DUKE POWER COMPANY

OCONEE NUCLEAR STATION

UNITS 1, 2 and 3

LICENSE APPLICATION

Docket Nos. 50-269, -270, and -287

ANSWERS TO ATTORNEY GENERAL'S QUESTION
ATTACHED TO DR. PETER A. MORRIS' LETTER OF FEBRUARY 25, 1971

Submitted as Amendment No. 26

March 29, 1971

DUKE POWER COMPANY
POWER BUILDING
422 SOUTH CHURCH STREET, CHARLOTTE, N. C.

A. C. THIES
VICE PRESIDENT
PRODUCTION AND OPERATION

P. O. BOX 2178
28201

March 29, 1971

Dr. Peter A. Morris, Director
Division of Reactor Licensing
Atomic Energy Commission
Washington, D. C. 20545

Re: Oconee Units 1, 2 and 3
Docket Nos. 50-269, -270, and -287

Dear Mr. Morris:

Duke Power Company is filing herewith Amendment No. 26 to its Application for Licenses for the Oconee Nuclear Station, which is under construction pursuant to provisional construction permits CPPR-33, -34, and -35 issued by the Commission on November 6, 1967. This filing includes three (3) signed original copies of the Amendment with attachments and twelve (12) copies of "Answers to Attorney General's Questions attached to Dr. Peter A. Morris' letter of February 25, 1971."

Sincerely,

s/A. C. Thies

A. C. Thies

mg

DUKE POWER COMPANY

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Question No. 1:

State separately for hydroelectric and thermal generating resources applicant's most recent peak load and dependable capacity for the same time period. State applicant's dependable capacity at time of system peak for each of the next ten years for which information is available. Identify each new unit or resource.

Answer:

Duke Power Company's most recent peak load occurred during the hour ending at 7 p.m., January 19, 1971. The load, installed generating capacity, and power available under firm purchase contracts at that time were:

6 399 MW	Peak Load
5 882 MW	Dependable thermal capacity
862 MW	Hydro capacity, dependable rating under adverse stream flow conditions
145 MW	Purchase from AEPA
21 MW	Purchase from SCE&G
3 MW	Dependable capacity purchase from miscellaneous small hydro plants
6 913 MW	Total Dependable Capacity

For each of the next ten years, the estimated system peak load and dependable capacity resources including additions scheduled or planned are:

6 913 MW	Present Dependable Capacity
	1971 Scheduled Additions
209 MW	Combustion Turbines (10 Units)
140 MW	Keowee Hydro
78 MW	Firm Purchase (CP&L Asheville No. 2 Unit)
886 MW	Oconee No. 1
8 226 MW	1971 Peak Load Dependable Capacity
6 856 MW	1971 Estimated summer peak load
7 005 MW	1971-72 Estimated winter peak load
	1972 Scheduled Additions:
590 MW	Cliffside No. 5
886 MW	Oconee No. 2
(20) MW	Firm purchase reduction (CP&L Asheville No. 2 Unit)
9 682 MW	1972 Peak Load Dependable Capacity
7 516 MW	1972 Estimated summer peak load
7 651 MW	1972-73 Estimated winter peak load

	1973 Scheduled Additions:
886 MW	Oconee No. 3
(79) MW	Retirement (Buzzard Roost, Tiger, Gwd. Mills)
(18) MW	Firm purchase reduction (CP&L Asheville No. 2 Unit)
10 471 MW	1973 Peak Load Dependable Capacity
8 237 MW	1973 Estimated summer peak load
8 374 MW	1973-74 Estimated winter peak load
	1974 Scheduled Additions:
305 MW	Jocassee Hydro
1 143 MW	Belews Creek No. 1
(18) MW	Firm purchase reduction (CP&L Asheville No. 2 Unit)
11 901 MW	1974 Peak Load Dependable Capacity
9 027 MW	1974 Estimated summer peak load
9 101 MW	1974-75 Estimated winter peak load
	1975 Scheduled Additions:
1 143 MW	Belews Creek No. 2
(22) MW	Firm purchase reduction (CP&L Asheville No. 2 Unit)
13 022 MW	1975 Peak Load Dependable Capacity
9 890 MW	1975 Estimated summer peak load
9 917 MW	1975-76 Estimated winter peak load
	1976 Scheduled Additions:
1 150 MW	McGuire No. 1
14 172 MW	1976 Peak Load Dependable Capacity
10 833 MW	1976 Estimated peak load
	1977 Scheduled Additions:
1 150 MW	McGuire No. 2
15 322 MW	1977 Peak Load Dependable Capacity
11 862 MW	1977 Estimated peak load
	1978 Scheduled and Planned Additions:
305 MW	Jocasse Hydro (scheduled)
1 150 MW	No. 1 Unit at New Plant X (planned)
16 777 MW	1978 Peak Load Dependable Capacity
12 985 MW	1978 Estimated peak load
	1979 Planned Additions:
1 150 MW	No. 2 Unit at Plant X
17 927 MW	1979 Peak Load Dependable Capacity

14 209 MW	1979 Estimated peak load	
1 300 MW	1980 Planned Additions No. 1 Unit at New Plant Y	
19 227 MW	1980 Peak Load Dependable Capacity	
15 542 MW	1980 Estimated peak load	

Question No. 2:

State applicant's estimated annual load growth for each of the next 20 years or for the period applicant utilizes in system planning.

Answer:

Applicant's generation planning currently extends through 1982. Estimated annual peak loads and growth for the 1971-1982 period are:

Year	Estimated Peak Load-MW	Annual Growth MW	Annual Growth %
1971	6 856	572	9.1
1972	7 516	660	9.6
1973	8 237	721	9.6
1974	9 027	790	9.6
1975	9 890	363	9.6
1976	10 833	943	9.5
1977	11 862	1 029	9.5
1978	12 985	1 123	9.5
1979	14 209	1 224	9.4
1980	15 542	1 333	9.4
1981	16 994	1 452	9.3
1982	18 575	1 581	9.3

Question No. 3

State estimated annual load growth of companies or pools upon which the economic justification of the subj-ct unit is based for each of the next 20 years or for the period applicant utilizes in system planning. Identify each company or pool member.

Answer:

Economic justifica' of the Oconee generating units was based on load growth solely within Duke Power Company's service area and was completely independent of any pooling or coordination arrangements with interconnected companies. The three Oconee generating units are sized to be about 12.9, 11.8, and 10.8 percent respectively of the estimated 1971, 1972, and 1973 peak loads. In 1959, 1960, and 1961, Duke installed the last three units at its Allen Steam electric station. These three units had capabilities of 11.6, 10.8, and 10.5 percent respectively of the peak load experienced during the year of installation.

During the period between completion of the Allen Station and the present, Duke constructed its four-unit Marshall steam electric station. The Marshall units ranged in size from 8.7 to 12.1 percent of the Duke area peak load during the year brought in service. The size and timing of the Oconee units are a continuation of Duke's practice of building the most economical units for supplying its service area.

Question No. 4

For the year the subject unit would first come on line, state estimated annual load growth of any coordinating group or pool of which the applicant is a member (other than the coordinating group or pool referred to in the applicant's response to Item 3) which has generating and/or transmission planning functions. Identify each company or pool member whose loads are indicated in the response hereto.

Answer:

Duke Power is a member of the Southeastern Electric Reliability Council and also of the Virginia-Carolinas Reliability Agreement. The purpose of each organization is to augment further the reliability of the members bulk power supply systems. Both organizations provide for review of matters pertaining to reliability, but do not have generation and transmission planning responsibilities, and hence are not coordinating groups under the definition of "coordination" as contained in the question. However, in response to the F.P.C. Order 383-2 load growth information for the Virginia-Carolinas group of the Southeastern Electric Reliability Council filed September 1, 1970, with the Federal Power Commission shows an annual load growth for the area of 9.8 percent. Members of the Virginia-Carolinas Sub-region group of SERC are Duke Power Company, Carolina Power & Light Company, Virginia Electric and Power Company, South Carolina Electric & Gas Company, Yadkin, Inc., Southeastern Power Administration and South Carolina Public Service Authority.

Question No. 5:

State applicant's minimum installed reserve criterion (as a percentage of load) 1/ for the period when the subject unit will first come on line. If applicant shares reserves with other systems, identify the other systems and provide minimum installed reserve criterion (as a percentage of load) 1/ by contracting parties or pool for the period when the proposed unit will first come on line.

Answer:

Duke Power's criteria for reserves in MW and as a percent of the peak load for winter season each year, would require reserves equal to 2393 MW or 34.1 percent in 1971, 2509 MW or 32.7 percent in 1972, and 2599 MW or 31.1 percent in 1973. Existing firm purchase contracts would reduce the required company owned reserves by 247 MW in 1971, 227 MW in 1972, and 209 MW in 1973. All load levels are considered in the determination of adequate reserves. The criteria, however, expresses required reserve in capacity in excess of peak load requirements and as a percent of peak load.

The high reserve levels indicated are considered prudent in view of the industry's experience with operation of large units and of nuclear plants. In spite of the high reserve required, these plants offer the most economical alternative for meeting our load growth.

Under the agreement whereby each of the four companies which formerly comprised the CARVA Pool voluntarily withdrew from the pool, Duke will share reserves with VEPCO, CP&L, and SCE&G until April 30, 1973. The reserve criteria of those companies is not known to Duke Power. The actual reserve level will depend on the completion dates of several capacity additions now under construction on all four systems, but will undoubtedly be substantially less than Duke's current criteria.

1/ Indicate whether loads other than peak loads are considered.

Question No. 6:

Describe methods used as a basis to establish, or as a guide in establishing the criteria for applicant's and/or applicant's pool's minimum amount of installed reserves. [e.g., (a) single largest unit down, (b) probability methods such as loss of load one day in 20 years, loss of capacity once in five years, (c) other methods and/or (d) judgment. List contingencies other than risk of forced outage that enter into the determination.]

Answer:

Duke Power's criteria for reserves includes allowances at the time of peak load for:

1. Load increases brought on by severe weather. (Peak load estimates are based on average weather.)

2. The unscheduled outage of the largest generating unit.

3. Forced outages or reductions in capability of other generating units, based on operating experience.

4. Forecast error or the outage of additional generation equivalent to the largest unit.

Question No. 7:

Indicate whether applicant's system interconnections are credited explicitly or implicity in establishing applicant's installed reserves.

Answer:

Except for the firm purchases referred to in Question 5, Duke Power's interconnections are not explicitly credited with reserve capability. Although Duke's interconnections have a combined capability of the same order of magnitude as its reserve requirements, they cannot be assigned a firm reserve responsibility simply because reserves throughout the eastern half of the country are so short that firm reserve of any significant amount is not available from other systems.

Question No. 8:

List rights to receive emergency power and obligations to deliver emergency power, rights or obligations to receive or deliver deficiency power or unit power, or other coordinating arrangements; by reference to applicant's Federal Power Commission (FPC) rate schedules (i.e. ABC Power & Light Company, FPC Rate Schedule No. 15 including supplement 1-5) 2/, and also by reference to applicant's state commission filings. Where documents are not on file with the FPC, supply copies, or where not reduced to writing describe arrangements. Identify for each such arrangement the participating parties other than applicant. Provide one line electrical and geographic diagrams of coordinating groups or power pools (with generation or transmission planning functions) of which applicant's generation and transmission facilities constitute a part.

Answer:

1. Duke Power Company FPC Rate Schedule No. 10, Interconnection Agreement between Duke Power Company and Carolina Power & Light Company, dated June 1, 1961, Service Schedules A, B, C, D, E, and F. Certificate of Concurrence filed by Carolina Power & Light Company.

2. Duke Power Company FPC Rate Schedule No. 8, Interconnection Agreement between Duke Power Company and South Carolina Electric & Gas Company dated August 28, 1956, Service Schedules A, B, C, D, and E. Certificate of Concurrence filed by South Carolina Electric & Gas Company.

3. Duke Power Company FPC Rate Schedule No. 9, including Supplements 2 and 3. Interchange Contract between Duke Power Company and Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Services, Inc., dated June 1, 1961, Service Schedules A, B, C, E, and F. Southern Company FPC Rate Schedule 25 including Supplements 1, 3, 5 and 6.

4. Duke Power Company FPC Rate Schedule No. 4 including Supplements 1, 3 and 4. Interchange Agreement between Duke Power Company and Appalachian Power Company dated February 28, 1949, Service Schedules A, B1, C, and E. Appalachian Power Company FPC Rate Schedule 18 including Supplements 4 and 6.

5. Duke Power Company FPC Rate Schedule No. 10 including Supplement 3. Standby Concurrent Exchange Agreement between Duke Power and Carolina Power and Light Company, dated January 1, 1957. Carolina Power & Light Company FPC Rate Schedule No. 45 including Supplement 1.

6. Wheeling Agreement between Duke Power Company and South Carolina Electric and Gas Company. South Carolina Electric & Gas Company FPC Rate Schedule No. 28.

2/ List separately and identify certificates of concurrence.

7. 1971 Generator Installation Agreement between Duke Power Company and Carolina Power & Light Company. Carolina Power & Light Company FPC Rate Schedule No.98.

8. Duke Power Company FPC Rate Schedule No. 11 including Supplements 1, 2, 3, and 4. Interconnection Agreement between Duke Power Company and Yadkin, Inc. Yadkin, Inc. FPC Rate Schedule No. 4 including Supplements 1, 2, 3, and 4.

9. Duke Power Company FPC Rate Schedule No. 130 including Supplements 1 and 2. Contract between Duke Power Company and the Southeastern Power Administration, Department of Interior, United States Government.

10. Letter Agreement between Duke Power Company and South Carolina Electric and Gas Company whereby Duke agrees to furnish up to 101 MW of standby power to South Carolina Electric and Gas Company beginning as of the commercial operating date of South Carolina Electric and Gas Company's 611 MW 1973 generating unit addition and terminating as of the installation date of a second unit of similar or larger size. South Carolina Electric & Gas Company's letter dated July 7, 1970; accepted by Duke as of July 9, 1970.

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Question No. 9:

List non-affiliated 3/ electric utility systems with peak loads smaller than applicant's which serve either at wholesale or at retail adjacent to areas served by applicant. Provide a geographic one line diagram of applicant's generation and transmission facilities (including sub-transmission), indicating the location of adjacent systems and as to such systems indicate (if available) their load, their annual load growth, their generating capacity, their largest thermal generating unit size, and their minimum reserve criteria.

Answer:

Adjacent non-affiliated electric systems are tabulated on the following two pages. The approximate location of each system is shown by number (column 2 of tabulation) on the attached Duke Power Company transmission map (page 9-4).

