in

FINAL REPORT

**Evaluation of Potential for Cogeneration of
Electricity and Process Heat
in North Carolina**

June 1, 1978 thru May 31, 1979

Work Supported By:

North Carolina Energy Institute
and the
U.S. Department of Energy
(Contract EM-78-S-01-5152)

Work Carried Out By:

Department of Nuclear Engineering
North Carolina State University
Raleigh, North Carolina
and the
Research Triangle Institute
Research Triangle Park, North Carolina

MASTER

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"COGENERATION" is a new name for an old and proven practice. In broadest terms, cogeneration denotes any form of the simultaneous production of electrical or mechanical energy and useful thermal energy (usually in the form of hot liquids or gases). Cogeneration systems include dual-purpose power plants, waste-heat utilization systems, certain types of district-heating systems, and total-energy systems.

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PREFACE AND ACKNOWLEDGEMENTS

This report presents the results of activities carried out by North Carolina State University and the Research Triangle Institute under contracts with the North Carolina Energy Institute and the United States Department of Energy. The statement of work for the above two contracts is so closely related that this single report has been prepared to meet the reporting requirements of both contracts.

Overall guidance on the project was provided by Dr. James C. Bresee, Director, and Linda McDaniel of the North Carolina Energy Institute; and by Richard L. Cowles, Program Manager for DOE. Andrew W. Williams, Director Electric Division, Public Staff, North Carolina Utilities Commission, served as Project Monitor for the Energy Institute.

We are indebted to numerous government and industrial officials for providing us with information. In particular, we wish to thank Mr. Harold Barkow of the National Air Data Branch of the Office of Air Quality Planning and Standards of the Environmental Protection Agency, Mr. James McColeman of the Air Quality Section of the North Carolina Department of Natural Resources and Community Development, Messrs. James Latham and James Aarstead of the Industrial Development Division of the North Carolina Department of Commerce, J. C. Franklin of General Electric's Atlanta Office, C. G. Collins of Babcock and Wilcox's Charlotte Office; and Charles Braswell, R. E. Fite, and David J. Lombardi of NCSU's Physical Plant. Suzanne Gordon of the NCSU Computer Center wrote the programs for the analysis of the Boiler Registry Data which was obtained through the assistance of Bennie L. Whitley, Director of the Boiler Division of the North Carolina Department of Labor.

Robert Koger, Chairman of the North Carolina Utilities Commission, Hugh Wells, Director of the Public Staff of the North Carolina Utilities Commission, and Brian Flattery, Head of the North Carolina Energy Division, provided help and encouragement on the study. Advice and assistance were provided by personnel of CP&L, Duke Power and VEPCo, and by engineers and managers of the many North Carolina institutions and corporations who invited us to visit or who supplied us with replies to our Cogeneration Questionnaire. We are grateful for the participation of the Program Committee, Chairmen and Speakers

at our March 7-8, 1979, conference, Cogeneration and North Carolina, as listed in Section VIII of this report and for the support of the Social Hour for this conference provided by Covington Diesel and The Allison Division of G.M.

And finally, we gratefully acknowledge the help of Ms. Jacki A. Epperson and Donna J. Albrecht of RTI and Ms. Nancy Cashwell, Sheila Simpson, and Joyce Martin of NCSU who typed this report.

SUMMARY AND RECOMMENDATIONS

Objectives of Study

The overall objective of this study was to enable North Carolina to more efficiently utilize available energy than would be possible without additional cogeneration. Effective use of cogeneration can ease the requirement for utility capital and power plant sites and, by reducing fuel usage, can lead to less environmental damage.

The specific objectives of this study were to examine the feasibility of using the National Emissions Data System data bank and the North Carolina Boiler Registry to identify potential candidates for cogeneration and to then ascertain the magnitude of the potential in existing, new, and expanded facilities as a function of cogeneration impediment elimination. The results of the study were to be presented in a conference and in this final report.

