Duke Energy

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August 31, 2000

Mr. Gary E. Walsh, Executive Director
The Public Service Commission of South Carolina
P. O. Drawer 11649
Columbia, SC 29211

Re: Docket Nos. 95-844-E and 87-223-E

Dear Mr. Walsh:

Pursuant to Section 58-33-430 of the Code of Laws of South Carolina, the Commission's Order No. 98-151, dated February 25, 1998, and Order No. 98-502, dated July 2, 1998, in Docket No. 87-223-E, I am enclosing 15 copies of the Duke Power Annual Plan.

Very truly yours,

William Larry Porter
Deputy General Counsel
Jeff D. Griffith III
Associate General Counsel

WLP/fhb
Encl.

cc: Mr. Wayne Burdett
Mr. Philip S. Porter

<u>CERTIFICATE OF SERVICE</u>

I hereby certify that I have served a copy of Duke Power's Annual Report on the following parties by depositing a copy of same in the United States mail, first class postage prepaid:

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This the 31st day of August, 2000.

W Larry Porter

William Larry Porter

THE DUKE POWER ANNUAL PLAN
SEPTEMBER 1, 2000

TABLE OF CONTENTS

INTRODUCTION:

Duke has developed an annual resource plan that will meet customers' energy needs with a combination of existing generation, customer demand-side options, short-term purchase power transactions, and self-build options. Duke will meet future capacity needs by assessing the supply and demand-side markets and determining the best way to acquire the needed resources.

OVERVIEW:

The Duke Power 2000 Annual Plan reflects commitment to meeting customers' need for a highly reliable energy supply at the lowest reasonable cost. Duke recognizes several trends that are key drivers in the plan:

- Robust wholesale purchased power markets have developed which provide a variety of products, opportunities and risks for both planners and market participants.

- Supply-side resource costs and construction lead times continue to make these resources cost effective and flexible options for planners.

- Customer incentives and expenses for demand-side resources continue to hamper their cost effectiveness.

The risks imposed and opportunities presented by an increasingly competitive industry demand that companies develop flexible resource portfolio strategies to meet customer energy needs in a reliable and cost-effective manner. The Duke Power 2000 Annual Plan represents a balanced strategy which incorporates the perspectives of customers, shareholders, and the public with options for flexibility.

The market for purchase power contracts has continued to expand and improve. Purchase power and self-build supply side resources are viable, complementary strategies for meeting customer energy needs reliably and at the lowest reasonable cost.

Recognizing the risks and uncertainties of the future, Duke has developed a resource acquisition strategy to meet near-term obligations in a manner that does not impose undue exposure to long-term financial burdens. Duke will review and select the most cost-effective options the market has to offer to meet customer needs in a reliable manner. Such options include purchased power options and self-build peaking and intermediate generation technologies.

The 2000 Annual Plan incorporates a 15-year load forecast, near-term purchase power contracts, existing generation, Demand-Side Management (DSM), and peaking and intermediate generation technologies. The plan is developed with the objective of minimizing revenue requirements with a planning reserve margin of 17 percent. The annual plan includes a detailed explanation of the basis for, and a justification for the adequacy and appropriateness of, the level of projected reserve margins and a discussion of the adequacy of the transmission system.

The following information is supplied pursuant to NCUC order dated June 21, 2000 in Docket No. E-100, Sub 84, NCUC Rules R8-60 and R8-62(p) and the NCUC Order dated July 13, 1999 in Docket No. E-100, SUB 82 as well as the PSCSC Order No. 98-151, dated February 25, 1998, Order No. 98-502, dated July 2, 1998, in Docket No. 87-223-E and Section 58-33-430 of the Code of Laws of South Carolina.

RESERVE MARGIN EXPLANATION AND JUSTIFICATION:

Reserve margins are necessary to help ensure adequate resources will be available considering customer demand uncertainty, unit outages, and weather extremes. Appropriate levels of reserves are impacted by existing generation performance, lead times needed to acquire or develop new resources, and product availability in the purchase power market. In recent years, Duke has reduced its planning reserve margin requirements. The reduction was primarily due to increased availability of existing generation, shorter lead times for construction of new generation, and the emergence of new purchase power options. The additional flexibility of shorter lead time generation alternatives has enabled Duke to more effectively use these resources to satisfy reserve margin requirements. Reductions in planning reserves under these circumstances has allowed for a closer match between generation resource commitments and customer needs while maintaining reliability.

Based on Duke's operating experience with approximately 19,300 MW's of existing generation, 1,200 MW's of purchase power contracts, and 1000 MW's of interruptible Demand Side Management (DSM) resources, Duke adopted a planning reserve margin target of 17 percent in 1997. As Duke nears each peak demand season, there is a greater level of certainty regarding the customer load forecast and total system capability due to near term weather conditions and greater knowledge of generation unit availability. The Duke total system capability includes the expected capacity of each generating station and the net of firm purchases less sales. Changes to the total system capability associated with seasonal capacity re-ratings and scheduled outages reveal the expected amount of sustainable generation available to meet load requirements. This capacity is then utilized in evaluating the potential exposure to DSM activations. If necessary, Duke would acquire additional capacity in the short-term power market. The adjusted system capacity, along with the Load Control DSM capability, are used to satisfy Duke's NERC Policy 1 Reserve Requirements (see Appendix A) and contingencies. Contingencies include events such as higher than expected unavailability of generating units and increased customer load due to extreme weather conditions.

Duke continually reviews the generating system capability, level of potential DSM activations, scheduled maintenance, purchased power availability and transmission capability to assess Duke's capability to reliably meet the customer load.

For the past four years Duke Power has utilized a 17 percent planning reserve margin. Between June 1998 and July 2000, there have been 15 days where generating reserves dropped below 3 percent. Generating reserves do not include purchases or DSM. When purchases and DSM are added to generating reserves, the lowest margin of reserves was 12 percent. From 1997, Duke has had sufficient reserves to reliably meet customer load with limited need to activate interruptible programs. The following table illustrates Duke's limited use of interruptible capacity, including the summer of 2000 through July 31. Based upon successful operations utilizing the 17 percent planning reserve margin, Duke concludes that its continued use is appropriate at this time.

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved
7/99 – 8/00	Air Conditioners	1 Load Test	170 – 200 MW	175 – 200 MW
7/99 – 8/00	Water Heaters	1 Load Test	6 MW	Included in Air Conditioners
7/99 – 8/00	Standby Generators	1 Capacity Need	70 MW	70 MW
		Monthly Test		
7/99 – 8/00	Interruptible Service	1 Communication Test	N/A	N/A
9/98 – 7/99	Air Conditioners	None		
9/98 – 7/99	Water Heaters	None		
9/98 – 7/99	Standby Generators	Monthly Test		
9/98 – 7/99	Interruptible Service	1 Communication Test	N/A	N/A
9/97 – 9/98	Air Conditioners	1 Load Test	180 MW	170 MW
9/97 – 9/98	Water Heaters	1 Communication Test	N/A	N/A
		1 Load Test	7 MW	7 MW
9/97 – 9/98	Standby Generators	2 Capacity Needs	68 MW	58 MW
		Monthly Test		
9/97 – 9/98	Interruptible Service	1 Communication Test	N/A	N/A
		1 Capacity Need	570 MW	500 MW
9/96 – 9/97	Air Conditioners	1 Communication Test	N/A	N/A
9/96 – 9/97	Water Heaters	None		
9/96 – 9/97	Standby Generators	4 Capacity Needs	62 MW	50 MW
		Monthly Test		
9/96 – 9/97	Interruptible Service	2 Communication Tests	N/A	N/A
		1 Capacity Need	650 MW	550 MW

TRANSMISSION SYSTEM ADEQUACY:

Duke Electric Transmission (ET) monitors the adequacy and reliability of the transmission system and its interconnections through analysis of internal transmission system models and participation in regional reliability groups. Corrective actions are planned and implemented in advance to ensure continued cost-effective high quality electric service is provided. Duke ET internal models cover the next ten years and are prepared in close coordination with Duke's resource planning and distribution personnel to accurately reflect available generating resources and load. The Duke ET internal model data is also used as input into industry models employed by regional reliability groups in their analyses.

Transmission system reliability is constantly monitored through evaluation of changes in load, generating capacity, transactions, or topography. Annually, a detailed screening of an internal model three years out is performed to identify any voltage or thermal loading violations of ET's Planning Guidelines. The screening methods are in compliance with Southeastern Electric Reliability Council (SERC) and North American Electric Reliability Council (NERC) planning guidelines. The annual screening results are used to evaluate a 10-year planning horizon that accounts for load growth, transmission reservations, and planned changes in generation and system topography. The screening results are a major input for the Transmission Asset Management Plan (TAMP). The TAMP controls the allocation of resources to ensure proper prioritization and funding of projects to maintain system reliability.

Duke ET participates in the following regional reliability groups for coordination of analysis of regional, sub-regional and inter-control area transfer capability and interconnection reliability:

1. VACAR – Carolina Power & Light (CP&L), Duke Power (DP), Fayetteville Public Works Comm., North Carolina Electric Membership Corporation (NCEMC), North Carolina Eastern Municipal Power Agency (NCEMPA), North Carolina Municipal Power Agency No. 1 (NCMPA1), South Carolina Electric & Gas (SCE&G), South Carolina Public Service Authority (SCPSA), Southeastern Power Administration (SEPA), Dominion Virginia Power, and Yadkin, Inc.
2. VAST – VACAR, American Electric Power (AEP), Southern and the Tennessee Valley Authority (TVA)
3. VEM – VACAR, East Central Area Reliability Council (ECAR) and the Mid-Atlantic Area Council (MAAC)
4. VSTO – VACAR, Southern, TVA and Oglethorpe

Each of these reliability groups evaluates the bulk transmission system to: 1) assess the interconnected system's capability to handle large firm and non-firm transactions, 2) ensure planned future transmission system improvements do not adversely affect neighboring systems and 3) ensure the interconnected systems' compliance with selected NERC Planning Standards.

Regional reliability groups normally participate in the evaluation of transfer capability and compliance to the NERC Planning Standards for the next peak load period through the next five to ten years. The regional reliability groups perform tests at sufficiently high transfer levels to verify satisfactory transfer capability is maintained for years in advance. Duke evaluates all requests for transmission reservation for impact on transfer capability and compliance with ET's Planning Guidelines. Studies, including transfer capability assessments, are performed to ensure transfer capability is acceptable and exceeds VACAR Reserve Sharing Agreement requirements. The VACAR Reserve Sharing Agreement ensures that all VACAR member control areas have sufficient generation to meet their largest single generation contingency. The TAMP process is also used to manage projects for improvement of transfer capability.

Duke ET's internal analyses, participation with industry reliability councils, and process for managing transmission system projects contribute to system security and reliable operation.

On July 18, 2000 CP&L Energy, Duke Energy and SCANA Corporation announced the formation of an independent regional transmission organization (RTO) in compliance with the Federal Energy Regulatory Commission's Order 2000. The RTO is to be known as GridSouth and would be responsible for operating and planning the transmission systems of the three companies.

Initially, the three utilities will continue to own their existing transmission networks, while the RTO assumes broad operational and planning responsibilities to ensure open and non-discriminatory access to the grid. The intent of the three companies is to create a framework that may lead to a broad, regional independent transmission company that spans the Southeast.

Historically, the three utilities have done an excellent job coordinating the planning and operation of their interconnected transmission systems to maintain a high degree of system reliability and adequacy. The formation of GridSouth, as the transmission operator for the combined transmission system, will further enhance the reliability of the interconnected systems. GridSouth will be uniquely positioned to coordinate not only the planning and operating activities of the three companies but to also coordinate the planning and operating activities with neighboring utilities and RTOs. This broader view may allow GridSouth to identify potential issues that the individual utilities previously may not have been able to identify.