3/ Systems not in the same holding company system.

ADJACENT NON-AFFILIATED SYSTEMS

	Ident. No.	Load Mw	Annual Load Growth %	Generating Capacity Mw	Largest Thermal Unit Mw	Minimum Reserve Criteria
South Carolina Electric & Gas Company	1	1,600	Unknown	1,863	385.000	Unknown
South Carolina Public Service Authority	2	650	Unknown	860	160.000	Unknown
Carolina Power & Light Company	3	3,400	Unknown	3,240	700.000	Unknown
Yadkin, Incorporated	4	195	Fixed Industrial Load	201	0	Supplied by Adjacent Utilities or by load reduction
Nantahala Power & Light Company	5	Unknown	Unknown	2.245	0	Not available
Lockhart Power Company	6	36.080	4.9	17.300	0	Depends on supplier
Southeastern Power Administration	7	Unknown	Unknown	544.000	0	Not available
Heath Springs Light & Power Company	8	1.620	4.5	0	0	Depends on supplier
The Electric Company	9	3.464	8.8	0	0	Depends on supplier
City of Albemarle	10	27.648	7.8	0	0	Depends on supplier
Town of Bostic	11	.600	Unknown	0	0	Depends on supplier
Town of Cherryville	12	4.620	5.9	0	0	Depends on supplier
Concord Board of Water & Lights	13	35.200	8.4	0	0	Depends on supplier
Town of Cornelius	14	1.176	6.3	0	0	Depends on supplier
Town of Dallas	15	4.260	8.5	0	0	Depends on supplier
Town of Davidson	16	2.808	6.9	0	0	Depends on supplier
Town of Drexel	17	1.648	7.7	0	0	Depends on supplier
Town of Forest City	18	7.488	6.9	0	0	Depends on supplier
City of Gastonia	19	55.248	9.8	0	0	Depends on supplier
Town of Granite Falls	20	3.744	8.9	0	0	Depends on supplier
City of High Point	21	64.800	8.8	0	0	Depends on supplier
City of Huntersville	22	1.440	7.8	0	0	Depends on supplier
City of Kings Mountain	23	9.630	8.0	0	0	Depends on supplier
Town of Landis	24	4.080	6.9	0	0	Depends on supplier
City of Lexington	25	40.662	8.1	0	0	Depends on supplier
Town of Lincolnton	26	6.804	4.9	0	0	Depends on supplier
Town of Maiden	27	5.220	11.3	0	0	Depends on supplier
City of Monroe	28	31.752	12.9	0	0	Depends on supplier
City of Morganton	29	23.220	10.0	0	0	Depends on supplier
City of Newton	30	7.776	7.4	0	0	Depends on supplier
Town of Pineville	31	1.968	9.1	0	0	Depends on supplier

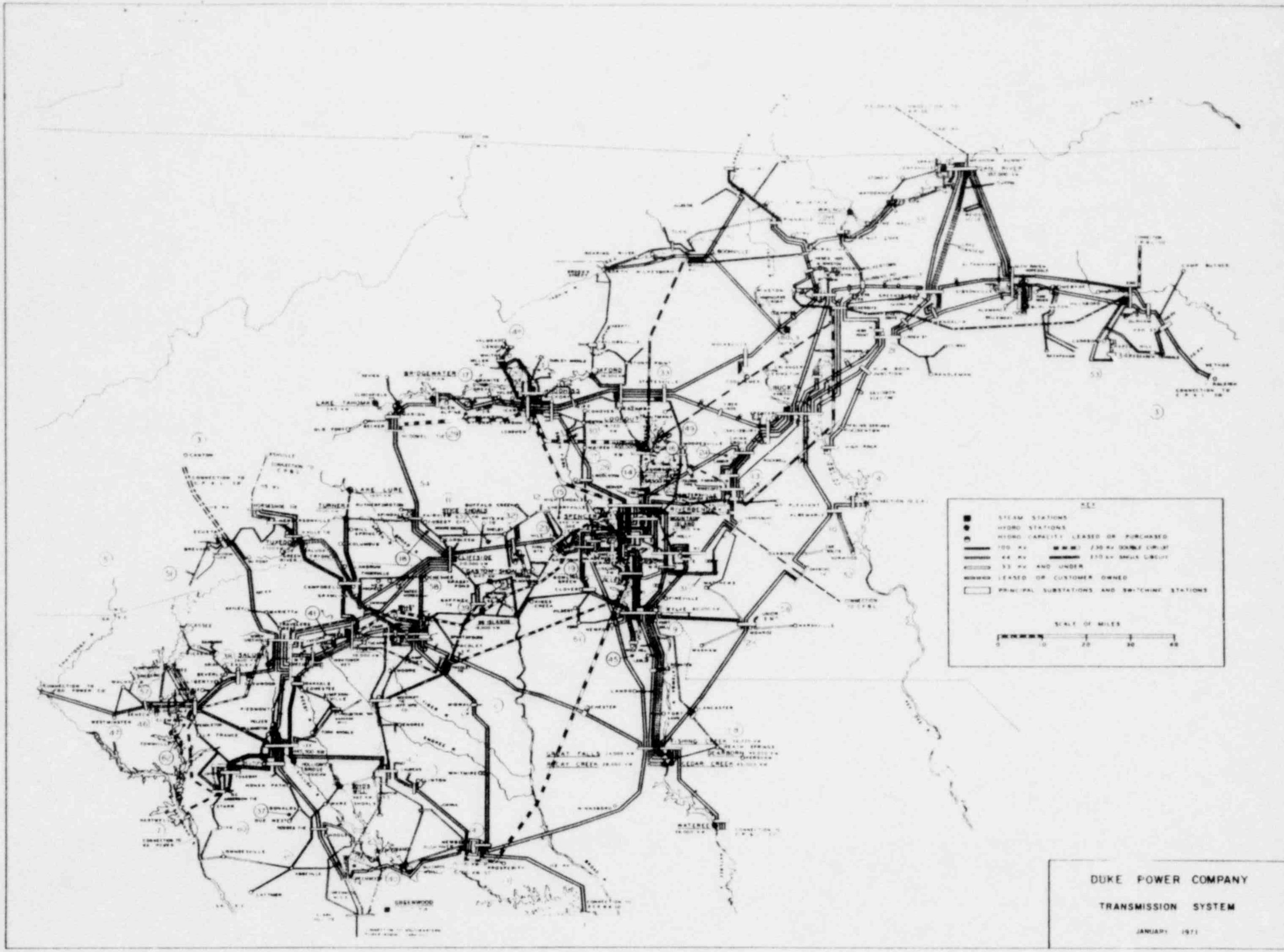
ADJACENT NON-AFFILIATED SYSTEMS

	Ident. No.	Load Mw	Annual Load Growth %	Generating Capacity Mw	Largest Thermal Unit Mw	Minimum Reserve Criteria
City of Shelby	32	22.122	6.2	0	0	Depends on supplier
City of Statesville	33	45.360	7.6	0	0	Depends on supplier
University of North Carolina	34	41.760	16.2	12.500	10.000	Depends on supplier
Abbeville Water & Electricity	35	5.880	Unknown	3.924	1.192	Depends on supplier
City of Clinton	36	13.329	12.9	0	0	Depends on supplier
Town of Due West	37	1.296	6.4	0	0	Depends on supplier
City of Easley	38	17.495	8.1	0	0	Depends on supplier
Commissioners of Public Works, Gaffney, S C	39	14.256	9.3	0	0	Depends on supplier
Commissioners of Public Works, Greenwood, S C	40	24.200	11.2	0	0	Depends on supplier
Commissioners of Public Works, Greer, S C	41	15.200	5.2	0	0	Depends on supplier
Commissioners of Public Works, Laurens, S C	42	10.912	7.2	0	0	Depends on supplier
City of Newberry	43	12.150	9.9	0	0	Depends on supplier
Town of Prosperity	44	.960	5.2	0	0	Depends on supplier
City of Rock Hill	45	42.360	9.2	0	0	Depends on supplier
Town of Seneca	46	9.072	8.6	0	0	Depends on supplier
Commissioners of Public Works, Westminster, S C	47	2.916	3.2	0	0	Depends on supplier
Blue Ridge E.M.C.	48	7[illegible].884	9.3	.175	0	Depends on supplier
Crescent E.M.C.	49	44 606	10.6	0	0	Depends on supplier
Davidson E.M.C.	50	27.566	10.7	0	0	Depends on supplier
Haywood E.M.C.	51	3.[illegible]50	16.6	0	0	Depends on supplier
Pee Dee E.M.C.	52	2.539	14.8	0	0	Depends on supplier
Piedmont E.M.C.	53	10.924	10.8	0	0	Depends on supplier
Rutherfordton E.M.C.	54	48.580	12.9	0	0	Depends on supplier
Surry-Yadkin E.M.C.	55	19.440	9.1	0	0	Depends on supplier
Union E.M.C.	56	31.426	8.8	0	0	Depends on supplier
Blue Ridge Electric Cooperative	57	34.463	9.8	0	0	Depends on supplier
Broad River Electric Cooperative	58	10.920	12.2	0	0	Depends on supplier
Laurens Electric Cooperative	59	23.948	15.5	0	0	Depends on supplier
Little River Electric Cooperative	60	8.805	17.9	0	0	Depends on supplier
York Electric Cooperative	61	17.878	12.1	0	0	Depends on supplier
Clemson University	62	11.520	9.5	0	0	Depends on supplier

Notes:

1. Growth rates for Lockhart Power Company, Heath Springs Light & Power Company, The Electric Company, Clemson University, Municipal Systems, Coop. Systems and Univ. of N. C. based on deliveries from Duke Power Company. Loads for these same systems are also based on metered demands of Duke deliveries.
2. Loads, Generating Capacity and Largest Thermal Units shown for SCE&G Co, SCPSA and CP&L Co are Duke estimates.

3/17/71



DUKE POWER COMPANY

TRANSMISSION SYSTEM

JANUARY 1971

Question No. 10:

List separately those systems in Item 9 which purchase from applicant (a) all bulk power supply and (b) systems which purchase partial bulk power supply requirements. Where information is available to applicant, identify those Item 9 systems purchasing part or all of their bulk power supply requirements from suppliers other than applicant.

Answer:

(1) Systems which purchase all bulk power supply from Duke Power Company:

The Electric Company
Heath Springs Light & Power Company
City of Albemarle
Town of Cherryville
Concord Board of Water & Lights
Town of Cornelius
Town of Dallas
Town of Davidson
Town of Forest City
City of Gastonia
Town of Granite Falls
City of Huntersville
City of Kings Mountain
Town of Landis
Surry-Yadkin E.M.C.
Town of High Point
City of Lexington
Town of Lincolnton
Town of Maiden
City of Monroe
City of Newton
Town of Pineville
City of Shelby
City of Statesville
Clemson University
City of Clinton
Town of Seneca
Commissioners of Public Works, Westminster, S. C.
Davidson E.M.C.
Town of Due West

(2) Systems which purchase partial bulk power requirements:

Piedmont E.M.C.
Lockhart Power Company
S. C. Electric & Gas Company
Yadkin, Inc.
Town of Bostic
Town of Drexel
City of Morganton
University of North Carolina
Abbeville Water and Electricity
City of Easley
Commissioners of Public Works, Gaffney, S. C.
Commissioners of Public Works, Greenwood, S. C.
Commissioners of Public Works, Greer, S. C.
Town of Prosperity
City of Rock Hill
Blue Ridge E.M.C.
Crescent E.M.C.
Haywood E.M.C.
Pee Dee E.M.C.
Rutherfordton E.M.C.
Union E.M.C.
Blue Ridge Electric Cooperative
Broad River Electric Cooperative
Laurens Electric Cooperative
Little River Electric Cooperative
York Electric Cooperative
Commissioners of Public Works, Laurens, S. C.

All systems in tabulation (2) except Lockhart Power Company, SCE&G, and Yadkin, Inc., purchase a part of their bulk power supply from SEPA. The Haywood, Piedmont, and Pee Dee E.M.C's and the Broad River, Little River, and Blue Ridge Electric Coops also purchase a part of their requirements from suppliers other than SEPA and Duke Power. SCE&G, through reserve equalization with Duke, CP&L, and VEPCO and under a reserve exchange contract with SCPSA has purchased power at various times. Yadkin, Inc., is interconnected with CP&L and has purchased from that company. CP&L, also through reserve equalization has purchased power at various times. SCPSA purchases a part of its supply.

Question No. 11:

State as to all power generated and sold by applicant the most recent average cost of bulk power supply experienced by applicant (a) at site of generating facilities, (b) at the delivery points from the primary transmission (backbone) system, (c) at delivery points from the secondary transmission system, and (d) at delivery points from the distribution system, in terms of dollars per kilowatt per year, in mills per kilowatt-hour, and in both the kilowatt costs and kilowatt hour costs divided by the kilowatt hours. If wholesale sales are made at varying voltages, indicate average cost at each voltage.

Answer:

The information requested in Item 11 requires a fully distributed cost of service study, which Duke Power Company has never made or had made for it. However, Duke Power Company has such a cost of service study underway, being conducted by Commonwealth Services, Inc., an independent public utility consulting firm. It is estimated that this study will be completed by the end of 1971. Duke Power Company is under orders to file the study with the North Carolina Utilities Commission when it is completed.

Commonwealth Services, Inc., has made a cost allocation of the Company's cost of service between wholesale and retail customers, and the same is on file with the Company's application for a wholesale rate increase, now pending before the Federal Power Commission in Docket No. E-7557.

Duke Power Company's cost (as of December 31, 1969) of its generation and bulk transmission system is set forth in Duke Power Company Rate Schedule F.P.C. No. 10, Service Schedule C, Limited Term Power and Energy, Appendix A; a copy of which is included as a continuation of the answer to Question No. 11.

SERVICE SCHEDULE C

LIMITED TERM POWER AND ENERGY

Section 1 - Duration

1.1 This Service Schedule, a part of and under an agreement dated June 1, 1961, between Duke Power Company and Carolina Power & Light Company, shall become effective September 1, 1970, and shall continue in effect for an initial period ending April 30, 1973, and thereafter until terminated as provided for in Section 1.2 below.

1.2 Either party upon at least three years' prior written notice to the other party may terminate this schedule at the expiration of said initial period or thereafter.

Section 2 - Power and Energy Delivery

2.1 Either party by giving the other party notice may reserve electric power (herein called Limited Term Power) for yearly periods, or for shorter periods where the availability of Limited Term Power depends upon the in-service dates of new generating equipment or by mutual agreement, in such amounts and at such times as the other party may have and is willing to make available as Limited Term Power.

