergeneration), the AGC may be offset to overgenerate and pay back inadvertent interchange accumulation and reduce time error.

      3.2.2. If time is fast and there is a positive accumulation (overgeneration), the AGC may be offset to undergenerate and pay back inadvertent interchange accumulation and reduce time error.

      3.2.3. AGC offset may be made by either offsetting the frequency schedule up to 0.02 Hz, leaving the bias setting normal or offsetting the net tie-line schedule by up to 20% of the control area's bias or 5 MW, whichever is greater.

      3.2.4. Inadvertent payback shall end when either the time error is zero or has changed signs, the accumulation of inadvertent interchange has been corrected to zero, or a scheduled time error correction begins, which takes precedence over offsetting frequency schedule to pay back inadvertent.

      3.2.5. Control areas within Interconnections using automatic time error control techniques shall not use Method 2 to reduce their accumulations of inadvertent. Method 1 is the only acceptable way for these control areas to manually reduce their accumulations of inadvertent.

4. Inadvertent interchange accumulated during "on-peak" hours shall be paid back during "on-peak" hours. Inadvertent interchange accumulated during "off-peak" hours shall be paid back during "off-peak" hours.

5. Each control area shall submit a monthly summary of inadvertent interchange as detailed in Appendix I.F., "Inadvertent Interchange Energy Accounting Practices."

RELIABILITY CRITERIA FOR INTERCONNECTED SYSTEMS OPERATION

PREAMBLE

OBJECTIVES AND RESPONSIBILITIES

The objectives of the Operating Committee (OC) of the North American Electric Reliability Council (NERC) are to promote the reliable operation of the interconnected electric systems in North America, establish criteria and guides for interconnected systems operation, and provide a forum for the coordination of interconnected systems operation. These objectives will be achieved through operating policies and procedures developed by the Operating Committee and approved by the Regions.

The NERC Operating Manual contains the NERC Reliability Criteria for Interconnected Systems Operation (Criteria) and the NERC Operating Guides (Guides) which are statements of operating policies, procedures, and practices designed to promote coordinated operation among interconnected systems and to assure that high levels of interconnected systems reliability and control are efficiently and continuously achieved. The Criteria establish the Operating Committee's basic operating policy. The Guides specify how this policy is to be implemented. The Criteria and Guides are based on established technical rationale and mature operating experience and judgment. They are reviewed and updated by the Operating Committee as necessary with present and future Interconnection and system requirements in mind.

All systems share the benefits of interconnected systems operation and, by their voluntary association in NERC, they recognize the need and accept the responsibility to operate in a manner that will enhance interconnected operation and not burden other interconnected systems. Responsibility to observe the Criteria and Guides and to contribute to their continued improvement extends to the member system operators. NERC Regions bear the responsibility of establishing regional operating policies based on the NERC Operating Criteria and Guides.

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BASIC OPERATING POLICY

I. INTERCONNECTED SYSTEMS CONTROL

Each system shall either operate a control area or make arrangements to be included in a control area operated by another system.

The generation sources and load of a control area shall be connected by adequate transmission facilities either owned by the systems within the control area or arranged for by those systems.

The following paragraphs present the basic operating policy pertaining to interconnected systems control:

A. MW Regulation

Each control area shall operate sufficient generating capacity under automatic control to meet its obligation to continuously balance its generation and interchange schedules to its load. It shall also provide its proper contribution to interconnection frequency regulation.

B. Voltage Control

Each system and control area shall operate capacitive and inductive reactive resources at proper levels to maintain system and interconnection voltages within established high and low limits. Reactive generation scheduling, transmission and switching, and load shedding, if necessary, shall be implemented to maintain these levels. Each system and control area shall maintain adequate Mvar reserve resources to support its voltage under credible contingency conditions.

C. Time and Frequency Regulation

Interconnection frequency shall be scheduled at 60 Hz and controlled to that value except for those periods in which frequency deviations are scheduled to correct time error.

Operating limits for frequency deviation and time error shall be established with interconnection reliability as first priority.

Each control area shall participate in interconnection time error correction procedures.

Control areas which are operating in parallel shall select one control area to monitor time error for the interconnection and to issue time error correction orders.

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D. **Interchange Scheduling**

Scheduling power between control areas shall be done through transmission paths established by contract or ownership.

The net amount of interchange scheduled between control areas shall not exceed the mutually established transfer limits of the common interconnections and alternate paths which have been arranged for between the parties. When establishing normal and emergency transfer limits, the sending, contract intermediary, and receiving control areas shall consider the effect of power flow through their own and other parallel systems or control areas based on mutually acceptable reliability criteria. In no case shall the scheduled power between two control areas exceed the total installed capacity of owned or arranged-for transmission facilities between the two control areas.

Scheduled changes shall be made at a time and rate agreeable to both the supplier and receiver and within the capability of each to control the change.

E. **Control Performance Criteria**

The Control Performance Criteria define a standard of minimum control performance. Each control area is to have the best operation above this minimum that can be achieved within the bounds of reasonable economic and physical limitations.

F. **Inadvertent Interchange Management**

Each control area shall, through daily schedule verification and the use of reliable metering equipment, accurately account for inadvertent interchange. Recognizing generation and load patterns, each control area shall be active in preventing unintentional inadvertent interchange accumulation. Each control area shall also be diligent in reducing accumulated inadvertent balances in accordance with Operating Committee procedures.

Each control area interconnection tie point shall be equipped with a common MWh meter, with readings provided hourly at the control centers of both areas.

G. **Control Surveys**

Periodic surveys of the control performance of the control areas shall be conducted. These surveys serve the purpose of revealing control equipment malfunctions, telemetering errors, improper frequency bias settings, scheduling errors, inadequate generation under automatic control, general control performance deficiencies, or other factors contributing to inadequate control performance.

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H. Control Equipment Requirements

The control equipment of each control area shall be designed and operated so that the control area can continuously and accurately meet its system and interconnection control obligations and measure its performance. The control equipment design and operation shall follow accepted industry techniques

All control area interconnection tie points shall be equipped to telemeter MW power flow to both area control centers simultaneously. The telemetering shall be from an agreed-upon terminal utilizing common metering equipment.

The control area operator's displays and consoles shall present him with a clear and understandable picture of his control area parameters. This includes necessary information from facilities within other control areas in addition to internal information.

II. INTERCONNECTED SYSTEMS SECURITY

Interconnection security is the responsibility of each system, control area, pool, and Region.

The interconnected systems shall be operated at all times so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. Multiple outages of a credible nature shall also be examined and, when practical, the systems shall be operated to protect against instability, uncontrolled separation or cascading outages resulting from these multiple outages.

The following paragraphs present the basic operating policy pertaining to interconnected systems security:

A. MW Generation Reserve

Each control area shall operate its MW power resources to provide for a level of operating reserve sufficient to account for such factors as errors in forecasting, generation and transmission equipment unavailability, number and size of generating units, system equipment forced outage rates, maintenance schedules, regulating requirements, and regional and system load diversity. Following loss of resources or load, a control area shall take appropriate steps to reduce its Area Control Error to zero within 10 minutes. It shall take prompt steps to protect itself against the next contingency.

Each Region or Subregion shall specify its operating reserve policies, including its allocation among members, the permissible mix of spinning and nonspinning reserve, and procedure for applying operating reserve in practice, and the limitations, if any, upon the amount of interruptible load which may be included.

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B. Reactive Power Reserve

Each control area shall provide for the supply of its reactive power requirements, including appropriate reserves to protect the voltage levels for contingency conditions. This includes the control area's share of the reactive requirements of interconnecting transmission circuits. The reserve shall be located electrically so that it can be applied effectively, within the appropriate time interval, when contingencies occur.

Control areas shall coordinate the use of voltage control equipment to maintain transmission voltages and reactive flows at levels consistent with interconnection security.

C. Transmission Operation

Transmission equipment is to be operated within its normal rating except for temporary conditions after a contingency has occurred.

When line loadings, equipment loadings, or voltage levels deviate from normal operating limits or can be expected to exceed emergency limits following a contingency, and reliability of the bulk power supply is threatened, control areas experiencing or causing the condition shall take immediate steps to relieve the condition. These steps include notifying other systems, adjusting generation, changing schedules between control areas, initiating load relief measures, and taking such other action as may be required.

Transmission system operation shall be coordinated among systems, control areas, pools, and Regions. This includes coordination of equipment outages, voltage levels, MW and Mvar flow monitoring, and switching that affects two or more systems.

D. Relay Coordination

Systems and control areas shall coordinate the application, operation, and maintenance of protective relays on the bulk transmission system, including the coordination of underfrequency load shedding relays. They shall develop criteria which will enhance their system reliability with the minimum adverse effect on the interconnection.

System operators shall be familiar with the intended operation of protective relay application and shall have access to appropriate relay operating information.

E. Monitoring Interconnection Parameters

Each system and control area shall continuously monitor those electric system parameters (such as MW flow, Mvar flow, frequency, voltage, phase angle,

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etc.), internal and external to its system or control area, that indicate the electrical system strength.

The system operator shall be provided with adequate equipment to accomplish this objective. Metering of suitable range and reliability for both normal and emergency operation shall be maintained from strategic system points.

F. Information Exchange

1. System Conditions

Information concerning system conditions shall be transmitted to adjacent control areas and non-adjacent control areas as needed to assure adequate protection to the interconnection.

2. Disturbance Reporting

Disturbances or unusual occurrences which jeopardize the operation of the interconnected systems, that result, or could result, in system equipment damage, or customer interruptions, shall be studied in sufficient depth to increase industry knowledge of electrical interconnection mechanics so that similar events can be prevented. The facts surrounding a disturbance shall be made available to system and control area operators, system managers, Reliability Councils, and regulatory agencies entitled to the information.

G. Maintenance Coordination

Each system shall establish schedules for inspection and preventive maintenance of its generation, transmission, relay, control, communication and other electric system facilities. These maintenance and inspection schedules shall be coordinated with other systems and control areas to assure an equipment outage pattern that will not violate interconnection reliability criteria.

III. EMERGENCY OPERATIONS OF INTERCONNECTED SYSTEMS

Each system and control area shall promptly take appropriate action to relieve any abnormal conditions which jeopardize reliable interconnection operation.

The following paragraphs present the basic operating policy pertaining to emergency operations of interconnected systems:

A. Insufficient Generation Capacity

A control area which has experienced an operating capacity emergency shall promptly balance its generation and interchange schedules to its load, without

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SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL

AGREEMENT

Dated as of January 14, 1970

Amended April 27, 1994

ARTICLE 2

PURPOSE OF AGREEMENT

2.01 The purpose of this Agreement is to augment further the reliability and adequacy of bulk power supply in the areas served by the Member Systems. To this end, the Council will:

(a) encourage the development of reliability and adequacy arrangements among the systems within the region;

(b) exchange information with respect to planning and operating matters relating to the reliability and adequacy of bulk power supplies;

(c) review periodically activities within the region on reliability and adequacy;

(d) provide information with respect to matters considered by the Council, where appropriate, to the Federal Energy Regulatory Commission and to other Federal and state agencies concerned with reliability adequacy.

ARTICLE 3

MEMBERSHIP

3.01 Membership in the council is open to any entity that is subject to or eligible to apply for an order under Section 211 of the Federal Power Act. There are two classes of membership: Regular members and Associate members.

Membership in SERC is voluntary, but members recognize a commitment to comply with NERC and SERC guidelines for the planning and operating of the interconnected electric power system.

3.02 Regular membership is open to any electric utility, Federal power marketing agency, or any other entity owning generation or owning network transmission of 69 kV and above and generating or transmitting electric energy for sale for resale and normally connected with the interconnected electric power system in the general area encompassed by the member systems.

3.03 Associate membership is open to any entity serving retail electric load in the area but not meeting the criteria for regular membership. Associate members may designate a representative to participate in meetings of the Executive Board, but the representative shall not be entitled to vote.

Associate members are entitled to receive all reports, reference documents, and minutes distributed to regular members.

Entities that meet the criteria for regular members will not be accepted as associate members except for those entities owning less than 25 MW of generation or with a peak demand of less than 25 MW.

Retail customers which purchase electricity as ultimate consumers and do not generate electricity for resale are not eligible for membership.

Any entity not currently meeting the requirements for membership but which has definite plans for the construction of generation or transmission which would qualify it for membership may apply for associate membership. These applications will be reviewed by the Executive Committee and approved on a year-to-year basis depending on the committee's determination of good faith and the reasonable feasibility of the project.

FPSC DOCKET NO. 941101-EQ
FPC WITNESS: **SOUTHWICK**
EXHIBIT NO. _____ (HIS-2)
CONSISTING OF 114 PAGES

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UNIT POWER SALES AGREEMENT
BETWEEN
FLORIDA POWER CORPORATION
AND
ALABAMA POWER COMPANY,
GEORGIA POWER COMPANY,
GULF POWER COMPANY,
MISSISSIPPI POWER COMPANY,
SAVANNAH ELECTRIC AND POWER COMPANY
AND SOUTHERN COMPANY SERVICES, INC.

THIS Unit Power Sales Agreement ("UPS Agreement"), made and entered into as of the 19th day of July, 1988, by and between FLORIDA POWER CORPORATION ("Corporation"), a Florida corporation, and ALABAMA POWER COMPANY ("APC"), an Alabama corporation, GEORGIA POWER COMPANY ("GaPC"), a Georgia corporation, GULF POWER COMPANY, ("GuPC"), a Maine corporation, MISSISSIPPI POWER COMPANY ("MPC"), a Mississippi corporation, and SAVANNAH ELECTRIC AND POWER COMPANY ("SEPCO"), a Georgia corporation (APC, GaPC, GuPC, MPC and SEPCO being sometimes collectively referred to as "Southern Companies") and SOUTHERN COMPANY SERVICES, INC. ("SCS"), an Alabama corporation.

W I T N E S S E T H:

WHEREAS, Southern Companies are all affiliates by virtue of the ownership of the common stock of such companies by The Southern Company, a registered public utility holding company under the Public Utility Holding Company Act of 1935; and

WHEREAS, APC, GaPC, GuPC and MPC, together with SCS and Corporation, are parties to an Interchange Contract dated December 15, 1968, as amended, ("Interchange Contract") which provides for certain points of interconnection between the parties, and, pursuant to the terms of which the parties have constructed and maintained points of interconnection which provide and improve system reliability of each of the systems and can accommodate transactions under this UPS Agreement as well as other agreements between the parties; and

WHEREAS, Corporation desires to purchase and APC, GaPC and GuPC desire to sell unit power capacity from designated coal-fired steam electric generating units of their J. H. Miller, Jr. Steam Electric Generating Plant ("Miller Plant") and Robert W. Scherer Steam Electric Generating Plant ("Scherer Plant") in designated amounts during the periods specified herein; and

WHEREAS, Southern Companies are joining in this UPS Agreement to provide, among other things, necessary transmission services, substitute capacity and energy in the event commercial operation of certain generating units of the Miller Plant is delayed or cancelled and supplemental energy when any designated unit of the Miller Plant or Scherer Plant is unavailable or derated; all as set forth herein.

NOW, THEREFORE, in consideration of the premises and the covenants and agreements of the parties hereinafter set forth, the parties hereto agree as follows:

ARTICLE I

TERM OF AGREEMENT

1.1 Term: This UPS Agreement shall become effective as of the date of the latest signature on the signature page hereof and shall continue in effect through May 31, 2010.

1.1.1 It is understood by the parties hereto that this UPS Agreement will be filed by Southern Companies with the Federal Energy Regulatory Commission ("FERC") or its successor in interest within sixty (60) days from the effective date hereof. Corporation agrees to cooperate and assist Southern Companies in securing conclusion of any initial review by FERC of this UPS Agreement without significant change, in an expeditious manner. It is further understood by the parties that timely FERC approval or acceptance of this UPS Agreement is important in order to facilitate capacity planning on the part of both Corporation and Southern Companies. Accordingly, if FERC has not approved or accepted for filing this UPS Agreement on or by June 1, 1989, the parties hereto agree that their representatives will meet to determine how to expedite the filing and review process.

ARTICLE II

UNIT POWER CAPACITY

2.1 Units from which Capacity Will be Made Available: Except as specifically provided for in this ARTICLE II, the capacity entitlement will be made available from Units 1, 2, 3 and 4 of the Miller Plant located in Jefferson County, Alabama and Unit 3 of the Scherer Plant located in Monroe County, Georgia. Exhibit A, which is attached hereto and incorporated herein by reference, sets forth the projected date for commercial operation of each unit; and the amount of the Expected Capacity of each unit owned by APC, GaPC and GuPC which is made available for sale hereunder to Corporation.

2.2 Capacity to be Purchased and Sold: Subject only to adjustments as provided in this Article II, APC, GaPC and GuPC hereby agree to sell and Corporation hereby agrees to purchase capacity entitlement from the units specified in 2.1

above, in the following aggregate amounts: (i) 200 megawatts ("MW") of unit power ("first 200 MW sale") during the period January 1, 1994 to May 31, 2010, which unit power will not be subject to cancellation or termination by any party to this UPS Agreement; and (ii) an additional 200 MW of unit power ("second 200 MW sale") during the period January 1, 1995 to May 31, 2010, which second 200 MW sale or any portion thereof, will be subject to termination by Corporation on or after January 1, 2000 (but in no event earlier) provided, that Corporation gives at least three (3) years advance written notice to APC, GaPC and GuPC that it desires to terminate the second 200 MW sale, or any portion thereof, on such date or thereafter. Exhibit A sets forth the amount of Expected Capacity to be purchased by Corporation and sold by APC, GaPC and GuPC from each designated unit of the Miller Plant and Scherer Plant during the above-specified periods assuming Corporation does not exercise its right to terminate the second 200 MW sale, or any portion thereof. In the event Corporation elects to terminate all or a portion of the second 200 MW sale on or after January 1, 2000, the remaining sale (not less than 200 MW) will be allocated equally among the units specified in Section 2.1 above. In the case of Unit 3 of the Scherer Plant, the remaining sale will be allocated on a basis of 2 MW out of GuPC's ownership portion of such unit to each 1 MW out of GaPC's ownership portion of such unit. For example, if the remaining sale is 200 MW, the sale to Corporation will be allocated as follows: 40 MW out of each of Units 1, 2, 3 and 4 of the Miller Plant; 27 MW out of GuPC's portion of Unit 3 of the Scherer Plant; and 13 MW out of GaPC's portion of Unit 3 of the Scherer Plant.

The parties hereto recognize that long-range plans and forecasts which provide the basis for such sales and purchases of capacity are affected by many factors. Therefore:

2.2.1 In addition to the above rights and obligations, Corporation shall have the option to commence taking the full unit power sale (400 MW), or any part thereof, on a date as early as January 1, 1993, provided that advance written notice is given to Southern Companies at least twenty-four (24) months prior to such take ("early option"). Further, the parties hereto agree that the early option will not be applied to allow the total sales of unit power capacity in any month to be less than the total sale for any previous month during the period January 1, 1993 to January 1, 1995. It is the intent of the parties hereto that additional unit power sales under the early option to contemporaneous parties (as defined in Section 10.10) will be supplied in equal amounts from the four units of the Miller Plant and the one unit of the Scherer Plant; however, it is recognized that in some time periods there will not be sufficient unsold capacity in Unit 4 of the Miller Plant and/or Unit 3 of the Scherer Plant to meet the one-fifth (1/5) allocation from each unit of the early option to contemporaneous parties. During such time periods, the additional unit power sales will be supplied first from Unit 4 of the Miller Plant and/or Unit 3 of the Scherer Plant to the extent unsold (in no event more than one-fifth (1/5) of the early option) with the remainder supplied equally from Units 1, 2 and 3 of the Miller Plant. All sales from Unit 3 of the Scherer Plant will be allocated on the basis of 2 MW from GuPC's ownership in that unit to each 1 MW from GaPC's ownership in that unit to the extent capacity is unsold. Without regard to the timing of the notice to exercise this early option by Corporation and other contemporaneous parties, Corporation and other contemporaneous parties will be supplied additional unit power sales from the units specified in Section 2.1 in accordance with the foregoing principles and in proportion to the amount of unit power sales advanced by Corporation and each of the other contemporaneous parties. Due to the complicated nature of this early option, the parties hereto have agreed to examples of the operation of the early option under different assumptions and have attached such examples to this UPS Agreement as a part of Exhibit A. In the event of any disputes concerning the operation of the early option, the examples will govern.

2.2.2 Further, Corporation shall have the right to take Long Term Power as provided for in Exhibit B, which is attached hereto and incorporated herein by reference, in substitution for any unit power that Corporation had a right to advance pursuant to the early option (set forth in Section 2.2.1). In no event, however, will Southern Companies, APC, GaPC, GuPC or Corporation be allowed to substitute Long Term Power for the first 200 MW sale or the second 200 MW sale or any unit power advanced under the early option.

2.2.3 If, however, Southern Companies have an opportunity to sell unit power or Long Term Power during the period January 1, 1993 to January 1, 1995 to third party utilities, Southern Companies shall give notice to Corporation of such opportunity and Corporation will have sixty (60) days in which to exercise the early option as to that amount of capacity which Southern Companies has an opportunity to sell during the period. Any such unit power or Long Term Power offered to third parties will be offered to Corporation and other contemporaneous parties (on a pro rata basis) at equal or improved terms. In the event Corporation does not elect to exercise the early option (or purchase the newly-offered unit power capacity or Long Term Power) at the end of such sixty (60) day period, the early option shall expire as to such amount of capacity. However, such option shall not expire as to any amount of capacity under the early option which remains unsold. As to such remaining amount of capacity, each contemporaneous party shall retain the early option for its pro rata share of such amount of capacity based on a ratio of its full unit power sale to the sum of the full unit power sales of all contemporaneous parties. A contemporaneous party exercising an early option does not trigger the early option provision for the other contemporaneous parties. For purposes of this provision, capacity purchases in addition to those incorporated in the contracts with contemporaneous parties shall be treated as purchases by third parties.

2.2.4 In the event that Southern Companies, prior to 1993, offer to sell unit power capacity from coal-fired generating resources during the period January 1, 1998 through May 31, 2010, to third party utilities located outside the geographical areas served by Southern Companies, Corporation and other contemporaneous parties shall each have the right of first refusal for the purchase of any part or all of its pro rata share of such capacity; provided, however, such right must be exercised within ninety (90) days after written notice from Southern Companies informing Corporation of such capacity being made available for sale and the terms and conditions of each offer. Furthermore, in the event that Southern Companies, after 1992, offer to sell unit power capacity from coal-fired generating resources during the period June 1, 1995 through May 31, 2010 to third party utilities located outside the geographical areas served by Southern Companies Corporation and other contemporaneous parties shall each have the right of first refusal for the purchase of any part or all of its pro rata share of such capacity; provided, however, such right must be exercised within ninety (90) days after written notice from Southern Companies informing Corporation of such capacity being made available for sale and the terms and conditions of each offer. In the event Corporation exercises its rights under Section 2.2 to terminate any portion of the second 200 MW sale, all rights of first refusal set forth in this Section 2.2.4 shall immediately terminate and be void as of the date of the notice to Southern Companies from Corporation terminating all or any portion of the second 200 MW sale; however, Southern Companies shall inform Corporation of their intent to seek offers for additional sales of unit power capacity or Long Term Power. For purposes of this Section 2.2.4, pro rata share shall be computed as the ratio of Corporation's unit power purchases under this UPS Agreement to the total unit power purchases by all contemporaneous parties on June 1, 1995. Any contemporaneous party which exercises its rights to terminate under sections similar to Section 2.2 of this UPS Agreement shall be excluded from the calculation of pro rata share.

2.2.5 In the event the rate for transmission charges (as such rate may be revised from time to time pursuant to Article III of the Unit Power Sale Manual incorporated by reference in Section 5.1 of this UPS Agreement) is rejected or modified by FERC, Southern Companies shall have the right, upon thirty (30) days written notice, to make a unilateral filing with FERC under Section 205 of the Federal Power Act, and Corporation shall have the right to file a complaint under Section 206 of the Federal Power Act, to amend Exhibit A to reallocate the capacity sales specified in Section 2.2 among all of the units specified in Section 2.1 so as to restore the economic positions of the parties hereto to that held prior to FERC's action. If Corporation determines that it cannot, in good faith, support Southern Companies' filing for such reallocation, it may oppose the filing before FERC; but it shall limit any participation in any FERC proceeding concerning the reallocation of the unit power sales to questions of whether the reallocation correctly restores the economic position of the parties hereto.

2.3 Determination of Capacity Available from Each Unit: The amount of capacity to be made available from each unit specified in Section 2.1 to constitute the total capacity to be sold by APC, GaPC and GuPC and purchased by Corporation hereunder, will vary from time to time during the term of this UPS Agreement. The nominal schedule of units, by time period, from which sales will be made is set forth in Exhibit A, such Exhibit A representing an agreed allocation to Corporation of capacity under this UPS Agreement from each of the units specified in Section 2.1 by time period based on Expected Capacity. It is recognized by the parties hereto and expressly provided for in Section 2.3.4 that the actual units from which sales will be made, and the total capacity to be sold and purchased, may vary from that set forth in Exhibit A and any such variance shall be based on the following principles:

2.3.1 On or before September 15, 1992 and September 15 of each year thereafter during the term hereof, the Net Dependable Capacity will be established for each unit which has theretofore been declared available for commercial operation or which is expected to be declared available for commercial operation during the ensuing calendar year. Net Dependable Capacity for each unit shall be determined in accordance with the procedure specified in Article I of the Unit Power Sale Manual described in Section 5.1 hereof.

2.3.2 If the Net Dependable Capacity established for a unit from which capacity is to be sold to Corporation during the ensuing year is equal to the Expected Capacity of such unit as set forth in Exhibit A, the amount of capacity scheduled to be furnished from such unit during the ensuing year shall be as specified in Exhibit A.