The NCUC order dated June 21, 2000 in Docket No. E-100, Sub 84 required that the Annual Plan due September 1, 2000 include a discussion of efforts by the interested parties to meet and develop an efficient and responsive reporting mechanism for transmission adequacy. On August 15, 2000, CP&L, Duke, Dominion, NCEMC and the Public Staff met to discuss reporting on transmission adequacy. The utilities explained that transmission reliability is the subject of certain assessments and reports provided periodically by the utilities to the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Council (NERC), the Department of Energy (DOE) and to the Southeastern Electric Reliability Council (SERC). The parties agreed that the utilities shall provide copies of the published reports to the Public Staff. After the Public Staff reviews the reports, the parties will have additional meetings, as necessary, in an effort to resolve this issue.

CP&L has agreed to provide to the Public Staff, on behalf of CP&L, Duke, Dominion, and NCEMC, copies of the following reports:

VST 2003 Summer Study
VACAR 2003 Reliability Study
1999 SERC Reliability Review Subcommittee Report
2000 Summer VAST Reliability Study
2000 Summer VEM Reliability Assessment
Each company's FERC Form 715 Filings from April, 2000.

CUSTOMERS SERVED UNDER ECONOMIC DEVELOPMENT

The incremental load (demand) for which customers are receiving credits under the economic development rates and/or self-generation deferral rates (Rider EC) is:

48MW For North Carolina
29MW For South Carolina

ANNUAL PLAN INFORMATION CONTENTS

1. LOAD FORECAST AND LOAD CAPACITY AND RESERVES (LCR) TABLE

This section includes a tabulation of summer and winter peak loads, annual energy forecast, generating capability, and reserve margins for each year, and a description of the methods and assumptions used to prepare the forecast.

THE LOAD FORECAST:

To determine customer energy needs, Duke prepares a load forecast of energy sales and peak demand using state-of-the-art econometric methodologies. The current forecast includes plans for the energy needs of all new and existing customers within Duke's service territory. This requirement may change in any restructured electric industry. Currently, certain wholesale customers have the option of obtaining all or a portion of their future energy needs from suppliers other than Duke Power.

As part of the joint ownership arrangement for the Catawba Nuclear Station, the North Carolina Electric Membership Cooperative (NCEMC), the Saluda River Electric Cooperative Incorporated (SR) and the North Carolina Municipal Power Agency #1 (NCMPA) have given notice that they will be solely responsible for their total load requirements beginning January 1, 2001. As a result, NCEMC, SR and NCMPA supplemental load requirements, above their ownership portions of the Catawba Nuclear Station, are not reflected in the forecast commencing in 2001. Likewise, Piedmont Municipal Power Agency (PMPA) has given notice that they will be solely responsible for their total load requirements beginning January 1, 2006. As a result, PMPA supplemental load requirements, above their ownership portions of the Catawba Nuclear Station, are not reflected in the forecast commencing in 2006.

The current forecast over a 15-year period reflects an average annual growth in summer peak demand of 1.6 percent. Winter peaks are forecasted to grow at an average annual rate of 1.2 percent, and the average annual territorial energy is forecasted to grow at 1.8 percent. The growth rates use 2000 as the base year with 18,693 MW summer peak, 16,485 MW winter peak, and 98,016 GWH average annual territorial energy.

YEAR[4,5]	SUMMER (MW)[1]	WINTER (MW)[2]	TERRITORIAL ENERGY (GWH)[3]
2001	18,335	16,241	98,568
2002	18,737	16,162	100,962
2003	19,122	16,399	103,230
2004	19,543	16,658	105,507
2005	19,951	16,934	107,758
2006	20,156	17,160	109,704
2007	20,540	17,431	111,913
2008	20,946	17,711	114,093
2009	21,364	17,954	116,126
2010	21,761	18,256	118,338
2011	22,164	18,527	120,414
2012	22,574	18,777	122,397
2013	22,943	19,056	124,476
2014	23,330	19,327	126,477
2015	23,763	19,583	128,410

Note 1: Summer peak demand is for the calendar years indicated and includes the demand of the other joint owners of the Catawba Nuclear Station (CNS). Beginning on January 1, 2001 total demand above NCEMC, SR and NCMPA retained ownership is not included. Also, beginning on January 1, 2006 total demand above PMPA retained ownership is not included.

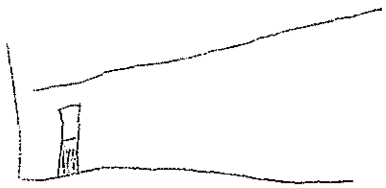
Note 2: Winter peak demand includes the demand of the other joint owners of the CNS. Beginning on January 1, 2001 total demand above NCEMC, SR and NCMPA retained ownership is not included. Also, beginning on January 1, 2006 total demand above PMPA retained ownership is not included.

Winter peak demand of 2001 is December 2000 which still includes the NCEMC, SR and NCMPA demand above their retained ownership. Winter peak demand of 2002 does not include NCEMC, SR and NCMPA demand above their retained ownership.

Note 3: Territorial energy is the total projected energy needs of the Duke service area, including losses and unbilled sales, and the energy requirements of the other joint owners of the CNS. Beginning on January 1, 2001 total energy above NCEMC, SR and NCMPA retained ownership is not included. Also, beginning on January 1, 2006 total energy above PMPA retained ownership is not included.

Note 4: This forecast is not comparable to that included in the 2000 Duke Power Forecast beginning January 1, 2001 due to removal of NCEMC, SR and NCMPA supplemental loads and beginning January 1, 2006 due to removal of PMPA supplemental loads.

Note 5: The impact of energy efficiency DSM programs is accounted for in the load forecast.



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Seasonal Projections of Load, Capacity, and Reserves for Duke Power and Nantahala Power and Light 2000 Annual Plan Base Case

W = WINTER, S = SUMMER	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S
	00/01	2001	01/02	2002	02/03	2003	03/04	2004	04/05	2005	05/06	2006	06/07	2007	07/08	2008
Forecast																
1 Duke System Peak	16,241	18,335	16,162	18,737	16,399	19,122	16,658	19,543	16,934	19,951	17,160	20,156	17,431	20,540	17,711	20,946
Cumulative System Capacity																
2 Generating Capacity	19,290	19,357	19,290	19,357	19,290	19,357	19,290	19,357	19,290	19,357	19,290	19,267	19,200	19,147	19,080	19,147
3 Capacity Retirements	0	0	0	0	0	0	0	0	0	0	(90)	0	(120)	0	0	0
4 Cumulative Generating Capacity	19,290	19,357	19,290	19,357	19,290	19,357	19,290	19,357	19,290	19,357	19,200	19,267	19,080	19,147	19,080	19,147
5 Cumulative Purchase Contracts	1,144	1,243	993	993	993	993	341	341	341	331	121	121	121	121	121	121
6 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Cumulative Future Resource Additions																
Peaking/Intermediate	0	0	0	600	0	1,070	0	2,245	0	2,735	200	3,379	644	3,865	1,130	4,347
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Production Capacity	20,434	20,600	20,283	20,950	20,283	21,420	19,631	21,943	19,631	22,423	19,521	22,767	19,845	23,133	20,331	23,615
Reserves w/o DSM																
9 Generating Reserves	4,193	2,265	4,121	2,213	3,884	2,298	2,973	2,400	2,697	2,472	2,361	2,611	2,414	2,593	2,620	2,669
10 % Reserve Margin	25.8%	12.4%	25.5%	11.8%	23.7%	12.0%	17.8%	12.3%	15.9%	12.4%	13.8%	13.0%	13.8%	12.6%	14.8%	12.7%
11 % Capacity Margin	20.5%	11.0%	20.3%	10.6%	19.1%	10.7%	15.1%	10.9%	13.7%	11.0%	12.1%	11.5%	12.2%	11.2%	12.9%	11.3%
DSM																
12 Cumulative DSM Capacity	566	1,003	564	980	562	959	560	940	559	920	557	900	556	882	555	862
13 Cumulative Equivalent Capacity	21,000	21,603	20,847	21,930	20,845	22,379	20,191	22,883	20,190	23,343	20,078	23,667	20,401	24,015	20,886	24,477
Reserves w/DSM																
14 Equivalent Reserves	4,759	3,268	4,685	3,193	4,446	3,257	3,533	3,340	3,256	3,392	2,918	3,511	2,970	3,475	3,175	3,531
15 % Reserve Margin	29.3%	17.8%	29.0%	17.0%	27.1%	17.0%	21.2%	17.1%	19.2%	17.0%	17.0%	17.4%	17.0%	16.9%	17.9%	16.9%
16 % Capacity Margin	22.7%	15.1%	22.5%	14.6%	21.3%	14.6%	17.5%	14.6%	16.1%	14.5%	14.5%	14.8%	14.6%	14.5%	15.2%	14.4%

W = WINTER, S = SUMMER	W 08/09	S 2009	W 09/10	S 2010	W 10/11	S 2011	W 11/12	S 2012	W 12/13	S 2013	W 13/14	S 2014	W 14/15	S 2015
Forecast														
1 Duke System Peak	17,954	21,364	18,256	21,761	18,527	22,164	18,777	22,574	19,056	22,943	19,327	23,330	19,583	23,763
Cumulative System Capacity														
2 Generating Capacity	19,080	18,881	18,814	18,881	18,814	18,881	18,814	18,881	18,814	18,881	18,814	18,881	18,814	18,773
3 Capacity Retirements	(266)	0	0	0	0	0	0	0	0	0	0	0	(108)	0
4 Cumulative Generating Capacity	18,814	18,881	18,814	18,881	18,814	18,881	18,814	18,881	18,814	18,881	18,814	18,881	18,706	18,773
5 Cumulative Purchase Contracts	121	121	121	121	121	121	121	121	121	121	33	33	33	33
6 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Cumulative Future Resource Additions														
Peaking/Intermediate	1,612	5,157	2,422	5,643	2,908	6,125	3,390	6,611	3,876	7,093	4,358	7,575	4,840	8,223
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Production Capacity	20,547	24,159	21,357	24,645	21,843	25,127	22,325	25,613	22,811	26,095	23,205	26,489	23,579	27,029
Reserves w/o DSM														
9 Generating Reserves	2,593	2,795	3,101	2,884	3,316	2,963	3,548	3,039	3,756	3,152	3,878	3,159	3,996	3,266
10 % Reserve Margin	14.4%	13.1%	17.0%	13.3%	17.9%	13.4%	18.9%	13.5%	19.7%	13.7%	20.1%	13.5%	20.4%	13.7%
11 % Capacity Margin	12.6%	11.6%	14.5%	11.7%	15.2%	11.8%	15.9%	11.9%	16.5%	12.1%	16.7%	11.9%	16.9%	12.1%
DSM														
12 Cumulative DSM Capacity	554	845	554	828	554	811	553	794	553	778	554	763	555	749
13 Cumulative Equivalent Capacity	21,101	25,004	21,911	25,473	22,397	25,938	22,878	26,407	23,364	26,873	23,759	27,252	24,134	27,778
Reserves w/DSM														
14 Equivalent Reserves	3,147	3,640	3,655	3,712	3,870	3,774	4,101	3,833	4,309	3,930	4,432	3,922	4,551	4,015
15 % Reserve Margin	17.5%	17.0%	20.0%	17.1%	20.9%	17.0%	21.8%	17.0%	22.6%	17.1%	22.9%	16.8%	23.2%	16.9%
16 % Capacity Margin	14.9%	14.6%	16.7%	14.6%	17.3%	14.5%	17.9%	14.5%	18.4%	14.6%	18.7%	14.4%	18.9%	14.5%

The following notes are numbered to match the line numbers on the SEASONAL PROJECTIONS OF LOAD, CAPACITY, AND RESERVES table. All values are MW except where shown as a Percent.