2.2 If the party receiving the request for Limited Term Power does not have it available from its own resources, it may, if requested, arrange to purchase Limited Term Power from a third party for resale to the party making the request, under the terms specified in Section 3.

2.3 To reserve Limited Term Power, the party desiring such power

Question 11-2

shall specify in its notice to the other party the number of kilowatts and the period for which it desires to reserve such power. The party receiving such notice shall signify the amount and period of time it is willing to make such power available. All notices and acceptances shall be in writing and signed by officers of the companies, and these notices and acceptances shall constitute binding agreements between the parties under the terms of this service schedule.

2.4 During the period that Limited Term Power has been contracted for as provided in Section 2.3 above, the party which agreed to supply such power shall deliver electric energy (herein called Limited Term Energy) to the other party upon call and in amounts up to the number of kilowatts contracted for. However, in the event of breakdown or other emergency conditions on the system of the supplying party resulting in loss of generating capacity in excess of 25% of the rated capacity of its largest generating unit, the supplying party may reduce the rate of delivery of such energy under that portion of Limited Term Power being made available from its own generation sources in the ratio that the total amount of capacity so lost bears to the rated capacity of its largest generating unit. The delivery of energy under that portion of Limited Term Power being made available from its own generation sources may be discontinued when the largest generating unit (or the newest of such largest units if there are more than one of identical size) on the system of the supplying party is out of service for scheduled maintenance. If a portion of the Limited Term Power contracted for hereunder is purchased by the supplying party from a third party for resale to the receiving party, and that portion is interrupted or reduced by the third party under provisions similar to those outlined above, then the supplying party may interrupt or reduce its deliveries to the receiving company by like amounts.

2.5 Subject to the provisions of Section 2.4, the supplying party will deliver Limited Term Power in accordance with schedules designated by the receiving party.

2.6 The losses associated with the transmission of capacity and energy under this agreement, either on the system of the supplying party, or on the system of a third party which may be supplying Limited Term Power to the supplying party hereunder for resale to the receiving party, will be borne by the receiving party. Compensation for such losses will be accomplished by scheduling coincidental delivery of loss compensation.

Section 3 - Rates and Charges

3.1 For capacity purchased from a third party by the supplying party for resale to the receiving party hereunder, the receiving party will pay the supplying party a rate per kilowatt equal to the rate per kilowatt paid to the third party by the supplying party. For capacity made available from the system of the supplying party, the purchasing party will pay the supplying party a rate per kilowatt equal to the Annual Demand Charge Rate calculated for the system of the supplying party in accordance with the formula set forth in Appendix A to this Agreement. The Demand Charge Rate will be calculated as of December 31, 1969, and December 31 of each calendar year thereafter when Limited Term Power is being sold. The initial Demand Charge Rate shall be effective during 1970, and thereafter the Demand Charge Rate for each calendar year shall become effective as of January 1, subject to recalculation in 1970 and subsequent years upon the occurrence of any of the following incidents (such recalculation to be made as of the date of each incident, except that initial billing may be on an estimated basis subject to adjustment when final accounting becomes available):

(a) A new generating unit is placed in service or an existing unit is retired on the system of the supplying party;

(b) A new transmission facility of sufficient size as to affect the Annual Demand Charge rate is placed in service on the system of the supplying party;

(c) A change occurs in the status of a transmission facility on the system of the supplying party which would affect the Annual Demand Charge rate; or

(d) A new issue of bonds or preferred stock is made, or an outstanding issue of bonds or preferred stock is retired on the system of the supplying party.

It is intended that changes in (a) above involving major units will be made effective as of the first day of commercial operation of the unit involved. Changes involving internal combustion turbine generators or small steam or hydro units of 25,000 KW or less may, at the option of the owning party be made effective as of the first of the month next following the date of commercial operation or the date of retirement, for purposes of calculating Annual Demand Charge rates hereunder. Payment for capacity shall begin with the initial date of the period of delivery and shall continue until the terminal date of such period of delivery, without any adjustment for periods when the delivery of energy is interrupted as provided in Section 2.4 above.

3.2 When energy delivered hereunder is generated on the system of the supplying party, the receiving party will pay for such energy at a rate per kilowatt-hour calculated as follows:

(a) For the 12-month period ending April 30, 1971, and for periods subsequent to April 30, 1973, the calculated average production cost (including operating and maintenance costs) of the energy produced by all plants on the system of the supplying party for the month in which the delivery is being billed, plus 10% of such average cost.

(b) For the periods from May 1, 1971, through April 30, 1973, two rates as follows: (i) the calculated average production cost (including operation and maintenance costs) of the energy produced by those I-C turbine generators scheduled for 1971 installation which have been installed and made available for use hereunder on the system of the supplying party, plus 10% thereof, and (ii) the calculated average production cost (including operating and maintenance costs) of the energy produced by all other units on the system of the supplying party, plus 10%, for the month in which the delivery is being billed. The amount of energy to be billed under (i) above will be the amount of energy generated on the I-C turbine generators in (i) as a result of the delivery of Limited Term Energy hereunder. The amount of energy to be billed under (ii) above will be the excess, if any, of total Limited Term Energy delivered during the month over the amount billed in (i) above. Billing each month will be on an estimated basis, subject to adjustment when all production costs for the billing month are available. If a party is selling Limited Term Power to more than one company at the same time, the amount of energy to be billed under (i) will be prorated between the purchasers of such energy in the ratio of the amounts of Limited Term Energy delivered to each during the time in which the proration is being made.

When energy delivered hereunder is purchased from a third party by the supplying party for resale to the receiving party, the receiving party will pay the supplying party at a rate equal to the cost of such energy per kilowatt-hour plus 10%.

3.3 Where applicable, taxes will be added to billings under Sections 3.1 and 3.2, including but not limited to:

Support of South Carolina Public Service Commission

Sales Tax or Energy Gross Receipts Taxes

Sales Tax or Use Tax or Fuel

South Carolina Generation Tax

Any new or additional applicable taxes imposed after the date of this Service Schedule shall be included in billings hereunder.

APPENDIX A
GENERAL EXPLANATION
OF
DETERMINATION OF CAPACITY CHARGES
AND ENERGY CHARGES-LIMITED TERM
POWER SERVICE SCHEDULE

The selling company will invoice the buying company for capacity and energy used on or before the tenth day of the month, payable by the twentieth day of the month, for capacity and energy used in the preceding month. Cost will be estimated if not known and adjusted at a later date. The charges will be calculated as follows:

A. <u>Capacity (Fixed) Charge Calculation:</u>

1. The monthly demand charge is the sum of one-twelfth of the annual production capacity charge and the annual transmission capacity charge.

2. The annual capacity charges will be calculated always as of the previous year end and recomputed during year whenever either a generating unit is placed in service or retired, or transmission facility of sufficient size as to affect the annual demand charge rate, is placed in service or retired, or whenever there is a new issue or retirement of long-term debt or capital stock. The annual capacity charges will be recomputed the first of the subsequent month of such incident, except in the case of a generating unit above 25,000 KW which shall require recomputation as of the date of such incident. At the time of any recomputation, the annual capacity charge rate shall be adjusted to reflect all additions and retirements of bulk transmission facilities, since the last previous computation.

3. The method of computing the annual production capacity charge per KW is to divide the sum of the production annual fixed charges, including return on investment, depreciation, income taxes, property and other taxes related to plant investment, and insurance, by the sum of all production plant capability, stated in KW, under the most adverse operating conditions (Major plants-FPC Form 1, pages 432 and 433, line 10, and small plants per company records).

4. The same procedure is used for computing the annual transmission capacity charge except that transmission O & M expense is included as a fixed charge and all transmission amounts are adjusted to eliminate (1) costs not associated with bulk transmission and (2) transmission investment currently being shared by former CARVA Pool members under termination agreement. Long-term firm purchase of KW capacity will be added to production capability determined under A. 3 above, to arrive at transmission charge per KW.

5. The annual fixed charges are computed or determined as follows:

5.1 <u>Return on Investment</u>
This item of annual fixed charge is computed by multiplying the total functional (Prod. & Trans.) investment by the latest embedded weighted composite cost of capital.

A. 5. (cont) 5.1.1. Investment

Investment consists of book plant balances in accounts 101-106 less accumulated depreciation (accounts 108-110) plus net nuclear fuel investment in plant account 120 and allocated portions of normal working capital, consisting of:

(a) Minimum bank balances in account 131.
(b) 60 Day production fuel supply in account 151.
(c) Other materials in accounts 154 and 163.
(d) 1/8 of all operating expenses for one year, except purchased power (accounts 500-557 less 555) for production and accounts 560-573 for transmission with both functions also being allocated a portion of A & G expense accounts 920-932).
(e) Federal income tax offset, consisting of an agreed percentage of the annual Federal provision in account 409, is deducted from other working capital item.

5.1.2. Composite Cost of Capital

Three costs of capital are computed: for long-term debt, preferred stock and common equity; and are weighted on basis of capitalization ratios, and summed to arrive at composite cost of capital. For bonds and preferred stock, weighted annual net cost to company is computed through most recent issue or retirement. For common equity, the sum of net earnings for common (excluding extraordinary items) for last three calendar years is divided by the sum of the daily weighted average common equity outstanding for the same three year period.

5.2 Depreciation - FPC Account 403

Depreciation will be calculated using depreciable plant balances (including a portion of general plant), and annual depreciation rates. When a production plant or transmission facility is added or retired, depreciation will be recomputed to account for the change.

5.3 Income Taxes

The income tax fixed annual charge is computed rather than allocating actual book amounts. The computation begins with the return on investment amount (Para. 5.1 above), deducts the tax deductible interest portion and, using the current composite Federal-State tax rate and making adjustments for differences between book and tax depreciation, computes what the income tax would be, assuming the return on investment previously computed.

5.4 Property and Other Taxes Related to Plant Investment-FPC Account 408

Taxes directly assignable to production plant are identified and remaining plant taxes are allocated on basis of gross book plant (accounts 101-106) with the general plant allocated portion further allocated to remaining functions on same basis.

A. 5 (Continued)

5.5 Insurance - FPC Account 924

Total insurance expense is assigned directly where possible with the balance allocated on basis of plant investment.

5.6 Transmission O & M Expense

This item is used only in computing the transmission capacity charge and consists of the last annual transmission O & M expense (accounts 560-573) increased by a percentage for A & G expense and payroll taxes and reduced by the portion applicable to non-bulk transmission plant.

6. The resulting production and transmission capacity rates per KW are multiplied by contracted KW to calculate the capacity charges for the month.

B. Energy Charge Calculation

1. The monthly energy charge is based on the actual production cost per net KWH of the selling company for the month in which the energy is sold.

2. The following costs will be used to calculate the energy charge rate:

   a. FPC accounts 500-557 excluding purchased power (account 555).

   b. An allocated portion of Administrative & General expense (excluding insurance) and payroll taxes.

3. The KWH net generation will be the net generation for all production plants with exceptions noted in the contract.

4. The monthly production cost, as stated in 2 above, will be divided by the KWH net generation as stated in 3 above. To the results will be added the 10% specified in the agreement.

5. The resulting rate per KWH, as calculated in 4 above, will be multiplied by the KWHrs of energy delivered by the selling company to calculate the total energy charge for the month.

C. Applicable Taxes

Applicable taxes not provided for elsewhere, in the capacity charge calculation or the energy charge calculation, will be included in the bill by the selling company.

Question 11-10

LIMITED TERM POWER SERVICE SCHEDULE______ I

Duke Power Selling Company

________________ Buying Company

Month of ________________

Line No.		Reference (1)	(2)	(3)	Total (4)	Account Numbers Selling Co. (5)	Buying Co. (6)
	CAPACITY CHARGES:						
	Production:						
1	KW						
2	Cost/KW	(Sch.II)					
3	Cost	(1 x 2)					
4	Applicable taxes	(Note A)					
5	Total Production	(3 + 4)			$	447	555.1
	Transmission:						
6	KW						
7	Cost/KW	(Sch.II)					
8	Cost	(6 x 7)					
9	Applicable taxes	(Note B)					
10	Total Transmission	(8 + 9)			$	454	567
11	Total Capacity Charge	(5 + 10)			$		
	ENERGY CHARGE:						
12	KWH Sold						
13	Cost/Kwh	(Sch.III					
14	Cost	(12 x 13)					
15	Applicable taxes	(Note C)					
16	Total Energy	(14 + 15)			$	447	555.1
17	Total Invoice	(11 + 16)			$		

Note: Reference and explain taxes on lines 4, 9, 15 below:

Question 11-11

LIMITED TERM POWER SERVICE SCHEDULE ______

Duke Power Company

CALCULATION OF FIXED CHARGES
as of 12-31-69

Line No.		Production Reference (1)	Production Amount (2)	Transmission Reference (3)	Transmission Amount (4)
1	Return on investment	A	30 002 850	A	11 692 034
2	Depreciation	B	17 947 741	B	5 518 494
3	Income taxes	C	18 999 920	C	7 493 285
4	Property taxes	D	4 640 023	D	1 958 660
5	Insurance	E	185 086	E	20 745
6	Operating and maintenance expense		——	F	5 491 950
7	Annual fixed charges		71 775 620		32 175 168
8	Net continuous plant capability - KW	G	5 769 269	G	5935644
9	Capacity charge/KW year (line 7 ÷ 8)		12.4410		5.4207
10	Monthly capacity charge/KW (Line 9 ÷ 12)		1.0368		.4517

Question 11-12

LIMITED TERM POWER SERVICE SCHEDULE

Duke Power Company

ENERGY CHARGE

Line No.		FPC I Reference	Month of Jan 1970 * (1)
	Steam		
1	Operation (500-507, excluding fuel)	p.417, line 12	606293
2	Maintenance (510-514)	p.417, line 19	402083
	Nuclear		
3	Operation (517-525, excluding fuel)	p.417, line 32	-0-
4	Maintenance (528-532)	p.417, line 39	-0-
	Hydraulic		
5	Operation (535-540)	p.417, line 49	140331
6	Maintenance (541-545)	p.418, line 5	52500
	Other Power		
7	Operation (546-550, Excluding fuel)	p.418, line 14	3672
8	Maintenance (551-554)	p.418, line 20	3875
	Other Power Supply Expense (Excluding Purchased Power)		
9	System control and load disp.	p.418, line 24	-0-
10	Other expenses	p.418, line 25	-0-
11	Total (Lines 1 thru 10)		1208754
12	Add 37.28% Line 11 (See Sch. IIIa)		450623
	Fuel		
13	Steam		8980067
14	Nuclear		-0-
15	Other		1046689
16	Total (Lines 11 thru 15)		11,686133
17	KWH Net Generation	p.43', line 9	3175029
18	Production Cost per Net KWH (line 16 ÷ 17)		.00368064
19	Add 10% (110% of line 18)		.00404870

* Exclude all cost from this schedule which can reasonably be expected to be received as claims from insurance companies and vendors.