2.3.3 If the Net Dependable Capacity established for the ensuing year for a unit from which capacity is to be sold to Corporation is more than or less than the Expected Capacity of such unit as specified in Exhibit A, the capacity to be sold and purchased during each period identified in Exhibit A for the ensuing year shall be Corporation's pro rata share of the Net Dependable Capacity determined by multiplying the amount of capacity sale shown for such unit in Exhibit A for each period by the ratio of the Net Dependable Capacity of the unit to the Expected Capacity of such unit as set forth in Exhibit A.

2.3.4 In the event Net Dependable Capacity for any unit is less than the Expected Capacity, Southern Companies shall include in their notice of determination of Net Dependable Capacity under Section 2.3.1 information as to capacity which is available, consistent with Prudent Utility Practices (as defined in Section 10.5 hereof), from any remaining Net Dependable Capacity in units specified in Exhibit A then owned by APC, GaPC, and GuPC or other coal-fired steam electric generating resources owned or operated by any of the Southern Companies, including the estimated additional capacity costs expected from any such other resources. Within fifteen (15) days of such notice, Corporation shall notify Southern Companies, in writing, whether it wishes to purchase a pro rata share (or any portion thereof) of such additional capacity. It is understood that Corporation's pro rata share shall be computed on the basis of all sales of unit power capacity from the unit under existing contemporaneous and future unit power sales from that unit. If any other purchaser of unit power capacity from the unit refuses to purchase such additional capacity, the refused amount of such capacity will be offered to Corporation on a pro rata basis with other purchasers of unit power capacity from the unit. To the extent capacity is made available pursuant to the above procedure from a unit other than those designated in Section 2.1, such unit shall be considered to be a unit specified in Exhibit A for the period capacity from such unit is made available.

2.3.5 To the extent, notwithstanding the above efforts, capacity in the total amount specified in Section 2.2 hereof cannot be made available to Corporation during any year (or portion thereof) because the Net Dependable Capacity determination for one or more units specified in Exhibit A is less than the Expected Capacity of such unit or units, the sole obligation of Southern Companies shall be to offer to sell additional capacity to Corporation in the amount determined in accordance with Sections 2.3.1 through 2.3.4.

2.4 <u>Delay in Commercial Operation of Units</u>: Notwithstanding the schedule of sales set forth in Section 2.2 above, the obligation of APC to make capacity from the units specified in Exhibit A available to Corporation may further be subject to delays in the projected dates for commercial operation of Units 3 and 4 of the Miller Plant. Construction of such units and any delays therein shall be governed by the following principles:

2.4.1 APC agrees to use best efforts consistent with Prudent Utility Practices to design and construct, or to have designed and constructed, Units 3 and 4 of the Miller Plant so that such units shall have been declared available for commercial operation as of the date set forth in Exhibit A. Southern Companies shall not be liable to Corporation for any loss or damage for delays or failures to have such units declared available for commercial operation as of such dates due to causes not reasonably within their control including, but not limited to, acts of civil or military authority (e.g., courts or administrative agencies), acts of God, war, riot or insurrection, inability to obtain any required permits or licenses, blockades, embargoes, sabotage, epidemics, fires, floods, strikes, lockouts or other labor disputes or difficulties, unusually severe weather conditions, breakdowns of machinery or equipment, inability to obtain necessary materials or equipment, and economic constraints such as inability to secure adequate capital on reasonable terms for continued construction. In the event of any delay resulting from such causes, the time for performance shall be extended for a period of time reasonably necessary to overcome the effect of such causes. APC shall keep Corporation informed of the construction schedules and any changes which alter the anticipated dates for commercial operation of the units, together with the reasons for such changes. The dates established in Exhibit A as the projected dates for commercial operation of Units 3 and 4 of the Miller Plant are based on the present plans of APC, and information available to it. It is recognized that the ability to predict such dates with exactness does not exist. In the event any of the dates for commercial operation are not met and the delay does not exceed one year from the projected date for commercial operation as set forth in Exhibit A, then it shall be conclusively presumed that the delay in the commercial operation of the unit resulted from events beyond the control of APC. In the event such delay extends beyond one (1) year, such presumption shall be revoked retroactive to the projected date for commercial operation set forth in Exhibit A.

2.4.2 Southern Companies agree, that in the event Unit 3 or 4 of the Miller Plant is not available for commercial operation by the date on which unit power sales are scheduled to commence under this UPS Agreement as a result of the type of delay or failure described in Section 2.4.1, Southern Companies shall use their best efforts, consistent with

Prudent Utility Practices, to make the amount of capacity from such unit which was scheduled to be made available to Corporation as specified in Exhibit A, available from other coal-fired steam electric generating resources owned or operated by any of the Southern Companies, including those resources specified in Section 2.1. To the extent such capacity is made available from a unit other than those designated in Section 2.1, such unit shall be considered to be a unit specified in Exhibit A for the period capacity from such unit is made available.

2.4.3 In the event Unit 3 or 4 of the Miller Plant is delayed due to reasons not excused under Section 2.4.1 but is available for commercial operation by the date on which unit power sales are scheduled to commence under this UPS Agreement, Southern Companies shall make adjustments in the capacity rates in accordance with the procedures specified in Article II of the Unit Power Sale Manual.

2.4.4 In the event Unit 3 or 4 of the Miller Plant is not available for commercial operation by the date on which unit power sales are scheduled to commence under this UPS Agreement, due to reasons not excused under Section 2.4.1, then in such event, as the sole obligation arising out of such delay, Southern Companies, shall (i) make available to Corporation unit power capacity from other coal-fired steam electric generating resources equal to the amount of capacity to have been furnished from the delayed unit as specified in Exhibit A with the understanding that capacity and energy rates of the units substituted for the delayed unit shall not in total exceed the combined capacity and energy rates for the delayed unit calculated on the basis of the delayed unit being completed on the date stated in Exhibit A (a seventy-five percent (75%) capacity factor and a seventy-five percent (75%) load point on the average heat rate curve will be utilized in calculating the cost from the Miller Plant unit and the substitute unit); and (ii) make adjustments in the capacity rates in accordance with the procedure specified in Article II of the Unit Power Sale Manual, when and if the delayed unit becomes available for commercial operation. To the extent such capacity is made available from units other than those designated in Section 2.1, such units shall be considered to be units specified in Exhibit A for the period capacity from such units is made available and the Expected Capacity of such units shall be defined as the nameplate rating less station service.

2.5 <u>Character of Sale</u>: The sale of unit power pursuant to this UPS Agreement shall not constitute a sale, lease, transfer or conveyance of an ownership interest in such units to Corporation, nor a dedication of ownership interest in such units to Corporation or any other party. Energy associated with capacity from units made available hereunder shall, however, be devoted to Corporation and the delivery of such energy to Corporation shall not be subject to preemption by Southern Companies for any other use. Except for capacity which is substituted during a year for capacity which was expected to be available, in accordance with Sections 2.4.2 or 2.4.3 or 2.4.4, the portion of such units to which Corporation and others have a contractual capacity entitlement, shall not be included in the determination of capacity pricing for the purposes of power sales made by Southern Companies to Corporation pursuant to any other power sales under contracts between Southern Companies and Corporation.

ARTICLE III

ENERGY AVAILABILITY

3.1 Energy: During each year specified in Section 2.2 (or portion thereof), Corporation will be entitled to schedule for delivery to the interconnection points identified in Section 4.1, energy in amounts up to a maximum of the capacity amount to which Corporation is entitled in the particular time period, as determined in accordance with Article II, subject to the principles and determinations set forth in Sections 3.2 through 3.10. All scheduling times specified herein are based on established practices and procedures between the parties hereto and are subject to change upon mutual agreement of the parties hereto. All times specified herein shall be prevailing Central Time unless otherwise agreed.

3.2 Scheduling Energy: By 11:00 a.m. on the day prior to commencement of energy deliveries under this UPS Agreement, and each day thereafter, Southern Companies will provide Corporation with an estimated hourly schedule of available energy for the following day. For Saturday, Sunday and Monday of each week such estimates, however, will be provided on the preceding Friday. Each estimate provided to Corporation will include, on a unit by unit basis, projected availability, together with the estimated applicable Base Energy Rates, Alternate Energy Rates, Supplemental Energy Rates, and Discretionary Energy Rates. By 1:30 p.m., on each day that Corporation receives an estimate of available energy, Corporation will provide Southern Companies with an estimated hourly schedule of capacity usage, and Southern Companies will provide Corporation, by 3:00 p.m., an estimate of energy rates associated with Corporation's estimated capacity usage. Corporation may not alter its hourly schedule of capacity usage, for each unit, on less than four (4) hours prior notice, unless otherwise mutually agreed upon by the Operating Representatives (as defined in Section 8.1) of Corporation and Southern Companies. The Operating Representatives will make a bona fide attempt to accommodate flexible energy scheduling (shorter than four (4) hours) and neither party hereto will unreasonably restrict or demand energy scheduling without sound operating reasons. In addition, Corporation will schedule total hourly capacity usage in amounts which are whole megawatts.

3.3 <u>Unavailability or Rating Change of Units</u>: Except as provided in Section 3.8, Corporation shall not be entitled to energy associated with any unit which has been made available under Article II, or portion of any such unit, at any time when and to the extent such unit, or portion thereof, is unavailable for service because of scheduled maintenance, forced outage or any other non-discretionary cause, or is partially derated from the Net Dependable Capacity of such unit determined in accordance with Section 2.3.1. In the event such a unit is derated but still capable of meeting the energy schedule of all utilities purchasing unit power from such unit, the energy will be scheduled from the unit provided that the derating is less than seven (7) days duration and ten (10) percent or less of the Net Dependable Capacity of the unit. If a derating is greater than ten (10) percent or a derating extends beyond seven (7) days or the unit is incapable of meeting the energy schedule, Corporation shall have the right to schedule energy associated with such unit, or to receive energy previously scheduled, up to a maximum of the capacity amount determined by the following formula for whatever period the derating may continue:

$$MUPC = \frac{UPC}{NDC} \times AOC$$

Where:

MUPC = Maximum Unit Power Capacity entitlement of Corporation from such unit after a rating change.

UPC = Unit Power Capacity entitlement of Corporation from such unit determined in accordance with Article II.

NDC = Net Dependable Capacity of such unit as determined in Section 2.3.1.

AOC = Actual Operating Capability after a rating change as determined by the company responsible for operating such unit.

In the event the Actual Operating Capability of a unit is greater than the Net Dependable Capacity, Corporation will be entitled to schedule the energy associated with the increased Actual Operating Capability in accordance with the above formula provided that the increased output is greater than ten percent (10%) or the output increase extends beyond seven (7) days. Corporation will not be entitled to the additional energy associated with the increase in Actual Operating Capability above the Net Dependable Capacity if the output increase is less than seven (7) days duration and ten percent (10%) or less of the Net Dependable Capacity.

3.4 Allocation of Energy Schedules to Generation Units: Schedules for hourly capacity usage provided by Corporation subject to Sections 3.1 and 3.2 above will be deemed to be requests for energy to be delivered from the generating units from which Corporation has a capacity entitlement, as determined under Article II and as modified by Section 3.3 for units unavailable or derated. Corporation may, upon four (4) hours notice, in accordance with Section 3.2, schedule energy from each generating unit for each hour in any amount, subject to Section 3.6, up to Corporation's maximum capacity entitlement from that generating unit. The energy so scheduled by Corporation and delivered by Southern Companies from the scheduled unit, is hereinafter called "Unit Energy." Unit Energy shall be supplied to all parties purchasing unit power from a generating unit on a pro rata basis based on the energy scheduled from that unit. Unit Energy supplied to Corporation shall be the lesser of (i) an amount equal to the total net generation of that unit multiplied by the ratio of the energy scheduled by Corporation to the total energy scheduled by all parties purchasing unit power from that unit, or (ii) the energy scheduled by Corporation. If the Unit Energy so supplied to Corporation is less than the energy scheduled from that unit in accordance with this Section 3.4, the balance of the energy scheduled shall be supplied as Alternate Energy pursuant to Section 3.7.

3.5 Minimum Energy Scheduling: Subject to the provisions of Sections 3.3 and 3.4, Corporation agrees to schedule energy made available from the units designated in Article II in excess of a fifty percent (50%) "Output Factor" on an annual basis for each calendar year through the year 2000. Output Factor is defined as the amount of Unit Energy (including Alternate Energy supplied in lieu of Unit Energy) and Replacement Energy scheduled by Corporation divided by the amount of energy made available by Southern Companies from the generating units designated in Article II, including Alternate Energy made available to Corporation. Corporation may reduce the fifty percent (50%) Output Factor for the calendar year 2001 and subsequent years if it gives written notice to Southern Companies at least one year in advance stating the amount of the requested reduction. If Corporation so elects to reduce the Output Factor, Southern Companies obligation to use reasonable efforts to make energy available on the basis of a ninety percent (90%) target capacity factor on an annual basis (as referenced in Sections 3.8, 3.8.4, 3.9, 4.2) will be reduced by one percent (1%) for each percentage point of reduction requested by Corporation (e.g., forty-five percent (45%) Output Factor will result in a eighty-five percent (85%) target capacity factor). Once Southern Companies have met the target capacity factor for a calendar year, they shall be under no obligation to supply Supplemental Energy, Discretionary Energy or any Replacement Energy supplied in lieu of Supplemental Energy during the remainder of that calendar year.

3.6 Minimum Operation Capacity Obligation: During all periods when a unit made available to Corporation under Article II is operating at "Minimum Operating Conditions," Corporation shall accept delivery of the energy associated with the Minimum Operation Capacity Obligation ("MOCO") of Corporation for such unit. For the purpose of this UPS Agreement, Minimum Operating Conditions shall mean the periods of (a) ramping to a unit's minimum load point required for stable operation of the unit as determined from time to time by the entity responsible for operation of the unit; (b) operation at the minimum load point required for stable operation; or (c) operation at a point above the minimum load point.

Corporation shall be required to take energy from a unit when such unit is at the Minimum Operating Conditions pursuant to this Section 3.6(a) and (b) for any of the following reasons:

(i) Unit operation based on economic unit commitment practices;

(ii) Unit operation to manage fuel stockpiles;

(iii) Unit operation for freeze protection;

(iv) Unit operation for precipitator warm-up; and

(v) Unit operation for non-discretionary tests (e.g., environmental and performance tests).

Corporation shall be required to take energy from a unit when such unit is at the Minimum Operating Conditions described in this Section 3.6(c) for any of the reasons set forth in (iii), (iv) and (v) above. Southern Companies agree that they will make best efforts to provide at least twenty-four (24) hour notification to Corporation of any planned non-discretionary unit tests or changes in unit operations to manage fuel stockpiles. When applicable, Corporation's Minimum Operation Capacity Obligation for each unit shall be determined by the following formula:

$$MOCO = \frac{UPC}{NDC} \times MC$$

Where:

MOCO = Minimum Operation Capacity Obligation of Corporation from such unit.

UPC = Unit Power Capacity entitlement of Corporation from such unit determined in accordance with Article II.

NDC = Net Dependable Capacity of such unit as determined in Section 2.3.1.

MC = Loading required for Minimum Operating Conditions as defined in this Section 3.6.

Southern Companies further agree that they will promptly notify Corporation if at any time the Minimum Operating Conditions of a given unit have changed and the reasons for such change.

3.7 Option to Furnish Scheduled Energy from Alternate Resources: Energy requested by Corporation, and deemed to be scheduled from specific units, as determined in Section 3.4, may be provided by Southern Companies from other resources owned or operated by Southern Companies. Such energy, delivered from resources other than those from which such energy was scheduled pursuant to Section 3.4, during periods in which such specific units are available for operation, is called "Alternate Energy." Any Alternate Energy delivered by Southern Companies in lieu of energy from a specific unit shall be delivered to all parties purchasing unit power from such unit on a pro rata basis to each party based on energy scheduled from that unit.

Alternate Energy may be supplied by Southern Companies from an assigned unit or from the units in economic dispatch on the system of Southern Companies at the time, at the sole option of Southern Companies. However, it is agreed that Alternate Energy will normally be supplied from units in economic dispatch except when system operating conditions indicate otherwise. Southern Companies will notify Corporation of the amount of Alternate Energy to be made available, the selected energy sources, and the estimated energy rates at the times set forth in Section 3.2.

3.8 <u>Supplemental Energy Scheduling</u>: APC, GaPC and GuPC agree to use reasonable efforts to make energy available to Corporation from each unit to which Corporation has a capacity entitlement pursuant to Article II on the basis of a ninety percent (90%) target capacity factor on an annual basis or such target capacity factor which may be in effect for the calendar year 2001 and subsequent calendar years as a result of the provisions of Section 3.5. It is recognized that such efforts to achieve such target may be frustrated by forced outage of the units, needs for repair or maintenance of the units, governmental restrictions or other non-discretionary reasons. The sole obligation of APC, GaPC, GuPC and Southern Companies for the failure to achieve such target capacity factor for each unit shall, where due to the aforesaid reasons, be as follows:

3.8.1 During periods in which a unit to which Corporation has a capacity entitlement under Article II is unavailable for service, Southern Companies shall use their best efforts, consistent with Prudent Utility Practices, to make available supplemental energy from other coal-fired or comparably-priced generating resources available to Southern Companies equal to one hundred percent (100%) of Corporation's entitlement in such unit under Article II.

3.8.2 During periods in which a unit to which Corporation has a capacity entitlement under Article II is partially derated, Southern Companies shall use their best efforts, consistent with Prudent Utility Practices, to make available supplemental energy from other coal-fired or comparably priced generating resources available to Southern Companies equal to one hundred percent (100%) of Corporation's entitlement in such unit under Article II less Corporation's entitlement to schedule energy from such derated unit pursuant to Section 3.3. Energy made available to Corporation pursuant to this Section 3.8.2 and Section 3.8.1 is called "Supplemental Energy."

3.8.3 In the event the Supplemental Energy provided for in Sections 3.8.1 and 3.8.2 cannot be provided from coal-fired or comparably-priced generating resources, Southern Companies agree to use their best efforts, consistent with Prudent Utility Practices, to make energy available from higher-priced generating resources of Southern Companies in amounts equal to the Supplemental Energy provided for in such sections. Such energy made available by Southern Companies and scheduled for delivery, at Corporation's election, shall be deemed Supplemental Energy.

3.8.4 Southern Companies will not be obligated to provide Corporation any additional Supplemental Energy for the remainder of any year from and after the date on which Southern Companies have made available to Corporation for scheduling under this UPS Agreement (except for energy made available under Sections 3.8.3 and 3.9 but not taken by Corporation and for energy made available but not deliverable because of Southern Companies' inability to deliver due to transmission contingencies of less than two (2) weeks duration pursuant to Section 4.2) energy in the aggregate equal to the target capacity factor percentage of Corporation's total capacity entitlement for such year, as determined in accordance with Article II, multiplied by the number of hours in such year. To the extent any energy requested by Corporation during the remainder of any such year is not available from units to which Corporation has a capacity entitlement, such energy and associated capacity shall be furnished, if at all, under other rate schedules between the parties hereto.

3.8.5 Supplemental Energy shall mean energy available on the systems of Southern Companies, not needed at that time on their own systems to meet their own system's requirements (including power used for pumping at pumped storage hydroelectric projects) and other power sale commitments taking precedence before delivery under this UPS Agreement. The only power sale commitments taking precedence over the availability of Supplemental Energy are: (i) any seasonal energy or capacity exchange agreements now existing or entered into in the future; (ii) any firm power interchange sales to other utilities or third parties now existing or entered into in the future; (iii) any other unit power sales with other utilities or third parties now existing (including, but not limited to, provisions for Unit Energy, Alternate Energy and Supplemental Energy); (iv) any future unit power sales with other utilities (including provisions for Unit Energy and Alternate Energy); and (v) any short-term power being supplied under the provisions of a now existing contract with Alabama Electric Cooperative, Inc. After Supplemental Energy has been made available in accordance with the existing unit power contracts with FPL and JEA, it is understood that Supplemental Energy made available for delivery by Southern Companies pursuant to this UPS Agreement will be made available to Corporation and other contemporaneous parties (as defined in Section 10.10 hereof) on a pro rata basis based upon each contemporaneous party's capacity entitlement under their respective contemporaneous unit power sales contracts in the unit unavailable for service.

Supplemental Energy, if available, will be supplied from the units in economic dispatch on the systems of Southern Companies at the time. Southern Companies will notify Corporation of the amount of Supplemental Energy to be made available and the estimated energy rates at the times set forth in Section 3.2.

3.9 Discretionary Energy Scheduling: In addition to the energy made available pursuant to Sections 3.8.1, 3.8.2 and 3.8.3, if requested by Corporation, Southern Companies will make available, after meeting all other obligations of Southern Companies and any energy sales of opportunity, energy from other coal-fired generating resources owned or operated by the Southern Companies, up to ten percent (10%) in excess of Corporation's total capacity entitlements. Energy made available to Corporation pursuant to this section is called "Discretionary Energy." If at Corporation's election such Discretionary Energy is scheduled for delivery, it will be considered as energy delivered in an effort to achieve the target capacity factor provided for in Section 3.8.

3.9.1 Discretionary Energy shall mean energy available on the systems of Southern Companies, not needed at that time to meet their own system's requirements and needs, any power sale commitments now existing or entered into in the future, and any other energy sales of opportunity under agreements with Corporation and other utilities (or third parties) now existing or entered into in the future. Discretionary Energy under this UPS Agreement shall have precedence over Discretionary Energy provisions in future unit power sales agreements.

3.9.2 After Discretionary Energy has been made available in accordance with existing unit power sales contracts with FPL and JEA, Discretionary Energy made available for delivery by Southern Companies will be made available to Corporation and other contemporaneous parties on a pro rata basis based upon each such party's capacity entitlements under its respective contemporaneous unit power sales contract for the term of this UPS Agreement. Discretionary Energy, if available, will be supplied from the units in economic dispatch on the systems of Southern Companies at the time. Southern Companies will notify Corporation of the amount of Discretionary Energy to be made available and the estimated energy rates at the times set forth in Section 3.2.

3.10 Replacement Energy Scheduling: In addition to Supplemental Energy, Alternate Energy and Unit Energy, Southern Companies shall also make available replacement energy, hereinafter called "Replacement Energy." Replacement Energy will be made available by Southern Companies to Corporation from the lowest energy cost generating resources that can be made available after priorities under Section 3.10.1 are satisfied, to permit Corporation to substitute such energy for Alternate Energy, Supplemental Energy and Unit Energy (but not including energy associated with Minimum Operation Capacity Obligation as defined in Section 3.6). Southern Companies will furnish information with respect to generating capacity available on their electric systems which might be made available to supply Replacement Energy at the times as set forth in Section 3.2. This information will include (i) the incremental cost, as set forth in Section 6.9 of the Replacement Energy that can be made available; and (ii) the quantity and period of time such energy is expected to be available. Southern Companies, in the sole discretion of SCS, shall determine if capacity is available on their systems for Replacement Energy.

3.10.1 Replacement Energy shall be supplied to contemporaneous parties from generating units in economic dispatch on the systems of Southern Companies after serving Southern Companies' own system requirements and the following transactions which shall have priority: (i) any seasonal or capacity exchange agreements now existing or entered into in the future; (ii) any firm power interchange sales to other utilities or third parties now existing or entered into in the future; (iii) any unit power sales agreements for the sale of capacity and energy from a specific unit or units (including any Unit Energy or Alternate Energy furnished under provisions similar to that specified in this UPS Agreement) now existing or entered into in the future; (iv) any Long Term Power sales with other utilities or third parties which were executed prior to the date of this UPS Agreement; (v) any sales of Supplemental Energy under the provisions of unit power sales agreements (now existing or entered into in the future) similar to the provisions of this UPS Agreement; (vi) any Replacement Energy sales under existing unit power sales contracts with FPL and JEA; and (vii) any short term capacity sales under the existing interchange agreement between APC and Alabama Electric Cooperative, Inc.

3.10.2 Each Replacement Energy transaction shall be agreed upon by the parties hereto prior to commencement of delivery of such energy. It is anticipated that, after Southern Companies have supplied the information pursuant to Section 3.10, the parties will establish a preliminary schedule for energy deliveries hereunder for the next day. Approximately thirty (30) minutes before the transaction is scheduled to commence, Southern Companies shall quote the price in dollars per megawatt hour ($/MWH) for Replacement Energy for the next hour and will provide similar quotes for each subsequent hour during the period of the transaction. As soon as practicable after the time of each price quote for the next hour, Corporation shall determine whether or not to take Replacement Energy during that next hour. If after the time of the price quote for the next hour and prior to the time of the price quote for the subsequent hour Southern Companies determine, in their sole judgment, that all or a portion of the then scheduled Replacement Energy can no longer be delivered, Southern Companies shall give as much notice as possible of the need for Corporation to change its schedule of Replacement Energy to energy that may be available under other provisions of this UPS Agreement at the next scheduling time for the subsequent hour. The delivery of Replacement Energy during the next hour may be continued at the option of Corporation subject to the pricing provisions of Section 6.9.

3.10.3 Replacement Energy is not intended and shall not be interpreted to change or modify the obligations, rights and duties of the parties under other provisions of Article III of this UPS Agreement except that Replacement Energy scheduled hereunder will be deemed to satisfy the provisions of Section 3.5.

ARTICLE IV

ESTABLISHMENT OF DELIVERY POINTS AND PROVISION FOR TRANSMISSION CONTINGENCIES

4.1 Points of Delivery: Southern Companies shall deliver the power and energy purchased by Corporation hereunder to the Points of Delivery specified in Article III of the Interchange Contract.

4.2 Transmission Contingencies: In the event energy scheduled to be delivered hereunder cannot be delivered or received because of contingencies of any nature affecting transmission facilities of either party hereto, there shall be no reduction in capacity charges hereunder; provided, however, where such inability to deliver energy hereunder continues for more than two (2) weeks because of a failure of Southern Companies to remedy problems within their systems, then Southern Companies shall waive capacity charges for periods during which such deliveries continue to be affected in excess of two (2) weeks.