1. Planning is done for the peak demand for the Duke System including Nantahala. Nantahala became a division of Duke Power August 3, 1998.

2. Generating Capacity. Capacity must be online by June 1 to be included in the available capacity for the summer peak of that year. Capacity must be online by Dec 1 to be included in the available capacity for the winter peak of that year. Includes 100 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station (2258 MW).

   Capacity changes are due to Summer (May - Sept) Lincoln Fogger capacity of 67MW.

3. The 90 MW capacity retirement in 2006 represents the projected retirement date for CTs at Lee.
   The 120 MW capacity retirement in 2007 represents the projected retirement date for CTs at Riverbend.
   The 93 MW capacity retirement in 2009 represents the projected retirement date for the CTs at Buck.
   The 173 MW capacity retirement in 2009 represents the projected retirement date for CTs at Dan River & Bz Rst (Wst).
   The 108 MW capacity retirement in 2015 represents the projected retirement date for CT's at Buzzard Roost(GE).
   Oconee Nuclear Station is relicensed.
   All retirement dates are subject to review on an ongoing basis.

5. Purchase Contracts have several components:

   A. Effective January 1, 2001, the SEPA allocation will be reduced to 72MW. This reflects self scheduling by Seneca, Greenwood, Saluda River, NCEMC, and NCMPA1. The 72MW reflects allocations for PMPA and Schedule 10A customers who continue to be served by Duke.
   B. Piedmont Municipal Power Agency has given notice that they will be solely responsible for total load requirements beginning January 1, 2006. This reduces the SEPA allocation to 13 MW, which is attributed to Schedule 10A customers who continue to be served by Duke.
   C. Purchase of 250 MW maximum summer peak capacity from PECO began in June 1998 and expires Sept. 2001.
   D. Cogeneration megawatts have increased due to the 88 MW Cherokee Cogen contract which began in June 1998 and expires June 2013, and an additional 10 MW due to the firm purchase contract with the Kannapolis Energy Partners signed February 2000 and expires February 2005. The RJReynold's contract for 52MW expires December 31, 2003.
   E. Purchase of 302 MW summer peak capacity from July 1, 2000 to May 31, 2001 from CP&L, and 151 MW from June 1, 2001 to December 31, 2005.
   F. Purchase of 600 MW from Dynegy began July 1, 2000 and expires December 31, 2003.

7. Future Resource Additions represent new capacity resources or capability increases which are being considered. Neither the date of operation, the type of resource, nor the size is firm. All Future Resource Additions are uncommitted and represent capacity required to maintain a minimum planning reserve margin.

10. Reserve margin is shown for reference only.
    Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand

11. Capacity margin is the industry standard term. A 14.6 percent capacity margin is equivalent to a 17.0 percent reserve margin.
    Capacity Margin = (Cumulative Capacity - System Peak Demand)/Cumulative Capacity

12. Cumulative Interruptible and Direct Load Control capacity represents the demand-side management contribution toward meeting the load. The programs reflected in these numbers include dispatchable load control programs designed to be activated during capacity problem situations.

2. EXISTING PLANTS IN SERVICE

This section includes a list of the existing plants in service with capacity, plant type, and location.

NAME	UNIT #	MW CAPACITY	LOCATION	PLANT TYPE
Allen	1	165	Belmont, N. C.	Fossil
Allen	2	165	Belmont, N. C.	Fossil
Allen	3	265	Belmont, N. C.	Fossil
Allen	4	275	Belmont, N. C.	Fossil
Allen	5	270	Belmont, N. C.	Fossil
Belews Creek	1	1120	Walnut Cove, N. C.	Fossil
Belews Creek	2	1120	Walnut Cove, N. C.	Fossil
Buck	3	75	Spencer, N. C.	Fossil
Buck	4	38	Spencer, N. C.	Fossil
Buck	5	128	Spencer, N. C.	Fossil
Buck	6	128	Spencer, N. C.	Fossil
Buck	7C	31	Spencer, N. C.	Combustion Turbine
Buck	8C	31	Spencer, N. C.	Combustion Turbine
Buck	9C	31	Spencer, N. C.	Combustion Turbine
Buzzard Roost	6C	22	Chappels, S. C.	Combustion Turbine
Buzzard Roost	7C	22	Chappels, S. C.	Combustion Turbine
Buzzard Roost	8C	22	Chappels, S. C.	Combustion Turbine
Buzzard Roost	9C	22	Chappels, S. C.	Combustion Turbine
Buzzard Roost	10C	18	Chappels, S. C.	Combustion Turbine
Buzzard Roost	11C	18	Chappels, S. C.	Combustion Turbine
Buzzard Roost	12C	18	Chappels, S. C.	Combustion Turbine
Buzzard Roost	13C	18	Chappels, S. C.	Combustion Turbine
Buzzard Roost	14C	18	Chappels, S. C.	Combustion Turbine
Buzzard Roost	15C	18	Chappels, S. C.	Combustion Turbine
Cliffside	1	38	Cliffside, N. C.	Fossil
Cliffside	2	38	Cliffside, N. C.	Fossil
Cliffside	3	61	Cliffside, N. C.	Fossil
Cliffside	4	61	Cliffside, N. C.	Fossil
Cliffside	5	562	Cliffside, N. C.	Fossil
Dan River	1	67	Eden, N. C.	Fossil
Dan River	2	67	Eden, N. C.	Fossil
Dan River	3	142	Eden, N. C.	Fossil
Dan River	4C	30	Eden, N. C.	Combustion Turbine
Dan River	5C	30	Eden, N. C.	Combustion Turbine
Dan River	6C	25	Eden, N. C.	Combustion Turbine
Lee	1	100	Pelzer, S. C.	Fossil
Lee	2	100	Pelzer, S. C.	Fossil
Lee	3	170	Pelzer, S. C.	Fossil
Lee	4C	30	Pelzer, S. C.	Combustion Turbine
Lee	5C	30	Pelzer, S. C.	Combustion Turbine
Lee	6C	30	Pelzer, S. C.	Combustion Turbine

Continued

EXISTING PLANTS IN SERVICE, continued

NAME	UNIT #	MW CAPACITY	LOCATION	PLANT TYPE
Lincoln	1	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	2	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	3	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	4	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	5	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	6	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	7	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	8	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	9	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	10	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	11	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	12	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	13	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	14	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	15	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	16	79.19	Lowesville, N. C.	Combustion Turbine
Marshall	1	385	Terrell, N. C.	Fossil
Marshall	2	385	Terrell, N. C.	Fossil
Marshall	3	660	Terrell, N. C.	Fossil
Marshall	4	660	Terrell, N. C.	Fossil
Riverbend	4	94	Mt. Holly, N. C.	Fossil
Riverbend	5	94	Mt. Holly, N. C.	Fossil
Riverbend	6	133	Mt. Holly, N. C.	Fossil
Riverbend	7	133	Mt. Holly, N. C.	Fossil
Riverbend	8C	30	Mt. Holly, N. C.	Combustion Turbine
Riverbend	9C	30	Mt. Holly, N. C.	Combustion Turbine
Riverbend	10C	30	Mt. Holly, N. C.	Combustion Turbine
Riverbend	11C	30	Mt. Holly, N. C.	Combustion Turbine
Catawba	1	1129	Clover, S. C.	Nuclear
Catawba	2	1129	Clover, S. C.	Nuclear
McGuire	1	1100	Cornelius, N. C.	Nuclear
McGuire	2	1100	Cornelius, N. C.	Nuclear
Oconee	1	846	Seneca, S. C.	Nuclear
Oconee	2	846	Seneca, S. C.	Nuclear
Oconee	3	846	Seneca, S. C.	Nuclear
Jocassee	1	152.5	Salem, S. C.	Pumped Storage
Jocassee	2	152.5	Salem, S. C.	Pumped Storage
Jocassee	3	152.5	Salem, S. C.	Pumped Storage
Jocassee	4	152.5	Salem, S. C.	Pumped Storage
Bad Creek	1	266.25	Salem, S. C.	Pumped Storage
Bad Creek	2	266.25	Salem, S. C.	Pumped Storage
Bad Creek	3	266.25	Salem, S. C.	Pumped Storage
Bad Creek	4	266.25	Salem, S. C.	Pumped Storage
Hydro (in various locations)		1136		Hydro

3. GENERATING UNITS UNDER CONSTRUCTION OR PLANNED

A list of generating units under construction or planned at plant locations for which property has been acquired, for which certificates have been received, or for which applications have been filed with location, capacity, plant type, and proposed date of operation included.

Duke has no generating units under construction or planned.

4. PROPOSED GENERATING UNITS AT LOCATIONS NOT KNOWN

This section includes a list of proposed generating units at locations not known with capacity, plant type, and date of operation included to the extent known.

The following table contains the recommended resource additions for maintaining the current minimum planning reserve margin through 2015. Neither the resource, date of operation, type, nor size is firm. Additionally, new resources may be a combination of short/long-term capacity purchases from the wholesale market, capacity purchase options, and building or contracting to build new generation.

CAPACITY[1] (MW)	SUPPLY SIDE RESOURCES	DATES OF OPERATION
600	Peaking/Intermediate	06/01/2002
470	Peaking/Intermediate	06/01/2003
1175	Peaking/Intermediate	06/01/2004
490	Peaking/Intermediate	06/01/2005
644	Peaking/Intermediate	06/01/2006
486	Peaking/Intermediate	06/01/2007
482	Peaking/Intermediate	06/01/2008
810	Peaking/Intermediate	06/01/2009
486	Peaking/Intermediate	06/01/2010
482	Peaking/Intermediate	06/01/2011
486	Peaking/Intermediate	06/01/2012
482	Peaking/Intermediate	06/01/2013
482	Peaking/Intermediate	06/01/2014
648	Peaking/Intermediate	06/01/2015

Note 1: Capacity amounts placed in service may vary due to selection of actual purchase amounts, generation technology capacity ratings, etc.

Note 2: Duke is currently evaluating responses to its Request For Proposal (RFP) issued January 5, 2000. Potential outcomes could include self build resources, purchased power resources, or a combination of both. In early 2001, Duke may issue another RFP for resource additions.

5. GENERATING UNITS PROJECTED TO BE RETIRED

This section includes a list of units projected to be retired from service with location, capacity and expected date of retirement from the system. The following table reflects decision dates for retirements or refurbishments during the planning horizon and are subject to review on an ongoing basis.

STATION	CAPACITY IN MW	LOCATION	DECISION DATE
Lee 4C	30	Pelzer, SC	12/31/2005
Lee 5C	30	Pelzer, SC	12/31/2005
Lee 6C	30	Pelzer, SC	12/31/2005
Riverbend 8C	30	Mt. Holly, NC	12/31/2006
Riverbend 9C	30	Mt. Holly, NC	12/31/2006
Riverbend 10C	30	Mt. Holly, NC	12/31/2006
Riverbend 11C	30	Mt. Holly, NC	12/31/2006
Buck 7C	31	Spencer, NC	12/31/2008
Buck 8C	31	Spencer, NC	12/31/2008
Buck 9C	31	Spencer, NC	12/31/2008
Buzzard Roost 6C	22	Chappels, SC	12/31/2008
Buzzard Roost 7C	22	Chappels, SC	12/31/2008
Buzzard Roost 8C	22	Chappels, SC	12/31/2008
Buzzard Roost 9C	22	Chappels, SC	12/31/2008
Dan River 4C	30	Eden, NC	12/31/2008
Dan River 5C	30	Eden, NC	12/31/2008
Dan River 6C	25	Eden, NC	12/31/2008
Buzzard Roost 10C	18	Chappels, SC	12/31/2014
Buzzard Roost 11C	18	Chappels, SC	12/31/2014
Buzzard Roost 12C	18	Chappels, SC	12/31/2014
Buzzard Roost 13C	18	Chappels, SC	12/31/2014
Buzzard Roost 14C	18	Chappels, SC	12/31/2014
Buzzard Roost 15C	18	Chappels, SC	12/31/2014

6. GENERATING UNITS WITH PLANS FOR LIFE EXTENSION

This section includes a list of units for which there are specific plans for life extension, refurbishment or upgrading. The reporting utility shall also provide the expected (or actual) date removed from service, general location, capacity rating upon return to service, expected return to service date, and a general description of work to be performed.