Question 11-13

LIMITED TERM POWER SERVICE SCHEDULE ________

Duke Power Company

Calculation of Allocation Percent for A & G Expense,
Payroll Taxes, etc.

Calendar Year 1969

Line No.		FPC Form 1 Reference	(1)
1	Adm. and Gen. Expense	Page 419 Line 53	15 281 989
2	Less Insurance	Page 419 Line 42	(215253)
3	Add All Fed. & State Payroll Taxes	Page 352	1 659 044
4	Total A & G and PR Taxes		# 16 725 780
5	Total O & M Expense	Page 419 Line 54	162 404 295
	Less:		
	Fuels Excluded;		
6	Steam - Acct. 501	Page 417, Line 5	(86 010 523)
7	Nuclear - Acct. 518	Page 417, Line 24	(-0-)
8	Other - Acct. 547	Page 418, Line 10	(5124584)
9	A & G Expense (Line 1 above)		(15281989)
10	Purchased Power	Page 418 Line 23	(11127192)
11	Balance O & M (Line 5 less 6 - 10)		44 860 007
12	Allocation Percent (Line 4/Line 11)		37.28%

Question 11-14

LIMITED TERM POWER SERVICE SCHEDULE________

Duke Power COMPANY

Return on Investment

as of 12-31-69

Line No.		Production Reference Sch.	Line	Col.	Amount (1)	Transmission Reference Sch.	Line	Col.	Amount (2)
	Gross Plant in Service:								
1	Electric	A-1	6	5	586257696	A-3	7	2	203622149
2	Electric-Nuc.fuel-net	A-7	4	5	-0-			-0-	
3	Less: Accum. depr.	A-1	17	5	(229188027)	A-3	15	2	(56271300)
4	Net plant in service				357,069669				147350849
	Materials and Supplies:								
5	Non - Fuel	A-4	21	1	6230599	A-4	23	2	5467605
6	Fuel	A-5	30	2	16150041				-0-
	Working Capital:								
7	Minimum bank balance	A-6	3	2	4976191	A-6	5	3	1728888
8	1/8 Oper.expense	A-6	15	2	13991703	A-6	17	3	649484
9	Fed. Inc.tax offset	A-6	20	2	(1535112)	A-6	22	3	(540296)
10	Total Investment				396863091				154656530
11	Composite cost of cap.	A-8	4	5	7.56%	A-8	4	5	7.56%
12	Return on Investment	(11 times 10)			30002850				11692034

LIMITED TERM POWER SERVICE SCHEDULE

Duke Power Company

Cost of Plant and Accumulated Depreciation

As of 12-31-69

Line No.	Description		FPC Page	1 Ref.	Balance as of 12/31/69 (1)	Subsequent Transactions (2)	Revised Balance (3)	General Plant Allocation (Sch. A-2) (4)	Total (1)+(2)+(4) (5)	% of Total Col. 5 (6)
	Cost of Plant (Accts. 101-106)									
1	Production: Steam		401		448360401		448360401			
2	Nuclear		401							
3	Hydro		401		101745887		101745887			
4	Internal Comb.		402		21729935		21729935			
5										
6	Total Production		402		571836223		571836223	14421473	586257691	41.18 %
7	Transmission		402		265866855		265866855	3886744	269753599	18.95
8	Distribution		403		548464131		548464131	19208621	567672752	39.87
✓ 9	General, Com., Intang.	(Sch. A-2)			37516838		37516838	(37516838)	-0-	-0-
10	TOTAL (6 - 9)				1423684047		1423684047	-0-	1423684047	100.00 %
	ACCUMULATED DEPRECIATION (Accts. 108, 109, 110)									
11	Production: Steam		408		183765334		183765334			
12	Nuclear		408							
13	Hydro-Conventional		408		40352876		40352876			
14	Hydro-Pomp. Stor.		408							
15	Internal Comb.		408		1484869		1484869			
16										
17	Total Production		408		225603079		225603079	3584748	229188027	-
18	Transmission		408		73169827		73169827	966183	74136010	-
19	Distribution		408		143595061		143595061	4774956	148370017	-
20	General, Common, etc.	(Sch.A-2)			9326087		9326087	(9326087)	-0-	-
✓ 21	TOTAL (17 - 20)				451694054		451694054	-0-	451694054	-

Question 11-16

LIMITED TERM POWER SERVICE SCHEDULE

Duke Power Company

General, Common, Intangible Plant Allocation
as of 12-31-69

Page	Description	Reference	Total	Production	Transmission	All Other
			(1)	(2)	(3)	(4)
	Plant	FPC 1				
1	General Plant	P.403	37516838			
	Common plant (elec.portion)	P.351B	-0-			
3	Intangible plant (elec.portion)	P.401	-0-			
	Total (lns. 1-3)		37516838			
5	Allocate on basis of Line 19 below		37516838	14421473	3886744	19208621
	Depreciation Reserve	FPC 1				
	General	P.408	9326087			
7	Common	P.351B	-0-			
	Total (lns. 6-7)		9326087			
9	Allocate on basis of Line 19 below		9326087	3584948	966183	4774956
	Non-Depreciable or Clearing Account Depreciable Plant	FPC 1				
0	Auto and trucks	P.403	3706891			
	Other Gen.Non-Depr.	P.403	2522468			
2	Common Non-Depr.	P351B	-0-			
	Other, if any		1268878			
4	Total (lns. 10-13)		7498237			
	Allocate on basis of Line 19 below		7498237	2882322*	776817*	3839098
	Allocation Basis-Electric O&M Salaries Other Than A&G	FPC 1 P355	Ln.25	Ln. 19	Ln. 20	25-(19&20)
16	Total O & M Salaries		34083701	10320294	2782417	20980490
	Less A & G (FPC 1, P355, Ln.24)		7232484	-0-	-0-	7232484
	Balance		26851217	10320294	2782417	13748506
	% of Total - Ln 18		100.00%	38.44 %	10.36 %	51.20 %

* Use on Schedule B, Col. 2, Lines 7 and 10.

Question 11-17

LIMITED TERM POWER SERVICE SCHEDULE

Duke Power Company

Transmission Plant

As of 12-31-69

Line	Description	(1)	(2)
	Plant Investment		
1	Balance (Sch. A1, Ln.7, Col.5)	269753599	
2	Less Non-bulk Transmission Plant (24 %)	64740864	
3	Bulk Transmission (Ln. 1 - Ln. 2)		205012735
4	Plant currently being shared by former CARVA Pool members under termination agreement (attach listing as A-3-a)	2,279649	
5	Former members' applicable percent	61 %	
6	Less former members' portion (Ln.4 x Ln.5)		1390586
7	Gross bulk Transmission Plant (Ln.3-Ln.6)		203622149
8	Bulk Transmission % (Ln.7 ÷ Ln.1)(XX.X%)		75.5 %
	Depreciation Reserve		
9	Balance from Sch. Apl, Ln. 18, Col.5	74136010	
10	Less Non-bulk Transmission Reserve (24 %)	17792642	
11	Bulk Transmission (Ln.9 - Ln.10)		56343368
12	Accumulated Reserve applicable to Investment on Ln.4 above (Sch. A-3-a)	118144	
13	Former members' applicable percent	61 %	
14	Less-Former members' portion (Ln.12 x Ln.13)		72068
15	Bulk Depreciation Reserve (Ln. 11 - Ln. 14)		56271300

Question 11-18

Limited Term Service Schedule
Duke Power Company
Transmission Plant

Plant Currently Being Shared by Former Pool Members Under Termination Agreement

Autotransformer bank breaker - Wateree	$ 25,449
Autotransformer - Dan River	288,646
Autotransformer - Davidson River	145,131
Autotransformer - Newberry	252,288
Eno to Roxboro	568,110
Skyland to Hendersonville	1,000,025
	$2,279,649

Accumulated Reserve Applicable to Above Plant Investment

Autotransformer bank breaker - Wateree	$ 2,038
Autotransformer - Dan River	22,341
Autotransformer - Davidson River	10,145
Autotransformer - Newberry	15,137
Eno to Roxboro	26,880
Skyland to Hendersonville	41,603
	$ 118,144

LIMITED TERM POWER SERVICE SCHEDULE

Duke Power Company

Materials and Supplies

(Excluding Fuel)

Date 12-31-69

Line No.	Warehouse Location or Class of Material	Reference or Allocation	Production (1)	Transmission (2)	Other (3)	Total (4)
1	Retail Districts				2581940	2,581,940
2	Warehouses 8300 + 191				253681	253,681
3	Trans warehouses			489891		489891
4	Central Whse (60% Trans			5696903	3797936	9494839
5	Steam plants		5735617			5735617
6	Hydro plants		293107			293107
7	Whse 193			459329	13513	472842
8	Loc 2502			14675	14816	29491
9	Water + Transit				222400	222400
10	Reels + Drums		7166	354173	26952	388291
11						
12						
13						
14						
15						
16	Total Account 154	FPC P207	6035890	7015571	6911238	19,962,699
17	Merchandise - Acct. 155	FPC P207	—	—	1320,295	1320295
18	Total	(16 + 17)	6035890	7015571	8231533	21282994
19	% of Total - Line 18		28.36%	32.96%	38.68%	100.00%
20	Stores Expense (163)	(Line 19)	194709	226290	265561	686560
21	Total	(18 + 20)	6230599	7241861	8497094	21969554
22	% Bulk Transmission	(A-3)		75.5%		
23	Bulk Transmission			5467625		

Question 11-20

LIMITED TERM POWER SERVICE SCHEDULE

Duke Power Company

Materials and Supplies
(Excluding Fuel)

Date 12-31-69

Line No.	Warehouse Location or Class of Material	Reference or Allocation	Production (1)	Transmission (2)	Other (3)	Total (4)
1	Retail Districts				2581940	2,581,940
2	Warehouses 8300 + 191				253681	253,681
3	Trans warehouses			489891		489,891
4	Central Whse (60% Trans			5696903	3797936	9,494,839
5	Steam plants		5735617			5,735,617
6	Hydro plants		293107			293107
7	Whse 193			459329	13513	472842
8	Loc 2502			14675	14816	29491
9	Water + Transit				222400	222400
10	Reels + Drums		7166	354773	26952	388891
11						
12						
13						
14						
15						
16	Total Account 154	FPC P207	6035890	7015571	6911238	19,762,659
17	Merchandise - Acct. 155	FPC P207	—	—	1320275	1320275
18	Total	(16 + 17)	6035890	7015571	8231533	21282994
19	% of Total - Line 18		28.36%	32.96%	38.68%	100.00%
20	Stores Expense (163)	(Line 19)	194709	226290	265561	686560
21	Total	(18 + 20)	6230599	7241861	8497094	21969554
22	% Bulk Transmission	(A-3)		75.5%		
23	Bulk Transmission			5467625		

Question 11-21

LIMITED TERM POWER SERVICE SCHEDULE________

Duke Power Company

Fuel Stock

As of 12-31-69

Line	Description				Fuel 60-Day Supply	Amount
	Steam Plants - Name:				(1)	(2)
1	Marshall				676 020	
2	Allen				569 640	
3	Lee				150 240	
4	Dan River				118 680	
5	Cliffside				76 200	
6	Riverbend				241 380	
7	Buck				177 480	
8	Tiger				—	
9	Buzzard Roost				7 800	
10						
11	Total - Tons Coal				2 017 440	
12	Average System Price ($/Ton)*				$7.65	
13	Amount - Coal (Ln.11 x Ln. 12)				-0-	15 433 416
					Normal Oil Supply (Bbls)	
14						
	Total Bbls. Oil - Steam Plants					
18	Average System Price ($/Bbl) *					
19	Amount - Oil - Steam Plants (17 x 18)				-0-	-0-
	Other Production: (Use Storage Capacity)					
20	Lee				16 881	
21	Dan River				24 190	
22	Riverbend				100 000	
23	Urquhart				21 429	
24						
25						
	Total - Bbls. Oil - Other Prod.				162 500	
	Average System Price ($/Bbl)*				$4.41	
29	Amount - Oil - Oth.Production (27x 28)				-0-	716 625
30	Total Fuel Stock (Lns. 13 + 19 + 29)					16 150 041

*Use year-end average for calendar year studies or previous month's average when revised for addition of new generating unit.

Question 11-22

LIMITED TERM POWER SERVICE SCHEDULE______

Duke Power Company

Working Capital

12-31-69

Year

Line	Description	Total	Production	Transmission	Other
		(1)	(2)	(3)	(4)
1	Minimum Bank Balances:	12,084,000			
2	Allocation % (A1, Col.6)	100.00%	41.18 %	18.95 %	39.87 %
	Allocated amounts (Ln.2 x Total)	12,084,000	4976191	2289918	4817891
	Bulk Trans.% (A3, Ln. 8)			75.5%	
	Bulk Trans.Amount (Ln.3 x Ln.4)			1728888	
	1/8 Annual Operating Expense				
	Production-FPC 1, page 418, Ln.27)	117186421	117186421	-0-	-0-
	Transmission,FPC 1,P. 418, Ln.47)	5298737	-0-	5298737	-0-
	Distribution,FPC 1, P.419, Ln.18	14136711	-0-	-0-	14136711
	Customer Accounts, FPC 1,P. 419,Ln.26)	6701767	-0-	-0-	6701767
	Sales FPC 1,P.419, Ln.35	3798470	-0-	-0-	3798470
	A & G FPC 1,P.419, Ln.53				
	Allocated on basis of A2, Ln.18	15281989	5874397	1583214	7824378
	Total O&M,FPC 1, P. 419, Ln.54	162404295	123,060,818	6,881,951	32,461,526
	Less purchased power, P.418, Ln.23	(11127192)	(11127192)	-0-	-0-
	Totals (Ln.12 - Ln.13)	151277103	111,933,626	6881951	32461526
	1/8 of Line 14 totals		13991703	860244	4,057,691
	Bulk Trans.% (A3, Ln.8)			75.5 %	
	Bulk Trans. Amount			649484	
	Federal Income Tax Offset:				
	Provision for Current Fed. Electric Income Tax				
	(FPC 1, p. 114, Ln. 12)	25,175852	-0-	-0-	-0-
	Percent Offset *	15 %			
	Offset Amount (Ln.16 x Ln.17)	3776378	-0-	-0-	-0-
	Allocation % (A1, Col.6)	100.00%	41.18 %	18.95 %	39.87 %
	Allocated Amounts (Ln.19 x Total)	3776378	1555112	715624	1505642
	Bulk Trans.% (A-3, Ln.8)			75.5%	
	Bulk Trans.Amount (Ln.20 x Ln.21)			540296	

* Offset % will vary as agreed upon.

