DUPLICATE ORIGINAL

This Copy to be returned for
files of S. C. Electric & Gas Company.

AMENDMENT TO INTERCHANGE AGREEMENT

THIS AMENDMENT TO THE INTERCHANGE AGREEMENT, made and entered into as of this 13th day of December, 1988, by and between SOUTH CAROLINA ELECTRIC & GAS COMPANY, a South Carolina corporation, and CAROLINA POWER & LIGHT COMPANY, a North Carolina corporation.

W I T N E S S E T H

WHEREAS, SOUTH CAROLINA ELECTRIC & GAS COMPANY and CAROLINA POWER & LIGHT COMPANY entered into an Interchange Agreement ("Agreement") dated July 9, 1970, which was subsequently amended in writing on January 1, 1974; April 1, 1979, and August 10, 1980; and

WHEREAS, the need for changes in the rate structures has necessitated the further revision of the Agreement, and the parties desire to further modify the Agreement as hereafter set forth.

NOW, THEREFORE, in consideration of the premises and the mutual covenants herein set forth, the parties agree as follows:

1. Article 5 of the Agreement is hereby deleted in its entirety and the following substituted in its place:

ARTICLE 5
SERVICES TO BE RENDERED

5.01 The power to be supplied by each party to the other hereunder, the terms and conditions of such supply, and the settlement therefore shall be in accordance with arrangements agreed to from time to time between the parties. Such arrangements shall be set up in the form of Service Schedules, each of which when signed by authorized officials of the parties hereto, shall become a part of this Agreement for the term hereof or for such shorter term as may be provided in the Service Schedule. The following Service Schedules and Appendices are hereby agreed to and attached as parts hereof:

Service Schedule A - 1979 Spinning Reserve

Service Schedule B - 1979 Economy Interchange

Service Schedule C - 1979 Limited Term Power

Service Schedule D - 1979 Short Term Power

Service Schedule E - Coordination of Scheduled Maintenance of Generating Facilities (Agreement dated July 9, 1970)

Service Schedule F - Fuel Conservation Energy (Effective January 1, 1974)

Service Schedule G - 1979 Other Energy

Appendix A - Determination of Interchange Demand Rates - SOUTH CAROLINA ELECTRIC & GAS COMPANY

Appendix B - Determination of Interchange Demand Rates - CAROLINA POWER & LIGHT COMPANY

2. A new Section 5.02 is hereby added to the Interchange Agreement to read as follows:

5.02 The demand rates for Limited Term, Short Term, Spinning Reserve, and Other Energy Service Schedules will be calculated by both parties under Appendix A or Appendix B as applicable. If South Carolina Electric & Gas Company is the delivering party, the Demand Rate shall not exceed the rate calculated under Appendix A. If Carolina Power & Light Company is the delivering party, the Demand Rate shall not exceed the rate calculated under Appendix B.

In third-party transactions or transactions where there is no Demand Rate for Limited Term, Short Term, Spinning Reserve, or Other Energy, the Transmission Use Rate charged by the delivering party under the applicable Service Schedules shall not exceed that which is calculated as described in Appendix A when South Carolina Electric & Gas Company is the delivering party, or Appendix B when Carolina Power & Light Company is the delivering party.

3. Article 11 of the Interchange Agreement is hereby deleted and the following is inserted in lieu thereof:

ARTICLE 11
BILLINGS AND PAYMENTS

All bills for amounts owed by one party to the other shall be due and payable fifteen (15) days following the calendar month or period service was rendered, or on the tenth day following receipt of bill, whichever date is later. Interest on unpaid amounts, both principal and interest, shall accrue daily at the then current prime interest rate per annum of CitiBank, plus two percent (2%)

per annum, from the date due until the date upon which payment is made. Unless otherwise agreed upon, a calendar month shall be the standard monthly period for the purpose of settlements under this Agreement.

4. Service Schedule A - 1979, Spinning Reserve

Schedule A, as amended by agreement dated August 10, 1980, is further amended by deleting the last sentence of paragraph 4.11; and all of paragraph 4.12 and paragraph 4.13; and inserting the following in place thereof:

4.11 When such capacity is from the system of the delivering party, the receiving party will pay a reserve Demand Rate per kW per day not to exceed the rate calculated in accordance with Appendix A or B, whichever is applicable.

4.12 When the capacity made available under Section 3.3 is from the system of the delivering party, the receiving party will pay a reserve Demand Rate per kW per day not to exceed the rate calculated in accordance with Appendix A or B, whichever is applicable.

4.13 In the event the delivering party provides capacity to the receiving party from a third-party system, the receiving party will pay the delivering party a Demand Rate equal to (1) the Demand Rate charged by the third party, plus (2) a Transmission Use Rate per kW per day not to exceed the rate calculated in accordance with Appendix A or B, whichever is applicable. In transactions where no demand charge is made by the third party, the receiving party will pay the delivering party a Transmission Use Rate per kW per day or per kWh, whichever is less, not to exceed the rate calculated in accordance with Appendix A or B, whichever is applicable.

5. Service Schedule C - 1979, Limited Term Power

Schedule C, as amended by agreement dated August 10, 1980, is further amended by deleting paragraphs 4.11 and 4.12 and inserting the following in place thereof:

4.11 For Limited Term capacity produced by the delivering party, the receiving party will pay the delivering party a rate per kW per month not to exceed the rate calculated in accordance with Appendix A or B, whichever is applicable.

4.12 For Limited Term capacity purchased from a third-party system, the receiving party will pay the delivering party a Demand Rate equal to (1) the Demand Rate per kW per month charged by the third party, plus (2) a Transmission Use Rate per kW per month not to exceed the rate calculated in accordance with Appendix A or B, whichever is applicable.

6. Service Schedule D - 1979, Short Term Power

Schedule D, as amended by agreement dated August 10, 1980, is further amended by deleting paragraph 3.11 in its entirety and inserting the following in place thereof:

3.11 <u>Demand Charge</u>

(a) When the capacity sold under this contract is from the system of the delivering party, the receiving party will pay a Short Term Demand Rate per kW per week not to exceed the rate calculated in accordance with Appendix A or B, whichever is applicable. For periods of less than one week, the receiving party will pay a Demand Rate per kW per day not to exceed the rate calculated by dividing the weekly Short Term Demand Rate by six. If the delivering party reduces the number of kilowatts of capacity reserved in accordance with Section 2.11 for all or part of a day, the delivering party will reduce the total weekly demand charge by an amount equal to one-sixth (1/6) of the weekly Short Term Demand Rate then being paid times the number of kW of capacity reduced for all or part of a day.

(b) In the event the delivering party provides Short Term power to the receiving party from a third-party system, the receiving party will pay the delivering party a Demand Rate equal to (1) the Demand Rate charged by the third party, plus (2) a Transmission Use Rate per kW per week or per kW per day for periods of less than a week, not to exceed the rate calculated in accordance with Appendix A or B, whichever is applicable.

7. Service Schedule G - 1979, Other Energy

Schedule G, as amended by agreement dated August 10, 1980, is further amended by deleting Subsection 3.1 in its entirety and inserting the following in place thereof:

3.1 (a) When energy delivered hereunder is generated on the system of the delivering party, the receiving party will pay the delivering party a rate per kWh equal to (1) the out-of-pocket cost; plus (2) the cost of transmission losses to make delivery; plus (3) ten percent (10%) of the sum of (1) and (2) under this section or 5 mills per kWh, whichever is less; plus (4) a Transmission Use Rate per kWh not to exceed the rate calculated in accordance with Appendix A or B, whichever is applicable; or at the option of the delivering party, the energy may be returned in kind.

(b) For energy delivered by the delivering party from a third party, the receiving party will pay the delivering party a rate per kWh equal to (1) the rate per kWh paid to the third party; plus (2) cost of associated transmission losses; plus (3) one mill per kWh for miscellaneous and unquantifiable incremental costs incurred for transmission services; plus (4) a Transmission Use Rate per kWh not to exceed the rate calculated in accordance with Appendix A or B, whichever is applicable; or by mutual agreement the energy may be returned in kind. In return-in-kind transactions, the receiving party will pay the delivering party a rate equal to (1) the cost of supplying associated transmission losses on the system of the delivering party; plus (2) one mill per kWh to provide compensation for miscellaneous and unquantifiable incremental costs incurred for transmission services; plus (3) a Transmission Use Rate per kWh not to exceed the rate calculated in accordance with Appendix A or B, whichever is applicable.

