# UNIT POWER SALES AGREEMENT
# BETWEEN
# JACKSONVILLE ELECTRIC AUTHORITY
# AND
# ALABAMA POWER COMPANY, GEORGIA POWER COMPANY, GULF POWER COMPANY, MISSISSIPPI POWER COMPANY AND SOUTHERN COMPANY SERVICES, INC.

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THIS AGREEMENT, made and entered into as of the 27th day of February, 1981, by and between JACKSONVILLE ELECTRIC AUTHORITY ("JEA"), a body politic and corporate in Duval County, Florida, and ALABAMA POWER COMPANY ("APC"), an Alabama corporation, GEORGIA POWER COMPANY ("GaPC"), a Georgia corporation, GULF POWER COMPANY ("GuPC"), a Maine corporation, and MISSISSIPPI POWER COMPANY ("MPC"), a Mississippi corporation (APC, GaPC, GuPC and MPC 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, the 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, together with SCS, are parties to an Intercompany Interchange Contract ("IIC") governing the coordination of operations between the Southern Companies; and

WHEREAS, Southern Companies, together with SCS, and JEA are parties to an Interchange Contract executed contemporaneously herewith pursuant to the terms of which the parties contemplate the construction and maintenance of points of interconnection which will provide and improve system reliability of each of the systems and accommodate transactions under this Agreement as well as other agreements between the parties; and

WHEREAS, GaPC and GuPC, electric public utilities in the States of Georgia and Florida respectively, have undertaken to construct, or to have constructed, for the benefit of their respective territorial customers, certain coal fired steam electric generating units; and

WHEREAS, unforeseen changes in economic conditions and an intensified conservation effort have reduced the expectation of territorial demand growth and thereby also reduced the immediate need for the capacity from these units on their most economical construction schedule; and

WHEREAS, JEA, a utility in the State of Florida, desires to purchase from Southern Companies, capacity and energy from such units in the years and amounts specified herein so as to reduce its dependence on oil fired steam electric generating facilities; and

WHEREAS, sales of such capacity to JEA will benefit the territorial customers of the Southern Companies by making use of capacity available during the time period of this Agreement and reducing ultimate cost to such territorial customers;

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 Agreement shall become effective as of the date of the latest signature on the signature page hereof and shall continue through December 31, 1992 or such extended period agreed to by the parties for an orderly decrease in sales and purchases as provided for in Sections 2.2.3 and 2.2.4 hereof. However, such term may be reduced as provided in Section 1.2 if the following condition is not met:

1.1.1 That review of this Agreement be concluded by the Federal Energy Regulatory Commission ("FERC"), or successor agency, without significant change hereto. To such end, the Southern Companies agree to take steps promptly to file this Agreement, together with appropriate supporting documents, with FERC. JEA agrees to cooperate and assist Southern Companies in securing conclusion of the review by FERC of this Agreement without significant change hereto, in an expeditious manner.

1.2 Reduction of Term: In the event the condition set forth in Section 1.1.1 is not met by January 1, 1983, Southern Companies shall have the right, at their option, to seek relief as provided in Section 5.4 hereof or give JEA notice that this Agreement shall terminate on a date certain not less than five (5) years from the date such notice is given to JEA, or both. In the event Southern Companies seek relief from FERC as provided in Section 5.4, but fail within twelve (12) months thereafter to obtain rates which would produce estimated charges to JEA at least equal to those which would have been produced under the Agreement as initially filed with FERC, then Southern Companies shall have the further right, at any time and from time to time, at their option, and notwithstanding any provision of this Agreement to the contrary, to terminate this Agreement or seek any administrative or judicial relief from FERC's determination which they deem appropriate, except that Southern Companies may not terminate the Agreement on less than five (5) years' notice. In the event Southern Companies have given notice of termination as provided above and, further, have obtained relief pursuant to Section 5.4 so that the charges produced hereunder are equal to or greater than those which would have been produced under the Agreement as filed initially, then, in such event, JEA may, at its election, upon notice to Southern Companies given within sixty (60) days after written notice that such change is contained in a final and non-appealable order, elect to have this Agreement extend for the entire term notwithstanding the notice of termination given by Southern Companies. In the event Southern Companies seek relief from a failure by FERC to conclude its review of the initial filing of this Agreement without significant change by the filing of unilateral changes pursuant to Section 5.4, and in the event FERC agrees to such change so that the rates to be charged would be higher than those which would have been imposed under the Agreement as initially filed then, in such events, JEA shall have the right, exercisable at any time up to sixty (60) days after the final and non-appealable order of FERC, to give Southern Companies notice that this Agreement shall terminate on a date not less than five (5) years from the date such notice is given to Southern Companies.

ARTICLE II

UNIT POWER CAPACITY

2.1 Units From Which Capacity Will Be Made Available: The Units referred to in Section 2.2 hereof from which capacity entitlement will be made available hereunder are (a) the V. J. Daniel, Jr. Steam Electric Generating Plant, Units 1 and 2 ("Daniel 1 and 2") located in Jackson County, Mississippi, and (b) the Robert W. Scherer Steam Electric Generating Plant, Units 1, 2, 3 and 4 ("Scherer 1, 2, 3 and 4") located in Monroe County, Georgia. Daniel 1 and 2 and Scherer 1, 2, 3 and 4 are or will be owned jointly by GuPC or GaPC with others, or between GuPC and GaPC. It is recognized that, with respect to Scherer 1 and 2, GaPC has entered into a Purchase and Ownership Participation Agreement and an Operating Agreement with other parties, both dated as of May 15, 1980, pursuant to which GaPC has agreed to purchase from such other parties an entitlement to capacity and energy from such units in amounts which diminish during the term thereof. Such capacity purchase is referred to herein as "buy-back capacity". Exhibit A hereto sets forth with respect to each unit identified above the Expected Total Operating Capacity ("Expected Capacity") of the unit; such values being 808 megawatts for each of the Scherer Units and 511 megawatts for each of the Daniel Units. Exhibit A also sets forth the projected date for commercial operation of each unit; and the amount of the Expected Capacity of each unit owned by or available to GaPC and GuPC which is made available for sale hereunder to JEA and others. For the purpose of determination of capacity availability hereunder, buy-back capacity from a unit shall be considered a separate unit from owned capacity in the same unit, and GuPC's ownership interest in Scherer 3 and 4 shall be considered separate units from GaPC's ownership interest in such units.

2.2 Capacity to be Purchased and Sold: Subject to adjustments as provided in this Article II, GaPC and GuPC hereby agree to sell and JEA hereby agrees to purchase, capacity entitlement from the units specified in 2.1 above, in the amounts and in the years set forth in the following schedule:

| Year | Capacity (Megawatts) |
|---|---|
| 1983 | 300 |
| 1984 | 300 |
| 1985 | 300 |
| 1986 | 300 |
| 1987 | 500 |
| 1988 | 400 |
| 1989 | 400 |
| 1990 | 400 |
| 1991 | 400 |
| 1992 | 400 |

The parties 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 the event either party desires to increase or decrease capacity sales or purchases for the years set forth above, the parties agree to negotiate in good faith and with diligence to proceed to evaluate alternatives which may reasonably provide for such desired change in capacity; provided, that no such change shall be made except upon mutual written agreement of the parties hereto.

2.2.2 In the event, after this Agreement becomes effective, Southern Companies shall offer to sell unit power capacity from coal-fired generating resources to third party utilities outside the geographical areas served by Southern Companies during the years 1983 through 1992, JEA and others which have executed Unit Power sale contracts with Southern Companies within thirty (30) days after February 19, 1981 (hereinafter referred to as "Contemporaneous Parties"), shall have the right of first refusal for the purchase of a pro rata share of the capacity made available on substantially the same terms offered other potential purchasers to the extent the sale of such capacity would not cause the then existing Transfer Limit as set forth in Section 4.4.1 to be exceeded; provided, however, such right must be exercised within ninety (90) days after written notice from Southern Companies informing JEA of the offer and the terms and conditions of each such offer. JEA and each of the other Contemporaneous Parties shall, prior to the end of such ninety (90) day period, notify Southern Companies of their election to purchase a pro rata share of such additional capacity being offered by Southern Companies based on the amount of unit power capacity each has previously agreed to purchase during each year for which the additional capacity is offered, and each Contemporaneous Party shall give notice whether it elects to purchase on the same pro rata basis any pro rata share refused by any of the other Contemporaneous Parties. In addition, in the event the additional capacity being offered is capacity not included in Exhibit A as being made available for sale to JEA and others, and JEA and other Contemporaneous Parties do not desire to purchase such additional capacity, JEA may request that the capacity being purchased by it be amended to include a portion of such additions to Exhibit A. Southern Companies agree, upon such request, and provided such additional capacity can be sold, to amend Exhibit A and Exhibit B such that the capacity charges for unit power capacity sold to other purchasers is no less than the capacity charges for unit power sold to JEA. To the extent 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 B for the period capacity from such unit is made available.

2.2.3 Southern Companies and JEA agree to negotiate in good faith, together with Contemporaneous Parties, prior to January 1, 1986 to determine to what extent, if any, unit power capacity from coal-fired generating resources can be made available to provide for an orderly decrease in capacity sales after December 31, 1992. Any offer of capacity by Southern Companies to JEA shall be predicated on the basis of an offer being made on a pro rata basis to all Contemporaneous Parties. On or before January 1, 1986, the parties shall agree on such capacity sales, or in the absence of mutual agreement by January 1, 1986, this Agreement shall terminate on December 31, 1992; except as provided for in Section 2.2.4.

2.2.4 If, prior to the year 1993, Southern Companies offer to sell unit power capacity from coal-fired generating resources to third party utilities outside of the geographical areas served by Southern Companies during the years 1993 through 1997, JEA and the other Contemporaneous Parties shall have the right of first refusal for the purchase of a pro rata share of such capacity on substantially the same terms offered other potential purchasers; provided, however, such right must be exercised within ninety (90) days after written notice from Southern Companies informing JEA of such capacity being made available for sale and the terms and conditions of each offer. JEA and each of the other Contemporaneous Parties shall, prior to the end of such ninety (90) day period, notify Southern Companies of their election to purchase a pro rata share of such capacity based upon the amount of Unit Power capacity each has previously agreed to purchase during the year 1992, and each Contemporaneous Party shall give notice whether it elects to purchase on the same pro rata basis any pro rata share refused by any of the other Contemporaneous Parties.

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 GaPC and GuPC, and purchased by JEA hereunder, will vary from time to time during the term of this Agreement. The nominal schedule of units, by time period, from which sales will be made is set forth in Exhibit B, such Exhibit B representing an agreed allocation to JEA of capacity from each of the units specified in Section 2.1 by time period based on Expected Capacity. It is recognized by the parties 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 B and any such variance shall be based on the following principles:

2.3.1 On or before September 15, 1982 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 JEA during the ensuing year is equal to or greater than ninety percent (90%) of the Expected Capacity of such unit as set forth in Exhibit A, the capacity to be sold to JEA from such unit during the ensuing year shall be as specified in Exhibit B.

2.3.3 If the Net Dependable Capacity established for the ensuing year for a unit from which capacity is to be sold to JEA is less than ninety percent (90%) of the Expected Capacity of such unit as specified in Exhibit A, the capacity to be sold and purchased from such unit during each period identified in Exhibit B for the ensuing year shall be JEA's pro rata share of the Net Dependable Capacity from such unit determined by multiplying the amount of capacity sale shown for such unit in Exhibit B for each period by the ratio of the Net Dependable Capacity of the unit to ninety percent (90%) of 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 ninety percent (90%) of 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, in Southern Companies' sole opinion, may be made available from remaining Net Dependable Capacity in units specified in Exhibit B or other coal-fired steam electric generating resources owned or operated by any of the Southern Companies, including the estimated capacity costs expected from any such other resources. On or before October 1 following such notice, JEA shall notify Southern Companies, in writing, whether it wishes to purchase such additional capacity. 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 B 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 JEA 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 the Southern Companies shall be to provide additional capacity to JEA in the amount determined in accordance with Sections 2.3.1 through 2.3.4.

2.3.6 In the event any of the capacity set forth in Exhibit B in any year cannot be made available because of the exercise by Municipal Electric Authority of Georgia of options granted to it in the Purchase and Ownership Participation Agreement dated May 15, 1980, then, in such event, Southern Companies shall make available to JEA capacity from other coal-fired steam electric generating resources owned or operated by Southern Companies. 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 B for the period capacity from such unit is made available.