STATION	ORIGINAL LICENSE EXPIRATION DATE	REVISED LICENSE EXPIRATION DATE
OCONEE 1	2/2013	2/2033
OCONEE 2	10/2013	10/2033
OCONEE 3	7/2014	7/2034

On May 23,2000, the Nuclear Regulatory Commission approved the License Renewal for all three units of the Oconee Nuclear Station located near Seneca, South Carolina. With renewal, the original 40 year licenses for the three units has been extended for 20 years. The 20 year extension moves the license expiration dates from 2013 for Units 1 and 2 and 2014 for Unit 3 to 2033 and 2034, respectively. Maintenance work is normally performed during regularly scheduled refueling outages. No capacity upgrades of the units are currently being planned.

STATION	PRESENT LICENSE EXPIRATION DATE	PROPOSED LICENSE EXPIRATION DATE
McGuire 1	6/12/2021	6/12/2041
McGuire 2	3/3/2023	3/3/2043
Catawba 1	12/6/2024	12/6/2044
Catawba 2	2/24/2026	2/24/2046

In 2001, Duke Energy plans to submit an application to the Nuclear Regulatory Commission for license renewal of four additional units. The two units at McGuire Nuclear Station located near Huntersville, North Carolina and the two units at Catawba Nuclear Station located near Clover, South Carolina. With renewal, the original 40 year licenses for the four units will be extended for 20 years. The 20 year extension moves the license expiration dates from 2021 for McGuire Unit 1 and 2023 for McGuire Unit 2 to 2041 and 2043, respectively. In addition, the 20 year extension moves the license expiration dates from 2024 for Catawba Unit 1 and 2026 for Catawba Unit 2 to 2044 and 2046, respectively. Maintenance work is normally performed during regularly scheduled refueling outages. No capacity upgrades of the units are currently being planned.

7. TRANSMISSION LINES AND OTHER ASSOCIATED FACILITIES UNDER CONSTRUCTION

This section includes a list of transmission lines and other associated facilities (161 KV or over) which are under construction or for which there are specific plans including the capacity and voltage levels, location, and schedules for completion and operation.

The following table identifies construction of one connection station for a project in Duke's transmission system.

PROJECT	VOLTAGE	LOCATION OF CONNECTION STATION	LINE CAPACITY	SCHEDULED OPERATION
Carolina Power & Light – New generation (~800MW)	500 kV	Guardian line–new connection station between McGuire Nuclear Station & Pleasant Garden, ~ 29 miles from McGuire (Rowan County)	Single circuit McGuire to CP&L to Pleasant Garden – 1666 MVA (No Upgrade)	June 1, 2001

In addition, NCUC Rule R8-62(p) requires the following information for existing transmission lines:

(1) For existing lines, the information required on FERC Form 1 pages 422, 423, 424, and 425.

Please see Appendix B for Duke's 1999 FERC Form 1 pages 422, 423, 422.1, 423.1, 422.2, 423.2, 422.3, 423.3, 424 and 425.

(2) For lines under construction, the following:
   a. commission docket number;
   b. location of end point(s);
   c. length;
   d. range of right-of-way width;
   e. range of tower heights;
   f. number of circuits;
   g. operating voltage;
   h. design capacity;
   i. date construction started;
   j. projected in-service date.

Duke has no new transmission lines under construction.

(3) For all other proposed lines, as the information becomes available, the following:
   a. county location of end point(s);
   b. approximate length;
   c. typical right-of-way width for proposed type of line;
   d. typical tower height for proposed type of line;
   e. number of circuits;
   f. operating voltage;
   g. design capacity;
   h. estimated date for starting construction;
   i. estimated in-service date.

Duke has no proposed new transmission lines.

8. GENERATION OR TRANSMISSION LINES SUBJECT TO CONSTRUCTION DELAYS

This section includes a list of any generation and associated transmission facilities under construction which have delays of over six months in the previously reported in-service dates and the major causes of such delays. Upon request from the Commission Staff, the reporting utility shall supply a statement of the economic impact of such delays.

There are no delays over six months in the stated in-service dates.

9. DEMAND-SIDE OPTIONS AND SUPPLY-SIDE OPTIONS REFLECTED IN THE PLAN

This section includes a list of demand-side options and supply-side options reflected in the resource plan.

ENERGY EFFICIENCY DEMAND-SIDE OPTIONS:

All effects of existing energy efficiency DSM programs listed below are captured in the customer load forecast:

RESIDENTIAL SERVICE WATER HEATING - CONTROLLED/SUBMETERED

This program shifts a participating customer's water heating usage to off peak periods as determined by Duke. The program is currently available in accordance with rate Schedule WC. The customer is billed at a lower rate for all water heating energy consumption in exchange for allowing Duke to control the water heater.

EXISTING RESIDENTIAL HOUSING PROGRAM

This residential program represents Duke's activities in the existing residential market to encourage increased energy efficiency in existing residential structures. The program consists of loans for heat pumps, central air conditioning systems, and energy efficiency measures such as insulation, HVAC tune-up, duct sealant, etc.

In the past year, Duke reviewed two energy efficiency pilot programs:

Special Needs Energy Products Loan
Neighborhood Revitalization Program

The pilots were combined into one program, Special Needs Energy Products Loan Program, effective February 24, 2000. This residential program represents Duke's activities in the existing residential market to encourage increased energy efficiency in existing residential structures for low income customers. The program consists of loans for heat pumps, central air conditioning systems, and energy efficiency measures such as insulation, HVAC tune-up, duct sealant, etc.

INTERRUPTIBLE DEMAND-SIDE OPTIONS:

These existing interruptible DSM options are identified on line 12 of the Seasonal Projections of Load, Capacity, and Reserves table. The interruptible DSM Options are not included in the customer load forecast because load control contribution depends upon actuation.

RESIDENTIAL LOAD CONTROL

This program is designed to provide a source of interruptible capacity to Duke at any time it encounters capacity problems. For air conditioning control, participants receive billing credits during the billing months of July through October for allowing Duke to interrupt electric service to their central air conditioning systems. For water heating control, participants receive billing credits each month for allowing Duke to interrupt electric service to their water heaters. Water heating load control was closed to new customers on January 1, 1993 in North Carolina and on February 17, 1993 in South Carolina.

STANDBY GENERATOR CONTROL

This program is designed to provide a source of interruptible capacity to Duke at any time it encounters capacity problems during the year. Participants in the program contractually agree to transfer electrical loads from the Duke source to their standby generators when so requested by Duke. The generators in this program do not operate in parallel with Duke's system and, therefore, cannot "backfeed" (or export power) into the Duke system. Participating customers receive payments for capacity and/or energy based on the amount of capacity and/or energy transferred to their generator.

INTERRUPTIBLE POWER SERVICE

This program is designed to provide a source of interruptible capacity to Duke at any time it encounters capacity problems during the year. Participants in the program contractually agree to reduce their electrical loads to specified levels when so requested by Duke. Failure to do so results in a penalty for the increment of demand which exceeds a specified level. The program has not been available to new participants since 1992.

Projected data on the Interruptible DSM Programs are contained on the following page.

INTERRUPTIBLE DEMAND SIDE PROGRAMS DATA

Number of Customers

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
AC/LC	199,676	198,723	196,100	193,476	190,853	188,230	185,606	182,983	180,359	177,736	175,113	172,489	169,866	167,242	164,619	161,996
WH/LC	41,964	37,924	34,876	31,829	28,781	25,733	22,686	19,638	16,591	13,543	10,495	7,448	4,400	1,353	0	0
IS	203	203	203	203	203	203	203	203	203	203	203	203	203	203	203	203
SG	140	142	144	146	148	150	152	154	156	158	160	162	164	166	168	170

Demand (kw)

	2000		2001		2002		2003		2004		2005		2006		2007	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
AC/LC	0	377,000	0	359,000	0	336,000	0	315,000	0	295,000	0	274,000	0	254,000	0	235,000
WH/LC	29,000	8,000	25,000	7,000	22,000	6,000	19,000	5,000	16,000	5,000	14,000	4,000	11,000	3,000	9,000	3,000
IS	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000
SG	70,000	84,000	71,000	85,000	72,000	86,000	73,000	87,000	74,000	88,000	75,000	90,000	76,000	91,000	77,000	92,000
Total	569,000	1,021,000	566,000	1,003,000	564,000	980,000	562,000	959,000	560,000	940,000	559,000	920,000	557,000	900,000	556,000	882,000

Demand (kw)

	2008		2009		2010		2011		2012		2013		2014		2015	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
AC/LC	0	215,000	0	197,000	0	179,000	0	161,000	0	144,000	0	127,000	0	111,000	0	95,000
WH/LC	7,000	2,000	5,000	2,000	4,000	1,000	3,000	1,000	1,000	0	0	0	0	0	0	0
IS	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000
SG	78,000	93,000	79,000	94,000	80,000	96,000	81,000	97,000	82,000	98,000	83,000	99,000	84,000	100,000	85,000	102,000
Total	555,000	862,000	554,000	845,000	554,000	828,000	554,000	811,000	553,000	794,000	553,000	778,000	554,000	763,000	555,000	749,000

Budget

	2000	2001	2002	2003	2004	2005
AC/LC	$6,443,000	$6,359,000	$6,275,000	$6,191,000	$6,107,000	$6,023,000
WH/LC	$983	$910	$837	$764	$691	$618
IS	$20,107,000	$20,107,000	$20,107,000	$20,107,000	$20,107,000	$20,107,000
SG	$2,340,000	$2,373,000	$2,407,000	$2,440,000	$2,473,000	$2,507,000
Total	$28,890,983	$28,839,910	$28,789,837	$28,738,764	$28,687,691	$28,637,618

Note: Only includes credits paid to customers.

Energy (kwh)	
AC/LC	None
WH/LC	None
IS	None
SG	None

Target Market Segment	
AC/LC	Residential
WH/LC	Residential
IS	Commercial & Industrial
SG	Commercial & Industrial

9. DEMAND-SIDE OPTIONS AND SUPPLY-SIDE OPTIONS REFLECTED IN THE PLAN, continued

The Supply-Side Options selected for the expansion plan are subjected to an economic screening process to determine cost effective supply side technologies. The most viable supply-side technologies are selected.

Viable Supply-Side Options:

Conventional Technologies: (technologies in common use)
162 MW Combustion Turbine
482 MW Combined Cycle
600 MW Conventional Fossil
400 MW Gas Fired Boiler
1600 MW Pumped Storage

Demonstrated Technologies: (technologies with limited acceptance and not in widespread use)
20 MW Lead Acid Battery
220 MW Compressed Air Energy Storage (CAES)

The most economically attractive technologies that were selected for expansion planning analysis were:

162 MW Combustion Turbine
482 MW Combined Cycle

10. WHOLESALE PURCHASE POWER COMMITMENTS REFLECTED IN THE PLAN

1. Rockingham L.L.C. has constructed a gas-fired, five-unit, 750 MW generation facility in Rockingham County, NC. Duke Power has a contract to purchase 600 megawatts of capacity and energy generated by the power plant. The contract term began July 1, 2000 and runs through the end of 2003, with options to extend through 2008.