8. Except as herein above modified, all terms and conditions of the Interchange Agreement dated July 9, 1970, as subsequently amended in writing on January 1, 1974; April 1, 1979, and August 10, 1980, shall remain in full force and effect.

DUPLICATE ORIGINAL

IN WITNESS WHEREOF, the parties hereto have caused this AMENDMENT TO INTERCHANGE AGREEMENT to be executed by their duly authorized officers.

ATTEST:

Secretary

CAROLINA POWER & LIGHT COMPANY

James M. Davis

ATTEST:

Barbara D. Blair

Secretary

SOUTH CAROLINA ELECTRIC & GAS COMPANY

APPROVED AS TO LEGALITY AND FORM

11-9-88

AS TO EXECUTION

11-18-88

APPENDIX A

DETERMINATION OF INTERCONNECTION DEMAND RATES

SOUTH CAROLINA ELECTRIC & GAS COMPANY

This Appendix incorporates the provisions applicable to the pricing of the various types of service being rendered under the Interconnection Agreement dated July 9, 1970, and subsequently amended, between South Carolina Electric & Gas Company (SCE&G) and Carolina Power & Light Company (CP&L).

Rates to be calculated under this Appendix will include Limited-Term, Short-Term, Spinning Reserves, Other Energy and any applicable transmission use when such services are provided to CP&L from SCE&G's system or through SCE&G's system from a third party.

The following pages show the elements which comprise the rates for each of these categories, and information schedules IS-1 through IS-4 provide the format for aggregating these elements to make up the rates. Pages W1 through W15 provide the format and methodology for deriving each of these elements, and references are made to these pages throughout the information schedules.

SUMMARY OF METHODOLOGY

Calculation of the capacity rate is determined from cost published in FERC Form "1". The billing format methodology outlines page numbers, account titles, FERC account numbers and dollar amount for each component of rate base and capacity expenses. Calculations for production and transmission capacity cost are found on pages W1-W15.

Rate base for both production and transmission is comprised of plant in service, less reserve for depreciation, plus working capital (Total O & M ÷ 8) and minus accumulated deferred income taxes. General and common plant and reserve are functionalized on a labor ratio (excluding administrative and general wages) methodology.

Capacity expenses are comprised of capacity related O & M expenses (per FERC), depreciation expense and taxes other than income (Ad Valorem and labor related taxes).

The capital structure is based on year end ratios of debt, preferred stock and common equity. The cost of each capital component is computed using year and embedded cost of debt, preferred stock and return on common equity as shown on page W7. Common equity is stated at 14.00% and would remain at 14.00% subject to appropriate filing with FERC.

?

Income taxes are computed on the current statutory tax rates. Any billing month will be computed on the current Federal and State corporate rate as shown on pages W9 and W10.

All allocations and calculations for the production and transmission capacity rate are explained on pages W11-W14.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

LIMITED-TERM SALES

Demand Rate

The demand rate for limited-term sales includes;

1. A production carrying cost.
2. A cost for capacity reserves.
3. A transmission cost.

By adding these costs, the total annual cost per KW is developed which is divided by 12 for a monthly rate.

Transmission Use Rate

The transmission use rate for limited-term sales for third-party transactions is the annual system transmission cost per KW, including any applicable taxes, divided by 12 for a monthly rate.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

SHORT-TERM SALES

Demand Rate

The demand rate for short-term sales includes:

1. A production carrying cost.
2. A transmission cost.

By adding these costs, the total annual cost per KW is developed which is divided by 52 for a weekly rate, and the weekly rate is divided by six for a daily rate.

Transmission Use Rate

The transmission use rate for short-term sales for third-party transactions is the annual system transmission cost per KW, including any applicable taxes, divided by 52 for a weekly rate, and the weekly rate is divided by six for a daily rate.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

SPINNING RESERVES

Demand Rate

The demand rate for spinning reserves includes:

1. A production carrying cost.
2. A transmission cost.

By adding these costs, the total annual cost per KW is developed, which is divided by 312 for a daily rate.

Transmission Use Rate

The transmission use rate for spinning reserves for third-party transactions is the annual system transmission cost per KW divided by 312 for a daily rate, or 3120 for an hourly rate, whichever is appropriate.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

OTHER ENERGY

Demand Rate

No demand rate is applied.

Transmission Use Rate

The transmission use rate for other energy sales where there is no demand rate or for third-party transactions is the annual system transmission cost per KW, including any applicable taxes, divided by 3120 for an hourly rate.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

INFORMATIONAL SCHEDULES

FOR YEAR ENDING

DECEMBER 31, 19___

SOUTH CAROLINA ELECTRIC & GAS COMPANY

YEAR ENDING DECEMBER 31, 19___

LIMITED TERM (1)

Demand Rate

Total Production Carrying Cost (Page W1)	$_____/KW/YR
Capacity Reserves (20%) of Production Carrying Cost	$_____/KW/YR
Transmission Cost (Page W4)	$_____/KW/YR
Subtotal	$_____/KW/YR
Total	$_____/KW/YR/ 12 = $____/KW/MO

Transmission Use Rate

Transmission Cost (Page W4)	$_____/KW/YR
Total	$_____/KW/YR/ 12 = $____/KW/MO

(1) Note: Actual rates charged for these transations will be as agreed by the two parties, but not to exceed these maximum rates.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

YEAR ENDING DECEMBER 31, 19__

SHORT-TERM (1)

Demand Rate

Total Production Carrying Cost (Page W1)	$_____/KW/YR
Transmission Cost (Page W4)	$_____/KW/YR
Subtotal	$_____/KW/YR
Total	$_____/KW/YR / 52 = $____/KW/WK
	$____/KW/WK / 6 = $____/KW/Day

Transmission Use Rate

Transmission Cost (Page W4)	$_____/KW/YR
Total	$_____/KW/YR/ 52 = $____/KW/WK
	$____/KW/WK / 6 = $____/KW/Day

(1) Note: Actual rates charged for these transations will be as agreed by the two parties, but not to exceed these maximum rates.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

YEAR ENDING DECEMBER 31, 19__

SPINNING RESERVES (1)

<u>Demand Rate</u>

Total Production Carrying Cost (Page W1)	$_____/KW/YR
Transmission Cost (Page W4)	$_____/KW/YR
Subtotal	$_____/KW/YR
Total	$_____/KW/YR / 312 = $____/KW/Day

<u>Transmission Use Rate</u>

Transmission Cost (Page W4)	$_____/KW/YR
Total	$_____/KW/YR / 312 = $____/KW/Day
	$_____/KW/YR / 3120 = $_____/KWH

(1) Note: Actual rates charged for these transations will be as agreed by the two parties, but not to exceed these maximum rates.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

YEAR ENDING DECEMBER 31, 19__

OTHER ENERGY (1)

Demand Rate

No demand rate is applied.

Transmission Use Rate

Transmission Cost (Page W4)	$_____/KW/YR
Total	$_____/KW/YR / 3120 = $_____/KWH

(1) Note: Actual rates charged for these transations will be as agreed by the two parties, but not to exceed these maximum rates.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CAPACITY RATE ANALYSIS
FOR YEAR ENDING DECEMBER 31, 19__

Line No.		
	Calculation of Capacity Related Revenue	
1	Total Production Rate Base (Page W2)	$
2	Rate of Return (Page W7)	x ________
3	Required Return	$
4	Composite Tax Factor (See Table 4, Page W9)	÷ ________
5	Revenue Requirement for Rate Base	$
6	Revenue for Capacity Related Expenses (Page W3)	________
7	Total Revenue Requirement	$ ________

Calculation of Capacity Rate

$$\frac{\$\_\_\_\_\_\_\ \text{(Revenue Requirement)}}{\text{KW (See Table 3, Page W8)}} = \$\_\_\_\_\_\_\ \text{Annual Capacity Cost/KW}$$

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CAPACITY RATE ANALYSIS

FERC Form 1 Page #		FERC Acct. #'s	Calendar Year 19 $
	Plant in Service		
204/205	Steam Production Plant	(310-316)	
204/205	Nuclear Production Plant	(320-325)	
204/205	Hydro Production Plant	(330-336)	
206/207	Other Production Plant	(340-346)	
	General Plant (See Page W11)	(389-398)	
	Common Plant (See Page W11)	(389-398)	
	Total Plant in Service		
	Accumulated Provision for Depreciation		
219	Steam Production	108	
219	Nuclear Production	"	
219	Hydro Production	"	
219	Other Production	"	
	General (See Page W11)	"	
	Common (See Page W11)	"	
	Total Accumulated Depr.	"	
	Working Cash		
	Total Working Capital (Total O&M ÷ 8) (W3) (Page W11)		
272	Accumulated Deferred Income Taxes		
	Steam Production (See Pg W6)	(281,282,283 & 190)	
	Nuclear Production (See Pg W6)	"	
	Hydro Production (See Pg W6)	"	
	Other Production (See Pg W6)	"	
	Gen. & Common (See Page W11)	"	
	Total Deferred Taxes	"	
Total Production Rate Base			