Introduction

North Carolina has a population of 5,525,000 persons widely dispersed over 52,600 square miles. The manufacturing sector currently employs approximately 35 percent of North Carolina's workers with the textile industry as the largest single employers with 252,000 workers (1/10th of work force) followed by the apparel (90,000 employees) and furniture (84,000 employees). Industries experiencing the most rapid recent growth include electronics - computers, fabricated metal, machinery, non-automotive transportation equipment, and chemical industries. Population growth has averaged 1.4 percent/year (compared to 1.1 percent/year for the nation); while nonagricultural employment has grown at 3.4 percent annually compared to 2.4 percent/year for the nation.

North Carolina is served by three major electrical utilities: Duke Power, Carolina Power and Light, and Virginia Electric and Power. Duke and Carolina Power and Light generate and sell in North and South Carolina. In 1978 the Duke peak exceeded 9,500 megawatts and sales were approximately 49 million megawatt hours; Carolina Power and Light's peak exceeded 5,800 megawatts and its sales were approximately 28 million megawatt hours. VEPCo is primarily a Virginia utility serving a small portion of the northeast corner of North Carolina. System load factors are presently 63.5 percent for Duke Power and 60.5 percent for Carolina

Power and Light. State electrical load growth is projected at 5 to 5-1/2 percent per year for which ambitious construction programs of nuclear and coal plants are under way. Electricity prices are relatively low, 2.80¢ to 3.00¢ per kW hour, and most electricity is produced by nuclear and coal plants.

Development of List of Prospective Cogenerators

We assembled a list of prospects for cogeneration from an examination of an emissions data file maintained by the State of North Carolina Air Quality Section (of the Department of Natural and Economic Resources) and from the North Carolina Boiler Registry which is maintained by the Boiler Inspections Division of the North Carolina Labor Department. Using prospects selected from the above two sources (plus an input on large electrical users from the major utilities) we were able to identify 286 plants and institutions as "Large Fuel Users." The emissions data file did not include clean fuel burners (gas or wood); the Boiler Registry provides information on boiler capacity, but not on actual steam production and it does not include cement plants or brick kilns which have a high energy use but no steam boilers. We used a cut off of 30,000 lbs/hr of steam or the equivalent energy use, and believe that our list of 286 plants and institutions included over 90 percent of all existing or prospective North Carolina cogenerators.

Survey of Present and Potential Cogenerators

As we compiled our list of cogeneration candidates, we proceeded with field visits to firms in each industry with cogeneration potential in the hope that we could develop institution and industry energy patterns such that we could then determine the potential for cogeneration directly from the Emissions Data and/or Boiler Registry information. After some ten visits, we concluded that it was desirable to develop a firm data base for existing and potential cogenerators by obtaining pertinent operating data for each candidate. We then developed an Analysis Form (Exhibit IV.2) which we mailed to our prospects. We succeeded in obtaining plant-specific data adequate for an analysis of cogeneration potential from 133 candidates comprising 90 percent of the steam capacity of the master list. We fed these responses to a computer which had been programmed to determine the years to payback and the return on investment (R.O.I.) for a cogeneration installation. We examined payback and R.O.I. based on each installation's fuel

and electricity costs, steam needs, and payout criteria and we then examined the effect on cogeneration potential of variations in: relative inflation rate of fossil energy vs electricity; investment tax credit; alternative investment decision criteria; utility stand by charges; and price of fuel used. We did not examine the major favorable impact of marginal pricing of electricity except for our look at gas turbines in Appendix C.

Our survey uncovered 372 MW of operable cogeneration capacity in North Carolina in fifteen plants as shown on Exhibit S.1 which presents the number of establishments, the megawatts (MW) of capacity and the kilowatt hours of electricity produced in 1979. The data in Exhibit S.1 are arranged by Standard Industrial Classification (SIC) and include firm information as obtained from 12 firms and estimated production for 3 other firms. Note that over one-half of this capacity is in SIC 26, Pulp and Paper Industry.

Exhibit S.2 is our estimate of the potential for expansion of cogeneration by firms presently operating in North Carolina, 130 MW. This estimate is based on our detailed analysis of data on steam and electrical loads and reflects cogeneration capacity whose payout meets the firms' own criteria or 5-year payback where no payback criteria was cited. Exhibit S.2 also includes the 911×10^9 kWh which would be produced per year by the 130 MW and the approximate energy saving of 1,000,000 bbls oil per year.