During the period of a transmission contingency of less than two (2) weeks in duration within Southern Companies' systems, energy which could not be delivered to Corporation shall not constitute energy made available toward the target capacity factor provided for in Section 3.8. Energy which cannot be delivered due to such transmission contingencies will not be considered as energy made available to Corporation for determination of the Output Factor provided for in Section 3.5. During the period of a transmission contingency of more than two (2) weeks in duration, the parties hereto acknowledge and agree that certain adjustments in operating and accounting procedures will be necessary and that such adjustments will be made in an equitable manner consistent with principles set forth in this UPS Agreement. Such adjustments will be referred to the Operating Representatives for resolution.

To the extent the occurrence of a contingency is controllable, Southern Companies shall use their best efforts consistent with Prudent Utility Practices to prevent the occurrence of contingencies which would result in restricted scheduled deliveries of power and energy hereunder and if not prevented shall promptly exert best efforts consistent with Prudent Utility Practices to restore the affected facilities to provide for deliveries as scheduled.

4.3 Limitation of Transmission Facilities: Southern Companies and Corporation recognize and acknowledge that transmission facilities pursuant to this UPS Agreement and other interconnections now existing or which may be constructed in the future between Southern Companies and other electric utilities in Florida are governed by principles and guidelines set forth in the Reliability Coordination Agreement effective July 1, 1980 between Southern Companies and Florida Electric Power Coordinating Group ("RCA"). Southern Companies and Corporation agree that in order for the full benefit of this UPS Agreement to accrue to the parties hereto while preserving the reliability of their systems, such principles and guidelines must be observed throughout the duration of existing power purchase and sale agreements, this UPS Agreement, and any and all power purchases and sales contemplated in the future.

Southern Companies and Corporation hereby agree to observe "Transfer Limit" between Southern Companies and Florida (excluding GuPC). Transfer Limit has been defined by the Executive Council of the RCA as the first contingency transfer capability utilizing the criteria established by the Executive Council. In the event the RCA or its successor agreement expires or fails to define Transfer Limit, Transfer Limit will be defined for this UPS Agreement by the criteria set forth below:

4.3.1 Transfer Limit: The Southern-Florida (excluding GuPC) Transfer Limit is defined as the total amount of power that can be transferred from Southern Companies to Florida (excluding GuPC) for periods up to several days with an assurance of adequate system reliability, based on the most limiting of the following:

(a) With all transmission facilities in service, all facility loadings are within normal ratings and all voltages are within normal limits.

(b) The bulk power electrical system is capable of absorbing the dynamic power swings without separation between Southern Companies and Florida (excluding GuPC) and of remaining stable following the loss of any single transmission circuit, breaker, or transformer in Southern Companies systems including the Southern-Florida interconnection circuits, or following the loss of the largest generating unit in Florida or in Southern Companies' systems.

(c) After the dynamic power swings following a disturbance contemplated under (b), but before operator-directed system adjustments are made, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

4.3.2 The parties hereto agree that, with the exception of the period January 1, 1993 through May 31, 1993, the total capacity and energy to be delivered to Florida (except GuPC) under existing unit power sales contracts with FPL and JEA, this UPS Agreement (including capacity and energy which may be taken under early option provisions), contemporaneous unit power sales contracts with other contemporaneous parties (including capacity and energy which may be taken under early option provisions), and an existing contract providing for Long Term Power sales to the City of Tallahassee can be accommodated under the now-existing Transfer Limit and should such Transfer Limit be reduced, so as to limit Southern Companies' ability to deliver energy as a result of actions by Corporation or conditions on the electric system of Corporation, there will not be a reduction in capacity charges under this UPS Agreement except in instances caused by actions of Southern Companies or conditions on the electric systems of Southern Companies and such reduction in Transfer Limit continues for more than two (2) weeks. With respect, however, to the period January 1, 1993 through May 31, 1993, Corporation and Southern Companies recognize that the Transfer Limit may be exceeded as a result of the exercise by Corporation and other contemporaneous parties of early option provisions similar to the early option incorporated in Section 2.2.1 of this UPS Agreement. In such event, the capacity to be sold under the early options will be prorated among Corporation and other contemporaneous parties (based upon the total unit power capacity sales to Corporation and other contemporaneous parties on June 1, 1995) so as not to exceed the Transfer Limit; provided, however, that with respect to such early option capacity, Corporation shall only pay for that amount of capacity it is entitled to receive under the early option after any proration.

4.3.3 If either party hereto desires to schedule transfers between Southern Companies and Florida (excluding GuPC) in excess of the level of transactions under existing unit power sales contracts with FPL and JEA, this UPS Agreement (including capacity and energy which may be taken under early option provisions), contemporaneous unit power sales contracts with other contemporaneous parties (including capacity and energy which may be taken under early option provisions), and an existing contract providing for Long Term Power sales to the City of Tallahassee so as to exceed the then existing Transfer Limit, then such party, in conjunction with any other third parties in interest, shall install facilities on their system or take any actions which are necessary to permit the desired transfer in conformance with this Section 4.3.

4.3.4 Schedules of power by Southern Companies to Florida (except GuPC) in excess of the level of transactions under existing unit power sales contracts with FPL and JEA, this UPS Agreement (including capacity and energy which may be taken under early option provisions), contemporaneous unit power sales contracts with other contemporaneous parties (including capacity and energy which may be taken under early option provisions), and an existing contract providing for Long Term Power sales to the City of Tallahassee may create an undue burden on the transmission system of Corporation, even though such schedules are within the Transfer Limit established under this Section 4.3. To the extent Southern Companies propose to make any additional sales of power or delivery of energy for others in excess of such amounts to utilities in Florida for periods of one year or more, Southern Companies shall notify Corporation of such proposal and Corporation agrees to notify Southern Companies, within sixty (60) days after receipt of notice of such proposal whether, in its judgment, based on a good faith evaluation by Corporation, a reasonable probability exists that such sale will result in the imposition of an undue burden on the transmission system of Corporation. In the event Corporation fails to identify any such burden within such time, the agreement for such sale by Southern Companies shall not be prohibited by this UPS Agreement. To the extent Corporation identifies any potential burden on its transmission system resulting from such sale, Corporation agrees to meet with Southern Companies and the party or parties to whom such sale is to be made to discuss in good faith what facilities or operating procedures are necessary to avoid such burden. In the event no agreement can be reached as to methods of avoiding such burdens, Southern Companies shall not enter into such sales.

In the event Southern Companies schedule transfers to Florida (except GuPC) in excess of the level of transactions identified above under schedules involving sales of power, or delivery of energy for others of less than one year duration, then, to the extent such scheduled transfers together with other sales do not exceed the Transfer Limit established under Section 4.3 above, such schedule of power shall not be prohibited by this UPS Agreement unless Corporation notifies Southern Companies that, in its reasonable judgment made in good faith, a burden on its transmission system has been created by such schedule. Southern Companies shall upon receipt of such notice reduce its schedule of such transfers to an acceptable level.

ARTICLE V

PROCEDURE FOR CAPACITY AND ENERGY RATES

5.1 Unit Power Sale Periodic Rate Computation Procedure: Corporation and Southern Companies recognize that the cost of providing the unit power and electric services contemplated herein may change during the term of this UPS Agreement. Thus, in order for Southern Companies to be compensated fairly and adequately, it will be necessary to revise or update, on a periodic basis, the cost, expense, and investment figures utilized in the derivation of the capacity charges and certain components of the energy charges provided for in this UPS Agreement.

In order to facilitate revisions or updates of the charges calculated under the basic procedure and methodology outlined in this UPS Agreement, Southern Companies have adopted a Unit Power Sale Periodic Rate Computation Procedure Manual ("Unit Power Sale Manual") which is attached hereto as Exhibit C to this UPS Agreement and incorporated herein by reference. The Unit Power Sale Manual describes in detail the methodology and procedure to be utilized in the periodic calculation of charges provided for in this UPS Agreement.

The Unit Power Sale Manual, together with this UPS Agreement shall serve as a formulary rate allowing periodic revisions of the charges to reflect changes in costs of providing the services contemplated by this UPS Agreement. The capacity charges and certain components of the energy charges calculated in accordance with the Unit Power Sale Manual will be shown on the Unit Power Sale Informational Schedule further described in Section 5.2 herein.

5.2 <u>Unit Power Sale Informational Schedule</u>: The Unit Power Sale Informational Schedule for Southern Companies showing estimated charges for the unit power sales contemplated by this UPS Agreement is attached hereto as Exhibit D for example purposes only and will be replaced with an updated Unit Power Sale Informational Schedule showing the initial charges for the unit power sales on or before November 1 of the year preceding the first calendar year in which the unit power sales occur. The Unit Power Sale Informational Schedule will be revised for each calendar year during the continuation of unit power sales hereunder. Revisions of charges contained in the Unit Power Sale Informational Schedule shall follow the methodology and procedure set forth in this UPS Agreement and the Unit Power Sale Manual. A revised Unit Power Sale Informational Schedule shall be submitted by Southern Companies to Corporation on or before November 1 of each year for application on January 1 of the following year. This time period will allow Corporation and Southern Companies to verify that the charges contained in the revised Unit Power Sale Informational Schedule have been computed in accordance with this UPS Agreement and the methodology and procedure set forth in the Unit Power Sale Manual. Since the charges contained in the revised Unit Power Sale Informational Schedule will be computed in accordance with formulary rate method and procedures described in this UPS Agreement and the Unit Power Sale Manual, it is the intent of Southern Companies and Corporation that such revisions will not be changes in rates which would require a filing and suspension under the Federal Power Act and the applicable rules and regulations of FERC. A revised Unit Power Sale Informational Schedule will be filed with FERC, or its successor in interest, for informational purposes to show the application of the formulary rate method and procedure and the resulting charges provided for in this UPS Agreement and the Unit Power Sale Manual.

5.3 <u>Unilateral Revision of Capacity and Energy Rates and/or Unit Power Sale Periodic Rate Computation Procedure Manual</u>: In addition to the right to change the charges as described in Sections 5.1 and 5.2 above, Southern Companies shall have the right to amend the formulary capacity and energy rates established in this UPS Agreement, Unit Power Sale Manual, and Unit Power Sale Informational Schedule. This right shall be limited to the following changes in the formulary capacity and energy rates: (i) changes in provision for percentage return on equity capital; and (ii) changes in provisions establishing capacity losses and energy losses. Southern Companies shall have the right to unilaterally make application to FERC for a change in rates under Section 205 of the Federal Power Act and pursuant to FERC's rules and regulations promulgated thereunder with respect to the specific matters identified above. In all such events, Corporation shall be free to support or contest such amendment or raise any objection it may have to such amendment before FERC. As to the two above-identified subjects over which Southern Companies retain the right to unilateral filing under Section 205, Corporation shall have the right to seek changes under Section 206 under a just and reasonable and non-discriminatory standard, as opposed to a public interest standard. Southern Companies shall further have the right to file unilateral changes in the capacity and energy rates to the extent, at any time, any additional legitimate cost not now in existence, is incurred with respect to charges for capacity and energy (including government impositions), which such cost is not recouped under the capacity and energy rates set forth herein. Corporation will support any such change and cooperate and assist Southern Companies in securing approval by FERC of such additional charges to the extent the additional charge can reasonably be defended by Corporation. Corporation has the right to oppose any such cost (or part thereof) which it, in good faith, does not consider to be an additional or legitimate cost not now in existence.

5.4 Unilateral Changes Resulting from Regulatory Action: In addition to the rights set forth in Section 2.2.5, Southern Companies shall further have the right to file one or more unilateral changes in the capacity and energy rates under this UPS Agreement if the rates provided for in this UPS Agreement are disapproved or modified by FERC, or its successor. Corporation agrees to support any such change and cooperate and assist Southern Companies in securing approval by FERC of such change to the extent the change by Southern Companies would not result in the imposition of higher estimated charges to Corporation than those which would have been produced under this UPS Agreement prior to the action taken by FERC; provided, however, that Corporation's support is contingent upon its determination that it can reasonably defend such change otherwise. If Corporation determines that it cannot, in good faith, support such change nothing herein will prevent it from opposing the change before FERC.

5.5 Establishment of Initial Return on Common Equity and Provisions for Change in Return on Common Equity: The initial return on common equity to be included in the formula rates to establish production and transmission capacity costs for unit power purchased and sold from the Miller Plant and Unit 3 of the Scherer Plant shall be 13.75%. Six (6) months prior to the time initial sales are scheduled under this UPS Agreement, representatives of Southern Companies and Corporation shall meet to discuss whether such return on equity remains appropriate for use. If the parties hereto agree upon a new return on common equity to be incorporated in this UPS Agreement, Southern Companies will make an appropriate filing with FERC three (3) months in advance of the date when sales are to commence. In the event the parties hereto are unable to agree upon an appropriate return on common equity, Southern Companies will file the 13.75% return on common equity or a new return on common equity to be incorporated into this UPS Agreement and Unit Power Sale Manual together with a request that FERC establish an appropriate return on common equity to be observed by the parties hereto under the just and reasonable and non-discriminatory standard. Any excess charges attributable to the return on common equity filed by Southern Companies (in the event of failure to agree upon such return prior to initial sales and a determination of a lower return by FERC) shall be subject to refund with interest (such interest being determined under the method prescribed by FERC) from the commencement of such sales. The return on common equity established by FERC in the event of failure to agree upon such return prior to initial sales shall be subject to subsequent change by unilateral filing of Southern Companies under Section 205 of the Federal Power Act and regulations thereunder or by order of FERC under Section 206 of the Federal Power Act upon complaint by Corporation. As to any such subsequent changes, in the event that FERC sets the return on common equity for hearing under Section 206, (i) the FERC's determination of the return on equity shall be rendered under the just and reasonable and non-discriminatory standard rather than under the public interest standard; and (ii) only in the event of a proceeding initiated by complaint of Corporation, charges attributable to the return on equity shall be subject to refund from the filing date of any pleading requesting such proceeding.

ARTICLE VI

CHARGES FOR SERVICE

6.1 Rates: Corporation shall pay each month for the capacity and energy furnished hereunder and transmission losses associated therewith on the following bases:

6.2 Capacity Rates: With respect to each unit from which capacity is made available to Corporation pursuant to Article II, the capacity charge shall be the sum of the dollar per kilowatt-month charge produced by the applicable formulary rate set forth in Article II of the Unit Power Sale Manual for each unit plus the dollar-per kilowatt-month charge produced by the formulary rate set forth in Article III thereof for associated transmission capacity. The dollar per kilowatt-month charge for each unit produced by the formulary rate shall be multiplied by the number of kilowatts of capacity from such unit made available to Corporation pursuant to Article II hereof each month and the sum of the charges for all units during each month shall be paid by Corporation in accordance with Section 7.1. In the event the Net Dependable Capacity of any unit from which capacity sales are to be made to Corporation is determined to be zero for any year, Corporation shall be responsible for the dollar per kilowatt-month charge for such unit produced by the formulary rate assuming such Net Dependable Capacity equaled the Expected Capacity and multiplying such charge by the capacity to which Corporation would have been entitled in such circumstance. Corporation shall not be responsible for capacity charges for any such unit to the extent the Net Dependable Capacity for such unit is zero for any year due to causes within the reasonable control of the operating company of Southern Companies responsible for operating the unit, as governed by Prudent Utility Practices. Southern Companies shall true-up the capacity charge, on a periodic basis (not less frequently than annually), to reflect actual costs. Such true-up will be performed in accordance with Article IX of the Unit Power Sale Manual.

6.3 Base Energy Rates: For Unit Energy supplied to Corporation during each month from the units specified in Exhibit A pursuant to Section 3.4, Corporation shall pay an amount per megawatt hour ("MWH") called Base Energy Rate delivered from each unit equal to the sum of the following items (expressed in $/MWH):

(a) Fuel Cost for each unit, which is defined in Article IV of the Unit Power Sale Manual, together with the procedure for determining this component of the energy charge.

(b) The variable operation and maintenance expenses for the unit. The procedure for determining this component of the energy charge is described in Article V of the Unit Power Sale Manual.

(c) Compensation for transmission losses, based on the average transmission loss percentage ($\%L_e$). The procedure for determining "$\%L_e$" is set forth in Article VII of the Unit Power Sale Manual. Using (a) and (b) above,

$$(c) = [(a) + (b)] \left[\frac{(\%L_e \div 100)}{1-(\%L_e \div 100)} \right]$$

6.4 Alternate Energy Rates: For energy supplied to Corporation at any time from alternate sources owned or operated by Southern Companies, in accordance with Section 3.7, Corporation shall pay an amount per MWH delivered which is the least of (i) the Base Energy Rate as determined in Section 6.3 for the unit for which Alternate Energy is provided; (ii) the Normalized Energy Rate as determined in Section 6.6 for the unit for which Alternate Energy is provided; or (iii) one-half (0.5) the sum of the Base Energy Rate for such unit and the cost of such Alternate Energy determined by the following principles:

For Alternate Energy whether supplied from an assigned unit of Southern Companies, or from the units in economic dispatch on the systems of Southern Companies, the cost of such energy ($/MWH) shall be the incremental expense of the assigned unit or the units in economic dispatch which is incurred in supplying the energy. With respect to energy supplied from units in economic dispatch, such energy shall be considered as having been delivered at the incremental cost of Southern Companies after serving their own systems' requirements (including energy used for pumping at pumped storage hydroelectric projects) and other power sale commitments taking precedence before delivery of such energy. The only power sale commitments taking precedence before delivery of such Alternate Energy are: (i) any seasonal energy or capacity exchange agreements now existing or entered into in the future; and (ii) any firm power interchange sales to other utilities or third parties now existing or entered into in the future. The expense from assigned units or units in economic dispatch shall include only the incremental cost of fuel, variable operation and maintenance expenses, change in system transmission losses, and other such energy related costs which would otherwise not have been incurred.

6.5 <u>Supplemental Energy Rates</u>: For energy supplied to Corporation at any time pursuant to Section 3.8, Corporation shall pay an amount per MWH delivered which is the greater of (i) the Base Energy Rate for the unit for which Supplemental Energy is provided, as determined in Section 6.3; provided, however, such Base Energy Rate shall be limited to a value no greater than the Normalized Energy Rate as determined in Section 6.6 for such unit; or (ii) the incremental cost of the units in economic dispatch incurred by Southern Companies after serving their own systems' requirements (including energy used for pumping at pumped storage hydroelectric projects) and other power sale commitments taking precedence before delivery of such Supplemental Energy as defined in Section 3.8.5. The expense of units in economic dispatch shall include only the incremental cost of fuel, variable operation and maintenance expenses, change in system transmission losses, and other such energy related costs which would otherwise not have been incurred.

6.6 <u>Normalized Energy Rates</u>: The Normalized Energy Rate each month for each unit specified in Exhibit A shall be equal to the sum of the following items (expressed in $/MWH):

(a) Normalized Fuel Cost for the unit, which is defined in Article IV of the Unit Power Sale Manual.

(b) The variable operation and maintenance expenses for the unit as described in Article V of the Unit Power Sale Manual.

(c) Compensation for transmission losses, based on the average transmission loss percentage ($\%L_e$) set forth in Article VII of the Unit Power Sale Manual.

Using (a) and (b) above,

$$(c) = [(a) + (b)] \left[\frac{(\%L_e \div 100)}{1-(\%L_e \div 100)} \right]$$

6.7 Station Service Charges: For station service energy required each month for a unit specified in Exhibit A during the hours in which the net electrical output of such unit is equal to or less than zero, Corporation shall pay an amount per MWH, for a pro rata share of such station service energy based on the ratio of Corporation's capacity entitlement in such unit pursuant to Article II to the Net Dependable Capacity of such unit, equal to the Base Energy Rate of such unit as determined in Section 6.3; provided, however, such Base Energy Rate shall be limited to a value no greater than the Normalized Energy Rate as determined in Section 6.6 for such unit.

6.8 Discretionary Energy Rates: For energy supplied to Corporation at any time pursuant to Section 3.9, Corporation shall pay an amount per MWH delivered which is the greater of (a) Weighted Average Energy Rate for Corporation's pro rata share of all units as determined by the following formula:

$$WAER = \frac{UPC_1 \times ER_1}{UPC_1 + UPC_2 + \ldots UPC_N} + \ldots + \frac{UPC_N \times ER_N}{UPC_1 + UPC_2 + \ldots + UPC_N}$$

Where:

WAER = Weighted Average Energy Rate for Corporation's pro rata share of all units.

N = Total number of units to which Corporation has capacity entitlement.

UPC_N = Unit Power Capacity entitlement of Corporation from such unit determined in accordance with Article II.

ER_N = Unit's respective Energy Rate which is lesser of (1) the Base Energy Rate of such unit as determined in accordance with Section 6.3; or (2) the Normalized Energy Rate of such unit as determined in accordance with Section 6.6.

or (b) the incremental cost of the units in economic dispatch incurred by Southern Companies after serving their own systems' requirements and needs, and any other energy sales taking precedence before delivery of such Discretionary Energy as defined in Section 3.9.1. The expense of units in economic dispatch shall include only the incremental cost of fuel, variable operation and maintenance expenses, change in system transmission losses, and other such energy-related costs which would otherwise not have been incurred.

6.9 Replacement Energy Rates: For Replacement Energy supplied to Corporation pursuant to Section 3.10, Corporation shall pay an amount per MWH equal to the hourly quoted rate agreed upon by the parties hereto prior to commencement of delivery of such energy for the next hour. The incremental cost quoted by Southern Companies for each hour (determined in accordance with the priorities established in Section 3.10.1) shall be based on the estimated incremental cost o1 fuel, estimated incremental maintenance cost; estimated incremental change in system transmission losses attributable to the transaction; and other costs, directly attributable to the transaction. If Corporation elects to continue receipt of Replacement Energy during the next hour after being notified that Southern Companies, in their sole judgment, can no longer make available Replacement Energy at the quoted price, the price of such energy shall be the greater of the quoted price for such Replacement Energy or the Weighted Average Energy Rate for Corporation's pro rata share of all units (WAER) as determined in Section 6.8.

ARTICLE VII

BILLING AND PAYMENTS

7.1 Presentation and Payment of Bills for Capacity Charges: Capacity charges in the amounts determined in accordance with Article VI for each month shall be stated in an invoice presented by Southern Companies to Corporation on or before December 1 of each year stating the amount due each month during the ensuing year. To the extent the monthly capacity charges specified in any such invoice change as a result of causes specified in this UPS Agreement, an amended invoice shall be presented to Corporation by Southern Companies as soon as practicable after such change occurs. On or before the fifteenth day of each month of the ensuing year, Corporation shall make payment to Southern Companies in accordance with the invoice or amended invoice in immediately available funds through wiring of funds or other mutually agreeable methods of payment. Payments of capacity charges not made when due shall accrue interest, at one hundred five percent (105%) of the prime rate quoted on the date due by Manufacturers Hanover Trust Company in New York, New York, from the due date to the date of payment (a day shall equal 1/30 of a month). Any adjustment due to be made as a result of the procedure set forth in Section 2.2.17 or Article IX of the Unit Power Sale Manual shall be added to or subtracted from the invoice due to be paid in the month next following the date on which Corporation is notified by Southern Companies (by mail and telecopy on the same day) of such adjustment. Such payment shall also include any amounts theretofore invoiced by Southern Companies and not paid by Corporation associated with the administration of the true-up provision as specified in Article IX of the Unit Power Sale Manual. Payments of capacity and transmission charges which are in excess (or deficient) of amounts which would have been due based upon actual trued-up costs shall be credited (or debited) to Corporation together with interest thereon from the date payment was due on the budgeted amount to the date payment is made for credit (or debit) resulting from the true-up. Interest on the excess or deficient amount shall be accrued at one hundred percent (100%) of the prime rate quoted by Manufacturers Hanover Trust Company in New York, New York, on the date payment of the budgeted amount was due. Said prime rate shall be applicable until the next succeeding payment date, at which time interest shall accrue at one hundred percent (100%) of the prime rate quoted by Manufacturers Hanover Trust Company on the date such next succeeding payment was due. This interest accrual procedure shall be repeated monthly until such time as the excess (or deficient) amounts are credited (or debited) to Corporation.

7.2 Presentation and Payment of Bills for Energy and Other Charges: As promptly as practicable after the first of each month during the term hereof, an invoice shall be sent by Southern Companies by mail and by telecopy on the same date stating the charges determined in accordance with Article VI for energy sold and delivered to Corporation hereunder during the preceding month together with any other charges then due by Corporation to Southern Companies pursuant to the terms of this UPS Agreement. All such invoices shall be due and payable within ten (10) days from the date of mailing (as determined by postmark) by Southern Companies, or by the 20th day of the month, whichever is later. Corporation shall make payment to Southern Companies in accordance with such invoices on or before the date due in immediately available funds through wiring of funds or other mutually agreeable methods of payment. Bills not paid when due shall accrue interest, at one hundred five percent (105%) of the prime rate quoted on the due date by Manufacturers Hanover Trust Company in New York, New York, from the due date to the date of payment (a day shall equal 1/30 of a month). With each monthly invoice, Southern Companies will provide Corporation a monthly statement to show the energy transactions and the basis for the settlement pertaining thereto, including the fuel cost components of energy charges. To expedite submission of invoices, the most recently available cost data will be used for the initial invoice. An adjusted invoice, if required to reflect the actual charges due for energy, shall be included in the monthly invoice immediately following the initial invoice, together with accrued interest on overpayments (or underpayments) at one hundred percent (100%) of the prime rate as provided for in Section 7.1.

7.3 Disputed Invoice: In case any portion of an invoice submitted pursuant to Sections 7.1 and 7.2 is in bona fide dispute, the undisputed amount shall be payable when due; and the remainder shall be paid promptly, upon determination of the correct amount, in accordance with Sections 7.1 and 7.2, including interest at one hundred percent (100%) of the prime rate as provided for in Section 7.1. Upon request by Corporation, Southern Companies shall provide copies of supporting documentation and records necessary to verify invoices whether disputed or undisputed.