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CAPACITY RATE ANALYSIS

FERC Form 1 Page #		FERC Acct. #'s	Calendar Year 19 $
	Operation & Maintenance Expense		
320	Steam	(500,502,504-507,511 & 514)	
320	Nuclear	(517,519,520,523-525,529 & 532)	
320/321	Hydro	(535-540,541-543 & 545)	
321	Other	(546, 548-554)	
323	A&G (See Page W11)	(923-935 Less: 928)	
	Total O&M		
	Depreciation Expense		
336	Steam	403	
336	Nuclear	"	
336	Hydro	"	
336	Other	"	
	General (See Page W12)	"	
	Common (See Page W12)	"	
	Total Depreciation	"	
	Other Taxes		
262	Operating Charge	408.1 & 409.1	
	Payroll Taxes (See Page W12)	"	
	County Property Taxes (See Page W12)	"	
	Total Other Taxes	"	
	Total Capacity Expenses		

SOUTH CAROLINA ELECTRIC & GAS COMPANY
TRANSMISSION USE RATE ANALYSIS
19__
TRANSMISSION

Line No.		
	Calculation of Capacity Related Revenue	
1	Total Transmission Rate Base (Page W5)	$
2	Rate of Return (See Page W7)	x ______
3	Required Return	$
4	Composite Tax Factor (See Page W10)	÷ ______
5	Revenue Requirement for Rate Base	$
6	Revenue for Capacity Related Expenses (Page W5)	$ ______
7	Total Revenue Requirement	$ ______

Calculation of Transmission Rate

$ ______ (Revenue Requirement) ______ = $ ______ /KW Annually
KW (Average of 12 Monthly Peaks
Form 1, Page 401)

SOUTH CAROLINA ELECTRIC & GAS COMPANY
TRANSMISSION USE RATE ANALYSIS

FERC Form 1 Page #		FERC Acct. #'s	Calendar Year 19 $
	Plant in Service		
206/207	Transmission Plant	(350-359)	
	General Plant (See Page WI3)	(389-398)	
	Common Plant (See Page W13)	(389-398)	
	Total Plant in Service		
	Accumulated Provision for Depreciation		
219	Transmission	108	
	General (See Page W13)	108	
	Common (See Page W13)	108	
	Total Accumulated Depreciation	108	
	Total Working Cash (See Page W13)		
272	Accumulated Deferred Income Taxes		
	Transmission (See Page W13)	(281,282,283 & 190)	
	General & Common (See Page W13)	"	
	Total Deferred Taxes	"	
	Total Transmission Rate Base		
	Operation & Maintenance Expense		
321	Transmission	(560-573)	
323	A&G (See Page W13)	(923-935 Less: 928)	
	Total O&M		
	Depreciation Expense		
336	Transmission	403	
	General (See Page W14)	403	
	Common (See Page W14)	403	
	Total Depreciation	403	
	Other Taxes		
259	Payroll (See Page W14)	408.1 & 409.1	
	County Property (See Page W14)	"	
	Total Other Taxes	"	
Total Capacity Expenses			

TABLE 1
SOUTH CAROLINA ELECTRIC & GAS COMPANY
ACCUMULATED DEFERRED INC. TAXES - 19__

FERC Acct.#	Steam	Other Hydro	Prod.	T&D	General & Common	Total	FERC Form 1 Page #
Acct 281							272-273
Acct 282							274-275
Acct 283							276-277
Less: Acct 190							234-234A
Total Accum Def. Inc. Taxes							

TABLE 2
SOUTH CAROLINA ELECTRIC & GAS COMPANY
COST OF CAPITAL
12 MONTHS ENDED DECEMBER 31, 19__

Component	Capitalization	Ratio	Embedded Cost/Rate	Overall Cost/Rate
	$	%	%	%
Long Term Debt				
Preferred Stock				
Common Equity	________	____	14.00 (1)	____
Total	========	====		====

(1) Stated Return on Common Equity

TABLE 3
SOUTH CAROLINA ELECTRIC & GAS COMPANY

GENERATING STATION STATISTICS

NAME AND LOCATION OF STATION	FIRST AND LAST UNIT	RATING IN KILOWATTS NET PEAK CAPABILITY
Steam:		
Canadys - Canadys, SC	1962-67	
Hagood - Charleston, SC	1947-51	
McMeekin - Near Irmo, SC	1958	
Urquhart - Beech Island, SC	1953-55	
Wateree - Eastover, SC	1970-71	
Williams - Charleston, SC	1973	______
Total Steam		______
IC Turbines:		
Burton, SC	1961	
Charleston, SC	1961	
Burton, SC	1963	
Burton, SC	1963	
Hardeeville, SC	1968	
Canadys, SC	1968	
Urquhart Turbines (2-17 MW & 13 MW)	1969	
Coit Turbines (2 x 16 MW)	1969	
Parr Turbines (2 x 14 MW)	1970	
Parr Turbines (2 x 18 MW)	1971	
Parr - Heat Recovery - Parr, SC	1925-29	
Williams Tubines (2 x 27 MW)	1972	______
Total IC Turbines		______
Hydro:		
Columbia - Columbia, SC	1927-29	
Neal Shoals - Union, SC	1905	
Parr Shoals - Parr, SC	1914-21	
Saluda - Near Irmo, SC	1930-71	
Stevens Creek - Near Martinez, GA	1914-26	
Fairfield Pumped Storage - Parr, SC	1978	______
Total Hydro		______
Total (Excl. V.C. Summer Nuclear)-As of _-_-__		______
V. C. Summer Nuclear	_-_-__	______ (1)
Total (Incl. V. C. Summer Nuclear)-After _-_-__		______

(1) S. C. Elec. & Gas Co.'s 2/3 Portion

SOUTH CAROLINA ELECTRIC & GAS COMPANY
DEVELOPMENT OF COMPOSITE
TAX FACTOR
TABLE 4
(YEAR ENDING DECEMBER 31, 19__)

Line No.		Debt (Col. 1)	Preferred (Col. 2)	Common (Col. 3)	Total (Col. 4)
1	Rate Base (Production)				
2	Weighted Cost of Capital (Table 2)	x ______ %	x ______ %	x ______ %	x ______ %
3	Required Return				
4	Revenue Effect (See Example)	+ ______	+ ______	+ ______	
5	Required Revenue				______
6	Composite Tax Factor (Col 4 Line 3 : Col 4 Line 5)				______ %

Example:

	$1,000,000	100.00%
Less:		
(A) Gross Receipts & SCPSC Tax ($1,000,000 x Gross Receipts and SCPSC Tax Rate) =		%
(B) State Income Tax ($1,000,000 - Gross Receipts and SCPSC Tax = ______ x State Income Tax Rate)		%
(C) Federal Income Tax (1,000,000 - (Gross Receipts and SCPSC & State Income Tax) = ______ x Federal Income Tax Rate)	______	______ %
(D) Total Taxes	______	______ %
Additional Return	______	______ %

Note #1: SCPSC = Assessment for expenses of Commission

Note #2: Any billing month will be charged the currently effective Federal or State Corporate Income rate

SOUTH CAROLINA ELECTRIC & GAS COMPANY
DEVELOPMENT OF COMPOSITE
TAX FACTOR
TABLE 5
(YEAR ENDING DECEMBER 31, 19__)

Line No.		Debt (Col. 1)	Preferred (Col. 2)	Common (Col. 3)	Total (Col. 4)
1	Rate Base (Transmission)				
2	Weighted Cost of Capital (Table 2)	x ______ %	x ______ %	x ______ %	x ______ %
3	Required Return				
4	Revenue Effect (See Example)	: ______	: ______	: ______	
5	Required Revenue				______
6	Composite Tax Factor (Col 4 Line 3 : Col 4 Line 5)				______ %

Example:

