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DOCKET NO. E-2, SUB 297

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

IN THE MATTER OF

APPLICATION OF
CAROLINA POWER AND LIGHT COMPANY
FOR INCREASE IN ITS RATES AND CHARGES

TESTIMONY OF

DENNIS J. NIGHTINGALE
UTILITIES ENGINEER
DIVISION OF ENGINEERING

Staff, North Carolina Utilities Commission

March 23, 1977

Q. Will you state your name and address for the record?

A. My name is Dennis J. Nightingale. My business address is One West Morgan Street, Raleigh, North Carolina 27602.

Q. What is your position with the North Carolina Utilities Commission Staff?

A. I am a Utilities Engineer in the Electric Section of the Engineering Division.

Q. Will you briefly discuss your education and experience?

A. I received my Bachelor of Science Degree in Electrical Engineering from Northeastern University in June, 1971. Upon graduation, I joined the Division of Power Supply and Reliability, Bureau of Power of the Federal Power Commission. My primary responsibility there was the analysis and evaluation of the adequacy and reliability of electric power planning by utilities, power pools and the nine regional reliability councils. In the performance of my duties, I have prepared several Bureau of Power Staff reports, represented the Federal Power Commission on both the FEA's Inter-agency Task Group on Power Plant Reliability and on a Florida Public Service Commission and Florida Coordinating Group's Joint Study using loss of load probability to ascertain the time frame for bulk power interconnections between Florida and Georgia. I also testified before the Atomic Safety and Licensing Board on the need for power (AEC Docket Nos. 50-346, 50-334, 50-413 and 50-414). In October, 1975, I joined the Staff of the North Carolina Utilities Commission. As a member of the Commission Staff, I have testified on the reasonableness of current plant in service and construction program for Carolina Power and Light Company (Docket No. E-2, Sub 264), the need for new generating facilities for both Duke Power Company (Docket No. E-7, Sub 166) and Carolina Power and Light Company (Docket No. E-2, Sub 241), and Docket No. E-100, Sub 22 in the matter of investigation, analysis and estimation of the need for future generating capacity for North Carolina. I have also assisted in the preparation of Commission testimony before the Environmental Protection Agency (EPA Docket No. AHNC 512 NR). Currently, I am a member of the Institute of Electrical and Electronics Engineers (IEEE).

Q. What is the subject of your testimony in this proceeding?

A. My testimony is concerned with the reasonableness of Carolina Power and Light Company's current plant in service and construction program.

Q. How did you proceed with your investigation of CP&L's current capacity and future construction program?

A. The analysis of CP&L's current capacity and future construction program relied heavily on the information contained in the Commission's "Report of Analysis and Plan; Future Requirements for Electricity Service to North Carolina," dated February, 1977. This report provides an independent long-term forecast of North Carolina utility peak loads and a plan for generation capacity requirements. Three basic conclusions of this report were that a reserve criterion ranging between 15 and 20 percent for the summer peaking season and a reserve of not less than 20 percent for the winter peaking season would provide adequate and reliable electric service, that nuclear facilities have an economic advantage over other types of base load generating facilities and that the utilities in North Carolina should have approximately 1/2 base, 1/3 intermediate and 1/6 peaking capacity.

In its report the Commission concluded that between 1976 and 1986 Carolina Power and Light Company would experience an annual peak load growth of 6.86 percent. Based on this load growth and its summer/winter reserve criterion the Commission developed a capacity construction schedule for CP&L as shown in DJN Exhibit No. 1. This capacity schedule would give CP&L about 50 percent base capacity, 32 percent intermediate capacity and 18 percent peaking capacity for 1977. DJN Exhibit No. 1 also contains CP&L's proposed capacity construction schedule (from Harris Exhibit No. 2) which results in a capacity mix of about 55 percent base capacity, 29 percent intermediate capacity and 16 percent peaking capacity for 1977.

The significant difference between these construction schedules is the timing of commercial operation for various units. Based on its reserve criterion the Commission's construction schedule has delayed Brunswick No. 1 one year while advancing the Mayo Creek and Harris units approximately one year. Since the timing of the Brunswick unit is of special importance to this proceeding further investigation into the need for the Brunswick unit was undertaken.

The load data used in the Commission's analysis and plan included the Summer of 1976. Peak load estimates were calculated from this point and reserve levels were calculated using these load estimates. DJN Exhibit No. 2, Part A, shows the peak load estimates for the years 1977-1979 and possible reserve margins depending on the commercial operation of Brunswick No. 1. The reserves shown on Part A of this exhibit indicate that CP&L would satisfy the Commission's reserve criterion in 1977 without the Brunswick unit, but would not meet this criterion if the unit were not operating in 1978. Since that analysis was performed, CP&L experienced a new winter peak load of 5,509 mw.