LIMITED TERM POWER SERVICE SCHEDULE

Duke Power Company

Nuclear Fuel

Line No.		Balance as of 12-31-69 (1)	Estimated (1) Additions (2)	Estimated (1) Deductions (3)	Balance 12/31/69 (4)	Average Balance (5)
1	Gross Investment (120.2,3,4)					
2	Accumulated Amortization					
3	Net Investment					
4	Average net investment					

(1) Adjust estimate after year end figures are known

LIMITED TERM POWER SERVICE SCHEDULE

Duke Power Company

Composite Cost of Capital

As of 12-31-69

Line No.	Description	Capitalization as of 12-31-69 Amount (1)	% Total (2)	Cost of Capital Reference (3)	% (4)		Composite Cost % (2) x (4) (5)	
1	Long-Term Debt	663750000	55.09	A-8-1 Line 20, Col. 7	5.108		2.81%	
2	Preferred Stock	155000000	12.86	A-8-2 Line 11, Col. 7	6.084		.78	
3	Common Equity	386189492	32.05	A-8-2 Line 16, Col. 7	12.401		3.97	
4	TOTAL	1204939492	100.00 %		-		7.56%	

Question 11-25

LIMITED TERM POWER SERVICE SCHEDULE ________

Duke Power Company

Cost of Debt Capital

as of 12-31-69

Line No.	Series		Principal Issued (1)	Debt. Disc. & Exp. or Prem.-Net (2)	Net Proceeds (3)	Coupon Rate (4) %	Net Cost to Company (5) (1)x(4)÷(3) X.XXX%	Outstanding as of (6)	Annual Cost (7) (6) x (5)
	First and Refunding Mortgage Bonds:								
1	3 % Series due	1-1-75	40 000 000		39920609	3.000	3.006	40000000	1 202 400
2	2.65% Series due	9-1-77	40 000 000		39928587	2.650	2.655	40000000	1 062 000
3	2 7/8% Series due	2-1-79	40 000 000		40145988	2.875	2.865	40 000 000	1 146 000
4	3 1/4% Series due	4-1-81	35 000 000		35 340 187	3.250	3.219	35 000 000	1 126 650
5	3 5/8% Series due	5-1-86	30 000 000		30 347006	3.625	3.584	30 000000	1 075 200
6	4 1/2% Series due	2-1-92	50 000 000		49 495 084	4.500	4.546	50 000 000	2 273 000
7	4 1/4% Series due	8-1-92	50 000 000		49 324 746	4.250	4.308	50 000 000	2 154 000
8	4 1/2% Series due	2-1-95	40 000 000		40 023 056	4.500	4.497	40 000 000	1 795 800
9	5 3/8% Series due	4-1-97	75 000 000		74 813 612	5.375	5.388	75 000 000	4 041 000
10	6 3/8% Series due	2-1-98	75 000 000		74 909 821	6.375	6.383	75 000 000	4 787 250
11	7 % Series due	2-1-99	75 000 000		73 778993	7.000	7.116	75 000 000	5 337 000
12	8 % Series due	9-1-99	75 000 000		74 622714	8.000	8.040	75 000 000	6 030 000
13									
14									
15									
16									
	Sinking Fund Debentures:								
17	4 7/8% Series due	1982	38,750 000		39 131688	4.875	4.827	38 750 000	1 870 463
18									
19	Total Long-Term Debt		663 750 000	1 967 909	661 782 091			663 750 000	33 903 763
20	Weighted Average Cost (Line 19, Col. 7/Line 19, Col. 6 - to 3 decimals)								5.108%

Question 11-26

LIMITED TERM POWER SERVICE SCHEDULE ________

Duke Power Company

Embedded Cost of Preferred and
Three Year Average Common Equity

12-31-69

Line No.	Embedded Cost of Preferred Series	Principal Issued (1)	Expense of Issue (2)	Net Proceeds (3) 1-2	Dividend Rate (4) %	Net Cost to Company (5) (1 x 4 ÷ 3) X.XXX%	Outstanding as of ____ (6)	Annual Cost (7) (5 x 6)
	Preference Stock:							
1	6.75% Conv. Series AA	50 000 000	804 839	49 195 161	6.75	6.860	50 000 000	3 430 000
2								
3								
	Preferred Stock:							
4	4.50% Series C	35 000 000	200 875	34 799 125	4.50	4.526	35 000 000	1 584 100
5	5.72% Series D	35 000 000	501 623	34 498 377	5.72	5.803	35 000 000	2 031 050
6								
7	6.72% Series E	35 000 000	489 163	34 510 837	6.72	6.815	35 000 000	2 385 250
8								
9								
10	Total Preferred Series	155 000 000	1 996 500	153 003 500			155 000 000	9 430 400
11	Weighted Average Cost (Line 10, Col. 7/Line 10, Col. 6, to 3% decimals)							6.084 %

Three Year Average Common Equity Cost

Line No.	Year	Daily Average Common Equity Reference	Daily Average Common Equity Amount	Earnings *
12	1967	A-8-3	344 083 085	42 679 694
13	1968	A-8-3	361 191 845	44 170 688
14	1969	A-8-3	377 711 408	47 447 496
15	TOTALS		1 082 986 338	134 297 878
16	Weighted Average Cost (Line 15, Col. 4/Line 15, Col. 2, to 3 decimals)			12.401 %

*After Preferred Dividends and Exclusive of Extraordinary Items

Question 11-27

LIMITED TERM POWER SERVICE SCHEDULE ________ A-8-3

Duke Power Company

Daily Weighted Average Common Equity

12-31-70

Line No.		Reference	1967	1968	1969
1	Common Equity - End of year	Form 1, p.111	353150366	369233323	386189492
2	Common Equity - Beginning of year	Form 1, p.111	335015803	353150366	369233323
3	Increase (Decrease)		18134563	16082957	16956169
4	Less public sale net proceeds		-0-	-0-	-0-
5	Public sale date		—	—	—
6	Normal change (ln. 3 - ln. 4)		18134563	16082957	16956169
7	One-half of normal change (50% ln. 6)		9067282	8041479	8478085
8	Daily pro-rata share of line 4 for no. of days outstanding (0 /365 x Ln. 4)		—	—	—
9	Average Daily Common Equity (lns. 2 + 7 + 8)		344083085	361191845	377711408

Question 11-28

LIMITED TERM POWER SERVICE SCHEDULE ________

Duke Power Company

Annualized Depreciation Expenses

as of 12-31-69

Line	Description	Plant Original Cost Balance (Al,col.3)	Less Non-Depreciable Amounts *	Depreciable Amount (1) - (2)	Weighted Composite Annual Rate (Form 1 P. 429	Annualized Depreciation Expense (3) x (4)
	Production Plant:	(1)	(2)	(3)	(4)	(5)
1	Steam	448 360 401	21 034 292	427 326 109	.0357	15 255 542
2	Nuclear					
3	Hydro - Conventional	101 745 887	10 293 115	91 452 772	.0150	1 371 792
4	Hydro -					
5	Other Prod. - Internal Comb	21 729 935	-0-	21 729 935	.0357	775 759
6	Other Prod. -					
7	General, Common, etc. Allocated to Prod. (Enter Col.1 from A2, ln.5, col.2)	14 421 473	2 882 322	11 539 151	.0472	544 648
8	Total Prod, (Sum, Col.5)	-0-	-0-	-0-	-0-	17 947 741
	Transmission Plant:					
9	Plant Cost (A-1, Col.3, Ln. 7)	265 866 855	17 169 807	248 697 048	.0288	7 162 475
10	General, Common, etc. Allocated to Trans. (Enter Col.1 from A2, Ln.5, col.3)	3 886 744	776 817	3 109 927	.0472	146 789
11	Total Trans. (Sum. Col.5)	-0-	-0-	-0-	-0-	7 309 264
12	Bulk Trans.% (Sch. A-3)					75.5 %
13	Bulk Trans. Amount (Ln. 11 x Ln. 12)					5 518 494

* For lines 7 and 10, tfr. non-depr. from Sch. A2, Line 14.

Question 11-29

LIMITED TERM POWER SERVICE SCHEDULE______

Duke Power Company

Income Taxes

Year 1970

Line No.		Production (1)	Transmission (2)
1	Return on investment (Sch. A)	30002850	11692034
2	Less: Interest on Long Term Debt (Sch.A, line 10 times Sch.A-8, line 1, Col.5)	11151853	4345848
3	Balance for equity earnings	18850997	7346186
4	Combined Federal & State income tax factor (1)	109.415 %	109.415 %
5	Total income taxes, before Sch. M adjustments (4 times 3)	20625818	8037829
6	Gross taxable income (line 3 plus line 5)	39476815	15384015
	Add or (Deduct)		
7	Difference between book and tax depreciation (Sch. C-1)	(3111939)	(1042250)
8	Difference between book and tax nuclear fuel amortization	-0-	-0-
9	Adjusted taxable income for Federal & State income tax	36,364876	14,341765
10	Composite Federal & State income tax rate (b)	52.248%	52.248%
11	Income taxes (10 times 9)	18999920	7493285

(1) Calculation of tax factor:

100.000% Tax factor = $\frac{(b)}{100 - (b)} = \frac{52.248}{47.752}$ = 109.415 %

Less: State rate 6.000

94.000 (a)

Federal (49.2* x 94 (a)) = 46.248

Add: State rate 6.000

Composite Federal & State rate 52.248 (b)

* Federal Tax Rate.

Question 11-30

LIMITED TERM POWER SERVICE SCHEDULE

Duke Power COMPANY

Calculation of Difference Between Book and Tax Depreciation

As of 12-31-69

Line	Description	Book Depreciation (Sch.B, Col.5) (1)	Depreciable Plant (Sch.B, Col.3) (2)	Tax Base Adjustment (3)	Depreciable Tax Base (2)-(3) (4)	Tax Rate (5)	Tax Depreciation (4) x (5) (6)	Difference (1) - (6) (7)
	Production Plant							
1	Steam	15,255,542	427,526,109	62,869,969	490,196,078	.0357	17,500,000	2,244,458
2	Nuclear							
3	Hydro Conventional	1,371,792	91 452,772	7,280,561	98,733,333	.0150	1 481,000	109,208
4	Hydro							
5	Other Prod. - Internal Comb.	775,759	21 729985	16,673,426	38,403,361	.0357	1 371008	595,241
6	Other Prod.							
7	General, Common, etc.							
	Allocated to Prod.	544,618	11 539 151	3,454,069	14,993,220	.0472	707,680	163,032
8	Total Prod. (Sum.Col.5)	17,947,741					21,059 680	3,111,939
	Transmission Plant:							
9	Plant Cost	7,162,475	248 697 048	46,407,119	295,104,167	.0288	8,499,000	1,336,525
10	General, Common, etc.							
	Allocated to Trans.	146,789	3 109 927	930,920	4,040,847	.0472	190,728	43,939
11	Total Trans. (Sum. Col.5)	7,309,264					8,689,728	1,380,464
12	Bulk Transmission % (Sch. A-3)							75.5 %
13	Bulk Transmission Amount (Ln.11 x Ln.12)							1,042,250

Question 11-31

D

LIMITED TERM POWER SERVICE SCHEDULE______

Duke Power Company

PROPERTY TAXES

YEAR 1976

Line	Description				Production		Transmission
					(1)		(2)
1	Local Property Taxes (Sch. D-1)				4527741		2538112
2	S. C. Franchise Tax (Sch. D-2)				112282		56139
3	Other, if any (explain)				-0-		-0-
4	Total (Ln. 1 + 2)				4640023		2594251
5	Transmission Bulk Percent (A-3, Ln.8)						75.5%
6	Bulk Transmission Amount (Ln. 4 x 5)						1958660

Question 11-32

LIMITED TERM POWER SERVICE SCHEDULE______

Duke Power Company

Local Property Taxes

Year 1970

Ln.	Item	(1)
1	Previous Year Taxes Assessed (Form 1, page 352)	10997795
2	Less Amount Applicable to Production Units (Sch. D-1-a, Ln. 19)	3883332
3	Balance Taxes Applicable to all other Plant	7114463
	Gross Plant Beginning of Previous Year:	
4	Electric (FPC 1, P. 403, Ln. 88)	1251627497
5	Add Common (FPC 1, P. 351)	-0-
6	Deduct Production (FPC 1, P.402, Ln.42)	(495498236)
7	Balance non-prod. (Lns. 4 + 5 - 6)	756129261
8	Effective prev. year non-prod. rate (Ln.3 ÷ Ln.7) .XXXXXX	.009409
	Current Year Taxes:	
	Production Plant:	
9	Previous year taxes (Ln. 2 above)	3883332
10	Add (deduct) Estimated Taxes for Production Plant additions and retirement last year (D-1-a, Ln. 27)	508717
11	Add General - Common allocation (Sch. Al, col.4, Ln. 6 x Line 8 above)	135692
12	Total Production, current year	4527741
	Transmission Plant:	
13	Plant in service beginning of current year (Al, col.1, Ln.7)	265866855
14	Add General - Common allocation (Al, col.4, Ln.7)	3886744
15	Total (Ln. 13 + 14)	269753599
16	Transmission Taxes Current Year (Ln.15 x Ln. 8 rate)	2538112

D-1-a

LIMITED TERM POWER SERVICE SCHEDULE

Duke Power Company

PRODUCTION PLANT LOCAL PROPERTY TAXES

YEAR 1969

Line	Plant Name	Type	County		Assessed Value	Rate	Tax
		Plant				(Mills per	
	Plants Taxes Previous Year	S-Steam N-Nuc H-Hydro 0-Other	(1)		(2)	$1) (3)	(3) x (4) (4)
1	N.C. Steam:						
2	Allen	S					693 893
3	Riverbend	S					229 377
4	Buck	S					99 578
5	Cliffside	S					88 358
6	Dan River	S + O					234 357
7	Marshall	S					432 206
8	Sub Total						1 777 769
9	N.C. Corp. Excess	2.5%					44 444
10	Total N.C. Steam						1 822 213
11	S.C. Steam:						
12	Lee	S+O					587 851
13	Tiger	S					18 994
14	Buzzard Roost	S					15 123
15	Total S.C. Steam						621 968
16	N.C. Hydro:						
17	Bridgewater						59 132
18							
19	Total previous calendar year taxes (Sum.1-18)						Fwd
	Annualized Tax on Units Added or Retired:						
20							
21							
22							
23							
24							
25							
26							
27	Total annual taxes on plant changes (Sum. 20-26)						Fwd

