will not be considered as a power or energy source to any party to the System Agreement but will be considered as a negative load.

2.14 Capability shall be the net output in megawatts that can be produced by a generating unit under conditions specified by the Operating Committee, that is devoted to serving System load but excluding that portion of any unit the output of which has been sold to another Company (other than through MSS-3), or the input in megawatts available under contract from a supplying source, excluding the portion of such supply that has been sold to another Company (other than through MSS-3), including any capacity determined in Sections 2.12 or 2.13 above, plus the allocated portion of Joint Account Capacity Purchases in the MISO Resource Adequacy Capacity Market, plus the contractual amount of firm purchases with reserves available during the month from other systems adjusted upward by the ratio of Seller's Capability and Seller's Load Responsibility as determined in Section 10.02C.

2.15 System Capability shall be the arithmetical sum in megawatts of the individual Company Capabilities.

2.16 Company Load Responsibility shall be determined as follows:

(a) To be used in conjunction with Service Schedules MSS-2 and MSS-6:

(i) The average of the sum of the Company's twelve monthly hourly loads coincident with the System's monthly peak hour load for the period ended with the current month measured in megawatts. Hourly load shall be defined as the sum of the hourly MW values for each of the Load Zones associated with an Operating Company plus net Behind the Meter Generation injections from within the load zone for each Operating Company and necessary adjustments due to Financial Schedules. To the extent that an Operating Company has engaged in a partial or full requirements sale to a third party, the load associated with that sale will be included in that Operating Company's hourly load if it is not included in the Load Zone associated with that Operating Company.

(b) As of April 1, 2004,* to be used in conjunction with Service Schedules MSS-1 and MSS-5 and in conjunction with the allocation of a purchase of capacity and energy for the joint account of all Companies under Section 4.02:

The average of the sum of the Company's twelve monthly hourly loads coincident with the System's monthly peak hour load for the period ended with the current month measured in megawatts. Hourly load shall be defined as the sum of the hourly MW values for each of the Load Zones associated with an Operating Company plus net Behind the Meter Generation injections from within the load zone for each Operating Company and necessary adjustments due to Financial Schedules less loads served under interruptible tariffs or contracts, where the interruptible load excluded at the time of the system's monthly peak hour load (which does not include the excludable interruptible load determined herein) is to be that load that, pursuant to said retail tariff or contract, is subject to interruption. To the extent practical the determination of what loads are interruptible shall be based on actual data and if it is not practical, shall be based on reasonable estimates. To the extent that an Operating Company has engaged in a partial or full requirements sale to a third party, the load associated with that sale will be included in that Operating Company's hourly load if it is not included in the Load Zone associated with that Operating Company.

* In the calculation pursuant to Section 2.16(b), the full amount of the interruptible load has been removed as of April 1, 2004 (as opposed to phased-in over a twelve month period).

(c) The most current information, updated for new or revised MISO peak data volumes, shall be used in this calculation and to true-up previous settlement data allocation.

2.17 System Load Responsibility:

(a) To be used in conjunction with Service Schedules MSS-2 and MSS-6 shall be the arithmetical sum in megawatts of the individual Company Load Responsibilities derived pursuant to Section 2.16(a).

(b) As of April 1, 2004, to be used in conjunction with Service Schedules MSS-1 and MSS-5 and in conjunction with the allocation of a purchase of capacity and energy for the joint account of all Companies under Section 4.02 shall be the arithmetical sum in megawatts of the individual Company Load Responsibilities derived pursuant to Section 2.16(b).

2.18 Responsibility Ratio of a Company shall be the ratio obtained by dividing the load responsibility of that company by the System Load Responsibility as follows:

(a) To be used in conjunction with Service Schedules MSS-2 and MSS-6 the Responsibility Ratio shall be equal to the amount determined in Section 2.16(a) divided by the amount determined in Section 2.17(a).

(b) To be used in conjunction with Service Schedules MSS-1 and MSS-5 and in conjunction with the allocation of a purchase of capacity and/or energy for the joint account of all Companies under Section 4.02 shall be equal to the amount determined in Section 2.16(b) divided by the amount determined in Section 2.17(b).

(c) The most current information, updated for new or revised MISO peak data volumes, shall be used in this calculation and to true-up previous settlement data allocation.

2.19 Capability Responsibility of a Company shall be the System Capability multiplied by the Responsibility Ratio as specified in Section 2.18(a) for that Company.

2.20 Pool Energy shall be the energy generated by a Company in excess of its own requirements, or acquired by any Company under economic dispatch or as directed by the System Operator, that goes to supply requirements of other Companies. Such energy shall in all cases be nonfirm, that is, it has no guaranteed or assured availability.

2.21 Cogeneration or Small Power Production Energy shall be the energy acquired by any Company from qualified facilities whether or not acquired under economic dispatch.

2.22 Transmission Responsibility of a Company shall be the System Net Inter-Transmission Investment multiplied by the Responsibility Ratio as specified in Section 2.18(b) for that Company.

2.23 System Net Inter-Transmission Investment shall be the arithmetical sum of the individual Company Net Inter-Transmission Investments.

2.24 Day shall be a continuous 24-hour period beginning at midnight I ST, or such other time as may be agreed upon by the Operating Committee.

2.25 Month shall be a calendar month using Eastern Standard Time. In the case of MISO Settlement Statements, the initial month shall be that period from the date the Operating Companies join MISO to the end of the calendar month.

2.26 Year shall be calendar year.

2.27 Power shall be the rate of doing work and shall be expressed in kilowatts (kW), megawatts (mW), or gigawatts (gW).

2.28 Energy shall be work and shall be expressed in kilowatt hours (kWh), megawatt-hours (mWh), or gigawatt-hours (gWh).

2.29 Load Zone shall be as defined in Section 1.363 of the MISO Tariff.

2.30 Operating Day shall be as defined in the MISO Tariff.

2.31 Ancillary Services Charges and Credits are those charges and credits that appear on the MISO Settlement Statements that relate to the provision of Ancillary Services. Such costs shall include, but shall not be limited to, Day Ahead Regulation, Day Ahead Spinning Reserve, Day Ahead Supplemental Reserve, Real Time Regulation, Real Time Spinning Reserve, Real Time Supplemental Reserve, Regulation Cost Distribution, Spinning Reserve Cost Distribution, Supplemental Reserve Cost Distribution, Excessive/Deficient Energy Deployment Cost.

2.32 Monthly Unit Fuel Cost Allocation Factor shall be calculated for each generating unit of an Operating Company that corresponds to Ancillary or Uplift Charges or Credits in a month. The Monthly Unit Fuel Cost Allocation Factor shall represent the percentage of the total monthly fuel cost for such a generating unit that is ultimately borne by an Operating Company. The Monthly Unit Fuel Cost Allocation Factor shall be defined on a unit-by-unit basis as:

(OS-PES+PEP-JAE)/UFC, where:

OS= an Operating Company's ownership share of a generating unit's monthly cost of fuel consumed

PES= the monthly cost of fuel used to supply Pool Energy from the Operating Company's ownership share of the generating unit

PEP= the monthly cost of fuel for energy taken from the Pool by the Operating Company for the generating unit. For the purpose of this calculation, each Operating Company that receives Pool Energy in any hour is deemed to have taken a pro rata share of the energy and associated costs for each generating unit that was supplying Pool Energy in that hour

JAE= the monthly cost of fuel used to supply joint account sales from the Operating Company's ownership share of the generating unit

UFC= the generating unit's total monthly cost of fuel consumed

2.33 MISO shall mean the Midcontinent Independent System Operator, Inc.

2.34 MISO Settlement Statements shall be the statements sent by MISO for Market Settlements.

2.35 Uplift Charges and Credits are those charges and credits that appear on the MISO Settlement Statements that relate to revenue sufficiency, make-whole payments, uplift, or miscellaneous MISO charges not included elsewhere in this Agreement. Such costs shall include, but shall not be limited to, Day Ahead RSG Make Whole Payments, Real Time RSG Make Whole Payments, Real Time Price Volatility Make Whole Payments, Net Regulation Adjustment, Day Ahead RSG Distribution, Real Time RSG First Pass Distribution, Day Ahead RSG Voltage and Reliability Charge, Real Time RSG

Voltage and Reliability Charge, Real Time Revenue Neutrality Uplift, Real Time Net Inadvertent Distribution, and Real Time Miscellaneous.

2.36 Marginal Losses Component (MLC) shall have the meaning ascribed to that term in the MISO tariff.

2.37 Financial Schedule shall have the meaning ascribed to that term in the MISO tariff.

2.38 Marginal Losses Surplus Distribution shall have the meaning ascribed to that term in the MISO tariff.

2.39 Monthly Basis shall mean that for all charges received from MISO that are to be allocated on a monthly basis, monthly means accumulated in the calendar month received and aggregated and allocated by calendar month to which the charges relate.

2.40 MISO Resource Adequacy Market shall mean a voluntary, short-term (annual) capacity market that provides load serving entities in MISO with the opportunity, but not the obligation, to meet their resource adequacy requirements through the purchase of qualified capacity credits from this market.

2.41 Behind the Meter Generation shall have the meaning ascribed to that term in the MISO tariff.

2.42 Monthly Energy Ratio shall be defined as the monthly ratio of each Operating Company's MWh load to the total System monthly load in MWh for the System Agreement Companies for the month.

ARTICLE III OBJECTIVES

3.01 The purpose of this Agreement is to provide the contractual basis for the continued planning, construction, and operation of the electric generation, transmission and other facilities of the Companies in such a manner as to achieve economies consistent with the highest practicable reliability of service, subject to financial considerations, reasonable utilization of natural resources and minimization of the effect on the environment. This Agreement also provides a basis for equalizing among the Companies any imbalance of costs associated with the construction, ownership and operation of such facilities as are used for the mutual benefit of all the Companies.

3.02 It is recognized by the Companies that economies of scale and integrated operations require that the planning, construction and operation of the bulk power supply and related facilities of the Companies be on a coordinated basis.

3.03 It is recognized that the Companies have traditionally used natural gas as their primary boiler fuel and that curtailments by suppliers have necessitated a conversion to oil as boiler fuel. Minimizing current and future costs of electricity and reducing energy dependence on oil and gas require the Companies to move toward a new fuel base of coal and nuclear.

3.04 It is recognized that these new coal and nuclear units will be Base Generating Units as defined in 2.08 and will be units of the larger ratings in generating stations of large size, strategically located with regard to fuel, water supply and electric load.

3.05 It is the long term goal of the Companies that each Company have its proportionate share of Base Generating Units available to serve its customers either by ownership or purchase.

Any Company which has generating capacity above its requirements, which desires to sell all or any portion of such excess generating capacity and associated energy, shall offer the right of first refusal for this capacity and associated energy to the other Companies under Service Schedule MSS-4 Unit Power Purchase.

3.06 It is recognized that the installation of large base generating stations at locations, in many cases necessarily remote from major load centers, will require the installation of additional major high voltage and extra high voltage transmission lines and substations to connect these large generating stations to the major load centers in a manner to assure the highest practicable reliability of service.

3.07 It is recognized that reliability of service and economy of operation require that the energy supply to the system be controlled, to the extent practicable, from a centralized dispatching office and that this will require adequate communication facilities and the provision of economic dispatch computer facilities and automatic controls of generation.

3.08 By jointly planning on a systemwide basis for the construction and operation of these major facilities:

(a) The combined loads of the Companies can be supplied with less aggregate installed capacity; and

(b) Installations of additional capacity can be made at lower cost per kW because of the large unit sizes; and

(c) The new installations will be more economical and require less operating labor and maintenance per kW because of the larger unit sizes; and

(d) The strengthened transmission system will make possible a fuller utilization of the capability of the lower cost generating units of the System; and

(e) Emergency conditions in any part of the System or other systems in adjacent areas can be met with less probability of impairment of service to the general public.

3.09 It is intended that each Company shall be willing and able to provide its portion of the major facilities determined to be necessary and each Company shall share in the benefits and pay its share of the costs of coordinated operations as agreed upon in accordance with Service Schedules to be attached hereto from time to time and made a part hereof.

ARTICLE IV OBLIGATIONS

4.01 Production Facilities

Each Company shall normally own, or have available to it under contract, such generating capability and other facilities as are necessary to supply all of the requirements of its own customers.

Each Company shall furnish the Operating Committee, at the time and in the manner designated, estimates of its annual peak load for the next succeeding 10-year period, or such period as may be required, together with estimates of its capability available from generating units in operation, under construction or already approved, capability available from other sources under contract and Qualified Cogeneration Capacity or Qualified Small Power Production Capacity in accordance with Sections 2.12 and 2.13 of this Agreement.

The Operating Committee shall then determine a generation addition plan to provide capacity for the projected system load and furnish reliable service to customers at the lowest cost consistent with sound business practice. Any anticipated large blocks of power sales not previously submitted to the Operating Committee shall be submitted to the Operating Committee as soon as load information is available so that appropriate capacity can be scheduled into the generation addition plan.

Each Company that installs a Generating Unit will make the necessary financial arrangements and promptly proceed with the design and construction of the unit to meet the "in-service" date of the generation addition plan.

Any Capability in excess of the Capability Responsibility of a Company that may exist in the system of one or more Companies as a result of installation of facilities in accordance with the provisions of the generation addition plan shall be equalized among the Companies in accordance with the provisions of the applicable Service Schedule.

4.02 Purchased Capacity & Energy

The Companies, with the consent of or under conditions specified by the Operating Committee, may agree to a contract by one or more of them, for the purchase of capacity and/or energy from outside sources for the account of a Company or Companies~~.~~

If purchased by a Company for its own account, the capacity shall be included by the purchasing Company in its Capability to the extent provided by the applicable Service Schedule. The energy purchased shall be considered as part of the purchasing Company's energy supply.

If purchased by a Company for the joint account of less than all of the Companies, the capacity and/or energy shall be allocated among the purchasing Companies in any manner mutually agreeable to them.

If purchased by a Company for the joint account of all the Companies, the capacity and/or energy shall be allocated to each Company in proportion to its Responsibility Ratio based on Section 2.18(b) in effect at the end of the preceding month. Each Company shall include its allocated portion of the capacity, so purchased, in its Capability to the extent provided by the applicable Service Schedule and shall include its portion of the energy so purchased in its energy supply. Each Company shall pay for capacity and/or energy allocated to it hereunder at the rates paid by the Company making the purchase.

Joint Account Capacity Purchases in the MISO Resource Adequacy Market refers to the net amount of capacity purchased in the MISO Resource Adequacy Market and shall be allocated to each Company in proportion to its Responsibility Ratio based on Section 2.18(b) in effect at the end of the preceding month, unless the Companies, with the consent of or under conditions specified by the Operating Committee, agree to a contract by one or more of them for the purchase of capacity in the MISO Resource Adequacy Market for the account of a Company or Companies.

4.03 Energy Purchased by Services

Services, through the System Operations Center, may purchase energy under economic dispatch or emergency conditions, in accordance with Article VI paragraph 6.02 of this Agreement, for the joint account of all the Companies. The energy purchased shall be allocated to each Company in proportion to its Responsibility Ratio as specified in Section 2.18(b) in effect at the end of the preceding month.

4.04 Capacity and Energy Exchanged with Outside Systems

Capacity and energy may be delivered to or received from an outside system under agreements providing for a return in kind. The accounting for such deliveries and receipts shall be as follows:

(a) If the System supplies first, the obligations to supply shall be prorated to each Company, in proportion to its Responsibility Ratio as specified in Section 2.18(b) in effect as of the preceding October 31st, and the capacity and energy which each Company is entitled to receive in return shall be equal to the obligation to supply.