2.4 Delay in Commercial Operation of Units: Notwithstanding the schedule of sales set forth in Section 2.2 above, the obligation of GaPC and GuPC to make capacity from each Scherer unit specified in Exhibit A available to JEA shall further be subject to delays in the projected dates for commercial operation of each such unit. Construction of such units and any delays therein shall be governed by the following principles:

2.4.1 GaPC and GuPC, respectively, agree to use best efforts consistent with Prudent Utility Practices (as defined in Section 10.5 hereof) to design and construct, or to have designed and constructed, the units in which they agree to have an ownership or buy-back interest 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 JEA 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. GaPC shall keep JEA 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 the Scherer units are based on the present plans of GaPC, 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, and in the further event capacity is made available to JEA during such period under Section 2.4.2, then it shall be conclusively presumed that the delay in the commercial operation of the unit resulted from events beyond the control of GaPC. 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, nevertheless, that in the event a unit specified in Exhibit A is not available for commercial operation as of the date specified therein, 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 JEA as specified in Exhibit B available from other coal-fired steam electric generating resources owned or operated by any of the Southern Companies, includin those 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 B for the period capacity from such unit is made available.

2.4.3 In the event any unit is not available for commercial operation as of the initial date for sales of capacity to JEA from such unit as specified in Exhibit B 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 (1) make available to JEA unit power from other coal-fired steam electric generating resources during the period of the delay attributable to causes not excused under Section 2.4.1 in the amount of capacity to have been furnished from the delayed unit as specified in Exhibit B, and (2) make adjustments in the capacity rates as specified in Article II of the Unit Power Sales Manual. 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 B for the period capacity from such unit is made available.

2.5 Character of Sale: The sale of unit power pursuant to this Agreement shall not constitute a sale, lease, transfer or conveyance of an ownership interest in such units to JEA nor a dedication of ownership of such units to JEA or any other party. Energy associated with capacity from units made available hereunder shall, however, be devoted to JEA and the delivery of such energy to JEA shall not be subject to preemption by the 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, the portion of such units to which JEA 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 JEA pursuant to any other power sales under contracts between Southern Companies and JEA.

## ARTICLE III

## ENERGY AVAILABILITY

3.1 Energy: During each year specified in Section 2.2 (or portion thereof), JEA 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 JEA 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 3.8. Beginning the week prior to the week for initial delivery hereunder and each week thereafter during the term hereof, Southern Companies will provide JEA with an estimated daily schedule of the availability of such energy for the coming week (herein defined as Monday through Sunday). Such estimated availability schedule by units, together with the estimated applicable Base Energy Rates, Alternate Energy Rates and Supplemental Energy Rates shall be furnished by 11:00 a.m. on the Friday of that week, unless mutually agreed otherwise. Further, Southern Companies will provide JEA an hourly schedule by units of the availability of such energy, together with estimated applicable energy rates, each day by 11:00 a.m. for the following day, and such schedule may not be altered on less than four (4) hours prior notice, unless an alteration is necessary due to forced outage or curtailment of generating capacity or unless otherwise mutually agreed by the Operating Representatives of JEA and Southern Companies. All hours specified herein shall be prevailing Central Time unless otherwise agreed.

3.2 Scheduling Energy: Beginning the week prior to the week for initial delivery hereunder and each week thereafter during the term hereof, JEA will supply Southern

Companies an estimated daily schedule of capacity usage by units for the coming week (herein defined as Monday through Sunday). Such estimated schedule shall be furnished by 3:00 p.m. on the Friday prior to the week in which the capacity is required, unless mutually agreed otherwise. Further, JEA will provide Southern Companies an hourly schedule of capacity usage, by units, by 3:00 p.m. the day prior to when the capacity is required, and such schedule may not be altered on less than four (4) hours prior notice, unless otherwise mutually agreed by the Operating Representatives of JEA and Southern Companies. All hours specified herein shall be prevailing Central time, unless otherwise agreed. JEA will schedule total hourly capacity usage in amounts which are multiples of fifty (50) megawatts, unless otherwise agreed.

3.3 <u>Unavailability or Derating of Units</u>: Except as provided in Section 3.8 hereof, JEA 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 of partial derating of a unit, JEA 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:

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

Where:

MUPC = Maximum unit power capacity entitlement of JEA from such unit after derating.

UPC = Unit power capacity entitlement of JEA from such unit determined in accordance with Article II.

NDC = Net Dependable Capacity of unit.

AOC = Actual operating capability after derating as determined by the company responsible for operating the unit.

3.4 Allocation of Energy Schedules to Generation Units: Schedules for hourly capacity usage provided by JEA subject to Sections 3.1 and 3.2 above will be deemed to be requests for energy to be delivered from the generation units from which JEA has a capacity entitlement, as determined under Article II and as modified by Section 3.3 for units unavailable or derated. JEA 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 JEA's maximum capacity entitlement from that generating unit. The energy so scheduled by JEA 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 JEA shall be the lesser of (1) an amount equal to the total net generation of that unit multiplied by the ratio of the energy scheduled by JEA to the total energy scheduled by all parties purchasing unit power from that unit, or (2) the energy scheduled by JEA. If the Unit Energy so supplied to JEA 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: JEA agrees to schedule energy from each unit made available under Article II in excess of a fifty percent (50%) output factor on an annual basis. JEA agrees to use its best efforts, consistent with Prudent Utility Practices, to make the energy scheduled from each unit pursuant to Section 3.4 such that during any year the total energy scheduled from each unit is more than one-half the total hourly capacity made available from that unit under Article II for such year, as adjusted pursuant to Section 3.3 above.

3.6 Minimum Operation Energy: During all periods when a unit made available to JEA under Article II is operating at minimum operating conditions, JEA shall accept delivery of the energy associated with the minimum operation capacity obligation of JEA associated with such unit. For the purpose of this Agreement, "minimum operating conditions" shall mean the minimum loading required for stable operation of a unit as determined from time to time by the entity responsible for operation of the unit. JEA's minimum operation capacity obligation for each unit shall be determined by the following formula:

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

Where:

MOCO = JEA's minimum operation capacity obligation of a unit.

UPC = JEA's unit power capacity entitlement from such unit determined in accordance with Article II.

NDC = Net Dependable Capacity as determined in Section 2.3.1.

MC = Minimum loading required for stable operation of the unit.

3.7 Option to Furnish Scheduled Energy from Alternate Resources: Energy requested by JEA, 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 hereinafter 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 the 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 JEA 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 3.1.

3.8 Supplemental Energy Scheduling: GaPC or GuPC, as the case may be, agrees to use reasonable efforts to make energy available to JEA from each unit to which JEA has a capacity entitlement pursuant to Article II on the basis of a ninety percent (90%) target capacity factor on an annual basis. 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 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 JEA 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 generating resources owned or operated by the Southern Companies equal to ninety percent (90%) of JEA's entitlement in such unit under Article II.

3.8.2 During periods in which a unit to which JEA 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 generating resources owned or operated by the Southern Companies equal to ninety percent (90%) of JEA's entitlement in such unit under Article II less JEA's entitlement to schedule energy from such derated unit pursuant to Section 3.3.

3.8.3 In addition to the energy made available pursuant to Sections 3.8.1 and 3.8.2 during periods in which a unit to which JEA has a capacity entitlement under Article II is unavailable or partially derated, energy may be made available at Southern Companies election, from other coal-fired generating resources owned or operated by the Southern Companies, up to ten percent (10%) of JEA's entitlement in such unit under Article II. Energy made available to JEA pursuant to this Section and Sections 3.8.1 and 3.8.2 is hereinafter called "Supplemental Energy."

3.8.4 In the event the Supplemental Energy provided for in Sections 3.8.1 and 3.8.2 cannot be provided from coal-fired generating resources, Southern Companies agree to use their best efforts, consistent with Prudent Utility Practices, to make energy available from other 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 JEA's election, shall be deemed Supplemental Energy.

3.8.5 Southern Companies will not be obligated to provide JEA any additional Supplemental Energy for the remainder of any year from and after the date on which Southern Companies have made available to JEA for scheduling under this Agreement (except for energy made available under Section 3.8.4 but not taken by JEA) energy in the aggregate equal to ninety percent (90%) of JEA'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 JEA during the remainder of any such year is not available from units to which JEA has a capacity entitlement, such energy and associated capacity shall be furnished, if at all, under other rate schedules between the parties.

3.8.6 Supplemental Energy shall mean energy available on the systems of the Southern Companies, not needed at that time on their own systems to meet their own system requirements (including power used for pumping at pumped storage hydroelectric projects) and other power sale commitments taking precedence before delivery under this Agreement. The only power sale commitments taking precedence over the availability of Supplemental Energy are: (1) any seasonal energy or capacity exchange agreements now existing or entered into in the future, (2) any firm power interchange sales to other utilities or third parties now existing or entered into in the future, (3) any other Unit Power sales with other utilities or third parties now existing or entered into in the future, (4) the Long Term Power sales with JEA and other utilities which were executed prior to this Agreement, and (5) any short term power being supplied under provisions of a now existing contract with Alabama Electric Cooperative, Inc. Notwithstanding the above, it is understood that any Supplemental Energy made available for delivery by the Southern Companies will be made available to all Contemporaneous Parties on a pro rata basis based upon each such party's capacity entitlement in the unit unavailable for service.

Supplemental Energy, if available, may be supplied from an assigned generating unit of the Southern Companies or from the units in economic dispatch on the system of the Southern Companies at the time. Southern Companies will, at their sole option, determine whether the energy is to be supplied from an assigned unit or from units in economic dispatch. However, it is agreed that Supplemental Energy will normally be supplied from units in economic dispatch except when system operating conditions indicate otherwise. Southern Companies will notify JEA of the amount of Supplemental Energy to be made available, the selected energy sources and the estimated energy rates at the times set forth in Section 3.1.

ARTICLE IV

DELIVERY POINT

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

4.2 Additional Points of Delivery to be Established: It is recognized that certain of the transmission facilities which are to be constructed by GaPC and for which JEA is responsible in order to establish the Points of Delivery for the delivery and receipt of the power and energy to be sold and purchased hereunder have not been completed. GaPC and JEA shall use best efforts consistent with Prudent Utility Practices to complete such facilities by the time such facilities are needed to deliver and receive power and energy sold and purchased hereunder.

4.2.1 In the event completion of transmission facilities to be constructed by GaPC is delayed for any reason and power and energy scheduled to be sold and purchased hereunder cannot be effected as a result thereof, GaPC and other Southern Companies shall, as their sole obligation for such delay, waive JEA's obligations to purchase capacity and energy until such facilities are completed. In the event GaPC has not completed such facilities by January 1, 1984 to the extent any delay is attributable to GaPC's failure to exert its best efforts consistent with Section 4.2 above, JEA may exercise all of its rights in equity and at law against GaPC and other of the Southern Companies for breach of contract, and Southern Companies shall not be relieved of any of their obligations hereunder.

4.2.2 In the event completion of transmission facilities for which JEA is responsible is delayed for any reason, and power and energy scheduled to be sold and purchased hereunder cannot be effected as a result thereof, JEA and Southern Companies shall suspend sales and purchases of power and energy with respect to Service Schedule E of the Interchange Contract (or the Power Sale Agreement if such Interchange Contract has not become effective) and JEA shall, as its sole obligation for such delay, purchase from Southern Companies the amount of power under this Agreement which can be accommodated over the then existing interconnections between the parties consistent with the Transfer Limits (as defined in Section 4.4) and consistent with the rights of other Florida Utilities including Contemporaneous Parties which had contracts with Southern Companies for the purchase of unit power or Long Term Power as of the effective date of this Agreement. Such purchases, if not JEA's full capacity entitlement hereunder, shall be allocated on a pro rata basis from each unit to which JEA has capacity entitlement. To the extent sales and purchases of power and energy are suspended under Service Schedule E of the Interchange

Contract (or Power Sale Agreement if applicable), JEA and Southern Companies shall, at JEA's option, add an equal period of time (up to one year) to the term of said contract providing for the sale and purchase of such power and energy suspended because of such delay. JEA shall exercise such option by giving written notice to Southern Companies on or before March 1, 1984.

In the event JEA has not completed such transmission facilities by January 1, 1984, to the extent any delay is attributable to JEA's failure to exert best efforts consistent with Section 4.2 above, Southern Companies may exercise all of their rights in equity and at law against JEA for breach of contract and JEA shall not be relieved of any of its obligations hereunder.

4.3 <u>Transmission Contingencies</u>: 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, 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.

To the extent the occurrence of a contingency is controllable, Southern Companies shall use their best efforts consistent with Prudent Utility Practice 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 Practice to restore the affected facilities to provide for deliveries as scheduled.