Question 11-34

LIMITED TERM POWER SERVICE SCHEDULE

D-1-a

Duke Power Company

PRODUCTION PLANT LOCAL PROPERTY TAXES

YEAR 1969

Line	Plant Name	Type	County		Assessed Value	Rate	Tax
		Plant S-Steam N-Nuc H-Hydro O-Other				(Mills per $1)	(3) x (4)
	Plants Taxes Previous Year		(1)		(2)	(3)	(4)
1	N.C. Hydro (Cont.)						
2	Rhodhiss	H					21 879
3	Oxford	H					35 042
4	Lookout Shoals	H					24 502
5	Cowans Ford	H					272 260
6	Mt. Island	H					37 695
7	Turner	H					16 306
8	Tuxedo	H					5 659
9	9 other minor						
10	N.C. Hydro						
11	Plants	H				–	11 216
12	Sub Total - N.C. Hydro						483 691
13	N.C. Corp. Excess 2.5%						12 092
14	Total N.C. Hydro						495 783
15	S.C. Hydro:						
16	Wylie	H					194 033
17	Fishing Creek	H					87 522
18	Great Falls	H					26 067
19	Total previous calendar year taxes (Sum.1-18)						Fwd
	Annualized Tax on Units Added or Retired:						
20							
21							
22							
23							
24							
25							
26							
27	Total annual taxes on plant changes (Sum. 20-26)						Fwd

LIMITED TERM POWER SERVICE SCHEDULE

Duke Power Company

PRODUCTION PLANT LOCAL PROPERTY TAXES

YEAR 1969

Line	Plant Name	Type Plant S-Steam N-Nuc H-Hydro O-Other	County (1)		Assessed Value (2)	Rate (Mills per $1) (3)	Tax (3) x (4) (4)
	Plants Taxes Previous Year						
1	S.C. Hydro (Cont.)						
2	Dearborn	H					79 088
3	Rocky Creek	H					37 275
4	Cedar Creek	H					119 394
5	Wateree	H					205 016
6	99 Islands	H					70 057
7	Gaston Shoals	H					47 024
8	Saluda	H					39 349
9	Buzzard Roost	H					16 301
10	5 other Minor S.C.						
11	Hydro Plants	H				—	22 242
12	Sub Total S.C. Hydro						943 368
13							
14							
15							
16							
17							
18							
19	Total previous calendar year taxes (Sum.1-18)						3 883 332
	Annualized Tax on Units Added or Retired:						
20	Marshall #3	S	Catawba		22 313 500	16.8	374 867
21	Riverbend	S	Gaston		5 343 000	16.4	87 625
22	Dan River	O	Rockingham		1 363 000	14.7	20 036
23	Urquhart	O	Aiken		381 500	74.0	28 231
24	Little River (Retired)	H	Alex + Cald		(80 730)	14.356	(1 159)
25	Gun Powder #1 (Retired)	H	Caldwell		(73 555)	12.0	(883)
26	All other Prod. Changes - Net				-0-		-0-
27	Total annual taxes on plant changes (Sum. 20-26)						508 717

LIMITED TERM POWER SERVICE SCHEDULE

Duke Power

South Carolina Franchise Tax (True Value)

Year 1969

1	Total Franchise-Electric Department-per Company Records						$286 569
	Assessment - Production Plants in S.C.						
			Assessment				
	Steam		$				
	Lee		5 224 130				
	Tiger		138 640				
	Buzzard Roost		219 180				
	Hydro						
	Various Plants		8 769 400				
	Internal Combustion Turbines						
	Lee		948 300				
2	Total Assessment		$15299 650	÷ 42x100=$	36 427 738		
3	Tax @ $.003-Applicable to Year End Production					$ 109 283	
4	Annualized Tax on Units added or retired:						
			$				
	Total Assessment		$15 299 650	÷ 42x100x$.003-$		-0-	
5	Taxes Applicable to Total Production in South Carolina (3+4)					$ 109 283	
6	Taxes Applicable to All Other Utility Plant in S.C.(Line 1 - 3)						$ 177 286
7	Summary -			Allocation			
	Taxes Applicable to:		Amount	of Gen.Plt. (A-1,Col.6)	Total		
	Production (Line 5)		$ 109 283	$ 2 999	$ 112 282		
	Transmission (1)		55 331	808	56 139		
	Distribution (1)		114 154	3 994	118 148		
	General (1)		7 801	(7 801)	-0-		
			$ 286 569	$ -0-	$ 286 569		
(1)	Allocation based on Plant Investment (A-1, Col.1):						
		Plant Invest. (A-1,Col.1)	% of Total		Allocation of Taxes (Line 6)		
	Transmission	265 864 855	31 21		55 331		
	Distribution	548 464 131	64 39		114 154		
	General Plant	37 516 838	4 40		7 801		
	Total	$851 847 824	100.00%		$ 177 286	Question 11-37	

LIMITED TERM POWER SERVICE SCHEDULE ______ E

Duke Power Company

ANNUAL INSURANCE

YEAR 1970

Line	Description	(1)	(2)	(3)	(4)
1	Total Insurance Previous Year (Acct.924, FPC 1, P.419)				215,253
2	Add (deduct) amount necessary to annualize Acct. 924 for addition or retirement of generating unit				64247
3	Total Insurance Current Year				279500
	Allocation of Ln.3 total (Explain Allocation Basis Below if not Directly Assignable):	Production	Transmission	Other	Total
4	Fire and extended coverage	59711	27477	57812	145000
5	Boiler and machinery	125,000	—	—	125000
6	Nuclear liability				-0-
	Other:				
7	Fidelity Bonds	—	—	8000	8000
8	Elevator Liability	375		1125	1500
9					
10					
11					
12					
13					
14					
15	Total - Per Ln.3	185,086	27477	66937	279,500
16	Bulk Transmission Percent		75.5 %		
17	Bulk Transmission Amount		20,745		

Explanation of Allocation Bases:

Line No.	Explanation
4	Sch A1 Col 6, Plant Basis
8	Actual

LIMITED TERM POWER SERVICE SCHEDULE ________ F

Duke Power Company

Transmission Operating and Maintenance Expense

Year 1970

Line No.					Amount		
1	1969 Expense (Form 1, p. 418, line 47)				5298737		
2	Add 37.28% for A & G, payroll taxes, etc. (Schedule III a)				1975369		
3	Total				7274106		
4	% applicable to bulk power (A-3, col. 7 ___ %)				75.5%		
5	Transmission expense applicable to bulk power				5491950		

Question 11-39

LIMITED TERM POWER SERVICE SCHEDULE____ G

Duke Power Company

Net Continuous Plant Capability

As of 12-31-69 Page 1 of 1

Line No.	Plant Name	Reference (1)	Nuclear (2)	Steam (3)	Other Prod. (4)	Hydro (5)	Total (6)
1	Reference	FPC Form 1	P432 -L10	P432 -L10	P432 - L 5	P433 -L10	
2	Riverbend			638 895	120 000		
	Buck			435 640			
4	Dan River			288 930	85 000		
5	Cliffside			197 980			
6	Tiger			28 600			
	Lee			361 550	90 000		
8	Allen			1 149 560			
	Marshall			1 454 700			
10	Urquhart				40 000		
11	Buzzard Roost Steam EEI Stat.			16 100			
	Bridgewater					18 600	
13	Rhodhiss					27 300	
	Oxford					37 400	
15	Lookout Shoals					21 500	
	Mt. Island					56 000	
17	Cowans Ford					372 000	
	Wylie					55 000	
19	Fishing Creek					42 200	
20	Great Falls					24 800	
	Dearborn					35 600	
22	Rocky Creek					27 000	
	Cedar Creek					39 500	
24	Wateree					71 500	
	99 Islands					9 850	
	Buzzard Roost Hydro					13 200	
	Small Plants					10 864	
	Total Production Capability			4 571 955	335 000	862 314	5 769 269
	Long-term firm purchase: From		SEPA	SCE+G			
	" " " " KW		145 000	21 375			166 375
	Total Trans. KW(L31 + L33)						5 935 644

Question 11-40

Question No. 12:

State (a) for generating facilities and (b) for transmission subdivided by voltage classes, the most recent estimated cost of applicant's bulk power supply expansion program of which the subject unit is a part, in terms of dollars per kilowatt/per year, in mills per kilowatt hour and in both the kilowatt costs and kilowatt hour costs divided by the kilowatt hours.

Answer:

The latest estimates of cost for the Oconee Nuclear generating units and associated transmission are:

Investment:

Generating Units, not including nuclear fuel	\$130.00 per kw
500 Kv transmission	26.62
230 & 100 kv transmission	6.18
Total	\$162.80 per kw

Annual Cost:

Generation	\$ 20.80 per kw per year
Transmission	5.25
Insurance	.70
Total Fixed Charges	\$ 26.75 per kw per year
Fuel (7000 hrs/year)	\$ 12.60 per kw per year
O & M	1.05
Total Production	\$ 13.65 per kw per year

Total Annual Cost:

Fixed Charges	\$ 26.75 per kw per year
Production Expense	13.65 per kw per year
Total	\$ 40.40 per kw per year
	5.77 mills/kw hour
	3.82 (fixed charges)
	1.95 (production)

Costs shown do not include components for other system fixed and operating expenses. In addition, power delivered in South Carolina is subject to a .5 mill per kwh generation tax and in North Carolina is subject to a 6% gross receipts tax.

Question No. 13:

List and describe all requests for interconnection and/or coordination and for purchases or sales of coordinating power and energy from adjacent utilities listed in Item 9 since 1960 and state applicant's response thereto. List and describe all requests for supply of full or partial requirements of bulk power for the same period and state applicant's response thereto.

Answer:

CP&L requested the right to transfer power from its western to its eastern division through the Duke system. CP&L also asked that Duke supply up to 36,000 kw of capacity for the seven month period June, 1965 through January, 1966. The capacity request was later increased to 71,000 kw and the time extended one month. The right to schedule power transfers was included in the interconnection contract which became effective in June, 1961. After having determined that its reserves would be adequate, a term service agreement providing for the sale of capacity as requested by CP&L was consummated.

CP&L requested Duke Power to purchase part of the output of a steam electric generating unit scheduled for service in 1971 at CP&L's Asheville generating plant. CP&L also requested Duke Power to build part of a new 230 kv interconnection to transmit a portion of the output of the Asheville unit. Duke Power responded positively to this request because of the economic and reliability advantages.

Yadkin, Inc., on two occasions requested supply by Duke of power to supplement their own generating resources to permit enlargement of the Alcoa facility at Badin, North Carolina. These requests resulted in an agreement whereby Duke supplies off-peak energy to Yadkin. The agreement also provides for sale of maintenance power and energy to Yadkin at pre-arranged times. Supply to Yadkin during peak load hours, if requested by Yadkin, is contingent on availability from Duke. Duke has accordingly at times refused to supply or has interrupted supply of on-peak power.

SEPA requested Duke to wheel power and energy from the Hartwell project to its preference customers; to purchase the excess capacity without accompanying firm energy; to purchase any excess energy occurring because of greater than average stream flows; and to supply deficiency energy when energy transmitted from the Hartwell project was less than SEPA's contractural obligation to its preference customers. These requests were accommodated by a contract dated December 16, 1963.

Under the former CARVA Pool Agreement, Duke was responsible for maintaining a pro rata share of the total pool reserve. This included an obligation to purchase or sell reserve capacity at various times. Although such sales and purchases were not in response to specific requests, the resulting transactions with adjacent utilities are listed following for completeness:

RESERVE EQUILIZATION TRANSACTIONS

Date Begin	Date End	Duke MW Purchase	Duke MW Sale	MW Purchased From SCE&G	MW Purchased From CP&L	MW Sold To SCE&G	MW Sold To CP&L
5-1-67	12-31-67	22		22			
1-1-68	1-31-68	18		18			
2-1-68	2-29-68	20		20			
3-1-68	3-31-68	19		19			
4-1-68	4-30-68	22		22			
5-1-68	5-3-68	42		42			
5-4-68	5-10-68	47		47			
5-11-68	5-12-68	224		88	134		
5-13-68	5-31-68	268		81	187		
6-1-68	6-30-68	236		81	155		
7-1-68	7-14-68	234		81	153		
7-15-68	3-31-69	376		51	325		
4-1-69	4-30-69	383		51	332		
5-1-69	5-19-69	286			286		
5-20-69	2-29-69		18			18	
5-30-69	5-31-69	158			158		
6-1-69	6-30-69	66			66		
7-1-69	7-15-69	110			110		
7-16-69	7-31-69	91			91		
8-1-69	9-30-69	59			59		
10-1-69	12-31-69	62			62		
1-1-70	4-30-70	60			60		
5-1-70	5-31-70		242			165	77
6-1-70	6-28-70		192			173	19
6-29-70	7-31-70		215			180	35
8-1-70	8-31-70		224			162	62
9-1-70	9-9-70		229			164	65
9-10-70	12-31-71		76				76
1-1-71	1-31-71		81				81
2-1-71	3-10-71		74				74
3-11-71		44		8	36		

SCPSA applied for admission to the Carva Pool. Negotiations in this matter were not completed at the time the pool agreement was terminated. SCPSA has been offered the reliability and limited and short term service scheduled which have replaced the former pooling agreement.

The City of High Point requested delivery at two points with either delivery point to be capable of supply of the entire bulk power requirements. This would have required parallel operation of the city's distribution system with the Duke Power transmission system between the two delivery points and would have subjected the city system to unmanageable and extremely heavy power flows in the event of outages on the paralleling Duke system. The request was, therefore, turned down in recognition of the technical difficulties. A subsequent request for similar service has been received from the Blue Ridge EMC. Based on studies which are still underway, it appears that the greater geographic separation of the two projected Blue Ridge EMC delivery points and the capability of the transmission through the Blue Ridge system between those points will allow satisfactory parallel operation.

The University of North Carolina, Abbeville Water and Electricity, and Lockhart Power and Light Company systems operate generation in parallel with Duke and have many times requested changes in the amount of supply by Duke Power Company. All such requests have been honored. The same was true with respect to the Belton Power and Light Company before acquisition by Duke.

