AMENDMENT NO. 1
TO AMENDED AND RESTATED
UNIT POWER SALES AGREEMENT
BETWEEN
FLORIDA POWER & LIGHT COMPANY
AND
ALABAMA POWER COMPANY, GEORGIA POWER COMPANY,
GULF POWER COMPANY, MISSISSIPPI POWER COMPANY,
AND SOUTHERN COMPANY SERVICES, INC.

THIS AMENDMENT made and entered into effective May 18th, 1982, by and between FLORIDA POWER & LIGHT COMPANY ("FPL") and ALABAMA POWER COMPANY, GEORGIA POWER COMPANY, GULF POWER COMPANY AND MISSISSIPPI POWER COMPANY ("Southern Companies") and SOUTHERN COMPANY SERVICES, INC. ("SCS"), being Amendment No. 1 to the Amended and Restated Unit Power Sales Agreement (the "Agreement") between FPL, Southern Companies and SCS dated February 18, 1982.

W I T N E S S E T H:

WHEREAS, FPL, Southern Companies and SCS entered into the Agreement on February 18, 1982; and

WHEREAS, the parties desire to amend the Agreement to reflect the product of certain agreements reached with Jacksonville Electric Authority ("JEA") as a Contemporaneous Party under the Agreement with respect to capacity sales after December 31, 1992; and

WHEREAS, the parties desire to reflect certain other changes in the Agreement.

NOW, THEREFORE, in consideration of the premises and the terms and conditions set forth herein, the parties hereto agree to amend the Agreement as follows:

1. Reference in Section 1.1 of the Agreement to "Sections 2.2.5 and 2.2.6" is hereby deleted and "Section 2.2.4" is substituted therefor.

2. Section 2.2 of the Agreement is hereby amended by striking the last three (3) lines of the table showing Contract Period and Capacity sold and substituting therefor the following:

Contract Period	Capacity (Megawatts)
Jan. 1, 1993-May 31, 1993	1,667
June 1, 1993-May 31, 1994	1,000
June 1, 1994-May 31, 1995	500

3. Section 2.2.3 is hereby stricken in its entirety.

4. Section 2.2.4 is hereby renumbered Section 2.2.3.

5. Sections 2.2.5 and 2.2.6 are hereby stricken in their entirety and the following is substituted therefor as Section 2.2.4:

> 2.2.4 Southern Companies and FPL agree to negotiate in good faith, together with the other Contemporaneous Party, prior to January 1, 1986 to determine to what extent, if any, additional unit power capacity from coal-fired generating resources can be made available for contract periods after December 31, 1992 to provide for a more orderly decrease in capacity sales. If, prior to the year 1993, Southern Companies offer to sell additional unit power capacity from coal-fired generating resources to utilities outside of the geographical areas served by Southern Companies during the years 1993 through 1997, FPL and the other Contemporaneous Party

shall each have the right of first refusal for the purchase of any part or all of its pro rata share of such capacity for the period of time it may require; provided, however, such right must be exercised within ninety (90) days after written notice from Southern Companies informing FPL of such capacity being made available for sale and the terms and conditions of each offer. FPL and the other Contemporaneous Party shall, prior to the end of such ninety (90) day period, notify Southern Companies of its election to purchase any part or all of its pro rata share of such capacity based upon the amount of unit power capacity each has agreed to purchase under its Unit Power Sales Agreement for the month of December 1992 at the time such additional capacity is offered by Southern Companies, and each Contemporaneous Party shall give notice whether it elects to purchase any capacity refused by the other Contemporaneous Party. In the absence of any adjustment pursuant to this Section 2.2.4, this Agreement shall terminate on June 1, 1995.

6. Exhibit A to the Agreement is hereby stricken in its entirety and Exhibit A - Amendment No. 1, which is attached hereto and made a part hereof, is hereby substituted therefor. All references in the Agreement to Exhibit A shall hereafter be construed to refer to Exhibit A - Amendment No. 1.

7. Exhibit B to the Agreement is hereby stricken in its entirety and Exhibit B - Amendment No. 1, which is attached hereto and made a part hereof, is hereby substituted therefor. All references in the Agreement to Exhibit B shall hereafter be construed to refer to Exhibit B - Amendment No. 1.

All other terms and conditions of the Agreement shall remain in full force and effect.

[The next page is the signature page, Page 4]

IN WITNESS WHEREOF, the parties hereto have caused this Amendment No. 1 to the Amended and Restated Unit Power Sales Agreement to be executed by their duly authorized officers effective as of the date first shown above.

ATTEST:

ASSISTANT SECRETARY

FLORIDA POWER & LIGHT COMPANY

By ____________________
J. J. Hudiburg
President
Date: May 18, 1982

ATTEST:

SOUTHERN COMPANY SERVICES, INC.