7.4 Audit Rights and Finality of Bills: Corporation shall, upon written notice, have the right to audit any and all books and records of Southern Companies which relate to and are necessary for verification of charges and costs included in invoices or amended invoices rendered under this UPS Agreement. Such audit rights shall extend for a period of three (3) calendar years prior to the calendar year in which Corporation gives written notice to Southern Companies of its intention to perform an audit or have an audit performed. All charges and costs billed or invoiced to Corporation during a subject calendar year shall become final and not subject to adjustment after the expiration of three (3) calendar years after the end of the subject calendar year if Corporation has not given written notice to Southern Companies of audit findings and any request for adjustments to bills or invoices rendered by Southern Companies during the subject calendar year (e.g., 1995 calendar year charges and cost billed or invoiced will be final if a notice and request for adjustment is not received by Southern Companies by December 31, 1998). Audits shall, at the option of Corporation and at Corporation's sole expense, be performed by Corporation, or a nationally recognized accounting firm experienced in utility accounting practices. Upon request, Southern Companies will be entitled to review the complete audit report and any supporting material.

After Southern Companies have been advised by written communication of the audit findings, the Operating Representatives will be responsible for arranging meetings between representatives of the parties hereto, to discuss and resolve all audit findings in an expeditious manner. It is contemplated that any adjustments to invoices or bills as a result of the audit will be resolved within a six (6) month period from the date of receipt of written communication from Corporation of the audit findings and request for billing adjustment. If the parties hereto are unable to resolve audit findings within such six (6) month period, interest on any adjustments made as the result of such audit after the close of such period shall accrue at one hundred and five percent (105%) of the prime rate quoted by Manufacturers Hanover Trust Company from the date of the receipt of written communication from Corporation, instead of the one hundred percent (100%) prime interest rate provided for in Section 7.1.

In the case of internal audits or other audits performed by or for Southern Companies, any adjustments to correct previous invoices or bills rendered under this UPS Agreement shall only be permitted for a period of three (3) calendar years prior to the date Corporation is rendered an adjusted invoice or bill. Upon request, Corporation will be entitled to review the complete audit report and any supporting materials.

ARTICLE VIII

OPERATING COMMITTEE

8.1 Establishment of Operating Committee: Corporation and SCS, acting as agent for Southern Companies, shall each appoint one representative ("Operating Representative") to act for it in matters pertaining to detailed operating arrangements for delivery of power hereunder, and Corporation and SCS may each appoint an alternate to act for it in the absence of its Operating Representative. The two Operating Representatives, or their alternates, so appointed shall comprise and be referred to as the Unit Power Sales Operating Committee. Evidence of such appointment shall be given by written notice to each of the parties, and such appointments may be changed at any time by similar notice.

8.2 Responsibilities of the Unit Power Sales Operating Committee: The Unit Power Sales Operating Committee, in addition to matters specifically referred to elsewhere in this UPS Agreement, shall be responsible for the following:

(a) Establishment of procedure for communications with respect to energy availability and scheduling under Article III.

(b) Establishment of arrangements for metering, telemetering, computer data link, telecommunications, data acquisition, etc., associated with the delivery and receipt of power and energy hereunder to the extent not provided for by the Operating Committee established under the Interchange Contract.

(c) Communications with respect to the construction and schedule for commercial operation of the units specified in Section 2.1.

(d) Establishment of control and operating procedures to the extent not provided for by the Operating Committee under the Interchange Contract.

(e) Establishment of methods and procedures for accounting and billing hereunder.

(f) Communications with respect to determination of capacity available from each unit under Section 2.3 including adjustments to Net Dependable Capacity as may be necessary to reflect changed conditions or anticipated conditions.

(g) Development of forecasts by month of energy availability, demand and pricing, including capacity costs for use in planning by the parties.

(h) Communications with respect to the maintenance of the units specified in Section 2.1 including the review and coordination of annual maintenance schedules for the upcoming five (5) year period.

(i) Communications with respect to minimum operating conditions when it becomes necessary to manage fuel stockpiles under Section 3.6.

(j) Such other duties as may be conferred upon it by mutual agreement of Corporation and Southern Companies.

Both Corporation and Southern Companies shall cooperate in providing to the Unit Power Sales Operating Committee all information required in the performance of its duties. If the Unit Power Sales Operating Committee is unable to agree on any matter falling under its jurisdiction, such matter shall be referred by the Operating Representatives to their principals for decision. Failure of the principals to agree on any matter referred to them shall not constitute a basis for cancellation of this UPS Agreement. All decisions and agreements made by the Unit Power Sales Operating Committee shall be evidenced in writing.

8.3 Unit Power Sales Operating Committee Meetings: The Unit Power Sales Operating Committee shall hold an annual meeting at a time and place agreed upon by its members and review the duties set forth herein. When requested by either Corporation or Southern Companies, the Unit Power Sales Operating Committee shall also meet at the earliest opportunity for consideration of matters under its jurisdiction.

ARTICLE IX

AGENCY OF SOUTHERN COMPANY SERVICES, INC. FOR SOUTHERN COMPANIES

9.1 Role of SCS: SCS joins in the execution of this Agreement for the sole purpose of serving and acting as agent for Southern Companies jointly and severally. Southern Companies may designate a new agent from time to time under this UPS Agreement by giving Corporation ten (10) days' written notice in which event the authority of SCS, as agent, shall cease and the newly designated agent shall be substituted for the sole purpose of serving and acting as agent for Southern Companies jointly and severally.

9.2 Payments and Notices to Agent: Corporation shall be entitled to make all payments due to be made in accordance with this UPS Agreement to SCS, or such other agent of Southern Companies as designated under Section 9.1, and the making of such payments shall discharge Corporation's obligation hereunder notwithstanding the fact that such payments shall be due to be paid to one or more of Southern Companies. Corporation shall be entitled to make any notices provided for in this UPS Agreement to the Vice President-Operating and Planning Services of SCS or such other person as Southern Companies may designate.

ARTICLE X

MISCELLANEOUS PROVISIONS

10.1 Interrelationship with Interchange Contract: It is recognized by the parties hereto that the Interchange Contract as of the date hereof governs the interconnected operations of the parties hereto necessary for conduct of the transactions contemplated hereunder. To the extent not inconsistent herewith, such Interchange Contract, including any amendments thereto, shall govern the operations of the parties hereunder. In the event such Interchange Contract is terminated or cancelled during the term of this UPS Agreement, the provisions of such Interchange Contract which are essential for the continuation of transactions hereunder shall survive the termination or cancellation of such Interchange Contract.

10.2 Provisions of Interchange Contract Specifically Incorporated by Reference: The parties hereto agree that the following provisions of the Interchange Contract are specifically incorporated herein by reference as though fully set forth herein:

(a) Section 5.4 Kilovar Supply.

(b) Section 5.5 Determination of Amounts of Power Supplied.

(c) Section 6.2 Metering and Metering Facilities.

(d) Section 6.3 Inspecting and Testing of Meters.

(e) Section 7.1 Records.

(f) Section 9.5 Third Parties.

(g) Section 10.5 Waivers.

(h) Section 10.6 Successors and Assigns.

10.3 Specification of Sole Obligation or Sole Remedy: With respect to the matters provided for herein where this UPS Agreement specifies an obligation or remedy as being the sole obligation or remedy, it is the agreement and intent of the parties hereto that such obligation or such remedy is the exclusive obligation or remedy. No expansion of such obligation or remedy shall be provided in any suit, action or proceeding of any nature whatsoever, whether the claim underlying such suit, action or proceeding is based on contract, tort (including strict liability) or otherwise.

10.4 Standard of Performance of Obligations: In connection with the operation and maintenance of units from which Corporation is entitled to capacity, other facilities (including transmission) referenced in this UPS Agreement and other facilities required in support of Southern Companies' obligations under this UPS Agreement, Southern Companies' standard of management and performance during the term of this UPS Agreement shall be at least equal to the standard which they would use if such units and facilities were solely for their own territorial customers.

10.5 Definition of "Prudent Utility Practices": For purposes of this UPS Agreement, "Prudent Utility Practices" at a particular time shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry prior to such time, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. "Prudent Utility Practices" are not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts expected to accomplish the desired results.

10.6 Limitation of Liability: In no event shall any party hereto be liable (in contract or in tort, including negligence) to any other party hereto for incidental or consequential loss or damage resulting from performance, nonperformance or delay in performance of obligations under this UPS Agreement, except where such loss or damage results from intentional tort or fraud.

10.7 General Cost Principles: Charges for electric services provided for in this UPS Agreement consist of and include both direct and indirect costs incurred by Southern Companies attributable to activities required for the construction, operation and maintenance of transmission and generation facilities necessary to meet their obligations hereunder. Corporation and Southern Companies have agreed upon certain formulary descriptions of methodology and procedure as contained in the Unit Power Sale Manual and this UPS Agreement which shall be used in computation of charges.

It is recognized that the derivation and computation of such charges will include costs both directly and indirectly incurred by Southern Companies and that in the case of costs indirectly incurred it will be necessary to apply certain allocation methods and procedures to assign such costs to the appropriate facilities. Such costs shall be allocated by using the allocation methods and procedures set forth in the

Unit Power Sale Manual. If no allocation methods or procedures have been specified herein for a particular cost or cost component, Southern Companies shall apply fair and equitable allocation methods and procedures consistent with Prudent Utility Practices. Further, Southern Companies agree to notify Corporation of such newly-developed allocations or procedures and the parties hereto will make a good faith effort to agree with such allocations or procedures within a six (6) month period following notification to Corporation. If the parties hereto are unable to agree within such six (6) month period, the matter will be referred to the Operating Representatives in accordance with Section 8.2.

It is the intent of the parties hereto that the accounting for Southern Companies' costs, both direct and indirect, and allocations thereof shall be pursuant to assessing actual costs incurred, and charges to Corporation shall not include duplication or allocations of greater than one hundred percent (100%) of such costs.

10.8 Section References: References herein to articles shall be interpreted to mean all sections of the article referenced. References to sections shall be interpreted to mean all subsections of the section referenced.

10.9 Equal Employment Opportunity and Civil Rights: The parties hereby certify that they will comply with Section 202, Paragraphs 1 through 7 of Executive Order 11246, as amended, and applicable portions of Executive Orders 11701 and 11758, relative to Equal Employment Opportunity and the Implementing Rules and Regulations of the Office of Federal Contracts Compliance which are incorporated herein by this reference.

10.10 Contemporaneous Parties Defined: For purposes of this UPS Agreement, contemporaneous parties will mean Florida Power & Light Company ("FPL") and/or Jacksonville Electric Authority ("JEA") if either or both of those utilities execute new unit power sales contracts for the purchase of capacity from the units specified in Section 2.1 within forty-five (45) days of the execution of this UPS Agreement. Execution by JEA shall mean upon approval and acceptance by the Jacksonville Electric Authority Board but shall not mean final approval by the City Council of Jacksonville. It is understood that FPL and JEA have existing unit power sale contracts with Southern Companies (executed in 1982) and that Corporation will not be considered as a contemporaneous party with respect to those existing contracts. The term "contemporaneous parties" as used in this UPS Agreement may include Corporation, FPL and JEA if the context so indicates and the above conditions are satisfied. The term "other contemporaneous parties" as used in this UPS Agreement will include FPL and JEA if the context so indicates and the above conditions are satisfied.

10.11 Additional Rights: Except as to differences (including but not limited to amount of capacity purchased and time periods of purchases) selected by the contemporaneous parties in initial unit power sales contracts, Southern Companies will offer any revisions or changes to the initial contracts (including but not limited to the return on equity, early options and associated Long Term Power sales) to all contemporaneous parties on non-discriminatory terms, conditions and rights. It is recognized, however, that the contemporaneous parties may exercise their early options in different amounts and time periods and that the exercise of such options can result in capacity and energy cost differences between the contemporaneous parties. If either of the other contemplated contemporaneous parties fails to execute a contemporaneous unit power sales contract but later (before June 1,1995) executes a contract to purchase unit power, Southern Companies will offer to amend this UPS Agreement to insure that it contains equal and non-discriminatory terms, conditions and rights.

10.12 Other Agreements: The parties hereto agree that this UPS Agreement, together with all exhibits and attachments hereto, constitute a contractual arrangement and agreement separate from and independent of all other existing agreements between the Southern Companies and Corporation.

10.13 Notices by Southern Companies: Southern Companies shall be entitled to make any notices provided for in this UPS Agreement to the Vice President - System Operations of Corporation or such other person as Corporation may designate.

10.14 Responsibility and Indemnification: With regard to transactions pursuant to this UPS Agreement, each party hereto agrees to operate and maintain its electrical equipment with reasonable diligence and care and in accordance with Prudent Utility Practices. Corporation and Southern Companies expressly agree to indemnify and save harmless and defend the other against all claims, demands, costs, or expense for loss, damage or injury to persons or property, in any manner directly or indirectly connected with or growing out of the generation, transmission, or use of electric capacity and energy on its own side of the delivery point or points hereunder, irrespective of negligence actual or claimed of the other. It is the intention of the parties to this UPS Agreement that each of them be responsible for their own conduct and neither be responsible for the conduct of the other. This UPS Agreement in no way creates a contractual relationship of one party with the customers of the other party; neither does it create a duty thereto.

[The next page is the signature page, page 41.]

IN WITNESS WHEREOF, the parties hereto have caused this UPS Agreement to be executed by their duly authorized officers effective as of the date set forth in Section 1.1.

POWER CORP. LEGAL DEPT. APPROVED 7-15-88

ATTEST:

Kathleen P. Kortright
Assistant Secretary

FLORIDA POWER CORPORATION

By ______
B. L. Griffin, Exec Vice President
Date: July 18, 1988

ATTEST:

Wayne Boston
Asst Secretary

SOUTHERN COMPANY SERVICES, INC.

By R. O. Usry
R. O. Usry, Vice President
Date: July 19, 1988

ATTEST:

Wayne Boston
Asst Secretary

ALABAMA POWER COMPANY

By R. E. Huffman
R. E. Huffman, Vice President
Date: July 19, 1988

ATTEST:

Wayne Boston
Asst Secretary

GEORGIA POWER COMPANY

By Fred D. Williams
Fred D. Williams, Vice President
Date: July 19, 1988

ATTEST:

Wayne Boston
Asst Secretary

GULF POWER COMPANY

By Earl B. Parsons Jr.
E. B. Parsons, Jr., Vice President
Date: July 19, 1988

ATTEST:

Wayne Boston
Asst Secretary

MISSISSIPPI POWER COMPANY

By Robert C. Pierce
Robert C. Pierce, Vice President
Date: July 19, 1988

ATTEST:

Wayne Boston
Asst Secretary

SAVANNAH ELECTRIC AND POWER COMPANY

By H. W. Kraft
H. W. Kraft, Vice President
Date: July 19, 1988

ALLOCATION OF EXPECTED CAPACITY FOR UNIT POWER SALES TO CORPORATION UNDER THIS UPS AGREEMENT (MW)

Year	Period	ALABAMA POWER COMPANY (APC) Mil 1	Mil 2	Mil 3	Mil 4	APC Total	GEORGIA POWER COMPANY (GaPC) Scherer 3	GULF POWER COMPANY (GuPC) Scherer 3	Total
1993	Jan-May	-	-	-	-	-	-	-	-
	Jun-Dec	-	-	-	-	-	-	-	-
1994	Jan-May	58	58	58	-	174	8	18	200
	Jun-Dec	41	40	40	41	162	13	25	200
1995	Jan-May	85	85	85	85	340	20	40	400
	Jun-Dec	80	80	80	80	320	26	54	400
1996	Jan-Dec	80	80	80	80	320	26	54	400
.	.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.	.
2010	Jan-May	80	80	80	80	320	26	54	400
	Jun-Dec	-	-	-	-	-	-	-	-

TOTAL CAPACITY AVAILABLE TO CORPORATION AND OTHER CONTEMPORANEOUS PARTIES TO MEET THE EARLY OPTIONS (MW)

Year	Period	ALABAMA POWER COMPANY (APC) Mil 1	Mil 2	Mil 3	Mil 4	APC Total	GEORGIA POWER COMPANY (GaPC) Scherer 3	GULF POWER COMPANY (GuPC) Scherer 3	Total
1993	Jan-May	453	453	453	-	1359	106	35	1500
	Jun-Dec	300	300	300	-	900	209	16	1125
1994	Jan-May	247	246	247	-	740	169	16	925
	Jun-Dec	140	140	140	140	560	106	34	700
1995	Jan-May	100	100	100	100	400	66	34	500

Notes:

Mil 1 - Miller 1, "Expected Capacity": 666 MW
Mil 2 - Miller 2, "Expected Capacity": 666 MW
Mil 3 - Miller 3, Expected Commercial Operation 5-1-89, "Expected Capacity": 666 MW
Mil 4 - Miller 4, Expected Commercial Operation 3-15-91, "Expected Capacity": 666 MW
Scherer 3 "Expected Capacity": 808 MW

Governing Examples for Interpretation of Early Option
Under Section 2.2.1

Example 1

FPL, JEA, and Corporation give proper notice to exercise the full amounts of their respective early options beginning 1/1/93. The capacity for such early options will be taken from the designated units in the amounts shown below:

Florida Power & Light Company

Year	Period	Mil 1	Mil 2	APC Mil 3	Mil 4	APC Total	GaPC Scherer 3	GuPC Scherer 3	Scherer 3 Total	UPS Advanced Total by FPL	Total Advanced by All Contemporaneous Parties	FPL Percent of Total Advanced	One Fifth Of UPS Advanced By FPL
1993	Jan-May	272	271	272	-	815	64	21	85	900	1500	60.0%	180
	Jun-Dec	160	160	160	-	480	112	8	120	600	1125	53.3%	120
1994	Jan-May	160	160	160	-	480	110	10	120	600	925	64.9%	120
	Jun-Dec	90	90	90	90	360	68	22	90	450	700	64.3%	90
1995	Jan-May	90	90	90	90	360	59	31	90	450	500	90.0%	90

Jacksonville Electric Authority

Year	Period	Mil 1	Mil 2	APC Mil 3	Mil 4	APC Total	GaPC Scherer 3	GuPC Scherer 3	Scherer 3 Total	UPS Advanced Total by JEA	Total Advanced by All Contemporaneous Parties	JEA Percent of Total Advanced	One Fifth Of UPS Advanced By JEA
1993	Jan-May	60	61	60	-	181	14	5	19	200	1500	13.3%	40
	Jun-Dec	33	34	33	-	100	23	2	25	125	1125	11.1%	25
1994	Jan-May	33	33	34	-	100	23	2	25	125	925	13.5%	25
	Jun-Dec	10	10	10	10	40	8	2	10	50	700	7.1%	10
1995	Jan-May	10	10	10	10	40	7	3	10	50	500	10.0%	10

Florida Power Corporation

Year	Period	Mil 1	Mil 2	APC Mil 3	Mil 4	APC Total	GaPC Scherer 3	GuPC Scherer 3	Scherer 3 Total	UPS Advanced Total by Corporation	Total Advanced by All Contemporaneous Parties	Corporation Percent of Total Advanced	One Fifth Of UPS Advanced by Corporation
1993	Jan-May	121	121	121	-	363	28	9	37	400	1500	26.7%	80
	Jun-Dec	107	106	107	-	320	74	6	80	400	1125	35.6%	80
1994	Jan-May	54	53	53	-	160	36	4	40	200	925	21.6%	40
	Jun-Dec	40	40	40	40	160	30	10	40	200	700	28.6%	40
1995	Jan-May	-	-	-	-	-	-	-	-	-	500	-	-

Example 2

FPL gives proper notice to exercise its early option for the full 900 MW beginning 1/1/93. Neither of the other contemporaneous parties exercises any portion of its early options. The capacity for FPL's early option will be taken from the designated units in the amounts shown below:

Florida Power & Light Company

Year	Period	Mil 1	Mil 2	APC Mil 3	Mil 4	APC Total	GaPC Scherer 3	GuPC Scherer 3	Scherer 3 Total	UPS Advanced Total by FPL	Total Advanced by All Contemporaneous Parties	FPL Percent of Total Advanced	One Fifth Of UPS Advanced By FPL
1993	Jan-May	253	253	253	-	759	106	35	141	900	900	100.0%	180
	Jun-Dec	160	160	160	-	480	104	16	120	600	600	100.0%	120
1994	Jan-May	160	160	160	-	480	104	16	120	600	600	100.0%	120
	Jun-Dec	90	90	90	90	360	56	34	90	450	450	100.0%	90
1995	Jan-May	90	90	90	90	360	56	34	90	450	450	100.0%	90

Jacksonville Electric Authority

Year	Period	Mil 1	Mil 2	APC Mil 3	Mil 4	APC Total	GaPC Scherer 3	GuPC Scherer 3	Scherer 3 Total	UPS Advanced Total by JEA	Total Advanced by All Contemporaneous Parties	JEA Percent of Total Advanced	One Fifth Of UPS Advanced By JEA
1993	Jan-May	-	-	-	-	-	-	-	-	-	900	-	-
	Jun-Dec	-	-	-	-	-	-	-	-	-	600	-	-
1994	Jan-May	-	-	-	-	-	-	-	-	-	600	-	-
	Jun-Dec	-	-	-	-	-	-	-	-	-	450	-	-
1995	Jan-May	-	-	-	-	-	-	-	-	-	450	-	-

Florida Power Corporation

Year	Period	Mil 1	Mil 2	APC Mil 3	Mil 4	APC Total	GaPC Scherer 3	GuPC Scherer 3	Scherer 3 Total	UPS Advanced Total by Corporation	Total Advanced by All Contemporaneous Parties	Corporation Percent of Total Advanced	One Fifth Of UPS Advanced by Corporation
1993	Jan-May	-	-	-	-	-	-	-	-	-	900	-	-
	Jun-Dec	-	-	-	-	-	-	-	-	-	600	-	-
1994	Jan-May	-	-	-	-	-	-	-	-	-	600	-	-
	Jun-Dec	-	-	-	-	-	-	-	-	-	450	-	-
1995	Jan-May	-	-	-	-	-	-	-	-	-	450	-	-

Governing Examples for Interpretation of Early Option
Under Section 2.2.1

Example 3

FPL gives proper notice to exercise its early option for the full 900 MW beginning 1/1/93. Corporation gives proper notice to exercise 100 MW of its early option beginning 1/1/94 through 12/31/94. JEA gives proper notice to exercise 50 MW of its early option beginning 6/1/94 through 5/31/95. The capacity for such early options will be taken from the designated units in the amounts shown below:

Florida Power & Light Company

Year	Period	Mil 1	Mil 2	APC Mil 3	Mil 4	APC Total	GaPC Scherer 3	GuPC Scherer 3	Scherer 3 Total	UPS Advanced Total by FPL	Total Advanced by All Contemporaneous Parties	FPL Percent of Total Advanced	One Fifth Of UPS Advanced By FPL
1993	Jan-May	253	253	253	-	759	106	35	141	900	900	100.0%	180
	Jun-Dec	160	160	160	-	480	104	16	120	600	600	100.0%	120
1994	Jan-May	160	160	160	-	480	106	14	120	600	700	85.7%	120
	Jun-Dec	90	90	90	90	360	65	25	90	450	600	75.0%	90
1995	Jan-May	90	90	90	90	360	59	31	90	450	500	90.0%	90

Jacksonville Electric Authority

Year	Period	Mil 1	Mil 2	APC Mil 3	Mil 4	APC Total	GaPC Scherer 3	GuPC Scherer 3	Scherer 3 Total	UPS Advanced Total by JEA	Total Advanced by All Contemporaneous Parties	JEA Percent of Total Advanced	One Fifth Of UPS Advanced By JEA
1993	Jan-May	-	-	-	-	-	-	-	-	-	900	-	-
	Jun-Dec	-	-	-	-	-	-	-	-	-	600	-	-
1994	Jan-May	-	-	-	-	-	-	-	-	-	700	-	-
	Jun-Dec	10	10	10	10	40	7	3	10	50	600	8.3%	10
1995	Jan-May	10	10	10	10	40	7	3	10	50	500	10.0%	10

Florida Power Corporation

Year	Period	Mil 1	Mil 2	APC Mil 3	Mil 4	APC Total	GaPC Scherer 3	GuPC Scherer 3	Scherer 3 Total	UPS Advanced Total by Corporation	Total Advanced by All Contemporaneous Parties	Corporation Percent of Total Advanced	One Fifth Of UPS Advanced by Corporation
1993	Jan-May	-	-	-	-	-	-	-	-	-	900	-	-
	Jun-Dec	-	-	-	-	-	-	-	-	-	600	-	-
1994	Jan-May	27	26	27	-	80	18	2	20	100	700	14.3%	20
	Jun-Dec	20	20	20	20	80	14	6	20	100	600	16.7%	20
1995	Jan-May	-	-	-	-	-	-	-	-	-	500	-	-

EXHIBIT B

LONG TERM POWER - EARLY OPTION

Section B0.1: This Exhibit B is an attachment to the Unit Power Sales Agreement between Corporation and Southern Companies.

ARTICLE I - DEFINITION AND PURPOSE

Section B1.1: Pursuant to Sections 2.2.1 and 2.2.2 of the UPS Agreement, Corporation has the right to purchase Long Term Power during the period beginning January 1, 1993 and extending through December 31, 1994 in accordance with the provisions of the early option (as that term is defined in Sections 2.2.1 and 2.2.2 of the UPS Agreement). This Exhibit B sets forth the terms and conditions and price of such Long Term Power in the event Corporation elects to exercise the early option.

Section B1.2: Long Term Power as used herein shall mean capacity and energy existing on the systems of Southern Companies not needed at that time on their systems to meet their own systems' requirements (including power used for pumping at pumped storage hydroelectric projects) and other power sale commitments taking precedence before delivery under this Exhibit B. It is understood that any capacity reserve requirements associated with Long Term Power shall be the responsibility of Corporation.

Section B1.3: With respect to the purchases of Long Term Power contemplated by this Exhibit B, the power sale commitments referred to in Section B1.2 having precedence before delivery under this Exhibit B, as a matter of capacity and energy priorities, shall include: (i) any seasonal energy or capacity exchange agreements now existing or entered into in the future; (ii) any firm power interchange sales to other utilities or third parties now existing or entered into in the future; (iii) any unit power sales agreements (including but not limited to those with contemporaneous parties) now existing or entered into in the future for the sale of capacity and energy from a specific generating unit or units (including but not limited to any Alternate, Supplemental or Replacement Energy furnished under provisions similar to that contained in the UPS Agreement with Corporation and similar agreements with FPL and JEA); (iv) any Short Term Power being supplied under provisions of the now existing contract with Alabama Electric Cooperative, Inc. or any amendments or replacements thereto; and (v) any Long Term Power furnished to City of Tallahassee, Florida under the provisions of an existing agreement and rate schedule with such City.