The estimate of 130 MW was based on current conditions of fuel costs, electricity rates, standby charges and investment tax credit. Exhibit S.3 presents the MW capacity for a variety of investment tax credits, standby charges, relative inflation rates of fuel and electricity and payback periods. Note a range from a low of zero to a high of 175 MW.

In accordance with a request from the Public Staff of the North Carolina Utilities Commission, we estimated the Actual, Potential, and Possible Cogeneration in North Carolina by the year 2000. The results of this estimate are presented in Exhibit S.4. The grand total of 600-900 MW equals the output of a large coal or nuclear power plant. New and expanded industry accounts for 110-255 MW of the total cogeneration capacity by the year 2000.

Impediments to Cogeneration

As we visited institutions and companies we discussed impediments to cogeneration; our Analysis Form requested input on impediments. Our survey findings are presented in attached Exhibit S.5 and our findings by industry in

Exhibit S.6. The principal impediment is "Poor Return on Investment" followed by "Lack of Available Capital" and "Uncertain Energy Policy." Institutions and companies indicated an unwillingness to make the major investment needed for a new coal burning cogeneration installation when faced with a vacillating picture of the availability of gas and fuel oil, the use of either of which could cut their capital investment by 30-50 percent. These uncertainties led to short term decisions to patch up and continue to use old, inefficient oil burning equipment or for expansion to purchase low first cost package oil fired boilers.

We examined the "theoretical" impact of improving the Return on Investment in our sensitivity analyses, which are discussed above, by looking at an investment tax credit (ITC) as high as 30 percent. The effect of investment tax credit is to reduce the cost of capital equipment. The 30 percent ITC did increase the amount of cogeneration potential by about 10 percent over the amount expected with the current 20 percent ITC. The major barrier to cogeneration in this state however, is the absence of large, steady steam loads.

Recommendations

In the light of our study and findings we make the following recommendations:

(1) The National Emissions Data System (NEDS) and State Boiler Registries are useful tools for locating cogeneration prospects. Exhibits S-1 and S-2 are based on information from these sources; our approach should indicate the most fruitful cogeneration prospects in any state. It is recommended that a Manual be prepared to serve as a guide for states other than North Carolina seeking to identify their cogeneration potential.

(2) As indicated in Section VI-I of this report, North Carolina has the potential for supporting a number of Cogeneration Centers, where more than one user would utilize the waste heat from a cogeneration installation. This study did not look at Cogeneration Centers and it is recommended that such centers be identified and evaluated.

(3) It is recommended that the North Carolina Utilities Commission and its Public Staff

(a) Review standby charges presently made by the major North Carolina Utilities. These charges range from approximately \$1.00 per kW to over \$5.00 per kW as discussed in Section VII.C of this report.

(b) Study methods of encouraging utility involvement in cogeneration. As discussed in Appendix C, cogeneration has a much better payout when a comparison is made between the cost of new electricity from cogeneration with new (or marginal) electricity from the utility rather than with averaged electricity costs. Encouragement could take the form of rewarding efficient operation and penalizing inefficient operation where efficient operation used a minimum of energy. Utilities might also be offered a higher rate of return on cogeneration facilities than on large generating stations on the premise that the cogenerating installations represent a greater risk and thus merit a greater return on investment.

(4) It is recommended that cogeneration be implemented in at least one institution in North Carolina in a manner (such as a combustion turbine burning wastes) so as to produce some electricity for sale back to the utility, as a means of developing procedures and pricing for such resale. Section VI.C. of this report discusses potential at North Carolina Institutions.

Exhibit S.1

Existing Establishments that Produce Electricity
Through Cogeneration in North Carolina Classified by Industry,
Capacity and Output (in Most Recent Year)

Industry	SIC ^{b/}	Number of Establishments	Capacity MW	10 ⁹ kWh
Food and Tobacco	20,21	2	38.5	190
Textiles	22	4	33.3	96
Pulp and Paper	26	6	251.0	1698
Chemicals	28	2	37.0	98
Institutions	82	<u>1</u>	<u>12.5</u>	<u>73</u>
Total		15	372.3	2155

SOURCE: RTI-NCSU Survey of Large Fuel Users.