By ____________________
R. O. Usry
Vice President
Date: May 18, 1982

ATTEST:

ALABAMA POWER COMPANY

By ____________________
R. E. Huffman
Vice President
Date: May 18, 1982

ATTEST:

GEORGIA POWER COMPANY

By ____________________
A. W. Dahlberg
Vice President
Date: May 18, 1982

ATTEST:

GULF POWER COMPANY

By ____________________
E. B. Parsons, Jr.
Vice President
Date: May 18, 1982

ATTEST:

MISSISSIPPI POWER COMPANY

By ____________________
H. H. Bell, Jr.
Vice President
Date: May 18, 1982

ALLOCATION OF EXPECTED CAPACITY FOR UNIT POWER SALES TO FPL

		ALABAMA POWER COMPANY (APC)					GEORGIA POWER COMPANY (GaPC)							GULF POWER COMPANY (GuPC)					MISSISSIPPI POWER COMPANY (MPC)			TOTAL SALES
YEAR	PERIOD	MIL(1) 1	MIL(1) 2	MIL(1) 3	MIL(1) 4	ALA TOT	SCH1(1) 8.4%	SCH1(1) BB	SCH2(1) 8.4%	SCH2(1) BB	SCH3(1) 75.%	SCH4(1) 75.%	GaPC TOT	DAN1(1) 50.%	DAN2(1) 50.%	SCH3(1,2) 25.%	SCH4(1,2) 25.%	GuPC TOT	DAN1(1) 50.%	DAN2(1) 50.%	MPC TOT	
1983	Jan-May						37	185					222	64	64			128				350
	Jun-Dec						37	185					222	64	64			128				350
1984	Jan	68				68	47	348					395	93	94			187				650
	Feb-May	68				68	47	130	47	197			421	80	81			161				650
	Jun-Dec	88				88	30	117	30	163			340	82	82			164	29	29	58	650
1985	Jan-Apr	453				453	46	347	46	446			885	148	146			294	34	34	68	1700
	May	453				453	46	347	46	446			885	148	146			294	34	34	68	1700
	Jun-Dec	353	377			730	39	262	39	344			684	116	114			230	28	28	56	1700
1986	Jan-May	277	377			654	39	248	39	330			656	145	143			288	51	51	102	1700
	Jun-Dec	332	377			709	39	220	39	303			601	145	143			288	51	51	102	1700
1987	Jan	261	381			642	39	208	39	291	346		923	146	145	115		406		29	29	2000
	Feb-May	261	381			642	39	208	39	291	346		923	146	145	115		406		29	29	2000
	Jun-Dec	345	380			725	39	181	39	264	346		869	132	130	115		377		29	29	2000
1988	Jan-May	326	392			718	40	171	40	257	356		864	136	134	119		389		29	29	2000
	Jun-Dec	352	392			744	40	143	40	229	356		808	151	149	119		419		29	29	2000
1989	Jan	381	392			773	40	129	40	214	356		779	151	149	119		419		29	29	2000
	Feb-Apr	235	392			627	40	129	40	214	356	356	1135			119	119	238				2000
	May		235	392		627	40	129	40	214	356	356	1135			119	119	238				2000
	Jun-Dec		292	392		684	40	100	40	186	356	356	1078			119	119	238				2000
1990	Jan-May		321	392		713	40	86	40	171	356	356	1049			119	119	238				2000
	Jun-Dec		378	392		770	40	57	40	143	356	356	992			119	119	238				2000
1991	Jan-Apr	14	392	392		798	40	43	40	129	356	356	964			119	119	238				2000
	May		14	392	392	798	40	43	40	129	356	356	964			119	119	238				2000
	Jun-Dec		72	392	392	856	40	14	40	100	356	356	906			119	119	238				2000
1992	Jan-May		100	392	392	884	40		40	86	356	356	878			119	119	238				2000
	Jun-Dec				555	555	57		57	60	476	477	1127			159	159	318				2000
1993	Jan-May				555	555					417	417	834			139	139	278				1667
	Jun-Dec				555	555					110	110	220			112	113	225				1000
1994	Jan-May				555	555					110	110	220			112	113	225				1000
	Jun-Dec				278	278					55	55	110			56	56	112				500
1995	Jan-May				278	278					55	55	110			56	56	112				500

Notes: (1) Mil 1 - Miller 1, Actual Commercial Operation 10-12-78, "Expected Capacity": 666MW
Mil 2 - Miller 2, Expected Commercial Operation 5-1-85, "Expected Capacity": 666MW
Mil 3 - Miller 3, Expected Commercial Operation 5-1-89, "Expected Capacity": 666MW
Mil 4 - Miller 4, Expected Commercial Operation 5-1-91, "Expected Capacity": 666MW
SCH 1 - Scherer 1, Expected Commercial Operation 2-1-82, "Expected Capacity": 808MW
SCH1 BB - Buy-Back
SCH2 - Scherer 2, Expected Commercial Operation 2-1-84, "Expected Capacity": 808MW
SCH2 BB - Buy-Back
SCH3 - Scherer 3, Expected Commercial Operation 2-1-87, "Expected Capacity": 808MW
SCH4 - Scherer 4, Expected Commercial Operation 2-1-89, "Expected Capacity": 808MW
Dan1 - Daniel 1, Actual Commercial Operation 9-6-77, "Expected Capacity": 512MW
Dan2 - Daniel 2, Actual Commercial Operation 6-1-81, "Expected Capacity": 506MW

(2) In the event Gulf Power Company does not purchase a 25% interest in Scherer 3 and 4, or in the event Gulf purchases a different percentage interest, the allocations of Scherer 3 and 4 between Georgia Power Company and Gulf Power Company shall be adjusted accordingly.