2. Duke Power has acquired capacity purchase options of 250 MW from PECO Energy. The contract term began in June 1998 and will continue through September 2001. This contract is applicable during summer months only (June - September).

3. Duke Power has acquired capacity purchase contract of 302 MW from CP&L. The contract term begins July 1, 2000 to May 31, 2001 at 302 MW. The contract capacity then drops to 151 MW from June 1, 2001 to December 31, 2005.

4. Duke purchases 88 MW of capacity from Cherokee Cogeneration on an annual basis, through June 2013.

5. Duke expects to purchase approximately 82 MW annually from other cogeneration and small power producers as identified in Appendix C. These firm purchases will decrease over time as contracts expire.

11. WHOLESALE POWER SALES COMMITMENTS REFLECTED IN THE PLAN

Duke provides wholesale power sales under Schedule 10A. The load requirements of Schedule 10A customers are reflected in the Seasonal Projections of Load, Capacity and Reserves table. Sales in 1999 totaled 1347 GWH as reported in Duke Energy's 1999 FERC Form 1 filing.

APPENDICES

APPENDIX A:

The following pages are the NERC Policy 1 Generation Control and Performance, Section A for Operating Reserve.

Policy 1 — Generation Control and Performance

For implementation February 15, 2000

Version 1a

Policy Subsections

General Criteria

Each system shall either operate a Control Area or make arrangements to be included in a Control Area operated by another system. All load, generation, and transmission operating in an Interconnection must be included within the metered boundaries of a Control Area.

A. Operating Reserve

[Appendix 1A – Area Control Error Equation]
[Performance Standard Training Document]

Criteria

Each CONTROL AREA shall operate its MW power resources to provide for a level of OPERATING RESERVE sufficient to account for such factors as errors in forecasting, generation and transmission equipment unavailability, number and size of generating units, system equipment forced outage rates, maintenance schedules, regulating requirements, and Regional and system load diversity. Following loss of resources or load, a CONTROL AREA shall take appropriate steps to reduce its AREA CONTROL ERROR to meet the Disturbance Control Standard (DCS). It shall take prompt steps to protect itself against the next contingency.

Each Region, subregion or RESERVE SHARING GROUP shall specify its operating reserve policies, including the minimum reserve requirement for the group, its allocation among members, the permissible mix of SPINNING RESERVE and nonspinning reserve, and procedure for applying operating reserve in practice, and the limitations, if any, upon the amount of interruptible load which may be included.

Requirements

1. **Operating reserve distribution.** OPERATING RESERVE shall be dispersed throughout the system and shall consider the effective use of capacity in an emergency, time required to be effective, transmission limitations, and local area requirements.

2. **Contingency review.** All Regions, subregions, RESERVE SHARING GROUPS, and CONTROL AREAS shall frequently review probable contingencies to determine the adequacy of operating reserve.

3. **Operating reserve.** Each Region, subregion, or RESERVE SHARING GROUP shall specify, and each CONTROL AREA shall provide, as a minimum, operating reserve as follows:

3.1. **Regulating reserve.** An amount of SPINNING RESERVE, responsive to AGC, which is sufficient to provide normal regulating margin, plus

3.2. **Contingency reserve.** An additional amount of OPERATING RESERVE sufficient to reduce AREA CONTROL ERROR to meet the Disturbance Control Standard following the most severe single contingency.

3.2.1. **Spinning reserve.** At least 50% of this operating reserve shall be SPINNING RESERVE, which will automatically respond to frequency deviations.

3.2.1.1. **Jointly owned generation with dynamic schedules.** CONTROL AREAS that share JOINTLY OWNED UNITS and incorporate DYNAMIC SCHEDULES or PSEUDO-TIES shall include only their share of the unit in their SPINNING RESERVE calculations.

3.2.1.2. **Jointly owned generation with fixed schedules.** CONTROL AREAS receiving their share of JOINTLY OWNED UNITS as fixed schedules should not include the jointly owned units' share(s) on which the schedules are based in their SPINNING RESERVE calculations. The CONTROL AREA in which the jointly owned unit resides may include the SPINNING RESERVES for its share of the unit.

3.2.2. **Reserve sharing group.** Each RESERVE SHARING GROUP shall comply with the Disturbance Control Standard as if it were a single CONTROL AREA. A RESERVE SHARING GROUP shall be considered in a DISTURBANCE condition any time a group member is in a DISTURBANCE condition and calls for reserves. Compliance may be demonstrated in either of the following two methods:

3.2.2.1. **Group compliance to Disturbance Control Standard.** The RESERVE SHARING GROUP reviews group ACE (or equivalent) and demonstrates compliance.

3.2.2.2. **Group member compliance to Disturbance Control Standard.** The RESERVE SHARING GROUP reviews each member's ACE in response to a call for reserves; to be in compliance each member's ACE must return to zero or to its respective pre-disturbance level within ten minutes of the start of the DISTURBANCE.

3.2.3. **RESERVE SHARING GROUP monitoring.** Each RESERVE SHARING GROUP shall monitor operating reserve availability and actual response.

3.2.4. **Reduction in SPINNING RESERVE.** The SPINNING RESERVE component may be reduced below 50% of the OPERATING RESERVE providing the Region, subregion, or reserve sharing group can demonstrate that with this reduction and upon its most severe single contingency, it will still be able to meet or exceed established Performance Standards, and not jeopardize the reliable operation of the Interconnection.

3.2.5. **INTERRUPTIBLE LOAD.** INTERRUPTIBLE LOAD may be included in the non-spinning reserve provided that it can be interrupted within ten minutes.

3.2.6. **Disturbance Control Performance Adjustment.** Each control area or reserve sharing group *not meeting the Disturbance Control Standard* during a given quarter, shall increase its Contingency Reserve obligation for the calendar quarter (offset by a month) following the evaluation. The increase shall be directly proportional to the control area's or reserve sharing group's non-compliance to the Disturbance Control Standard. (See the "Performance Standard Training Document," Section C.)

3.3. **Jointly owned generation in another CONTROL AREA.** CONTROL AREAs using fixed schedules for JOINTLY OWNED UNITS that reside outside their CONTROL AREA may include their share of the facility in their OPERATING RESERVE calculations. The OPERATING RESERVE is constrained by their share of the unit(s) capability and their share of the unit(s) ramp capability achievable over a ten-minute period. Included in the ten minutes is the time necessary to schedule the generation into the CONTROL AREA.

3.4. **Reestablishing OPERATING RESERVE.** An additional amount of reserve shall be made available as soon as practicable to aid in reestablishing this minimum OPERATING RESERVE after such reserve has been used.

APPENDIX B:

The following are Duke's 1999 FERC Form 1 pages 422, 423, 422.1, 423.1, 422.2, 423.2, 422.3, 423.3, 424 and 425.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1999

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not re| substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tow or (4) underground construction if a transmission line has more than one type of supporting structure, indicate the mileage of each type of constructic by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of whic reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Rep pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Nun C Circ (h
1								
2	Antioch Tie	Appalachian Power	525.00	525.00	Tower	27.65		
3	McGuire SW	Antioch Tie	525.00	525.00	Tower	54.35		
4	McGuire	Newport	525.00	525.00	Tower	32.26		
5	McGuire-Pleasant Garden	East Durham-Parkwood	525.00	525.00	Tower	131.81		
6	Newport	Rockingham	525.00	525.00	Tower	48.68		
7	Oconee	Newport	525.00	525.00	Tower	107.92		
8	Oconee	Norcross	525.00	525.00	Tower	22.51		
9	Oconee	Jocassee-McGuire	525.00	525.00	Tower	140.77		
10	Jocassee	Bad Creek	525.00	525.00	Tower	9.24		
11	————————							
12	Total 525kv Lines					575.19		
13	————————							
14								
15								
16	Allen	Pacolet-Tiger	230.00	230.00	Tower	80.22		
17	Allen	Beckerdite	230.00	230.00	Tower	79.89		
18	Allen	Riverbend	230.00	230.00	Tower	12.50		
19	Allen	Woodlawn	230.00	230.00	Tower	8.13		
20	Antioch Tie	Wilkes Tie	230.00	230.00	Tower	4.32		
21	Beckerdite	Pleasant Garden-Eno	230.00	230.00	Tower	71.26		
22	Beckerdite	Rural Hall	230.00	230.00	Tower	107.03		
23	Belews Creek	Sadler Tie	230.00	230.00	Tower	26.27		
24	Catawba	Peacock	230.00	230.00	Tower	14.82		
25	Central	Anderson	230.00	230.00	Tower	23.13		
26	Cliffside	Pacolet	230.00	230.00	Tower	23.01		
27	Cliffside	Shelby	230.00	230.00	Tower	14.12		
28	East Durham	Parkwood-Eno-Roxboro	230.00	230.00	Tower	33.00		
29	Eno Tie - East Durham	CP&L	230.00	230.00	Tower	15.80		
30	Greenville	Shady Grove-Central	230.00	230.00	Tower/Poles	34.01		
31	Greenville	Shiloh-Pisgah Forest	230.00	230.00	Tower	30.82		
32	Hartwell	Anderson-Hodges	230.00	230.00	Tower	36.96		
33	Jocassee Tie	Tuckaseegee	230.00	230.00	Tower	26.63		
34	Lincoln CT	Longview Tie	230.00	230.00	Tower	31.22		
35	Longview	McDowell	230.00	230.00	Tower	31.96		
36					TOTAL			

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Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1999

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
2515								2
2515								3
2515								4
2515								5
2515								6
2515								7
2515								8
2515								9
2515								10
	20,264,522	92,433,012	112,697,534					11
	20,264,522	92,433,012	112,697,534					12
								13
								14
								15
954 & 1272								16
954								17
954 & 1272								18
2156								19
954 & 1272								20
954								21
954 & 2156								22
1272								23
1272								24
954								25
954								26
954								27
1272								28
1272								29
954 & 2515								30
954								31
954 & 2515								32
1272								33
795								34
954								35
								36

ne of Respondent ce Energy Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year of Report Dec. 31, 1999

TRANSMISSION LINE STATISTICS

Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 volts or greater. Report transmission lines below these voltages in group totals only for each voltage.
Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report station costs and expenses on this page.
Report data by individual lines for all voltages if so required by a State commission.
Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
ndicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; 4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction he use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the ainder of the line.
Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is orted for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report e miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Marshall	Longview	230.00	230.00	Tower	29.06		2
2	Marshall	Mitchell River	230.00	230.00	Tower	49.49		2
3	Marshall	Winecoff	230.00	230.00	Tower	24.36		2
4	McGuire-Harrisburg-Oakboro	Newport-Catawba	230.00	230.00	Tower	139.44		[illegible]
5	McGuire SW	Lincoln CT	230.00	230.00	Tower	5.34		2
6	Mitchell	Rural Hall	230.00	230.00	Tower	43.74		2
7	Newport	Parr-Bush River	230.00	230.00	Tower	63.25		1
8	Oconee	Central	230.00	230.00	Tower	17.64		2
9	Oconee	Jocassee-Shiloh-Tiger	230.00	230.00	Tower/Poles	85.54		2
10	Pisgah Forest	Skyland	230.00	230.00	Tower	14.42		2
11	Riverbend	Lakewood (Pinoca)	230.00	230.00	Tower	10.64		2
12	Riverbend	McGuire-Marshall-Beckerdite	230.00	230.00	Tower	79.95		2
13	Riverbend	Shelby-Peach Valley-Tiger	230.00	230.00	Tower	109.42		2
14	Tiger	North Greenville	230.00	230.00	Tower	18.40		2
15	————							
16	Total 230kv Lines					1,395.79		63
17	————							
18								
19								
20	Dan River	Appalachian	138.00	138.00	Tower/Poles	6.50		1
21	Greenwood	Clark Hill	110.00		Wood Poles	35.76		1
22	Horseshoe Tie	Skyland CP&L	115.00	115.00	Tower/Poles	7.63		1
23	Lake Emory S.S.	Webster	161.00		S pole	12.00		1
24	Nantahala	Marble S. S.	161.00		Steel tower	17.00		2
25	Nantahala	Robbinsville S. S.	161.00		Steel tower	8.00		1
26	Oak Grove	Lake Emory S. S.	161.00		H frame	7.00		1
27	Oak Grove	Nantahala	161.00		Steel tower	14.00		2
28	Robbinsville S. S.	Santeetlah	161.00		Steel tower	11.00		1
29	Saluda Dam	Bush River Tie	110.00	110.00	Tower	11.48		2
30	Thorpe	Tuckasegee Tie	161.00		H frame	2.00		1
31	Tuckaseegee Tie	Thorpe Hydro	161.00	161.00	Tower	1.40		1
32	Tuckasegee Tie	Webster	161.00		Steel tower	9.00		2
33	Webster	Oak Grove	161.00		Steel tower	13.00		2
34	100kv Lines		100.00	100.00	Tower	3,024.94		[illegible]
35	100kv Lines		100.00	100.00	Poles	335.40		[illegible]
36					TOTAL			

