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 <u>Determination of Capacity Available from Each Unit</u>: 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 Character of Sale: 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 Unavailability or Rating Change of Units: 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 <u>Option to Furnish Scheduled Energy from Alternate Resources</u>: 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 Supplemental Energy Scheduling: 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 <u>Limitation of Transmission Facilities</u>: 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 Unit Power Sale Informational Schedule: 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 Unilateral Revision of Capacity and Energy Rates and/or Unit Power Sale Periodic Rate Computation Procedure Manual: 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 <u>Base Energy Rates</u>: 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 <u>Alternate Energy Rates</u>: 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 Supplemental Energy Rates: 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 Normalized Energy Rates: 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,

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

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:

$$WAER = \frac{UPC_1 \text{ X } ER_1}{UPC_1 + UPC_2 + \ldots UPC_N} + \ldots + \frac{UPC_N \text{ x } ER_N}{UPC_1 + UPC_2 + \ldots + UPC_N}$$

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 of 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 <u>Presentation and Payment of Bills for Energy and Other Charges</u>: 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 <u>Disputed Invoice</u>: 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 <u>Audit Rights and Finality of Bills</u>: 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 (<u>e.g.</u>, 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.

FLORIDA POWER CORP. LEGAL DEPT. APPROVED Date 7-15-88 By

ATTEST:	FLORIDA POWER CORPORATION
Kathleen P. Kortright Assistant Secretary	By B. L. Griffin, Exec. Vice President Date: July 18, 1988
ATTEST:	SOUTHERN COMPANY SERVICES, INC.
Wayne Boston Asst Secretary	By R. O. Usry R. O. Usry, Vice President Date: July 19, 1988
ATTEST:	ALABAMA POWER COMPANY
Wayne Boston Asst Secretary	By R. E. Huffman R. E. Huffman, Vice President Date: July 19, 1988
ATTEST:	GEORGIA POWER COMPANY
Wayne Boston Asst Secretary	By Fred D. Williams Fred D. Williams, Vice President Date: July 19 1988
ATTEST:	GULF POWER COMPANY
Wayne Boston Asst Secretary	By Earl B. Parsons Jr. E. B. Parsons, Jr., Vice President Date: July 19, 1988
ATTEST:	MISSISSIPPI POWER COMPANY
Wayne Boston Asst Secretary	By Robert C. Robert C. Pierce, Vice President Date: July 19, 1988
ATTEST:	SAVANNAH ELECTRIC AND POWER COMPANY
Wayne Boston Asst Secretary	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.

<u>Section B3.3</u>: 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.

<u>Section B3.4</u>: 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 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:

Section M2.2.1: Rated Production Capability 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.

Section M2.2.2: Gross Production Investment 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.

Section M2.2.3: Accumulated Depreciation 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.

Section M2.2.4: Net Production Investment 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 $$IT_i = IT_n \text{ or } IT_g$$

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

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

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

Where: $T = \dfrac{F + S - 2FS}{1 - FS}$ (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.

<u>Section M2.2.16</u>: <u>Salaries and Wages</u> 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:

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

where:

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

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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.

<u>EXHIBIT D</u>

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.	24,238,548.	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.	24,861,456.	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.	30,912,300.	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.	605,468,934.	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.	10,450,512.	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.	177,773,013.	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.

INFORMATIONAL SCHEDULE
7/14/88

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

MONTH	CAPITALIZATION RATIOS DR	PR	ER	EMBEDDED COST DEBT I	PREFERRED P	RETURN ON COMMON EQUITY C	TAX RATES 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	13.2905	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	12.9049	11.5533	13.75	34.0	5.66
OCTOBER	50.8561	9.6287	39.5152	12.9049	11.5534	13.75	34.0	5.66
NOVEMBER	50.8561	9.6287	39.5152	12.9048	11.5533	13.75	34.0	5.66
DECEMBER	50.8561	9.6287	39.5152	12.9049	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.