EXHIBIT A - AMENDMENT NO. 1
Revised 2/15/82

ALLOCATION OF EXPECTED CAPACITY FOR UNIT POWER SALES TO FPL

		ALABAMA POWER COMPANY (APC)					GEORGIA POWER COMPANY (GaPC)							GULF POWER COMPANY (GuPC)					MISSISSIPPI POWER COMPANY (MPC)			TOTAL SALES
YEAR	PERIOD	MIL(1) 1	MIL(1) 2	MIL(1) 3	MIL(1) 4	ALA TOT	SCH1(1) 8.4%	SCH1(1) BB	SCH2(1) 8.4%	SCH2(1) BB	SCH3(1) 75.%	SCH4(1) 75.%	GaPC TOT	DAN1(1) 50.%	DAN2(1) 50.%	SCH3(1,2) 25.%	SCH4(1,2) 25.%	GuPC TOT	DAN1(1) 50.%	DAN2(1) 50.%	MPC TOT	
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	May	453				453	46	347	46	446			885	148	146			294	34	34	68	1700
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	Feb-Apr	235	392			627	40	129	40	214	356	356	1135			119	119	238				2000
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1990	Jan-May		321	392		713	40	86	40	171	356	356	1049			119	119	238				2000
	Jun-Dec		378	392		770	40	57	40	143	356	356	992			119	119	238				2000
1991	Jan-Apr	14	392	392		798	40	43	40	129	356	356	964			119	119	238				2000
	May		14	392	392	798	40	43	40	129	356	356	964			119	119	238				2000
	Jun-Dec		72	392	392	856	40	14	40	100	356	356	906			119	119	238				2000
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(2) In the event Gulf Power Company does not purchase a 25% interest in Scherer 3 and 4, or in the event Gulf purchases a different percentage interest, the allocations of Scherer 3 and 4 between Georgia Power Company and Gulf Power Company shall be adjusted accordingly.

EXHIBIT B - AMENDMENT NO. 1

ADDENDUM TO
FPL-SOUTHERN COMPANIES UNIT POWER SALES AGREEMENT

UNIT POWER SALE PERIODIC RATE
COMPUTATION PROCEDURE MANUAL OF SOUTHERN COMPANIES

Section 0.0 Description and Purpose of this Manual: This addendum to the FPL-Southern Companies Amended and Restated Unit Power Sales Agreement entered into the 18th day of May, 1982, contains a formulary description of the methodology and procedure used to calculate the charges for each Contract Year for the electric services provided for in the Agreement. The term "Contract Year" as used herein shall mean calendar year. 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 Charges for Coal-Fired Electric Generating Units
- Article III - Derivation of the Capacity Charges for Transmission Line Facilities
- Article IV - Derivation of Fuel Costs and Normalized Fuel Costs for Electric Generating Units
- Article V - Derivation of Fixed Operation and Maintenance, Variable Operation and Maintenance, and In-Plant Fuel Handling 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 Support Schedules and Informational Schedules, and Monthly Statement of Energy Transactions
- Article IX - Adjustments for Actual Cost

Section 0.1 Allocation Methods and Procedures: The allocation methods and procedures set forth in this Unit Power Sale Manual have been developed with reference to the 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 the Southern Companies, provided such changed allocation methods and procedures are fair and equitable.

<u>Section 0.2</u> <u>"Uniform System of Accounts"</u>: The accounts set forth in this Unit Power Sale Manual are currently prescribed in the Federal Energy Regulatory Commission's (FERC) "Uniform System of Accounts Prescribed for Public Utilities and Licensees (Class A and Class B)" in effect as of the date of this Agreement. If these 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 the 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 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 the operating companies of Southern Companies.

Section 1.0 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 (kWh) of each unit will be determined for the highest four (4) continuous hours during the peak-period (hours between 7 a.m. and 9 p.m. - prevailing Central Time), without overpressure, for five (5) different days during July and August of the year preceding the Contract Year. 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 1.1 and 1.2 below.

Section 1.1 Adjustments for Unusual Circumstances: In the event unusual circumstances occur during the months of July and August preceding the Contract Year or circumstances during the Contract Year are expected to be significantly different from those during such July and August, in the sole opinion of the company responsible for operating the unit, such 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 1.0 and the method used to establish the Net Dependable Capacity for the Contract Year.

Section 1.2 Units Being Declared Commercial: The Net Dependable Capacity for a unit declared commercial after the month of August 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 system of the Southern Companies.

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Section 1.3 Data to be Provided: The data used in the determination of the Net Dependable Capacity for each unit each Contract Year, pursuant to Sections 1.0, 1.1, and 1.2 above, will be provided to purchasers of unit power in accordance with Article VIII.