^{a/} This figure consists of 1,745 million kWh of electricity generated by 12 firms that supplied data plus 410 million kWh for three additional firms that cogenerate. A 67 percent utilization capacity was assumed for these latter firms.

^{b/} SIC means Standard Industrial Classification

Exhibit S.2
Estimates of Additional Potential for Cogeneration
from Existing Firms in North Carolina^{a/}

Time Period	No. of Plants	MW	10 ⁹ kWh	Steam (000#/hr)	Bbl. Oil Equiv. (000) ^{c/}
<u>Noncogenerating Establishments</u>					
1979	4	21	147	457	145
1985	1	12	84	240	83
1990	4	91	638	1469	630
1995 & later	2	6	42	112	41
TOTAL	11	130	911	2278	902
<u>Cogenerating Establishments</u>					
1979		80 ^{b/}			

SOURCE: Analysis of RTI-NCSU survey data.

^{a/}Plants considered to have potential meet the payback or return on investment criteria of the respective firms, or where this data is missing meet a 5-year payback criteria or have a 15 percent return on investment (after inflation). Management may find these unacceptable returns, or view the risk on such an investment as too great, and therefore not carry out the investment.

^{b/}This figure is based on the steam load at 6 paper mills which cogenerate but still have the potential to produce more electricity. If the potential were fully realized, the generating capacity would be approximately equal to their present demand for electricity.

^{c/}These figures represent the energy value of the kilowatts of electricity that are produced. Each kWh was assumed to be equal to 3,412 Btu's. This is a modest estimate of the savings because the heat rate of cogenerators is about 4,200 Btu's per kWh, while the heat rate of central power plants is 9,000 or more.

Exhibit S.3

Major Parameters and Results of Sensitivity Analysis

Run Number	Investment Tax Credit	Standby Charge	<u>Differential Inflation</u>		Fuel Price \$/mBtu	<u>MW Capacity</u>	
			Fuel	of Electricity		Payback 4 years	Payback 6 years
1	.3	\$1.00 kW/mo	0	2%	\$1.25	99	130
2	.1	actual	0	0	1.25	99	115
3	.2	actual	0	0	1.25	141	175
4	.3	actual	0	0	1.25	108	143
5	.2	actual	2%	0	1.25	89	124
6	.2	actual	0	2%	1.25	124	166
7	.2	1.59/kW/mo	0	0	1.25	99	130
8	.2	5.36/kW/mo	0	0	1.25	0	88
9	.2	actual	0	0	1.50	99	121
10	.2	actual	0	0	1.75	88	108
11	.1	5.36/kW/mo	2%	0	1.75	0	0

Source: Analysis of RTI-NCSU Survey data.

Exhibit S.4

Actual, Potential and Possible Cogeneration
In North Carolina by 2000 AD*

Cogeneration Capacity	MW
Existing and in place	372 - 372
Potential in existing firms	
Pulp and paper	40 - 80
Other firms	
Respondents	130 - 130
Nonrespondents	<u>20</u> - <u>50</u>
	190 - 260
New and Expanded Industry	
Pulp and paper	60 - 170
Chemicals	40 - 70
Food and tobacco	<u>10</u> - <u>15</u>
	110 - 255
GRAND TOTAL	672 - 887
Variability due to sensitivity analysis	<u>+</u> 45 <u>-</u>
Adjusted Grant Total	627 - 932*

*No special government actions are assumed except for the sensitivity analysis, but it is expected that some firms will make investments in projects that have payback periods as long as 4-1/2 years.

**These figures do not consider cogeneration centers, with more than one process heat user from a single turbine, nor do they consider any potential from Diesel Engines or Combustion Turbines -- we have confined our analysis to coal fired systems on the premise that gas and petroleum products will not be available for electrical generation. Appendix C reports on one analysis of Gas Turbine Potential and Section VI-1 discusses possible cogeneration centers.

Exhibit S.5.