Name of Respondent Duke Energy Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year of Report Dec. 31, 1999

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report t pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining th arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272								1
954								2
1272								3
954 & 1272								4
795								5
954 & 2156								6
954								7
795 & 1272								8
1272 & 2156								9
954								10
795 & 954								11
954 & 1272								12
795 & 954								13
954								14
	39,500,621	188,599,933	228,100,554					15
	39,500,621	188,599,933	228,100,554					16
								17
								18
								19
477								20
398								21
477 & 1272								22
636	1,637,424	34,656,911	36,294,335	99,897	230,608	2,957	333,462	23
795								24
636								25
795								26
795								27
636								28
336								29
397.5								30
1272								31
795								32
795								33
								34
								35
								36

...e of Respondent ...e Energy Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year of Report Dec. 31, 1999

TRANSMISSION LINE STATISTICS

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...dicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; ... underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction ...e use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the ...inder of the line.
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DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
100kv Lines		100.00	100.00	Underground	1.78		
Total 100kv Lines					3,517.89		19
44kv Lines		44.00	44.00	Tower	283.85		
44kv Lines		44.00	44.00	Poles	2,215.35		
44kv Lines		44.00	44.00	Underground	0.73		1
Bear Creek	Thorpe	66.00		H frame	4.00		1
Bryson plant	E. Bryson tap	66.00		Spole&Hframe	4.00		1
Cashiers	Shortoff S. S.	66.00		H frame	4.00		1
Cherokee S. S. tap	Bryson Plant	66.00		S pole	1.00		1
Cherokee S. S. tap	Cherokee S. S.	66.00		SPole&Hframe	4.00		1
Cullowee tap	Cullowhee S. S.	66.00		S Pole	1.00		1
Cullowee tap	Webster	66.00		H frame	4.00		1
E. Bryson tap	E. Bryson S. S.	66.00		Spole&Hframe	1.00		1
E. Franklin S. S.	Otto S. S. tap	66.00		Spole&Hframe	3.00		1
Gateway	Cherokee S. S. tap	66.00		S pole	2.00		1
Glenville	Cashiers	66.00		H frame	2.00		1
Glenville	Sapphire	66.00		S pole	4.00		1
Jenkins Branch tap	E. Bryson tap	66.00		Spole&Hframe	2.00		1
Lake Emory S. S.	E. Franklin S. S.	66.00		S pole	2.00		1
N. Franklin S. S.	Lake Emory S. S.	66.00		S pole	2.00		1
Oak Grove	Jenkins Branch S. S.	66.00		Spole&Hframe	12.00		1
Otto S. S. tap	Otto S. S.	66.00		S pole	8.00		1
Otto S. S. tap	S. Franklin S. S.	66.00		Spole&Hframe	2.00		1
S. Franklin S. S.	W. Franklin S. S.	66.00		S pole	2.00		1
Thorpe	Cashiers S. S.	66.00		Spole&Hframe	8.00		1
Thorpe	Cullowhee tap	66.00		H frame	7.00		1
Thorpe	Glenville	66.00		H frame	6.00		1
Tennessee Creek	Bear Creek	66.00		H frame	4.00		1
W. Franklin S. S.	N. Franklin S. S.	66.00		S pole	4.00		1
Webster	Gateway	66.00		S pole	8.00		1
Webster	Sylva S. S.	66.00		H frame	3.00		1
				TOTAL			

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TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	Line No.
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
								1
	47,478,399	287,048,972	334,527,371					2
	49,115,823	321,705,883	370,821,706	99,897	230,608	2,957	333,462	3
								4
								5
								6
								7
								8
								9
266.8								10
795								11
266.8								12
397.5								13
266.8								14
3/0								15
397.5								16
3/0								17
795								18
397.5								19
266.8								20
636								21
397.5								22
636								23
397.5 & 795								24
397.5								25
636								26
266.8								27
397.5								28
795	3,261,805	32,750,125	36,011,930	29,197	112,350	7,780	149,327	29
397.5								30
266.8								31
159								32
397.5 & 795								33
397.5								34
397.5								35
								36

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5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) towe or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Repc pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Numl Of Circu (h)
1	———————							
2	Total 44kv & 66kv Lines					2,603.93		
3	———————							
4								
5								
6	33kv Lines		33.00	33.00	Poles	5.46		
7	22kv Lines		22.00	22.00	Poles	118.61		
8	13kv Lines		13.00	13.00	Poles	36.63		
9	13kv Lines		13.00	13.00	Underground	0.25		
10	———————							
11	Total 33kv Lines					160.95		
12	———————							
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	8,253.75		1

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1999

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
	19,694,292	104,765,976	124,460,268					1
	22,956,097	137,516,101	160,472,198	29,197	112,350	7,780	149,327	2
								3
								4
								5
								6
								7
								8
								9
	568,683	3,486,613	4,055,296					10
	568,683	3,486,613	4,055,296					11
								12
								13
				1,459,555	11,018,491		12,478,046	14
								15
								16
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								35
	132,405,746	743,741,542	876,147,288	1,588,649	11,361,449	10,737	12,960,835	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1999

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to repo minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	To (b)	Line Length in Miles (c)	SUPPORTING STURCTURE Type (d)	Average Number per Miles (e)	CIRCUITS PER STURCTU Present (f)	Ultimate (g)
1	Overhead Construction:						
2	Rexnord Tap		0.35	Pole	11.00	1	
3	Transco Pine Needle Tap		1.82	Pole	9.00	1	
4	Triangle Ret Tap		3.25	Pole	9.00	1	
5	Wildcat Tie to Cornelius Tap		0.04	Pole	4.00	1	
6	Blue Ridge EC Del # 25		0.17	Pole	12.00	1	
7	Clinton City Del # 2 Tap		0.18	Pole	17.00	1	
8	Ebenezer Ret Tap		3.11	Pole	11.00	1	
9	Laurens EMC Del # 31		0.08	Pole	13.00	1	
10							
11							
12							
13							
14							
15							
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42							
43							
44	TOTAL		9.00		86.00	8	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1999

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST				Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Total (o)	
								1
556.5	ACSR		100		132,793	59,661	192,454	2
556.5	ACSR		100	185,118	367,182	142,793	695,093	3
556.5	ACSR		100	2,386	233,483	73,731	309,600	4
556.5	ACSR		100		24,812	22,004	46,816	5
556.5	ACSR		100		17,514	11,676	29,190	6
556.5	ACSR		100		62,461	38,282	100,743	7
556.5	ACSR		100	598,246	487,804	162,601	1,248,651	8
556.5	ACSR		100		38,298	14,893	53,191	9
								10
								11
								12
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								43
				785,750	1,364,347	525,641	2,675,738	44

APPENDIX C:

The following table is the 2000 Non-Utility Generation Status Report filed September 2000.

Duke Power
A Duke Energy Company

2000 NON-UTILITY GENERATION STATUS REPORT

September 1, 2000

NCUC Docket No. E-100, Sub. 41B
NCUC Docket No. E-100, Sub. 84

SECTION I

SECTION I: NON-UTILITY GENERATORS WHO HAVE CONTACTED DUKE POWER BUT NOT YET EXECUTED A CONTRACT

Project Number	Owner/Developer Address City State Zip	Contact Phone Plant Name Plant Location	Capacity Fuel/Technology	Status
1998-12 C			300 KW Run-of-River Hydro	Inquiry - interested in purchasing existing PP hydro facility (11/98) <<INACTIVE since 09/99>>
1998-13 C			Unknown Small Hydro	Inquiry - info regarding small hydro operations (11/98) <<INACTIVE since 09/99>>
1998-14 C			Unknown Unknown	Initial Inquiry. (02/98) <<INACTIVE since 09/99>>
1998-15 C			4,000 KW Coal/Waste	Initial Inquiry regarding self-generation. (02/98) <<INACTIVE since 09/99>>
1998-16 C			300 KW Run-of-River Hydro	Inquiry - interested in purchasing existing PP hydro facility (02/98) <<INACTIVE since 09/99>>

Project Number	Owner/Developer Address City State Zip	Contact Phone Plant Name Plant Location	Capacity Fuel/Technology	Status
1998-17 C			300 KW Run-of-River Hydro	Inquiry - interested in purchasing existing PP hydro facility (02/98) <<INACTIVE since 09/99>>
1998-18 N	Jim Horton 1800 Statesville Blvd Salisbury NC 28144	Jim Horton 704-638-0506 Idols Hydro Winston-Salem, NC	1,400 KW Run-of-River Hydro	Inquiry - interested in purchasing damaged hydro facility (02/98)
1999-01 C			Unknown Landfill Gas	Initial inquiry re rates and interconnection (6/99) <<INACTIVE since 09/99>>
1999-02 C			50 KW Unknown	Initial Inquiry regarding generation of power (3/99) <<INACTIVE since 09/99>>
1999-03 C			Unknown Solar PV	Inquiry regarding residential PV systems (4/99) <<INACTIVE since 09/99>>
1999-04 C			Unknown Diesel Reciprocating	Inquiry regarding PP rates and interconnection (4/99) <<INACTIVE since 09/99>>

Project Number	Owner/Developer Address City State Zip	Contact Phone Plant Name Plant Location	Capacity Fuel/Technology	Status
1999-05 C			Unknown Solar PV	Inquiry regarding residential PV systems (4/99) <<INACTIVE since 09/99>>
1999-06 C			Unknown Solar PV	Inquiry regarding residential PV systems (4/99) <<INACTIVE since 09/99>>
1999-07 C			Unknown Unknown	Inquiry re interconnection equipment and installation (4/99) <<INACTIVE since 09/99>>
1999-08 C			Unknown Tire Burning Cogen	Initial inquiry regarding rates and procedures (5/99) <<INACTIVE since 09/99>>
1999-09 C			Unknown Wind/Solar PV	Inquiry regarding residential PV systems (5/99) <<INACTIVE since 09/99>>
1999-10 C			250,000 KW Coal	Inquiry regarding power sales. (3/99) <<INACTIVE since 09/99>>

Project Number	Owner/Developer Address City State Zip	Contact Phone Plant Name Plant Location	Capacity Fuel/Technology	Status
1999-11 C			Unknown Coal cogeneration	Initial inquiry regarding upgrading existing facility and sales to DP (7/99) <<INACTIVE since 09/99>>
1999-12 C			Unknown Solar PV	Inquiry regarding residential PV systems (7/99) <<INACTIVE since 09/99>>
1999-13 C			300 KW each Run-of-River Hydro	Inquiry - interested in abandoned hydro facility and existing PP hydro facility (6/99) <<INACTIVE since 09/99>>
1999-14 C			540,000 KW Gas-fired Combined Cycle	Inquiry through economic development contacts regarding possible merchant plant in service area (9/99)
1999-15 C				Inquiry regarding PP rates and interconnection (11/99)
1999-16 C			Hydroelectric	Inquiry regarding PP rates and interconnection (11/99)

Project Number	Owner/Developer Address City State Zip	Contact Phone Plant Name Plant Location	Capacity Fuel/Technology	Status
2000-01 C			Unknown Wind	Inquiry regarding interconnection and buy-back of excess energy on residential system (4/00)
2000-02 C			Unknown Hydro - water wheel	Inquiry regarding PP rates and interconnection (3/00)
2000-03 C			600 KW Run-of-River Hydroelectric	Inquiry - interested in purchasing existing PP hydro facility (2/00)
2000-04 C			1,500 KW each Gas-fired CT	Inquiry regarding use of 1.5 MW CTs for peaking needs. (7/00)
2000-05 C				Initial Inquiry. (7/00)

Duke Power is currently evaluating capacity offers received in response to its 2000 Request for Proposals for up to approximately 2,900 MW. Duke Power is negotiating with a short-list of bidders. Information on RFP respondents has not been included in this report.