To the extent any such transmission limitation is expected to exceed one hour Southern Companies shall use their best efforts, consistent with Prudent Utility Practices at the time, to sell to other utilities such power and energy for which JEA would be paying capacity charges; or Southern Companies, at their option, may make use of such power and energy for their own purposes. In the event Southern Companies sell such power and energy to third parties, Southern Companies shall credit JEA with the excess of revenues over generation expenses based on Base Energy Rates as specified in Section 6.3. For purposes of this Section 4.3, sales to others from resources of Southern Companies, other than oil-fired resources, shall take precedence over any sale made from capacity to which JEA is entitled. In the event

Southern Companies elect to make use of energy for which JEA would be paying capacity charges but are unable to receive because of transmission contingencies on either system, such energy shall be transacted under the provisions of Service Schedule C - Economy Interchange under the Interchange Contract between the parties, and Southern Companies shall pay to JEA the Base Energy Rate for such power and energy plus one-half the difference between such Base Energy Rate and the energy cost avoided by Southern Companies (if greater than the Base Energy Rate.)

4.4 Limitation of Transmission Facilities: Southern Companies and JEA recognize and acknowledge that transmission facilities being constructed pursuant to this 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 FCG-Southern Reliability Coordination Agreement. Southern Companies and JEA agree that in order for the full benefit of this 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 sales agreements, this Agreement and any and all power purchase and sales contemplated in the future.

Southern Companies and JEA hereby agree to observe "Transfer Limits" between Southern Companies and Florida (excluding GuPC) consistent with criteria set forth in the FCG-Southern Reliability Coordination Agreement. Until Transfer Limits are defined under the FCG-Southern Reliability Coordination Agreement, Transfer Limits will be defined by the criteria set forth below:

4.4.1 Transfer Limits: The Southern-Florida (excluding GuPC) First Contingency 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 the Southern Companies system including the Southern-Florida interconnection circuits, or following the loss of the largest generating unit in Florida or in the 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.

4.4.1.1 The total amount of power scheduled from Southern Companies to Florida (excluding GuPC), including any other sales or transfers from Southern Companies to other Florida utilities, shall not exceed the Transfer Limit except by mutual agreement during emergencies or other agreed to circumstances.

4.4.1.2 If either party desires to schedule transfers other than emergency transfers between Southern Companies and Florida (excluding GuPC) in excess of the then existing Transfer Limit, except as mutually agreed to in Section 4.4.1.1, 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 4.4.1.1.

4.4.1.3 Schedules of power by Southern Companies to Florida (except GuPC) in excess of the level of transactions under existing or contemporaneous agreements with JEA, FPL, Florida Power Corporation and the City of Tallahassee may create an undue burden on the transmission system of JEA, even though such schedules are within the Transfer Limit established under this Section 4.4. To the extent Southern Companies propose to make any additional sales of power in excess of such amounts to utilities in Florida for periods of one year or more, Southern Companies shall notify JEA of such proposal and JEA 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 JEA a reasonable probability exists that such sale will result in the imposition of an undue burden on the transmission system of JEA. In the event JEA fails to identify any such burden within such time, the agreement for such sale by Southern Companies shall not be prohibited by this Agreement. To the extent JEA identifies any potential burden on its transmission system resulting from such sale, JEA 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 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 4.4 above, such schedule of power shall not be prohibited by this Agreement unless JEA 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: JEA and Southern Companies recognize that the cost of providing the unit power and electric services contemplated herein may change during the term of this 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 Agreement.

In order to facilitate revisions or updates of the charges calculated under the basic procedure and methodology outlined in this 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 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 Agreement.

The Unit Power Sale Manual, together with this 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 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 Agreement is attached hereto 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 during 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 Agreement and the Unit Power Sale Manual. A revised Unit Power Sale Informational Schedule shall be submitted by Southern Companies to JEA on or before November 1 of each year for application on January 1 of the following year. This time period will allow JEA and Southern Companies to verify that the charges contained in the revised Unit Power Sale Informational Schedule have been computed in accordance with this 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 the formulary rate method and procedures described in this Agreement and the Unit Power Sale Manual, it is the intent of Southern Companies and JEA 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 the FERC. A revised Unit Power Sale Informational Schedule will be filed with the 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 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 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 and energy losses. In addition, Southern Companies shall have the right on a single occasion prior to January 1, 1983 to amend cost components included in the formulae for capacity and energy rates to add thereto any legitimate costs which though existing as of the date of execution of this Agreement, were not recognized as being applicable hereto and were inadvertently omitted from a formula component. In the event such amendment would result in imposition of charges to JEA greater than two percent (2%) higher than charges to JEA which would have resulted without such amendment, and Southern Companies do not agree to eliminate such charges greater than two percent (2%), JEA shall have the right, within sixty (60) days from FERC's approval of such amendment, to terminate this Agreement by written notice to Southern Companies specifying a termination date as any date prior to December 31, 1992. Southern Companies shall have the right to unilaterally make application to the Federal Energy Regulatory Commission for a change in rates under Section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder with respect to the specific matters identified above. In all such events, JEA shall be free to support or contest such amendment or raise any objection it may have to such amendment before FERC. 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. JEA 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 JEA.

5.4 Unilateral Changes Resulting From Regulatory Action: Southern Companies shall further have the right to file one or more unilateral changes in the capacity and energy rates under this Agreement if the rates provided for in this Agreement are disapproved or modified by the FERC, or its successor. JEA 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 JEA than those which would have been produced under the Agreement prior to the action taken by FERC; provided, however, that JEA's support is contingent upon its determination that it can reasonably defend such change otherwise.

## ARTICLE VI

## CHARGES FOR SERVICE

6.1 Rates: JEA 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 JEA 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 JEA pursuant to Article II hereof each month and the sum of the charges for all units during each month shall be paid by JEA in accordance with Section 7.1 hereof (Billing and Payment). In the event the Net Dependable Capacity of any unit from which capacity sales are to be made to JEA is determined to be zero for any year, JEA shall be responsible for the dollar per kilowatt month charge for such unit produced by formulary rate assuming such Net Dependable Capacity equaled ninety percent (90%) of the Expected Capacity and multiplying such charge by the capacity to which JEA would have been entitled in such circumstance. JEA 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 Company responsible for operating the unit, as governed by Prudent Utility Practices. Southern Companies shall true up the capacity charge, on a periodic basis (not less frequently than annually), to reflect actual costs. Such true up will be performed in accordance with Article IX of the Unit Power Sale Manual.

6.3 Base Energy Rates: For Unit Energy supplied to JEA during each month from the units specified in Exhibit B pursuant to Section 3.4, JEA shall pay an amount per MWh (hereinafter 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) The in-plant fuel handling 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.

(d) 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), (b) and (c) above,

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

6.4 <u>Alternate Energy Rates</u>: For energy supplied to JEA at any time from alternate sources owned or operated by Southern Companies, in accordance with Section 3.7, JEA shall pay an amount per MWh delivered which is the lesser of (1) the Base Energy Rate as determined in Section 6.3 for the unit for which Alternate Energy is provided, (2) the Normalized Energy Rate as determined in Section 6.6 for the unit for which Alternate Energy is provided, or (3) 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 system 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 the 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: (1) any seasonal energy or capacity exchange agreements now existing or entered into in the future, and (2) 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, in-plant fuel handling 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 JEA at any time pursuant to Section 3.8, JEA shall pay an amount per MWh delivered which is the greater of (1) 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 (2) the cost of such Supplemental Energy determined by the following principle:

For Supplemental Energy whether supplied from an assigned unit of Southern Companies or from the units in economic dispatch on the system of Southern Companies, the cost of such energy 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 Supplemental Energy as defined in Section 3.8.6. The expense from assigned units or units in economic dispatch shall include only the incremental cost of fuel, variable operation and maintenance expenses, in-plant fuel handling 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 B 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) The in-plant fuel handling expenses for the Unit as described in Article V of the Unit Power Sale Manual.

(d) 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), (b), and (c) above,

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

6.7 Station Service Charges: For station service energy required each month for a unit specified in Exhibit B during the hours in which the net electrical output of such unit is equal to or less than zero, JEA shall pay an amount per MWh, for a pro rata share of such station service energy based on the ratio of JEA'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.

## 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 JEA 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 Agreement, an amended invoice shall be presented to JEA by Southern Companies as soon as practicable after such change occurs. On or before the fifteenth day of each month of the ensuing year, JEA 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. 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 Sales Manual shall be added to or subtracted from the invoice due to be paid in the month next following the date on which JEA 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 JEA associated with the administration of the true up provision as specified in Article IX of the Unit Power Sales Manual. Payments of capacity charges not made when due shall accrue interest, at the then current rate under regulations of FERC provided for refunds made under the Federal Power Act, from the due date to the date of payment (a day shall equal 1/30 of a month).

7.2 Presentation and Payment of Bills for Energy and Other Charges: As promptly as practicable after the first of each month during the term hereof, an invoice shall be sent by Southern Companies by mail and by telecopy on the same date stating the charges determined in accordance with Article VI for energy sold and delivered to JEA hereunder during the preceeding month together with any other charges then due by JEA to Southern Companies pursuant to the terms of this 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. JEA 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 the then current rate under regulations of FERC provided for refunds made under the Federal Power Act, 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 JEA 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 recent 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.

7.3 Disputed Invoice: In case any portion of an invoice submitted pursuant to Section 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 Section 7.2. Upon request by JEA Southern Companies shall provide copies of supporting documentation and records necessary to verify invoices whether disputed or undisputed.

7.4 Audit Rights: Southern Companies shall, upon written request from JEA promptly make arrangements for JEA to audit any and all books and records of the Southern Companies which relate to and are necessary for verification of charges and costs paid by JEA under this Agreement. Such audit shall, at the option of JEA, and at JEA's sole expense, be performed by JEA, its designee being an employee of the City of Jacksonville, or by a nationally recognized accounting firm experienced in utility accounting practices. JEA's right to audit such records shall extend for a period of three years following any year to which such audit relates.

## ARTICLE VIII

## OPERATING COMMITTEE

8.1 Establishment of Operating Committee: JEA and SCS, acting as agent for Southern Companies, shall each appoint one representative to act for it in matters pertaining to detailed operating arrangements for delivery of power hereunder, and JEA and SCS may each appoint an alternate to act for it in the absence of its representative. The two 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 Agreement, shall be responsible for the following:

(a) Communications with respect to energy scheduling under Sections 3.1 through 3.5.

(b) Establishment of arrangements for metering, telemetering, 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 and transmission facilities referred to in Section 4.2.

(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 Alternate Energy and Supplemental Energy transactions under Sections 3.7 and 3.8.

(g) Communications with respect to determination of capacity available from each unit under Section 2.3.

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

(i) 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 5-year period.

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

Both JEA 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 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 Agreement. All decisions and agreements made by the Operating Committee shall be evidenced in writing.

8.3 <u>Unit Power Sales Operating Committee Meetings</u>: 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 JEA 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 <u>Role of SCS</u>: 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 Agreement by giving JEA 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 to Agent: JEA shall be entitled to make all payments due to be made in accordance with this Agreement to SCS, or such other agent of Southern Companies as designated under Section 9.1, and the making of such payments shall discharge JEA's obligations hereunder notwithstanding the fact that such payments shall be due to be paid to one or more of the Southern Companies.

ARTICLE X

MISCELLANEOUS PROVISIONS

10.1 Interrelationship with Interchange Contract: It is recognized by the parties that the Interchange Contract between the parties executed contemporaneously herewith shall govern the interconnected operations of the parties and is 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 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 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 Supplied.

(c) Section 5.6 Transfer of Power and Energy Through Other Systems.

(d) Section 6.2 Metering and Metering Facilities.

(e) Section 6.3 Inspecting and Testing of Meters.

(f) Section 6.4 Billing Adjustments.

(g) Section 7.1 Records.

(h) Section 10.1 Third Parties.

(i) Section 10.3 Liability.

(j) Section 10.4 Responsibility and Indemnification.

(k) Section 10.7 Notices.

(l) Section 10.8 Waivers.

(m) Section 10.9 Successors and Assigns.

10.3 Specification of Sole Obligation or Sole Remedy: With respect to the matters provided for herein where the Agreement specifies an obligation or remedy as being the sole obligation or remedy, it is the parties agreement and intent 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 JEA is entitled to capacity, other facilities (including transmission) referenced in this Agreement and other facilities required in support of Southern Companies' obligations under this Agreement, Southern Companies' standard of management and performance during the term of this Agreement shall be at least equal to the standard which it 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 contract, "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 either party hereto be liable (in contract or in tort, including negligence) to the other party for incidental or consequential loss or damage resulting from performance, nonperformance or delay in performance of their obligations under this Agreement, except where such loss or damage results from intentional tort or fraud.

10.7 <u>General Cost Principles</u>: Charges for electric services provided for in this 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. JEA and Southern Companies have agreed upon certain formulary descriptions of methodology and procedure as contained in the Unit Power Sale Manual and this 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 the 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 Unit Power Sales 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.