Perceived Impediments to Cogeneration from the
Survey of Potential Cogenerators in North Carolina

Impediment	Ranking				Sum Total	Weighted Sum Total
	1st	2nd	3rd	4th		
Limited Capital	34	19	6	17	76	222
Poor Return on Invest- ment	54	29	9	6	98	327
Uncertain Energy Policy	11	16	34	26	87	186
Health, Safety, and Environmental Problems	1	22	26	15	64	137
Potential Regulation		5	14	16	35	59
Charge for Standby Service	5	16	20	19	60	127
(WEIGHT FACTOR)	(4)	(3)	(2)	(1)		
Other	15	7	4	8	33	
No Response	13	19	20	26	78	

Other Impediments	Times Mentioned
Availability of fuel and cost	7
Modification of plant and operational reliability	7
Finding qualified personnel	5
Have not considered the econo- mics or feasibility	5
Very low steam pressure needed	4
Irregular and low demands for steam and electric power; boiler shutdowns; impractical	2
Already cogenerating	1
Total electric plant - no steam	1
Demand for manufactured product	1
Government regulation	1

SOURCE: Research
Triangle
Institute
and
North Carolina
State University

Exhibit S.6

Rank Order of Major Impediments to Cogeneration
in North Carolina by Industry Group^{1/}

Major Impediment	Industry Group			
	Food and Tobacco	Textiles	Pulp & Paper	Chemicals & Petroleum
Poor Return on Investment ^{2/}	1	2	1	1
Limited Capital	2	1	2	4
Uncertain Energy Policy	3	3	4	2
Health, Safety, and Environmental Problems	4	4	5	5
Potential Regulation	6	6	6	6
Charge for Standby Service	5	5	3	3

^{1/}As revealed by survey responses and results of sensitivity analyses; only industry groups near cogeneration threshold are included.

^{2/}Includes steam load conditions and match between steam and electrical loads implicitly.

SOURCE: Research Triangle Institute - North Carolina State University

I. SETTING OF STUDY AND APPROACH TO ESTIMATION OF COGENERATION POTENTIAL

A. An Overview of North Carolina

North Carolina currently is the eleventh most populous state in the nation, with an estimated 1977 population of 5,525,000 persons. This population is widely distributed over many small cities and towns. The largest city, Charlotte, has approximately 306,000 residents; four other cities have a population in excess of 100,000 persons. The next 20 cities ordered by size have populations that range between 18,000 and 66,000 persons. Rural areas are dotted with small towns that contain more than one-half of the total rural area population. The Piedmont region in the center of the state contains approximately one-third of the land area but more than one-half of the population and employment. The Mountain and Coastal Plain regions flank the Piedmont region; population and employment growth in the Coastal Plains have exceeded the statewide rates in recent years. These regions are shown on the map in Exhibit I.1.

Population and employment are growing slightly faster in North Carolina than in the nation. The rate of population growth has averaged 1.14 percent annually in recent years, compared with 1.11 percent for the nation. Approximately one-third of North Carolina's population growth between 1970 and 1977 is estimated to have come from net immigration. The total work force exceeded 2.56 million persons in 1978, with fewer than 100,000 persons employed in agriculture. Nonagricultural employment growth has averaged 3.4 percent annually over the last 15 years, compared with 2.4 percent for the nation.

The manufacturing sector currently employs approximately 35 percent of North Carolina's workers. The textile industry employs 252,000 workers, approximately one-tenth of the total work force. Two other major industries are apparel (90,000 employees) and furniture (84,000 employees). These industries are experiencing relatively slow growth, and the textile industry has actually lost employees over the last five years. Industries experiencing the most rapid growth in North Carolina in recent years include the fabricated metal, machinery, non-automotive transportation equipment, and chemical industries. Thus, while growing rapidly, the North Carolina economy continues to be dominated by light industry.

Exhibit I.1. Geographical Regions in North Carolina

B. An Overview of Electric Utilities Serving North Carolina

North Carolina is served by four Class A electric utilities: Carolina Power and Light, Duke Power, Nantahala, and Virginia Electric Power Company. The Nantahala Power Company operates in the mountains in the southwestern part of the State, and barely qualifies for the Class A designation. Virginia Electric Power Company (VEPCo) serves a predominantly rural area in the northeastern corner of the State; its electricity sales to this service area represent a small portion of its total generation, which is concentrated in Virginia. A map of service areas is presented in Exhibit I.2.