Duke Power
A Duke Energy Company

2000 NON-UTILITY GENERATION STATUS REPORT

September 1, 2000

NCUC Docket No. E-100, Sub. 41B
NCUC Docket No. E-100, Sub. 84

SECTION II

SECTION II. NON-UTILITY GENERATORS WHO HAVE EXECUTED A CONTRACT WITH DUKE POWER BUT HAVE NOT BEGUN PRODUCING POWER

Project No.	Supplier Name Address City State Zip Facility Name/Location	Contact Telephone Installed Capacity Contract Capacity	Fuel/Technology Contract Type Contract Date Contract Delivery Date	Contract Rates Contract Term Anticipated Power Production Date
1	Mayo Hydro 1240 Springwood Circle Gibsonville NC 27249 Mayo Dam Hydroelectric Facility	Charles C. Wood 910-449-5054 951 KW 175 KW	Run-of-River Hydroelectric Total Output 8/11/98 On or Before 3/11/01	Negotiated (NC) Fixed, Levelized 10 years On or Before 3/11/01
Terminated	Southern Power Corporation 4162 Maria Street Chattanooga TN 37411-1209 Old Fort Generating Plant	Michael R. Knauff 423-624-0852 5,000 KW 4,500 KW	Waste-Wood Cogeneration Total Output 3/6/96 On or Before 9/6/98	Schedule PP(NC) 15-year Fixed Ser. 4, 3rd Revised 15 years Late 1998 (est'd)

2000 NON-UTILITY GENERATION STATUS REPORT

September 1, 2000

SECTION III. NON-UTILITY GENERATORS WHO HAVE EXECUTED A CONTRACT WITH DUKE POWER AND HAVE BEGUN PRODUCING POWER (includes only facilities selling power to Duke Power)

Project Number	Supplier Name Address City State Zip Facility Name/Location	Contact Telephone Installed Capacity Contract Capacity	Fuel/Technology Contract Type Contract Date Contract Delivery Date	Contract Rates Initial Contract Term	Comments Initial Power Production Date Initial Term Expires
01	Aquenergy Systems, Inc. P.O. Box 8597 Greenville SC 29604 Piedmont Hydro	Beth Harris 864-281-9630 X-105 1,050KW 1,050KW	Hydroelectric Total Output 2/13/98 12/29/97	Schedule PP (SC) Variable 1 year, then yearly thereafter	Owned by Consolidated Hydro Southeast, Inc. Pre-PURPA 12/28/97
02	Aquenergy Systems, Inc. P.O. Box 8597 Greenville SC 29604 Ware Shoals Hydro	Beth Harris 864-281-9630 X-105 6,300KW 6,300KW	Hydroelectric Total Output 2/13/98 12/29/97	Schedule PP (SC) Variable 1 year, then yearly thereafter	Owned by Consolidated Hydro Southeast, Inc. Pre-PURPA 12/28/97
03	Aquenergy Systems, Inc. P.O. Box 8597 Greenville SC 29604 Woodside I Hydro	Beth Harris 864-281-9630 X-105 450KW 450KW	Hydroelectric Total Output 2/13/98 12/29/97	Schedule PP (SC) Variable 1 year, then yearly thereafter	Owned by Consolidated Hydro Southeast, Inc. 12/29/83 12/28/97
04	Aquenergy Systems, Inc. P.O. Box 8597 Greenville SC 29604 Woodside II Hydro	Beth Harris 864-281-9630 X-105 500KW 500KW	Hydroelectric Total Output 2/13/98 12/29/97	Schedule PP (SC) Variable 1 year, then yearly thereafter	Owned by Consolidated Hydro Southeast, Inc. 12/29/83 12/28/97

Project Number	Supplier Name Address City State Zip Facility Name/Location	Contact Telephone Installed Capacity Contract Capacity	Fuel/Technology Contract Type Contract Date Contract Delivery Date	Contract Rates Initial Contract Term	Comments Initial Power Production Date Initial Term Expires
05	Avalon Hydro 1240 Springwood Church Road Gibsonville NC 27249 Avalon Hydro	Timothy H. Henderson 910-449-5054 1,275 KW 212 KW	Hydroelectric Total Output 12/27/94 4/26/97	Schedule PP (NC) 15-year Fixed Ser.4, 1st Revised 15 years	Formerly H & H Properties. Assigned to Avalon Hydro on 8/25/98 4/26/97 4/25/12
06	Bluestone Energy Design, Inc. P.O. Box 181 Converse SC 29329 Clifton Dam #3 Hydro	Tim Lamb 864-579-4640 1,250 KW 1,250 KW	Hydroelectric Total Output 1/7/98 1/12/98	Schedule PP (SC) Variable 1 year, then yearly thereafter	Alt. Contact: Victoria Miller - 864-579-4640 7/16/85 1/11/99
07	Brushy Mountain Hydro-Electric Power Co. Route 1, Box 383 Jackson GA 30233 Millersville, NC	J. Herb Warren/Winston Moore 404-775-5303 320 KW 350 KW	Hydroelectric Total Output 10/2/85 9/23/85	Schedule PP (NC) 15-year Fixed Ser.3, 7th Revised 15 years	Formerly Brushy Mt. Power Co. (Contract Assigned 2/5/90) 6/14/83 9/22/00
08	Buck Creek Corporation P.O. Box 1330 Marion NC 28752 Lake Tahoma Hydro	Bob King 704-355-3063 240 KW 159 KW	Hydroelectric Total Output 10/25/99 8/14/99	Schedule PP-H (NC) 15-year Fixed Ser.4, 1st Revised 15 years	Formerly McRay Energy, Inc. (Contract Assigned 9/15/92) 12/13/82 8/13/2014
09	Carolina Power & Light Company P.O. Box 1551, CPB 10A Raleigh NC 27602 Broad River SC CT; Rowan County NC CT	Kent Fonvielle 919-546-3257 ,250,000 KW 302,000 KW	Gas-fired CT w/ oil backup Dispatchable 3/22/00 7/1/00	Negotiated 5.5 years	Contract Capacity reduced to 151000 kW on 6/1/2001. Delivery from Broad River through 5/31/01, then from Rowan County. 7/1/2000 12/31/2005
10	Cascade Power Company P.O. Box 1137 Brevard NC 28712 Brevard, NC	Charles Pickelshimer 704-884-9011 900 KW 950 KW	Hydroelectric Total Output 4/29/86 4/16/86	Schedule PP (NC) 15-year Fixed Ser.3, 10th Revised 15 years	4/16/86 4/15/01

Project Number	Supplier Name Address City State Zip Facility Name/Location	Contact Telephone Installed Capacity Contract Capacity	Fuel/Technology Contract Type Contract Date Contract Delivery Date	Contract Rates Initial Contract Term	Comments Initial Power Production Date Initial Term Expires
11	Catawba County P O Box 389 Newton NC 28658 Blackburn Landfill Gas Facility	Barry B. Edwards 704-465-8260 4,000 KW 3,700 KW	Landfill Methane Gas Total Output 6/16/97 8/23/99	Schedule PP (NC) 15-year Fixed Ser.4, 3rd Revised 15 years	8/23/99 8/22/14
12	Catawba County P O Box 389 Newton NC 28658 Newton Landfill Gas Facility	Barry B. Edwards 704-465-8260 2,000 KW 1,800 KW	Landfill Methane Gas Total Output 8/11/98 8/23/99	Schedule PP (NC) 15-year Fixed Ser.4, 3rd Revised 15 years	8/23/99 8/22/14
13	Cherokee County Cogeneration Partners, LLP 132 Peoples Creek Rd Gaffney SC 29340 Cherokee County Cogeneration	Steve Patrick 864-488-3630 X-101 100,000 KW 88,000 KW	Gas-Fired Combined-Cycle Cogen Total Output 8/26/94 7/1/98	Negotiated (SC) 15 years escalating	4/18/98 6/30/2013
14	Clearwater Hydro B 4 Chimney Rock Road Rutherfordton NC 28139 Caroleen, NC	Richard Gresham 520-473-3232 324 KW 187 KW	Hydroelectric Total Output 12/30/99 1/6/00	Schedule PP-H (NC) 15-year Fixed Ser.4, 1st Revised 15 years	8/13/85 1/6/2015
15	Harden Manufacturing Co. 5265 Mallard Point Dr Lake Wylie SC 29710 Harden Hydro # 2 & # 3	Adrienne LaFar 552-5204 620 KW 620 KW	Hydroelectric Total Output 2/28/86 12/20/86	Schedule PP (NC) 15-year Fixed Ser.3, 9th Revised 15 years	12/20/85 12/19/00
16	Haw River Hydro Co. P O Box 1459 Asheboro NC 27204 Haw River Hydro-Saxapahaw	William H. Lee 910-824-2008 1,500 KW 1,500 KW	Hydroelectric Total Output 2/25/97 1/8/97	Schedule PP (NC) 15-year Fixed Ser.4, 3rd Revised 15 years	Formerly Deep River Hydro Co. (Change eff. 1/7/93) 1/8/82 1/7/12