Section B1.4: The purpose of Long Term Power is to promote economy of power supply, to achieve more efficient utilization of generating and transmission facilities, to conserve generation by more expensive fuels, and for any other uses to take advantage of capacity and energy that is available on the systems of Southern Companies.

ARTICLE II - TERM

Section B2.1: This Exhibit B shall become operable when and if Corporation exercises its early option rights under Sections 2.2.1 and 2.2.2 of the UPS Agreement and shall continue in effect through December 31, 1994 when this Exhibit B shall expire and terminate by its terms.

ARTICLE III - SERVICES TO BE RENDERED

Section B3.1: Southern Companies will make available to Corporation and Corporation shall have the right to purchase up to the following amounts of Long Term Power under the early option set forth in Sections 2.2.1 and 2.2.2 of the UPS Agreement:

Period	Capacity Available Under Early Option
Jan. 1. 1993 - Dec. 31, 1993	400 MW
Jan. 1, 1994 - Dec. 31, 1994	200 MW

Section B3.2: It is understood that the above amounts of capacity are the maximum amounts of Long Term Power available under the early option set forth in Sections 2.2.1 and 2.2.2 of the UPS Agreement. To the extent that Corporation advances sales of unit power capacity under the early option, the availability of Long Term Power as specified in the foregoing table shall be reduced by a corresponding amount. It is the understanding of the parties hereto that the total amount of capacity to be sold by Southern Companies to Corporation under the UPS Agreement and this Exhibit B at any point in time will be limited to 400 MW with the unit power sales specified in Section 2.2 of the UPS Agreement being set and not subject to change or revision pursuant to the early option rights of Corporation.

Section B3.3: In the event Corporation purchases Long Term Power under the early option, Corporation has the right to schedule use of capacity and related energy under this Exhibit B as its deems desirable for its system. Southern Companies will supply Corporation, when requested, a daily estimate by 11:00 a.m. prevailing Central Time of energy prices which Corporation can use and schedule capacity usage for the following day. Corporation will supply Southern Companies an estimated schedule of capacity usage by 1:30 p.m. the day prior to when the capacity is required unless other arrangements are mutually agreed upon.

Section B3.4: Southern Companies may exercise the right to withdraw capacity and energy provided for in this Exhibit B prior to dropping its own system power requirements (including power used for pumping at pumped storage hydroelectric projects) or other power sale commitments taking precedence for delivery under this Exhibit B, as defined in Sections B1.2 and B1.3, or because of transmission limitations on their systems. In the event this right is exercised by Southern Companies, adjustments will be made in capacity charges as determined in Section B4.2(a).

Section B3.5: It is contemplated that energy supplied by Southern Companies under this Exhibit B will be from coal-fired steam generation. However, there may be times when such energy is supplied by Southern Companies from sources which cost is in excess of coal-fired steam generation. During such times of supply from such higher cost sources, Corporation shall have the right to refuse such supply and adjustments will be made in capacity charges as determined in Section B4.2(b).

ARTICLE IV - BASIS OF SETTLEMENT

Section B4.1: Corporation shall pay Southern Companies for the supply of Long Term Power at the following rates:

Section B4.1.1: Capacity: There shall be applied to each kilowatt of billing capacity, a monthly capacity charge which shall not exceed Southern Companies' cost of fossil, steam and combustion turbine plant and transmission facilities, as determined in accordance with the procedure and methodology described in the Exhibit B Manual attached to and incorporated in this Exhibit B. This monthly charge will be shown on the Exhibit B Informational Schedule further described in Section B4.3.

Section B4.1.2: Energy: The cost of energy shall be the incremental expense incurred by Southern Companies in supplying energy hereunder. Such energy shall be considered as having been delivered from the next most economical

CURTAILMENT EVENT DATA

Curtailment Event Data	CURTAILMENT EVENT							
	Oct 19, 1995	Jan 1, 1995	Jan 2, 1995	Jan 7, 1995	Jan 8, 1995	Jan 14, 1995	Jan 30 1995	Average
Curtailments - MW	150	100	264	282	100	51	100	150
Duration - hours	4.00	4.50	6.00	4.00	3.25	2.50	4.00	3.89
Curtailments - MWH	600	450	1,488[3]	1,128	325	128	400	631
Avoided Energy Cost - $/MWH[4]	15.38	15.38	15.38	15.38	15.38	15.38	15.38	15.38
Unit Cycling Data								
No. of Units Cycled Off	2	1	2	2	1	1	1	
Unit Start-up Costs - $[5]	29,137	14,568	29,137	29,137	14,568	14,568	14,568	

[3] January 2, 1995 curtailments were 200 MW for 1.5 hours and 264 for 4.5 hours.

[4] Average energy price during midnight to 6:00 am for the first five curtailment days.

[5] Unit start-up costs based on light oil firing at $3.90/MMBtu.

resources available to Southern Companies after serving their own systems' requirements (including energy used for pumping at pumped storage hydroelectric projects) and other power sale commitments taking precedence before delivery under this Exhibit B, as defined in Sections B1.2 and B1.3. This expense shall reflect both incremental expense of generating the energy and/or obtaining the energy from a third party. Included in the expense shall be the following incremental costs: Fuel, maintenance and supplies and change in system transmission losses attributable to the transactions.

Section B4.2: Adjustment: (a) Should provisions of Section B3.4 be invoked by Southern Companies for any day or portion of a day, Southern Companies will credit to Corporation a capacity credit for each day of reduced delivery of capacity by Southern Companies to Corporation. This daily capacity rate will be shown on the Exhibit B Informational Schedule. (b) Should provisions of Section B3.5 be invoked, Southern Companies will credit to Corporation a capacity credit for each hour of reduced delivery of capacity by Southern Companies to Corporation. This hourly capacity rate will be shown on the Exhibit B Informational Schedule.

Section B4.3: Exhibit B Manual: In the event Corporation elects to take Long Term Power under this Exhibit B, Corporation and Southern Companies recognize that the cost of providing the power contemplated will change during the term of this Exhibit B. Thus, in order for Southern Companies to be fairly compensated under this Exhibit B, it will be necessary to revise and update on a yearly basis, the cost, expense and investment figures utilized in the derivation of the charges provided for herein. The procedure and methodology for determining the rates and charges are set forth in the Exhibit B Manual. The Exhibit B Manual will serve as a formula rate allowing periodic revision to the charges so as to reflect changes in the cost of providing the services contemplated by this Exhibit B. In the event Corporation exercises the early option to purchase Long Term Power, charges for the services contemplated by this Exhibit B will be set forth on an Initial Exhibit B Informational Schedule developed in accordance with the formula rate incorporated in the Exhibit B Manual. The Exhibit B Informational Schedule will be revised annually in accordance with the specific procedures and methodologies set forth in the Exhibit B Manual. The initial Exhibit B Informational Schedule and any revisions thereto shall be submitted by Southern Companies to Corporation sixty (60) days in advance of the date on which such charges are to become effective (except for the initial Exhibit B Informational Schedule, revisions will be submitted on November 1 of each year). This time period will allow Corporation and Southern Companies to verify that the charges contained in the Exhibit B Informational Schedule have been computed in accordance with the Exhibit B Manual. Since the charges will be computed in accordance with the formula rate method and procedures described in the Exhibit B Manual, it is contemplated that the yearly revisions to such charges will not be changes in rates which will require a filing and suspension under the Federal Power Act and the applicable rules and regulations of the FERC.

Section B4.4: Unilateral Revision of Rates: In addition to the right to revise charges as described in Section B4.3 above, Corporation and Southern Companies shall have the right by mutual agreement to amend, either in whole or in part, Exhibit B, the Exhibit B Manual and Exhibit B Informational Schedule. If, within sixty (60) days of the commencement of negotiations to make any such amendments, Corporation and Southern Companies are unable to reach agreement on any such amendment, either Corporation or Southern shall have the unilateral right to make changes or substitutions in this Exhibit B, the Exhibit B Manual and Exhibit B Informational Schedule, including, but not limited to any methodology or procedure for the computation of charges contained therein by making a legally effective filing with or by order of FERC or its successor agency.

Section B4.5: Settlement for capacity and energy transactions under this Exhibit B shall be made monthly in accordance with monthly statements rendered by Southern Companies to Corporation. The monthly statement shall show the capacity and energy transactions and the respective basis for the settlement pertaining thereto. Southern Companies shall submit, as soon as practicable after the first of each month, a bill for the capacity and energy charges related to Long Term Power under this Exhibit B supplied during the preceding calendar month. All such bills shall be due and payable within ten (10) days from the date of mailing (as determined by postmark) or by the twentieth (20th) day of the month, whichever is later. Bills not paid when due shall accrue interest at one hundred percent (100%) of the prime rate quoted on the date due by Manufacturers Hanover Trust Company in New York, New York from the due date to the date of payment (a day shall equal 1/30 of a month).

[End of Exhibit B]

EXHIBIT B MANUAL

LONG TERM POWER - EARLY OPTION

Section M0.0 Description and Purpose of Exhibit B Manual: Exhibit B Manual is attached to and made a part of Exhibit B (Long Term Power - Early Option) to the UPS Agreement between Corporation and Southern Companies. Exhibit B Manual contains a formulary description of the methodology and procedure used to calculate the charges for Long Term Power as provided for in Exhibit B. Exhibit B Manual is divided into four (4) basic articles as follows:

- Article I - Definition of Contract Year and Derivation of Peak-Period Load Ratios
- Article II - Derivation of Capacity Charge for Fossil Steam and Combustion Turbine Plant
- Article III - Derivation of Capacity Charge for Transmission Facilities (Rated 115 kV and above)
- Article IV - Average Transmission Loss Percentage

ARTICLE I

DEFINITION OF CONTRACT YEAR AND DERIVATION OF PEAK-PERIOD LOAD RATIOS

This article of Exhibit B Manual establishes the definition of Contract Year as utilized throughout Exhibit B Manual and provides for the yearly derivation of Peak-Period Load Ratios which are utilized in the computation of certain charges for Long Term Power under Exhibit B. In Exhibit B Manual, Southern Companies may be referred to individually as an "operating company".

Section M1.0 Contract Year and Peak-Period Load Ratios: The Contract Year shall be defined to be the calendar year for which charges for Long Term Power are being established. The Contract Year will be divided into two distinct periods, January through May, and June through December. This division of the Contract Year into two periods is necessary to recognize that the Southern Companies consider an operating year to be June 1 through May 31 of the following year.

Peak-Period Load Ratios (with peak-period defined to be the fourteen (14) hours between 7:00 a.m. and 9:00 p.m. prevailing Central Time of each weekday, excluding holidays) will be determined by dividing each operating company's peak-period energy by the total system peak-period energy. Each operating company's peak-period energy to be used in calculating Peak-Period Load Ratios for the twelve (12) months of the Contract Year will be based upon actual peak-period energy for the months of June, July, and August of the previous calendar year.

The Peak-Period Load Ratios will be shown on Exhibit B Informational Schedule for the Contract Year.

ARTICLE II

DERIVATION OF CAPACITY CHARGE FOR FOSSIL STEAM AND COMBUSTION TURBINE PLANT

This article of Exhibit B Manual establishes the formulary methodology for deriving capacity charges for production plant used in Exhibit B for determination of charges for Long Term Power to be supplied under Exhibit B.

Section M2.1 System Production Capacity Charge: The derivation of the system production capacity charge ($/kW-month) for Long Term Power to be supplied under Exhibit B is based on the cost of fossil steam and combustion turbine production facilities and associated generator step-up substation facilities. The computation of the monthly system production capacity charge for Long Term Power to be supplied under Exhibit B is determined for each period of the Contract Year in the following manner. The monthly capacity charge ($/kW-month) is multiplied by the rated production capacity in kilowatts (kW) (including buy-back capacity) in each month to obtain the total monthly capacity dollars ($) for each operating company. The total monthly production capacity dollars are then summed and divided by the sum of the rated production capacity (including buy-back capacity) to obtain a weighted average production capacity charge ($/kW-month) for each operating company. The weighted average production capacity charge ($/kW-month) for each operating company for each period of the Contract Year is multiplied by its Peak-Period Load Ratio.

These results for each operating company are summed to obtain the total system production capacity charge for each period of the Contract Year. This total system production capacity charge for each period will constitute the charge for capacity sold by Southern Companies to Corporation under Exhibit B. This charge for each period of the Contract Year will be shown on Exhibit B Informational Schedule and will be revised in accordance with Exhibit B in subsequent calendar years.

Section M2.2 Derivation of Monthly Capacity Charges of Each Operating Company: The derivation of the monthly capacity charges of each operating company is based on the capacity, investments, and expenses related to production and generator step-up substation facilities of each operating company during the respective periods of the Contract Year. This derivation excludes the capacity, investments, and expenses associated with nuclear facilities, hydro facilities, the units or portion of such units from which unit power sales are made (including buy-back capacity utilized in supplying a portion of such sales), and the portion of fossil steam and combustion turbine units owned and retained by Oglethorpe Power Corporation ("OPC"), Municipal Electric Authority of Georgia ("MEAG"), and the City of Dalton, Georgia ("Dalton"). The capacity, investment, and expense associated with Southern Electric Generating Company ("SEGCO") facilities is allocated between GaPC and APC based upon the respective ownership of SEGCO by GaPC and APC. The derivation of the monthly capacity charges of each operating company is expressed in the following formulae:

$$R_3 = \frac{I \times [(CM + IT)/100\%] + E + IT_i + IT_b}{C}$$

$$R_2 = \frac{(R_3 \times C) + (BR \times CB)}{C + CB}$$

$$R_1 = \frac{R_2 \times 100/(100-\%L)}{12}$$

Where:

R_3 = Total production fixed charges ($/kW-year).

R_2 = Total production charges with buy-back ($/kW-year).

R_1 = Monthly production capacity charges ($/kW-month).

CM = The weighted average cost of capital (%).

IT = The income tax requirement associated with the preferred stock and common equity weighted cost of capital (%).

IT_i = Additional income taxes due to the treatment of Allowance for Funds Used During Construction ("AFUDC") and Amortization of Investment Tax Credits ("AITC"). The subscript "i" denotes whether the company uses a "gross of tax" (IT_g) method or a "net of tax" (IT_n) method in accounting for AFUDC.

IT_b = Income tax effect of five percent (5%) basis reduction.

I = Total fossil steam and combustion turbine net investment ($).

E = Total fossil steam and combustion turbine annualized fixed expenses ($).

C = Rated fossil steam and combustion turbine production capability (kW).

CB = Buy-back fossil steam rated capability (kW).

BR = Buy-back rate ($/kW).

L = Average transmission loss percentage of Southern Companies as determined in Article IV of this Exhibit B Manual.

The source of the capacity, investment, and expense data incorporated in the above formulae for each operating company (including FERC Account numbers and description of allocation procedure and calculation of the cost of capital) is as follows:

<u>Section M2.2.1</u>: <u>Rated Production Capability</u> is the rating in kW of the production facilities associated with the production investment and expenses. The capacity, investment and expense represent the facilities owned by the operating companies. The GaPC capacity entitlement (buy-back) from units fractionally owned by OPC, MEAG and Dalton (except for those amounts used to supply a portion of the unit power sales) is included as a separate item in the formulae shown in Section M2.2.

<u>Section M2.2.2</u>: <u>Gross Production Investment</u> is a summation of FERC Accounts 310 through 316, 340 through 346, and the generator step-up substation investment in FERC Accounts 352 and 353 related to the fossil steam and combustion turbine production facilities. Each operating company's investments in general plant that are recorded in FERC Accounts 389, 398, and 399 that directly serve a production function are included in the production plant investment summation.

<u>Section M2.2.3</u>: <u>Accumulated Depreciation</u> is that depreciation associated with the gross production investment defined above. The accumulated depreciation associated with production plant is directly assigned to the production function. A portion of the accumulated depreciation for transmission plant is allocated to generator step-up substation facilities on the basis of gross investment in generator step-up substation facilities to total investment in the transmission function excluding land.

<u>Section M2.2.4</u>: <u>Net Production Investment</u> is the difference between Section M2.2.2 (Gross Production Investment) and Section M2.2.3 (Accumulated Depreciation).

Section M2.2.5: General Plant (Net) includes the investment in FERC Accounts 389 through 399, excluding amounts directly assigned to production. The assignment of net general plant excluding the direct assignments to production plant is accomplished on the basis of salaries and wages developed in Section M2.2.16. After net general plant has been allocated to transmission plant on the basis of salaries and wages, it is allocated to the generator step-up substation facilities based on the ratio of the total net generator step-up investment to the total net transmission investment.

Section M2.2.6: Working Capital is the summation of cash working capital, prepayments, and materials and supplies, and is computed for each month of the Contract Year. The cash working capital is developed by taking one-eighth (45/360) of the sum of Operation and Maintenance (O&M) expenses, Administrative and General (A&G) expenses and adjustments reflecting the operating agreements governing the operation of jointly owned facilities where applicable. The monthly fixed O&M[1] and variable O&M (including fuel burned expense) are both multiplied by twelve (12) to obtain an annualized fixed and variable O&M expense. The monthly A&G expense for production plant is added to the monthly A&G expense for the generator step-up substations. These two items (production A&G and generator step-up substations A&G) are added and multiplied by twelve (12) to obtain an annualized A&G expense. Total working capital is computed by adding deposits, prepayments, and materials and supplies to cash working capital. The deposits included in the computation of total working capital reflect the operating agreements applicable to the operation of jointly owned facilities. The deposits increase the working capital requirements for one operating company, but reduce another operating company's by a corresponding amount. These deposits are computed utilizing a thirteen (13) month average. Prepayments are computed on the basis of a thirteen (13) month average and are directly assigned to production, transmission, and general plant functions. Prepayments associated with general plant are allocated to production plant and transmission plant on the basis of salaries and wages. The amount allocated to transmission plant is allocated to the generator step-up substation facilities on the basis of net investment. Materials and supplies are computed on the basis of a thirteen (13) month average and consist of two parts: (i) fuel stock, and (ii) plant materials and operating supplies recorded in FERC Account 154 that are related to the production plant and the transmission plant. The amount allocated to the generator step-up substations is on the basis of gross investment.

1. O&M expenses as used in this Exhibit B Manual do not include Administrative and General expenses.

Section M2.2.7: Accumulated Deferred Income Taxes are the net total of FERC Accounts 190, 281, 282, and 283 which have been analyzed and allocated by each operating company in accordance with each FERC Account's functional use. The portion related to general plant is assigned in accordance with the general plant assignments described in Section M2.2.5. The portion related to transmission plant is allocated to the generator step-up substations on the basis of net investment in generator step-up substation facilities to total transmission net investment excluding land.

Section M2.2.8: Total Net Production Investment represents the direct and allocated investments that are associated with the fossil steam and combustion turbine production and generator step-up substation facilities and is the summation of Section M2.2.4 (Net Production Investment) through Section M2.2.7 (Accumulated Deferred Income Taxes) and is the value for "I" in the formulae in Section M2.2.

Section M2.2.9: Operation and Maintenance Expense--Fixed is determined to be the total of the fixed expenses recorded in FERC Accounts 500 through 514, and 546 through 554 excluding 547 plus a portion of the O&M expenses in FERC Accounts 562, 569, and 570 allocated to generator step-up substation facilities on the basis of net investment in generator step-up substation facilities to total net substation investment.

Section M2.2.10: Administrative and General Expenses, FERC Accounts 920 through 935, excluding FERC Account 924, are allocated to fossil steam, combustion turbine, and associated generator step-up substation facilities based on salaries and wages (for allocation to function) and net investment (for allocation within function). FERC Account 924 is directly assigned to function by the operating company and allocated within function based on net investment. FERC Account 924 (property insurance) associated with general plant is allocated to fossil steam, combustion turbine, and associated generator step-up facilities based upon salaries and wages (for allocation to function) and net investment (for allocation within function).

Section M2.2.11: Depreciation Expense is net of Amortization of Investment Tax Credit (AITC). The depreciation expense for production facilities is taken directly from the records of each operating company. The depreciation expense associated with the generator step-up substation facilities is determined on the basis of the gross investment in generator step-up substation facilities and the associated depreciation rates. The depreciation expense associated with general plant is assigned to production and transmission plant in accordance with the general plant assignments described in Section M2.2.5. The general plant depreciation expense allocated to the total transmission function is further allocated to the generator step-up substation facilities on the basis of depreciation expense.

Section M2.2.12: Real and Personal Property Taxes are assigned directly to the fossil steam and combustion turbine and generator step-up substation facilities based on operating company records. The real and personal property taxes associated with general plant are assigned in accordance with the general plant assignments described in Section M2.2.5.

Section M2.2.13: Payroll Taxes are developed for the fossil steam and combustion turbine production facilities and the transmission function by applying the expected payroll tax rates to the budgeted salaries and wages developed in Section M2.2.16. The payroll taxes associated with the transmission function are allocated to the generator step-up substation facilities on the basis of net investment in the generator step-up substations.

Section M2.2.14: Total Production Fixed Expenses represent the direct and allocated fixed expenses associated with the fossil steam and combustion turbine production and generator step-up substation facilities and are the summation of Section M2.2.9 (Operation and Maintenance Expense--Fixed) through Section M2.2.13 (Payroll Taxes) and is the value for "E" in the formulae in Section M2.2.

Section M2.2.15: The Cost of Capital and Associated Income Taxes are computed in the following manner:

$$CM = [(DR \times i) + (PR \times p) + (ER \times c)]$$

Where:

$$DR + PR + ER = 1.0$$

$$IT = \frac{T}{1 - T} \times [(PR \times p) + (ER \times c)]$$

$$IT_b = \frac{T}{1 - T} \times BD^2$$

and $IT_i = IT_n$ or IT_g

$$IT_n = \frac{T}{1 - T} \times [AFUDC_{equity} + AFUDC_{debt} - AITC]$$

$$IT_g = \frac{T}{1 - T} \times [AFUDC_{equity} - AITC]$$

2. This is applicable only to an operating company which elects the ten percent (10%) investment tax credit.

Where: $T = \frac{F + S - 2FS}{1 - FS}$ (federal income taxes deductible for state income tax purposes)

or

$T = F + S - FS$ (federal income taxes not deductible for state income tax purposes)

CM = Weighted average cost of capital (%).

IT = Income tax requirement associated with preferred stock and common equity weighted cost of capital (%).

IT_i = Additional income taxes due to the treatment of AFUDC and AITC, and the subscript "i" denotes whether the company uses a "gross of tax" (IT_g) method or a "net of tax" (IT_n) method for accounting for AFUDC.

IT_n = Income tax effect of equity AFUDC, debt AFUDC, and AITC for operating companies using the "net of tax" method.

IT_g = Income tax effect of equity AFUDC and AITC for operating companies using the "gross of tax" method.

IT_b = Income tax effect of five percent (5%) basis reduction.

$AFUDC_{equity}$ = Depreciation expense of the AFUDC equity component associated with the production facilities and their step-up substations.

$AFUDC_{debt}$ = Depreciation expense of the AFUDC debt component associated with the production facilities and their step-up substations.

AITC = Amortization of investment tax credit associated with the production facilities and their step-up substations.

BD = The amortization of the permanent difference between book basis and tax basis arising from the five percent (5%) basis reduction for purposes as specified by the Tax Equality and Fiscal Responsibility Act of 1982 ("TEFRA").

DR = Ratio of debt capital (target ratio; includes first mortgage bonds, pollution control obligations, and capitalized leases).

PR = Ratio of preferred stock (target ratio).

ER = Ratio of common equity (target ratio).

i = Embedded cost of debt capital (%).

p = Embedded cost of preferred stock (%).

c = 14.0%, return on common equity.

T = Combined state and federal income tax rate.

F = Federal income tax rate.

S = State income tax rate.

Section M2.2.16: Salaries and Wages are budgeted and accounted for by each operating company for each functional group for the Contract Year. The budgeted salaries and wages account for changes in wage rates and number of employees.

The salaries and wages associated with the administrative and general classification are allocated to the functional groups based upon the ratio of the functional group's salaries and wages to the total salaries and wages less the administrative and general classification salaries and wages. The salaries and wages associated with the transmission function, including the allocated administrative and general salaries and wages, are allocated to the transmission plant's substations based upon the labor in FERC Accounts 562, 569, and 570.

ARTICLE III

DERIVATION OF CAPACITY CHARGE FOR TRANSMISSION FACILITIES

This article of Exhibit B Manual establishes the formulary methodology for deriving capacity charges for transmission facilities for Long Term Power to be supplied under Exhibit B.

Section M3.1 Transmission Capacity Charge: The computation of the transmission capacity charge for transmission facilities is based on the investment, expenses, and load related to transmission lines rated 115 kV and above and associated substations. This capacity charge excludes the investment and expenses associated with the generator step-up substations and the investment, expenses, and associated load in transmission owned by OPC, MEAG, and Dalton. The transmission capacity charge ($/kW-month) for each period of the Contract Year for capacity sold under Exhibit B to Corporation will be the sum of GaPC's transmission capacity charge ($/kW-month) plus one-half (1/2) of APC's transmission capacity charge ($/kW-month). This charge for each period of the Contract Year will be shown on the Exhibit B Informational Schedule and will be revised in accordance with Exhibit B in subsequent calendar years.