Carolina Power and Light (CP&L) and Duke Power serve both North and South Carolina. The Duke service area is primarily in the Piedmont region and CP&L serves the Coastal Plain counties not served by VEPCo. Duke and CP&L both provide service to the mountain region.

Both Duke Power and CP&L are summer peakers, although the summer and previous winter peaks are more similar in magnitude on the Duke system than for CP&L. In 1978, the Duke Power system peak exceeded 9,500 megawatts (MW) and its system energy sales were approximately 49 million megawatt-hours (MWh). During this same period, the CP&L system peak exceeded 5,800 MW and its system energy sales were approximately 28 million MWh. System load factors for Duke Power and CP&L are 63.5 and 60.5 percent, respectively. Load growth on the Duke and CP&L systems is currently projected at between 5.0 and 5.5 percent per year, down from approximately 10 percent per year during the 1960's. Electricity prices are relatively low in comparison with many utilities; in 1977 the average price per kilowatt-hour was 2.80 cents on the Duke Power system and 2.98 cents on the CP&L system. These rates are expected to remain relatively low as base load assumes a larger share of total load (through load management and related measures), as fossil plant heat rates continue to be among the national leaders, and as nuclear power assumes a large share of total generation.

Legend: Carolina Power and Light
 Duke Power
 Nantahala Power
 Virginia Electric Power Co.

Exhibit I.2. Electric Power Service Areas in North Carolina

C. Approach to Estimation of Cogeneration Potential

Estimating present and future cogeneration in North Carolina could have proceeded by two separate methodologies:

- (1) analysis of aggregate data (examine entire industries);
- (2) analysis of disaggregated data (examine individual plants).

Prior studies of U.S. cogeneration utilized aggregated data while this study used disaggregated data and analyzed the potential for cogeneration in 133 plants and institutions across the state. This approach offers several distinct advantages over the use of aggregated data. Primary data is current, contains details on plant operations, and can incorporate the actual policies of individual firms. Aggregated data is often several years old, offers only gross data on industry-wide operations and contains no information on corporate investment policy. The advantage of disaggregated data encouraged this study team to focus on a plant-by-plant analysis of potential cogeneration.

1. The Analytical Model

The analytical model for this study was influenced by information received from five sources:

- (1) review of major cogeneration industries studies;
- (2) review of case studies on the feasibility of individual plants;
- (3) site visits to plants and institutions;
- (4) consultations with representatives of corporations in the cogeneration industry;
- (5) consultations with the class A electric utilities on their policies regarding cogenerating customers.

The subsequent analysis of the potential for cogeneration, as well as analysis of the present level of cogeneration in North Carolina were based on these sources. By studying the inputs from each of these sources, a general model was developed which was used as a rough tool to test the economic feasibility of installing cogeneration equipment at existing plants.

The literature review provided the general model for testing the feasibility of cogeneration. Major studies by RPA and Thermo¹ Electron outlined the major cost elements of cogeneration installations as well as the savings to be expected by cogenerating power instead of

¹See References in Appendix D

purchasing it from utilities. The engineering literature is an excellent source of cogeneration feasibility case studies which served to highlight particular problem areas in installing cogeneration equipment and in studying the economic feasibility of cogeneration equipment and in studying the economic feasibility of cogeneration electricity.

Site visits allowed the study team to discuss and observe firsthand the problems encountered in specific industries. The individual plant problems could be incorporated into the general model for analyzing data collected from other institutions by means of the mail survey. The visits were of invaluable help in designing the analysis form (questionnaire) on which data were collected for computerized analysis of cogeneration potential.

Study teams made visits to plants and institutions in the following categories:

- . pulp and paper
- . textiles
- . chemicals
- . tobacco
- . furniture
- . brick
- . universities
- . hospitals
- . utilities

Cost and performance data were obtained through meetings with representatives of firms manufacturing cogeneration equipment including boiler, steam turbine-generator, diesel-generator, and combustion turbine manufacturers.

Representatives of the three class A electric utilities serving North Carolina were visited for information about utility service policies and industrial rate schedules. The three utilities have markedly different rate structures, which provide incentives of varying strengths for cogeneration. While it was neither possible nor desirable to completely model the rate structures of the major utilities, it was possible to model conservatively the savings plants might realize by introducing cogeneration.