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 JEA shall not include duplication or allocations of greater than 100% of such costs.

10.8 <u>Effect of Approval of Agreement by City of Jacksonville</u>: It is understood that JEA will exert every reasonable effort to obtain all necessary approvals of this Agreement from the City Council of the City of Jacksonville so as to allow JEA to perform all the obligations established in this Agreement including, but not limited to, timely payment of all bills rendered under this Agreement from yearly appropriations by such City Council for such purpose or from other funds legally available to JEA. Neither this Agreement nor the obligation for payment evidenced herein shall be or constitutes an indebtedness of the City of Jacksonville within the meaning of any constitutional, statutory or charter provisions requiring the City to levy ad valorem taxes, nor a lien upon any properties of the City of Jacksonville.

10.9 Section References: References herein to Articles or Sections of Articles shall be interpreted to mean all Sections of the Article referenced and all subsections of the Section referenced.

10.10 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.

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

| | |
|---|---|
| ATTEST: | JACKSONVILLE ELECTRIC AUTHORITY |
| ______________________ | By ______________________ 2/27/81<br>Royce Lyles Date<br>Managing Director |
| ATTEST: | SOUTHERN COMPANY SERVICES, INC. |
| ______________________ | By ______________________ 2/23/81<br>Bill M. Guthrie Date<br>Executive Vice President |
| ATTEST: | ALABAMA POWER COMPANY |
| ______________________ | By ______________________ 2/27/81<br>R. E. Huffman Date<br>Vice President |
| ATTEST: | GEORGIA POWER COMPANY |
| ______________________ | By ______________________ 2/27/81<br>A. W. Dahlberg Date<br>Vice President |
| ATTEST: | GULF POWER COMPANY |
| ______________________ | By ______________________ 2/27/81<br>E. B. Parsons, Jr. Date<br>Vice President |
| ATTEST: | MISSISSIPPI POWER COMPANY |
| ______________________ | By ______________________ 2/27/81<br>H. H. Bell, Jr. Date<br>Vice President |

EXHIBIT

ALLOCATION OF EXPECTED CAPACITY[1]
FOR UNIT POWER SALES

| YEAR | MONTH(S) | GEORGIA POWER COMPANY SCHERER 1 OWNED (MW) | SCHERER 1 BUY-BACK (MW) | SCHERER 2 OWNED (MW) | SCHERER 2 BUY-BACK (MW) | SCHERER 3 (MW) | SCHERER 4 (MW) | GaPC TOTAL (MW) | GULF POWER COMPANY DANIEL 1 (MW) | DANIEL 2 (MW) | SCHERER 3[2] (MW) | SCHERER 4[2] (MW) | GuPC TOTAL (MW) | TOTAL CAPACITY (MW) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1983 | JAN | 68 | 432 | | | | | 500 | 150 | 150 | | | 300 | 800 |
| | FEB-MAY | 68 | 432 | | | | | 500 | 150 | 150 | | | 300 | 800 |
| | JUN-DEC | 68 | 432 | | | | | 500 | 150 | 150 | | | 300 | 800 |
| 1984 | JAN | 68 | 583 | | | | | 651 | 150 | 150 | | | 300 | 951 |
| | FEB-MAY | 68 | 300 | 68 | 364 | | | 800 | 150 | 150 | | | 300 | 1100 |
| | JUN-DEC | 68 | 300 | 68 | 364 | | | 800 | 150 | 150 | | | 300 | 1100 |
| 1985 | JAN | 68 | 393 | 68 | 481 | | | 1010 | 150 | 150 | | | 300 | 1310 |
| | FEB-MAY | 68 | 393 | 68 | 481 | | | 1010 | 150 | 150 | | | 300 | 1310 |
| | JUN-DEC | 68 | 393 | 68 | 481 | | | 1010 | 150 | 150 | | | 300 | 1310 |
| 1986 | JAN | 68 | 437 | 68 | 583 | | | 1156 | 150 | 150 | | | 300 | 1456 |
| | FEB-MAY | 68 | 437 | 68 | 583 | | | 1156 | 150 | 150 | | | 300 | 1456 |
| | JUN-DEC | 68 | 389 | 68 | 535 | | | 1060 | 150 | 150 | | | 300 | 1360 |
| 1987 | JAN | 68 | 364 | 68 | 510 | | | 1010 | 150 | 150 | | | 300 | 1310 |
| | FEB-MAY | 68 | 364 | 68 | 502 | 606 | | 1608 | 150 | 150 | 202 | | 502 | 2110 |
| | JUN-DEC | 68 | 316 | 68 | 462 | 606 | | 1520 | 150 | 150 | 202 | | 502 | 2022 |
| 1988 | JAN | 68 | 291 | 68 | 437 | 606 | | 1470 | 224 | 224 | 202 | | 650 | 2120 |
| | FEB-MAY | 68 | 291 | 68 | 437 | 606 | | 1470 | 224 | 224 | 202 | | 650 | 2120 |
| | JUN-DEC | 68 | 243 | 68 | 389 | 606 | | 1374 | 224 | 224 | 202 | | 650 | 2024 |
| 1989 | JAN | 68 | 219 | 68 | 364 | 606 | | 1325 | 224 | 224 | 202 | | 650 | 1975 |
| | FEB-MAY | 68 | 140 | 68 | 228 | 606 | 606 | 1716 | 0 | 0 | 202 | 202 | 404 | 2120 |
| | JUN-DEC | 68 | 140 | 68 | 228 | 606 | 606 | 1716 | 0 | 0 | 202 | 202 | 404 | 2120 |
| 1990 | JAN | 68 | 140 | 68 | 274 | 606 | 606 | 1762 | 0 | 0 | 202 | 202 | 404 | 2166 |
| | FEB-MAY | 68 | 140 | 68 | 274 | 606 | 606 | 1762 | 0 | 0 | 202 | 202 | 404 | 2166 |
| | JUN-DEC | 68 | 97 | 68 | 243 | 606 | 606 | 1688 | 0 | 0 | 202 | 202 | 404 | 2092 |
| 1991 | JAN | 68 | 73 | 68 | 219 | 606 | 606 | 1640 | 0 | 0 | 202 | 202 | 404 | 2044 |
| | FEB-MAY | 68 | 73 | 68 | 219 | 606 | 606 | 1640 | 0 | 0 | 202 | 202 | 404 | 2044 |
| | JUN-DEC | 68 | 24 | 68 | 170 | 606 | 606 | 1542 | 0 | 0 | 202 | 202 | 404 | 1946 |
| 1992 | JAN | 68 | 0 | 68 | 146 | 606 | 606 | 1494 | 0 | 0 | 202 | 202 | 404 | 1898 |
| | FEB-MAY | 68 | 0 | 68 | 146 | 606 | 606 | 1494 | 0 | 0 | 202 | 202 | 404 | 1898 |
| | JUN-DEC | 68 | 0 | 68 | 97 | 606 | 606 | 1445 | 0 | 0 | 202 | 202 | 404 | 1849 |

NOTES: (1) Expected Total Operating Capacity ("Expected Capacity") for each unit is: Scherer 1-4 = 808 MW, Daniel 1 & 2 = 511 MW.

(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**

**ALLOCATION OF EXPECTED CAPACITY FOR UNIT POWER SALES TO JEA**

| | | GEORGIA POWER COMPANY | | | | | | | GULF POWER COMPANY | | | | | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | SCHERER 1 | | SCHERER 2 | | | | GaPC | | | (1) | (1) | GuPC | SALES |
| YEAR | MONTH(S) | OWNED (2) (MW) | BUY-BACK (MW) | OWNED (2) (MW) | BUY-BACK (MW) | SCHERER 3 (MW) | SCHERER 4 (MW) | TOTAL (MW) | DANIEL 1 (MW) | DANIEL 2 (MW) | SCHERER 3 (MW) | SCHERER 4 (MW) | TOTAL (MW) | TO JEA (MW) |
| 1983 | JAN | 31 | 159 | | | | | 190 | 55 | 55 | | | 110 | 300 |
| | FEB-MAY | 31 | 159 | | | | | 190 | 55 | 55 | | | 110 | 300 |
| | JUN-DEC | 31 | 159 | | | | | 190 | 55 | 55 | | | 110 | 300 |
| 1984 | JAN | 31 | 177 | | | | | 208 | 46 | 46 | | | 92 | 300 |
| | FEB-MAY | 31 | 74 | 31 | 90 | | | 226 | 37 | 37 | | | 74 | 300 |
| | JUN-DEC | 31 | 74 | 31 | 90 | | | 226 | 37 | 37 | | | 74 | 300 |
| 1985 | JAN | 31 | 80 | 31 | 98 | | | 240 | 30 | 30 | | | 60 | 300 |
| | FEB-MAY | 31 | 80 | 31 | 98 | | | 240 | 30 | 30 | | | 60 | 300 |
| | JUN-DEC | 31 | 80 | 31 | 98 | | | 240 | 30 | 30 | | | 60 | 300 |
| 1986 | JAN | 31 | 79 | 31 | 105 | | | 246 | 27 | 27 | | | 54 | 300 |
| | FEB-MAY | 31 | 79 | 31 | 105 | | | 246 | 27 | 27 | | | 54 | 300 |
| | JUN-DEC | 31 | 76 | 31 | 104 | | | 242 | 29 | 29 | | | 58 | 300 |
| 1987 | JAN | 30 | 137 | 30 | 191 | | | 388 | 56 | 56 | | | 112 | 500 |
| | FEB-MAY | 30 | 82 | 30 | 112 | 135 | | 389 | 33 | 33 | 45 | | 111 | 500 |
| | JUN-DEC | 30 | 74 | 30 | 108 | 141 | | 383 | 35 | 35 | 47 | | 117 | 500 |
| 1988 | JAN | 19 | 53 | 19 | 80 | 110 | | 281 | 41 | 41 | 37 | | 119 | 400 |
| | FEB-MAY | 19 | 53 | 19 | 80 | 110 | | 281 | 41 | 41 | 37 | | 119 | 400 |
| | JUN-DEC | 19 | 47 | 19 | 74 | 116 | | 275 | 43 | 43 | 39 | | 125 | 400 |
| 1989 | JAN | 19 | 43 | 19 | 72 | 119 | | 272 | 44 | 44 | 40 | | 128 | 400 |
| | FEB-MAY | 19 | 26 | 19 | 42 | 110 | 110 | 326 | 0 | 0 | 37 | 37 | 74 | 400 |
| | JUN-DEC | 19 | 26 | 19 | 42 | 110 | 110 | 326 | 0 | 0 | 37 | 37 | 74 | 400 |
| 1990 | JAN | 19 | 25 | 19 | 49 | 108 | 108 | 328 | 0 | 0 | 36 | 36 | 72 | 400 |
| | FEB-MAY | 19 | 25 | 19 | 49 | 108 | 108 | 328 | 0 | 0 | 36 | 36 | 72 | 400 |
| | JUN-DEC | 19 | 19 | 19 | 45 | 112 | 112 | 326 | 0 | 0 | 37 | 37 | 74 | 400 |
| 1991 | JAN | 19 | 14 | 19 | 42 | 115 | 115 | 324 | 0 | 0 | 38 | 38 | 76 | 400 |
| | FEB-MAY | 19 | 14 | 19 | 42 | 115 | 115 | 324 | 0 | 0 | 38 | 38 | 76 | 400 |
| | JUN-DEC | 19 | 6 | 19 | 34 | 121 | 121 | 320 | 0 | 0 | 40 | 40 | 80 | 400 |
| 1992 | JAN | 19 | 0 | 19 | 30 | 125 | 125 | 318 | 0 | 0 | 41 | 41 | 82 | 400 |
| | FEB-MAY | 19 | 0 | 19 | 30 | 125 | 125 | 318 | 0 | 0 | 41 | 41 | 82 | 400 |
| | JUN-DEC | 19 | 0 | 19 | 20 | 128 | 128 | 314 | 0 | 0 | 43 | 43 | 86 | 400 |

NOTE: (1) In the event Gulf Power Company does not purchase a 25% interest in Scherer 3 and 4, or in the event Gulf Power Company purchases a different percentage interest, the allocations of Scherer 3 and 4 between Georgia Power Company and Gulf Power Company shall be adjusted accordingly.

(2) Under circumstances described in Section 2.3.2 affecting this unit, that portion of the amount shown in this column which cannot be supplied will be supplied by increasing the sale amount from Scherer Buy-Back.

EXHIBIT C

ADDENDUM TO
JEA-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 JEA-Southern Companies Unit Power Sales Agreement entered into the 27th day of February, 1981, 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. The Net Dependable Capacity for Scherer Unit Number 1 for the initial year of commercial operation shall be 808 megawatts; except, should unusual circumstances occur prior to

Scherer Unit Number 1 being declared commercial which causes GaPC to change the Net Dependable Capacity for such year, GaPC will provide a statement giving the reason(s) for not using 808 megawatts for the Net Dependable Capacity and the method used to establish the Net Dependable Capacity for such year.