Section M3.2 Derivation of Transmission Capacity Charges of APC and GaPC: The derivation of the transmission capacity charges of APC and GaPC is based on the investments, expenses, and load related to transmission lines and associated substation facilities rated 115 kV and above excluding generator step-up substations of each operating company during the Contract Year and the cost of capital and taxes in each period of the Contract Year. This derivation excludes the investment, expenses, and associated load in transmission owned by OPC, MEAG, and Dalton. The investment and expense associated with SEGCO transmission facilities is assigned to GaPC. The derivation of the monthly transmission capacity charge for APC and GaPC for each period of a Contract Year is expressed in the following formulae:

$$R_1 = \left[\frac{I \times [(CM_1 + IT_1)/100\%] + E + IT_i + IT_b}{D \times 12}\right] \times \left[\frac{100}{100 - \%L}\right]$$

$$R_2 = \left[\frac{I \times [(CM_2 + IT_2)/100\%] + E + IT_i + IT_b}{D \times 12}\right] \times \left[\frac{100}{100 - \%L}\right]$$

Where: R_1 = Transmission capacity charge for January through May ($/kW-month).

R_2 = Transmission capacity charge for June through December ($/kW-month).

CM_1 = The weighted average cost of capital (%) associated with the January through May period of the Contract Year.

CM_2 = The weighted average cost of capital (%) associated with the June through December period of the Contract Year.

IT_1 = The income tax requirement associated with the preferred stock and common equity weighted cost of capital (%) associated with the January through May period of the Contract Year.

IT_2 = The income tax requirement associated with the preferred stock and common equity weighted cost of capital (%) associated with the June through December period of the Contract Year.

IT_i = Additional income taxes due to the treatment of AFUDC and AITC. The subscript "i" denotes whether the company uses a "gross of tax" (IT_g) method or a "net of tax" (IT_n) method of accounting for AFUDC.

IT_b = Income tax effect of five percent (5%) basis reduction.

I = The twelve (12) month average investment in transmission lines and associated substation facilities (excluding generator step-up substations) rated 115 kV and above ($).

E = The twelve (12) month annual expenses for transmission lines and associated substation facilities (excluding generator step-up substations) rated 115 kV and above ($).

D = The five-day average estimated load (kW).

L = Average transmission loss percentage of Southern Companies as determined in Article IV of this Exhibit B Manual.

The source of the load, investment, and expense data incorporated in the above formulae for APC and GaPC (including FERC Account numbers and description of allocation procedures and calculation of the cost of capital) is as follows:

Section M3.2.1: Five-Day Average Load is the estimated peak one-hour load (kW) at the generator adjusted to a five-day average load based on the preceding year's actual loads. APC's and GaPC's one-hour peak net territorial load (kW) is the sum of the following: (1) generation, (2) associated companies' pool receipts, (3) associated companies' pool deliveries, (4) non-associated companies' receipts, (5) non-associated companies' deliveries, and (6) any known loads associated with the transmission services that are responsible for revenues which were not credited to operating expenses. The generation owned and retained by OPC, MEAG, and Dalton and their partial requirements load at the generator bus are excluded for the GaPC load calculation. Also the investment and expenses associated with OPC, MEAG, and Dalton ownership in transmission facilities are excluded.

Section M3.2.2: Gross Transmission Investment is the summation of FERC Accounts 350, 354, 355, 356, 357, 358, and 359 associated with 115 kV and higher voltage lines plus FERC Accounts 350, 352, and 353 associated with transformation and switching between 115 kV and the higher voltages. (Generator step-up substations are excluded.)

Section M3.2.3: Accumulated Depreciation is that depreciation associated with the gross transmission investment defined above and is allocated to FERC Account based on investment and depreciation rates by FERC Account. The allocation to voltage level is based on gross investment.

Section M3.2.4: Net Transmission Investment is the difference between Section M3.2.2 (Gross Transmission Investment) and Section M3.2.3 (Accumulated Depreciation).

Section M3.2.5: General Plant (Net) includes the investment in FERC Accounts 389 through 399. All coal properties and coal handling equipment carried in FERC Accounts 398 and 399 are directly assigned to production plant. The allocation of net general plant to transmission plant (excluding the direct assignments) is done on the basis of salaries and wages as developed in Section M3.2.17.

After net general plant has been allocated to transmission plant, it is allocated to the 115 kV and above facilities based on the ratio of the total net investment in the 115 kV and above facilities to the total net transmission plant investment.

Section M3.2.6: Working Capital is the summation of cash working capital, prepayments, and material and supplies. Cash working capital is one-eighth (45/360) of the allocated O&M expense plus one-eighth (45/360) of the allocated A&G expense associated with the facilities considered herein, adjusted for working capital deposits as appropriate. Prepayments are allocated on the basis of O&M expenses associated with the facilities considered herein. Materials and supplies are allocated on the basis of gross plant less land.

Section M3.2.7: Accumulated Deferred Income Tax is the net total of FERC Accounts 190, 281, 282, and 283 which have been analyzed and allocated by APC and GaPC in accordance with each FERC Account's functional use. The portion related to general plant is allocated to the transmission function with the general plant assignments as described in Section M3.2.5. The allocation to facilities rated 115 kV and above is on the basis of net plant less land.

Section M3.2.8: Total Net Transmission Investment represents the direct and allocated investments that are associated with the facilities rated 115 kV and above and is the summation of Section M3.2.4 (Net Transmission Investment) through M3.2.7 (Accumulated Deferred Income Tax) and is the value for "I" in the formulae in Section M3.2.

Section M3.2.9: Transmission Operation and Maintenance Expenses, FERC Accounts 560 through 573 are allocated in relation to the net transmission plant associated with the facilities considered herein unless more detailed assignments can be made from existing operating company records.

Section M3.2.10: Administrative and General Expenses, FERC Accounts 920 through 935, excluding FERC Account 924, are allocated to the transmission function based on salaries and wages and to facilities rated 115 kV and above on the basis of net investment. FERC Account 924 is directly assigned to function by the operating company and allocated within function based on net investment.

Section M3.2.11: Depreciation Expense is net of AITC. The depreciation expense for transmission plant is taken directly from the records of APC and GaPC. The depreciation expense associated with the 115 kV and above facilities is determined on the basis of the gross investment in 115 kV and above facilities and the associated depreciation rates. The depreciation expense associated with general plant is allocated to transmission plant in accordance with the general plant allocations as described in Section M3.2.5. The general plant depreciation expense allocated to transmission function is further allocated to the 115 kV and above facilities on the basis of depreciation expense related to the 115 kV and above facilities and the total transmission plant.

Section M3.2.12: Real and Personal Property Taxes are assigned directly to the transmission plant. These taxes are allocated to the 115 kV and above facilities based on the ratio of the net investment in the 115 kV and above facilities to the net transmission plant. The real and personal property taxes associated with general plant are allocated to the transmission function on the basis of salaries and wages and within transmission to the facilities rated 115 kV and above on the basis of net investment.

Section M3.2.13: Payroll Taxes are developed for the transmission function by applying the expected payroll tax rates to the salaries and wages developed in Section M3.2.17. The transmission plant payroll taxes plus the allocated A&G are allocated to the 115 kV and above facilities based on the ratio of the net investment in the 115 kV and above facilities to the total net transmission plant investment.

Section M3.2.14: Credits (or Debits) to Operating Expenses: The revenues classified as "Other Operating Revenue" in the operating company's budget will be credited to the operating expenses if the transmission facilities considered herein were responsible for such revenues (e.g., such revenues associated with Long Term Power sales, Short Term Power sales, and unit power sales). If the revenues for transmission service are not credited, the estimated demands associated with the revenues will be added to the demand of the affected operating company for the transmission rate calculation. Because an operating company may have operating agreements with third parties with respect to the transmission facilities considered herein, there may be revenues or expenses associated with the facilities rated 115 kV and above that will be appropriately credited or debited to the operating expenses for the affected operating company. In addition, revenues associated with the transmission facilities rated 115 kV and above that appear in the "Purchased Power Account" in the operating company's budget (e.g., such revenues associated with Long Term Power sales, Short Term Power sales, and unit power sales) will be credited to the operating expenses for these transmission facilities.

Section M3.2.15: Total Transmission Expenses represent the direct and allocated fixed expenses associated with the facilities considered herein and are the summation of Section M3.2.9 (Transmission Operation and Maintenance Expenses) through Section M3.2.14 (Credits (or Debits) to Operating Expenses) and is the value for "E" in the formulae in Section M3.2.

Section M3.2.16: The Cost of Capital and Associated Income Taxes are computed as described in Section M2.2.15.

Section M3.2.17: Salaries and Wages are budgeted and accounted for by APC and GaPC for each functional group for the Contract Year. The budgeted salaries and wages account for changes in wage rates and number of employees.

The salaries and wages associated with the administrative and general classification are allocated to the functional groups based upon the ratio of the functional groups' salaries and wages to the total salaries and wages less the administrative and general classification's salaries and wages.

The transmission plant salaries and wages which include the allocated A&G, are allocated to the 115 kV and above facilities based on the ratio of the net investment in the 115 kV and above facilities to the total net transmission plant investment.

ARTICLE IV

AVERAGE TRANSMISSION LOSS PERCENTAGE

This article of Exhibit B Manual establishes the average transmission loss percentage for deriving the charges for Long Term Power under Exhibit B.

Section M4.0 Average Transmission Loss Percentage: For purposes of determining charges for Long Term Power under Exhibit B, the average transmission loss percentage for Southern Companies shall be three percent (3%).

EXHIBIT C

UNIT POWER SALE MANUAL

Section C0.0 Description and Purpose of Unit Power Sale Manual: This Unit Power Sale Manual contains a formulary description of the methodology and procedure used to calculate the charges for each Contract Year for the unit power sales provided for in the UPS Agreement and is attached to the UPS Agreement between Corporation and Southern Companies. Contract Year shall be defined to be the calendar year for which charges for unit power sales are being established. The Unit Power Sale Manual is divided into nine (9) basic articles as follows:

Article I - Derivation of Net Dependable Capacity Ratings for Electric Generating Units

Article II - Derivation of Capacity Charge for Coal-Fired Electric Generating Units

Article III - Derivation of Capacity Charge for Transmission Facilities

Article IV - Derivation of Fuel Costs and Normalized Fuel Costs for Electric Generating Units

Article V - Derivation of Fixed Operation and Maintenance and Variable Operation and Maintenance Expenses for Electric Generating Units

Article VI - Derivation of Return on Common Equity

Article VII - Derivation of Average Transmission Loss Percentages

Article VIII - Unit Power Sale Informational Schedule and Support Schedules and Monthly Report of Energy Transactions

Article IX - Adjustments for Actual Cost

Section C0.1 Allocation Methods and Procedures: The allocation methods and procedures set forth in this Unit Power Sale Manual have been developed with reference to Southern Companies present accounting practices; if such accounting practices change in the future so as to make the allocation methods and procedures specified in this Unit Power Sale Manual inappropriate, the allocation methods and procedures shall be deleted or changed to meet the new accounting practices of Southern Companies, provided such changed allocation methods and procedures are fair and equitable.

Section C0.2 "Uniform System of Accounts": The FERC Accounts set forth in this Unit Power Sale Manual are currently prescribed in FERC's "Uniform System of Accounts Prescribed for Public Utilities and Licensees (Class A and Class B)" in effect as of the date of the UPS Agreement. If these FERC Accounts are amended, then this Unit Power Sale Manual shall be construed to reflect the amended accounts prescribed by FERC or its successor agency.

ARTICLE I

DERIVATION OF NET DEPENDABLE CAPACITY RATINGS FOR ELECTRIC GENERATING UNITS

This article of this Unit Power Sale Manual establishes the definition and methodology for the yearly derivation of Net Dependable Capacity ratings used in the computation of capacity charges and for such other purposes as specified in the UPS Agreement. The definition and methodology for the derivation of Net Dependable Capacity ratings specified in this article are also used in the computation of capacity charges in other contracts of Southern Companies, including contracts with third parties and between one operating company of Southern Companies and another operating company of Southern Companies. Southern Companies may be referred to individually as an "operating company".

Section C1.0 Net Dependable Capacity: For the purpose of deriving the Net Dependable Capacity of each electric generating unit for the ensuing Contract Year, the net generation in kilowatt hours (kWh) of each unit will be determined for the highest four (4) continuous hours during the peak-period hours (with peak-period defined to be the fourteen (14) hours between 7:00 a.m. and 9:00 p.m. prevailing Central Time of each weekday, excluding holidays) without overpressure, for five (5) different days during July and August of the calendar year preceding the Contract Year (or June, July, and August as per the then current practice of Southern Companies in rating their generating units for intercompany use). The Net Dependable Capacity of a unit for the Contract Year is defined as the average of the net generation for such twenty (20) hours, subject to the principles in Sections C1.1 and C1.2 below. Southern Companies will use best efforts, consistent with Prudent Utility Practice, to maximize the Net Dependable Capacity rating for each unit.

Section C1.1 Adjustments for Unusual Circumstances: In the event unusual circumstances occur during the months of July and August in the calendar year preceding the Contract Year (or June, July, and August as per the then current practice of Southern Companies in rating their generating units for intercompany use) or circumstances during the Contract Year are expected to be significantly different from those during such July and August (or June, July, and August as per the then current practice of Southern Companies in rating their generating units for intercompany use), in the sole opinion of the operating company responsible for operating the unit, such operating company will determine the Net Dependable Capacity for such unit for the Contract Year and will provide a statement giving the reason(s) for not using the value for Net Dependable Capacity determined in Section C1.0 and the method used to establish the Net Dependable Capacity for the Contract Year.

Section C1.2 Units Being Declared Commercial: The Net Dependable Capacity for a unit declared commercial after the month of August in the calendar year preceding the Contract Year will be determined from the turbine manufacturer's design gross generation capability at valves wide open, adjusted for station service and further adjusted by the historical ratio of Net Dependable Capacity to design generation capability for similar units on the systems of Southern Companies.

Section C1.3 Data to Be Provided: The data used in the determination of the Net Dependable Capacity for each unit each Contract Year, pursuant to Sections C1.0, C1.1, and C1.2 above, will be provided to purchasers of unit power in accordance with Article VIII of this Unit Power Sale Manual.

ARTICLE II

DERIVATION OF CAPACITY CHARGE FOR COAL-FIRED ELECTRIC GENERATING UNITS

This article of this Unit Power Sale Manual establishes the formulary methodology for deriving capacity cost and charges related to coal-fired electric generating units dedicated to unit power sales under the UPS Agreement. The formulary methodology will be used to derive both estimated capacity cost for preliminary billing and actual capacity cost for corrections to such preliminary billing.

Section C2.1 Capacity Cost of Unit Power Sales: The computation of the capacity cost of unit power sales for each month of the Contract Year will be accomplished in the following manner. The monthly capacity cost ($/kW-month) of each coal-fired electric generating unit participating in the unit power sales is multiplied by the portion (MW) of the unit applicable to the sale in each month to obtain the total monthly capacity dollars ($). The total monthly unit power sales capacity dollars are then summed and to this sum will be added an amount equal to the total MW applicable to the unit power sales multiplied by an amount (fixed at a rate of $0.08/kW-month), as agreed to by the parties hereto, to compensate for scheduling, coordination and other difficult-to-quantify cost applicable to the transactions under the UPS Agreement. This capacity cost for each month will constitute the charge for capacity sold by Southern Companies under the UPS Agreement. This charge for each month of the first Contract Year will be shown on the Unit Power Sale Informational Schedule, and will be revised in accordance with this Unit Power Sale Manual in subsequent calendar years.

Section C2.2 Derivation of Estimated Monthly Capacity Charge of Coal-Fired Electric Generating Units: The derivation of the estimated monthly capacity charge of the coal-fired electric generating units participating in the unit power sales is based on the capacity (determined in Article I of this Unit Power Sale Manual) and the projected investments and expenses related to production and generator step-up substation facilities of each such unit during the Contract Year. The derivation of the monthly capacity charge of each applicable unit is expressed in the following formula:

$$R = \left[\frac{I \times [(CM + IT)/100] + E}{C \times 12}\right] \times \left[\frac{100}{100 - L_C}\right]$$

where:

R = Monthly production capacity charge for operating company owned capacity ($/kW-month)

I = Total of the net investment associated with the operating company's portion of the unit ($).

CM = The weighted average cost of capital associated with the operating company's cost of construction of the unit (%).

IT = The income tax requirement associated with the preferred stock and common equity weighted cost of capital associated with the operating company's cost of construction of the unit (%).

E = Total of the annualized fixed expenses associated with the operating company's portion of the unit ($).

C = Net Dependable Capacity of the operating company's portion of the generating unit (kW).

L_c = Average transmission capacity loss percentage of Southern Companies as determined in Article VII of this Unit Power Sale Manual (%).

The source of the capacity, investment, and expense data incorporated in the above formula for coal-fired electric generating units (including FERC Account numbers and description of allocation procedures and calculation of the cost of capital) is as follows:

Section C2.2.1: Net Dependable Capacity is the rating in kW of the coal-fired electric generating unit as determined in Article I of this Unit Power Sale Manual. The value of "C" in Section C2.2 is determined by multiplying the percent ownership of the operating company by the unit's Net Dependable Capacity.

Section C2.2.2: Gross Generating Unit Investment for a unit owned by an operating company is the book cost of the coal-fired electric generating unit and its associated generator step-up substation. The cost of these facilities is recorded in FERC Accounts 310-316 for the generating unit and FERC Accounts 352 and 353 for the step-up substation at the end of each month of the Contract Year. The amount of booked Allowance for Funds Used During Construction ("AFUDC") shall have added to it an amount to reflect the effect of Construction Work In Progress ("CWIP") in retail rate base. The amount of AFUDC to be added, if any, shall be calculated on a monthly basis for the construction period of the unit using the following formulae:

$$DA = \Sigma[(AR - BR) \times AB]$$

DA = Dollar amount to be added to booked AFUDC.

AR = The monthly AFUDC rate prescribed by the applicable state public service commission.

BR = The actual monthly AFUDC rate applied by the operating company (this rate being affected by CWIP in the operating company's retail rate base).

AB = The actual monthly AFUDC base used by the operating company in computing booked AFUDC.

All coal properties and coal handling equipment that are recorded at the end of each month of the Contract Year in FERC Accounts 389, 398, and 399 that are directly associated with the generating unit are included in the gross generating unit investment summation. Where allocations to the generating unit are required, such allocations shall be based on the usage of the property and equipment.

The common facilities of the plant site and the step-up substation yard are allocated equally among the units at the plant site.

Section C2.2.3: Accumulated Depreciation is associated with the gross production investment defined in Section C2.2.2. The accumulated depreciation for generating units is adjusted to include the amount of AFUDC determined in Section C2.2.2. If the depreciation records of the operating company do not allow for the identification of the accumulated depreciation of the specific coal-fired unit's step-up substation, a portion of the accumulated depreciation associated with the transmission plant will be allocated to the unit's generator step-up substation. The amount allocated to the generator step-up substation facilities will be on the basis of the ratio of the gross investment in the generator step-up substation facilities to the total gross investment in the transmission function excluding land.

Section C2.2.4: Net Generating Unit Investment is the difference between Section C2.2.2 (Gross Generating Unit Investment) and Section C2.2.3 (Accumulated Depreciation).

Section C2.2.5: General Plant (Net) includes the investment in FERC Accounts 389 through 399 at the end of each month of the Contract Year, excluding amounts directly assigned to production as listed in Sections C2.2.2 and C2.2.3. Net general plant, excluding the direct assignments, is allocated to the specific coal-fired generating unit and its generator step-up substation on the basis of salaries and wages as described in Section C2.2.17.

Section C2.2.6: Working Capital is the summation of cash working capital, prepayments, deposits (if any), and materials and supplies, and is computed for each month of the Contract Year.

The cash working capital for the specific coal-fired generating unit is calculated by taking one-eighth (45/360) of the sum of the annualized operating and maintenance (O&M)[1] expenses (including fuel burn) and administrative and general (A&G) expenses. The fixed O&M expense is developed in Section C2.2.9 and the A&G expense is developed in Section C2.2.10. The cash working capital for the specific unit's generator step-up substation is calculated by taking one-eighth (45/360) of the sum of the annualized fixed O&M and A&G expenses. The fixed O&M and A&G expenses are developed in Sections C2.2.9 and C2.2.10, respectively.

Prepayments are computed on the basis of a thirteen (13) month average and are directly assigned to production, transmission, general plant functions, and the specific coal-fired generating unit. The amount assigned to the transmission function is allocated to the specific coal fired unit's generator step-up substation on the basis of net transmission investment less land. Prepayments associated with general plant are allocated to the specific coal-fired generating unit and its step-up substation on the basis of salaries and wages as described in Section C2.2.17.

Materials and supplies are computed on the basis of a thirteen (13) month average and consist of two parts: (i) fuel stock recorded in FERC Account 151, and (ii) plant materials and operating supplies recorded in FERC Account 154 that are related to the production function and the transmission function. The fuel stock recorded in FERC Account 151 is allocated to the specific unit at the plant site based upon the nameplate ratings of the respective units. The plant materials and operating supplies, FERC Account 154, if not directly identifiable with the plant and associated generator step-up substation, are allocated to the specific coal-fired generating unit and its associated generator step-up substation on the basis of the ratio of the respective gross investment of the specific coal-fired generating unit and its associated generator step-up substation to the gross investment in the fossil steam production function and the associated generator step-up substations. The plant material and operating supplies, FERC Account 154, directly identifiable with the plant are allocated equally among the units.

Deposits are included as working capital requirements to reflect the operating agreements that exist between one operating company and another operating company for the operation of jointly owned generating units. It should be

1. O&M expenses as used in this Unit Power Sale Manual do not include A&G expenses.

noted that while these deposits increase the working capital requirements of one operating company, they have a corresponding reduction in the working capital requirements of the other operating company.

Section C2.2.7: Accumulated Deferred Income Taxes are developed for each applicable generating unit for each month of the Contract Year and is the net total of FERC Accounts 190, 281, 282, and 283. Accumulated deferred income taxes related to general plant for both the generating unit and its step-up substation are allocated in accordance with the general plant assignments for the unit and its step-up substation described in Section C2.2.5. The accumulated deferred income taxes related to transmission plant are allocated to the specific coal-fired unit's generator step-up substation on the basis of net investment in coal-fired unit's generator step-up substation facilities to total transmission net investment excluding land.

Section C2.2.8: Total Net Generating Unit Investment represents the direct and allocated investments that are associated with the coal-fired electric generating unit and its generator step-up substation facilities and is the summation of Section C2.2.4 (Net Generating Unit Investment) through Section C2.2.7 (Accumulated Deferred Income Taxes) and is the value for "I" for capacity in the formula in Section C2.2 for each applicable generating unit.

Section C2.2.9: Fixed Operation and Maintenance Expense is the total of the fixed expenses associated with the coal-fired electric generating unit recorded in FERC Accounts 500 through 514. The definition of fixed and variable as defined in these FERC Accounts is shown in Article V of this Unit Power Sale Manual. The O&M expenses in FERC Accounts 562, 569, and 570 associated with the generator step-up substation facilities of such generating unit are added to the generating unit's fixed expenses. Where O&M expenses of the generator step-up facilities are not directly identifiable, they will be allocated on the basis of the ratio of the gross investment in the specific coal-fired unit's generator step-up substation to the total gross substation investment.

Section C2.2.10: Administrative and General Expenses, FERC Accounts 920 through 935, excluding FERC Account 924 (Property Insurance), are allocated to the specific coal-fired generating unit and its step-up substation based upon salaries and wages as described in Section C2.2.17. The property insurance is developed and assigned to the specific coal-fired generating unit. The property insurance specifically assigned to the transmission function is allocated to the unit's step-up substation based upon the net transmission investment excluding land.

Section C2.2.11: Depreciation Expense for the coal-fired electric generating unit is based on straight line depreciation with the exception of the Scherer Plant units in which case the expense is based on units of production during the first six (6) months of operation and the remaining life on straight line depreciation. The depreciation expense for generating units is adjusted to reflect the AFUDC determined in Section C2.2.2. The depreciation expense associated with the generator step-up substation facilities is determined on the basis of the gross investment in generator step-up substation facilities and the associated depreciation rates. The depreciation expense associated with general plant is allocated to the specific coal-fired electric generating unit and its step-up substation in the same manner as the general plant allocations described in Section C2.2.5.

Section C2.2.12: Amortization of Investment Tax Credits ("AITC") is computed for each coal-fired electric generating unit. AITC associated with the transmission plant is allocated to the generator step-up substation facilities on the basis of the ratio of the depreciation expense of the generator step-up substation facilities to the depreciation expense of the transmission plant. The AITC associated with general plant is allocated to the specific coal-fired electric generating unit and its step-up substation in the same manner as the general plant allocations described in Section C2.2.5.

Section C2.2.13: Real and Personal Property Taxes are computed for the specific coal-fired electric generating unit and its associated step-up substation in a manner which equitably relates the pro rata share of such taxes to each facility with regard to its value for tax purposes and which is consistent with computation of such taxes for the respective operating company. The real and personal property taxes associated with general plant are allocated in accordance with the general plant allocation described in Section C2.2.5. Detailed documentation of computation of the real and personal property taxes for each unit in accordance with the computation of such taxes for the operating company will be prepared, and if requested, will be made available.

Section C2.2.14: Payroll Taxes applicable to a specific coal-fired electric generating unit and its step-up substation are computed in the following manner. The expected payroll tax rates are applied to the budgeted salaries and wages developed in Section C2.2.17. The payroll taxes reflect the use of the taxable wage base and the maximum payroll tax payable during each month of the Contract Year.

Section C2.2.15: Total Production Fixed Expenses represent the direct and allocated fixed expenses associated with the coal-fired electric generating unit and generator step-up facilities and are the summation of Section C2.2.9 (Fixed Operation and Maintenance Expense) through Section C2.2.14 (Payroll Taxes) and is the value for "E" for capacity in the formula in Section C2.2 for each applicable coal-fired electric generating unit.

Section C2.2.16: The Cost of Capital and Associated Income Taxes are computed in the following manner:

$$CM = [(DR \times i) + (PR \times p) + (ER \times c)]$$

Where: $DR + PR + ER = 1.0$

$$IT = \frac{T}{1 - T} \times [(PR \times p) + (ER \times c)]$$

Where: $T = \frac{F + S - 2FS}{1 - FS}$ (federal income taxes deductible for state income tax purposes)

or

$T = F + S - FS$ (federal income taxes not deductible for state income tax purposes)

CM = Weighted average cost of capital associated with the operating company's cost of construction of the unit (%).