	$1,000,000	100.00%
Less:		
(A) Gross Receipts & SCPSC Tax ($1,000,000 x Gross Receipts and SCPSC Tax Rate) =		%
(B) State Income Tax ($1,000,000 - (Gross Receipts and SCPSC Tax = __________ x State Tax Rate)		%
(C) Federal Income Tax ($1,000,000 - (Gross Receipts and SCPSC Tax & State Income Tax) = __________ x Federal Tax Rate)	______	______ %
(D) Total Taxes	______	______ %
Additional Return	______	______ %

Note #1: SCPSC = Assessment for expenses of Commission

Note #2: Any billing month will be charged the currently effective Federal or State Corporate Income rate.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CAPACITY RATE ANALYSIS
PRODUCTION

Page References are from Form 1

General & Common Plant Allocation

[1]Production Payroll (Pg 354)+ PT&D Payroll (pg 354) x General Plant (pg 206-207)

[2]Production Payroll (Pg 354)+ PT&D Payroll (pg 354) x Common Plant (pg 356b) + GENCO common plant + Fuel Co. Common Plant (pg 356b)

General & Common Accumulated Provision for Depreciation Allocation

[1]Production Payroll (pg 354) +PT&D Payroll (pg 354) x General Accumulated Provision (pg 219)

[2]Production Payroll (pg 354) +PT&D Payroll (pg 354) x Common Accumulated Provision (pg 356b) + Genco Common Accumulated Provision + Fuel Co. Common Accumulated Provision (pg. 356b)

Working Cash Computation

Total O&M (Exclusive of Purchased Power and Nuc. Fuel.) from W5 : 8 (45 day formula)

Accumulated Deferred Income Taxes

[1]Production Payroll (pg. 354 + PT&D Payroll (pg 354) x General & Common Deferred Taxes (Table 1)

Administrative & General Expenses Allocation

[1]Production Payroll (pg 354) + PT&D Payroll (Pg 354) x (Total A&G less Account 928)

1 Includes GENCO, Excludes Nuclear (W15)
2 Excludes Nuclear (W15)

General & Common Depreciation Expenses Allocation

[1]Production Payroll (pg 354) ÷ PT&D Payroll (pg 354) x General Provision (pg 336)

[2]Production Payroll (pg 354) ÷ PT&D Payroll (pg 354) x Common Provision (pg 336) + Genco Common Provision (Pg 336)

Other Taxes

Payroll Taxes: [2]Production Payroll (pg 354) ÷ PT&D Payroll (pg. 354) x Payroll taxes (pg. 263, Lines 3, 4, & 13) & GENCO Payroll Taxes (p. 263, Lines 3, 4, & 8)

County Propery tax: Total Production Plant (W2) ÷ Total Plant (pg 207) x Property tax (pg. 263, Line 16) & GENCO Propety Tax (p.263)

Rate of Return

The allowable rate of return shall be computed using capitalization figures and debt and preferred embedded costs as of December 31. The cost of equity shall be at the stated rate of 14%.

1 Includes GENCO, excludes Nuclear. (W15)
2 Excludes Nuclear (W15)

SOUTH CAROLINA ELECTRIC & GAS COMPANY
RATE ANALYSIS
TRANSMISSION

Page References are from Form 1

General & Common Plant Allocation

Transmission Payroll (pg 354) ÷ PT&D Payroll (pg. 354) x General Plant (pg 206 & 207)

Transmission Payroll (pg 354) ÷ PT&D Payroll (pg 354) x Common Plant (pg 356b)

General & Common Accumulated Provision for Depreciation Allocation

Transmission Payroll (pg 354) ÷ PT&D Payroll (pg 354) x General Accumulated Provision (pg 219)

Transmission Payroll (pg 354) ÷ PT&D Payroll (pg 354) x Common Accumulated Provision (pg 356b)

Working Cash Computation

Total O&M (Exclusive of Purchased Power and Nuc. Fuel) from W5 : 8 (45 day formula)

Accumulated Deferred Income Taxes

Transmission Plant (pg 206 & 207) ÷ (Transmission Plant (Pg. 206 & 207) + Distribution Plant (pg 206 & 207) x T&D Deferred Taxes (W6)

Transmission Payroll (pg. 354) ÷ PT&D Payroll (pg 354) x General & Common Deferred Taxes (Table 1)

Administrative & General Expenses Allocation

Transmission Payroll (pg 354) PT&D Payroll (Pg 354) x (Total A&G less Account 928) (Pg. 323)

General & Common Depreciation Expenses Allocation

Transmission Payroll (pg 354) ÷ PT&D Payroll (pg 354) x General Provision (pg 336)

Transmission Payroll (pg 354) ÷ PT&D Payroll (pg 354) x Common Provision (pg 336)

Other Taxes

Payroll Taxes: Transmission Payroll (pg 354) ÷ PT&D Payroll (pg. 354) x Payroll taxes (pg. 263, Lines 3, 4, & 13)

County Property taxes: Total Plant (W5) ÷ Total Plant (pg 206 & 207) x Property Tax (pg 263, Line 16)

Rate of Return

The allowable rate of return shall be computed using capitalization figures and debt and preferred embedded costs as of December 31. The cost of equity shall be at the stated rate of 14%.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
FUNCTIONALIZATION OF PRODUCTION PAYROLL
FOR YEAR ENDING DECEMBER 31, 1986

	Ferc Form 1 Page #	Operation $	Maintenance $	Total $
Production				
Steam				
Hydro				
Nuclear				
Other Power				
Total Production	354			

SOUTH CAROLINA ELECTRIC & GAS COMPANY

INFORMATIONAL SCHEDULES

FOR YEAR ENDING

DECEMBER 31, 19 87

SOUTH CAROLINA ELECTRIC & GAS COMPANY

YEAR ENDING DECEMBER 31, 1987

LIMITED TERM (1)

Demand Rate

Total Production Carrying Cost (Page W1)	$ 42.77 /KW/YR
Capacity Reserves (20%) of Production Carrying Cost	$ 8.55 /KW/YR
Transmission Cost (Page W4)	$ 14.43 /KW/YR
Subtotal	$ 65.75 /KW/YR
Total	$ 65.75 /KW/YR/ 12 = $ 5.48 /KW/MO

Transmission Use Rate

Transmission Cost (Page W4)	$ 14.43 /KW/YR
Total	$ 14.43 /KW/YR/ 12 = $ 1.20 /KW/MO

(1) Note: Actual rates charged for these transations will be as agreed by the two parties, but not to exceed these maximum rates.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

YEAR ENDING DECEMBER 31, 19 87

SHORT-TERM (1)

Demand Rate

Total Production Carrying Cost (Page W1)	$ 42.77/KW/YR
Transmission Cost (Page W4)	$ 14.43/KW/YR
Subtotal	$ 57.20/KW/YR
Total	$ 57.20/KW/YR / 52 = $ 1.10 /KW/WK
	$ 1.10/KW/WK / 6 = $ 0.18 /KW/Day

Transmission Use Rate

Transmission Cost (Page W4)	$ 14.43/KW/YR
Total	$ 14.43/KW/YR/ 52 = $ 0.28/KW/WK
	$ 0.28/KW/WK / 6 = $ 0.05/KW/Day

(1) Note: Actual rates charged for these transations will be as agreed by the two parties, but not to exceed these maximum rates.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

YEAR ENDING DECEMBER 31, 1987

SPINNING RESERVES (1)

Demand Rate

Total Production Carrying Cost (Page W1)	\$ 42.77/KW/YR
Transmission Cost (Page W4)	\$ 14.43/KW/YR
Subtotal	\$ 57.20/KW/YR
Total	\$ 57.20/KW/YR / 312 = \$ 0.18/KW/Day

Transmission Use Rate

Transmission Cost (Page W4)	\$ 14.43/KW/YR
Total	\$ 14.43/KW/YR / 312 = \$ 0.05/KW/Day
	\$ 14.43/KW/YR / 3120 = \$ 0.005/KWH

(1) Note: Actual rates charged for these transations will be as agreed by the two parties, but not to exceed these maximum rates.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

YEAR ENDING DECEMBER 31, 1987

OTHER ENERGY (1)

Demand Rate

No demand rate is applied.