ARTICLE II

DERIVATION OF CAPACITY CHARGE FOR COAL-FIRED ELECTRIC GENERATING UNITS

This article of the Unit Power Sale Manual establishes the formulary methodology for deriving capacity costs of coal-fired electric generating units used in unit power sales for determination of charges for the services to be supplied under such sales. 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 2.1 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 ($/kW-month) of each coal-fired electric generating unit participating in the unit power sale is multiplied by the portion (megawatts) of the unit applicable to the sale in each month to obtain the total monthly capacity dollars ($). The total monthly unit power sales capacity dollars are then summed and divided by the sum of the portion (megawatts) of the unit applicable to the sale in each month to obtain a weighted average capacity cost ($/kW-month). This weighted average capacity cost for each month will constitute the charge for capacity sold by Southern Companies under the Unit Power Sales Agreement. This charge for each month of the Contract Year 1983 will be shown on Unit Power Sale Informational Schedule for the year 1983, and will be revised in accordance with this Unit Power Sale Manual in subsequent calendar years.

Section 2.2 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 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 "buy-back capacity" provisions as they exist for Scherer Units 1 and 2 will be recognized by developing a monthly capacity charge for the buy-back portion of each unit separately from the Georgia Power Company ownership portion of such units. The derivation of the monthly capacity charge of each applicable unit is expressed in the following formulae:

$$R = \left[\frac{I \times [(CM + IT)/100] + E}{C \times 12.0}\right] \times \left[\frac{100}{100 - I_c}\right]$$

$$BR = \frac{1}{12}\left[\frac{\sum_{i=1}^{N} AFC_{si}}{\sum_{i=1}^{N} CB_{si}}\right] \times \left[\frac{100}{100 - I_c}\right]$$

where:

$$AFC_{si} = \{I_{si} \times \left[\frac{(CM_v + IT_v + CM_{si})/100}{2.0} + \frac{2.0\%}{100\%}\right] + E_{si}\} \times \left[\frac{BB_{si}}{O_{si}}\right]$$

and:

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

BR = Monthly production capacity charge for buy-back capacity (\$/kW-month).

AFC_{si} = Annual fixed charges of the operating company's buy-back entitlement including the effect of a split between the cost of money between the operating company and each participant[1] plus 2.0 percent (Dollars).

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

I_{si} = Total of the net investment associated with the participants' portion of the unit (Dollars).

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

E_{si} = Total of the annualized fixed expenses associated with the participants' portion of the unit (Dollars).

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[1]Participant as used herein shall mean any entity which has an ownership interest in a designated unit and an agreement to sell capacity in such designated unit to an operating company.

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

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 (Percent).

CM_Y = The operating company's weighted average cost of capital associated with buy-back capacity as determined by the purchase and resale agreement between the operating company and each participant (Percent).

IT_Y = The income tax requirement associated with the buy-back cost of capital of the operating company's preferred stock and common equity components (Percent).

CM_{si} = The weighted average cost of capital associated with the participants' cost of construction of the unit as determined by the purchase and resale agreement between the operating company and each participant (Percent).

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

CE_{si} = Net Dependable Capacity of each participants' portion of the unit related to buy-back (kW).

BE_{si} = Portion of the Net Dependable Capacity of the unit related to buy-back from each participant (Percent).

C_{si} = Portion of the Net Dependable Capacity of the unit owned by each participant (Percent).

N = Number of participants (other than the operating company) in the unit.

L_c = Average transmission capacity loss percentage of the Southern Companies as determined in Article VII.

The source of the capacity, investment, and expense data incorporated in the above formulae 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 2.2.1: Net Dependable Capacity is the rating in kW of the coal-fired electric generating unit as determined in Article I. The value of C is determined by multiplying the percent ownership of the operating company by the unit's Net Dependable Capacity. The value of CB_{si} for each participant is determined by multiplying the participant's buy-back related portion (BB_{si}) by the Net Dependable Capacity.

Section 2.2.2: 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 Accounts 352 and 353 for the step-up substation at the end of each month of the Contract Year. The amount of booked AFUDC (Allowance for Funds Used During Construction) shall have added to it an amount to reflect the effect of CWIP (Construction Work In Progress) 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 formula:

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

DA = Dollar amount to be added to booked AFUDC.

AR = The monthly AFUDC rate prescribed by the applicable state Public Service Commission.

ER = 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.

The gross generating unit investment of the participants of the coal-fired electric generating unit and its associated step-up substation is the book cost recorded at the end of each month of the Contract Year in the prescribed accounts of the other participants with which GaPC has buy-back arrangements.

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. GaPC will own an undivided ownership interest in common facilities at Plant Scherer which is greater than GaPC's percentage undivided ownership interest in the units prior to commerical operation of Scherer No. 3. The percent ownership in common facilities in excess of the percent ownership in Scherer No. 1 and No. 2 (the "long percentage") will not be included in the pricing of the GaPC owned capacity. The long percentage ownership will be included in the pricing of buy-back capacity from the participant as determined in Section 7(a), "Compensation For Use of Common Facilities," of the Plant Robert W. Scherer Purchase, Sale and Option Agreement Between Georgia Power Company and Municipal Electric Authority of Georgia, dated May 15, 1980, (the "Scherer Agreement"). In the event the Scherer Agreement is changed and amended by the parties thereto, FPI will not be required to pay capacity nor energy charges in excess of those that would have been produced by the use of the Scherer Agreement as referenced.

Section 2.2.3: Accumulated Depreciation is associated with the gross production investment defined in Section 2.2.2. The accumulated depreciation for generating units is adjusted to include the amount of AFUDC determined in Section 2.2.2. 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 2.2.4: Net Generating Unit Investment is the difference between Section 2.2.2 (Gross Generating Unit Investment) and Section 2.2.3 (Accumulated Depreciation).