<u>Section 1.3</u> <u>Data to be Provided</u>: 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:

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

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

where:

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

and:

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

$BR$ = Monthly production capacity charge for buy-back capactiy ($/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).

$BB_{Si}$ = 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:

<u>Section 2.2.1</u>: <u>Net Dependable Capacity</u> 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 ($BP_{si}$) by the Net Dependable Capacity.

<u>Section 2.2.2</u>: <u>Gross Generating Unit Investment</u> for GaPC 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 gross generating unit investment for GuPC is the cost of the coal-fired generating unit recorded in FERC Accounts 310-316 plus the cost of the associated generator step-up substation recorded in Accounts 352 and 353 at the end of each month of the Contract Year. For units owned by GuPC, 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 GuPC's retail rate base. The amount shall be calculated on a monthly basis for the construction period of the unit using the following formula:

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

DA = Dollar amount to be added to booked AFUDC.

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

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

AB = The actual monthly AFUDC base used by GuPC 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 in the step-up substation yard are allocated equally among the units at the plant site.

Section 2.2.3: Accumulated Depreciation is associated with the gross production investment defined in Section 2.2.2. The accumulated depreciation for GuPC 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 payroll taxes as described in Section 2.2.14.

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.

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

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 payroll taxes as described in Section 2.2.14.

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. 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.

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 payroll taxes as described in Section 2.2.14. 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 Units of Production during the first six months of operation and the remaining life on Straight Line depreciation. The depreciation expense for generating units owned by GuPC 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, its associated step-up substation, and the major functional groups in the following manner. A percentage (as defined by applicable law) is applied to the gross investment plant balances which yields the fair market value of the investment being considered. The fair market value is then multiplied by the assessment rate and the estimated millage rate to obtain the tax for the specific unit, its generator step-up substation, and the major functional groups. 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.

Section 2.2.14: Payroll Taxes for a specific coal-fired generating unit are calculated in the following manner. The operating company budgets the salaries and wages by functional group for the Contract Year and accounts for expected changes in number of employees. The expected payroll tax rates for the ensuing Contract Year are then applied to the budgeted salaries and wages by functional group to obtain each function's payroll tax. The production function is subdivided into fossil steam, nuclear, hydro and combustion turbine production groups.

The salaries and wages for a specific coal-fired generating unit are determined on an historical basis and compared to the total salaries and wages for the steam production function. This ratio (the actual unit's salaries and wages divided by the total steam production salaries and wages) is applied to the total steam production payroll taxes as described above to obtain the specific unit's associated payroll taxes. For a unit which does not have an historical basis as required for the salaries and wages calculation described above, the most recent vintage and similar coal-fired unit that does have an historical basis will be used for the first year's estimate.

The payroll taxes 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 payroll taxes to the total payroll taxes less the administrative classification's payroll taxes. The payroll taxes associated with the transmission function, including the allocated administrative payroll taxes, 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. The payroll taxes for a specific unit which is jointly owned by the operating company and participants or GaPC and GuPC are computed for 100 percent of the unit. The total payroll taxes for such jointly owned units are allocated on the basis of percent ownership.

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

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 = 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 Mortgage 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 = 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:

$$CM_y = (DR \times i_y) + (PR \times p_y) + (ER \times c_y)$$

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 Fist 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 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 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 2.2.18 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</u> <u>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.

<u>Section 3.2.1</u> <u>Five-Day Average Load</u> 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.

<u>Section 3.2.2</u> <u>Gross Transmission Investment</u> 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 betwen 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 payroll taxes as described in Section 3.2.13.

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 payroll taxes as described in Section 3.2.13. 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 payroll taxes 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 payroll taxes and within transmission to the facilities rated 115 kV and above on the basis of net investment.

Section 3.2.13 Payroll Taxes are calculated in the following manner. The operating company budgets the salaries and wages by functional group for the Contract Year and accounts for expected changes in number of employees. The expected payroll tax rates for the ensuing Contract Year are then applied to the budgeted salaries and wages by functional group to obtain each function's payroll tax.

The payroll taxes associated with the administrative and general classification are allocated to the transmission function. 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 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.

<u>Section 3.2.15</u> <u>Total Transmission Expenses</u> 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.

<u>Section 3.2.16</u> <u>The Cost of Capital</u> 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.

## 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 (excluding 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 (excluding 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 overtime labor charged to FERC Accounts 502, 505, 506, 512, 513, and 514, (ii) all contract labor, (iii) all operating material charged to Accounts 502, 505, and 506, and (iv) 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.

INFORMATIONAL SCHEDULE AND WORK PAPERS

FOR

UNIT POWER SALES AGREEMENT

BETWEEN

JACKSONVILLE ELECTRIC AUTHORITY

AND

SOUTHERN COMPANIES

UNIT POWER SALE INFORMATIONAL SCHEDULE
TO UNIT POWER SALES AGREEMENT
BETWEEN JEA AND SOUTHERN COMPANIES

***FOR ILLUSTRATIVE PURPOSES ONLY***

SUMMARY OF 1982 CAPACITY CHARGES [1/]

| | PRODUCTION | TRANSMISSION |
|---|---|---|
| January | - | - |
| February | 14.055345 | 0.979994 |
| March | 14.055345 | 0.979994 |
| April | 14.055345 | 0.979994 |
| May | 14.055345 | 0.979994 |
| June | 14.018828 | 0.980138 |
| July | 14.018828 | 0.980138 |
| August | 14.018828 | 0.980138 |
| September | 14.018828 | 0.980138 |
| October | 14.018828 | 0.980138 |
| November | 14.018828 | 0.980138 |
| December | 14.018828 | 0.980138 |

1/ Data for illustrative purposes based on 1982 estimated cost and the schedule of sales for 1983.

WORK PAPER SUPPORTING
UNIT POWER SALE INFORMATIONAL SCHEDULE
TO UNIT POWER SALES AGREEMENT
BETWEEN JEA AND SOUTHERN COMPANIES

***ILLUSTRATIVE PURPOSES ONLY***

| UNIT | SCHERER NO. 1 | | DANIEL NO. 1 | DANIEL NO. 2 | REFERENCES |
|---|---|---|---|---|---|
| Net Dependable Capacity - MW | 808 | | 511 | 511 | Exhibit C, Article I |
| February | Owned | Buy Back | | | |
| Capacity Purchased - MW | 31 | 159 | 55 | 55 | Exhibit B |
| Capacity Charge - $/KW-Mo. | 20.079 | 16.338 | 9.035 | 9.035 | |
| March | | | | | |
| Capacity Purchased - MW | 31 | 159 | 55 | 55 | |
| Capacity Charge - $/KW-Mo. | 20.079 | 16.338 | 9.035 | 9.035 | |
| April | | | | | |
| Capacity Purchased - MW | 31 | 159 | 55 | 55 | |
| Capacity Charge - $/KW-Mo. | 20.079 | 16.338 | 9.035 | 9.035 | |
| May | | | | | |
| Capacity Purchased - MW | 31 | 159 | 55 | 55 | |
| Capacity Charge - $/KW-Mo. | 20.079 | 16.338 | 9.035 | 9.035 | |
| June | | | | | |
| Capacity Purchased - MW | 31 | 159 | 55 | 55 | |
| Capacity Charge - $/KW-Mo. | 20.079 | 16.338 | 9.035 | 9.035 | |
| July | | | | | |
| Capacity Purchased - MW | 31 | 159 | 55 | 55 | |
| Capacity Charge - $/KW-Mo. | 20.079 | 16.338 | 9.035 | 9.035 | |
| August | | | | | |
| Capacity Purchased - MW | 31 | 159 | 55 | 55 | |
| Capacity Charge - $/KW-Mo. | 20.079 | 16.338 | 9.035 | 9.035 | |
| September | | | | | |
| Capacity Purchased - MW | 31 | 159 | 55 | 55 | |
| Capacity Charge - $/KW-Mo. | 20.079 | 16.338 | 9.035 | 9.035 | |
| October | | | | | |
| Capacity Purchased - MW | 31 | 159 | 55 | 55 | |
| Capacity Charge - $/KW-Mo. | 20.079 | 16.338 | 9.035 | 9.035 | |
| November | | | | | |
| Capacity Purchased - MW | 31 | 159 | 55 | 55 | |
| Capacity Charge - $/KW-Mo. | 20.079 | 16.338 | 9.035 | 9.035 | |
| December | | | | | |
| Capacity Purchased - MW | 31 | 159 | 55 | 55 | |
| Capacity Charge - $/KW-Mo. | 20.079 | 16.338 | 9.035 | 9.035 | |

WORK PAPER SUPPORTING
UNIT POWER SALE INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***

## RATE CALCULATION FOR SCHERER UNIT NO. 1 - 1982

**Fixed Charges Calculation:**

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

February-May:

$$AFC_{OPC} = \left[ \$460{,}350{,}942 \times \left[ \frac{(12.63 + 5.88 + 9.69)/100}{2.0} + \frac{2.0\%}{100\%} \right] + \$23{,}543{,}595 \right] \times \left[ \frac{60.0\%}{60.0\%} \right] = \$97{,}660{,}097$$

June-December:

$$AFC_{OPC} = \left[ \$460{,}350{,}942 \times \left[ \frac{(12.63 + 5.88 + 9.69)/100}{2.0} + \frac{2.0\%}{100\%} \right] + \$23{,}543{,}595 \right] \times \left[ \frac{54.0\%}{60.0\%} \right] = \$87{,}894{,}087$$

February-May:

$$AFC_{MEAG} = \left[ \$201{,}109{,}563 \times \left[ \frac{(12.63 + 5.88 + 7.28)/100}{2.0} + \frac{2.0\%}{100\%} \right] + \$10{,}982{,}226 \right] \times \left[ \frac{30.2\%}{30.2\%} \right] = \$40{,}937{,}495$$

June-December:

$$AFC_{MEAG} = \left[ \$201{,}109{,}563 \times \left[ \frac{(12.63 + 5.88 + 7.28)/100}{2.0} + \frac{2.0\%}{100\%} \right] + \$10{,}982{,}226 \right] \times \left[ \frac{30.2\%}{30.2\%} \right] = \$40{,}937{,}495$$

## RATE CALCULATION FOR SCHERER UNIT NO. 1 - 1982

Buy-Back Rate Calculation:

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

February-May:

$$BR = \frac{1}{12}\left[\frac{\$97,660,097 + \$40,937,495}{484,800 + 244,000}\right] \times \left[\frac{100}{100-3}\right] = \$16.338/\text{kW-month}$$

June-December:

$$BR = \frac{1}{12}\left[\frac{\$87,894,087 + \$40,937,495}{436,320 + 244,000}\right] \times \left[\frac{100}{100-3}\right] = \$16.269/\text{kW-month}$$

Production Capacity Charge Calculation:

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

February-December:

$$R_{GPC} = \left[\frac{\$66,038,732 \times [(12.87 + 6.11)/100] + \$3,335,332}{67,900 \times 12.0}\right] \times \left[\frac{100}{100-3}\right]$$

$$= \$20.079/\text{kW-month}$$

WORK PAPER SUPPORTING
UNIT POWER SALE INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***

SCHERER PLANT - 1982
INVESTMENTS FOR UNIT NO. 1

| | GPC OWNERSHIP 3/ | OPC OWNERSHIP 3/ | MEAG OWNERSHIP 3/ | TOTAL 1/ |
|---|---|---|---|---|
| Gross Investment | | | | |
| Unit 2/ | $66,450,000 | $426,859,341 | $184,242,124 | $711,432,235 |
| GSU | 622,000 | 4,442,857 | 2,236,238 | 7,404,762 |
| Total | $67,072,000 | $431,302,198 | $186,478,362 | $718,836,997 |
| Accum. Depreciation | | | | |
| Unit 2/ | $ 1,406,000 | $ 10,042,857 | $ 5,054,905 | $ 16,738,095 |
| GSU | 15,861 | 113,297 | 57,026 | 188,828 |
| Total | $ 1,421,861 | $ 10,156,154 | $ 5,111,931 | $ 16,926,923 |
| Net Investment | | | | |
| Unit 2/ | $65,044,000 | $416,816,484 | $179,187,219 | $694,694,140 |
| GSU | 606,139 | 4,329,560 | 2,179,212 | 7,215,934 |
| Total | $65,650,139 | $421,146,044 | $181,366,431 | $701,910,074 |
| General Plant | | | | |
| Unit | $ 1,576,358 | $ 11,259,697 | $ 5,667,381 | $ 18,766,161 |
| GSU | 6,801 | 48,579 | 24,451 | 80,965 |
| Total | $ 1,583,159 | $ 11,308,276 | $ 5,701,832 | $ 18,847,126 |
| Working Capital | | | | |
| Unit | $ 3,903,630 | $ 27,883,070 | $ 14,034,479 | $ 46,471,784 |
| GSU | 1,897 | 13,552 | 6,821 | 22,587 |
| Total | $ 3,905,527 | $ 27,896,622 | $ 14,041,300 | $ 46,494,371 |
| Accum. Def. Income Taxes | | | | |
| Unit | $ 4,001,833 | $ - | $ - | $ 4,001,833 |
| GSU 2/ | 1,098,260 | - | - | 1,098,260 |
| Total | $ 5,100,093 | $ - | $ - | $ 5,100,093 |
| Total Production Investment | $66,038,732 | $460,350,942 | $201,109,563 | $762,151,478 |

NOTES:

1/ Totals include Dalton. Numbers will not add across.