A more reasonable load scenario would be to apply the annual 6.86 percent growth factor to both CP&L's 1976 Summer and 1976-77 Winter peaks to forecast future summer and winter peak loads. Part B of DJN Exhibit No. 2 contains the reserve margins using this assumption. This approach indicates a need for Brunswick No. 1 in the Winter of 1977-78.

Q. Have you studied any of the costs associated with delaying Brunswick No. 1 from 1977 to 1978?

A. Yes, I have looked at some of the possible costs associated with delaying the Brunswick unit one year.

The first cost I looked at was an additional year of allowance for funds used during construction if the plant was not declared commercial. Using an eight (8) percent factor to CP&L's estimated

331.4 million dollar cost results in an additional cost of 26.5 million dollars. This raises the installed cost from about 404 dollars per KW to about 436 dollars per KW. Using a fixed charge rate of sixteen (16) percent over thirty (30) years, the additional 26.5 million dollar cost results in an additional annual cost of about 4.3 million dollars.

Another cost studied was the cost of replacing the energy which could have been generated by the new Brunswick unit. In looking at this cost various assumptions were made in determining the amount of energy the Brunswick unit could produce and the costs associated with energy from other sources.

With regards to the amount of energy the new Brunswick unit could produce in 1977 it was assumed that the new unit would not exceed the current licensed capacity rating (790 mw) of Brunswick No. 2. The second assumption involved the selection of a capacity factor for the unit. There is a high degree of uncertainty surrounding the availability of any new unit during its first year of operation. Brunswick No. 2 had a capacity factor around 35 percent its first year of operation. Because of the experience CP&L has gained with the operation of Brunswick No. 2, its sister unit Brunswick No. 1 should not experience the same events and therefore should have a better (higher) capacity factor during its first year of operation. For this analysis it was assumed that Brunswick No. 1 would generate at a 65 percent capacity factor. This assumption results in a probable energy generation of 4,498,260 megawatt hours.

Assuming nuclear energy has a production cost (fuel plus O & M expenses) of 4 mills/KWH, the cost of this nuclear energy would be slightly under 18.0 million dollars (DJN Exhibit No. 3). If we further assume that the nuclear fuel cost is approximately 3.5 mills/KWH then the cost of fuel for this energy would be about 15.7 million dollars.

CP&L could pick up this "lost" energy by generation on its own system or by purchasing energy from neighboring utilities. If the assumption was made that CP&L would generate this energy internally they should use the lowest cost, generally the most efficient, units available. The other end of the cost spectrum would occur if the most expensive energy producing units (combustion turbines) had to be used.

The cheapest energy on CP&L's system would probably come from existing base load nuclear units. Since nuclear base load units operate as long as physically possible they would not be available to supply any make up energy. The next cheapest energy would come from CP&L's coal fired units.

For this analysis it was assumed that CP&L would use its ten (10) most efficient coal units, as reported in the 1975 FPC Form 1, to supply make up energy. DJN Exhibit No. 3 shows the assumptions used to calculate the cost of the coal fired make up energy. The energy cost would be about 51.0 million dollars, or about 33.0

million dollars more than the estimated cost of the energy from the Brunswick unit. The fuel cost increase would be approximately 33.0 million dollars.

Under the assumption that the probable Brunswick energy was supplied by combustion turbines the cost as shown in DJN Exhibit No. 3 would be approximately 222.4 million dollars. This is a 204.4 million dollar difference from the estimated Brunswick energy cost. The fuel cost increase would be about 197.7 million dollars.

It is doubtful that the make up energy would be supplied by just coal fired units or by just combustion turbines. Depending on load variations a combination of both types of units will be required to supply the energy which the Brunswick unit would have provided to the system. However, these two scenarios do provide upper and lower bounds on the additional energy costs associated with a one year delay of the Brunswick unit.

Purchase power from neighboring utilities is another alternative to the energy the Brunswick unit could provide. Neighboring utilities, specifically Duke and Vepco, appear to have sufficient reserves to sell large blocks of power to CP&L during the next year. It seems unlikely that CP&L would be able to purchase large amounts of inexpensive base generation. CP&L would probably purchase intermediate or low cost peaking capacity. A cost of 15 mills/KWH was assumed to approximate the cost of purchase energy. Using this assumed value, purchase energy would cost approximately 67.5 million dollars to replace the Brunswick energy. That is about 49.5 million dollars above the estimated cost of the Brunswick nuclear energy.