(b) If the System receives first, the capacity and energy to be received shall be prorated to each Company in proportion to its Responsibility Ratio as specified in Section 2.18(b) in effect as of the preceding October 31st, and each Company shall be obligated to supply in return the amount of capacity and energy that it was entitled to receive.

4.05 Sales to Others for the Joint Account of All the Companies

Sales of capacity and energy to others for which any Company does not wish to assume sole responsibility, shall, with the consent of or under conditions specified by the Operating Committee, be made by the Company having direct connection with such others, for the joint account of all the Companies, and the net balance derived from such sales shall be divided among the Companies as provided in the applicable Service Schedule.

Joint Account Capacity Sales in the MISO Resource Adequacy Market refers to the net amount of capacity sold in the MISO Resource Adequacy Market and the net balance from such sales shall be allocated to each Company in proportion to its Responsibility Ratio based on Section 2.18(b) in effect at the end of the preceding month, unless the Companies, with the consent of or under conditions specified by the Operating Committee, agree to a contract by one or more of them for the sale of capacity in the MISO Resource Adequacy Market for the account of a Company or Companies.

4.06 Transmission Facilities

The Companies own and operate extensive transmission systems traversing their operating areas and interconnecting with each other, as well as with the transmission systems of adjacent utilities.

It is agreed that portions of each Company's bulk power transmission system shall be equalized in accordance with the applicable Service Schedule so that the ownership costs of those transmission facilities shall be distributed equitably among the Companies.

The Operating Committee shall make studies of bulk power transmission facilities and agree upon the facilities that will be required to transmit the power supply from generating or other sources to the load centers. The facilities agreed upon shall be built to comply with a time schedule determined by the Operating Committee and shall be adequate to provide the bulk power transmission system requirements with due allowances for contingencies that may reasonably be expected. The Operating Committee shall agree on the general routes of bulk power transmission lines, the voltages and conductor sizes, and the location of substations which are covered by this Agreement.

4.07 Communication and Other Facilities

The Companies shall provide communication and other facilities, determined by the Operating Committee and/or MISO to be necessary for metering, control, protection and dispatch of the production and transmission facilities, and for such other purposes as may be necessary or desirable for the operation of the Companies' Systems.

4.08 Dispatch

Under general direction of the Operating Committee, Services will operate a centralized operations center properly equipped and staffed to dispatch the capacity and energy capability of the Companies, in the efficient, economical, and reliable manner as provided in this Agreement. All generating units, included in System Capability under this Agreement, presently in operation or installed in the future, shall be equipped with such controls as may be determined by the Operating Committee to be necessary to accomplish such centralized economic dispatch.

It is recognized by the Companies that, because of such economic dispatch, a Company may not, at all times, be supplying the energy requirements of its system, but may be taking energy from the resources of the other Companies or supplying energy to the other Companies. The payments or charges for such energy exchange shall be as provided in the applicable Service Schedule.

4.09 Records and Reports

Services shall keep such records as may be necessary for the efficient administration of the Agreement, and shall make such records available to any Company on request. Each Company shall make all reports requested by the Operating Committee within the time prescribed.

4.10 Regulatory Authorization

This Agreement is subject to certain regulatory approvals and each Company shall diligently seek all necessary regulatory authorization for this Agreement and the performance of its obligations thereunder.

4.11 Effect on Other Agreements

This Agreement shall not modify the obligations of any Company under any Agreement between that Company and others not parties to this Agreement in effect at the date of this Agreement.

4.12 Service Schedules

The basis of compensation for the use of facilities and for the capacity and energy provided or supplied by a Company to another Company or Companies under this Agreement shall be in accordance with arrangements agreed upon from time to time among the Companies. Such arrangements shall be in the form of Service Schedules, each of which, when signed by the parties hereto, and approved or accepted for filing by appropriate regulatory authority shall be attached to and become a part of this Agreement.

Each Company reserves the right to unilaterally seek amendments or changes in the terms and conditions of service and increases or decreases in the rates and charges provided in any of the Service Schedules from any regulatory body having or acquiring jurisdiction thereover.

4.13 Measurements

All capacity and energy measurements, such as between the systems of the Companies, shall be made at or corrected to the points of interconnection unless otherwise agreed to by the Operating Committee.

4.14 Billings

Bills for services rendered hereunder shall be calculated in accordance with applicable Service Schedules, and shall be issued on the fifth working day of the month following that in which such service was rendered and shall be payable on or before the 15th day of such month. After the 20th day, interest shall accrue on any balance due at the rate as determined in Section 35.19a(2)iii of the FERC Regulations, or at such other rate established by the Operating Committee.

4.15 Waivers

Any waiver at any time by a Company of its rights with respect to a default by any other Company under this Agreement, shall not be deemed a waiver with respect to any subsequent default.

4.16 Successors and Assigns

This Agreement shall inure to the benefit of and be binding upon the successors and assigns of the respective Companies here to, but shall not be assignable by any Company without the written consent of the other Companies, except upon foreclosure of a mortgage or deed of trust.

4.17 Amendment

This Agreement may be changed, amended, or supplemented, only by an instrument in writing, signed by all the Companies.

4.18 Independent Contractors

It is agreed among the Companies that by entering into this Agreement providing for the coordinated planning, construction and operation of power production, transmission, communications and other facilities of the Companies, the Companies shall not become partners, but as to each other and to third persons, the Companies shall remain independent contractors in all matters relating to this Agreement.

4.19 Responsibility for Loss or Damage

Each Company shall defend, indemnify, and save harmless the other Companies, against liability, loss, costs and expenses on account of any injury or damage to persons or property occurring on or in connection with its facilities on its side of any of the points of interconnection, except to the extent such injury or damage was caused by the sole or contributory negligence of another Company, its agent or employees.

ARTICLE V COMPOSITION AND DUTIES OF THE OPERATING COMMITTEE

5.01 Operating Committee

An Operating Committee shall be the administrative organization of this Agreement and shall consist of members designated by the chief executive officers of each Company and by the chief executive officer of the Parent Company. Such designation shall be by written notice to the Secretary of the Operating Committee with copies to each of the other Companies. The Companies and the Parent Company may change its designated members at any time by written notice to the Secretary of the Operating Committee and each of the other Companies.

5.02 Officers of the Operating Committee

The Operating Committee shall have the following officers with duties as designated:

(a) Chairman - The Chairman shall issue calls for and shall preside at meetings of the Operating Committee. The Chairman shall have responsibility for the general coordination of the Operating Committee functions among the various members.

(b) Vice Chairman - The Vice Chairman shall perform the duties of the Chairman in his absence or incapacity.

(c) Secretary - The Secretary shall be responsible for keeping the minutes of the meetings of the Operating Committee and for preparing copies thereof and for distributing them to the Companies. The Secretary shall be responsible for obtaining written approval from the Companies for any acts or decisions of the Operating Committee which may require such written approval, and shall be responsible for distributing copies of such approvals to the Companies.

The Chairman and Vice Chairman shall be elected from the members by majority vote at the first meeting held in each calendar year and shall take office immediately upon being elected.

The Secretary shall be designated by the Operating Committee.

5.03 Meeting Dates

The Operating Committee shall hold meetings at least quarterly and at any time upon the request of a member, and shall keep minutes of its proceedings.

5.04 Decisions

All decisions of the Operating Committee shall be by a majority vote. For the purposes of voting, the Parent Company shall have twenty (20) percent of the vote and the remaining eighty (80) percent shall be divided among the Companies in proportion to each Company's Responsibility Ratio in effect as of the preceding December 31st.

5.05 Attendance at Meetings

Each Company and the Parent Company shall be represented at each Operating Committee meeting by their members on the Committee or a proxy designated by the member or chief executive officer. Such proxy member need not be an employee of the Company represented.

5.06 Duties

The Operating Committee shall:

(a) Be responsible for the day-to-day administration of the Agreement and for the filing of this Agreement and any amendments thereto with the Federal Energy Regulatory Commission for approval or acceptance for filing and for distributing copies of such filings to the Companies.

(b) Make the studies required to fulfill the obligations agreed to in the Article IV of this Agreement, and its decisions shall become the basis for the installation of generation, bulk power transmission, communication, and other facilities necessary for the supply of capacity and energy to the System.

(c) Determine the amount of and require installation of adequate reserves of System Capability to assure, insofar as practicable, the continuous supply of capacity and energy to the major load centers of the System.

(d) Establish safe loading criteria for generating units, transmission lines and any other facilities necessary for the supply of power and energy to the major load centers of the System, consistent with the requirements imposed by MISO, NERC and the Federal Energy Regulatory Commission.

(e) Promulgate whatever standards may be required for the safe and reliable operation of the System, consistent with the requirements imposed by MISO, NERC and the Federal Energy Regulatory Commission.

(f) Consult with and provide general supervision for Services in employing and supervising a System Operator and provide for such assistance as needed.

(g) Determine the need for and generally supervise the keeping of records and the making of such reports as are deemed necessary or appropriate.

(h) Determine the need for and generally supervise communications, interchange and automatic generation control, metering, economic dispatch and relaying facilities necessary for the purpose of this Agreement, consistent with the requirements imposed by MISO, NERC and the Federal Energy Regulatory Commission.

(i) Make any determinations required for the purpose of administering any schedules subject to its administration.

(j) Study and determine from time to time additions or changes in facilities necessary to keep abreast of the production and transmission requirements of the System.

(k) Provide for and coordinate safe dispatching, switching and other routine procedures.

(l) Provide for proper distribution of spinning reserves and the supply of reactive kVa, consistent with the requirements imposed by MISO, NERC and the Federal Energy Regulatory Commission.

(m) Establish, amend, supplement or terminate from time to time rules, procedures or practices as necessary to insure functioning of the System within the scope of this Agreement.

(n) Coordinate negotiations with others from time to time for interchange and sale of power and energy.

(o) Coordinate arrangements for the sale and delivery to others on a profitable basis, of power and energy not required for System purposes.

(p) Coordinate arrangements from time to time to procure for the Companies, or for their account, such power and energy from external sources as may be required or will result in savings to the Companies.

(q) Keep abreast of all environmental factors as they affect the operation of the System in order to comply with all established criteria for minimizing pollution.

(r) Undertake any other duties that may from time to time be assigned to it or deemed appropriate.

5.07 Employment of Consultants

The Operating Committee, in the performance of its duties, may employ such technical and consulting services as warranted.

5.08 Expenses of Committee

Each Company (except the Parent Company) shall pay the expenses of its representatives on the Operating Committee. The expenses of the representatives of the Parent Company shall be paid by Services. Any other expenses of the Committee shall be prorated among the Companies as determined by the Operating Committee.

ARTICLE VI SYSTEM OPERATIONS CENTER

6.01 System Operations Center

The operation of the System shall be controlled by the System Operations Center which is operated by Services.

6.02 Duties

Services through the System Operations Center shall:

(a) Determine the most effective scheduling of sources for the reliable supply of power and energy on an economical basis to the Companies.

(b) Supervise the operation and maintenance of computer facilities specified by the Operating Committee for the following purposes:

1. Economic system dispatch,

2. Determination of billing information, and

3. Determination of other data required by the Operating Committee.

(c) Supervise safe switching procedures and other routine procedures in the system.

(d) Determine the availability of energy for purchase from or sale to outside systems on an economical basis under effective contracts and arrange for and schedule such transactions.

(e) Coordinate the operation of communication facilities owned or leased by the Companies to provide the communication essential to the safe, reliable and economical operation of the System.

(f) Maintain such records and prepare such reports as the Operating Committee designates.

6.03 Expenses

All expenses of the Systems Operations Center shall be paid by Services and billed monthly to each Company in accordance with the applicable Service Schedule.

IN WITNESS WHEREOF each of the Companies has caused these presents to be signed in its name and on its behalf by its President, attested by its Secretary, both being duly authorized.

Attest	LOUISIANA POWER & LIGHT COMPANY
Original signed by	Original signed by
W. H. Talbot	J. M. Wyatt
Secretary	President
Attest	MISSISSIPPI POWER & LIGHT COMPANY
Original Signed by	Original signed by
R. J. Estrada	D. C. Lutken
Assistant Secretary	President
Attest	NEW ORLEANS PUBLIC SERVICE INC.
Original signed by	Original signed by
William C. Nelson	James M. Cain
Secretary	President
Attest	MIDDLE SOUTH SERVICES, INC.
Original signed by	Original signed by
D. E. Stapp	Frank G. Smith
Secretary	President

SERVICE SCHEDULE MSS-1 RESERVE EQUALIZATION

10.01 Purpose

The purpose of this Service Schedule is to provide the basis for equalizing the capability and ownership cost incidental to such capability among the Companies in such a manner that the capability and reserves of each Company after equalization shall be equal to its Capability Responsibility.

10.02 Company Capability

A Company's Capability shall be determined monthly and shall be the sum of available owned or leased generating units, purchases and seasonal or other energy exchange from demonstrated reliable sources as follows:

(a) The total capability of available generating units owned, operated under Operating Agreements for its own benefit, or leased by such Company, devoted to serving System load but excluding that portion of any unit owned or leased by such Company that has been sold or leased to another Company (other than through MSS-3). Such units shall be included at their demonstrated net output measured in megawatts under conditions established by the Operating Committee. A unit is considered available to the extent the capability can be demonstrated and (1) is under the control of the System Operator, or (2) is down for maintenance or nuclear refueling, or (3) is in extended reserve shutdown (ERS) with the intent of returning the unit to service at a future date in order to meet Entergy System requirements. The Operating Committee's decision to consider an ERS unit to be available to meet future System requirements shall be evidenced in the minutes of the Operating Committee and shall be based on consideration of current and future resource needs, the projected length of time the unit would be in ERS status, the projected cost of maintaining such unit, and the projected cost of returning the unit to service. A unit is considered unavailable if in the judgment of the Operating Committee it is of insufficient value in supplying system loads because of (1) obsolescence, (2) physical condition, (3) reliability, (4) operating cost, (5) start-up time required, or (6) lack of due-diligence in effecting repairs or nuclear refueling in the event of a scheduled or unscheduled outage.

The generating units of Gulf States that were in extended reserve shutdown on the date of the merger of Entergy and Gulf States, shall not be considered available for the purpose of determining Capability in the Service Schedule MSS-1 Reserve Equalization calculation until the units are brought into service.

If, as part of a settlement or judgment adverse to Gulf States in Cajun Electric Power Cooperative, Inc. v. Gulf States Utilities Co., Civil Action No. 89-474-B (M.D. La.) and/or Southwest Louisiana Electric Membership Corp. and Dixie Electric Membership Corp. v. Gulf States Utilities Co., Civil Action No. 92-2129 (W.D. La.), Gulf States acquires Cajun Electric Power Cooperative, Inc.'s 30 percent share of the River Bend Nuclear Generating Facility (River Bend) (or any portion thereof), then the net output in megawatts associated with such share shall not be considered available for the purpose of determining Capability in the Service Schedule MSS-1 Reserve Equalization calculation.

(b) The contract quantity of capacity in megawatts purchased without reserves by the Company.

(c) The contract quantity of firm capacity in megawatts purchased plus an additional amount as developed from the following formula:

$$A = \frac{FP \times SC}{(SL - FP)} - FP$$

where:

A = Amount, in megawatts (mW), to be added to contract quantity of firm capacity purchased.

FP = Amount of firm purchase in Mw

SL = Seller's load responsibility in mW, determined by calculating the average of the Seller's monthly hour peak loads for the twelve month period ending with the current month. Each such peak load shall represent the simultaneous hourly input from all sources into the Seller's system, less the sum of the simultaneous hourly outputs to the systems of other interconnected utilities.