Many other requests for new delivery points, abandonment of existing delivery points, or changes in the amount of supply have been received and complied with. New deliveries which have been established and existing delivery points which have been abandoned in response to such requests since 1960 are:

NEW DELIVERY POINTS TO RESALE CUSTOMERS

JANUARY 1, 1960 THROUGH PRESENT

CUSTOMER-DELIVERY-LOCATION	DELIVERY SIZE KW	RATE SCHE	DATE OF AGREEMENT	EFFECTIVE DATE
Greenwood County Electric Power Commission Laurens, S. C.	5,000	Opr	7-27-59	3-1-60
Broad River Electric Membership Corporation Carlisle Delivery, Whitmire, SC	750	11-A	10-29-59	6-1-60
Piedmont Electric Membership Corp Eno Delivery, Durham, NC	1,500	11-A	3-21-60	10-1-60
Pee Dee Electric Membership Corp Norwood Delivery, Norwood, NC	800	11-A	7-18-60	9-1-60
Laurens Electric Cooperative, Inc Fountain Inn Del, Fountain Inn, SC	750	11-A	8-16-60	10-1-60
Blue Ridge Electric Cooperative, Inc Anderson Delivery, Anderson, SC	1,000	11-A	10-3-60	1-1-61
Little River Electric Cooperative, Inc Latimer, SC	750	11-A	10-7-60	11-1-61
Davidson Electric Membership Corp Walnut Cove, NC Delivery No. 7	1,000	11-A	6-16-61	10-15-61
Rutherford Electric Membership Corp Hardins, NC	1,500	11-A	7-24-61	11-1-61
Pee Dee Electric Membership Corp Marshville, NC	300	11-A	6-23-61	7-17-61
City of Lexington Delivery No. 2, Lexington, NC	7,500	10	5-9-61	2-1-62
Cornelius Electric Membership Corp Cowans Ford Delivery, Lowesville, NC	1,200	11-A	8-3-61	11-1-61
City of Shelby Delivery No. 4, Shelby, NC	2,000	10	3-5-63	9-1-63
Laurens Electric Cooperative, Inc Princeton, S. C.	300	11-A	2-21-63	4-15-63
Laurens Electric Cooperative, Inc Near Duncan, SC	300	11-A	9-3-63	9-1-63
Laurens Electric Cooperative, Inc Lanford, SC	800	11-A	10-23-63	10-23-63
Pee Dee Electric Membership Corp Sturdivants Crossroads Del., Marshville, NC	600	11-A	7-2-64	7-1-64

CUSTOMER-DELIVERY-LOCATION	DELIVERY SIZE KW	RATE SCHE	DATE OF AGREEMENT	EFFECTIVE DATE
Lockhart Power Company Union, SC	20,000	10	12-6-63	9-15-64
City of Gastonia Delivery No. 5, Gastonia, NC	4,200	10	1-6-64	6-1-64
Commissioners of Public Works of the City of Greer and the City of Greer, SC	3,000	10	6-19-64	11-1-64
City of Gastonia East Gastonia Del., Gastonia, NC	4,500	10	2-24-65	4-15-65
City of Newberry Newberry, SC	1,000	10	3-29-65	8-15-65
City of Morganton Delivery No. 2, Morganton, NC	3,000	10	12-29-65	1-20-66
Cornelius Electric Membership Corp				
Sherrills Ford, NC - Delivery No. 5	1,600	11-A	6-7-65	1-15-66
Hambrights Crossroads, Huntersville, NC	800	11-A	6-14-65	11-15-66
Davidson Electric Membership Corp Gold Hill Delivery, Madison, NC	600	11-A	6-22-64	10-1-64
Surry-Yadkin Electric Membership Corp Pilot Mountain, NC - Delivery No. 5	900	11-A	10-8-64	1-17-65
Blue Ridge Electric Cooperative, Inc				
Central, SC	800	11-A	4-2-60	9-15-60
Cateechee, SC	1,000	11-A	2-26-65	4-18-65
Broad River Electric Cooperative, Inc Cowpens, SC	1,400	11-A	1-1-66	11-15-66
York Electric Cooperative, Inc				
Tirzah, S. C. Delivery No. 6	1,800	11-A	3-22-65	9-15-65
Ogden, S. C. Delivery No. 7	500	11-A	6-1-65	11-1-65
Piedmont Electric Membership Corp Delivery No. 4, Buckhorn, NC	1,800	11-A	6-30-65	3-15-66
Davie Electric Membership Corp Bethlehem School Del., Del. No. 6, Hickory, NC	900	11-A	12-22-65	4-7-66
Cornelius Electric Membership Corp Davidson Del., Del. No. 7, Davidson, NC	1,600	11-A	1-3-66	10-1-66
Broad River Electric Cooperative, Inc N. Blacksburg Del., Del. No. 7, Blacksburg, SC	750	11-A	6-9-65	10-1-66
Davie Electric Membership Corp Charles Delivery, Charles, NC	1,800	11-A	3-8-66	10-1-66

CUSTOMER-DELIVERY-LOCATION	DELIVERY SIZE KW	RATE SCHE	DATE OF AGREEMENT	EFFECTIVE DATE
City of Gastonia Delivery No. 6, Gastonia, NC	5,500	10	4-25-66	8-8-66
Laurens Electric Cooperative				
Delivery No. 10, Laurens, SC	1,800	11-A	12-16-66	11-20-66
Delivery No. 11, Hooker St., Laurens, SC	200	11-A	12-16-66	11-20-66
Delivery No. 12, Clinton, SC	1,600	11-A	12-16-66	11-20-66
Delivery No. 13, Cold Point, SC	1,200	11-A	12-16-66	11-20-66
Delivery No. 14, Waterloo, SC	500	11-A	12-16-66	11-20-66
Delivery No. 15, Joanna, SC	1,200	11-A	12-16-66	11-20-66
Delivery No. 16, Belfast Del., Joanna, SC	800	11-A	12-16-66	11-20-66
Little River Electric Cooperative, Inc				
Del. No.4, Rocky River Del., Abbeville, SC	1,500	11-A	12-12-66	11-20-66
Del. No.5, Secession Ave Del.Abbeville, SC	1,200	11-A	12-12-66	11-20-66
Commissioners of Public Works of the Town of Ninety Six, SC	2,500	GCEPC Rate	5-1-63	5-1-63
Abbeville, City of Abbeville, SC	3,000	10 Class 2	1-3-67	7-1-66
Commissions of Public Works of the City of Laurens, SC				
Hampton St Delivery	5,000	10	12-15-66	11-20-66
Royal St Delivery	3,000	10	12-15-66	11-20-66
Hooker Ave Delivery	2,500	10	12-15-66	11-20-66
Commissioners of Public Works of the City of Greenwood, SC				
City Substation Delivery	6,500	10	1-12-67	11-20-66
Water Works Delivery	3,500	10	1-12-67	11-20-66
Mathews Substation	1,000	10	1-12-67	11-20-66
Cokesbury Street Delivery	3,000	10	1-12-67	11-20-66
Clark Hill Delivery	2,500	10	1-12-67	11-20-66
South Carolina Electric and Gas Co Chapells, SC Delivery	150	10	1-3-67	11-20-66
Blue Ridge Electric Cooperative, Inc Delivery No. 11, Easley, SC	2,000	11-A	2-23-67	4-15-67
Broad River Electric Cooperative, Inc. Delivery No. 9, Jonesville, SC	750	11-A	2-27-67	4-15-67
Laurens Electric Cooperative, Inc Del No.17, Marion St Del., Joanna, SC	1,500	11-A	1-25-67	4-15-67
Laurens Electric Cooperative, Inc Del No. 18, Ware Place Del., Pelzer, SC	800	11-A	3-1-67	5-15-67

CUSTOMER-DELIVERY-LOCATION	DELIVERY SIZE KW	RATE SCHE	DATE OF AGREEMENT	EFFECTIVE DATE
Rutherford Electric Membership Corporation Delivery No. 11, Sevier, NC	2,500	11-A	7-25-69	10-22-69
City of Statesville Delivery No. 2, Statesville, NC	25,000	10	10-21-68	12-22-69
Davie Electric Membership Corporation Delivery No. 10, Boomer, NC	750	11-A	6-3-68	11-21-69
Commissioners of Public Works of the City of Easley and the City of Easley, SC Delivery No. 2, Easley, SC	2,500	10	12-18-69	2-20-70
Commissioners of Public Works of the City of Greenwood, SC Edgefield Street Substation	6,000	10	12-1-69	5-21-70
Commission of Public Works of the City of Laurens, SC Caroline Street Delivery	14,000	10	4-21-69	6-22-70
Piedmont Electric Membership Corporation Delivery No. 6, Camp Springs, NC	3,000	11-A	10-24-69	7-22-70
Town of Maiden Delivery No. 2, Maiden, NC	2,000	10	3-3-69	7-22-70
Davidson Electric Membership Corporation				
Delivery No. 8, Walkertown, NC	400	11-A	4-28-70	7-22-70
Delivery No. 9, Belews Creek, NC	400	11-A	4-28-70	6-22-70
Delivery No.10, South of Walnut Cove, NC	500	11-A	4-28-70	6-22-70
Little River Electric Cooperative, Inc Delivery No. 6,Watson Substation,Starr, SC	1,000	11-A	3-14-70	11-20-70
City of Gastonia Delivery No. 9, Gastonia, NC	3,500	10	4-7-70	1-20-71
Town of Prosperity Delivery No. 2, Prosperity, SC	600	10	12-4-70	2-19-71

CANCELLATION OF DELIVERY POINTS

AT CUSTOMERS REQUEST OR DUE TO PURCHASE

CUSTOMER-DELIVERY-LOCATION	DELIVERY KW	RATE SCHE	DATE OF AGREEMENT	EFFECTIVE DATE
The United States of America Donaldson Air Force Base Greenville, S. C.	4,000	10	2-7-64	1-24-64
Belton Light and Power Co Belton, S. C.	8,200	10	Purchased	11-11-63
Pisgah Mountain Electric Co Long Shoals, NC	1,100	10	Purchased	7-20-64
Greenwood County Electric Power Commission Laurens, S. C.	20,000	Oper	Purchased	~~11-20-66~~ 7-1-66
Rutherford Electric Membership Corp Delivery No. 2, Dallas, NC	1,800	11-A	2-21-67	2-21-67
Commissioners of Public Works of the City of Greenwood, SC - Mathews Substation	1,000	10	12-4-67	11-19-67
Commission of Public Works of the City of Laurens,SC - Hooker Ave Delivery	2,500	10	10-30-67	6-16-68
Davie Electric Membership Corp Delivery No. 1, Mocksville, NC	2,600	11-A	10-15-68	10-9-68
Pee Dee Electric Membership Corp Delivery No. Temp. 1, Marshville, NC	400	11-A	11-9-68	11-4-68
Commission of Public Works of the Town of Ninety Six, SC	2,500	GCEPC	Purchased	10-1-69
Commissioners of Public Works of the City of Greenwood, SC - Cokesbury Substation	3,000	10	11-24-69	11-16-69
Commission of Public Works of the City of Laurens,SC - Royal Substation	5,000	10	5-18-70	6-22-70
Kershaw Oil Mill Kershaw, SC	4,000	10	Purchased	8-17-70
Commissioners of Public Works of the City of Greenwood, SC - Clark Hill Delivery	2,500	10	9-18-70	7-22-70

CANCELLATION OF DELIVERY POINTS

AT CUSTOMERS REQUEST OR DUE TO PURCHASE

CUSTOMER-DELIVERY-LOCATION	DELIVERY KW	RATE SCHE	DATE OF AGREEMENT	EFFECTIVE DATE
The United States of America Donaldson Air Force Base Greenville, S. C.	4,000	10	2-7-64	1-24-64
Belton Light and Power Co Belton, S. C.	8,200	10	Purchased	11-11-63
Pisgah Mountain Electric Co Long Shoals, NC	1,100	10	Purchased	7-20-64
Greenwood County Electric Power Commission Laurens, S. C.	20,000	Oper	Purchased	7-1 ~~11-20~~-66
Rutherford Electric Membership Corp Delivery No. 2, Dallas, NC	1,800	11-A	2-21-67	2-21-67
Commissioners of Public Works of the City of Greenwood, SC - Mathews Substation	1,000	10	12-4-67	11-19-67
Commission of Public Works of the City of Laurens, SC - Hooker Ave Delivery	2,500	10	10-30-67	6-16-68
Davie Electric Membership Corp Delivery No. 1, Mocksville, NC	2,600	11-A	10-15-68	10-9-68
Pee Dee Electric Membership Corp Delivery No. Temp. 1, Marshville, NC	400	11-A	11-9-68	11-4-68
Commission of Public Works of the Town of Ninety Six, SC	2,500	GCEPC	Purchased	10-1-69
Commissioners of Public Works of the City of Greenwood, SC - Cokesbury Substation	3,000	10	11-24-69	11-16-69
Commission of Public Works of the City of Laurens, SC - Royal Substation	5,000	10	5-18-70	6-22-70
Kershaw Oil Mill Kershaw, SC	4,000	10	Purchased	8-17-70
Commissioners of Public Works of the City of Greenwood, SC - Clark Hill Delivery	2,500	10	9-18-70	7-22-70

Question No. 14:

List (a) agreements to which applicant is a party (reproducing relevant paragraphs) and (b) state laws (supply citations only), which restrict or preclude coordination by, with, between, or among any electric utilities or systems identified in applicant's response to Items 8 and 9. List (a) agreements to which the applicant is a party (reproducing relevant paragraphs) and (b) state laws (supply citations only) which restrict or preclude substitution of service or establishment of service of full or partial bulk power supply requirements by an electric utility other than applicant to systems identified in Items 8 and 9. Where the contract provision appears in contracts or rate schedules on file with a federal agency, identify each in the same form as in previous responses. Where the contract has not been filed with a federal agency, a copy should be supplied unless it has been supplied pursuant to another item hereto. Where it is not in writing, it should be described.

Answer

The Applicant knows of no agreements to which it is a party or State laws "which restrict or preclude coordination by, with, between or among any electric utilities or systems identified in Applicant's response to Items 8 and 9."