Transmission Use Rate

Transmission Cost (Page W4)	$ 14.43/KW/YR
Total	$ 14.43/KW/YR / 3120 = $ 0.005 /KWH

(1) Note: Actual rates charged for these transations will be as agreed by the two parties, but not to exceed these maximum rates.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CAPACITY RATE ANALYSIS
FOR YEAR ENDING DECEMBER 31, 1987

Line No.	Calculation of Capacity Related Revenue	
1	Total Production Rate Base (Page W2)	$468,444,008
2	Rate of Return (Page W7)	x 10.12%
3	Required Return	$ 47,406,534
4	Composite Tax Factor (See Table 4, Page W9)	÷ .72849
5	Revenue Requirement for Rate Base	$ 65,075,065
6	Revenue for Capacity Related Expenses (Page W3)	76,106,567
7	Total Revenue Requirement	$141,181,632

Calculation of Capacity Rate

$$\frac{\$141{,}181{,}632\ \text{(Revenue Requirement)}}{3{,}301{,}000\ \text{KW (See Table 3, Page W8)}} = \underline{\$42.77\ \text{Total Production Carrying Cost/KW}}$$

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CAPACITY RATE ANALYSIS

FERC Form 1 Page #		FERC Acct. #'s	Calendar Year 1987 $
	Plant in Service		
204/205	Steam Production Plant	(310-316)	552,655,662
204/205	Nuclear Production Plant	(320-325)	-0-
204/205	Hydro Production Plant	(330-336)	240,246,450
206/207	Other Production Plant	(340-346)	18,329,865
	General Plant (See Page W11)	(389-398)	22,144,978
	Common Plant (See Page W11)	(389-39)	11,812,615
	Total Plant in Service		845,189,570
	Accumulated Provision for Depreciation		
219	Steam Production	108	216,332,431
219	Nuclear Production	"	-0-
219	Hydro Production	"	42,454,204
219	Other Production	"	14,482,539
	General (See Page W11)	"	7,805,160
	Common (See Page W11)	"	2,028,751
	Total Accumulated Depr.	"	283,103,085
	Working Cash		
	Total Working Capital (Total O&M : 8) (W3) (Page W11)		5,516,830
272	Accumulated Deferred Income Taxes		
	Steam Production (See Pg W6)	(281,282,283 & 190)	73,826,649
	Nuclear Production (See Pg W6)	"	-0-
	Hydro Production (See Pg W6)	"	22,753,484
	Other Production (See Pg W6)	"	1,629,886
	Gen. & Common (See Page W11)	"	949,288
	Total Deferred Taxes	"	99,159,307
Total Production Rate Base			468,444,008

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CAPACITY RATE ANALYSIS

FERC Form 1 Page #		FERC Acct. #'s	Calendar Year 1987 $
	Operation & Maintenance Expense		
320	Steam	(500,502,504-507,511 & 514)	14,780,015
320	Nuclear	(517,519,520,523-525,529 & 532)	-0-
320/321	Hydro	(535-540,541-543 & 545)	3,205,742
321	Other	(546, 548-554)	1,939,987
323	A&G (See Page W11)	(923-935 Less: 928)	24,208,893
	Total O&M		44,134,637
	Depreciation Expense		
336	Steam	403	14,230,200
336	Nuclear	"	-0-
336	Hydro	"	3,133,800
336	Other	"	976,800
	General (See Page W12)	"	445,759
	Common (See Page W12)	"	495,711
	Total Depreciation	"	19,282,270
	Other Taxes		
262	Operating Charge	408.1 & 409.1	894,146
	Payroll Taxes (See Page W12)	"	1,551,390
	County Property Taxes (See Page W12)	"	10,244,124
	Total Other Taxes	"	12,689,660
	Total Capacity Expenses		76,106,567

SOUTH CAROLINA ELECTRIC & GAS COMPANY
TRANSMISSION USE RATE ANALYSIS
1987
TRANSMISSION

Line No.	Calculation of Capacity Related Revenue	
1	Total Transmission Rate Base (Page W5)	$140,793,315
2	Rate of Return (See Page W7)	x 10.12%
3	Required Return	$ 14,248,283
4	Composite Tax Factor (See Page W10)	÷ .72849
5	Revenue Requirement for Rate Base	$ 19,558,653
6	Revenue for Capacity Related Expenses (Page W5)	$ 15,848,173
7	Total Revenue Requirement	$ 35,406,826

Calculation of Transmission Rate

$$\frac{\$35{,}406{,}826 \text{ (Revenue Requirement)}}{2{,}454{,}500 \text{ KW (Average of 12 Monthly Peaks Form 1, Page 401)}} = \$14.43/\text{KW Annually}$$

SOUTH CAROLINA ELECTRIC & GAS COMPANY
TRANSMISSION USE RATE ANALYSIS

FERC Form 1 Page #		FERC Acct. #'s	Calendar Year 1987 $
	Plant in Service		
206/207	Transmission Plant	(350-359)	235,543,552
	General Plant (See Page W13)	(389-398)	2,483,975
	Common Plant (See Page W13)	(389-398)	1,374,574
	Total Plant in Service		239,402,101
	Accumulated Provision for Depreciation		
219	Transmission	108	67,058,737
	General (See Page W13)	108	875,495
	Common (See Page W13)	108	236,076
	Total Accumulated Depreciation	108	68,170,308
	Total Working Cash (See Page W13)		919,082
272	Accumulated Deferred Income Taxes		
	Transmission (See Page W13)	(281,282,283 & 190)	31,251,080
	General & Common (See Page W13)		106,480
	Total Deferred Taxes		31,357,560
	Total Transmission Rate Base		140,793,315
	Operation & Maintenance Expense		
321	Transmission	(560-573)	4,637,175
323	A&G (See Page W13)	(923-935 Less: 928)	2,715,482
	Total O&M		7,352,657
	Depreciation Expense		
336	Transmission	403	5,779,800
	General (See Page W14)	403	50,000
	Common (See Page W14)	403	61,736
	Total Depreciation	403	5,891,536
	Other Taxes		
259	Payroll (See Page W14)	408.1 & 409.1	166,533
	County Property (See Page W14)	"	2,437,447
	Total Other Taxes	"	2,603,980
Total Capacity Expenses			15,848,173

General & Common Depreciation Expenses Allocation

Transmission Payroll (pg 354) ÷ PT&D Payroll (pg 354) x General Provision (pg 336)

Transmission Payroll (pg 354) ÷ PT&D Payroll (pg 354) x Common Provision (pg 336)

Other Taxes

Payroll Taxes: Transmission Payroll (pg 354) ÷ PT&D Payroll (pg. 354) x Payroll taxes (pg. 263, Lines 3, 4, & 15)

County Property taxes: Total Plant (W5) ÷ Total Plant (pg 206 & 207) x Property Tax (pg 263, Line 21)

Rate of Return

The allowable rate of return shall be computed using capitalization figures and debt and preferred embedded costs as of December 31. The cost of equity shall be at the stated rate of 14%.

E14

SOUTH CAROLINA ELECTRIC & GAS COMPANY
FUNCTIONALIZATION OF PRODUCTION PAYROLL
FOR YEAR ENDING DECEMBER 31, 1987

	Ferc Form 1 Page #	Operation $	Maintenance $	Total $
Production				
Steam		8,023,435	3,755,713	11,779,148
Hydro		1,776,032	709,985	2,486,017
Nuclear		13,226,890	3,163,212	16,390,102
Other Power		591,181	203,544	794,725
Total Production	354	23,617,538	7,832,454	31,449,992

APPENDIX B

DETERMINATION OF INTERCHANGE DEMAND RATES - CAROLINA POWER & LIGHT COMPANY

This Appendix incorporates the provisions applicable to pricing of the various types of service being rendered under the Interchange Agreement dated July 9, 1970, and as subsequently amended, between South Carolina Electric & Gas Company and Carolina Power & Light Company (CP&L). All investments associated with transmission or production will be based on a projected, end-of-year test period and, where applicable, the rate per kilowatt will be determined using CP&L's Combined System Peak Demand. The rates will be calculated under the following provisions. Unless otherwise mutually agreed to by CP&L and South Carolina Electric and Gas Company, the rates shall be calculated on an annual basis and will be applicable to service rendered during the 12 months beginning July 1 of the test year subject to Article 18 of the Interchange Agreement as amended April 1, 1979.

The Combined System Peak Demand on CP&L's transmission system is the forecasted coincident peak demand determined by the sum of the following components:

(1) the demand served directly by CP&L to its customers;

(2) that portion of another utility's or agency's demand supplied from jointly owned generation and served through CP&L's transmission system;

(3) the demand placed on CP&L's transmission system by others for customers within CP&L's service area; and

(4) less the demand for Company use and production step-up losses.

Should future events alter the foregoing components, the projected combined system peak demand as used herein will be superseded by a new definition and revised application.

The rates to be calculated under this Appendix will include spinning reserve, limited term, short term, other energy, and any applicable transmission use when such services are provided to South Carolina Electric & Gas Company from CP&L's system or through CP&L's system from a third party.