SC = Seller's total capability which shall be determined monthly and shall be the sum of the net demonstrated capabilities of Seller's owned or leased generating units and the contract quantity of capacity purchased by Seller, all measured in mW.

(d) That portion of the contract quantity of capacity in megawatts purchased with or without reserves, for the joint account of all the Companies as allocated to the Company on the basis of Section 4.02, including Joint Account Capacity Purchases in the MISO Resource Adequacy Market.

(e) That portion of the contract quantity of capacity in megawatts received under any seasonal or other exchange with outside suppliers for the joint account of all Companies, as allocated to the Company on the basis of its Responsibility Ratio.

(f) Cogeneration or Small Power Production Capacity in accordance with Sections 2.12 and 2.13. The Operating Committee shall have the authority to allocate any such capacity to one or more of the Companies in accordance with FERC Opinion Nos. 246 and 246-A.

10.03 Basis of Reserve Equalization

Company Capability in excess of the Capability Responsibility of any Company shall be allocated among the Companies so that the resultant capability and reserves of each Company shall be equal to its Capability Responsibility.

$$ER = CC - SC \times \frac{CLR}{SLR}$$

where:

ER = Equalized Reserve

CC = Company Capability (Section 2.14)

SC = System Capability (Section 2.15)

CLR = Company Load Responsibility (Section 2.16 (b))

SLR = System Load Responsibility (Section 2.17 (b))

If more than one Company has Company Capability in excess of its Capability Responsibility, the excess of each such Company from its Intermediate Generating Units, as defined in Section 2.09 shall be allocated to each deficient Company in the ratio of such Company's deficiency to the sum of the deficiencies of the deficient Companies.

10.04 Reserve Equalization Payment

For the reserve allocated in accordance with Section 10.03, the Company or Companies having an excess shall receive, from the Company or Companies having a deficiency, an equalization payment, determined in accordance with the method hereinafter described, for such reserve so allocated each month.

10.05 Investment in Intermediate Reserve Generating Units

The generating units to be reflected in determining the costs to be billed under this Service Schedule are those that serve as reserves to the System and shall be defined by reference to their average annual heat rate. The Reserve Generating Units for each Party (based on Federal Energy Regulatory Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees) shall be those gas- and oil-fired units that had an annual average heat rate in the preceding calendar year of at least 10,000 Btu per kilowatt-hour. For Reserve Generating Units that were not in commercial operation for all of the preceding calendar year, the heat rate used to determine eligibility under this provision shall be specified by the Operating Committee. The investment in such Reserve Generating Units shall be determined as follows:

(a) The cost includable for all such units in Accounts 310, 311, 312, 313, 314, 315 and 316.

(b) The cost of step-up transformers, circuit breakers, and switching equipment etc. included in Account 353 and required to connect all such units to the transmission system.

10.06 Determination of Monthly Billing Charge

The Monthly Charge (MC) per kW for billings under Reserve Equalization shall be determined for each Company based upon the previous year's operating results. The MC will be based on the average of all units included as Intermediate Generating Units as included in Sections 10.05 (a) and (b).

$$MC = (1/12)\ \frac{RB \times (CM + F) + D + PT + I + FT + OM}{C}$$

where:

CM = the weighted average cost of capital as determined in the following manner:

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

C = The sum of capacity in kW for the generating units in RB

DR = Ratio of Debt Capital at Dec. 31 of the previous year

PR = Ratio of Preferred Stock at Dec. 31 of the previous year

ER = Ratio of Common Stock at Dec. 31 of the previous year

i = Average embedded cost of debt capital outstanding at Dec. 31 of the previous year

p = Average embedded cost of preferred stock outstanding at Dec. 31 of the previous year

c = Return on Common Equity at 11.0%

D = The amount of depreciation for the preceding year as reported on page 429 of the Company FERC Form No. 1 report as related to Intermediate Generating Units and associated equipment required to connect generating equipment to the transmission system.

F = Federal and State Income Taxes determined from the following formulae:

$$F = \frac{T}{(1 - T)} \times (CM - DR \times i)$$

where:

T = f + s - fs when federal tax is not deductible in computing state tax, and

$$T = \frac{(f + s - 2fs)}{(1 - fs)}$$ when federal tax is deductible in computing state tax, and

f = Federal Income Tax Rate

s = State Income Tax Rate

RB = The amount as of December 31, of the preceding year reflected in Plant Accounts 310, 311, 312, 313, 314, 315 and 316 for gas or oil fired Steam Production Plants, plus an amount included in Account 353 which represents the investment in step-up transformers, circuit breakers, and switching equipment, etc. required to connect all such units to the transmission system, less the accumulated provision for depreciation for the gas or oil fired units in the Steam Production plants and the accumulated provision for depreciation associated with the equipment included in Account 353 described above, and less the proportionate amount of Account 282 Accumulated Deferred Income Taxes.

I = Preceding year insurance premium for Intermediate Generating Units included in RB

PT = Ad Valorem taxes for the preceding year for Intermediate Generating Units Included in RB

FT = Applicable Corporation Franchise Tax for the preceding year for Intermediate Generating Units included in RB

OM = Operation and maintenance expenses plus the applicable general and administrative expenses. These combined expenses will be determined annually by taking the applicable accounts for each Company related to their owned generating capacity, together with the applicable general and administrative expenses, proportioned to the direct labor expenses.

Fossil Fueled Units

Direct - Accounts 500, 502, 503, 504, 505, 506, 507, 510, 511, 512, 513 and 514.

Allocable - Accounts 920, 921, 922, 923, 924, 925, 926, 927, 928, 929, 930, 931 and 932.

10.07 Adjustment for Tax Changes

The Reserve Equalization Payment as determined above shall be adjusted to reflect the imposition of any applicable new taxes not included in the above formula, or for any increase or decrease in taxes included as of the date of this Agreement.

10.08 Billing Procedure

The billing parameters will be in effect from June 1 to the succeeding May 31 based on the preceding year's results.

This Service Schedule MSS-1 shall be attached to and become a part of the Agreement dated the 23rd day of April, 1982 and shall be effective with said Agreement or at such later date as may be fixed by any requisite regulatory approval or acceptance for filing.

Attest	LOUISIANA POWER & LIGHT COMPANY
Original signed by	Original signed by
W. H. Talbot	J. M. Wyatt
Secretary	President
Attest	MISSISSIPPI POWER & LIGHT COMPANY
Original signed by	Original signed by
R. J. Estrada	D. C. Lutken
Assistant Secretary	President
Attest	NEW ORLEANS PUBLIC SERVICE INC.
Original signed by	Original signed by
William C. Nelson	James M. Cain
Secretary	President

SERVICE SCHEDULE MSS-2 TRANSMISSION EQUALIZATION

20.01 Purpose

The purpose of this Service Schedule is to provide the basis for equalizing among the Companies the ownership costs associated with Inter-Transmission Investment in such a manner that each Company will bear a portion of these costs proportional to its Responsibility Ratio.

20.02 Inter-Transmission Investment

A Company's Inter-Transmission Investment for the purpose of this schedule shall consist of:

(a) All of the investment in transmission lines operated at 230 kV or higher voltage to the extent that such investment is not included in billings under other agreements.

(b) Investment in transmission substations with three or more lines operated at a voltage of 230 kV or higher to the extent that such investment is not included in billings under other agreements. Investment in such substations shall include facilities down to but not including the high side disconnecting device of the transformer, 50% of common facilities, and other facilities as approved by the Operating Committee. Common substation facilities are those facilities not directly associated with any of the major power supplying voltages of the substation. They include but are not limited to land, roadway, lighting, control house, fill, fencing, supervisory equipment, etc.

(c) All lines 115 kV and higher from the owning Company's last substation to the connecting point of another Company (either Entergy System Company or nonsystem Company) not included in (a), or not included in billings under other agreements.

The investment in a generating unit step-up transformer and associated switchgear, necessary to connect the generating unit to the lines or all buses, shall not be included in subsection (b).

In determining the investments above referred to under subsections (a) and (c), only those transmission line costs includable in Accounts 350, 352, 354, 355, 356, 357, 358 and 359 of the Federal Energy Regulatory Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees.

The investments above referred to under subsection (b) are amounts includable in the accounts listed in the preceding paragraph plus Account 353.

The investment in new transmission facilities included under this Service Schedule shall be added to a Company's Inter-Transmission Investment on the first day of the month following the "in service" date of the facilities. Each Company's Inter-Transmission Investment shall be revised as of the end of each month to adjust for any additions or retirements. Investments for upgrades contained in Schedules 26 and 26-A of the MISO Tariff are considered billings under other agreements and excluded from the calculation of a Company's Inter-Transmission Investment.

20.03 Company Net Inter-Transmission Investment - Company Net Inter-Transmission Investment shall be the sum of the Company Inter-Transmission Investments reduced for the Accumulated Provision for Depreciation and Deferred Taxes as adjusted at each December 31.

20.04 Transmission Responsibility - A Company's Transmission Responsibility shall be the sum of the System Net Inter-Transmission Investments multiplied by that Company's Responsibility Ratio.

20.05 Transmission Equalization Payments - Each Company shall pay or receive each month, as appropriate, an amount in dollars determined by the following formula:

Dollars ($) = 1/12 (TR - TI) (AOC)

where:

TR = The Company's Transmission Responsibility as defined in Section 20.04

TI = The Company's Net Inter-Transmission Investment as defined in Section 20.03

AOC = System Average Annual Ownership Cost

20.06 Development of Company's Annual Ownership Cost - (AOC_C) - The Annual Ownership Cost, expressed as a decimal, shall be determined as follows:

$$AOC_C = (CM + F) + \left| \frac{D + I + PT + FT + OM}{K} \right|$$

where:

CM = the weighted average cost of capital determined as follows:

CM = (DR x i) + (PR x p) + (ER x c)

DR = Ratio of Debt Capital at Dec. 31 of the previous year

PR = Ratio of Preferred Stock at Dec. 31 of the previous year

ER = Ratio of Common Stock at Dec. 31 of the previous year

i = Average embedded cost of debt capital outstanding at Dec. 31 of the previous year

p = Average embedded cost of preferred stock outstanding at Dec. 31 of the previous year

c = Return on common equity at 11.0%

F = Federal and State Income Taxes as determined from the formulas:

$$F = \frac{T}{(1 - T)} \times [CM - DR \times i]$$

T = f + s - fs when federal tax is not deductible in computing state tax, and

$$T = \frac{f + s - 2fs}{1 - fs}$$ when federal tax is deductible in computing state tax, and

f = Federal Income Tax Rate

s = State Income Tax Rate weighted on prior year jurisdictional revenues if two or more state jurisdictions are served

K = The ratio of a Company's Net Inter-Transmission Investment and Inter-Transmission Investment (i.e., Section 20.03 □ Section 20.02)

D = Book depreciation as used by each Company expressed as a decimal of Inter-Transmission Investment (Section 20.02).

I = Annual insurance cost expressed as a decimal of Inter-Transmission Investment (Section 20.02).

PT = Average ad valorem taxes based on preceding year's tax rates and assessments for the Inter-Transmission Investment expressed as a decimal of Inter-Transmission Investment (Section 20.02).

FT = Corporate Franchise Tax based on preceding year's Inter-Transmission Investment expressed as a decimal of Inter-Trans-mission Investment (Section 20.02).

OM = Operating and maintenance expenses plus the applicable general and administrative expenses expressed as a decimal of Inter-Transmission Investment (Section 20.02). These combined expenses will be determined annually by taking the applicable accounts for each Company, related to their total transmission investment, together with the applicable general and administrative expenses and proportioned to the direct labor expenses.

Direct - Accounts 560, 561, 562, 563, 564, 565, 566, 567, 568, 569, 570, 571, 572 and 573

Allocable - Accounts 920, 921, 922, 923, 924, 925, 926, 927, 928, 929, 930, 931 and 932

20.07 Development of System Average Annual Ownership Cost

The System Average Annual Ownership Cost to be applied to this Service Schedule shall be developed from the following formula:

$$AOC = \frac{(G \times AOC_G)+(L \times AOC_L)+(M \times AOC_M)+(N \times AOC_N) + (T \times AOC_T)}{G + L + M + N + T}$$

where:

AOC = System Average Annual Ownership Cost

G = EGSL Net Inter-Transmission Investment

L = ELL Net Inter-Transmission Investment

M = EMI Net Inter-Transmission Investment

N = ENOI Net Inter-Transmission Investment

T = ETI Net Inter-Transmission Investment

AOC_G = EGSL - Annual Ownership Cost

AOC_L = ELL - Annual Ownership Cost

AOC_M = EMI - Annual Ownership Cost

AOC_N = ENOI - Annual Ownership Cost

AOC_T = ETI - Annual Ownership Cost

20.08 Adjustment for Tax Changes

The Transmission Equalization Payment as determined in Section 20.05 shall be adjusted to reflect the imposition of any applicable new taxes not included in the above formula, or for any increase or decrease in taxes included as of the date of this Agreement.

20.09 Billing Procedure

The billing parameters will be in effect from June 1 to the succeeding May 31, based on the preceding year's results.

This Service Schedule MSS-2 shall be attached to and become a part of the Agreement dated the 23rd day of April, 1982 and shall be effective with said Agreement or at such later date as may be fixed by any requisite regulatory approval or acceptance for filing.

Attest	LOUISIANA POWER & LIGHT COMPANY
Original signed by	Original signed by
R. J. Estrada	Jerry Maulden
Secretary	President

Attest	MISSISSIPPI POWER & LIGHT COMPANY
Original signed by	Original signed by
R. J. Estrada	D. C. Lutken
Assistant Secretary	President

Attest	NEW ORLEANS PUBLIC SERVICE INC.
Original signed by	Original signed by
William C. Nelson	James M. Cain
Secretary	President

SERVICE SCHEDULE MSS-3 EXCHANGE OF ELECTRIC ENERGY AMONG THE COMPANIES

30.01 Purpose

The purpose of this Service Schedule is to provide the method of pricing energy exchanged among the Companies and to provide for payments and receipts in accordance with the provisions of Opinion Nos. 480 and 480-A.

30.02 Scheduling of Energy Sources

The System Capability shall be operated as scheduled and/or controlled by the System Operator to obtain the lowest reasonable cost of energy to all the Companies consistent with the requirements of daily operating generation reserve, voltage control, electrical stability, loading of facilities and continuity of service to the customers of each Company.

In no event shall the remaining margin payment obligations of ETI to Southwestern Electric Power Corporation under Section 9.1 of the Restated and Amended Interconnection Agreement between ETI and Southwestern Electric Power Company, be included, considered or otherwise taken into account by the System Operator under Section 30.02 of the System Agreement, except for the circumstance where the lowest reasonable cost energy available to the System Operator is identical in price to that offered to ETI under such Section 9.1.

30.03 Allocation of Energy

The energy from the lowest cost source available and scheduled as in Section 30.02 above shall be allocated on an hourly basis, in the order of the following priorities:

(a) first to the loads of the Company having such sources available, except that in the case of energy generated by a Designated Generating Unit, each Company to which a portion of the Capability of the Designated Generating Unit as defined in Section 40.02 has been sold shall be entitled to receive each hour that portion of the total energy generated by the Designated Generating Unit that the capability sold to the Company bears to the total capability of the Designated Generating Unit.

(b) second to supply the requirements of the other Companies' Loads (Pool Energy).

30.04 Energy for Sales to Others

Energy used to supply others will be provided in accordance with rate schedules on file with the Federal Energy Regulatory Commission. A Company will be reimbursed for the current estimated cost of fuel used by the specific unit or units supplying the energy together with the adder determined in Section 30.08(f) on an hour by hour basis.