IT = Income tax requirement associated with the preferred stock and common equity weighted cost of capital associated with the operating company's cost of construction of the unit (%).

T = Combined state and federal income tax rate.

F = Federal income tax rate.

S = State income tax rate.

DR = Ratio of debt capital[2].

PR = Ratio of preferred stock[2].

ER = Ratio of common equity[2].

c = Return on common equity of Southern Companies as determined in Article VI of this Unit Power Sale Manual.

2. The components of the capital structure of the operating company will be determined from the most recent Quarterly Report on Form 10-Q (or in event such report ceases to be required to be filed by an operating company, such other report to a governmental agency containing the operating company's capital structure) at the time the unit goes into commercial operation; except the capital structure for Miller Plant Unit 1 which will be determined by calculating the simple arithmetical averages of each of the components as determined by the capitalization as recorded on Form 10-K (or U5S where 10-K is not applicable) for end of year capitalization for each year 1972 through 1978. In the case of a unit which will go into commercial operation during the Contract Year, the components of the capital structure may change between the information available at the time the estimated capacity charges are developed and the time the applicable Form 10-Q is available. This one time change in capital structure will be recognized as soon as practicable.

i - The cost of debt capital[3], which shall be determined as of the date the unit goes into commercial operation, shall be the weighted average percent rate of first mortgage bonds issued during the construction of the unit, which shall be calculated by applying the annual percent interest rate of the most recent issue of first mortgage bonds prior to the incurrence of each monthly capital expenditure on the unit. The cost of debt capital shall be modified after the date of commercial operation to account for additional monthly capital expenditures to the unit by applying the annual percent interest rate of the most recent issue of first mortgage bonds prior to the incurrence of such monthly capital expenditure. Such costs of debt capital shall be modified to include the amount and the cost of pollution control bonds specifically related to the unit.

3. In the case of Miller Plant Unit 1 only, the cost of debt capital will be adjusted to account for the period during construction of the unit exceeding twelve months when no first mortgage bonds were issued. Adjustment for such periods will be as follows: The monthly capital expenditures occurring after the twelve-month period will have applied to them the annual percentage rate of first mortgage bonds issued up to six months subsequent to such expenditures. If no such bond issue were made in the six-month period subsequent to the monthly capital expenditure, the rate of the most recent previous bond issue will continue to be applied to such expenditures incurred up to six months prior to the next bond issue.

p = The cost of preferred stock[4], which shall be determined as of the date the unit goes into commercial operation, shall be the weighted average dividend percentage rate of such stock, which such percent rate shall be calculated by applying the annual dividend percentage rate of the most recent issue of preferred stock prior to the incurrence of each monthly capital expenditure on the unit.

The cost of preferred stock shall be modified after the date of commercial operation to account for additional monthly capital expenditures to the unit by applying the annual percentage interest rate of the most recent issue of preferred stock prior to the incurrence of such monthly capital expenditure.

Section C2.2.17: Salaries and Wages are budgeted and accounted for on an actual basis by each operating company for each functional group and the specific coal-fired electric generating unit for the Contract Year. The budgeted salaries and wages account for changes in wage rates and number of employees.

The salaries and wages associated with the administrative and general classification are allocated to the functions including the specific coal-fired electric generating unit based upon the ratio of the functional group's salaries and wages to the total salaries and wages less the administrative and general classification's salaries and wages. The salaries and wages associated with the transmission function, including the allocated administrative and general salaries and wages, are allocated to the transmission plant's substations based upon the labor in FERC Accounts 562, 569, and 570 and are further allocated to the unit's generator step-up substation facilities on the basis of the ratio of the gross investment in the specific

4. In the case of Miller Plant Unit 1 only, the cost of preferred stock will be adjusted to account for the period during construction of the unit exceeding twelve months when no issues of preferred stock were issued. Adjustments for such periods will be made as follows: The monthly capital expenditures occurring after the twelve-month period will have applied to them the annual dividend percentage rate of preferred stock issued up to six months subsequent to such expenditures. If no such stock issue were made in the six months subsequent to the monthly capital expenditure, the rate of the most recent previous preferred stock issue will continue to be applied to such expenditures incurred up to six months prior to the next preferred stock issue.

unit's step-up substation to the gross investment in the transmission substations unless a direct assignment of salaries and wages is available from the operating company's records.

The salaries and wages for a specific unit which is jointly owned are computed for one hundred percent (100%) of the unit. The total salaries and wages for such jointly owned units are allocated on the basis of percent ownership.

For a unit which does not have a historical basis of salaries and wages, the most recent vintage and similar coal-fired unit that does have a historical basis will be used for the first year's estimate.

Section C2.2.18: Adjustment for Delayed Unit Subject to Sections 2.4.3 or 2.4.4 of the UPS Agreement: The development of the capacity charge for a unit delayed subject to the provisions of Section 2.4.3 or Section 2.4.4 of the UPS Agreement will be made in accordance with the above described methodology subject to the following:

The increased amount of AFUDC attributable to the delay of the unit will not be included in the gross investment of the unit except as this increased amount of AFUDC is offset by savings made available through the substitution of less expensive capacity during the period of the delay. The amount of savings as may be available will be determined from the difference between the estimated cost of the unit as if it had not been delayed and the actual cost of the substituted unit.

Section C2.2.19: Adjustment to Cost of Capital Resulting From Retirement of Outstanding Securities: The cost of capital calculation provided in Section C2.2.16 is impacted when security issues are retired through either maturities, regular redemptions, or improvement fund redemptions. For consistent treatment of adjustments to the cost of capital calculations resulting from retirements and subsequent refundings, the following guidelines will be followed when security issues are completely retired:

1) Determine the existence of a refunding security. To identify a refunding issue, a like security must be issued within a given time frame either prior to or subsequent to the retirement. The time frame will be three (3) months and may be changed upon mutual agreement of the parties hereto. The timing for issues of like securities is identified in a) and b) below.

   a) Three (3) months prior to refunding -

   If there are multiple potential refunding issues, the refunding issues will be identified as the last security issued within the three-month time frame prior to the retirement. The amount of the refunding issue does not have to equal the amount of the redemption.

b) Three (3) months subsequent to refunding -

If no like securities were issued within three (3) months prior to the redemption, the first security issued within three (3) months subsequent to the redemption will be identified as the refunding issue. During any interim period from the redemption of a security up to three (3) months thereafter, an appropriate replacement rate will be determined for billing purposes. Such replacement rate for that period will be subject to agreement by the parties hereto. The amount of the refunding issue does not have to equal the amount of the redemption.

If multiple retirement and multiple refunding issues are identified within the designated time frame, the first security issued will be identified as the refunding security. However, a previously identified refunding issue may not be identified as the refunding issue for a subsequent retirement.

For the purpose of determining dates applicable to issued or retired securities, the date of refunding issues shall be the closing date of the issue and the date of retired or refunding issues shall be the settlement date.

If no like security issues have occurred within three months prior to or three (3) months subsequent to a redemption, a substitute rate will be determined by mutual agreement of the parties hereto.

2) Treatment of premium. Whenever a security is redeemed through a regular redemption, the affected operating company purchases the security from the holder at a premium. This premium is viewed as an investment which produces interest cost savings. The unit power sales purchasers receive a benefit of lower rates from these redemptions and should also bear a portion of the premium cost. Therefore, the unamortized discount and expense and the premium expense of a redeemed issue will be included in the cost of capital calculation for the replacement issue for unit power sales capital costs. The calculation will use the following methodology.

a) The net proceeds of the replacement issue will be reduced by the amount of the unamortized debt discount and expense of the redeemed issue, the call expense, and the premium expense. The expenses, discounts, call premiums and net proceeds will be prorated as appropriate to reflect differences in the amounts of the refunding and the refunded issues and in the calculation of replacement debt rates.

b) The yield to maturity of the replacement issue will be calculated using the adjusted net proceeds.

c) The example below illustrates a company refunding a series of fifteen percent (15%) first mortgage bonds with an equal size more recent issue of ten and one-eighth percent (10-1/8%) bonds.

$49,429,500	New issue price to company
(272,000)	New issue estimated expenses
(593,068)	Redeemed issue - unamortized discount and expense
(50,000)	Estimated call expense
(5,210,000)	Call premium
$43,304,432	Adjusted net proceeds

Adjusted yield to maturity = eleven and three-quarters percent (11.75%)

It is the intent of the parties hereto that the costs of debt and preferred stock reflect actual cost experienced by each operating company. The parties hereto agree, however, that no predetermined methodology can anticipate all future financial circumstances and further agree that the guidelines in this Section C2.2.19 are applicable only to the conditions described above, and exceptions to these conditions will be evaluated jointly by the parties hereto on a case-by-case basis.

ARTICLE III

DERIVATION OF CAPACITY CHARGE FOR TRANSMISSION FACILITIES

This article of this Unit Power Sale Manual establishes the formulary methodology for deriving the capacity charge for transmission facilities for unit power sales under the UPS Agreement.

Section C3.1 Transmission Capacity Charge: The computation of the transmission capacity charge for transmission facilities is based on the investment, expenses, and load related to transmission lines rated 115 kV and above and associated substations. This capacity charge excludes the investment and expenses associated with the generator step-up substations and the investment, expenses, and associated load in transmission owned by Oglethorpe Power Corporation ("OPC"), Municipal Electric Authority of Georgia ("MEAG"), and City of Dalton, Georgia ("Dalton"). The transmission capacity charge for unit power sales under the UPS Agreement from APC's Miller Plant Units 1, 2, 3, and 4 to Corporation will be the sum of APC's transmission capacity charge ($/kW-month) and GaPC's transmission capacity charge ($/kW-month). The transmission capacity charge for unit power sales under the UPS Agreement from GaPC's and GuPC's ownership in Scherer Plant Unit 3 to Corporation will be the GaPC transmission capacity charge ($/kW-month).

The computation of the transmission capacity charge is made for each period of the Contract Year. For purposes of this Article of this Unit Power Sale Manual, the Contract Year is divided into two distinct periods, January through May, and June through December. This division of the Contract Year into two periods is necessary in order to recognize that Southern Companies consider an operating year to be June 1 through May 31 of the following year.

The transmission charges for each period of the Contract Year will be shown on the Unit Power Sale Informational Schedule and will be revised in accordance with the UPS Agreement in subsequent calendar years.

Section C3.2 Derivation of Transmission Capacity Charge of APC and GaPC: The derivation of the transmission capacity charge of APC and GaPC is based on the investments, expenses, and load related to transmission lines and associated substation facilities rated 115 kV and above (excluding generator step-up substations) of each such company during the Contract Year and the cost of capital and associated income taxes in each period of the Contract Year. This derivation excludes the investment, expenses, and associated load in transmission owned by OPC, MEAG, and Dalton. The investment and expense associated with Southern Electric Generating Company ("SEGCO") transmission facilities is assigned to GaPC. The derivation of the monthly transmission capacity charge of APC and GaPC for each period of the Contract Year is expressed in the following formulae:

$$R_1 = \left[\frac{I \times [(CM_1 + IT_1)/100] + E}{D \times 12}\right] \times \left[\frac{100}{100 - L_c}\right]$$

$$R_2 = \left[\frac{I \times [(CM_2 + IT_2)/100] + E}{D \times 12}\right] \times \left[\frac{100}{100 - L_c}\right]$$

Where: R_1 = Transmission capacity charge for January through May ($/kW-month).

R_2 = Transmission capacity charge for June through December ($/kW-month).

CM_1 = The weighted average cost of capital associated with the January through May period of the Contract Year (%).

CM_2 = The weighted average cost of capital associated with the June through December period of the Contract Year (%).

IT_1 = The income tax requirement associated with the preferred stock and common equity weighted cost of capital associated with the January through May period of the Contract Year (%).

IT_2 = The income tax requirement associated with the preferred stock and common equity weighted cost of capital associated with the June through December period of the Contract Year (%).

I = The twelve-month average investment in transmission lines and associated substation facilities (excluding generator step-up substations) rated 115 kV and above ($).

E = The annual expenses for transmission lines and associated substation facilities (excluding generator step-up substations) rated 115 kV and above ($).

D = The five-day average estimated load (kW).

L_c = Average transmission capacity loss percentage of Southern Companies as determined in Article VII of this Unit Power Sale Manual.

The source of the load, investment, and expense data incorporated in the above formulae for APC and GaPC (including FERC Account numbers and description of allocation procedures and calculation of the cost of capital) is as follows:

Section C3.2.1: Five-Day Average Load is the estimated peak one-hour load (kW) at the generator adjusted to a five-day average load based on the preceding calendar year's actual loads. APC's and GaPC's one-hour peak net territorial load (kW) is the sum of the following: (1) generation, (2) associated companies' pool receipts, (3) associated companies' pool deliveries, (4) non-associated companies' receipts, (5) non-associated companies' deliveries, and (6) any known loads associated with the transmission services that are responsible for revenues which are not credited to operating expenses. The generation owned and retained by OPC, MEAG, and Dalton and their partial requirements load at the generator bus are excluded for the GaPC load calculation. Also the investment and expenses associated with OPC, MEAG, and Dalton ownership in transmission facilities are excluded.

The five-day average estimated load will be adjusted to the actual five-day average load for APC and GaPC pursuant to Article IX of this Unit Power Sale Manual.

Section C3.2.2: Gross Transmission Investment is the summation of FERC Accounts 350, 354, 355, 356, 357, 358 and 359 associated with 115 kV and higher voltage lines plus FERC Accounts 350, 352, and 353 associated with the transformation and switching between 115 kV and the higher voltages (generator step-up substations are excluded).

Section C3.2.3: Accumulated Depreciation is that depreciation associated with the gross transmission investment defined above and is allocated to FERC Account based on investment and depreciation rates by FERC Account. The allocation to voltage level is based on gross investment.

Section C3.2.4: Net Transmission Investment is the difference between Section C3.2.2 (Gross Transmission Investment) and Section C3.2.3 (Accumulated Depreciation).

Section C3.2.5: General Plant (Net) includes the investment in FERC Accounts 389 through 399. All coal properties and coal handling equipment carried in FERC Accounts 389, 398 and 399 are directly assigned to production plant as described in Sections C2.2.2 and C2.2.3. The allocation of net general plant to transmission facilities (excluding the direct assignments) is done on the basis of salaries and wages as described in Section C3.2.17.

After net general plant has been allocated to transmission plant, it is allocated to the 115 kV and above facilities based on the ratio of the total net investment in the 115 kV and above facilities to the total net transmission plant investment.

Section C3.2.6: Working Capital is the summation of cash working capital, prepayments, deposits (if any), and materials and supplies, and is computed for each month of the Contract Year. The cash working capital for the transmission facilities rated 115 kV and above is calculated by taking one-eighth (45/360) of the sum of the annualized fixed O&M and A&G expenses. The fixed O&M and A&G expenses are developed in Sections C3.2.9 and C3.2.10, respectively.

Prepayments are computed on the basis of a thirteen (13) month average and are directly assigned to production, transmission, general plant functions, and the specific coal-fired generating unit. Prepayments associated with general plant are allocated to the transmission function on the basis of salaries and wages as described in Section C3.2.17. The amount allocated and assigned to the transmission function is allocated to the facilities rated 115 kV and above on the basis of O&M expenses as described in Section C3.2.9.

Materials and supplies are computed on the basis of a thirteen (13) month average and consist of plant materials and operating supplies recorded in FERC Account 154 that are related to the transmission function. The plant materials and operating supplies, FERC Account 154, are allocated to the transmission facilities rated 115 kV and above on the basis of the ratio of the gross investment excluding land of the facilities rated 115 kV and above to the gross investment excluding land in the transmission plant.

Deposits are included as a working capital requirement to reflect the operating agreements that exist between one operating company and another operating company for the operation of transmission facilities. It should be noted that while these deposits increase the working capital requirements of one operating company, they have a corresponding reduction in the working capital requirements of another operating company.

Section C3.2.7: Accumulated Deferred Income Taxes are the net total of FERC Accounts 190, 281, 282, and 283 which have been analyzed and allocated by APC and GaPC in accordance with each FERC Account's functional use. The portion related to general plant is allocated to the transmission function as described in Section C3.2.5. The allocation to facilities rated 115 kV and above is on the basis of net plant less land.

Section C3.2.8: Total Net Transmission Investment represents the direct and allocated investments that are associated with the facilities rated 115 kV and above and is the summation of Section C3.2.4 (Net Transmission Investment) through C3.2.7 (Accumulated Deferred Income Taxes) and is the value for "I" in the formulae in Section C3.2.

Section C3.2.9: Transmission Operation and Maintenance Expenses, FERC Accounts 560 through 573 are allocated in relation to the net transmission plant associated with the facilities considered herein unless more detailed assignments can be made from existing operating company records. The O&M expenses will be adjusted to reflect actual O&M expenses pursuant to Article IX of this Unit Power Sale Manual.

Section C3.2.10: Administrative and General Expenses, FERC Accounts 920 through 935, excluding FERC Account 924, are allocated to the transmission function based on salaries and wages and to facilities rated 115 kV and above on the basis of net investment. FERC Account 924 is directly assigned to function APC and GaPC and allocated within function based on net investment.

Section C3.2.11: Depreciation Expense and Amortization of Investment Tax Credit (AITC) are developed as follows. The depreciation expense for transmission plant is taken directly from the records of APC and GaPC. The depreciation expense associated with the 115 kV and above facilities is determined on the basis of the gross investment in 115 kV and above facilities and the associated depreciation rates. The depreciation expense and related AITC associated with general plant are allocated to transmission plant in accordance with the general plant allocations as described in Section C3.2.5. The general plant depreciation expense allocated to transmission function is further allocated to the 115 kV and above facilities on the basis of depreciation expense related to the 115 kV and above facilities and the total transmission plant.

The AITC associated with the transmission plant is allocated to the transmission facilities rated 115 kV and above on the basis of the ratio of the depreciation expense of the transmission facilities rated 115 kV and above to the depreciation expense of the transmission plant.

Section C3.2.12: Real and Personal Property Taxes are assigned directly to the transmission plant. These taxes are allocated to the 115 kV and above facilities based on the ratio of the net investment in the 115 kV and above facilities to the net transmission plant. The real and personal property taxes associated with general plant are allocated to the transmission function on the basis of salaries and wages as described in Section C3.2.17 and within transmission to the facilities rated 115 kV and above on the basis of net investment.

Section C3.2.13: Payroll Taxes applicable to the 115 kV and above transmission facilities are computed in the following manner. The expected payroll tax rates are applied to the budgeted salaries and wages developed in Section C3.2.17 to obtain each function's payroll taxes. The payroll taxes reflect the use of the taxable wage base and the maximum payroll tax payable during each month of the Contract Year.

Section C3.2.14: Credits (or Debits) to Operating Expenses: The revenues classified as "Other Operating Revenue" in APC's and GaPC's budget will be credited to the operating expenses if the transmission facilities considered herein were responsible for such revenues (e.g., such revenues associated with Long Term Power sales, Short Term Power sales, and unit power sales). If the revenues for transmission service are not credited, the estimated demands associated with the revenues will be added to the demand of the affected operating company for the transmission rate calculation. Because an operating company may have operating agreements with third parties with respect to the transmission facilities considered herein, there may be revenues or expenses associated with the facilities rated 115 kV and above that will be appropriately credited or debited to the operating expenses for the affected operating company. In addition, revenues associated with the transmission facilities rated 115 kV and above that appear in the "Purchased Power Account" in APC's and GaPC's budget (e.g., such revenues from Long Term Power sales, Short Term Power sales, and unit power sales) will be credited to the operating expenses for these transmission facilities.

Section C3.2.15: Total Transmission Expenses represent the direct and allocated fixed expenses associated with the facilities considered herein and are the summation of Section C3.2.9 (Transmission Operation and Maintenance Expenses) through Section C3.2.14 (Credits (or Debits) to Operating Expenses) and is the value for "E" in the formulae in Section C3.2.

Section C3.2.16: The Cost of Capital and Associated Income Taxes are computed in the following manner:

$$CM = [(DR \times i) + (PR \times p) + (ER \times c)]$$

Where: $DR + PR + ER = 1.0$

$$IT = \frac{T}{1 - T} \times [(PR \times p) + (ER \times c)]$$

Where: $T = \frac{F + S - 2FS}{1 - FS}$ (federal income taxes deductible for state income tax purposes)

or

$T = F + S - FS$ (federal income taxes not deductible for state income tax purposes)

CM = Weighted average cost of capital (%).

IT = Income tax requirement associated with preferred stock and common equity weighted cost of capital (%).

DR = Ratio of debt capital (target ratio; includes first mortgage bonds, pollution control obligations, and capitalized leases).

PR = Ratio of preferred stock (target ratio).

ER = Ratio of common equity (target ratio).

i = Embedded cost of debt capital (%).

p = Embedded cost of preferred stock (%).

c = Return on common equity as specified in Article VI of this Unit Power Sale Manual.

T = Combined state and federal income tax rate.

F = Federal income tax rate.

S = State income tax rate.

Section C3.2.17: Salaries and Wages are budgeted and accounted for on an actual basis by APC and GaPC for each functional group. The budgeted salaries and wages account for changes in wage rates and number of employees.

The salaries and wages associated with the administrative and general classification are allocated to the functional groups based upon the ratio of the functional group's salaries and wages to the total salaries and wages less the administrative and general classification's salaries and wages.

The transmission plant salaries and wages which include the allocated A&G, are allocated to the 115 kV and above facilities based on the ratio of the net investment in the 115 kV and above facilities to the total net transmission plant investment.

ARTICLE IV

DERIVATION OF FUEL COSTS AND NORMALIZED FUEL COSTS FOR ELECTRIC GENERATING UNITS

This article of this Unit Power Sale Manual establishes the definition and provides the procedures for determining the Fuel Costs and Normalized Fuel Costs for the computation of charges for unit power sales under the UPS Agreement.

Section C4.0 Fuel Costs: The Fuel Cost ($/mWh) for a unit is defined as the cost ($) of the fuel issued from the weighted-average stockpile for the unit divided by the net electrical output (mWhs) of the unit during operation periods of the unit during the month energy was delivered under the UPS Agreement. Operation periods as used herein include all hours in which the net electrical output of the unit is greater than zero. The cost of fuel issued for the unit will be the actual monthly cost of fossil fuel issued from FERC Account 151, including the actual monthly cost of gaseous fuels charged directly to FERC Account 501. In the event that there were no operation periods of a unit during a month, the Fuel Cost for the unit for such month will be equal to the Fuel Cost for the unit in the first preceding month in which there were operation periods.

Section C4.1: Normalized Fuel Costs: The Normalized Fuel Cost ($/mWh) for a unit is defined as the average net heat rate (millions of BTU's per mWh) of such unit at a specified generation level multiplied by the actual monthly cost ($) of fossil fuel issued from FERC Account 151, including the actual monthly cost of gaseous fuels charged directly to FERC Account 501, and divided by the heat content (millions of BTU's) of such fuel issued for the month. In the event the cost of fuel issued is zero for a unit during a month, the cost of fuel issued and the associated heat content for other similar unit(s) receiving fuel from the same stockpile in that month will be used in the calculation of the Normalized Fuel Cost. Furthermore, in the event there was no fuel issued from such stockpile in that month, the cost of fuel issued and the associated heat content for the first preceding month in which there was fuel issued will be used in the calculation of the Normalized Fuel Cost. The specified generation level at which the average net heat rate is determined shall be sixty-five percent (65%) of the Net Dependable Capacity of each unit, unless otherwise mutually agreed by the parties hereto. This generation level will be reviewed periodically by the Unit Power Sales Operating Committee to determine if it shall be revised to more accurately represent the normal historical or projected output factor for each unit. The average net heat rate, as used herein, shall be calculated for each unit from the net heat rate equation which is used in the economic dispatch for Southern Companies.

ARTICLE V

DERIVATION OF FIXED OPERATION AND MAINTENANCE AND VARIABLE OPERATION AND MAINTENANCE EXPENSES FOR ELECTRIC GENERATING UNITS

This article of this Unit Power Sale Manual establishes the formulary method for deriving fixed O&M and variable O&M expenses for the computation of charges for unit power sales under the UPS Agreement.

Section C5.0 Fixed Operation and Maintenance Expenses: The fixed O&M expense ($) for a unit for the Contract Year is based upon the following components budgeted for the unit: (i) all operation supervision and engineering charged to FERC Account 500, (ii) the in-plant fuel handling expenses charged to FERC Account 501, (iii) operational labor (including overtime labor) charged to FERC Accounts 502 and 505, (iv) all miscellaneous steam power expenses charged to FERC Account 506, (v) rent charged to FERC Account 507, (vi) all maintenance supervision and engineering charged to FERC Account 510, (vii) all maintenance expenses charged to FERC Account 511, (viii) maintenance labor (including overtime labor) charged to FERC Accounts 512 and 513, and (ix) all maintenance of miscellaneous steam plant charged to FERC Account 514.

Section C5.1 Variable Operation and Maintenance Expenses: The variable O&M expenses ($/mWh) for a unit for the Contract Year shall be based upon the following components budgeted for the unit: (i) all operating material and non-labor expenses charged to FERC Accounts 502 and 505, and (ii) all maintenance material and non-labor expenses charged to FERC Accounts 512 and 513. The variable O&M expenses for the unit for the Contract Year shall be the sum of the components listed above ($) divided by the budgeted net electrical output of the unit (mWhs).

Section C5.2 Data to be Provided: The data used in the determination of the fixed and variable O&M expenses for each unit each Contract Year will be provided to the purchasers of unit power in accordance with Article VIII of this Unit Power Sale Manual.

ARTICLE VI

DERIVATION OF RETURN ON COMMON EQUITY

This article of this Unit Power Sale Manual establishes the return on common equity used in the computation of capacity charges for unit power sales under the UPS Agreement.