SPINNING RESERVES

The rates for Spinning Reserves sales consist of a production demand rate and transmission use rate.

The annual production demand rate is the sum of the total production demand cost (page 7 of 14), annual transmission cost (page 9 of 14), and applicable taxes (page 10 of 14). The annual production demand rate per kW is divided by 312 for a daily rate.

The transmission use rate for third-party transactions is the annual transmission cost per kW, including any applicable taxes, divided by 312 for a daily rate or divided by 3,120 for an hourly rate, whichever is appropriate.

LIMITED TERM

The rates for Limited Term sales consist of a production demand rate and transmission use rate.

The annual production demand rate is the sum of the total production demand cost (page 7 of 14), cost for capacity reserves (page 11 of 14), annual transmission cost (page 9 of 14), and applicable taxes (page 10 of 14). The annual production demand rate per kW is divided by 12 for a monthly rate.

The transmission use rate for third-party transactions is the annual transmission cost per kW, including any applicable taxes, divided by 12 for a monthly rate.

SHORT TERM

The rates for Short Term sales consist of a production demand rate and transmission use rate.

The annual production demand rate is the sum of the total production demand cost (page 7 of 14), annual transmission cost (page 9 of 14), and applicable taxes (page 10 of 14). The annual production demand rate per kW is divided by 52 for a weekly rate, and the weekly rate is divided by 6 for a daily rate.

The transmission use rate for third-party transactions is the annual transmission cost per kW, including any applicable taxes, divided by 52 for a weekly rate and the weekly rate is divided by 6 for a daily rate.

OTHER ENERGY

The transmission use rate for transactions where there is no demand rate or for third-party transactions is the annual transmission cost per kW (page 9 of 14), including any applicable taxes, divided by 3,120 for an hourly rate.

TOTAL PRODUCTION DEMAND COST

The total production demand cost is determined by subtracting the accumulated deferred income tax credit per kW from the production demand cost per kW and adding the demand-related production expense per kW and the allowed CWIP per kW.

An explanation of the components used in calculating the total production demand cost is as follows:

A. Production demand cost per kW - This cost is the sum of the production-related demand costs per kW of the generating plants contributing to the sale. Individual generating plant production related demand cost per kW is the product of the weighted investment per kW for that plant and the applicable annual carrying charge. The annual carrying charge consists of the components listed below and explained on pages 12, 13, and 14 of 14.

1. Cost of Capital
2. Income Taxes
3. Ad Valorem and Labor-Related Taxes
4. Depreciation
5.a. Decommissioning Expenses
6. Administrative and General Expenses
7. General Plant
8. Working Capital
   (a) Cash Working Capital
   (b) Materials and Supplies
   (c) Prepayments

B. Accumulated deferred income tax credit per kW - This credit is determined by summing the products of the weighted accumulated deferred income tax per kW and the annual carrying charge, consisting of the cost of capital and income tax components, for each generating plant contributing to the sale.

C. Demand-related production expense per kW - This cost is determined by summing the products of demand-related production expense per kW and the percent participation for each generating plant contributing to the sale. The demand-related portion of Accounts 500-554 is determined through an analysis of each FERC account. The purchased capacity, including related O&M from jointly owned units, is included in the calculation of demand-related production expenses. This purchased capacity is booked in Account 555.

D. Allowed CWIP per kW - This cost is determined by summing the products of the FERC allowed production-related CWIP and the annual carrying charge, consisting of the cost of capital and income tax components for each generating plant contributing to the sale where CWIP is projected for the test period.

ANNUAL TRANSMISSION COST

The annual transmission cost is determined by applying an annual carrying charge to the projected end-of-year net transmission plant investment. The annual carrying charge consists of the components listed below and explained on pages 12, 13, and 14 of 14.

1. Cost of Capital
2. Income Taxes
3. Ad Valorem and Labor-Related Taxes
4. Depreciation

5.b. Transmission Operation and Maintenance Expenses

6. Administrative and General Expenses
7. General Plant
8. Working Capital
    a. Cash Working Capital
    b. Materials and Supplies
    c. Prepayments
9. Plant Held for Future Use

The net transmission cost is increased by an amount determined by applying a carrying charge, consisting of cost of capital and income tax components, to the transmission CWIP allowed by the FERC during the test period and reduced by an amount determined by applying the same carrying charge to accumulated deferred taxes associated with transmission investment and also reduced by revenue credits for wheeling revenues from non-associated utilities. The resulting value is the Annual Transmission Cost which is divided by the Combined System Peak Demand to determine the annual cost per kW.

APPLICABLE TAXES

The Service Schedule with which this Appendix is used provides for adding to the cost any taxes which might be applicable to the transactions. Such taxes may include, but are not limited to:

Support of South Carolina Public Service Commission

South Carolina Gross Receipts Tax

South Carolina Excise Tax (kWh Tax)

North Carolina Gross Receipts Tax

North Carolina Sales Tax

COST FOR CAPACITY RESERVES

The cost for capacity reserves is determined by taking 20 percent of the total production demand cost.

CARRYING CHARGES

The carrying charges will include the appropriate following components which are determined using projected values with an end-of-year test period:

1. Cost of Capital - The capital structure is based on end-of-year ratios of debt, preferred stock, and common equity. The cost of each capital component is computed using the end-of-year embedded cost of debt and preferred stock and the return on common equity as set forth in the Exhibit No. 1 to this Appendix as the same may be changed subject to appropriate filing with the FERC.

2. Income Taxes - Income taxes are the product of the current statutory tax rates applied to the return on preferred stock and common equity as computed above.

3. Ad Valorem and Labor-Related Taxes - This component is the result of dividing the sum of ad valorem and labor-related taxes by the total end-of-year net plant investment in the computation period.

4. Depreciation - The depreciation rates are the rates last allowed by the FERC adjusted to apply to net plant investment. These rates differ for the type of plant. The allowed rates are adjusted by the ratio of gross plant investment to net plant investment.

5.a. Decommissioning - The decommissioning component will only be applicable in the case of nuclear production. The annual decommissioning accrual is divided by the end-of-year net nuclear production plant investment to determine this percentage.

5.b. Transmission Operation and Maintenance Expenses - The O&M component is determined by dividing the O&M expenses by the end-of-year net transmission plant investment.

6. Administrative and General Expenses - The A&G expenses for the computation period are allocated between power production plant, transmission plant, and distribution plant based on the labor ratios of these items. The A&G expenses so determined are divided by the end-of-year net plant investment for power production plant and transmission plant.

7. General Plant - The general plant is allocated between power production plant, transmission plant, and distribution plant based on the labor ratios of these items. The carrying charge applicable to general plant consists of the cost of capital, income taxes, ad valorem and labor-related taxes, and depreciation (all as determined above). This carrying charge is applied to the general plant applicable to power production and transmission. The costs of general plant applicable to power production and transmission are divided by their respective end-of-year net plants.

8. Working Capital - Working capital is composed of the three portions defined below: cash working capital, materials and supplies, and prepayments. A carrying charge, consisting of cost of capital and income taxes (both described above), will be applied to each of the three in determining the annual cost for working capital. The working capital percentage is determined by dividing the annual cost by the end-of-year net plant investment.

   a. Cash Working Capital - This portion is calculated by taking one-eighth of the applicable operation and maintenance expenses. In the case of production, the O&M expenses should be exclusive of purchased power and nuclear fuel.

   b. Materials and Supplies - This is the end-of-year balance of the appropriate materials and supplies.

   c. Prepayments - This is the end-of-year balance of the appropriate prepaid expenditures, such as taxes and insurance.

9. Plant Held For Future Use - This component will only be applicable in the case of transmission plant. A carrying charge, consisting of cost of capital and income taxes (both described above), is applied to the end-of-year transmission-related plant held for future use. The component percentage is determined by dividing the annual cost by the end-of-year net transmission plant investment.

DEMAND AND TRANSMISSION RATE FOR
LIMITED-TERM, SHORT-TERM, SPINNING RESERVES,
AND OTHER ENERGY INTERCHANGE SALES
Year Ending December 31, 1988

Annual updates, pursuant to the Appendix, will require a filing when changes are made to the return on common equity, CWIP balances, and acquisition adjustments and that such filings will be governed by the applicable parts of Sections 35.13 and 35.26 of the Commission's Regulations, as modified by Order No. 448 or any superseding Commission Regulation or Order.