30.05 Unscheduled Energy

Energy produced by generating units not scheduled for system energy requirements but operated at the request of a Company beyond what is deemed necessary for overall system purposes by the System Operator, shall not be considered as part of Sections 30.03 or 30.04 above, but shall be for the use, and at the expense of the Company requesting the operation of such generating units.

30.06 Fuel Contract Energy

Energy produced by generating units for system energy requirements shall be allocated as follows:

(a) When operated to satisfy "take or pay" minimums under fuel contracts negotiated for System benefit as approved by the Operating Committee shall be shared by all companies in proportion to their current Responsibility Ratio.

(b) When operated with fuel acquired for the benefit of two or more of the Companies shall be shared in proportion to their participation in such contracts.

(c) When operated pursuant to fuel purchases negotiated for System benefit as approved by the Operating Committee, the Company owning the units utilizing the fuel has a one-time option to either assume responsibility for purchase of the fuel for its own account or to allow the fuel to be purchased for the System's joint account in accordance with 30.06(a) or (b) as appropriate.

30.07 Cogeneration or Small Power Production Energy

Energy received by any Company from Cogeneration or Small Power Production Sources that is included as a part of Inter-Company billings shall be priced under this Agreement in accordance with rates established by the appropriate regulatory authority. The Operating Committee shall have the authority to allocate such energy to one or more of the Companies or to determine that the energy is for the use, and at the expense of, the Company making the purchase from such Source in accordance with FERC Opinion Nos. 246 and 246-A.

30.08 Payments to be Received for Energy Supplied

Each Company shall receive, for energy furnished in accordance with Sections 30.03 (a),(b) and 30.04 in excess of its load requirements, on an hourly basis:

(a) For each kWh generated as short term purchase energy from a Designated Generating Unit in accordance with Section 30.03(a), whether or not taken by the Company or Companies making the purchase, the cost of fuel consumed.

(b) For each kWh generated by use of fossil fuel, in accordance with Sections 30.03(b) and 30.04, the cost of fuel consumed plus an adder as determined in Section 30.08 (f).

(c) For each kWh generated as Fuel Contract Energy, in accordance with Section 30.06, the cost of fuel consumed plus an adder as determined in Section 30.08(f).

(d) For purchased energy, the actual cost of such purchased energy. The "actual cost" of purchased energy for ETI shall not include the remaining margin payment obligation of ETI to Southwestern Electric Power Company, under Section 9.1 of the Restated and Amended Interconnection Agreement between ETI and Southwestern Electric Power Company.

(e) For each kWh received as Cogeneration or Small Power Production energy in accordance with Section 30.07, the price established in Section 30.07.

(f) The adder for Sections 30.08(b) and 30.08(c) shall be determined pursuant to the following formula.

Adder = A + B + C

where:

A = .5563 <u>O&M (current) □ NSGC</u>

O&M (base) □ NSGB where,

A = O&M adder in mills/kWh adjusted annually

O&M = Accounts 500, 502, 503, 504, 505, 506, 507, 510, 511, 512, 513 and 514

Current = Three years ending with preceding year

NSGC = Net steam generation in kWh for the three years ending with preceding year

Base = Three years of 1978, 1979 and 1980

NSGB = Net steam generation in kWh for 1978, 1979 and 1980 base period

.5563 = The amount applicable at the date of this agreement

□ O&M (base) □ NSGB = 1.6724

B = AC x HR x (SR/2,000,000) where,

B = Incremental replacement SO_2 cost (in mills/kWh) for the particular generating unit, adjusted weekly

AC = allowance cost (in \$/allowance), adjusted weekly based on the average cost of purchasing an emission allowance from an index accepted by FERC.

HR = heat rate (in Btu/kWh)

SR = SO_2 rate for fuel (in lb SO_2/MMBtu)

C = NC x HR x (NR/2,000,000) where,

C = incremental replacement NO_x cost (in mills/kWh) for the particular generating unit, adjusted weekly

NC = allowance cost (in \$/allowance), adjusted weekly based on the average cost of purchasing a NO_x emission allowance from an index accepted by FERC.

HR = heat rate (in Btu/kWh)

NR = NO_x rate for fuel (in lb NO_x/MMBtu)

30.09 Payments Made for Energy

(a) Each Company shall pay for energy allocated to it from a Designated Generating Unit as purchased energy the cost of fuel consumed per kWh.

(b) Each Company shall pay for energy received from the energy allocated in accordance with the provisions of Section 30.03(b) above, the weighted average cost per kWh of energy, as provided under Section 30.08(b) above, accumulated and distributed on a hourly basis.

(c) Each Company shall pay for energy received from the energy allocated in accordance with the provisions of Section 30.06 above, the cost per kWh of energy as provided under Section 30.08(c) above, accumulated and distributed on a hourly basis.

(d) Each Company shall pay or receive funds to the extent required to maintain Rough Production Cost Equalization in accordance with the provisions of Sections 30.11 through 30.14 below.

30.10 Cost of Fuel Per kWh

Cost of fuel per kWh shall be determined for each generating unit by multiplying the BTU consumed per kWh of net generation during the preceding calendar year by the current estimated cost per BTU of the fuel used as furnished by each Company monthly. For the first year of operation of a new unit, BTU consumed per kWh of net generation shall be based on the design heat rate at 60% of full load capability at anticipated average annual back pressure.

30.11 Rough Production Cost Equalization

To maintain Rough Production Cost Equalization (RPCE) among the Companies, each Company's actual Production Cost (PC) as determined in accordance with Section 30.12, shall be compared to its respective allocation of the System Average Production Cost (APC), as determined in accordance with Section 30.13, to determine if a Company's PC deviates from its APC by more than +/-11%.

where:

Paying Company(ies) is a Company or Companies with a negative Disparity that could make payments under this provision;

Receiving Company(ies) is a Company or Companies with a positive Disparity that could receive payments under this provision; and,

Disparity (D) equals the ratio of PC to APC expressed in terms of the divergence from 100%

$D = ({}^{PC}/_{APC} - 1) * 100\%$

(a) If one or more Companies has a positive Disparity greater than eleven percent (11%), but no Company(ies) has a negative Disparity greater than 11%, then a payment shall be made by the Paying Company(ies) to the Receiving Company(ies) such that the positive Disparity of any Receiving Company(ies) after reflecting such payment is equal to 11% and the negative Disparity of any Paying Company(ies) after reflecting such payment is no less than the negative Disparity of any other Paying Company.

(b) If one or more Companies has a negative Disparity greater than 11%, but no Company has a positive Disparity greater than 11%, then a payment shall be made by the Paying Company(ies) to the Receiving Company(ies) such that after reflecting such payment, any Paying Company(ies) has a negative Disparity equal to 11% and that the positive Disparity of any Receiving Company(ies), after reflecting such payment, is no less than another Receiving Company.

(c) If one or more Receiving Companies has a positive Disparity greater than 11% and one or more Companies has a negative Disparity greater than 11%, then a payment shall be made by the Paying Company(ies) with a negative Disparity greater than 11% to the Receiving Company(ies) with a positive Disparity greater than 11% such that after reflecting such payments, all Receiving Company(ies) will not have a Disparity exceeding 11% and the payment obligation shall be distributed among Paying Companies such that no Company that will be making payments has a negative Disparity after reflecting such payments less than that of any other Paying Company. In the event that the payments made reduce the positive Disparity of a Receiving Company(ies) to 11% but that one or more Paying Companies has a negative Disparity after reflecting such payments that is greater than 11%, then payments shall be made such that no Paying Company has a negative Disparity that is greater than 11% and that the positive Disparity of any Receiving Company, after reflecting such payments, is no less than another Receiving Company.

30.12 Actual Production Cost

The actual production cost (PC) is the sum of the actual variable production cost (VPC) and the actual fixed production cost (FPC) and shall be determined for each Company.(See Note 1) The formula for developing the actual production cost is as follows:

(Note 1: All Rate Base, Revenue and Expense items shall be based on the actual amounts on the Company's books for the twelve months ended December 31 of the previous year as reported in FERC Form 1 or such other supporting data as may be appropriate for each Company; and shall include certain retail regulatory adjustments pursuant to the production cost methodology set forth in Exhibit ETR-26/ETR-28 filed in Docket No. EL01-88-001, including but not limited to: (1) the Deregulated Asset Plan adjustment for EGSL, (2) the regulated portion (70%) of River Bend for EGSL, (3) repricing of energy associated with the Vidalia purchase power contract for ELL based on the average annual Service Schedule MSS-3 rate paid by ELL, including the exclusion of the income tax savings of the Vidalia purchase power contract from ADIT and reflecting the reversal of the Vidalia capital transaction, and the debt rate associated with the Waterford 3 Sale/Leaseback for ELL, (4) exclusion of the EMI retail approved Grand Gulf Accelerated Recovery Tariff effects on purchased power on EMI's production cost; (5) exclusion of any increased costs resulting from the amended Toledo Bend Power Sales Agreement accepted for filing in Docket No. ER07-984, (6) repricing of energy associated with the Rain CII Carbon power purchase contract for EGSL based on the average annual Service Schedule MSS-3 rate paid by EGSL, and (7) repricing of energy associated with the Agrilectric power purchase contract for EGSL based on the average annual Service Schedule MSS-3 rate paid by EGSL.)

$$PC = VPC + FPC$$

where:

VPC = Variable Production Cost

$$= VPRB * (CM + F) + VPX$$

where:

VPRB = Variable Production Rate Base (See Note 2)

(Note 2: Rate Base values shall be based on the actual balances on the Company's books as of December 31 of the previous year except for Fuel Inventory, Materials & Supplies and Prepayments which shall be based on the average of the beginning and ending actual balances on the Company's books.)

= NPP – NAD – (ADIT * NPPR)

NPP = Nuclear Production Plant in Service as recorded in FERC Plant Accounts 320 through 325 and FERC Account 101.1 excluding Asset Retirement Obligations (ARO) recorded in FERC Plant Account 326, if any, plus the cost of plant acquired recorded in FERC Account 114 pertaining to nuclear plant, to the extent recovery is authorized by FERC.

NAD = Nuclear Accumulated Provision for Depreciation and Amortization excluding ARO associated with NPP above, as recorded in FERC Accounts 108, 111 and, to the extent recovery is authorized by FERC, Account 115 (consistent with the accounting relating to Statement of Financial Accounting Standards (SFAS) 143 approved by the retail regulator having jurisdiction over the Company, unless the FERC determines otherwise)

ADIT = Net Accumulated Deferred Income Taxes (ADIT) recorded in FERC Accounts 190, 281 and 282 (as reduced by amounts not generally and properly includable for FERC cost of service purposes, including but not limited to, SFAS 109 ADIT amounts and ADIT amounts arising from retail ratemaking decisions) plus Accumulated Deferred Income Tax Credit-3% portion only recorded in FERC Account 255

NPPR = Ratio of Nuclear Production Plant in Service defined as NPP above excluding Waterford 3 Capital Lease and less Plant Adjustments pertaining to nuclear plant to Electric Plant in Service excluding Waterford 3 Capital Lease plus the cost of plant acquired recorded in FERC Account 114 to the extent recovery is authorized by FERC and less Total Plant Adjustments (See Notes 3 and 4)

(Note 3: Plant ratios shall be determined based on plant in service balances exclusive of associated ARO as of December 31 of the previous year.)

(Note 4: For the acquisition of Electric Plant in Service, the Plant Adjustment is equal to the original cost of electric plant acquired as recorded in FERC Account 101 plus the cost of plant acquired recorded in FERC Account 114, to the extent recovery is authorized by FERC, minus the purchase price of acquired electric plant less any amount for which recovery is not authorized by FERC.)

= NPPXW3L / PXW3L

where:

NPPXW3L =	Nuclear Production Plant in Service defined as NPP above excluding Waterford 3 Capital Lease as recorded in FERC Account 101.1 less Plant Adjustments pertaining to nuclear plant.
PXW3L =	Electric Plant in Service which includes the sum of the Company's Production, Transmission, Distribution, General and Intangible Plant in Service recorded in FERC Plant Accounts 301 through 399 less Total Plant Adjustments (See Note 4), Property under Capital Lease excluding Waterford 3 Capital Lease as recorded in FERC Account 101.1, and Completed Construction not yet Classified as recorded in FERC Account 106 excluding ARO, if any, plus the cost of plant acquired recorded in FERC Account 114, to the extent recovery is authorized by FERC

CM = The weighted average cost of capital determined as follows:

= (DR * i) + (PR * p) + (ER * c)

where:

DR = Ratio of Debt Capital and Preferred Stock with tax deductible dividends (QUIPS) at Dec. 31 of the previous year

PR = Ratio of Preferred Stock without tax deductible dividends at Dec. 31 of the previous year

ER = Ratio of Common Stock at Dec. 31 of the previous year

i = Average embedded cost of debt capital and preferred stock with tax deductible dividends (QUIPS) outstanding at Dec. 31 of the previous year

p = Average embedded cost of preferred stock outstanding at Dec. 31 of the previous year

c = Simple average of the Companies' approved retail return on common equity rates at Dec. 31 of the previous year

F = Federal and State Income Taxes determined from the following:

= T / (1-T) * (CM – DR * i)

where:

T = f + s - fs when federal tax is not deductible in computing state tax, and

T = (f + s - 2fs) / 1 – (fs) when federal tax is deductible in computing state tax, and

f = Federal Income Tax Rate

s = State Income Tax Rate

VPX = Variable Production Expense

= NPOMNF + FE + PURP – RC + NDE

where:

NPOMNF = Nuclear Production Operation and Maintenance (O&M) Non-Fuel Expense, recorded in FERC Accounts 517 through 532 excluding Nuclear Fuel in FERC Account 518

FE = Production O&M Fuel Expense recorded in FERC Accounts 501, 518 and 547

PURP = Purchased Power Expense recorded in FERC Account 555, but excluding payments made pursuant to Section 30.09(d) of this Service Schedule and excluding the effects, debits and credits, resulting from a regulatory decision that causes the deferral of the recovery of current year costs or the amortization of previously deferred costs

RC = Revenue Credits resulting from revenue received from customers outside the Company's Net Area for Production Service recorded in FERC Account 447, but excluding receipts received pursuant to Section 30.09(d) of this Service Schedule

NDE = Nuclear Depreciation and Amortization Expense associated with (NPP) as recorded in Accounts 403, 404, and, to the extent recovery is authorized by FERC ,Account 406 and Decommissioning Expense, as approved by Retail Regulators, unless the jurisdiction for determining the depreciation and/or decommissioning rate is vested in the FERC under otherwise applicable law

FPC = Fixed Production Cost

= FPRB * (CM + F) + FPX – [(ITC / TX) * PPR]

where:

FPRB = Fixed Production Rate Base

= PPXN + CME – ADXN + FI - (ADIT * PPRXN) + [(GP – GAD + IP – IAA) * PLR] + (MS + P) * PPREG

where:

PPXN =	Production Plant in Service excluding Nuclear Plant recorded in FERC Plant Accounts 310 through 317, Accounts 330 through 346, and FERC Account 101.1 excluding ARO recorded in FERC Plant Accounts 317 and 337, if any, plus the cost of plant acquired recorded in FERC Account 114, to the extent recovery is authorized by FERC
CME =	Coal Mining Equipment in FERC Plant Account 399 owned by the Company
ADXN =	Accumulated Provision for Depreciation and Amortization associated with PPXN and CME above, as recorded in FERC Accounts 108, 111, and, to the extent recovery is authorized by FERC, Account 115 excluding ARO associated with PPXN and CME, if any, (consistent with the accounting relating to SFAS 143 approved by the retail regulator having jurisdiction over the Company, unless the FERC determines otherwise)
FI =	Fuel Inventory recorded in FERC Account 151
ADIT =	Net Accumulated Deferred Income Taxes plus Accumulated Deferred Income Tax Credit
PPRXN =	Ratio of Production Plant in Service excluding Nuclear Plant defined as PPXN above less Plant Adjustments pertaining to non-nuclear plant (See Note 4) plus Production allocation of General and Intangible Plant to Electric Plant in Service defined as PXW3L above
=	[PPXNPA + (GP + IP) * PLR] / PXW3L

where:

PPXNP = PPXN above less Plant Adjustments pertaining to non-nuclear plant (Note 4)

GP =	General Plant in Service recorded in FERC Plant Accounts 389 through 398 excluding ARO, if any
GAD =	General Plant Accumulated Provision for Depreciation, as recorded in FERC Account 108 excluding ARO associated with GP above, if any, (consistent with the accounting relating to SFAS 143 approved by the retail regulator having jurisdiction over the Company, unless the FERC determines otherwise)
IP =	Intangible Plant in Service recorded in FERC Plant Accounts 301 through 303
IAA =	Intangible Plant Accumulated Provision for Amortization associated with IP above recorded in FERC Account 111
PLR =	Ratio of Production Labor to Total Labor excluding A&G Labor (See Note 5)

(Note 5: Labor ratios shall be determined based on the payroll expense for each Operating Company, including those payroll expenses billed to it by EOI and ESI, for the twelve months ended December 31 of the previous year.)