Section 2.2.5: 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 2.2.2 and 2.2.3. 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 2.2.17.

The net general plant related to the generating unit and its step-up substation is allocated to the operating company and participants based upon the owned capacity of the respective entities.

Section 2.2.6: 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 total annual operation and maintenance (O&M)[2] (including fuel burn), and administrative and general (A&G) expenses. The fixed O&M expense is developed in Section 2.2.9 and the A&G expense is developed in Section 2.2.10.

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 2.2.9 and 2.2.10, respectively.

Prepayments are computed on the basis of a 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 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 2.2.17.

Materials and supplies are computed on the basis of a 13-month average and consists 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 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, 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, 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 the operating companies for the operation of jointly owned generating units.

[2] O&M as used in this Unit Power Sale Manual does not include administrative and general expenses.

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 the other operating company.

Total working capital is computed by adding deposits (if any), prepayments, and material and supplies to cash working capital. The working capital of a generating unit which is jointly owned by the operating company and participants is allocated based upon the owned capacity of the respective entities.

Section 2.2.7: 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 2.2.5. 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 2.2.8: 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 2.2.4 (Net Generating Unit Investment) through Section 2.2.7 (Accumulated Deferred Income Taxes) and is the value for "I" for owned capacity and "I_{s1}" for buy-back capacity in the formula in Section 2.2 for each applicable generating unit.

Section 2.2.9 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, excluding 501. The definition of fixed and variable as defined in these accounts is shown in Article V. 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. The separation of O&M expenses between the operating company and participants is computed based on the capacity that each entity owns in each generating unit.

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Section 2.2.10: Administrative and General Expenses, FERC Accounts 920 through 932, excluding 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 2.2.17. 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 investment excluding land.

The separation of the administrative and general expenses between the operating company and participants is computed based on the capacity that each entity owns in each generating unit.

Section 2.2.11: Depreciation Expense for the coal-fired generating unit is based on Straight Line depreciation with the exception of the Scherer units in which case the expense is based on Units of Production during the first six 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 2.2.2. 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 generating unit and its step-up substation in the same manner as the general plant allocations described in Section 2.2.5. The depreciation expense for owned capacity and buy-back capacity are handled separately and take into account the records of the owners.

Section 2.2.12: Amortization of Investment Tax Credits (AITC) is computed for each coal-fired generating unit. The 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 generating unit and its step-up substation in the same manner as the general plant allocations described in Section 2.2.5. The AITC for owned capacity and buy-back capacity are handled separately and take into account the records of the owners.

Section 2.2.13: Real and Personal Property Taxes are computed for the specific coal-fired 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 2.2.5. 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 2.2.14: Payroll Taxes applicable to a specific coal-fired 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 2.2.17. 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 2.2.15: 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 2.2.9 (Fixed Operation and Maintenance Expense) through Section 2.2.14 (Payroll Taxes) and is the value for "E" for owned capacity and "E_{S1}" for buy-back capacity in the formula in Section 2.2 for each coal-fired electric generating unit.

Section 2.2.16: The Cost of Capital and associated income taxes are computed for each unit 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 = The weighted average cost of capital associated with the operating company's cost of construction of the unit (Percent).

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 (Percent).

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DR = Ratio of debt capital)*

PR = Ratio of preferred stock)*

ER = Ratio of common equity)*

*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 the operating companies, such other report to a governmental agency containing the operating companies' capital structure) at the time the unit goes into commercial operation; except the capital structure for Miller Unit No. 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 ensuing 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

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[3]In the case of Miller Unit No. 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 issues of 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 percent 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.

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.

p = The cost of preferred stock*, which shall be determined as of the date the unit goes into commercial operation, shall be the weighted average dividend percent rate of such stock, which such percent rate shall be calculated by applying the annual dividend percent rate of the most recent issue of the 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 percent interest rate of the most recent issue of the Preferred Stock prior to the incurrence of such monthly capital expenditure.

c = Return on common equity of the Southern Companies as determined in Article VI.

As agreed to by the parties, the cost of capital associated with the buy-back capacity includes the effect of a split between the cost of money of the operating company and each participant as described by the then current purchase and resale agreement between the operating company and each participant plus 2%. The development of the terms CM_Y and IT_Y are as shown below:

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*In the case of Miller Unit No. 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 percent rate of Preferred Stock issued up to six months subsequent to such expenditures. If no such stock issue were made in the six-month period subsequent to the monthly capital expenditure, the rate of the most recent previous stock issue will continue to be applied to such expenditures incurred up to six months prior to the next stock issue.

$$CM_Y = (DR \times i_Y) + (PR \times p_Y) + (ER \times c_Y)$$

where:

$$DR + PR + ER = 1.0$$

$$IT_Y = \frac{T}{1-T} \times [(PR \times p_Y) + (ER \times c_Y)]$$

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

or

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

CM_Y = The operating company's weighted average cost of capital associated with buy-back capacity as determined by the purchase and resale agreement between the operating company and each participant (Percent).

IT_Y = The income tax requirement associated with the buy-back cost of capital of the operating company's preferred stock and common equity components (Percent).