Q. Did you calculate the cost to the consumer of placing the Brunswick unit into service one year earlier than needed for system reliability?

A. Using an original cost factor of 9.69 percent, calculated from the requested rates in Exhibit I of CP&L's Application, and multiplying this by the cost of the Brunswick unit (331.4 million dollars) the gross increase in cost to the consumer for Brunswick No. 1's first year of operation would be about 32.1 million dollars.

Q. Would you please summarize your testimony?

A. CP&L's current installed capcity closely approximates the Commission's recommended capacity breakdown. The addition of Brunswick No. 1 slightly alters the proportions of base and intermediate generating capacity. In determining the need for the Brunswick unit two load scenarios were studied. In both cases there was no need, based on the Commission's reserve criterion for adequate and reliable electric service, shown for Brunswick No. 1 for the Summer of 1977. The second scenario did, however, indicate a need for this unit in the Winter of 1977-78.

Calculations of some of the possible costs associated with a one year delay of Brunswick No. 1 indicated that a delay could increase the capital cost approximately 26.5 million dollars (about a 4.3 million dollar additional annual cost) or from 404 dollars per KW to 436 dollars per KW. There would also be an additional fuel expenditure ranging from 33.0 to 197.7 million dollars due to the delay of the Brunswick unit.

These costs of delaying the unit should be compared to the cost to the consumer for the Brunswick units first year of operation. Based on CP&L's rate of return request on original cost investment the gross increase in cost to the consumer for the first year of operation would be about 32.1 million dollars.

It should be noted that the fuel cost and production statistics utilized in these computations are estimates from various sources and do not tie directly to the rate case numbers, though they compare closely.

Q. Does this conclude your testimony?
A. Yes.

DJN EXHIBIT NO. 1

CP&L Construction Schedule 1977-1986

Year	NCUC 2/77	CP&L 12/76
1977	-	Brunswick 1
1978	Brunswick 1	-
1979	-	-
1980	Roxboro 4	Roxboro 4
1981	Mayo Creek 1*	-
1982	-	-
1983	Harris 1	Mayo Creek 1
1984	Mayo Creek 2*	Harris 1
1985	Harris 2	Mayo Creek 1
1986	Peaking Units	Harris 2

*The Mayo Creek units were not specifically listed in the Commission's construction schedule in the February report.

DJN EXHIBIT NO. 2

Possible CP&L Reserve Margins

	Peak Load MW	Percent Reserves Brunswick Installed Summer of 1977	1978	1979
PART A				
1977				
S	5,472	35.8	21.3	21.3
W	5,472	42.1	27.6	27.6
1978				
S	5,848	27.1	27.1	13.6
W	5,848	32.9	32.9	19.4
1979				
S	6,249	19.4	19.4	19.4
W	6,249	24.4	24.4	24.4
PART B				
1977				
S	5,472	35.8	21.3	21.3
W	5,887	32.0	18.6	18.6
1978				
S	5,848	27.1	27.1	13.6
W	6,291	23.6	23.6	11.0
1979				
S	6,249	19.4	19.4	19.4
W	6,722	15.6	15.6	15.6

DJN EXHIBIT NO. 3

Energy Replacement Cost for Brunswick No. 1

	Dollars 1000's
Assumption: 65 percent capacity factor	
Probable Energy - eneration	
790,000 x .65 x 8,760 = 4,498,260,000 KWH	
1) Cost of Brunswick production	
assume nuclear production cost of 4 mills/KWH	
$4,498,260,000 \times 4 \times 10^{-3}$	17,993
2) Probable coal production (10 most efficient units - 1975)	
assume heat rate of 9,862 BTU/KWH*	
assume coal cost of 110¢/MBTU	
estimate O & M expense at .5 mills/KWH	
$4,498,260,000 \times 9,862 \times 1.1 \times 10^{-6}$	48,798
$4,498,260,000 \times 5 \times 10^{-4}$	2,249
	51,047
3) Probable turbine production	
assume heat rate of 18,250 BTU/KWH+	
assume oil cost of 260¢/MBTU	
estimate O & M expense at 2 mills/KWH	
$4,498,260,000 \times 18,250 \times 2.6 \times 10^{-6}$	213,442
$4,498,260,000 \times 2 \times 10^{-3}$	8,987
	222,439
4) Probable purchase power	
assume a 15 mill/KWH charge	
$4,498,260,000 \times 15 \times 10^{-3}$	67,474

*Numerical average of 10 most efficient units reported in CP&L's 1975 FPC Form 1

+Heat rate based on Darlington County GT heat rate for 1975