= PL / LXAG

where:

PL =	Production Labor charged to O&M Expense
LXAG =	Total Labor charged to O&M Expense excluding A&G Labor

MS = Materials and Supplies recorded in FERC Account 154

P = Prepayments as recorded in FERC Account 165

PPREG = Ratio of Production Plant in Service plus the cost of plant acquired recorded in FERC Account 114 pertaining to production plant to the extent recovery is authorized by FERC and less Total Plant Adjustments (See Note 4) to Electric and Gas Plant in Service excluding Intangible Plant, plus the cost of plant acquired recorded in FERC Account 114 to the extent recovery is authorized by FERC and less Total Plant Adjustments (See Note 4)

= PP / EGPXI

where:

PP = Production Plant in Service as recorded in FERC Plant Accounts 310 through 346 less Total Plant Adjustments (See Note 4) and FERC Account 101.1 excluding ARO recorded in FERC Plant Accounts 317, 326 and 337, if any, plus the cost of plant acquired recorded in FERC Account 114 pertaining to production plant, to the extent recovery is authorized by FERC

EGPXI = Electric and Gas Plant in Service defined as PXW3L above less Intangible Plant plus Waterford 3 Capital Lease as recorded in FERC Account 101.1 and Gas Plant as recorded in FERC Account 118 excluding ARO, if any

FPX = Fixed Production Expense

= NFPOMXN + DEXN + [(AGX924 + GDX + IAX) * PLR] + ((OT + 924AG) * PPR + RSRA + LGCC

where:

NFPOMXN=	Non-Fuel Production O&M Expense excluding Nuclear; i.e. costs recorded in FERC Accounts 500 through 514 plus Accounts 535 through 554 plus Account 556 less Accounts 501 and 547
DEXN =	Depreciation and Amortization Expense associated with the plant investment in PPXN as recorded in FERC Accounts 403, 404, and, to the extent recovery is authorized by FERC, Account 406, as approved by Retail Regulators unless the jurisdiction for determining the depreciation rate is vested in the FERC under otherwise applicable law.
AGX924 =	Administrative and General (A&G) O&M Expense recorded in FERC Accounts 920 through 935 excluding FERC Account 924
GDX =	General Plant Depreciation Expense recorded in FERC Account 403
IAX =	Intangible Plant Amortization Expense recorded in FERC Account 404
OT =	Other Tax Expense recorded in FERC Account 408
924AG =	FERC Account 924 excluding Storm Accrual Expense
PPR =	Ratio of Production Plant to Total Plant excluding Intangible Plant
= PP / PXI	
PXI =	Electric Plant in Service defined as PXW3L above less Intangible Plant plus Waterford 3 Capital Lease as recorded in FERC Account 101.1, excluding ARO, if any

RSRA = Return on the Spindletop Regulatory Asset as billed by ETI to EGSL

LGCC = Little Gypsy Cancelled Costs (See Note 6)

(Note 6: Little Gypsy Cancelled Costs (LGCC) shall be the annual amount associated with the cancelled Little Gypsy Project as identified in docket Nos. ER12-1384, ER12-1385, ER12-1386, ER12-1387, ER12-1388 and ER12-1390).

ITC = Investment Tax Credit Amortization recorded in FERC Account 411

TX = Composite Corporate After Tax Income Tax Rate

= (1-T)

30.13 <u>Average Production Cost</u>

Each Company's share of System Average Variable and Fixed Production Cost shall be determined based on its respective Annual Energy Ratio (Energy Ratio) and Load Responsibility Ratio (Demand Ratio), respectively. The formula for determining each Company's share of System Average Production Cost is as follows:

APC = Average Production Cost

= AVPC + AFPC

where:

AVPC = Company's Allocation of the System's Variable Production Cost

= SVPC * ER

where:

SVPC = Sum of the Companies' Actual Variable Production Cost

ER = Each Company's Annual Energy (Net Area Requirements less Non-Requirements Sales for Resale defined as Total Disposition of Energy (FERC Form 1 Page 401a, Line 28) less Non-Requirements Sales for Resale (FERC Form 1 Page 401a, Line 24) less Net Transmission for Others (FERC Form 1 Page 401a, Line 18)) Divided by the Sum of all Companies Annual Energy (Energy Ratio)

AFPC = Company's Allocation of the System's Fixed Production Cost

= SFPC * DR

where:

SFPC = Sum of the Companies' Actual Fixed Production Cost

DR = The ratio for each Company of its 12 CP loads divided by the sum of all Companies' 12 CP loads as defined in Section 2.16(b)* (Demand Ratio)

* Note: Pursuant to *Louisiana Public Serv. Comm. V. Entergy Corp.*, 139 FERC ¶ 61,100 (2012), the refund effective date established pursuant to section 206(b) of the Federal Power Act is April 3, 2007; accordingly the DR variable shall utilize the 12 CP loads defined in Section 2.16(b) between April 3, 2007 and June 3, 2008 (the end of the fifteen month refund period), and prospectively from the date of the Commission order on May 7, 2012. For all other periods, the DR variable shall utilize the 12 CP loads defined in the Section 2.16(a).

30.14 Billing Procedure for Section 30.09(d)

The billing parameters will be in effect from June 1 to the succeeding December 31 based on the preceding year's results. Any amounts payable pursuant to Section 30.09(d) shall be paid on a monthly basis based on dividing the amount payable by seven. All amounts paid shall be recorded by each Company in FERC Account 555 – Purchased Power and all amounts received shall be recorded by each Company in FERC Account 447 – Sales for Resale. This billing procedure shall be effective June 1, 2007.

30.15 Allocation of Losses

The cost of losses shall be calculated for the System on a Monthly Basis and allocated to the Operating Companies on the basis of Monthly Energy Ratio as defined in Section 2.42 and in effect in the applicable period.

The cost of losses shall be equal to AMLC+MLCFS-MLSD,

where:

AMLC = Aggregated Marginal Losses Component of MISO Transactions: equal to MWh of each LMP-based transaction multiplied by the MLC associated with that LMP.

MLCFS = Aggregated Marginal Losses Component of Financial Schedules: equal to dollar amount identified by MISO and associated with loss charge or credit resulting from a Financial Schedule

MLSD = Aggregated Marginal Losses Surplus Distribution: equal to dollar amount identified by MISO and associated with allocation of the marginal loss surplus collected by MISO

30.16 Allocation of Ancillary Services Charges and Credits Related to Load Zones

The monthly sum of the Ancillary Services Charges and Credits related to Load Zones associated with an Operating Company shown on the MISO Settlement Statements shall be allocated to each Operating Company on the basis of each Operating Companies' Monthly Energy Ratio as defined in Section 2.42 applicable to that Month.

30.17 Allocation of Ancillary Services Charges and Credits Related to Generating Units

The monthly sum of the Ancillary Services Charges or Credits for each Generating Unit shown on the MISO Settlement Statements shall be allocated to each Operating Company based on the corresponding Monthly Unit Fuel Cost Allocation Factor defined in Section 2.32.

30.18 Allocation of Uplift Charges or Credits Related to Load Zones

The monthly sum of the Uplift Charges and Credits related to Load Zones associated with an Operating Company shown on the MISO Settlement Statements shall be allocated to each Operating Company on the basis of each Operating Companies' Monthly Energy Ratio as defined in Section 2.42 applicable to that Month.

30.19 Allocation of Uplift Charges or Credits Related to Generating Units

The monthly sum of the Uplift Charges and Credits related to Generating Units shown on the MISO Settlement Statements, as well as the monthly sum of the Hourly Excessive Energy Uplift Amounts calculated in accordance with Section 30.20 shall be allocated to each Operating Company based on the corresponding Monthly Unit Fuel Cost Allocation Factor defined in Section 2.32.

30.20 Determination of Hourly Excessive Energy Uplift Amount

In hours when real time imbalances from generators are compensated by MISO at less than the applicable Real Time LMP, the Hourly Excessive Energy Uplift Amount shall be the difference between the applicable Real Time LMP and the level of compensation provided by MISO.

30.21 Determination of Monthly Net Congestion Amount

The Total Monthly Net Congestion Amount shall be equal to ICC + ECC – NCR, where:

ICC = Implicit Congestion Charge: equal to (a) sum of energy-related charges net of credits in MISO Day Ahead and Real Time Markets during a month that are associated with the Operating Companies' Load Zones and Generating Units as well as bilateral purchases and sales scheduled in the Day Ahead and Real Time Markets; minus (b) cost of Joint Account Energy Purchases in the Day Ahead and Real Time Markets determined in accordance with Section 30.24 net of revenue from Joint Account Energy Sales in the Day Ahead and Real Time Markets determined in accordance with Section 30.25; minus (c) the cost of losses determined in accordance with Section 30.15; and minus (d) the excessive energy amount determined in accordance with Section 30.20. For the purposes of this Section 30.21, energy-related charges and credits include, but are not necessarily limited to the following: Day Ahead Asset Energy, Day Ahead Non-Asset Energy, Real Time Asset Energy, Real Time Non-Asset Energy, Non-Excessive Energy, and Excessive Energy.

ECC = Explicit Congestion Charge: equal to dollar amount identified by MISO and associated with congestion charge or credit resulting from a Financial Schedule.

NCR = Net Congestion Revenue: equal to the sum of MISO charges and credits related to Auction Revenue Rights and Financial Transmission Rights, including but not necessarily limited to the following: FTR Hourly Allocation, FTR Full Funding Guarantee, FTR Guarantee Uplift, FTR Monthly Allocation, ARR Transaction, FTR Annual Transaction, FTR Monthly Transaction, FTR Transaction, ARR Infeasible Uplift, ARR Stage 2 Distribution.

30.22 Allocation of Monthly Net Congestion Amount

The Monthly Net Congestion Amount determined in Section 30.21 shall be allocated to each Operating Company on the basis of each Operating Company's allocation of short-term purchases, after exchange accounting made during the month. For the purposes of this Section, short-term purchases shall include all purchases with a term less than one year.

30.23 Allocation of MISO FTR Yearly Allocation Amount

In a year when MISO issues an FTR Yearly Allocation Amount associated with the overfunding of FTRs on an annual basis, such yearly amount shall be divided by twelve to establish twelve monthly amounts. Each monthly amount shall be distributed on the same basis as the Monthly Net Congestion Amount Congestion Charge in accordance with Sections 30.22.

30.24 Determination of Cost of Joint Account Energy Purchases in MISO Day Ahead and Real Time Market

In each hour when the sum of the load of each Operating Company in the Day Ahead Market plus energy sales scheduled in the Day Ahead Market exceeds the sum of generation schedules in the Day Ahead Market plus energy purchases scheduled in the Day Ahead Market, the Operating Companies are determined to be "short" energy and shall make a Joint Account Energy Purchase in the Day Ahead Market in an amount equal to the difference. The price of this Joint Account Energy Purchase shall be based on a weighted average of the Day Ahead Load Zone LMP, less the MLC component of the LMP, of the individual Operating Companies that are short using the criteria described above. The weight applied to each short Operating Company's Load Zone LMP, less the MLC component of the LMP, shall be its short position divided by the sum of the short positions. All calculations in this Section 30.24 shall be made without adjustment for exchange sales and purchases.

In each hour when the sum of the load of each Operating Company in the Day Ahead and Real Time Markets plus energy sales scheduled in the Day Ahead and Real Time Markets exceeds the sum of generation schedules in the Day Ahead and Real Time Markets plus energy purchases scheduled in the Day Ahead and Real Time Markets, the Operating Companies are determined to be "short" energy and shall make a Joint Account Energy Purchase in the Real Time Market in an amount equal to the difference. The price of this Joint Account Energy Purchase shall be based on a weighted average of the Real Time Load Zone LMP, less the MLC component of the LMP, of the individual Operating Companies that are short using the criteria described above. The weight applied to each short Operating Company's Load Zone LMP, less the MLC component of the LMP, shall be its short position divided by the sum of the short positions. All calculations in this Section 30.24 shall be made without adjustment for exchange sales and purchases.

30.25 Determination of Cost of Joint Account Energy Sales in MISO Day Ahead and Real Time Market

In each hour when the sum of generation schedules in the Day Ahead Market plus energy purchases scheduled in the Day Ahead Market exceeds the sum of the load of each Operating Company in the Day Ahead Market plus energy sales scheduled in the Day Ahead Market, the Operating Companies are determined to have excess energy and shall make a Joint Account Energy Sale in the Day Ahead Market in an amount equal to the difference. The price of this Joint Account Energy Sale shall be based on the weighted average of the Day Ahead LMP, less the MLC component of the LMP, of the resource(s) determined to source the sale. All calculations in this Section 30.25 shall be made without adjustment for exchange sales and purchases.

In each hour when the sum of generation schedules in the Day Ahead and Real Time Markets plus energy purchases scheduled in the Day Ahead and Real Time Markets plus Joint Account Energy Purchases in the Day Ahead market exceeds the sum of the load of each Operating Company in the Day Ahead and Real Time Markets plus energy sales scheduled in the Day Ahead and Real Time Markets plus Joint Account Energy Sales in the Day Ahead market, the Operating Companies are determined to have excess energy and shall make a Joint Account Energy Sale in the Real Time Market in an amount equal to the difference. The price of this Joint Account Energy Sale shall be based on the weighted average of the Real Time LMP, less the MLC component of the LMP, of the resource(s) determined to source the sale. All calculations in this Section 30.25 shall be made without adjustment for exchange sales and purchases.

This Service Schedule MSS-3 shall be attached to and become a part of the Agreement dated the 23rd day of April, 1982 and shall be effective with said Agreement or at such later date as may be fixed by any requisite regulatory approval or acceptance for filing.

Attest	LOUISIANA POWER & LIGHT COMPANY
Original signed by	Original signed by
W. H. Talbot	J. M. Wyatt
Secretary	President
Attest	MISSISSIPPI POWER & LIGHT COMPANY
Original signed by	Original signed by
R. J. Estrads	D. C. Lutken
Assistant Secretary	President
Attest	NEW ORLEANS PUBLIC SERVICE INC.
Original signed by	Original signed by
William C. Nelson	James M. Cain
Secretary	President

SERVICE SCHEDULE MSS-4 UNIT POWER PURCHASE

40.01 Purpose

The purpose of this Service Schedule is to provide the basis for making a unit power purchase between Companies and/or the sale of power purchased by another Company, unless an alternative basis is agreed to by the parties subject to the approval of the Commission and the regulatory agencies of the purchasing and selling Companies under otherwise applicable law and which provides a lower monthly capacity charge than the charge determined pursuant to Section 40.06 or Section 40.09 of this Service Schedule MSS-4.