2/ Includes Common Facilities.

3/ Unit Ownership
GPC = 8.4%
OPC = 60.0%
MEAG = 30.2%

Common Facilities Ownership
GPC = 11.7%
OPC = 60.0%
MEAG = 15.1%

WORK PAPER SUPPORTING
UNIT POWER SALE INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***



## SCHERER PLANT - 1982
## EXPENSES FOR UNIT NO. 1

| | GPC OWNERSHIP 3/ | OPC OWNERSHIP 3/ | MEAG OWNERSHIP 3/ | TOTAL 1/ |
|---|---|---|---|---|
| Operation & Maintenance-Fixed | | | | |
| Unit | $ 287,235 | $ 2,051,678 | $ 1,032,678 | $ 3,419,464 |
| GSU | 9,383 | 67,020 | 33,733 | 111,700 |
| Total | $ 296,618 | $ 2,118,698 | $ 1,066,411 | $ 3,531,164 |
| Administrative & General | | | | |
| Unit | $1,142,763 | $ 8,162,591 | $ 4,108,504 | $13,604,318 |
| GSU | 4,937 | 35,261 | 17,748 | 58,768 |
| Total | $1,147,700 | $ 8,197,852 | $ 4,126,252 | $13,663,086 |
| Depreciation Expense | | | | |
| Unit 2/ | $1,471,129 | $10,508,062 | $ 5,289,058 | $17,513,437 |
| GSU | 16,143 | 115,304 | 58,036 | 192,173 |
| Total | $1,487,272 | $10,623,366 | $ 5,347,094 | $17,705,610 |
| Amort. of Invest. Tax Credits | | | | |
| Unit | $ 25,191 | $ - | $ - | $ 25,191 |
| GSU 2/ | 14,035 | - | - | 14,035 |
| Total | $ 39,226 | $ - | $ - | $ 39,226 |
| Real & Personal Property Tax | | | | |
| Unit | $ 241,374 | $ 1,724,098 | $ - | $ 1,965,472 |
| GSU | 71 | 505 | - | 576 |
| Total | $ 241,445 | $ 1,724,603 | $ - | $ 1,966,048 |
| Payroll Taxes | | | | |
| Unit | $ 122,542 | $ 875,300 | $ 440,568 | $ 1,458,833 |
| GSU | 529 | 3,776 | 1,901 | 6,294 |
| Total | $ 123,071 | $ 879,076 | $ 442,469 | $ 1,465,127 |
| Total Production Expenses | $3,335,332 | $23,543,595 | $10,982,226 | $38,370,261 |

NOTES:

1/ Totals include Dalton. Numbers will not add across.

2/ Includes Common Facilities.

3/

| Unit Ownership | Common Facilities Ownership |
|---|---|
| GPC = 8.4% | GPC = 11.7% |
| OPC = 60.0% | OPC = 60.0% |
| MEAG = 30.2% | MEAG = 15.1% |

## SCHERER PLANT - 1982
## WORKING CAPITAL FOR UNIT NO. 1 1/

| | GPC OWNERSHIP 3/ | OPC OWNERSHIP 3/ | MEAG OWNERSHIP 3/ | TOTAL 2/ |
|---|---|---|---|---|
| **FOR UNIT** | | | | |
| Fixed O&M Expense | | | | $ 3,419,464 |
| Variable O&M Expense | | | | 4,945,066 |
| Fuel Burn Expense | | | | 58,680,158 |
| Administrative & General Expense | | | | 13,604,318 |
| Total Basis for Cash Working Capital | | | | $80,649,006 |
| Cash Working Capital (1/8 of above) | | | | $10,081,126 |
| Prepayments | | | | $ 400,429 |
| Material & Supplies | | | | $36,260,229 |
| Total for Unit | $3,903,630 | $27,883,070 | $14,034,479 | $46,471,784 |
| **FOR STEP-UP SUBSTATION** | | | | |
| Fixed O&M Expense | | | | $ 111,700 |
| Administrative & General Expense | | | | $ 58,768 |
| Total Basis for Cash Working Capital | | | | $ 170,468 |
| Cash Working Capital (1/8 of above) | | | | $ 21,309 |
| Prepayments | | | | $ 1,278 |
| Materials & Supplies | | | | $ - |
| Total for Substation | $ 1,897 | $ 13,552 | $ 6,821 | $ 22,587 |
| TOTAL WORKING CAPITAL | $3,905,527 | $27,896,622 | $14,041,300 | $46,494,371 |

NOTES:
1/ For reference see Exhibit C, Section 2.2.6.
2/ Totals include Dalton. Numbers will not add across.
3/

| Unit Ownership | Common Facilities Ownership |
|---|---|
| GPC = 8.4% | GPC = 11.7% |
| OPC = 60.0% | OPC = 60.0% |
| MEAG = 30.2% | MEAG = 15.1% |

WORK PAPER SUPPORTING
UNIT POWER SALE INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***

GEORGIA POWER COMPANY
1982 ALLOCATIONS FOR SCHERER NO. 1

| UNIT | | | REFERENCES |
|---|---|---|---|
| PAYROLL TAXES | = [14,062,583/(14062583 - 3313145)] x $1,115,132 | = $ 1,458,833 | Exhibit C, Section 2.2.14 |
| GENERAL PLANT | = $81,811,370 x ($1,458,833/6,359,805) | = $18,766,161 | Exhibit C, Section 2.2.5 |
| A&G EXPENSE | | | Exhibit C, Section 2.2.10 |
| Insurance (Assigned) | = | = $ 354,286 | |
| Insurance (General Plant) & Other | = ($226,076 + $57,537,645) x (1,458,833/6,359,805) | = $13,250,032 | |
| | | $13,604,318 | |
| O&M EXPENSE | = | = $ 3,419,464 | Exhibit C, Section 2.2.9 |
| PREPAYMENTS | | | Exhibit C, Section 2.2.6 (For Working Capital) |
| Assigned | = | = $ 358,000 | |
| General Plant | = ($184,970) x (1,458,833/6,359,805) | = $ 42,429 | |
| | | $ 400,429 | |
| REAL & PERSONAL PROPERTY TAX | | | Exhibit C, Section 2.2.13 |
| Assigned | = | = $ 2,678,571* | |
| General Plant | = ($849,778) x (1,458,833/6,359,805) | = $ 194,925 | |
| | | $ 2,873,496 | |
| ACCUMULATED DEFERRED INCOME TAXES | | | Exhibit C, Section 2.2.[illegible] |
| Assigned | = | = $ 1,039,784 | |
| General Plant | = 12,913,098 x (1,458,833/6,359,805) | = $ 2,962,049 | |
| | | $ 4,001,833 | |
| DEPRECIATION EXPENSE | | | Exhibit C, Section 2.2.11 |
| Assigned | = | = $16,738,095 | |
| General Plant | = 3,380,117 x (1,458,833/6,359,805) | = 775,342 | |
| | | $17,513,437 | |

*Fuel stock only

WORK PAP[illegible] SUPPORTING
UNIT POWER SALE [illegible]RMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***

GEORGIA POWER COMPANY
1982 ALLOCATIONS FOR SCHERER NO. 1

| STEP-UP SUBSTATION | | | REFERENCES |
|---|---|---|---|
| PAYROLL TAXES | = $818,662 x .3308619116 x .0232381526 | = $ 6,294 | Exhibit C, Section 2.2.14 |
| GENERAL PLANT | = $ 10,531,118 x 6,294/818,662 | = $ 80,965 | Exhibit C, Section 2.2.5 |
| A&G EXPENSE | | | Exhibit C, Section 2.2.10 |
| Insurance | = ($114,353 + 29,102) x .0127305384 | = $ 1,826 | |
| Other | = ($ 7,406,498) x 6,294/818,662 | = $ 56,942 | |
| | | $ 58,768 | |
| O&M EXPENSE | = ($ 4,806,742) x .0232381526 | = $ 111,700 | Exhibit C, Section 2.2.9 |
| PREPAYMENTS | | | Exhibit C, Section 2.2.6 (For Working Capital) |
| Substation | = ($86,000) x .0127305384 | = $ 1,095 | |
| General Plant | = ($23,810) x 6,294/818,662 | = $ 183 | |
| | | $ 1,278 | |
| REAL & PERSONAL PROPERTY TAX | | | Exhibit C, Section 2.2.13 |
| Assigned | = | = 0* | |
| General Plant | = (109,387) x 6,294/818,662 | = $ 841 | |
| ACCUMULATED DEFERRED INCOME TAXES | | | Exhibit C, Section 2.2.7 |
| Assigned | = | $1,085,481 | |
| General Plant | = 1,662,231 x 6,294/818,662 | $ 12,779 | |
| | | $1,098,260 | |
| DEPRECIATION EXPENSE | | | Exhibit C, Section 2.2.11 |
| Assigned | = | = $ 188,828 | |
| General Plant | = 435,104 x 6,294/818,662 | = $ 3,345 | |
| | | $ 192,173 | |

*For first year only.

WORK PAPER SUPPORTING
UNIT POWER SALE INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***

GEORGIA POWER COMPANY

1982 ALLOCATION RATIOS FOR SCHERER NO. 1
GENERATOR STEP-UP SUBSTATIONS

| ITEM | GROSS TRANSMISSION INVESTMENT | ACCUMULATED DEPRECIATION | NET TRANSMISSION INVESTMENT | LAND | NET TRANSMISSION INVESTMENT LESS LAND | OPERATION & MAINTENANCE EXPENSE |
|---|---|---|---|---|---|---|
| Lines | $486,014,000 | $132,157,113 | $353,856,887 | $57,176,000 | $296,680,887 | $ 9,721,19[illegible] |
| Substations | 318,657,000 | 42,843,387 | 275,813,613 | 5,655,000 | 270,158,613 | 4,806,742 |
| Total Transmission Plant | 804,671,000 | 175,000,500 | 629,670,500 | 62,831,000 | 566,839,500 | 14,527,940 |
| Scherer No. 1 | 7,405,000 | 188,828 | 7,216,172 | - | 7,216,172 | - |

Gross Investment Ratio $= \frac{7,405,000}{318,657,000} = .0232381526$

O&M Ratio $= \frac{4,806,742}{14,527,940} = .3308619116$

Net Investment Less Land Ratio $= \frac{7,216,172}{566,839,500} = .0127305384$

WORK PAPER SUPPORTING
UNIT POWER SALE INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***



SCHERER UNIT NO. 1 - 1982

Cost of Capital
for
Georgia Power Company

| | Percentage of Capitalization | Cost | Weighted Cost |
|---|---|---|---|
| Long-term Debt and Capitalized Leases | 57% | 11.52% | 6.57% |
| Preferred Stock | 11 | 10.70 | 1.18 |
| Common Equity | 32 | 16.00 | 5.12 |
| Total | 100% | | 12.87% |

Income Tax Rate = 49.24%

Income Tax Requirement = (tax rate/(1 - tax rate)) (equity return)

= (49.24%/(100% - 49.24%)) (6.30%)

= 6.11%

SCHERER UNIT NO. 1 - 1982

Cost of Capital
for
Buy-Back

GEORGIA POWER COMPANY

| | Percentage of Capitalization | Cost | Weighted Cost |
|---|---|---|---|
| Long-term Debt and Capitalized Leases | 57% | 11.52% | 6.57% |
| Preferred Stock | 11 | 10.70 | 1.18 |
| Common Equity | 32 | 15.25* | 4.88 |
| Total | 100% | | 12.63% |

Income Tax Rate = 49.24%

Income Tax Requirement = (tax rate/(1 - tax rate)) (equity return)

= (49.24%/100% - 49.24%)) (6.06%)

= 5.88%

OGLETHORPE POWER CORPORATION

Long-term Debt 9.69%

MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA

Long-term Debt 7.28%

*Return granted in FERC Docket No. ER80-326

WORK PAPER SUPPORTING
UNIT POWER SALE INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***