The feasibility analysis model is based on inputs and feedback from these five sources. The model developed is sufficiently general to account for major components of costs and savings. We believe that this model includes all the factors that have a major influence on the costs and benefits of a cogeneration installation

at each of the plants in the survey and thus provides a reliable estimate of the economic feasibility of cogeneration at each plant. Before making a decision on cogeneration, prospects should have detailed calculations made by their engineers or by consulting engineers.

The details of the analytical model are presented in Section V, which contains the analysis plan, and in the appendix, which contains the actual computer program. A brief description of the model is included here for the convenience of the reader. The model calculates the number of years necessary to pay back the extra cost of cogeneration equipment. The extra cost includes the turbine generator and its installation, the incremental costs of a larger and higher pressure coal fired boiler, the additional fuel costs, and the additional maintenance and operating costs. It is assumed that plants and institutions have to replace their present equipment with a low pressure coal fired boiler and are considering only the incremental costs necessary to cogenerate. The benefits from cogeneration consist only of savings in electricity purchases with no allowance for reliability. Cogeneration is deemed feasible, if the calculated payback is less than the payback period specified by the firm, or five years, if one was not specified. The length of the payback period was analyzed to determine how sensitive economic feasibility is to the period specified.

We also calculated the return on investment, which some firms specified rather than the payback periods but the use of this criteria had little effect on estimates of total potential. Other parameters such as the investment tax credit, the standby charge for electricity, and the rate of inflation for fuel and electricity were varied to check the effect of the variation on cogeneration potential. Variation in these parameters did not have much impact on the total amount of cogeneration potential. Our study did not consider peak load pricing of electricity, comparison of the cost of cogeneration capacity to new baseload plants, major charges in the electricity rate structure, or immediately higher electricity rates.

D. The Aggregation Process

Estimation of the total potential for cogeneration in North Carolina was based on a plant-by-plant analysis of the existing industrial and institutional base of the state. The results of the feasibility study of each plant were combined to yield an estimate of total potential. This approach allowed us to identify specific candidates for cogeneration, test the likelihood of their installing or enlarging cogeneration plants, and study the sensitivity of investment

decisions to a variety of public policy options and economic scenarios.

The most important step in our plant-by-plant study of cogeneration potential was identification of likely candidates for cogeneration. The major criterion for establishing a plant or institution's potential for cogeneration is the quantity of heat energy that it uses. Two data sources were examined for their potential use in identifying large heat energy users. These are the NEDS and Boiler Registry data that are discussed in the next two sections. These data sources contain information about heat energy consumption or capacity for consumption of individual users, and allow a potential list of cogenerators to be compiled. We contacted this list of candidates with a high potential for cogeneration to obtain more detailed operating data.

Detailed analysis of a plant's potential for cogeneration was then carried out using the operating data. The potential from all existing plants and institutions was summed to yield a total potential for cogeneration in the state from presently existing and operating plants and equipment.

Our plant-by-plant approach offers various strengths and weaknesses. The primary advantage is that individual analysis is possible for each plant, given a set of general assumptions, and the impact of public policies and economic scenarios can be evaluated. Potential weaknesses arise in (1) compilation of the list of potential candidates from secondary sources; and, (2) obtaining sufficient data to make an analysis (non-response to primary data collection efforts). We believe that we avoided these weaknesses.

II. THE USE OF NORTH CAROLINA AIR POLLUTION EMISSIONS DATA

Emissions data maintained by the State of North Carolina Air Quality Section were used to identify major fuel users, and thus was one source of cogeneration candidates. The data file has a record for each plant that has the potential for emitting 100 tons or more per year of any of the air pollutants: suspended particulates; sulfur oxides; nitrogen oxides; hydrocarbons; or carbon monoxide. Each record includes information on the location and industrial category of the establishment; estimated potential and controlled emissions; and process parameters such as process type, capacity, and normal operating rate. Exhibit II-1 is the NEDS Point Source Coding Form. The EPA national file is termed the National Emissions Data System or NEDS. The file consists of all air pollution emissions point source types, including both boilers and direct-fired processes.