DR = Ratio of debt capital)*

PR = Ratio of preferred stock)*

ER = Ratio of common equity)*

*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 the event such report ceases to be required to be filed by the 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. In the case of a unit which will go into commercial operation during the ensuing 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_Y = The cost of debt capital, 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 Mortage Bonds prior to the incurrence of each monthly capital expenditure on the unit. Such cost of debt capital shall be modified as of the date the unit goes into commercial operation to include the amount and the cost of pollution control bonds specifically related to 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.

p_y = The cost of preferred stock, which shall be determined as of the date the unit goes into commercial operation, shall be the weighted average dividend percent rate of such stock, which such percent rate shall be calculated by applying the annual dividend percent rate of the most recent issue of the 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 percent interest rate of the most recent issue of the Preferred Stock prior to the incurrence of such monthly capital expenditure.

c_y = The cost of Common Equity shall be the most recent percent return allowed on equity by the Federal Energy Regulatory Commission (FERC) for sales to the operating company's wholesale customers or such percent return submitted in a rate settlement with its wholesale customers (whichever is most recent).

T = Combined state and federal income tax rate.

F = Federal income tax rate.

S = State income tax rate.

<u>Section 2.2.17</u>: <u>Salaries and Wages</u> are budgeted and accounted for on an actual basis by the operating companies for each functional group and the specific coal-fired 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 classification are allocated to the functions including the specific coal-fired generating unit based upon the ratio of the administrative classification's salaries and wages to the total salaries and wages less the administrative classification's salaries and wages. The salaries and wages associated with the transmission function, including the allocated administrative salaries and wages, are allocated to the transmission plant's substations based upon the labor in Accounts 562, 569, and 570 and is further allocated to the unit's generator step-up substation facilities on the basis of the ratio of the gross investment in the specific 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 company's records. The salaries and wages for a specific unit which is jointly owned are computed for 100 percent 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 an historical basis of salaries and wages, the most recent vintage and similar coal-fired unit that does have an historical basis will be used for the first year's estimate.

<u>Section 2.2.18</u> <u>Adjustment for Delayed Unit Subject to Section 2.4.3 of the Agreement</u>: The development of the capacity charge for a unit delayed subject to the provisions of Section 2.4.3 of the 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.

<u>Section 2.2.19</u> <u>Data to be Provided</u>: The data contained in this article will be supplied on informational and support schedules described in article VIII and shall be made available for both estimated and actual cost data as specified in Article IX.

ARTICLE III

DERIVATION OF CAPACITY CHARGE FOR TRANSMISSION LINE FACILITIES

This article of the Unit Power Sale Manual establishes the formulary methodology for deriving the capacity charge for transmission plant used for the service to be supplied under the Unit Power Sales Agreement.

Section 3.1 System Transmission Capacity Cost: The computation of the system transmission capacity cost 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 cost excludes the investment and expenses associated with the generator step-up substations which are included in Article II.

The computation of the system transmission capacity cost is made for each period of the Contract Year. 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 the Southern Companies consider an operating year to be June 1 through May 31 of the following year. Billings and payments for capacity and interchange transactions between the Southern Companies (referred to individually as "operating company") are based on an operating year. The Southern Companies utilize Peak-Period Load Ratios to allocate certain billings and payments between each of the operating companies. The peak-period is defined to be the fourteen (14) hours between 7:00 a.m. and 9:00 p.m. of each day. The Peak-Period Load Ratios shall be determined by dividing each operating company's summation of the July and August estimated weekday peak-period energy loads by the total system July and August estimated weekday peak-period energy loads. The Peak-Period Load Ratios for the first five (5) months of the Contract Year are based upon the prior year's critical months of July and August. The Peak-Period Load Ratios for the last seven (7) months of the Contract Year are based upon the critical months of July and August of the Contract Year. Consequently, during a Contract Year there shall be two Peak-Period Load Ratios--one to be used in the January through May period, and the other in the June through December period. The Peak-Period Load Ratios are shown on the Unit Power Sale Informational Schedule for the Contract Year.

The transmission capacity cost for each operating company for each period of the Contract Year is multiplied by its Peak-Period Load Ratio for each period of the Contract Year. These results for each operating company are summed to obtain the total system transmission capacity cost for each period of the Contract Year. This total system transmission capacity cost for each period will constitute the transmission charge for capacity sold by Southern Companies to purchasers of unit power under the Unit Power Sales Agreement. These charges for each period of the Contract Year 1983 will be shown on the Unit Power Sale Informational Schedule for the year 1983, and will be revised in accordance with this Unit Power Sale Manual in subsequent calendar years.

<u>Section 3.2 Derivation of Transmission Capacity Costs of Each Operating Company</u>: The derivation of the transmission capacity cost of each operating company 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 income taxes in each period of the Contract Year. This derivation excludes the investments, expenses, and associated load in transmission owned by Oglethorpe Power Corporation (OPC), Municipal Electric Authority of Georgia (MEAG), and the City of Dalton, Ga. (Dalton). The investment and expense associated with the Southern Electric Generating Company (SEGCO) transmission facilities is assigned to GaPC. The derivation of the monthly transmission capacity cost of each operating company for each period of a Contract Year is expressed in the following formulae:

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

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

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 (Percent) associated with the January through May period of the Contract Year.