Project Number	Supplier Name Address City State Zip Facility Name/Location	Contact Telephone Installed Capacity Contract Capacity	Fuel/Technology Contract Type Contract Date Contract Delivery Date	Contract Rates Initial Contract Term	Comments Initial Power Production Date Initial Term Expires
17	Kannapolis Energy Partners, LLC 220 N. Main Street, Suite 603 Greenville SC 29601 Kannapolis Power Project	Ralph Walker 864-242-4624 22,500 KW 9 KW	Pulverized Coal Cogeneration Total Output 2/22/200	Negotiated (NC) Fixed, levelized 5 years	Formally owned & operated self-generation by Fieldcrest-Cannon. Pre-PURPA 2/22/2005
18	Kannapolis Energy Partners, LLC 220 N. Main Street, Suite 603 Greenville SC 29601 Spencer Power Project	Ralph Walker 864-242-4624 3,500 KW 1 KW	Pulverized Coal Cogeneration Total Output 2/22/00	Negotiated (NC) Fixed, levelized 5 years	Formally owned & operated self-generation by Fieldcrest-Cannon. Pre-PURPA 2/22/2005
19	Mill Shoals Hydro Company, Inc. P.O. Box 8597 Greenville SC 29604 Long Shoals Hydro	Beth Harris 864-281-9630 X-105 900 KW 1,000 KW	Hydroelectric Total Output 11/20/84 11/20/84	Schedule PP-H (NC) Variable 15 years	Owned by Consolidated Hydro Southeast, Inc. Formerly Long Shoals Hydro Inc. (Contract Assigned 7/14/93) Payment reverted to Variable Rate upon expiration of 6/4/85 11/19/99
20	Mill Shoals Hydro Company, Inc. P.O. Box 8597 Greenville SC 29604 High Shoals Hydro	Beth Harris 864-281-9630 X-105 1,800 KW 1,800 KW	Hydroelectric Total Output 8/12/97 4/2/97	Schedule PP (NC) 15-year Fixed Ser.4, 3rd Revised 15 years	Owned by Consolidated Hydro Southeast, Inc. Formerly McBess Industries, Inc. (Contract Assigned 7/14/93) 4/2/82 4/1/12
21	Northbrook Carolina Hydro, LLC 225 W. Wacker Dr., St. 2330 Chicago IL 60606 Boyd's Mill Hydro	Mark Sundquist 312-553-2136 1,500 KW 110 KW	Hydroelectric Total Output 12/4/96 12/4/96	Negotiated (SC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Pre-PURPA 12/4/06, if extended by Northbrook
22	Northbrook Carolina Hydro, LLC 225 W. Wacker Dr., St. 2330 Chicago IL 60606 Holliday's Bridge Hydro	Mark Sundquist 312-553-2136 3,500 KW 2,230 KW	Hydroelectric Total Output 12/4/96 12/4/96	Negotiated (SC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Pre-PURPA 12/4/06, if extended by Northbrook

Project Number	Supplier Name Address City State Zip Facility Name/Location	Contact Telephone Installed Capacity Contract Capacity	Fuel/Technology Contract Type Contract Date Contract Delivery Date	Contract Rates Initial Contract Term	Comments Initial Power Production Date Initial Term Expires
23	Northbrook Carolina Hydro, LLC 225 W. Wacker Dr., St. 2330 Chicago IL 60606 Saluda Hydro	Mark Sundquist 312-553-2136 2,400 KW 515 KW	Hydroelectric Total Output 12/4/96 12/4/96	Negotiated (SC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Pre-PURPA 12/4/06, if extended by Northbrook
24	Northbrook Carolina Hydro, LLC 225 W. Wacker Dr., St. 2330 Chicago IL 60606 Stice Shoals Hydro	Mark Sundquist 312-553-2136 600 KW 125 KW	Hydroelectric Total Output 12/4/96 12/4/96	Negotiated (NC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Pre-PURPA 12/4/06, if extended by Northbrook
25	Northbrook Carolina Hydro, LLC 225 W. Wacker Dr., St. 2330 Chicago IL 60606 Spencer Mountain Hydro	Mark Sundquist 312-553-2136 640 KW 560 KW	Hydroelectric Total Output 12/4/96 12/4/96	Negotiated (NC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Pre-PURPA 12/4/06, if extended by Northbrook
26	Northbrook Carolina Hydro, LLC 225 W. Wacker Dr., St. 2330 Chicago IL 60606 Turner Shoals Hydro	Mark Sundquist 312-553-2136 5,500 KW 3,000 KW	Hydroelectric Total Output 12/4/96 12/4/96	Negotiated (NC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Pre-PURPA 12/4/06, if extended by Northbrook
27	Pacolet River Power Co. Inc. 5250 Clifton-Glendale Road Spartanburg SC 29307-4618 Clifton No. 1 Hydro	Charles B. Mierek 864-579-4405 800 KW 800 KW	Hydroelectric Total Output 4/19/88 3/20/86	Schedule PP (SC) Variable 5 years	3/10/82 Yearly thereafter
28	Pelzer Hydro Co. P.O. Box 8597 Greenville SC 29602 Lower Pelzer Hydro	Beth Harris 864-281-9630 X-105 3,300 KW 3,300 KW	Hydroelectric Total Output 9/11/98 9/11/98	Schedule PP (SC) Variable 1 year	Owned by Consolidated Hydro Southeast, Inc. Pre-PURPA Yearly thereafter

Project Number	Supplier Name Address City State Zip Facility Name/Location	Contact Telephone Installed Capacity Contract Capacity	Fuel/Technology Contract Type Contract Date Contract Delivery Date	Contract Rates Initial Contract Term	Comments Initial Power Production Date Initial Term Expires
29	Pelzer Hydro Co. P.O. Box 8597 Greenville SC 29602 Upper Pelzer Hydro	Beth Harris 864-281-9630 X-105 2,020 KW 2,020 KW	Hydroelectric Total Output 9/11/98 9/11/98	Schedule PP (SC) Variable 1 year	Owned by Consolidated Hydro Southeast, Inc. Pre-PURPA Yearly thereafter
30	Pharr Yarns,Inc. P. O. Box 1939 McAdenville NC 28101	Jim Howard 1,056 KW 800 KW	Hydroelectric As-Available Excess 11/25/92 11/19/92	Schedule PP-H (NC) Variable 5 years	Formerly Known as Stowe Mills, Inc. 6/12/84 11/18/97
31	R.J. Reynolds Tobacco Company Bowman Gray Technical Center Winston-Salem NC 27102 Tobaccoville Cogeneration Facility	Tom Casey 336-741-6224 80,000 KW 52,000 KW	Coal-fired Cogen Firm Excess 12/14/98 12/22/98	Negotiated (NC) Fixed Capacity Indexed Energy 5 years	7/19/85 12/31/03
31	Rockingham Power, LLC 1000 Louisiana St., Suite 5800 Houston TX 77002 Rockingham CT Facility/Reidsville NC	Ketan Patel 713-767-8760 800,000 KW 600,000 KW	Gas-fired CT w/ oil backup Dispatchable 9/30/98 7/1/00	Negotiated 3.5 years	7/18/2000 12/31/2003
33	Salem Energy Systems, LLC 335 W. Hanes Mill Road Winston-Salem NC 27105 Winston-Salem Gas Recovery	Robert (Bob) Biskeborn 910-776-1462 4,750 KW 4,170 KW	Landfill Gas-fueled Turbine Cogen Total Output 3/24/95 7/10/96	Schedule PP (NC) 15-year Fixed Ser.4, 1st Revised 15 years	Formerly Enerdyne II, LLC 7/10/96 7/10/11
34	South Yadkin Power, Inc. 6898A Coltrane Mill Rd. Greensboro NC 27406 Cooleemee Dam Hydro Project	Lyn & Breck Bullock 704-284-4051 1,400 KW 280 KW	Hydroelectric Total Output 7/2/97 7/9/97	Negotiated (NC) Fixed Levelized, 5 + 5 10 years	Formerly Turbine Industries, Inc. 7/9/97 7/8/07

Project Number	Supplier Name Address City State Zip Facility Name/Location	Contact Telephone Installed Capacity Contract Capacity	Fuel/Technology Contract Type Contract Date Contract Delivery Date	Contract Rates Initial Contract Term	Comments Initial Power Production Date Initial Term Expires
35	Spray Cotton Mills P O Box 3207 Eden NC 27280-3207	Mark Bishopric 910-627-6200 500KW 500KW	Hydroelectric Total Output 11/28/94 11/3/94	Schedule PP (NC) 15-year Fixed Ser.4, 1st Revised 15 years	Pre-PURPA 11/2/09
36	The Harden Company 5265 Mallard Point Dr Lake Wylie SC 29710 Harden Hydro # 1	Adrienne LaFar 552-5204 200KW 200KW	Hydroelectric Total Output 3/11/99 2/17/99	Schedule PP-H (NC) 15-year Fixed Ser.4, 1st Revised 15 years	3/31/83 2/16/04
37	Town of Lake Lure P.O. Box 2255 Lake Lure NC 28746 Lake Lure Hydro Facility	H.M. "Chuck" Place 828-625-9983 3,600KW 2,500KW	Hydroelectric Total Output 8/24/99 2/18/99	Negotiated (NC) 7-year Fixed 7 years	Pre-PURPA 2/18/2006
38	Whitney Mills 212 Range Road Kings Mountain NC 28086 Spartanburg, SC	Nelson Evans 704-739-9710 225KW 225KW	Hydroelectric Total Output 11/7/97 4/30/98	Schedule PP (SC) 5 yrs, yearly thereafter	4/30/98 4/29/03

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Cancelled	Aquenergy Systems, Inc. P.O. Box 8597 Greenville SC 29604 Apalache Hydro	Beth Harris 864-281-9630 X-105 420 KW 420 KW	Hydroelectric Total Output 2/13/98 12/29/97	Schedule PP (SC) Variable 1 year, then yearly there	Plant has discontinued operation. 3/15/84 12/28/97
Cancelled	BMW Manufacturing, Inc. P. O. Box 11000 Spartanburg SC 29304 BMW Cogeneration Facility	Lennie Beamon, Fac.Coord. 5,000 KW 5,000 KW	Gas-Fired Cogen Total Output 1/27/95 2/1/95	Schedule PP (SC) Variable 10 years	Now using cogen plant for displacement purposes. 2/1/95 1/31/05
Cancelled	Bob Jones University Wade Hampton Blvd. Greenville SC 29614 Bob Jones University	Attn: Business Office 4,500 KW 2,000 KW	Diesel-fired Cogen As-Available Excess 12/30/88 10/15/88	Schedule PG (SC) 5 years	Now using cogen plant for displacement purposes. 10/15/88 Yearly thereafter
Cancelled	Coltrane Mill Hydro 7023 Troy Caveness Road. Ramseur NC 27316 Randolph County, NC	Susan P. White 910-879-2594 60 KW 60 KW	Hydroelectric Total Output 8/17/83 8/16/83	Schedule PP-H (NC) Variable Yearly	Plant has discontinued operation. 8/16/83 2/15/99
Cancelled	FMC Corp./Lithium Div. P O Box 3925 Gastonia NC 28053 Bessemer City Plant	 11,500 KW 3,000 KW	Coal Fired Cogen As-Available Excess 3/21/91 3/21/91	Schedule PG (NC) 5 years	(03/12/91 is Operation Date for 5,000 KW condensing turbine gen. add'n) Now using cogen plant for displacement purposes. 9/19/86 3/20/96

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Terminated	Northbrook Carolina Hydro, LLC 225 W. Wacker Dr., St. 2330 Chicago IL 60606 Idols Hydro	Mark Sundquist 312-553-2136 1,411 KW 163 KW	Hydroelectric Total Output 12/4/96 12/4/96	Negotiated (NC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Contract terminated by agreement of both parties effective May 1, 1998 due to the destruction of the facility by fire on Febryary 8, 1998. Pre-PURPA 3/1/99
Terminated	Preservation NC P O Box 12338 Winston-Salem NC 27117 Glencoe Hydro	Kirk Carrison 910-798-0765 250 KW 250 KW	Hydroelectric Total Output 7/5/84 2/10/84	Schedule PP (NC) 15-year Fixed Ser.3, 5th Revised 15 years	Formerly Glencoe Hydroelectric Co., Inc. Purchased by Preservation NC in 1997. (Contract Assigned 2/5/90) Supplier requested termination of PPA upon expiration, effective 2/9/99. 2/10/84 2/9/99
Cancelled	R.J. Reynolds Tobacco Company Bowman Gray Technical Center Winston-Salem NC 27102 Whitaker Park Cogen Facility	Tom Casey 336-741-6224 8,500 KW 8,500 KW	Coal-fired Cogen Total Output 3/6/91 9/24/90	Schedule PP (NC) Variable 5 years	Plant has discontinued operation. 9/24/90 9/23/95