COST OF CAPITAL
FOR
SCHERER UNIT NO. 1

LONG-TERM DEBT AND CAPITALIZED LEASES

| YEAR (1) | EXPENDITURE (MILLIONS) (2) | INCREMENTAL COST(%) (3) | INCREMENTAL COST($) (4)=(2)x(3) | INCREMENTAL COST OF DEBT (5)=(4)÷(2) |
|---|---|---|---|---|
| 1974 | 8.8 | 8.70 | 0.77 | |
| 1975 | 6.9 | 11.92 | 0.82 | |
| 1976 | 21.4 | 10.08 | 2.16 | |
| 1977 | 81.1 | 10.08 | 8.17 | |
| 1978 | 84.0 | 9.86 | 8.28 | |
| 1979 | 144.6 | 10.89 | 15.75 | |
| 1980 | 201.4 | 13.50 | 27.19 | |
| 1981 | 63.2 | 11.50 | 7.27 | |
| | 611.4 | | 70.41 | 11.52 |

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UNIT POWER SALE INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***

COST OF CAPITAL
FOR
SCHERER UNIT NO. 1

PREFERRED STOCK

| YEAR (1) | EXPENDITURE (MILLIONS) (2) | INCREMENTAL COST(%) (3) | INCREMENTAL COST($) (4)=(2)x(3) | INCREMENTAL COST OF DEBT (5)=(4)÷(2) |
|---|---|---|---|---|
| 1974 | 8.8 | 7.81 | 0.69 | |
| 1975 | 6.9 | 11.74 | 0.81 | |
| 1976 | 21.4 | 10.51 | 2.25 | |
| 1977 | 81.1 | 10.51 | 8.52 | |
| 1978 | 84.0 | 10.51 | 8.83 | |
| 1979 | 144.6 | 10.62 | 15.36 | |
| 1980 | 201.4 | 10.62 | 21.39 | |
| 1981 | 63.2 | 12.00 | 7.58 | |
| | 611.4 | | 65.43 | 10.70 |

RATE CALCULATION FOR DANIEL UNITS NOS. 1 & 2 - 1982

Production Capacity Charge Calculation:

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

$$R_{Gulf} = \left[\frac{\$214,417,778 \times [(12.01 + 6.02)/100] + \$15,078,522}{511,000 \times 12.0}\right] \times \left[\frac{100}{100 - 3}\right]$$

$$= \$9.035/\text{kW-month}$$

DANIEL PLANT - 1982
INVESTMENTS FOR UNIT NOS. 1 & 2

| | GULF OWNERSHIP 1/ | TOTAL PLANT |
|---|---|---|
| Gross Investment | | |
| Unit 2/ | $216,871,250 | $433,742,500 |
| GSU | 3,204,771 | 6,409,542 |
| Total | $220,076,021 | $440,152,042 |
| Accum. Depreciation | | |
| Unit 2/ | $ 22,202,500 | $ 44,405,000 |
| GSU | 269,086 | 538,171 |
| Total | $ 22,471,586 | $ 44,943,171 |
| Net Investment | | |
| Unit 2/ | $194,668,750 | $389,337,500 |
| GSU | 2,935,685 | 5,871,371 |
| Total | $197,604,435 | $395,208,871 |
| General Plant | | |
| Unit | $ 1,224,017 | $ - |
| GSU | 76,382 | - |
| Total | $ 1,300,399 | $ - |
| Working Capital | | |
| Unit | $ 31,106,570 | $ - |
| GSU | 22,982 | - |
| Total | $ 31,129,552 | $ - |
| Accum. Def. Income Taxes | | |
| Unit 2/ | $ 15,013,792 | $ - |
| GSU | 602,806 | - |
| Total | $ 15,616,598 | $ - |
| Total Production Investment | $214,417,788 | $ - |

NOTES:

1/ Gulf ownership is 50.0%.

2/ Includes Common Facilities.

WORK PAPER SUPPORTING
UNIT POWER SALE INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***



DANIEL PLANT - 1982
EXPENSES FOR UNIT NOS. 1 & 2

| | GULF OWNERSHIP 1/ | TOTAL PLANT |
|---|---|---|
| Operation & Maintenance-Fixed | | |
| Unit | $ 1,756,000 | $ 3,512,000 |
| GSU | 126,561 | -- |
| Total | 1,882,561 | -- |
| Administrative & General | | |
| Unit | 687,116 | -- |
| GSU | 57,041 | -- |
| Total | 744,157 | -- |
| Depreciation Expense | | |
| Unit 2/ | 7,717,317 | 15,434,000 |
| GSU | 94,447 | -- |
| Total | 7,811,764 | -- |
| Amort. of Invest. Tax Credits | | |
| Unit 2/ | 562,250 | 1,124,500 |
| GSU | 9,156 | 18,313 |
| Total | 571,406 | 1,142,813 |
| Real & Personal Property Tax | | |
| Unit | 3,889,167 | 7,765,333 |
| GSU | 55,268 | 109,724 |
| Total | 3,944,435 | 7,875,057 |
| Payroll Taxes | | |
| Unit | 120,264 | -- |
| GSU | 3,935 | -- |
| Total | 124,199 | -- |
| TOTAL EXPENSES | 15,078,522 | -- |

NOTES:

1/ Gulf ownership is 50.0%.
2/ Includes Common Facilities.

DANIEL PLANT - 1982
WORKING CAPITAL FOR UNIT NOS. 1 & 2[2/]

| | GULF OWNERSHIP[1/] | TOTAL PLANT |
|---|---|---|
| UNIT | | |
| Fixed O&M Expense | $ 1,756,000 | $ 3,512,000 |
| Variable O&M Expense | 2,558,000 | 5,116,000 |
| Fuel Burn Expense | 56,024,330 | 112,043,660 |
| Administrative & General Expense | 687,116 | -- |
| Total Basis for Cash Working Capital | 61,025,446 | -- |
| Cash Working Capital (1/8 of above) | 7,628,181 | -- |
| Material & Supplies | 23,477,872 | 46,955,744 |
| Prepayments | 517 | -- |
| Total for Unit | $31,106,570 | -- |
| STEP-UP SUBSTATION | | |
| Fixed O&M Expense | $ 126,561 | -- |
| Administrative & General Expense | 57,041 | -- |
| Total Basis for Cash Working Capital | 183,602 | -- |
| Cash Working Capital (1/8 of above) | 22,950 | -- |
| Material & Supplies | -- | -- |
| Prepayments | 32 | -- |
| Total for Substation | $22,982 | -- |
| TOTAL WORKING CAPITAL | $31,129,552 | -- |

NOTES:

1/ Gulf ownership is 50.0%.

2/ For reference see Exhibit C, Section 2.2.6.

WORK PAPER SUPPORTING
UNIT POWER SALE INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***

GULF POWER COMPANY

1982 ALLOCATIONS FOR DANIEL UNIT NOS. 1 & 2

| UNIT | | | REFERENCES |
|---|---|---|---|
| PAYROLL TAXES | = $1,359,288/($1,359,288 - $251,642) x $98,000 | = $ 120,264 | Exhibit C, Sec. 2.2.14 |
| GENERAL PLANT | = $13,834,460 x $120,264/$1,359,288 | = $ 1,224,017 | Exhibit C, Sec. 2.2.5 |
| A&G EXPENSE | | | Exhibit C, Sec. 2.2.10 |
| Insurance (Assigned) | = | = $ 128,000 | |
| Other | = ($25,905 = $6,293,522) x $120,264/$1,359,288 | = $ 559,116 | |
| | | $ 687,116 | |
| O&M EXPENSE | = | = $ 1,756,000 | Exhibit C, Sec. 2.2.9 |
| PREPAYMENTS | | | Exhibit C, Sec. 2.2.6 (For Working Capital) |
| Assigned | = | = $ 0 | |
| General Plant | = $5,846 x ($120,264/$1,359,288) | = $ 517 | |
| | | $ 517 | |
| REAL AND PERSONAL PROPERTY TAX | | | Exhibit C, Sec. 2.2.13 |
| Assigned | = | = $ 3,882,667 | |
| General Plant | = $73,476 x ($120,264/$1,359,288) | = $ 6,500 | |
| | | $ 3,889,167 | |
| ACCUMULATED DEFERRED INCOME TAXES | | | Exhibit C, Sec. 2.2.7 |
| Assigned | = | = $14,835,220 | |
| General Plant | = $2,018,317 x ($120,264/$1,359,288) | = $ 178,572 | |
| | | $15,013,792 | |
| DEPRECIATION EXPENSE | | | Exhibit C, Sec. 2.2.11 |
| Assigned | = | = $ 7,717,000 | |
| General Plant | = $3,587 x ($120,264/$1,359,288) | = $ 317 | |
| | | $ 7,717,317 | |

WORK PAPER SUPPORTING
UNIT POWER SALE INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***

GULF POWER COMPANY
1982 ALLOCATIONS FOR UNIT NOS. 1 & 2

| STEP-UP SUBSTATION | | | REFERENCES |
|---|---|---|---|
| PAYROLL TAXES | = 0.6167725618 x 0.107990883 x $59,079 | = $ 3,935 | Exhibit C, Section 2.2.14 |
| GENERAL PLANT | = $3,935/$59,079 x $1,146,782 | = $ 76,382 | Exhibit C, Section 2.2.5 |
| A&G EXPENSE | | | Exhibit C, Section 2.2.10 |
| Insurance | = 0.1274901347 x ($172,715 + $2,147) | = $ 22,293 | |
| Other | = $3,935/$59,079 x ($521,690) | = $ 34,748 | |
| | | $ 57,041 | |
| O&M EXPENSE | = 0.1079908893 x $1,171,961 | = $126,561 | Exhibit C, Section 2.2.9 |
| PREPAYMENTS | | | Exhibit C, Section 2.2.6 (For Working Capital) |
| Substation | = 0.1274901347 x $0 | = $ 0 | |
| General Plant | = $3,935/$59,079 x $485 | = $ 32 | |
| | | $ 32 | |
| REAL & PERSONAL PROPERTY TAX | | | Exhibit C, Section 2.2.1[illegible] |
| Assigned | = | = $ 54,862 | |
| General Plant | = $3,935/$59,079 x $6,091 | = $ 406 | |
| | | $ 55,268 | |
| ACCUMULATED DEFERRED INCOME TAXES | | | Exhibit C, Section 2.2.7 |
| Substation | = $12,532,095 x ($5,871,371 x .5)/$62,181,192 | = $591,663 | |
| General Plant | = $167,305 x ($3,935/$59,079) | = $ 11,143 | |
| | | $602,806 | |
| DEPRECIATION EXPENSE | | | Exhibit C, Section 2.2.11 |
| Assigned | = | =$ 91,565 | |
| General Plant | = $43,274 x ($3,935/$59,079) | =$ 2,882 | |
| | | $ 94,447 | |

WORK PAPER SUPPORTING
UNIT POWER SALES INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***

## GULF POWER COMPANY
## 1982 ALLOCATION RATIOS FOR DANIEL NOS. 1 & 2
## GENERATOR STEP-UP SUBSTATIONS

| | GROSS TRANSMISSION INVESTMENT | ACCUMULATED DEPRECIATION | NET TRANSMISSION INVESTMENT | LAND | NET TRANSMISSION INVESTMENT LESS LAND | OPERATION & MAINTENANCE EXPENSE |
|---|---|---|---|---|---|---|
| Lines | $61,537,136 | $14,446,976 | $47,090,160 | $7,935,734 | $39,154,426 | $ 728,140 |
| Substations | 29,676,309 | 6,200,570 | 23,475,739 | 448,973 | 23,026,766 | 1,171,961 |
| Total Transmission Plant | 91,213,445 | 20,647,546 | 70,565,899 | 8,384,707 | 62,181,192 | 1,900,151 |
| Daniel No. 1&2 GSU | 6,409,542 | 538,171 | 5,871,371 | - | 5,871,371 | - |

Gross Investment Ratio $= \frac{\$6,409,542 \times .5}{\$29,676,309} = .1079908893$

O&M Ratio $= \frac{\$1,171,961}{1,900,151} = .6167725618$

Net Investment Less Land Ratio $= \frac{\$5,871,371 \times .5}{\$23,026,766} = .1274901347$

DANIEL PLANT UNIT NOS. 1 & 2

Cost of Capital
for
Gulf Power Company

| | Percentage of Capitalization | Cost | Weighted Cost |
|---|---|---|---|
| Long-term Debt and Capitalized Leases | 56% | 10.01% | 5.61% |
| Preferred Stock | 11 | 10.14 | 1.12 |
| Common Equity | 33 | 16.00 | 5.28 |
| Total | 100% | | 12.01% |