40.02 Designated Generating Unit

(a) A Designated Generating Unit shall be any generating unit from which the unit power purchase is made under Section 40.01 that is mutually agreed upon by the purchaser and the seller.

(b) Any Company that makes a Unit Power Purchase of a portion of capability shall be entitled to receive each hour, the same portion of the total energy generated by the Designated Generating Unit. Such energy shall be purchased at the cost of fuel consumed per kWh in accordance with Section 30.08(a), will be treated in the same manner as any other energy available to the purchasing Company, and shall include the Ancillary Services Charges and Credits provided by the DGU, in addition to any Uplift Charges and Credits that may be attributable to the DGU.

40.03 Capability Payment

For the capability purchased in accordance with Section 40.02, the Company making the sale shall receive, from the Company making the purchase, a monthly payment determined in accordance with the method described in Section 40.06 hereinafter.

The monthly capability payment to be received by a Company shall be determined by multiplying the kW of capability sold from its Designated Generating Unit by a charge per kW–month as defined below.

40.04 Investment in Designated Generating Unit (DGURB)

For the purpose of calculating the Monthly Charge under Section 40.06, the investment in the Designated Generating Unit (based on the Federal Energy Regulatory Commission's Uniform System of Accounts prescribed for the Public Utilities and Licensees) shall be:

DGURB =Designated Generating Unit Rate Base

DGURB =DGUPTPLT + DGUCME - DGUDR + DGUFINV - DGUADIT + [(GPLT – GDR + IPLT – IAA) * (DGUL / LXAG)] + [(MS + PP) * (DGUPLT / PLT)]

(a) The cost of the Designated Generating Unit included in FERC Plant Accounts 310 through 346; the cost of the Designated Generating Unit acquired recorded in FERC Account 114, to the extent recovery is authorized by FERC; the cost for step-up transformers, circuit breakers, switching equipment, etc. included in FERC Plant Account 353 which are required to connect the Designated Generating Unit to the transmission system (DGUPTPLT),

(b) Plus Coal Mining Equipment in FERC Plant Account 399 directly associated with the Designated Generating Unit (DGUCME),

(c) Less the Accumulated Provision for Depreciation (consistent with the accounting relating to Statement of Financial Accounting Standards (SFAS) 143 approved by the retail regulator having jurisdiction over the Designated Generating Unit, unless the FERC determines otherwise) associated with items (a) and (b) above, as recorded in FERC Account 108, excluding Nuclear

Decommissioning Trust Fund Balances, if applicable, and FERC Account 115 (DGUDR),

(d) Plus Fuel Inventory for the Designated Generating Unit, if applicable, in FERC Accounts 151 and 152 (DGUFINV),

(e) Less net Accumulated Deferred Income Taxes recorded in FERC Accounts 190, 281, 282 and 283 and Accumulated Deferred Investment Tax Credit – 3% portion only recorded in FERC Account 255 (DGUADIT) directly associated with the Designated Generating Unit if known; otherwise, an allocation of the plant-related balances in FERC Accounts 190, 281, 282 and 283, as reduced by amounts not generally and properly includable for FERC cost of service purposes, including, but not limited to, SFAS 109 ADIT amounts and ADIT amounts arising from retail ratemaking decisions, and Accumulated Deferred Investment Tax Credit – 3% portion only recorded in FERC Account 255 based on the proportion of gross Plant in Service for the Designated Generating Unit (DGUPLT), where DGUPLT is the sum of the investment pursuant to Section 40.04 (a) above plus the calculated General and Intangible plant pursuant to Sections 40.04 (f) and (h) below less Plant Adjustments (Note 1) pertaining to the Designated Generating Unit, to the Company's total gross Plant in Service (PLT), where PLT is the sum of Production, Transmission, Distribution, General and Intangible Plant in Service, plus the cost of plant acquired recorded in FERC Account 114 to the extent recovery is authorized by FERC and less Total Plant Adjustments (Note 1)

(Note 1: For the acquisition of Electric Plant in Service, the Plant Adjustment is equal to the original cost of electric plant acquired as recorded in FERC Account 101 plus the cost of plant acquired recorded in FERC Account 114, to the extent recovery is authorized by FERC, minus the purchase price of acquired electric plant less any amount for which recovery is not authorized by FERC.)

(f) Plus an allocation of General Plant recorded in FERC Plant Accounts 389 through 398 (GPLT) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding Administrative and General ("A&G") Labor (LXAG),

(g) Less an allocation of Accumulated Provision for Depreciation (consistent with the accounting relating to SFAS 143 approved by the retail regulator having jurisdiction over the Designated Generating Unit, unless the FERC determines otherwise) associated with item (f) above as recorded in FERC Account 108 (GDR) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding A&G Labor (LXAG),

(h) Plus an allocation of Miscellaneous Intangible Plant recorded in FERC Plant Account 303 (IPLT) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding A&G Labor (LXAG),

(i) Less an allocation of Accumulated Provision for Amortization associated with item (h) above recorded in FERC Account 111 (IAA) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding A&G Labor (LXAG),

(j) Plus an allocation of Materials & Supplies and Stores Expense Undistributed recorded in FERC Accounts 154 and 163, respectively, (MS) based on the proportion of Plant in Service for the Designated Generating Unit (DGUPLT) to the Company's total Plant in Service (PLT), and

(k) Plus an allocation of Prepayments recorded in FERC Account 165 (PP) based on the proportion of Plant in Service for the Designated

Generating Unit (DGUPLT) to the Company's total Plant in Service (PLT).

The Investment in the Designated Generating Unit (Designated Generating Unit Rate Base) shall be based on the actual balances on the seller's books as of the end of the month immediately preceding the service month.

If the Designated Generating Unit is one of a multi-unit station, its costs shall include an allocation of the amounts in the above plant accounts, which are allocable to all the generating units in the station, such allocation to be in the ratio of the capability of the Designated Generating Unit to the total capability of all generating units installed in the station for the service month.

40.05 <u>Expenses associated with Designated Generating Unit (OXP)</u>

For the purpose of calculating the Monthly Charge under Section 40.06, expenses associated with Designated Generating Unit shall be the following:

OXP =Operating Expense

OXP =DGUPOM + [SEOM * (DGUSEPLT / SEPLT)] + DGUDE + DGUI + DGUPT + DGUAG + [(GDX + OT + INDX) * (DGUL / LXAG)] + [FT * (DGUPLT / PLT)]

(a) The Designated Generating Unit Production Operation and Maintenance Expense ("O&M") Expense, included in FERC Accounts 500 through 554 excluding fuel in Accounts 501, 518 and 547 (DGUPOM),

(b) Plus an allocation of O&M associated with Designated Generating Unit step-up transformers and related transmission investment recorded in FERC Accounts 562 and 570 (SEOM) based on the proportion of the Designated Generating Unit Step-up Transformer Plant recorded in Plant Account 353 (DGUSEPLT) to the Company's total Transformer Station Equipment Plant recorded in Plant Account 353 (SEPLT),

(c) Plus any Depreciation Expense associated with the plant investment in Designated Generating Unit referred to in Section 40.04 items (a) and (b) (as recorded in FERC Accounts 403 and 406) and Decommissioning Expense, as approved by Retail Regulators, directly assigned to the Designated Generating Unit, if applicable (DGUDE) unless the jurisdiction for determining the depreciation and/or decommissioning rate is vested in the FERC under otherwise applicable law,

(d) Plus Property Insurance Expense recorded in FERC Account 924 directly assigned to the Designated Generating Unit (DGUI),

(e) Plus Ad Valorem Taxes recorded in FERC Account 408 directly assigned to the Designated Generating Unit (DGUPT),

(f) Plus A&G Expense (DGUAG) directly associated with a nuclear-fueled Designated Generating Unit recorded in FERC Accounts 920 through 935, excluding property insurance in Account 924; otherwise, an allocation of A&G Expense recorded in FERC Accounts 920 through 935 excluding property insurance in Account 924 based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total labor charged to O&M Expense excluding EOI and A&G labor,

(g) Plus an allocation of General Plant Depreciation Expense recorded in FERC Account 403 (GDX) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding A&G Labor (LXAG),

(h) Plus an allocation of Payroll Taxes recorded in FERC Account 408 (OT) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding A&G Labor (LXAG),

(i) Plus an allocation of Miscellaneous Intangible Plant Amortization Expense recorded in FERC Account 404 (INDX) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding A&G Labor (LXAG), and

(j) Plus an allocation of Corporate Franchise Taxes recorded in FERC Account 408 (FT) based on the proportion of Plant in Service for the Designated Generating Unit (DGUPLT) to the Company's total Plant in Service (PLT).

The expenses shall be based on transactions recorded on the seller's books for the service month.

If the Designated Generating Unit is one of a multi-unit station, expenses relating to the common plant shall be allocated to the Designated Generating Units in the station based on the ratio of the capability of the Designated Generating Unit to the total capability of all generating units installed in the station for the service month.

40.06 Determination of Monthly Capacity Charge

For the purpose of calculating the Monthly Capacity Charge (MC) per kW for billings under Capability Payment for each unit, the following formula shall be followed:

MONTHLY CAPACITY CHARGE

MC =Monthly Capacity Charge ($/kW-Month)

MC = [DGURB * ((CM + F)/12) + OXP - ITC/(1-T)] / CP

Where:

DGURB =Designated Generating Unit Rate Base per Section 40.04

CM =The weighted average cost of capital consistent with the procedures used by each Operating Company to calculate its AFUDC rate, determined as follows:

CM =(DR * i) + (PR * p) + (ER * c), where

DR =Ratio of Debt Capital and Preferred Stock with tax deductible dividends (QUIPS) at the last day of the month immediately preceding the current service month

PR =Ratio of Preferred Stock without tax deductible dividends at the last day of the month immediately preceding the current service month

ER =Ratio of Common Stock at the last day of the month immediately preceding the current service month

i =Average embedded cost of debt capital outstanding at the last day of the month immediately preceding the current service month

p =Average embedded cost of preferred stock outstanding at the last day of the month immediately preceding the current service month

c =Return on common equity at 11.0%

F =Federal and State Income Tax as determined from the following:

F =T /(1 - T)* (CM – DR * i)

Where:

T =f + s – fs when federal tax is not deductible in computing state tax, and

T =(f + s – 2fs) / (1-fs) when federal tax is deductible in computing state tax, and f = Federal Income Tax Rate

s =State Income Tax Rate

OXP =Operating Expense per Section 40.05

ITC =ITC Amortization recorded in FERC Account 411 directly associated with the Designated Generating Unit if known; otherwise, an allocation of ITC Amortization recorded in FERC Account 411 based on a gross plant-related balance ratio

CP =Capability for the Designated Generating Unit as defined in Section 2.14 of the Entergy System Agreement for the service month

General Notes:

(a) Labor ratios shall be determined based on the sum of the payroll expenses for the owner of the DGU, including those payroll expenses billed to it by EOI and ESI, for the service month.

(b) Plant ratios shall be determined based on plant in service balances as of the end of the month immediately preceding the service month.

40.07 <u>Adjustment for Tax Changes</u>

The Capability Payment as determined above shall be adjusted to reflect the imposition of any applicable new taxes not included in the above formula or for any increase or decrease in taxes included as of the date of this Agreement.

40.08 Billings Procedure

Bills for services rendered under Section 40.06 shall be issued within 45 days following the end of the service month and shall be payable within 10 days of receipt. Five days after such bill is due, interest shall accrue on any balance due at the rate as determined in Section 35.19a(2)iii of the FERC Regulations. The billing provisions under Section 4.14 of the Entergy System Agreement shall not apply to billings under Section 40.06 of this Service Schedule MSS-4.

40.09 Designated Power Purchase

(a) A Designated Power Purchase shall be any portion of a power purchase contract the sale and purchase of which is made pursuant to Section 40.01 hereof, which is mutually agreed upon by the purchaser and the seller. Any resale of a power purchase from the Grand Gulf nuclear unit pursuant to Section 40.09 shall be subject to the approval of the Commission and the regulatory agency of the purchasing company.

(b) Any Company that makes a Designated Power Purchase of a portion of the capability of the power purchase contract from which the sale and purchase is made shall be entitled to receive each hour, the same portion of the total energy purchased pursuant to the Designated Power Purchase subject to review by the FERC.

(c) Sales to one Company of power purchased by another Company shall be priced at the delivered cost of said purchase incurred by the selling Company as recorded in FERC Accounts 555 and 565, excluding all timing effects on such costs due to retail ratemaking decisions on a monthly basis, and shall be billed pursuant to

Section 4.14 of the Entergy System Agreement subject to review by the FERC.

This Service Schedule MSS-4 shall be attached to and become a part of the Agreement dated the _23rd_ day of _April_, _1982_ and shall be effective with said Agreement or at such later date as may be fixed by any requisite regulatory approval or acceptance for filing.

Attest	LOUISIANA POWER & LIGHT COMPANY
Original signed by	Original signed by
W. H. Talbot	J. M. Wyatt
Secretary	President
Attest	MISSISSIPPI POWER & LIGHT COMPANY
Original signed by	Original signed by
R. J. Estrada	D. C. Lutken
Assistant Secretary	President
Attest	NEW ORLEANS PUBLIC SERVICE INC.
Original signed by	Original signed by
William C. Nelson	James M. Cain
Secretary	President

SERVICE SCHEDULE MSS-5 DISTRIBUTION OF REVENUE FROM SALES MADE FOR THE JOINT ACCOUNT

50.01 Purpose

The purpose of this Schedule is to provide a basis for the distribution among the Companies of the net balance received from sales to others for the joint account of all the Companies, including Joint Account Energy Sales in the MISO Day Ahead and Real Time markets and Joint Account Capacity Sales in the MISO Resource Adequacy Market.

50.02 Revenue Deductions

From the gross revenue received for such sales there shall be deducted the cost of the sales determined by taking the sum of:

(a) Any direct tax imposed on the sale of capacity or energy or revenue derived there from.

(b) Any appropriate adjustment for losses in the system of the Company providing the connection.

(c) The cost of energy determined under the provisions of Section 30.04 of Service Schedule MSS-3.

(d) The Ownership Costs for the specific connecting facilities not equalized elsewhere. For this purpose, Ownership Costs shall be computed at the rate developed for the connecting Company's Annual Ownership Cost under Service Schedule MSS-2 on the facilities provided by the Company and approved by the Operating Committee.

50.03 Distribution of Net Balance

The net balance remaining after the deductions provided for in 50.02 shall be distributed among the Companies in proportion to the Responsibility Ratio of each based on Sections 2.16(b) and 2.17(b). Provided, however, that EGSL and ETI shall not share in the distribution of the net revenue balance from sales to others for the joint account of all the Companies received from contracts entered by ELL, EMI, ENOI or Services prior to the merger. The net balance remaining after the deductions provided for in 50.02 for pre-merger sales shall be distributed among ELL, EMI and ENOI in proportion to the Company Load Responsibility of each divided by the sum of their Company Load Responsibilities based on Section 2.18(b). EGSL and ETI shall participate pursuant to MSS-5 in any future sales, but shall only participate in the incremental portion of any extensions or expansions of existing contracts.