LIMITED-TERM

Demand Rate

Total Production Demand Cost	$38.30 /KW/YR
Capacity Reserves (20%) of Total Production Demand Cost	$7.66 /KW/YR
Annual Transmission Cost	$14.02 /KW/YR
Applicable Taxes	$0.00 /KW/YR

Total	$59.98 /KW/YR / 12 = $5.00 /KW/Mo.

Transmission Use Rate

Annual Transmission Cost	$14.02 /KW/YR
Applicable Taxes	$0.00 /KW/YR

Total	$14.02 /KW/YR / 12 = $1.17 /KW/Mo.

SHORT-TERM

Demand Rate

Total Production Demand Cost	$38.30 /KW/YR
Annual Transmission Cost	$14.02 /KW/YR
Applicable Taxes	$0.00 /KW/YR

Total	$52.32 /KW/YR / 52 = $1.01 /KW/WK
	$1.01 /KW/WK / 6 = $0.17 /KW/Day

Transmission Use Rate

Annual Transmission Cost	\$14.02 /KW/YR
Applicable Taxes	\$0.00 /KW/YR

Total	\$14.02 /KW/YR / 52= \$0.27 /KW/WK
	\$0.27 /KW/WK / 6 = \$0.04 /KW/Day

SPINNING RESERVE

Demand Rate

Total Production Demand Cost	\$38.30 /KW/YR
Annual Transmission Cost	\$14.02 /KW/YR
Applicable Taxes	\$0.00 /KW/YR

Total	\$52.32 /KW/YR / 312= \$0.17 /KW/Day

Transmission Use Rate

Annual Transmission Cost	\$14.02 /KW/YR
Applicable Taxes	\$0.00 /KW/YR

Total	\$14.02 /KW/YR / 312= \$0.04 /KW/Day
	\$14.02 /KW/YR /3120=\$0.004 /KW/Hr.

OTHER ENERGY

Transmission Use Rate

Annual Transmission Cost	\$14.02 /KW/YR
Applicable Taxes	\$0.00 /KW/YR

Total	\$14.02 /KW/YR /3120=\$0.004 /KW/Hr.

TOTAL PRODUCTION DEMAND COST

Year Ending December 31, 1988

1.	Production Demand Cost/KW	$36.37 /KW/YR
2.	Less: Accumulated Deferred Income Tax/Kw	$4.17 /KW/YR
3.	Plus: Demand-Related Production Expenses/KW	$6.10 /KW/YR
4.	Plus: Allowed CWIP/Kw	$0.00 /KW/YR

5.	Total Production Demand Cost/KW	$38.30 /KW/YR

PRODUCTION DEMAND COST

(1) Generating Plants	(2) Net Plant Investment	(3) Capacity (MW)	(4) Investment/KW (2) / (3)	(5) Percent Particip.	(6) Weighted Investment Cost/KW (4) x (5)	(7) Annual Carrying Charge	(8) Annual Carrying Cost/KW (6) x (7)
Asheville	$30,762,000	392	78.47	6.33%	4.97	23.55%	1.17
Cape Fear	$37,035,000	316	117.20	9.86%	11.56	23.55%	2.72
Lee	$24,343,000	407	59.81	11.80%	7.06	23.55%	1.66
Mayo (1)	$378,552,274	633	598.03	10.88%	65.07	23.55%	15.32
Robinson	$14,378,000	174	82.63	4.29%	3.54	23.55%	0.83
Roxboro	$278,968,000	2,462	113.31	40.20%	45.55	23.55%	10.73
Sutton	$66,968.000	613	109.25	12.60%	13.77	23.55%	3.24
Weatherspoon	$12,987,000	176	73.79	4.04%	2.98	23.55%	0.70
				Total Production Demand Cost/KW			$35.37 /KW/YR

(1) Includes capacity charge capital costs and buy-back capacity from another part owner of the Mayo Unit No. 1.
$363,499,000 + ($3,545,046/23.55%) = $378,552,274
591 MW + 42 MW = 633 MW

Exhibit No.1
to Appendix
Page 5 of 14

ACCUMULATED DEFERRED INCOME TAX

(1) Generating Plants	(2) Accumulated Deferred Income Tax	(3) Capacity (MW)	(4) Accumulated Deferred Income Tax/KW (2) / (3)	(5) Percent Particip.	(6) Weighted Accumulated Deferred Income Tax Cost/KW (4) x (5)	(7) Annual Carrying Charge Rate	(8) Accumulated DIT/KW (6) x (7)
Asheville	$5,766,000	392	14.71	6.33%	0.93	13.96%	0.13
Cape Fear	$6,647,000	316	21.03	9.86%	2.07	13.96%	0.29
Lee	$4,710,000	407	11.57	11.80%	1.37	13.96%	0.19
Mayo	$68,710,000	591	116.26	10.88%	12.65	13.96%	1.77
Robinson	$2,691,000	174	15.47	4.29%	0.66	13.96%	0.09
Roxboro	$54,505,000	2,462	22.14	40.20%	8.90	13.96%	1.24
Sutton	$13,413,000	613	21.88	12.60%	2.76	13.96%	0.38
Weatherspoon	$2,624,000	176	14.91	4.04%	0.60	13.96%	0.08

Total Accumulated DIT/Kw $4.17 /Kw/YR

Exhibit No.1
to Appendix
Page 6 of 14

DEMAND-RELATED PRODUCTION EXPENSE

(1) Generating Plants	(2) Demand-related Production Expense	(3) Capacity (MW)	(4) Demand-Related Production Expense/KW (2) / (3)	(5) Percent Particip.	(6) Weighted Demand-Related Production Expense/Kw (4) x (5)
Asheville	$2,770,457	392	7.07	6.33%	0.45
Cape Fear	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Lee	$2,727,654	407	6.70	11.80%	0.79
Mayo (2)	$3,419,632	633	5.40	10.88%	0.59
Robinson	$2,425,662	174	13.94	4.29%	0.60
Roxboro	$8,744,351	2,462	3.55	40.20%	1.43
Sutton	$3,812,466	613	6.22	12.60%	0.78
Weatherspoon	$2,397,147	176	13.62	4.04%	0.55
	Total				$6.10 /KW/YR

(2) Includes capacity charge demand-related O&M and buy-back
capacity from another part owner of Mayo Unit No. 1.
$2,872,102 + $547,530 = $3,419,632
591 MW + 42 MW = 633 MW

CONSTRUCTION WORK IN PROGRESS

(1) Generating Plants	(2) Allowed Construction Work In Progress	(3) Installed Capacity (MW)	(4) Cost/KW (2) / (3)	(5) Percent Particip.	(6) Weighted Cost/KW (4) x (5)	(7) Annual Carrying Charge Rate	(8) Allowed CWIP/KW (6) x (7)
Asheville	$0	392	0.00	6.33%	0.00	13.96%	0.00
Cape Fear	$0	316	0.00	9.86%	0.00	13.96%	0.00
Lee	$0	407	0.00	11.80%	0.00	13.96%	0.00
Mayo	$0	591	0.00	10.88%	0.00	13.96%	0.00
Robinson	$0	174	0.00	4.29%	0.00	13.96%	0.00
Roxboro	$0	2,462	0.00	40.20%	0.00	13.96%	0.00
Sutton	$0	613	0.00	12.60%	0.00	13.96%	0.00
Weatherspoon	$0	176	0.00	4.04%	0.00	13.96%	0.00
						Total CWIP/Kw	$0.00 /KW/YR

ANNUAL TRANSMISSION COST

Year Ending December 31, 1988

Year-end Net Transmission Plant Investment	$589,128,000 /YR
Carrying Charge	21.86%
Subtotal	$128,783,381 /YR
Less: Accumulated Deferred Income Tax (3)	$14,981,732 /YR
Less: Revenue Credits (4)	$1,513,749 /YR
Plus:Allowable CWIP (5)	$0 /YR
Total	$112,287,900 /YR
Load	8,007,468 KW
Total Transmission Cost	$14.02 /KW/YR

System Peak Demand	8,129,000 KW
Less: Company Use	18,000 KW
Less: Wheeling Input	82,700 KW
Less: Production Step-Up Losses	20,832 KW
Total Load	8,007,468 KW

(3) Accumulated DIT = $107,319,000 x (10.18%+3.78%)

= $14,981,732

(4) Revenue Credits = SEPA Wheeling
= $1,564,113 x (1-3.22%)
= $1,513,749

(5) Allowable CWIP = $0

CARRYING CHARGE RATE FOR PRODUCTION COST

	Steam Production
Cost of Capital	10.18%
Income Taxes	3.78%
Ad Valorem and Labor-Related Taxes	0.97%
Depreciation	4.79%
Decommissioning Expense	0.00%
A&G Expenses	2.20%
General Plant	0.56%
Working Capital	
Cash	1.05%
M&S	0.00%
Prepayments	0.02%
Total	23.55%

PRODUCTION CARRYING CHARGES

ALL YEAR-END INVESTMENTS ARE FROM 1988 PROJECTED VALUES.
ORIGINAL COST MUST BE REDUCED BY DEPRECIATION.