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

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

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

D = The 5-day average estimated load (kW)

L_c = Average transmission capacity loss percentage as determined in Article VII.

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

Section 3.2.1 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. Each operating company'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. For Mississippi Power Company (MPC), the generation of the Standard Oil Station is excluded.

The five-day average estimated load will be adjusted to the actual five-day average load for each operating company pursuant to Article IX of this Unit Power Sale Manual.

Section 3.2.2 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 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 3.2.3 Accumulated Depreciation is that depreciation associated with the gross transmission investment defined above and is allocated to Account based on investment and depreciation rates by Account. The allocation to voltage level is based on gross investment.

Section 3.2.4 Net Transmission Plant is the difference between Section 3.2.2 (Gross Transmission Investment) and Section 3.2.3 (Accumulated Depreciation).

Section 3.2.5 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 2.2.2 and 2.2.3 of Article II. The allocation of net general plant to transmission facilities rated 115 kV and above (excluding the direct assignments) is done on the basis of salaries and wages as described in Section 3.2.17.

Section 3.2.6 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 3.2.9 and 3.2.10, respectively.

Prepayments are computed on the basis of a 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 3.2.17. The amount allocated and assigned to the transmission function is allocated to the facilities rated 115 kV and above on the basis of operation and maintenance expenses as described in Section 3.2.9.

Materials and supplies are computed on the basis of a 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, 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 the operating companies 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.

Total working capital is computed by adding deposits (if any), prepayments, and material and supplies to cash working capital.

Section 3.2.7 Accumulated Deferred Income Tax is the net total of FERC Accounts 190, 281, 282, and 283 which have been analyzed and allocated by each operating company in accordance with each Account's functional use. The portion related to general plant is allocated to the transmission function as described in Section 3.2.5. The allocation to facilities rated 115 kV and above is on the basis of net plant less land.

Section 3.2.8 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 3.2.4 (Net Transmission Plant) through 3.2.7 (Accumulated Deferred Income Tax) and is the value for "I" in the formula in Section 3.2.

Section 3.2.9 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 detail assignments can be made from existing company records. The operation and maintenance (O&M) expenses will be adjusted to reflect the actual O&M expenses for each operating company pursuant to Article IX of this Unit Power Sale Manual.

Section 3.2.10 Administrative and General expenses, FERC Accounts 920 through 932, excluding 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. Account 924 is directly assigned to function by the operating company and allocated within function based on net investment.

Section 3.2.11 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 each operating company. 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 3.2.5. 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 115kV and above to the depreciation expense of the transmission plant.

Section 3.2.12 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 3.2.13 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 3.2.17 to obtain each function's payroll taxes and reflect the use of the taxable wage base and the maximum payroll tax payable during each month of the Contract Year.

Section 3.2.14 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 capacity, short term capacity, 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 certain companies have operating agreements with other 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 companies. In addition, revenues associated with the transmission facilities rated 115 kV and above that appear in the 'Purchased Power Account' (e.g., such revenues from long term capacity, short term capacity, and unit power sales) will be credited to the operating expenses for these transmission facilities.

Section 3.2.15 Total Transmission Expenses represent the direct and allocated fixed expenses associated with the facilities considered herein and are the summation of Section 3.2.9 (Transmission Operation and Maintenance) through Section 3.2.14 (Credits (or Debits) to Operating Expenses) and is the value for "E" in the formula in Section 3.2.

Section 3.2.16 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 (Percent).

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

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 (Percent).

p = Embedded cost of preferred stock (Percent).

c = Return on common equity of the Southern Companies as determined in Article VI.

T = Combined state and federal income tax rate.

F = Federal income tax rate.

S = State income tax rate.

Section 3.2.17 Salaries and Wages are budgeted and accounted for on an actual basis by the operating companies for each functional group.

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

The transmission plant salaries and wages which includes 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 the 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 services under the Agreement.

Section 4.0 Fuel Costs: The Fuel Cost ($/mWh) for a unit is defined as the cost (dollars) 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 this 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 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 4.1 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 (dollars) of fossil fuel issued from FERC Account 151, including the actual monthly cost of gaseous fuels charged directly to 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 65% of the Expected Capacity of each unit, unless otherwise mutually agreed by the parties to the Agreement. This generation level will be reviewed periodically by the 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 the Southern Companies.

ARTICLE V

DERIVATION OF FIXED OPERATION AND MAINTENANCE, VARIABLE OPERATION AND MAINTENANCE, AND IN-PLANT FUEL HANDLING EXPENSES FOR ELECTRIC GENERATING UNITS

This article of the Unit Power Sale Manual establishes the formulary method for deriving fixed operation and maintenance, variable operation and maintenance, and in-plant fuel handling expenses for the computation of charges for services under the Agreement.

Section 5.0 Fixed Operation and Maintenance Expenses: The fixed operation and maintenance expense (dollars) for a unit is based upon the following components budgeted for the unit for the Contract Year: (i) all operation supervision and engineering charged to FERC Account 500, (ii) operational labor (including overtime labor) charged to FERC Accounts 502, 505, and 506, (iii) rent charged to Account 507, (iv) all maintenance supervision and engineering charged to Account 510, (v) all maintenance expenses charged to Account 511, and (vi) maintenance labor (including overtime labor) charged to Accounts 512, 513, and 514.