This Service Schedule MSS-5 shall be attached to and become a part of the Agreement dated the 23rd day of April, 1982 and shall be effective with said Agreement or at such later date as may be fixed by any requisite regulatory approval or acceptance for filing.

Attest	LOUISIANA POWER & LIGHT COMPANY
Original signed by	Original signed by
W. H. Talbot	J. M. Wyatt
Secretary	President
Attest	MISSISSIPPI POWER & LIGHT COMPANY
Original signed by	Original signed by
R. J. Estrada	D. C. Lutken
Assistant Secretary	President
Attest	NEW ORLEANS PUBLIC SERVICE INC.
Original signed by	Original signed by
William C. Nelson	James M. Cain
Secretary	President

SERVICE SCHEDULE MSS-6: DISTRIBUTION OF OPERATING EXPENSES OF SYSTEM OPERATIONS CENTER

60.01 Purpose

The purpose of this Schedule is to provide a basis for the distribution among the Companies of the costs incurred by Services in providing and operating the System Operations Center.

60.02 Costs

Costs for the purpose of this Schedule shall include such items as salaries, wages, rentals, the cost of materials and supplies, interest, taxes, depreciation, transportation, travel expenses, consulting and other professional services, and other costs incurred by Services in providing, maintaining, and operating the System Operations Center in accordance with budget approved by the Operating Committee.

60.03 Distribution of Costs

All costs of the Center shall be paid by Services. All normal costs shall be billed by Services to the Companies in proportion to the Responsibility Ratio of each. However, if the System Operations Center makes a study or performs a service in which all Companies are not proportionately interested, any resulting cost shall be distributed to the interested parties in accordance with the standard procedures of Services as outlined in their application declaration as filed with the Securities and Exchange Commission.

This Service Schedule MSS-6 shall be attached to and become a part of the Agreement dated the 23rd day of April, 1982 and shall be effective with said Agreement or at such later date as may be fixed by any requisite regulatory approval or acceptance for filing.

Attest	LOUISIANA POWER & LIGHT COMPANY
Original signed by	Original signed by
W. H. Talbot	J. M. Wyatt
Secretary	President
Attest	MISSISSIPPI POWER & LIGHT COMPANY
Original signed by	Original signed by
R. J. Estrada	D. C. Lutken
Assistant Secretary	President
Attest	NEW ORLEANS PUBLIC SERVICE INC.
Original signed by	Original signed by
William C. Nelson	James M. Cain
Secretary	President

SERVICE SCHEDULE MSS-7 MERGER FUEL PROTECTION PROCEDURE

70.01 Purpose

This Service Schedule provides a procedure for protecting the participating Companies from incurring higher fuel and purchased power costs as a result of the merger with Gulf States. For a Company which incurs an increase in its fuel costs as a result of the merger, the increase in cost will be transferred back to the companies obtaining fuel savings in proportion to those savings, in accordance with the following provisions.

70.02 Participating Companies

Companies covered by this Service Schedule shall include Gulf States and any other Company notifying the Operating Committee prior to the first calculation performed pursuant to 70.03 of its intent to participate and that its participation has the approval of the regulatory agency with jurisdiction over the Company's retail rates. Any Company directed to participate by its retail regulator shall do so.

70.03 Calculation Procedure of Fuel Cost Changes

Each year after the effective date of the Entergy-Gulf States Merger (Merger), merger-related fuel cost changes (MRFC) will be Calculated for each Company in accordance with 70.05. The MRFC will be used to calculate a Cumulative Fuel Change Balance (CFCB) for each Company, as follows:

Year ending CFCB = (Year beginning CFCB x (1 + i)) + MRFC)

where: i = the average yield on ten-year U.S. Treasury Notes for the year just ended.

At the end of each of the years prior to the final year, if the CFCB is negative for one or more Companies and positive for one or more Companies, then 50 percent of the Company's positive CFCB (i.e., higher fuel costs due to the merger) shall be transferred to the CFCB of the Company or Companies with a negative balance. At the end of the tenth year (or such shorter period of time as set forth in Section 70.04) of this procedure, the above procedure will apply except that the full amount (100%) of a positive CFCB will be transferred subject to the limitation that such transfer does not cause the CFCB to become positive for another Company. For the Companies receiving the transferred amount, the transfer shall be allocated in proportion to each Company's percentage of the total of the negative balances of the participating companies.

Any year after a positive amount is transferred from a Company's CFCB and that Company's CFCB subsequently becomes negative, then such previous transfers will be reversed to the extent the reversals do not cause the Company's CFCB to become positive.

70.04 Limitation of Term

This procedure shall apply for the shorter of: (1) the ten years following the effective date of the merger, or (2) the period between the effective date of the merger and the date of implementation of retail access in a jurisdiction in which one of the Companies operate.

70.05 Fuel Cost Change Measurement Procedure

Merger-related fuel cost changes (MRFC) for each Company are measured annually as the difference between estimated stand-alone fuel costs (SAFC) and estimated merger fuel costs (MFC), where:

SAFC = The estimated annual cost of fuel and purchased energy incurred to serve the Company's net area dispatch, as determined by a simulation of the dispatch of generating units and system operations under stand-alone (non-combined) operation of the Gulf States and Entergy System (excluding Gulf States) using Entergy's most current delivery of the PROMOD III production cost model and the input assumptions set forth in 70.06.

MFC = The estimated annual cost of fuel and purchased energy incurred to serve a Company's net area requirements as determined by a simulation of the dispatch of generating units and system operations under merged operation (combined) of the system using Entergy's most current delivery of the PROMOD III production cost model and the input assumptions set forth in 70.06.

70.06 Input Assumptions for Production Cost Simulations

Customer Loads

Actual hourly net area load, without off-system sales transactions, will be used as hourly load inputs.

Resources

The Gulf States and Entergy resources available to meet customer loads shall be those reflected in Entergy's most recent Business Plan applicable to that year.

Generating Unit Efficiency

The heat rate data shall be the then current data used in Entergy's Bulk Power Management system (BPMS).

Generating Unit Availability

Generating unit availability data (available MW's for each generating unit) shall be those reflected in the BPMS data for that time period.

System Operating Constraints

All generating unit constraints, fuel constraints, and transmission constraints as represented in Entergy's most current Business Plan applicable to that year will be reflected in the input assumptions. However, the transmission constraint known as Amite South shall be changed after the end of the fifth post merger year in the Entergy stand-alone analysis to that contained in the merger analysis for the remaining time period.

Fuel Costs

Nuclear -- Actual monthly fuel cost as used in the Intra-System Billing (ISB) program will be used as the nuclear fuel cost input.

Coal -- Actual monthly fuel cost as used in the ISB program will be used as the coal fuel cost input except that the stand-alone fuel cost for North Antelope coal shall be multiplied by the ratio of the stand-alone cost of North Antelope coal to the merger cost of North Antelope coal for each Entergy coal unit as reflected in 70.08.

Gas/Oil -- Fuel cost for each gas/oil unit will be based on actual weighted average fuel cost for each unit as calculated from fuel cost inputs to the ISB program.

Off System Economy Purchases

The simulations will reflect the off-system economy sources listed in 70.09. For the stand-alone simulations, these sources will be allocated to Gulf States and Entergy based on the most current year ending load responsibility ratios. The pricing of these transactions will be based on the actual monthly average on-peak and off-peak price of economy energy purchases, as determined by the ISB, plus a $2/MWH markup for each transaction for which Gulf States would require wheeling service from Entergy.

In addition, the Gulf States stand-alone simulation will also reflect a 300 MW off-peak source to be priced at the actual average monthly off-peak price of economy energy purchases as determined by the ISB. The available capacity for each Entergy stand-alone off-system economy source, as determined above, will be increased (to reflect economy energy not taken in the Gulf States stand-alone simulation) by the following method:

IMW = Monthly on-peak and off-peak increase for each Entergy stand-alone off-system economy source rounded at the nearest whole MW.

= AMW x (1-CF)

where:

AMW = The available capacity (MW) for the off-system economy source in the Gulf States stand-alone.

CF = Monthly on-peak or off-peak capacity factor at which energy is taken in the Gulf States stand-alone simulation for the off-system economy source.

Operating Reserves

An operating reserve level of 6 percent of annual peak will be reflected in the input assumptions.

70.07 PROMOD Benchmark

A benchmark of PROMOD based on the actual 1992 and 1997 operating data will be made to verify the reasonableness of the model.

70.08 North Antelope Coal Prices

The following ratios will be used to increase the actual North Antelope coal prices used in the stand-alone simulation case:

Year	Stand Alone ($/MMBtu)	Combined ($/MMBtu)	Ratio
1994	1.8261	1.7910	1.0196
1995	1.8997	1.8500	1.0269
1996	1.9423	1.9190	1.0122
1997	2.0918	2.0240	1.0335
1998	2.2096	2.1760	1.0155
1999	2.2556	2.2160	1.0179
2000	2.3466	2.2960	1.0221
2001	2.4274	2.3800	1.0199
2002	2.5114	2.4830	1.0114
2003	2.6041	2.5690	1.0137

70.09 Joint Dispatch Economy Purchase Capacities

The following off-system economy resources will be used in the PROMOD simulations, with the figures below being capacity in MW:

Company	Type of Purchase	Month	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
AECI	On Peak & Off Peak	Year Round	400	400	400	400	400	400	400	400	400	400
Cajun	On Peak & Off Peak	Jan.	200	200	200	200	200	200	200	200	200	200
Cajun	On Peak & Off Peak	Feb.	200	200	200	200	200	200	200	200	200	200

Cajun	**On Peak & Off Peak**	**Mar.**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**
Cajun	**On Peak & Off Peak**	**Apr.**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**
Cajun	**On Peak & Off Peak**	**May**	**110**	**95**	**80**	**120**	**100**	**160**	**160**	**160**	**160**	**160**
Cajun	**On Peak & Off Peak**	**Jun.**	**110**	**95**	**80**	**120**	**100**	**160**	**160**	**160**	**160**	**160**
Cajun	**On Peak & Off Peak**	**Jul.**	**110**	**95**	**80**	**120**	**100**	**160**	**160**	**160**	**160**	**160**
Cajun	**On Peak & Off Peak**	**Aug.**	**110**	**95**	**80**	**120**	**100**	**160**	**160**	**160**	**160**	**160**
Cajun	**On Peak & Off Peak**	**Sep.**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**
Cajun	**On Peak & Off Peak**	**Oct.**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**
Cajun	**On Peak & Off Peak**	**Nov.**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**
Cajun	**On Peak & Off Peak**	**Dec.**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**
Empire	**On Peak & Off Peak**	**Year Round**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**
Oklahoma	**On Peak Only**	**Year Round**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**
Oklahoma	**On Peak & Off Peak**	**Year Round**	**250**	**150**	**60**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Southern	**On Peak & Off Peak**	**Year Round**	**75**	**75**	**75**	**75**	**50**	**50**	**50**	**50**	**50**	**50**
SWEPCO	**On Peak & Off Peak**	**Year Round**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
SWEPCO	**On Peak Only**	**Year Round**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**
TVA	**On Peak & Off Peak**	**Year Round**	**1,000**	**1,000**	**1,000**	**750**	**500**	**500**	**500**	**500**	**500**	**500**
Union EL	**On Peak & Off Peak**	**Year Round**	**400**	**400**	**400**	**400**	**400**	**400**	**400**	**400**	**400**	**400**

SERVICE SCHEDULE MSS-8 DISTRIBUTION OF ADMINISTRATIVE CHARGES OF MISO

80.01 Purpose

The purpose of this Service Schedule is to provide the basis for allocating among the Operating Companies the administrative costs associated with membership in MISO (the "MISO Admin Charges").

80.02 Costs

Costs for the purpose of this Service Schedule shall be the net charges and credits associated with MISO's administration of the Regional Transmission Organization, which costs shall include but not be limited to, support, coordination and administration of Financial Transmission Rights ("FTRs"), market support, market settlements and billing, and market monitoring functions, and any other such costs incurred by MISO in accordance with the MISO tariffs on file and approved by FERC.

80.03 Distribution of Costs

All MISO Admin Charges shall be allocated to Companies pursuant to the Responsibility Ratio as defined in Section 2.18(a).

Agreement Among:

Entergy Gulf States Louisiana, L.L.C.

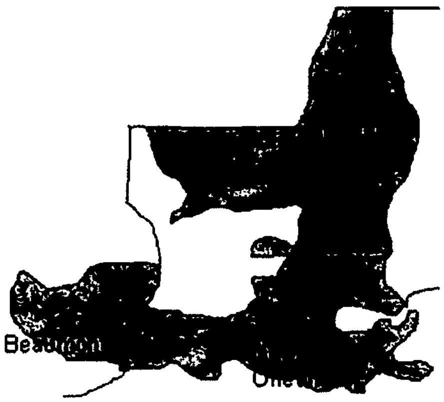
Entergy Louisiana, LLC

~~Entergy Mississippi, Inc.~~

Entergy New Orleans, Inc.

Entergy Texas, Inc.

Entergy Services, Inc.



AGREEMENT

Among

ENTERGY GULF STATES LOUISIANA, L.L.C.

ENTERGY LOUISIANA, LLC

~~ENTERGY MISSISSIPPI, INC.~~

ENTERGY NEW ORLEANS, INC.

ENTERGY TEXAS, INC.

ENTERGY SERVICES, INC.

INDEX

Exchange of Electric Energy Among the Companies

Service Schedule MSS-4

Unit Power Purchase

Service Schedule MSS-5

Distribution of Revenue from Sales Made for the Joint Account of All Companies

Service Schedule MSS-6

Distribution of Operating Expenses of System Operations Center

Service Schedule MSS-7

Merger Fuel Protection Procedure

Service Schedule MSS-8

Distribution of Administrative Charges of MISO

AGREEMENT

Among

ENTERGY GULF STATES LOUISIANA, L.L.C.

ENTERGY LOUISIANA, LLC

~~**ENTERGY MISSISSIPPI, INC.**~~

ENTERGY NEW ORLEANS, INC.

ENTERGY TEXAS, INC.

ENTERGY SERVICES, INC.

THIS AGREEMENT, first made and entered into on the 23rd day of April 1982, and subsequently amended, is by and among; Entergy Gulf States Louisiana, L.L.C., herein-after called EGSL or Gulf States Louisiana; Entergy Louisiana, LLC, hereinafter called ELL; ~~Entergy Mississippi Inc., hereinafter called EMI~~; Entergy New Orleans Inc., hereinafter called ENOI; Entergy Texas Inc., hereinafter called ETI, and Entergy Services, Inc., hereinafter called Services, all of whose common stock is wholly owned by Entergy Corporation, hereinafter called Parent Company.