The Applicant knows of no "agreements to which the Applicant is a party .. which restrict or preclude substitution of service or establishment of service of full or partial bulk power supply requirements by an electric utility other than the Applicant to systems identified in Items 8 and 9." While the Applicant's contracts for wholesale power supply to its municipal and rural electric cooperative customers listed in response to Item 10 provide that the Applicant will furnish all of their bulk power requirements (other than that portion of their requirements which Applicant is now wheeling to some of them from the U. S. Army Corps of Engineers Hartwell and Clark Hill projects on the Savannah River in South Carolina for Southeastern Power Administration, U. S. Department of Interior, and other than portions of the requirements of some of the rural electric cooperatives being supplied to them at some of their delivery points by Carolina Power & Light Company) such wholesale power contracts after their initial term of five years, which initial term has in most instances expired, are contracts from year to year, terminable upon sixty days' written notice by either party. As a practical matter, they do not "restrict or preclude substitution of service."

The following State laws might, in a given factual situation, be construed to "restrict or preclude substitution of service or establishment of service of full or partial bulk power supply requirements by an electric utility other than Applicant to the system identified in Items 8 and 9."

N. C. G. S. 62-110. Certificate of Convenience and Necessity.

State ex rel. Utilities Commission v. Carolina Tel. & Tel. Co., 267 N. C. 257, 148 S.E. 2d 100 (1966)

State ex rel. Utilities Commission v. Two-Way Radio Service, Inc., 272 N. C. 591, 158 S.E. 2d 855 (1968).

N.C.G.S. 62-118. Abandonment and Reduction of Service.

Code of Laws of South Carolina 1962, Section 24-63. When Certification of Convenience and Necessity Required; Section 24-64, Prerequisites to Issue of Certificate; Section 24-67, Action When Utility Proceeds Without Certificate; Section 24-68, Interference with Another Utility; Section 24-69, Abandonment of Service.

The following State statutes restrict competition between electric utility companies and rural electric cooperatives.

N.C.G.S. 62-110.1 and 110.2.

_N.C.G.S. 160-510_ thru _519_, inclusive.

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Code of Laws of S.C. 1962, _Sections 24-13_ thru _24-18_, inclusive;

Code of Laws of S.C. 1962, _Sections 24-63.1_ and _63.2_;

Code of Laws of S.C. 1962, _Sections 24-67_ and _68_;

Code of Laws of S.C. 1962, _Sections 24-76_.

Question No. 15:

State, at point of delivery, average future costs of power purchased from applicant to adjacent systems identified in applicant's response to Item 9 in terms of dollars/month/kw for capacity, mills/kwh for energy and mills/kwh for both power and energy at purchaser's present load factor (a) at present load, (b) at 50 percent increase over present load, (c) at 100 percent increase over present load, and (d) at 200 percent increase over present load. [All costs should be determined under present rate schedules.] Where sales are made under contracts or rate schedules on file with a federal agency and not included in the response to Item 9, identify each in the same form as in previous responses. Where the contract has not been filed with a federal agency, a copy should be supplied.

Answer:

Duke Power Company has limited and short term rate schedules in effect for sales to SCE&G Company and CP&L Company. The cost of limited term capacity is based on the investment in production and transmission facilities adjusted for transmission losses. In February this year, the rate was $1.50 per kw per month before adjustment for losses. This rate w . change as costs of new facilities are incurred. Energy under the limited term schedule is priced at the calculated average production cost of energy produced at all plants plus ten percent plus an adjustment for losses. During February, the rate was 5.9 mills per kwh before loss adjustment. Short term capacity is priced at $1.52 per kw per month plus losses. Energy is priced at 110 percent of the calculated average production cost of the highest cost generating units being used to produce the energy plus losses. There have been no recent short-term sales. Loss adjustment on both limited and short-term schedules is accomplished by scheduling coincidental delivery of loss compensation.

Duke's rate for off-peak energy to Yadkin depends on the clock hour of scheduling. During 25 hours per week, the rate is 3.98 mills/kwh; during 30 hours, the rate is 4.3 mills; and, during 29 hours, the rate is 4.5 mills. Energy during peak load hours is priced at 5.58 mills per kwh for the first 400,000 kwh per day and at 6.20 mills per kwh for all additional. Maintenance energy is priced at 7.5 mills per kwh. A fuel adjustment is applicable to all of the above rates to Yadkin when Duke's fuel cost exceeds 26.5 cents per MBTU. Including the effect of the fuel adjustment, rates for February of this year were:

7.04 mills/kwh during the 25 lowest cost off peak hours
7.51 mills/kwh during the next 30 lowest cost off peak hours
7.98 mills/kwh during the next 29 lowest cost off peak hours
9.92 mills/kwh for the lowest cost block during peak load hours
10.91 mills/kwh for all additional during peak load hours
13.37 mills/kwh for maintenance energy

Duke has contracts with Appalachian Power Company and Southern Services which provide for short-term power and energy sales. Short-term capacity sold to the Southern Company is priced at $.30 per kw per week. A second schedule entitled "Special Short-Term Power" provides for capacity at $.35 per kw per week. The Appalachian contract provides for capacity at $.40 per kw per week. Energy accompanying short term capacity sold to either company is priced at 110 percent of the incremental cost to make the delivery.

Under all of the above rate schedules, increased power sales would be at the same rates so that the rate per kw and per kwh would remain constant.

Duke has no contracts for power sales to Nantahala Power & Light, SCPSA, or SEPA.

All other systems listed in Question 9 are supplied under Duke Power Company's filed rate schedules 10, 11, or 11A. These schedules do not identify specific rates for capacity and energy. The total rate for capacity and energy expressed as mills per kwh and the total cost per billing period for supply at various loads and load factors are tabulated on the following page. This tabulation shows the downward trend in the rate per kwh for all loads larger than 3,000 kw at 400 or more hours use per billing period. The rates as shown include the .5 mill per kwh South Carolina generation tax or the 6 percent North Carolina gross receipts tax, as applicable.

SCHEDULES 10, 11, AND 11A POWER COSTS

MWD	Equivalent Hours Per Billing Period	$	MILLS/ KWH	MWD	Equivalent Hours Per Billing Period	$	MILLS/ KWH
1	300	2,250.00	7.5	1	400	3,000.00	7.5
2		4,500.00	7.5	2		6,000.00	7.5
3		6,750.00	7.5	3		9,000.00	7.5
4		9,000.00	7.5	4		11,970.50	7.48
5		11,250.00	7.5	5		14,770.50	7.38
6		13,500.00	7.5	6		17,570.50	7.32
7		15,750.00	7.5	7		20,370.50	7.27
8		18,000.00	7.5	8		23,170.50	7.24
9		20,250.00	7.5	9		25,958.00	7.21
10		22,500.00	7.5	10		28,745.50	7.18
15		33,750.00	7.5	15		42,683.00	7.11
20		45,000.00	7.5	20		56,620.50	7.07
30		67,500.00	7.5	30		84,495.50	7.04
40		90,000.00	7.5	40		112,370.50	7.02
50		112,500.00	7.5	50		140,245.50	7.01
60		135,000.00	7.5	60		168,120.50	7.00
1	500	3,750.00	7.5	1	600	4,500.00	7.5
2		7,370.50	7.37	2		8,370.50	6.97
3		10,670.50	7.11	3		12,170.50	6.76
4		13,970.50	6.98	4		15,970.50	6.65
5		17,270.50	6.90	5		19,770.50	6.59
6		20,570.50	6.85	6		23,470.50	6.51
7		23,870.50	6.82	7		27,170.50	6.46
8		27,170.50	6.79	8		30,870.50	6.43
9		30,458.00	6.76	9		34,558.00	6.39
10		33,745.50	6.74	10		38,245.50	6.37
15		49,933.00	6.65	15		56,683.00	6.29
20		66,120.50	6.61	20		75,120.50	6.26
30		98,495.50	6.56	30		111,995.50	6.22
40		130,870.50	6.54	40		148,870.50	6.20
50		163,245.50	6.52	50		185,745.50	6.19
60		195,620.50	6.52	60		222,620.50	6.18

Question No. 16:

State whether applicant has prepared, caused to be prepared, or received engineering studies for generation and transmission expansion programs which include loads of each system in Item 9.

Answer:

Duke Power has always included the loads of all of its customers in planning for expansion of generation and transmission. Duke has at various times participated in, or individually made studies which included the loads of all systems listed in Question 9 except for those loads of SEPA which are served by systems other than those listed in Question 9. Duke makes continuing planning studies for generation and transmission expansion which include all growth requirements estimated for all of its customers including those which are served at wholesale rates. (Rate Schedules 10, 11, and 11A). Duke Power Company has at all times been willing to serve all of the present and future requirements of all of its wholesale customers.

Question No. 17

List adjacent systems to which applicant has offered to sponsor or to conduct system surveys in contemplation of an offer by applicant to purchase, merge or consolidate with said adjacent system, subsequent to January 1, 1960.

Answer

Since January 1, 1960, Duke Power Company has offered to sponsor or conduct surveys of the following systems in contemplation by Duke to purchase, merge or consolidate such systems:

The Electric Company
Town of Huntersville
Town of Prosperity
Lockhart Power Company
Pisgah Mountain Electric Company
Belton Light and Power Company
Town of Ninety-Six
Kershaw Power and Light Company
City of Greenville and County of
Greenville (Donaldson Air Force Base System)
Greenwood County R.E.A.
Clemson Agricultural College of South Carolina
Nantahala Power and Light Company (offer to purchase made 1/31/59) (In connection with this proposed purchase, Duke had accompanying discussions with the Town of Highlands and Western Carolina College covering service to or possible system acquisition if the Nantahala system was acquired by Duke.)

In each instance listed above, except Pisgah Mountain Electric Company, the initial invitation to make an offer to purchase came from the other system to Duke Power Company. In the case of Pisgah Mountain Electric Company the initial request to negotiate for the acquisition of the system came from the staff of the North Carolina Utilities Commission, which was concerned about service problems being experienced by that distribution system. Since January 1, 1960, one or more salesmen in Duke Power Company's Power Sales Department, who make regular calls on Duke's industrial and wholesale customers with respect to reliability of service, increases in customers' demands, etc., may have inquired of a city electrical superintendent or other city official whether his municipality would be interested in selling its distribution system to Duke Power Company. However, to the best of the Company's knowledge and belief, no such inquiry resulted in any surveys or offers by Duke to purchase, merge or consolidate such systems.

Question No. 18:

List applicant's offers or proposals to purchase, merge or consolidate with electric utilities, subsequent to January 1, 1960.

Answer:

Duke Power Company, South Carolina Electric & Gas Company, and Carolina Power & Light Company each offered to purchase the rural electric cooperatives in each utility's service area and to lease and operate the State-owned South Carolina Public Service Authority generation, transmission and distribution system. At various times during the 1960's, there have been proposals considered by the South Carolina General Assembly to make rural electric cooperatives in South Carolina and South Carolina Public Service Authority, which is the bulk power supplier for certain of those rural electric cooperatives, subject to local property taxation. The companies mentioned above suggested purchase by the three major electric utilities operating in South Carolina as a means of accomplishing this result. The companies' offer was promptly rejected and no further action was taken by the companies mentioned above. Laws taxing rural electric cooperatives were subsequently passed by the South Carolina General Assembly.

At about the same time, when the issue of subjecting North Carolina electric membership corporations to local property taxation was being considered in the North Carolina General Assembly, Duke Power Company and Carolina Power & Light Company publicly announced their willingness to purchase all electric membership corporations operating in their respective service areas in North Carolina. The offer was rejected and no further action was taken by the companies. Subsequent legislation enacted by the North Carolina General Assembly made all electric membership corporations in North Carolina subject to local property taxation, and provided that the North Carolina Utilities Commission should fix service territories for the electric membership corporations as well as the regulated electric utilities. See answer to Question 14 for citation of statutes.

Duke Power Company also made offers to purchase or lease the following systems:

Nantahala Power & Light Company (offer - Jan. [illegible], 1959) (offer expired after 1960)	$4,000,000 (approximately) to be adjusted for further capital additions and retirements and accrued depreciation to the date of acquisition.
Pisgah Mountain Electric Company	4,000 shares Duke common $252,298 cost of shares
Belton Light & Power Company	26,000 shares Duke common $1,577,936 cost of shares
Town of Ninety-Six	$751,200 offer to be adjusted at date of closing

Kershaw Power & Light Company	$1,260,161 offer to be adjusted at date of closing (payment - 58,639 shares Duke common)
City of Greenville and County of Greenville (Donaldson Air Force Base)	$304,280
Greenwood County R.E.A.	$12,918,176 which includes acquisition of a distribution system, transmission system, 14,000 KW generation plant, and $2,087,981 in cash and investments. Duke offered to lease for 40 years at $250,000 annually the R.E.A. 15 000 KW hydroelectric plant.
Clemson Agricultural College of South Carolina	$279,068

Each of the systems listed above except Pisgah Mountain Electric Company initially requested Duke Power Company to make an offer to purchase. The offer to purchase Pisgah Mountain Electric Company, a small rural distribution system in Lincoln County, North Carolina, was suggested to Duke by the staff of the North Carolina Utilities Commission, which was concerned with service and maintenance problems on the Pisgah Mountain system.

Question No. 19:

List all acquisitions of or mergers or consolidations with electric utilities by applicant, subsequent to January 1, 1960, including:

a. The name and principal place of business of the system prior to the acquisition, merger, or consolidation;
b. The date the acquisition merger or consolidation was consummated;
c. Gross annual revenue and most recent peak load, dependable capacity and the largest thermal generating unit of the system, prior to the date of consummation.

Answer

Electric utilities acquired by Duke Power Company since 1960 and data requested on such utilities are:

System	Location	Acquisition Date	Revenue of Adjacent System	Peak Load of Adjacent System	Generation
Pisgah Mountain Electric Co.	Lincolnton, N.C.	7-17-64	$74,884 (1963)	864 KWD	None
* Belton Light & Power Co.	Belton, S.C.	11-13-63	$621,962 (1962)	6,810 KWD	Hydro-electric 3-1000 KW 1-500 KW
* Ninety-Six, Town of	Ninety-Six, S.C.	10-1-69	$157,479 (year ending 9-30-68)	1,920 KWD	None
* Kershaw Power & Light Co.	Kershaw, S.C.	8-17-70	$144,507 (6 months ending 6-30-70)	3,960 KWD	None
* City of Greenville & County of Greenville (former Donaldson Air Force Base)	Greenville, S.C.	5-11-64	Not available	3,456 KWD	None
* Greenwood County R.E.A.	Greenwood, S.C.	7-1-66	$4,144,375 (year ending 6-30-66)	81,700 KWD	14,000 KW, incl. one 10,000 KW unit.
* Clemson Agricultural College of South Carolina	Clemson, S.C.	12-15-64	$62,105 (app.)	Not available	None

* Indicates that negotiations for acquisition by Duke Power Company were initiated by the system subsequently acquired.