Section C6.0 Return on Common Equity: For the purposes of determining charges for unit power and transmission, as set forth in this Unit Power Sale Manual and the UPS Agreement, the return on common equity (c) for Southern Companies shall be thirteen and three-quarters percent (13.75%). This return on common equity will be reviewed periodically to determine if revisions are required. Any such revisions shall be made in accordance with the provisions of Section 5.3 and Section 5.5 of the UPS Agreement.

ARTICLE VII

DERIVATION OF AVERAGE TRANSMISSION LOSS PERCENTAGES

This article of this Unit Power Sale Manual establishes the average transmission loss percentages used in the computation of capacity and energy charges under the UPS Agreement.

Section C7.0 Average Transmission Loss Percentages: For the purposes of determining charges for capacity and energy, as set forth in this Unit Power Sale Manual and the UPS Agreement, the average transmission loss percentage of Southern Companies associated with capacity ($\%L_c$) and the average transmission loss percentage of Southern Companies associated with energy ($\%L_e$) shall each be three percent (3%). These average loss percentages will be reviewed periodically from annual power supply statistical reports and from load-flow studies to determine if any revisions are required. Any such revisions shall be made in accordance with the provisions of Section 5.3 of the UPS Agreement.

ARTICLE VIII

UNIT POWER SALE
INFORMATIONAL SCHEDULE AND SUPPORT SCHEDULES
AND MONTHLY REPORT OF ENERGY TRANSACTIONS

Section C8.0 Support Schedules: The development of cost components for the sale of unit power will be provided on formats mutually agreed to by the parties hereto. Such support schedules will describe the source of the data with reference to the applicable articles and sections of this Unit Power Sale Manual and will show how the data is used in the computation of cost components shown on the Unit Power Sale Informational Schedule.

Section C8.1 Unit Power Sale Informational Schedule: The results of the formulary methodology set forth in this Unit Power Sale Manual shall be displayed on a Unit Power Sale Informational Schedule for the Contract Year in a format mutually agreed to by the parties hereto.

Section C8.2 Schedules for Estimated and Actual Charges: The support schedules described in Section C8.0 shall be recomputed to include actual cost data as contemplated in Article IX of this Unit Power Sale Manual and supplied to unit power sales purchasers.

Section C8.3 Monthly Report of Energy Transactions Monthly reports shall be supplied to unit power sales purchasers, which reports will list the hourly energy transactions and the energy rates which are applicable to each hourly transaction. The energy rates used in the calculation of the energy charge for each unit during each hour will also be identified. Both preliminary and actual cost data will be supplied as provided for in Section 7.2 of the UPS Agreement.

ARTICLE IX

ADJUSTMENTS FOR ACTUAL COST

This article of this Unit Power Sale Manual establishes the formulary components of the unit power capacity charge and the transmission capacity charge which are subject to adjustment for actual cost. Such adjustments for actual cost pursuant to Section 6.2 of the UPS Agreement will be made using the applicable procedures described in Article II, Article III, and Article V of this Unit Power Sale Manual.

Section C9.0 Capacity Cost for Unit Power: The monthly capacity charges computed under Article II of this Unit Power Sale Manual for each unit participating in sales of unit power for the Contract Year will be recalculated using the formula specified in Section C2.2 and the actual cost data for the unit. All cost items contained in Article II of this Unit Power Sale Manual will be adjusted to reflect their actual costs. The adjustment will be made as soon as practicable following the end of the month, but shall be made within three (3) months of the monthly rendered bill. The capital structure and cost of debt capital and preferred stock will be modified as described in Section C2.2.16 and further as provided for in Section C2.2.19.

Section C9.1 Capacity Cost for Transmission Service: The transmission capacity cost computed under Article III of this Unit Power Sale Manual for the Contract Year will be recalculated using actual cost and load data and the formulae specified in Section C3.2. Southern Companies shall make this adjustment on a periodic basis, but not less frequently than annually as soon as practicable following the end of the Contract Year.

Section C9.2 Variable Operation and Maintenance Expenses: The variable O&M expenses as defined and computed in accordance with Article V of this Unit Power Sale Manual will be recalculated using actual data. The adjustment for variable O&M expenses will be handled separately from the energy billing. This adjustment will be made annually (or for such lesser periods as mutually agreed by the parties hereto) using the actual data for expenses and net electrical output of each unit. Such annual adjustment will be made for the Contract Year as soon as practicable following the end of the Contract Year.

Section C9.3 Administrative Cost for Adjustment Procedure: Corporation as a purchaser of unit power shall reimburse Southern Companies for its equal share of all costs incurred by Southern Companies directly in administering this Article IX of this Unit Power Sale Manual. Such costs shall be accumulated by Southern Companies at standard rates of each operating company and SCS for the services performed and shall include, but not be limited to, charges for computer time associated with the calculation of capacity charges based on actual data, personnel engaged in administering this Article IX of this Unit Power Sale Manual based on time actually spent, and materials and supplies consumed in connection with administration of this Article IX of this Unit Power Sale Manual. Such administrative charges will not be included in the development of capacity charges in Section C2.2.10.

EXHIBIT D

UNIT POWER SALE INFORMATIONAL SCHEDULE

ATTACHED FOR EXAMPLE PURPOSES ONLY

USING 1988 ESTIMATED COST

UNIT POWER SALE
INFORMATIONAL SCHEDULE
CAPACITY CHARGES FOR THE YEAR 1988 1/
($/KW-MONTH)

*** FOR ILLUSTRATIVE PURPOSES ONLY ***

	ALABAMA POWER COMPANY				GEORGIA POWER COMPANY	GULF POWER COMPANY	TRANSMISSION CHARGES FOR UNIT POWER SALES FROM	
MONTH	MILLER 1	MILLER 2	MILLER 3	MILLER 4	SCHERER 3	SCHERER 3	MILLER PLANT UNITS 1,2,3 AND 4	SCHERER PLANT UNIT 3
JAN	7.064417	12.239333	N/A	N/A	15.648750	16.288667	1.989714	1.108964
FEB	7.233500	12.402750	"	"	15.371583	15.974917	1.989714	1.108964
MAR	7.174917	12.346917	"	"	15.306000	15.874000	1.989714	1.108964
APR	7.138667	12.404083	"	"	15.426833	16.024167	1.989714	1.108964
MAY	7.198417	12.316083	"	"	15.367000	15.927833	1.989714	1.108964
JUN	7.180333	12.301333	"	"	15.354917	15.860917	1.993348	1.110115
JUL	7.219250	12.345000	"	"	15.389333	15.918167	1.993348	1.110115
AUG	7.246417	12.349917	"	"	17.661250	15.796167	1.993348	1.110115
SEP	7.239250	12.290500	"	"	17.795250	15.773250	1.993348	1.110115
OCT	7.317583	12.424583	"	"	17.842167	15.826583	1.993348	1.110115
NOV	7.052167	12.211833	"	"	17.664500	15.654917	1.993348	1.110115
DEC	7.160833	12.152500	"	"	17.578333	15.525667	1.993348	1.110115

NOTE: CAPACITY CHARGES ARE CALCULATED USING A 13.75% RETURN ON EQUITY.

REFERENCES:

MILLER 1,2,3 AND 4 -- ARTICLE II, SECTION C2.2
SCHERER 3 -- ARTICLE II, SECTION C2.2
TRANSMISSION -- ARTICLE III, SECTION C3.2

1/ DATA FOR ILLUSTRATIVE PURPOSES BASED ON 1988 ESTIMATED COST AND DATA FOR MILLER PLANT UNITS 3 & 4 NOT APPLICABLE TO 1988.

UNIT POWER SALE
INFORMATIONAL SCHEDULE
FORMULA DATA INPUT FOR CAPACITY CHARGE
FOR THE YEAR 1988
SECTION C2.2

ALABAMA POWER COMPANY
MILLER 1

MONTH	C -KW-	I -$-	E -$-	CM -%-	IT -%-
JANUARY	667,300.	220,706,255.	23,880,456.	10.805	3.237
FEBRUARY	667,300.	227,279,870.	24,268,500.	10.806	3.237
MARCH	667,300.	226,431,902.	23,932,176.	10.806	3.237
APRIL	667,300.	220,170,057.	24,530,304.	10.806	3.237
MAY	667,300.	226,294,995.	24,132,468.	10.807	3.237
JUNE	667,300.	226,957,931.	23,898,420.	10.807	3.237
JULY	667,300.	228,598,723.	23,972,700.	10.807	3.236
AUGUST	667,300.	228,203,831.	24,230,548.	10.807	3.236
SEPTEMBER	667,300.	229,432,936.	24,010,944.	10.807	3.236
OCTOBER	667,300.	230,004,003.	24,538,848.	10.807	3.236
NOVEMBER	667,300.	216,559,007.	24,365,100.	10.807	3.236
DECEMBER	667,300.	219,036,521.	24,061,456.	10.807	3.236

NOTE: MONTHLY CAPACITY CHARGE IS CALCULATED USING A 13.75% RETURN ON COMMON EQUITY.

UNIT POWER SALE
INFORMATIONAL SCHEDULE
FORMULA DATA INPUT FOR CAPACITY CHARGE
FOR THE YEAR 1988
SECTION C2.2

ALABAMA POWER COMPANY
MILLER 2

MONTH	C -KW-	I -$-	E -$-	CM -%-	IT -%-
JANUARY	667,400.	438,682,913.	30,582,516.	11.234	3.469
FEBRUARY	667,400.	445,073,157.	30,912,308.	11.234	3.469
MARCH	667,400.	444,395,879.	30,573,156.	11.235	3.469
APRIL	667,400.	442,742,918.	31,261,092.	11.235	3.469
MAY	667,400.	441,338,116.	30,783,348.	11.235	3.469
JUNE	667,400.	441,622,235.	30,627,504.	11.235	3.469
JULY	667,400.	444,190,270.	30,633,312.	11.229	3.465
AUGUST	667,400.	443,021,513.	30,843,324.	11.229	3.465
SEPTEMBER	667,400.	440,914,475.	30,690,852.	11.229	3.465
OCTOBER	667,400.	440,882,846.	31,777,392.	11.223	3.462
NOVEMBER	667,400.	435,870,170.	30,860,988.	11.223	3.462
DECEMBER	667,400.	432,517,884.	30,892,020.	11.223	3.462

NOTE: MONTHLY CAPACITY CHARGE IS CALCULATED USING A 13.75% RETURN ON COMMON EQUITY.

UNIT POWER SALE
INFORMATIONAL SCHEDULE
FORMULA DATA INPUT FOR CAPACITY CHARGE
FOR THE YEAR 1988
SECTION C2.2

GEORGIA POWER COMPANY
SCHERER 3

MONTH	C -KW-	I -$-	E -$-	CM -%-	IT -%-
JANUARY	636,525.	529,822,594.	24,109,608.	13.343	3.990
FEBRUARY	636,525.	522,963,521.	23,255,604.	13.341	3.990
MARCH	636,525.	521,232,042.	23,085,516.	13.338	3.990
APRIL	636,525.	520,076,628.	24,180,864.	13.338	3.990
MAY	636,525.	518,837,911.	23,952,120.	13.338	3.990
JUNE	636,525.	522,281,767.	23,265,492.	13.338	3.990
JULY	636,525.	521,075,264.	23,729,772.	13.338	3.990
AUGUST	636,525.	621,255,072.	24,763,248.	13.109	3.968
SEPTEMBER	636,525.	618,722,991.	26,188,692.	13.109	3.968
OCTOBER	636,525.	616,966,246.	26,836,212.	13.109	3.968
NOVEMBER	636,525.	614,477,490.	25,944,804.	13.109	3.968
DECEMBER	636,525.	609,468,934.	26,844,816.	13.109	3.968

NOTE: MONTHLY CAPACITY CHARGE IS CALCULATED USING A 13.75% RETURN ON COMMON EQUITY.

UNIT POWER SALE
INFORMATIONAL SCHEDULE
FORMULA DATA INPUT FOR CAPACITY CHARGE
FOR THE YEAR 1988
SECTION C2.2

GULF POWER COMPANY
SCHERER 3

MONTH	C -KW-	I -$-	E -$-	CM -%-	IT -%-
JANUARY	212,175.	185,805,741.	10,852,476.	12.227	3.583
FEBRUARY	212,175.	182,957,896.	10,527,816.	12.227	3.583
MARCH	212,175.	181,869,893.	10,458,512.	12.227	3.583
APRIL	212,175.	181,318,882.	10,908,672.	12.227	3.583
MAY	212,175.	180,409,586.	10,814,508.	12.227	3.583
JUNE	212,175.	181,119,220.	10,536,960.	12.227	3.583
JULY	212,175.	180,896,467.	10,713,456.	12.227	3.583
AUGUST	212,175.	179,764,801.	10,591,188.	12.227	3.583
SEPTEMBER	212,175.	179,028,973.	10,651,128.	12.227	3.583
OCTOBER	212,175.	178,554,139.	10,859,364.	12.227	3.582
NOVEMBER	212,175.	177,773,813.	10,560,708.	12.226	3.582
DECEMBER	212,175.	174,625,905.	10,739,232.	12.226	3.582

NOTE: MONTHLY CAPACITY CHARGE IS CALCULATED USING A 13.75% RETURN ON COMMON EQUITY.

UNIT POWER SALE
INFORMATIONAL SCHEDULE
FORMULA DATA INPUT FOR COST OF CAPITAL
FOR THE YEAR 1988
SECTION C2.2.16

ALABAMA POWER COMPANY
MILLER 1

	CAPITALIZATION RATIOS			EMBEDDED COST DEBT	EMBEDDED COST PREFERRED	RETURN ON COMMON EQUITY	TAX RATES	
MONTH	DR	PR	ER	I	P	C	F	S
JANUARY	55.4326	11.9859	32.5815	9.2104	10.1759	13.75	34.0	5.0
FEBRUARY	55.4326	11.9859	32.5815	9.2112	10.1756	13.75	34.0	5.0
MARCH	55.4326	11.9859	32.5815	9.2120	10.1753	13.75	34.0	5.0
APRIL	55.4326	11.9859	32.5815	9.2127	10.1749	13.75	34.0	5.0
MAY	55.4326	11.9859	32.5815	9.2135	10.1746	13.75	34.0	5.0
JUNE	55.4326	11.9859	32.5815	9.2144	10.1741	13.75	34.0	5.0
JULY	55.4326	11.9859	32.5815	9.2149	10.1680	13.75	34.0	5.0
AUGUST	55.4326	11.9859	32.5815	9.2155	10.1674	13.75	34.0	5.0
SEPTEMBER	55.4326	11.9859	32.5815	9.2161	10.1669	13.75	34.0	5.0
OCTOBER	55.4326	11.9859	32.5815	9.2163	10.1605	13.75	34.0	5.0
NOVEMBER	55.4326	11.9859	32.5815	9.2167	10.1596	13.75	34.0	5.0
DECEMBER	55.4326	11.9859	32.5815	9.2171	10.1589	13.75	34.0	5.0

UNIT POWER SALE
INFORMATIONAL SCHEDULE
FORMULA DATA INPUT FOR COST OF CAPITAL
FOR THE YEAR 1988
SECTION C2.2.16

ALABAMA POWER COMPANY
MILLER 2

	CAPITALIZATION RATIOS			EMBEDDED COST		RETURN ON COMMON EQUITY	TAX RATES	
				DEBT	PREFERRED			
MONTH	DR	PR	ER	I	P	C	F	S
JANUARY	52.6731	10.0964	37.2305	9.7306	9.8012	13.75	34.0	5.0
FEBRUARY	52.6731	10.0964	37.2305	9.7309	9.8012	13.75	34.0	5.0
MARCH	52.6731	10.0964	37.2305	9.7313	9.8012	13.75	34.0	5.0
APRIL	52.6731	10.0964	37.2305	9.7318	9.8012	13.75	34.0	5.0
MAY	52.6731	10.0964	37.2305	9.7321	9.8010	13.75	34.0	5.0
JUNE	52.6731	10.0964	37.2305	9.7324	9.8012	13.75	34.0	5.0
JULY	52.6731	10.0964	37.2305	9.7328	9.7381	13.75	34.0	5.0
AUGUST	52.6731	10.0964	37.2305	9.7330	9.7380	13.75	34.0	5.0
SEPTEMBER	52.6731	10.0964	37.2305	9.7331	9.7378	13.75	34.0	5.0
OCTOBER	52.6731	10.0964	37.2305	9.7334	9.6748	13.75	34.0	5.0
NOVEMBER	52.6731	10.0964	37.2305	9.7336	9.6745	13.75	34.0	5.0
DECEMBER	52.6731	10.0964	37.2305	9.7336	9.6745	13.75	34.0	5.0

UNIT POWER SALE
INFORMATIONAL SCHEDULE
(OWNED CAPACITY)
FORMULA DATA INPUT FOR COST OF CAPITAL
FOR THE YEAR 1988
SECTION C2.2.16

GEORGIA POWER COMPANY
SCHERER 3

	CAPITALIZATION RATIOS			EMBEDDED COST DEBT	EMBEDDED COST PREFERRED	RETURN ON COMMON EQUITY	TAX RATES	
MONTH	DR	PR	ER	I	P	C	F	S
JANUARY	50.8561	9.6287	39.5152	13.2954	11.9288	13.75	34.0	5.66
FEBRUARY	50.8561	9.6287	39.5152	13.2985	11.9287	13.75	34.0	5.66
MARCH	50.8561	9.6287	39.5152	13.2853	11.9287	13.75	34.0	5.66
APRIL	50.8561	9.6287	39.5152	13.2849	11.9286	13.75	34.0	5.66
MAY	50.8561	9.6287	39.5152	13.2845	11.9285	13.75	34.0	5.66
JUNE	50.8561	9.6287	39.5152	13.2845	11.9285	13.75	34.0	5.66
JULY	50.8561	9.6287	39.5152	13.2843	11.9285	13.75	34.0	5.66
AUGUST	50.8561	9.6287	39.5152	12.9050	11.5535	13.75	34.0	5.66
SEPTEMBER	50.8561	9.6287	39.5152	12.9849	11.5533	13.75	34.0	5.66
OCTOBER	50.8561	9.6287	39.5152	12.9849	11.5534	13.75	34.0	5.66
NOVEMBER	50.8561	9.6287	39.5152	12.9848	11.5533	13.75	34.0	5.66
DECEMBER	50.8561	9.6287	39.5152	12.9849	11.5533	13.75	34.0	5.66

UNIT POWER SALE
INFORMATIONAL SCHEDULE
FORMULA DATA INPUT FOR COST OF CAPITAL
FOR THE YEAR 1988
SECTION C2.2.16

GULF POWER COMPANY
SCHERER 3

	CAPITALIZATION RATIOS			EMBEDDED COST DEBT	EMBEDDED COST PREFERRED	RETURN ON COMMON EQUITY	TAX RATES	
MONTH	DR	PR	ER	I	P	C	F	S
JANUARY	55.5324	8.2415	36.2261	11.3255	11.6113	13.75	34.0	5.5
FEBRUARY	55.5324	8.2415	36.2261	11.3253	11.6111	13.75	34.0	5.5
MARCH	55.5324	8.2415	36.2261	11.3253	11.6107	13.75	34.0	5.5
APRIL	55.5324	8.2415	36.2261	11.3252	11.6105	13.75	34.0	5.5
MAY	55.5324	8.2415	36.2261	11.3251	11.6103	13.75	34.0	5.5
JUNE	55.5324	8.2415	36.2261	11.3251	11.6099	13.75	34.0	5.5
JULY	55.5324	8.2415	36.2261	11.3249	11.6096	13.75	34.0	5.5
AUGUST	55.5324	8.2415	36.2261	11.3249	11.6093	13.75	34.0	5.5
SEPTEMBER	55.5324	8.2415	36.2261	11.3247	11.6090	13.75	34.0	5.5
OCTOBER	55.5324	8.2415	36.2261	11.3245	11.6086	13.75	34.0	5.5
NOVEMBER	55.5324	8.2415	36.2261	11.3244	11.6083	13.75	34.0	5.5
DECEMBER	55.5324	8.2415	36.2261	11.3243	11.6080	13.75	34.0	5.5

UNIT POWER SALE
INFORMATIONAL SCHEDULE
FORMULA DATA INPUT FOR CAPACITY CHARGES
FOR TRANSMISSION FACILITIES RATED 115KV AND ABOVE
SECTION C3.2

JANUARY-MAY	D -KW-	I -$-	E -$-	CM -%-	IT -%-
ALABAMA	7,528,265	362,501,474	24,507,783	10.93	3.60
GEORGIA	10,001,852	670,345,042	25,538,972	11.45	4.00

JUNE-DECEMBER	D -KW-	I -$-	E -$-	CM -%-	IT -%-
ALABAMA	7,528,265	362,501,474	24,507,783	10.99	3.60
GEORGIA	10,001,852	670,345,042	25,538,972	11.46	4.01

NOTE: CAPACITY CHARGE IS CALCULATED USING A 13.75% RETURN ON COMMON EQUITY.

FPSC DOCKET NO. 941101-EQ
FPC WITNESS: **SOUTHWICK**
EXHIBIT NO. _____ (HIS-3)
CONSISTING OF 3 PAGES

		Base Case	Change Case	Difference	Simulation Notes
10/19/94 analysis					
	Energy $	$881,379	$873,683	$7,696	CR1 cycled off 6 hours. CR2 cycled off 5 hours.
	Start-up $	$0	$17,404	($17,404)	
	Total $	$881,379	$891,087	($9,708)	
		Avoided Cost Impact		($9,708)	
		Avoided Cost Per MWH		($16.18)	
01/01/95 analysis					
	Energy $	$526,323	$528,585	($2,262)	CR2 already off. CR1 cycled off all day. UC did not start a coal unit until the following day.
	Start-up $	$0	$53	($53)	
	Total $	$526,323	$528,638	($2,315)	
		Avoided Cost Impact		($2,315)	
		Avoided Cost Per MWH		($6.77)	
01/02/95 analysis					
	Energy $	$573,898	$603,094	($29,196)	CR2 already off. CR1 cycled off 6 hours.
	Start-up $	$343	$11,235	($10,892)	
	Total $	$574,241	$614,329	($40,088)	
		Avoided Cost Impact		($40,088)	
		Avoided Cost Per MWH		($27.36)	
01/07/95 analysis					
	Energy $	$636,945	$625,746	$11,199	CR2 cycled off 5 hours. CR4 cycled off all day.
	Start-up $	$0	$15,879	($15,879)	
	Total $	$636,945	$641,625	($4,680)	
		Avoided Cost Impact		($4,680)	
		Avoided Cost Per MWH		($3.03)	
01/08/95 analysis					
	Energy $	$819,591	$814,451	$5,140	CR4 and Bartow 1 already off. Both units restarted after curtailment.
	Start-up $	$2,993	$36,077	($33,084)	
	Total $	$822,584	$850,528	($27,944)	
		Avoided Cost Impact		($27,944)	
		Avoided Cost Per MWH		($120.45)	
01/14/95 analysis					
	Energy $	$579,031	$576,824	$2,207	CR2 already off. CR1 cycled off 6 hours.
	Start-up $	$0	$11,055	($11,055)	
	Total $	$579,031	$587,879	($8,848)	
		Avoided Cost Impact		($8,848)	
		Avoided Cost Per MWH		($66.06)	
01/30/95 analysis					
	Energy $	$806,294	$806,293	$1	CR2 already off. CR1 cycled off 7 hours. CR4 cycled off 6 hours
	Start-up $	$27,846	$44,312	($16,466)	
	Total $	$834,140	$850,605	($16,465)	
		Avoided Cost Impact		($16,465)	
		Avoided Cost Per MWH		($35.79)	

Base Case - Costs considering curtailment occurred.
Change Case - Costs had no curtailment been implemented.

MANUAL DEMONSTRATION OF NEGATIVE AVOIDED COST FOR FPC'S FIRST SEVEN CURTAILMENT EVENTS

	CURTAILMENT EVENTS							
Costs	Oct 19, 1994	Jan 1, 1995	Jan 2, 1995	Jan 7, 1995	Jan 8, 1995	Jan 14, 1995	Jan 30, 1995	Average
A) Effect of start-up cost:								
Avoided energy cost - $	9,228	6,921	22,885	17,349	4,999	1,961	6,152	9,928
Unit Start-up Cost - $	(25,626)	(12,813)	(25,626)	(26,626)	(12,813)	(12,813)	(12,813)	(18,304)
Subtotal - avoided cost - $	(16,398)	(5,892)	(2,740)	(8,277)	(7,814)	(10,852)	(6,661)	(8,376)
Avoided energy cost - $/MWH	(27.33)	(13.09)	(1.84)	(7.34)	(24.04)	(85.11)	(16.65)	(12.98)
B) Effect of replacement energy:								
Previous subtotal - $	(16,398)	(5,892)	(2,740)	(8,277)	(7,814)	(10,852)	(6,661)	(8,376)
Replacement Energy Cost - $[1]	(7,743)	(3,306)	(6,612)	(7,743)	(4,695)	(4,695)	(3,872)	(5,524)
Subtotal - avoided cost - $	(24,141)	(9,198)	(9,352)	(16,020)	(12,510)	(15,547)	(10,532)	(13,900)
Avoided energy cost - $/MWH	(40.23)	(20.44)	(6.28)	(14.20)	(38.49)	(121.94)	(26.33)	(21.53)
C) Effect of other unit impact costs:								
Previous subtotal - $	(24,141)	(9,198)	(9,352)	(16,020)	(12,510)	(15,547)	(10,532)	(13,900)
Other unit impact costs - $[2]	(34,374)	(17,187)	(34,374)	(34,374)	(17,187)	(17,187)	(17,187)	(24,553)
Total avoided energy cost - $	(58,515)	(26,385)	(43,726)	(50,395)	(29,697)	(32,734)	(27,720)	(38,453)
Avoided energy cost - $/MWH	(97.53)	(58.63)	(29.39)	(44.68)	(91.38)	(256.74)	(69.30)	(59.57)

[1] Derived from actual 1994 Crystal River Unit start-up experience

[2] Other unit impact costs assumes the most conservative, low-end estimate of cycling costs of $30,000 per unit per event less unit start-up costs identified in part (A).