(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 <u>Employment of Consultants</u>

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

5.08 <u>Expenses of Committee</u>

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

(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 <u>Reserve Equalization Payment</u>

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 <u>Investment in Intermediate Reserve Generating Units</u>

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 x i) + (PR x p) + (ER x 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	ARKANSAS POWER & LIGHT COMPANY
Original signed by R.J. Estrada Assistant Secretary	Original signed by Jerry Maulden President
Attest	LOUISIANA POWER & LIGHT COMPANY
Original signed by W. H. Talbot Secretary	Original signed by J. M. Wyatt President
Attest	MISSISSIPPI POWER & LIGHT COMPANY
Original signed by R. J. Estrada Assistant Secretary	Original signed by D. C. Lutken President
Attest	NEW ORLEANS PUBLIC SERVICE INC.
Original signed by William C. Nelson Secretary	Original signed by James M. Cain 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.

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:

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

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:

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

where:

AOC = System Average Annual Ownership Cost

A = EAI Net Inter-Transmission Investment

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_A = EAI - Annual Ownership Cost

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

$$A = .5563 \quad \frac{\text{O\&M (current)} \div \text{NSGC}}{\text{O\&M (base)} \div \text{NSGB}}$$ 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

$\therefore$ 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 within a test block approximately equal to the amount of emission allowances needed to support wholesale transactions under this System Agreement and power sales arrangements between the Companies and others.
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 within a test block approximately equal to the amount of emission allowances needed to support wholesale transactions under this System Agreement and power sales arrangements between the Companies and others.

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.

Issued by: Kimberly Despeaux, Associate General Counsel
Effective: November 22, 2008

Issued on: November 21, 2008

Filed to comply with unpublished letter order of the Federal Energy Regulatory Commission, Docket No. ER08-460, issued April 22, 2008.

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.[1] The formula for developing the actual production cost is as follows:

PC = VPC + FPC

where:

VPC = Variable Production Cost
= VPRB * (CM + F) + VPX

where:

VPRB = Variable Production Rate Base [2]
= 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

[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 EAI and EMI retail approved Grand Gulf Accelerated Recovery Tariff effects on purchased power on EAI's and EMI's production cost and (5) exclusion of any increased costs resulting from the amended Toledo Bend Power Sales Agreement accepted for filing in Docket No. ER07-984.

[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.

NAD = Nuclear Accumulated Provision for Depreciation and Amortization excluding ARO associated with NPP above, as recorded in FERC Accounts 108 and 111 (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 excluding Waterford 3 Capital Lease to Total Plant excluding Intangible Plant and Waterford 3 Capital Lease [3]

= NPPXW3L / PXIW3L

where:

NPPXW3L = Nuclear Production Plant in Service excluding Waterford 3 Capital Lease as recorded in FERC Account 101.1

PXIW3L = Electric Plant in Service which includes the sum of the Company's Production, Transmission, Distribution and General Plant in Service recorded in FERC Plant Accounts 310 through 399, 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

[3] Plant ratios shall be determined based on plant in service balances exclusive of associated ARO as of December 31 of the previous year.

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 and 404 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

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 and 111, 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 to Total Plant excluding Intangible Plant and Waterford 3 Capital Lease
=	PPXN / PXIW3L
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[4]

= 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 to Electric and Gas Plant in Service excluding Intangible Plant

= PP / EGPXI

where:

PP = Production Plant in Service as recorded in FERC Plant Accounts 310 through 346 and FERC Account 101.1 excluding ARO recorded in FERC Plant Accounts 317, 326 and 337, if any

EGPXI = Electric and Gas Plant in Service defined as PXIW3L above 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

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[4] 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.

FPX = Fixed Production Expense

= NFPOMXN + DEXN + [(AG + GDX + IAX) * PLR] + OT * PPR

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 and 404, as approved by Retail Regulators unless the jurisdiction for determining the depreciation rate is vested in the FERC under otherwise applicable law.

AG = Administrative and General (A&G) O&M Expense recorded in FERC Accounts 920 through 935 excluding Storm Accrual Expense recorded in 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

PPR = Ratio of Production Plant to Total Plant excluding Intangible Plant

= PP / PXI

PXI = Electric Plant in Service defined as PXIW3L above plus Waterford 3 Capital Lease as recorded in FERC Account 101.1, excluding ARO, if any

ITC = Investment Tax Credit Amortization recorded in FERC Account 411

TX = Composite Corporate After Tax Income Tax Rate

= (1-T)

30.13 Average Production Cost

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(a) (Demand Ratio)

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.

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

ARKANSAS POWER & LIGHT COMPANY

Original signed by
R. J. Estrada
Assistant Secretary

Original signed by
Jerry Maulden
President

Attest

LOUISIANA POWER & LIGHT COMPANY

Original signed by
W. H. Talbot
Secretary

Original signed by
J. M. Wyatt
President

Attest

MISSISSIPPI POWER & LIGHT COMPANY

Original signed by
R. J. Estrads
Assistant Secretary

Original signed by
D. C. Lutken
President

Attest

NEW ORLEANS PUBLIC SERVICE INC.

Original signed by
William C. Nelson
Secretary

Original signed by
James M. Cain
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) and will be treated in the same manner as any other energy available to the purchasing Company.

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 <u>Investment in Designated Generating Unit (DGURB)</u>

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 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 (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, 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,

(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 Expenses associated with Designated Generating Unit (OXP)

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 Account 403) 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 Adjustment for Tax Changes

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

SERVICE SCHEDULE MSS-5

DISTRIBUTION OF REVENUE FROM SALES MADE FOR THE JOINT ACCOUNT OF ALL THE COMPANIES

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.

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 EAI, 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 EAI, ELL, EMI and ENOI in proportion to the Company Load Responsibility of each divided by the sum of their Company Load Responsibilities based on Sections 2.16(b) and 2.17(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	ARKANSAS POWER & LIGHT COMPANY
Original signed by R. J. Estrada Assistant Secretary	Original signed by Jerry Maulden President
Attest	LOUISIANA POWER & LIGHT COMPANY
Original signed by W. H. Talbot Secretary	Original signed by J. M. Wyatt President
Attest	MISSISSIPPI POWER & LIGHT COMPANY
Original signed by R. J. Estrada Assistant Secretary	Original signed by D. C. Lutken President
Attest	NEW ORLEANS PUBLIC SERVICE INC.
Original signed by William C. Nelson Secretary	Original signed by James M. Cain 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.