Section 5.1 Variable Operation and Maintenance Expenses: The variable operation and maintenance expenses ($/mWh) for a unit shall be based upon the following components budgeted for the unit for the Contract Year: (i) all contract labor, (ii) all operating material charged to Accounts 502, 505, and 506, and (iii) all maintenance material charged to Accounts 512, 513, and 514. The variable operation and maintenance expenses for the unit shall be the sum of the components listed above (in dollars) divided by the budgeted net electrical output of the unit (in mWhs) for the Contract Year.

Section 5.2 In-Plant Fuel Handling Expenses: The in-plant fuel handling expenses ($/mWh) for a unit shall be the in-plant fuel handling costs (dollars) budgeted in FERC Account 501 divided by the budgeted net electrical output (mWhs) for the unit during the Contract Year. The in-plant fuel handling expenses shall include all expenses in Account 501 except the cost of fuel which includes freight, switching, demurrage and other transportation charges.

Section 5.3 Data to be Provided: The data used in the determination of the fixed and variable operation and maintenance expenses and the in-plant fuel handling expenses for each unit each Contract Year, will be provided to the purchasers of unit power in accordance with Article VIII.

ARTICLE VI

DERIVATION OF
RETURN ON COMMON EQUITY

This article of the Unit Power Sale Manual establishes the return on common equity used in the computation of capacity charges for unit power and transmission.

Section 6.0 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 Agreement, the return on common equity (c) for the Southern Companies shall be sixteen percent (16.0%). 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 of the Agreement.

ARTICLE VII

DERIVATION OF AVERAGE TRANSMISSION LOSS PERCENTAGES

This article of the Unit Power Sale Manual establishes the average transmission loss percentages used in the computation of capacity and energy charges.

Section 7.0 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 Agreement, the average transmission loss percentage of the Southern Companies associated with capacity ($\%L_c$) and the average transmission loss percentage of the Southern Companies associated with energy ($\%Le$) 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 Agreement.

ARTICLE VIII

UNIT POWER SALE SUPPORT SCHEDULES AND INFORMATIONAL SCHEDULES AND MONTHLY STATEMENT OF ENERGY TRANSACTIONS

Section 8.0 Unit Power Sale Support Schedules: The development of cost components for the sale of unit power will be provided on formats mutually agreed to by the parties. Such support schedules will describe the source of the data with reference to the applicable articles and sections of the 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 Schedules.

Section 8.1 Unit Power Sale Informational Schedules: The results of the formulary methodology set forth in this Unit Power Sale Manual shall be displayed on informational schedules with a format mutually agreed to by the parties.

Section 8.2 Schedules for Estimated and Actual Charges: The support schedules and informational schedules described in Sections 8.0 and 8.1 above shall be made available for both estimated and actual cost data as specified in Article IX.

Section 8.3 Monthly Statements of Energy Transactions: Monthly statements shall be made available which will list the hourly energy transactions and the energy rate(s) (Base Energy Rate, Alternate Energy Rate and Supplemental Energy Rate) which are applicable to each hourly transaction. The energy rate(s) used in the calculation of the energy charge for each unit each hour, will be identified and the fuel cost components of the energy charges will be shown. This data will be made available for both preliminary and actual cost data as provided for in Section 7.1 of the Agreement.

ARTICLE IX

ADJUSTMENTS FOR ACTUAL COST

This article of the 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 Agreement will be made using the applicable procedures described in Article II, Article III, and Article V of this Unit Power Sale Manual.

Section 9.0 Capacity Cost for Unit Power: The monthly capacity charges computed under Article II for each unit participating in sales of unit power for each Contract Year will be recalculated using the formulae specified in Section 2.2 of Article II, and the actual cost data for the unit. All cost items contained in Article II 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 months of the monthly rendered bill. The capital structure and cost of debt capital and preferred stock will be modified as described in Section 2.2.16.

Section 9.1 Capacity Cost for Transmission Service: The transmission capacity cost computed under Article III for the Contract Year will be recalculated using the actual data for the following items: (i) Section 3.2.1 (Five-day Average Load) and (ii) Section 3.2.9 (Transmission Operation and Maintenance Expenses) and as it affects Section 3.2.6 (Working Capital). The adjustment will be made annually as soon as practicable following the end of the Contract Year.

Section 9.2 Variable Operation and Maintenance Expenses: The variable operation and maintenance expenses and the in-plant fuel handling expenses, as defined and computed in accordance with Article V, will be recalculated using actual data. The adjustment for variable operation and maintenance expenses and the in-plant fuel handling 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 of this Agreement) 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 9.3 Administrative Cost for Adjustment Procedure: The purchasers of unit power shall reimburse the Southern Companies for all costs incurred by the Southern Companies directly in administering this article of the Unit Power Sale Manual. Such costs shall be accumulated by the Southern Companies at standard rates of the operating companies and the service company 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 of the Unit Power Sale Manual based on time actually spent, and materials and supplies consumed in connection with administration of this article of the Unit Power Sale Manual. Such administrative charges will not be included in the development of capacity charges in Section 2.2.10 of Article II. The cost will be prorated equally to each purchaser of unit power.