Income Tax Rate = 48.45%

Income Tax Requirement = (tax rate/(1 - tax rate)) (equity return)

= (48.45%/(100% - 48.45%)) (6.40%)

= 6.02%

WORK PAPER SUPPORTING
UNIT POWER SALE INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***

COST OF CAPITAL
FOR
DANIEL UNIT NOS. 1 & 2

LONG-TERM DEBT AND CAPITALIZED LEASES

| YEAR (1) | EXPENDITURE ($) (2) | INCREMENTAL COST(%) (3) | INCREMENTAL COST($) (4)=(2)x(3) | INCREMENTAL COST OF DEBT (5)=(4)÷(2) |
|---|---|---|---|---|
| 1970 | 8,941 | 8.22 | 735 | |
| 1971 | 137,931 | 8.45 | 11,655 | |
| 1972 | 1,711,498 | 7.72 | 132,128 | |
| 1973 | 10,288,365 | 7.72 | 794,262 | |
| 1974 | 43,270,132 | 7.72 | 3,340,454 | |
| 1975 | 34,512,262 | 9.82 | 3,389,104 | |
| 1976 | 34,378,835 | 9.19 | 3,159,415 | |
| | 54,007,609 | 8.55 | 4,617,650 | |
| 1977 | 32,791,166 | 9.19 | 3,013,508 | |
| | 36,550,731 | 8.55 | 3,125,087 | |
| 1978 | 9,824,728 | 9.84 | 966,753 | |
| | 20,543,695 | 9.12 | 1,873,584 | |
| 1979 | 2,026,520 | 9.84 | 199,410 | |
| | 36,923,336 | 10.47 | 3,865,873 | |
| 1980 | 60,045,000 | 15.26 | 9,162,867 | |
| 1981 | 23,013,000 | 10.50 | 2,416,365 | |
| | 400,033,749 | | 40,068,850 | 10.01 |

WORK PAPER SUPPORTING
UNIT POWER SALE INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***

COST OF CAPITAL
FOR
DANIEL UNIT NOS. 1 & 2

PREFERRED STOCK

| YEAR (1) | EXPENDITURE ($) (2) | INCREMENTAL COST(%) (3) | INCREMENTAL COST($) (4)=(2)x(3) | INCREMENTAL COST OF PREFERRED STOCK (5)=(4)÷(2) |
|---|---|---|---|---|
| 1970 | 8,941 | 8.43 | 754 | |
| 1971 | 137,931 | 8.43 | 11,627 | |
| 1972 | 1,711,498 | 8.43 | 144,279 | |
| 1973 | 10,288,365 | 8.43 | 867,309 | |
| 1974 | 43,270,132 | 8.83 | 3,820,753 | |
| 1975 | 34,512,262 | 10.52 | 3,630,689 | |
| 1976 | 34,378,835 | 10.52 | 3,616,653 | |
| | 54,007,609 | 10.64 | 5,746,409 | |
| 1977 | 32,791,166 | 10.52 | 3,449,631 | |
| | 36,550,731 | 8.50 | 3,106,812 | |
| 1978 | 9,824,728 | 10.52 | 1,033,561 | |
| | 20,543,695 | 8.50 | 1,746,214 | |
| 1979 | 2,026,520 | 10.52 | 213,190 | |
| | 36,923,336 | 9.70 | 3,581,563 | |
| 1980 | 60,045,000 | 11.56 | 6,941,202 | |
| 1981 | 23,013,000 | 11.56 | 2,660,303 | |
| | 400,033,749 | | 40,570,949 | 10.14 |

WORK PAPER SUPPORTING
UNIT POWER SALE INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***

1982 CAPACITY CHARGE FOR
TRANSMISSION FACILITIES RATED 115 KV AND ABOVE

FEBRUARY - MAY

| COMPANY | ANNUAL COST ($/KW-MO.) | PEAK PERIOD RATIO | WEIGHTED COST ($/KW-MO.) |
|---|---|---|---|
| Alabama | 0.953971 | 34.84 | 0.332363 |
| Georgia | 1.030485 | 51.50 | 0.530700 |
| Gulf | 0.882665 | 6.31 | 0.055696 |
| Mississippi | 0.833135 | 7.35 | 0.061235 |
| Total Cost | | | 0.979994 |

JUNE - DECEMBER

| COMPANY | ANNUAL COST ($/KW-MO.) | PEAK PERIOD RATIO | WEIGHTED COST ($/KW-MO.) |
|---|---|---|---|
| Alabama | 0.953971 | 34.89 | 0.332840 |
| Georgia | 1.030485 | 51.57 | 0.531421 |
| Gulf | 0.882665 | 6.20 | 0.054725 |
| Mississippi | 0.833135 | 7.34 | 0.061152 |
| Total Cost | | | 0.980138 |

UNIT POWER SALE INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***

TRANSMISSION FACILITITES RATED 115 KV AND ABOVE
DETERMINATION OF MONTHLY CAPACITY COSTS
January 1, 1982 to December 31, 1982 Inclusive

CAPACITY COSTS FOR 1982

| | ----ALABAMA--- (a) | ----GEORGIA-- (a) | ----GULF------ | -MISSISSIPPI- |
|---|---|---|---|---|
| 1 TRANSMISSION LOAD (KILOWATTS) | | | | |
| 2 Transmission Load | 6,927,266 | 8,609,072 | 1,193,855 | 1,365,295 |
| 3 INVESTMENT ITEMS (AS OF JANUARY 31) | | | | |
| 4 Gross Transmission Investment | $ 409,400,328 | $ 547,825,219 | $ 72,768,605 | $ 87,181,562 |
| 5 Accumulated Depreciation | ( 80,989,039) | ( 124,652,713) | ( 16,699,936) | ( 25,573,361) |
| 6 Net Transmission Investment | 328,411,289 | 423,172,506 | 56,068,669 | 61,607,701 |
| 7 General Plant (Net) | 7,823,532 | 6,984,080 | 911,184 | 573,117 |
| 8 Working Capital (b) | 4,354,319 | 2,893,569 | 1,009,254 | 257,693 |
| 9 Accumulated Deferred Income Taxes | ( 35,052,215) | ( 63,893,620) | ( 9,880,502) | ( 15,151,463) |
| 10 Total Net Transmission Investment | $ 305,536,925 | $ 369,156,535 | $ 48,108,605 | $ 47,287,048 |
| 11 EXPENSE ITEMS (EXPENSES FOR 1982) | | | | |
| 12 Operation & Maintenance - Fixed | $ 8,574,039 | $ 8,708,926 | $ 1,196,179 | $ 1,449,016 |
| 13 Administrative & General Expense | 3,367,918 | 4,453,542 | 438,602 | 456,305 |
| 14 Depreciation Expense | 10,235,568 | 14,201,533 | 1,572,911 | 1,733,750 |
| 15 Real & Personal Property Taxes | 2,199,805 | 3,268,910 | 417,314 | 1,647,345 |
| 16 Payroll Taxes | 375,220 | 554,235 | 46,942 | 67,731 |
| 17 Revenue Credits | ( 596,893) | ( -9,173,053) | ( -299,758) | ( -40,643) |
| 18 Total Transmission Fixed Expenses | $ 24,155,657 | $ 40,360,199 | $ 3,972,006 | $ 5,395,290 |
| 19 ANNUAL CAPACITY CHARGES (PER KW OF TRANSMISSION LOAD) | | | | |
| 20 Total Net Transmission Investment | $ 41.106 | $ 42.880 | $ 40.297 | $ 34.635 |
| 21 Percent - Return on Investment | 11.710% | 11.120% | 11.300% | 10.800% |
| 22 Percent - Associated Income Taxes | 5.560% | 5.920% | 5.940% | 5.790% |
| 23 Return on Investment | $ 5.165 | $ 4.768 | $ 4.554 | $ 3.741 |
| 24 Associated Income Taxes | $ 2.452 | $ 2.538 | $ 2.394 | $ 2.005 |
| 25 Return & Income Taxes | $ 7.617 | $ 7.307 | $ 6.947 | $ 5.746 |
| 26 Total Transmission Fixed Expenses | $ 3.487 | $ 4.688 | $ 3.327 | $ 3.952 |
| 27 Total Transmission Fixed Charges | $ 11.104 | $ 11.995 | $ 10.274 | $ 9.698 |
| 28 Fixed Charge Associated With Losses | $ 0.343 | $ 0.371 | $ 0.318 | $ 0.300 |
| 29 Total Transmission Fixed Charges (With Losses) | $ 11.448 | $ 12.366 | $ 10.592 | $ 9.998 |
| 30 Monthly Capacity Rate (c) | $ 0.953971 | $ 1.030485 | $ 0.882665 | $ 0.833135 |
| 31 Weekly Capacity Rate (d) | $ 0.220147 | $ 0.237804 | $ 0.203692 | $ 0.192262 |

Notes: (a) SEGCO Investment and Expenses allocated 100% to Georgia Power.
(b) Working Capital includes Cash Working Capital, Prepayments, and Materials and Supplies
(c) Total Transmission Fixed Charges (With Losses) divided by 12.
(d) Total Transmission Fixed Charges (With Losses) divided by 52.

WORK PAPER SUPPORTING
UNIT POWER SALE INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***

TRANSMISSION FACILITIES RATED 115 KV AND ABOVE

COST OF CAPITAL FOR ALABAMA POWER COMPANY[1/]
(INCLUDING 1/2 OF SEGCO)

January - December, 1982

| Item | Capitalization Ratio | Net Cost | Weighted Cost |
|---|---|---|---|
| Long Term Debt and Capitalized Leases | 57% | 9.75% | 5.56% |
| Preferred Stock | 11 | 9.39 | 1.03 |
| Common Equity | 32 | 16.00 | 5.12 |
| Cost of Capital (as of 12-31-82) | | | 11.71% |

Income Tax Requirement = [Tax Rate/(1-Tax Rate)](Equity Return)

= [47.49%/(100% - 47.49%)](6.15%)

= 5.56%

[1/] Reference Section 3.2.16 of Exhibit C.

WORK PAPER SUPPORTING
UNIT POWER SALE INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***

TRANSMISSION FACILITIES RATED 115 KV AND ABOVE

COST OF CAPITAL FOR GEORGIA POWER COMPANY[1/]
(INCLUDING 1/2 OF SEGCO)

January - December, 1982

| Item | Capitalization Ratio | Net Cost | Weighted Cost |
|---|---|---|---|
| Long Term Debt and Capitalized Leases | 57% | 8.81% | 5.02% |
| Preferred Stock | 11 | 8.89 | 0.98 |
| Common Equity | 32 | 16.00 | 5.12 |
| Cost of Capital (as of 12-31-82) | | | 11.12% |

Income Tax Requirement = [Tax Rate/(1-Tax Rate)](Equity Return)

= [49.24%/(100% - 49.24%)](6.10%)

= 5.92%

[1/]Reference Section 3.2.16 of Exhibit C.

WORK PAPER SUPPORTING
UNIT POWER SALE INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***

TRANSMISSION FACILITIES RATED 115 KV AND ABOVE

COST OF CAPITAL FOR GULF POWER COMPANY[1/]

January - December, 1982

| Item | Capitalization Ratio | Net Cost | Weighted Cost |
|---|---|---|---|
| Long Term Debt and Capitalized Leases | 56% | 9.00% | 5.04% |
| Preferred Stock | 11 | 8.94 | 0.98 |
| Common Equity | 33 | 16.00 | 5.28 |
| Cost of Capital (as of 12-31-82) | | | 11.30% |

Income Tax Requirement = [Tax Rate/(1-Tax Rate)](Equity Return)

= [48.70%/(100% - 48.70%)](6.26%)

= 5.94%

[1/] Reference Section 3.2.16 of Exhibit C.

WORK PAPER SUPPORTING
UNIT POWER SALE INFORMATIONAL SCHEDULE
***ILLUSTRATIVE PURPOSES ONLY***

TRANSMISSION FACILITIES RATED 115 KV AND ABOVE

COST OF CAPITAL FOR MISSISSIPPI POWER COMPANY[1/]

January - December, 1982

| Item | Capitalization Ratio | Net Cost | Weighted Cost |
|---|---|---|---|
| Long Term Debt | 56% | 8.18% | 4.58% |
| Preferred Stock | 11 | 8.57% | 0.94 |
| Common Equity | 33 | 16.00 | 5.28 |
| Cost of Capital (as of 12-31-82) | | | 10.80% |

Income Tax Requirement = [Tax Rate/(1-Tax Rate)](Equity Return)

= [48.20%/(100% - 48.20%)](6.22%)

= 5.79%

[1/] Reference Section 3.2.16 of Exhibit C.