1.COST OF CAPITAL (6)

	% CAPITAL STRUCTURE	COST OF EACH %	COST COMPONENT
DEBT	48.66%	8.45%	4.11%
PREFERRED	7.62%	8.39%	0.64%
EQUITY	43.72%	12.42%	5.43%
TOTAL			10.18%

2. INCOME TAXES

STATE 6.67%
FEDERAL 34%
INCOME TAX ON PREFERRED & COMMON EQUITY:

NET INCOME BEFORE TAXES	100.00%
STATE INCOME TAX	6.67%
	93.33%
FEDERAL = 93.33%*34% =	31.73%
	61.60%

$$\text{INCOME TAX} = \frac{1 - .6160}{0.616} * (0.64 + 5.43) = \quad 3.78\%$$

3. AD VALOREM & LABOR-RELATED TAXES (7)

$$\frac{\$61,981,000}{\$6,382,665,000} = \quad 0.97\%$$

4. DEPRECIATION (8)
THESE ARE THE CURRENT FERC APPROVED COMPOSITE RATES FOR THE APPLICABLE ACCOUNTS.THESE COMPOSITE RATES ARE THEN ADJUSTED TO APPLY TO NET PLANT INVESTMENT.

$$\text{STEAM PRODUCTION} \quad 2.96\% \quad * \quad \frac{\$1,324,471,000}{\$818,877,000} = \quad 4.79\%$$

5. DECOMMISSIONING EXPENSES
NO NUCLEAR UNITS WERE INCLUDED
IN THIS STUDY.

$$\frac{\$0}{\$0} = \quad 0.00\%$$

(6) FERC Benchmark Return on Common Equity for the 2nd quarter 1988.
(7) Analysis of Company books.

6. A&G EXPENSES (9)

$$\frac{\$101,128,470}{\$4,602,555,000} = 2.20\%$$

7. GENERAL PLANT (10)

CARRYING CHARGE = 10.18% + 3.78% + 0.97% + 2.64% = 17.57%

17.57% * $145,831,005
= $25,622,508

$$\frac{\$25,622,508}{\$4,602,555,000} = 0.56\%$$

8. WORKING CAPITAL (11)

a. CASH

STEAM PRODUCTION

1/8 * $493,046,000
= $61,630,750

CARRYING CHARGE = 10.18% + 3.78%
= 13.96%

13.96% * $61,630,750
= $8,603,653

$$\frac{\$8,603,653}{\$818,877,000} = 1.05\%$$

b. MATERIALS & SUPPLIES

STEAM $0

13.96% * $0 = 0.00%

c. PREPAYMENTS

STEAM PRODUCTION

$896,484 * 13.96%= $125,149

$$\frac{\$125,149}{\$818,877,000} = 0.02\%$$

(9) Analysis of Company books. Power Production-related A&G allocated on the basis of Labor.

(10) Analysis of Company books. Power Production-related General Plant allocated on the basis of Labor.

(11) Analysis of Company books.

CARRYING CHARGE RATE FOR TRANSMISSION COST

Cost of Capital	10.18%
Income Taxes	3.78%
Ad Valorem and Labor-Related Taxes	0.97%
Depreciation	2.24%
O&M Expense	3.11%
A&G Expenses	0.92%
General Plant	0.23%
Working Capital	
Cash	0.05%
M&S	0.34%
Prepayments	0.01%
Plant Held for Future Use	0.03%
Total	21.86%

TRANSMISSION CARRYING CHARGES

ALL YEAR-END INVESTMENTS ARE 1988 PROJECTED VALUES.
ORIGINAL COST MUST BE REDUCED BY DEPRECIATION.

1.COST OF CAPITAL (12)

	% CAPITAL STRUCTURE	COST OF EACH %	COST COMPONENT
DEBT	48.66%	8.45%	4.11%
PREFERRED	7.62%	8.39%	0.64%
EQUITY	43.72%	12.42%	5.43%
TOTAL			10.18%

2. INCOME TAXES

STATE 6.67%
FEDERAL 34%

INCOME TAX ON PREFERRED & COMMON EQUITY:

NET INCOME BEFORE TAXES	100.00%
STATE INCOME TAX	6.67%
	93.33%
FEDERAL = 93.33%*34% =	31.73%
	61.60%

$$\text{INCOME TAX} = \frac{1 - .6160}{.6160} * (0.64 + 5.43) = \quad 3.78\%$$

3. AD VALOREM & LABOR-RELATED TAXES (13)

$$\frac{\$61,981,000}{\$6,382,665,000} = \quad 0.97\%$$

4. DEPRECIATION (14)

THESE ARE THE CURRENT FERC APPROVED COMPOSITE RATES FOR THE APPLICABLE ACCOUNTS.THESE COMPOSITE RATES ARE THEN ADJUSTED TO APPLY TO NET PLANT INVESTMENT.

$$\text{TRANSMISSION} \quad 1.82\% \quad * \quad \frac{\$727,700,000}{\$589,128,000} = \quad 2.24\%$$

5. O&M EXPENSES (15)

$$\text{TRANSMISSION} \quad \frac{\$18,351,000}{\$589,128,000} = \quad 3.11\%$$

(12) FERC Benchmark Return on Common Equity for the 2nd quarter 1988.
(13) Analysis of Company books.
(14) Analysis of Company books.

6. A&G EXPENSES (16)

$$\frac{\$5,393,339}{\$589,128,000} = 0.92\%$$

7. GENERAL PLANT (17)

CARRYING CHARGE = 10.18% + 3.78% + 0.97% + 2.64% = 17.57%

17.57% * $7,777,395
= $1,366,488

$$\frac{\$1,366,488}{\$589,128,000} = 0.23\%$$

8. WORKING CAPITAL (18)

a. CASH

TRANSMISSION 1/8 * $18,351,000
= $2,293,875

CARRYING CHARGE = 10.18% + 3.78%
= 13.96%

13.96% * $2,293,875
= $320,225

$$\frac{\$320,225}{\$589,128,000} = 0.05\%$$

b. MATERIALS & SUPPLIES

TRANSMISSION M&S = $14,315,000
$14,315,000 * 13.96% = $1,998,374

$$\frac{\$1,998,374}{\$589,128,000} = 0.34\%$$

c. PREPAYMENTS

TRANSMISSION
$492,472 * 13.96% = $68,749

$$\frac{\$68,749}{\$589,128,000} = 0.01\%$$

9. PLANT HELD FOR FUTURE USE (19)

TRANSMISSION

$$\$1,341,000 * 13.96 = \frac{\$187,204}{\$589,128,000} = 0.03\%$$

(16) Analysis of Company books. Transmission-related A&G allocated on the basis of Labor.
(17) Analysis of Company books. Transmission-related General plant allocated on the basis of Labor.
(18) Analysis of Company books.
(19) Analysis of Company books.

SUPPLEMENTAL INFORMATION
CAROLINA POWER & LIGHT COMPANY

Derivation of Labor Ratios for A&G and General Plant Allocations

1. Distribution of Salaries and Wages	
a. Production	$124,026,000
b. Transmission	$6,620,000
c. Distribution	$34,306,000
d. Total	$164,952,000
2. Labor Ratios	
a. Production (1.a./1.d.)	0.7519
b. Transmission (1.b./1.d.)	0.0401
c. Distribution (1.c./1.d.)	0.2080
d. Total	1.0000
3. A&G Expense(page 11 & 14 of 14, Exhibit to Appendix)	
a. Total A&G Expense	$134,497,234
b. Allocated Transmission A&G Expense (3.a. x 2.b.) =	$5,393,339
c. Allocated Production A&G Expense (3.a. x 2.a.) =	$101,128,470
4. General Plant Expense(page 11 & 14 of 14, Exhibit to Appendix)	
a. Total Net General Plant	$193,950,000
b. Allocated Net Transmission-related General Plant (4.a. x 2.b.) =	$7,777,395
c. Allocated Net Production-related General Plant (4.a. x 2.a.) =	$145,831,005