WITNESSETH

0.01 WHEREAS, EGSL, ELL, EMI, ENOI, and ETI hereinafter called Companies, are the owners and operators of electric generation, transmission and distribution facilities with which they are engaged in the business of generating, transmitting and selling electric energy to the general public and to other electric distributing agencies; and

0.02 WHEREAS, Services is an associated Service Company acting as the Agent for the Companies under the terms of the Middle South Utilities System Agency Agreement and the Middle South Utilities System Agency Coordination Agreement dated the 11th day of December 1970; and

0.03 WHEREAS, the Companies have been achieving substantial benefits for their customers by operating within the framework of an interconnection agreement dated April 11, 1973; and

0.04 WHEREAS, the individual Companies are interconnected by transmission lines and operated as a coordinated system from a central dispatching center; and

0.05 WHEREAS, technological progress and changed economic conditions have necessitated the updating of the aforementioned interconnection agreement to continue to obtain the maximum benefits for them and their respective customers;

NOW THEREFORE, the Parties hereto mutually understand and agree as follows:

ARTICLE I TERM OF AGREEMENT

1.01 This agreement shall become effective on August 1, 1982, or such later date as may be fixed by any requisite regulatory approval or acceptance for filing and shall continue in full force and effect until terminated by mutual agreement of the Companies. Notwithstanding this, any Company may terminate its participation in this Agreement by sixty (60) months written notice to the other companies hereto; and effective upon and after the date of implementation of retail open access in Texas, ETI shall terminate its participation in this Agreement, except as to Service Schedule MSS-2 (Transmission Equalization), consistent with Section 2.02 below. This agreement shall terminate effective August 31, 2016 at 11:59:59 PM Central Daylight Time. ~~The foregoing sixty-month notice period shall apply to any written notice of termination received by the Operating Committee on or after October 12, 2013.~~

1.02 This Agreement shall supersede the agreement listed below: Agreement among Arkansas Power & Light Company, Arkansas-Missouri Power Company, Louisiana Power & Light Company, Mississippi Power & Light Company, New Orleans Public Service Inc. and Middle South Services, Inc. dated the 16th day of April 1973 in FPC Docket No. E-8130 as amended in FERC Docket No. ER79-277, FERC Docket No. ER80-366, and FERC Docket No. ER 81-405.

1.03 This Agreement will be reviewed periodically by the Operating Committee to determine whether revisions are necessary to meet changing conditions. In the event that revisions are made by the parties hereto, and after requisite approval or acceptance for filing by the appropriate regulatory authorities, the Operating Committee will thereafter, for the purpose of ready reference to a single document, prepare for distribution to the Companies an amended document reflecting all changes in and additions to this Agreement with notations thereon of the date amended.

ARTICLE II DEFINITIONS

For the purpose of this Agreement and of the Service schedules which are a part hereof, the following definitions shall apply:

2.01 Agreement shall be this Agreement together with all attachments and service schedules applying thereto and any amendments made hereafter.

2.02 Company shall be one of the Entergy System Operating Companies (ELL, EMI, ENOI, EGSL, ETI).

2.03 Parent Company shall be Entergy Corporation.

2.04 Agent shall be Entergy Services, Inc. which shall act as Agent for one or more of the Companies whenever appropriate.

2.05 System shall be the interconnected coordinated systems of the Companies.

2.06 Operating Committee shall be the administrative organization created under this Agreement to administer its provisions.

2.07 Generating Unit shall be an electric generator, together with its prime mover and all auxiliary and appurtenant devices and equipment designed to be operated as a unit for the production of electric power and energy or as otherwise determined by the Operating Committee.

2.08 Base Generating Units - shall be all generating units included in FERC accounts 310 through 316 and whose fuel supply is coal and all generating units included in FERC accounts 320 through 325 whose fuel supply is nuclear respectively, and such other generating units as may be designated from time to time by the Operating Committee.

2.09 Intermediate Generating Units - shall be all generating units included in FERC accounts 310 through 316 and whose fuel supply is gas or oil and such other generating units as may be designated from time to time by the Operating Committee.

2.10 Peaking Generating Units - shall be all generating units included in FERC accounts 340 through 346 and such other generating units as may be designated from time to time by the Operating Committee.

2.11 Hydraulic Production Units - shall be all generating units included in FERC accounts 330 through 336.

2.12 Qualified Cogeneration Capacity shall be any capacity available from a cogeneration facility that qualifies under Subpart B of Part 292 of the Regulations of the FERC, 18 C.F.R. § 292.201, et seq., as amended, or any successor provisions issued pursuant to Section 3(18)(B)of the Federal Power Act, and which, in accordance with Section 4.08 of this Agreement is under the control of the System Operator, to the extent practicable, and where the State or local regulatory body having jurisdiction over any Company which establishes the rate for a particular purchase also determines that the purchase will permit non-qualifying facility capacity costs to be avoided or, in the absence of such determination, to the extent that the Operating Committee determines that, in accordance with Section 4.01 of this Agreement and pursuant to Section 292.304 of the FERC Regulations or any successor provision, the capacity will be employed to postpone generation that would otherwise be installed and thereby benefit the customers of all Companies. Individual Qualified Cogeneration Capacity below 10 mW will not be considered as a power or energy source to any party to the System Agreement but will be considered as a negative load.

2.13 Qualified Small Power Production Capacity shall be any capacity available from a small power production facility that qualifies under Subpart B of Part 292 of the FERC Regulations, 18 C.F.R. § 292.201, et seq., as amended, or any successor provisions issued pursuant to Section 3(17)(C) of the Federal Power Act, and which, in accordance with Section 4.08 of this Agreement, is under the control of the System Operator, to the extent practicable, and where the State or local regulatory body having jurisdiction over any Company which establishes the rate for a particular purchase also determines that the purchase will permit non-qualifying facility capacity costs to be avoided or, in the absence of such determination, to the extent that the Operating Committee determines that, in accordance with Section 4.01 of this Agreement and pursuant to Section 292.304

of the FERC Regulations or any successor provision, the capacity will be employed to postpone generation that would otherwise be installed and thereby benefit the customers of all Companies. Individual Qualified Small Power Production Capacity below 10 mW will not be considered as a power or energy source to any party to the System Agreement but will be considered as a negative load.

2.14 Capability shall be the net output in megawatts that can be produced by a generating unit under conditions specified by the Operating Committee, that is devoted to serving System load but excluding that portion of any unit the output of which has been sold to another Company (other than through MSS-3), or the input in megawatts available under contract from a supplying source, excluding the portion of such supply that has been sold to another Company (other than through MSS-3), including any capacity determined in Sections 2.12 or 2.13 above, plus the allocated portion of Joint Account Capacity Purchases in the MISO Resource Adequacy Capacity Market, plus the contractual amount of firm purchases with reserves available during the month from other systems adjusted upward by the ratio of Seller's Capability and Seller's Load Responsibility as determined in Section 10.02C.

2.15 System Capability shall be the arithmetical sum in megawatts of the individual Company Capabilities.

2.16 Company Load Responsibility shall be determined as follows:

(a) To be used in conjunction with Service Schedules MSS-2 and MSS-6:

(i) The average of the sum of the Company's twelve monthly hourly loads coincident with the System's monthly peak hour load for the period ended with the current month measured in megawatts. Hourly load shall be defined as the sum of the hourly MW values for each of the Load Zones associated with an Operating Company plus net Behind the Meter Generation injections from within the load zone for each Operating Company and necessary adjustments due to Financial Schedules. To the extent that an Operating Company has engaged in a partial or full requirements sale to a third party, the load associated with that sale will be included in that Operating Company's hourly load if it is not included in the Load Zone associated with that Operating Company.

(b) As of April 1, 2004,* to be used in conjunction with Service Schedules MSS-1 and MSS-5 and in conjunction with the allocation of a purchase of capacity and energy for the joint account of all Companies under Section 4.02:

The average of the sum of the Company's twelve monthly hourly loads coincident with the System's monthly peak hour load for the period ended with the current month measured in megawatts. Hourly load shall be defined as the sum of the hourly MW values for each of the Load Zones associated with an Operating Company plus net Behind the Meter Generation injections from within the load zone for each Operating Company and necessary adjustments due to Financial Schedules less loads served under interruptible tariffs or contracts, where the interruptible load excluded at the time of the system's monthly peak hour load (which does not include the excludable interruptible load determined herein) is to be that load that, pursuant to said retail tariff or contract, is subject to interruption. To the extent practical the determination of what loads are interruptible shall be based on actual data and if it is not practical, shall be based on reasonable estimates. To the extent that an Operating Company has engaged in a partial or full requirements sale to a third party, the load associated with that sale will be included in that Operating Company's hourly load if it is not included in the Load Zone associated with that Operating Company.

* In the calculation pursuant to Section 2.16(b), the full amount of the interruptible load has been removed as of April 1, 2004 (as opposed to phased-in over a twelve month period).

(c) The most current information, updated for new or revised MISO peak data volumes, shall be used in this calculation and to true-up previous settlement data allocation.

2.17 <u>System Load Responsibility:</u>

(a) To be used in conjunction with Service Schedules MSS-2 and MSS-6 shall be the arithmetical sum in megawatts of the individual Company Load Responsibilities derived pursuant to Section 2.16(a).

(b) As of April 1, 2004, to be used in conjunction with Service Schedules MSS-1 and MSS-5 and in conjunction with the allocation of a purchase of capacity and energy for the joint account of all Companies under Section 4.02 shall be the arithmetical sum in megawatts of the individual Company Load Responsibilities derived pursuant to Section 2.16(b).

2.18 Responsibility Ratio of a Company shall be the ratio obtained by dividing the load responsibility of that company by the System Load Responsibility as follows:

(a) To be used in conjunction with Service Schedules MSS-2 and MSS-6 the Responsibility Ratio shall be equal to the amount determined in Section 2.16(a) divided by the amount determined in Section 2.17(a).

(b) To be used in conjunction with Service Schedules MSS-1 and MSS-5 and in conjunction with the allocation of a purchase of capacity and/or energy for the joint account of all Companies under Section 4.02 shall be equal to the amount determined in Section 2.16(b) divided by the amount determined in Section 2.17(b).

(c) The most current information, updated for new or revised MISO peak data volumes, shall be used in this calculation and to true-up previous settlement data allocation.

2.19 Capability Responsibility of a Company shall be the System Capability multiplied by the Responsibility Ratio as specified in Section 2.18(a) for that Company.

2.20 Pool Energy shall be the energy generated by a Company in excess of its own requirements, or acquired by any Company under economic dispatch or as directed by the System Operator, that goes to supply requirements of other Companies. Such energy shall in all cases be nonfirm, that is, it has no guaranteed or assured availability.

2.21 Cogeneration or Small Power Production Energy shall be the energy acquired by any Company from qualified facilities whether or not acquired under economic dispatch.

2.22 Transmission Responsibility of a Company shall be the System Net Inter-Transmission Investment multiplied by the Responsibility Ratio as specified in Section 2.18(b) for that Company.

2.23 System Net Inter-Transmission Investment shall be the arithmetical sum of the individual Company Net Inter-Transmission Investments.

2.24 Day shall be a continuous 24-hour period beginning at midnight LST, or such other time as may be agreed upon by the Operating Committee.

2.25 Month shall be a calendar month using Eastern Standard Time. In the case of MISO Settlement Statements, the initial month shall be that period from the date the Operating Companies join MISO to the end of the calendar month.

2.26 Year shall be calendar year.

2.27 Power shall be the rate of doing work and shall be expressed in kilowatts (kW), megawatts (mW), or gigawatts (gW).

2.28 Energy shall be work and shall be expressed in kilowatt hours (kWh), megawatt-hours (mWh), or gigawatt-hours (gWh).

2.29 Load Zone shall be as defined in Section 1.363 of the MISO Tariff.

2.30 Operating Day shall be as defined in the MISO Tariff.

2.31 Ancillary Services Charges and Credits are those charges and credits that appear on the MISO Settlement Statements that relate to the provision of Ancillary Services. Such costs shall include, but shall not be limited to, Day Ahead Regulation, Day Ahead Spinning Reserve, Day Ahead Supplemental Reserve, Real Time Regulation, Real Time Spinning Reserve, Real Time Supplemental Reserve, Regulation Cost Distribution, Spinning Reserve Cost Distribution, Supplemental Reserve Cost Distribution, Excessive/Deficient Energy Deployment Cost.

2.32 Monthly Unit Fuel Cost Allocation Factor shall be calculated for each generating unit of an Operating Company that corresponds to Ancillary or Uplift Charges or Credits in a month. The Monthly Unit Fuel Cost Allocation Factor shall represent the percentage of the total monthly fuel cost for such a generating unit that is ultimately borne by an Operating Company. The Monthly Unit Fuel Cost Allocation Factor shall be defined on a unit-by-unit basis as:

(OS-PES+PEP-JAE)/UFC, where:

OS= an Operating Company's ownership share of a generating unit's monthly cost of fuel consumed

PES= the monthly cost of fuel used to supply Pool Energy from the Operating Company's ownership share of the generating unit

PEP= the monthly cost of fuel for energy taken from the Pool by the Operating Company for the generating unit. For the purpose of this calculation, each Operating Company that receives Pool Energy in any hour is deemed to have taken a pro rata share of the energy and associated costs for each generating unit that was supplying Pool Energy in that hour

JAE= the monthly cost of fuel used to supply joint account sales from the Operating Company's ownership share of the generating unit

UFC= the generating unit's total monthly cost of fuel consumed

2.33 MISO shall mean the Midcontinent Independent System Operator, Inc.

2.34 MISO Settlement Statements shall be the statements sent by MISO for Market Settlements.

2.35 Uplift Charges and Credits are those charges and credits that appear on the MISO Settlement Statements that relate to revenue sufficiency, make-whole payments, uplift, or miscellaneous MISO charges not included elsewhere in this Agreement. Such costs shall include, but shall not be limited to, Day Ahead RSG Make Whole Payments, Real Time RSG Make Whole Payments, Real Time Price Volatility Make Whole

Payments, Net Regulation Adjustment, Day Ahead RSG Distribution, Real Time RSG First Pass Distribution, Day Ahead RSG Voltage and Reliability Charge, Real Time RSG Voltage and Reliability Charge, Real Time Revenue Neutrality Uplift, Real Time Net Inadvertent Distribution, and Real Time Miscellaneous.

2.36 Marginal Losses Component (MLC) shall have the meaning ascribed to that term in the MISO tariff.

2.37 Financial Schedule shall have the meaning ascribed to that term in the MISO tariff.

2.38 Marginal Losses Surplus Distribution shall have the meaning ascribed to that term in the MISO tariff.

2.39 Monthly Basis shall mean that for all charges received from MISO that are to be allocated on a monthly basis, monthly means accumulated in the calendar month received and aggregated and allocated by calendar month to which the charges relate.

2.40 MISO Resource Adequacy Market shall mean a voluntary, short-term (annual) capacity market that provides load serving entities in MISO with the opportunity, but not the obligation, to meet their resource adequacy requirements through the purchase of qualified capacity credits from this market.

2.41 Behind the Meter Generation shall have the meaning ascribed to that term in the MISO tariff.

2.42 Monthly Energy Ratio shall be defined as the monthly ratio of each Operating Company's MWh load to the total System monthly load in MWh for the System Agreement Companies for the month.

ARTICLE III OBJECTIVES

3.01 The purpose of this Agreement is to provide the contractual basis for the continued planning, construction, and operation of the electric generation, transmission and other facilities of the Companies in such a manner as to achieve economies consistent with the highest practicable reliability of service, subject to financial considerations, reasonable utilization of natural resources and minimization of the effect on the environment. This Agreement also provides a basis for equalizing among the Companies any imbalance of costs associated with the construction, ownership and operation of such facilities as are used for the mutual benefit of all the Companies.

3.02 It is recognized by the Companies that economies of scale and integrated operations require that the planning, construction and operation of the bulk power supply and related facilities of the Companies be on a coordinated basis.

3.03 It is recognized that the Companies have traditionally used natural gas as their primary boiler fuel and that curtailments by suppliers have necessitated a conversion to oil as boiler fuel. Minimizing current and future costs of electricity and reducing energy dependence on oil and gas require the Companies to move toward a new fuel base of coal and nuclear.

3.04 It is recognized that these new coal and nuclear units will be Base Generating Units as defined in 2.08 and will be units of the larger ratings in generating stations of large size, strategically located with regard to fuel, water supply and electric load.

3.05 It is the long term goal of the Companies that each Company have its proportionate share of Base Generating Units available to serve its customers either by ownership or purchase.

Any Company which has generating capacity above its requirements, which desires to sell all or any portion of such excess generating capacity and associated energy, shall