The data on boilers in the emissions file were used for validating the boiler data obtained from the State of North Carolina Boiler Registry File. Several boilers that were overlooked in the Boiler Registry were identified through the use of emissions data. In addition, some major fuel users in direct-fired processes, such as brick kilns, were identified with the emissions data that were not in the boiler registry. It was possible to develop certain patterns of industrial fuel use from these data that were not available elsewhere.

The use of emissions-based data for a cogeneration study presents some difficulties. For example, the lower limit of 100 tons per year of emissions on the reporting requirement means that some fairly large fuel-using plants will be omitted when clean fuels are being burned. Based on EPA's standard emission rates, the smallest combustion sources that will be included in the emissions file would be 2,000,000 Btu/hr. for coal, 20,000,000 Btu/hr. for residual or distillate oil, and 200,000,000 Btu/hr. for natural or process gas. These lower limits assume that the fuel-burning source operates continuously; if the source operates less than continuously, even larger-capacity users would be missing. This effect is mitigated somewhat in that the lower emission limits apply to stack emissions and not individual process emissions; that is, if several small units are served by one stack, the potential stack emissions may

1 Identification information (columns 1-13) common to all six types of cards (see column 80)

State	County	AOCR	Plant ID Number
1	2	3	4
5	6	7	8
9	10	11	12
13			

NATIONAL EMISSIONS DATA SYSTEM (NEDS)
ENVIRONMENTAL PROTECTION AGENCY
OFFICE OF AIR PROGRAMS

POINT SOURCE
Input Form

FORM APPROVED
OMB NO. 158-R0095
Date

Name of Person
Completing Form

3

Contact - Personal

OWN

Action

cd

- 2 Name and address
3 Person to contact

City	Utm Zone	Year of Record	Establishment Name and Address	Contact - Personal	OWN	Action	cd
14	15	16	17	18	19	20	21
22	23	24	25	26	27	28	29
30	31	32	33	34	35	36	37
38	39	40	41	42	43	44	45
46	47	48	49	50	51	52	53
54	55	56	57	58	59	60	61
62	63	64	65	66	67	68	69
70	71	72	73	74	75	76	77
78	79	80					

4 Standard Industrial Classification (SIC) code

Point ID	Year of Record	SIC	UTM COORDINATES	STACK DATA	Points with common stack	Action	cd
14	15	16	17	18	19	20	21
22	23	24	25	26	27	28	29
30	31	32	33	34	35	36	37
38	39	40	41	42	43	44	45
46	47	48	49	50	51	52	53
54	55	56	57	58	59	60	61
62	63	64	65	66	67	68	69
70	71	72	73	74	75	76	77
78	79	80					

5 Boiler design capacity

Year of Record	Boiler Design Capacity 10 ⁶ BTU/hr	Primary Part.	Secondary Part.	Primary SO ₂	Secondary SO ₂	Primary NO _x	Secondary NO _x	Primary HC	Secondary HC	Primary CO	Secondary CO	ESTIMATED CONTROL EFFICIENCY (%)	Action	cd
16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
61	62	63	64	65	66	67	68	69	70	71	72	73	74	75
76	77	78	79	80										

6 Cards 4 and 5 contain additional (unrelated) air pollution control information

7 Source Classification code (SCC)

7

8

9 Fuel heat content

8 Annual operating rate

Year of Record	SCC	Annual Fuel, Process, Solid Waste Operating Rate	Hourly Maximum Design Rate	Fuel Sulfur Content %	Fuel Ash Content %	Fuel Heat Content 10 ⁶ BTU/lcc	Comments	Source Cont.	Action	cd
16	17	18	19	20	21	22	23	24	25	26
27	28	29	30	31	32	33	34	35	36	37
38	39	40	41	42	43	44	45	46	47	48
49	50	51	52	53	54	55	56	57	58	59
60	61	62	63	64	65	66	67	68	69	70
71	72	73	74	75	76	77	78	79	80	

NEDS Point Source Coding Form

Exhibit II.1.

become large enough that sources below those lower limits may be reported.

Another missing data problem that may be specific to North Carolina is that certain counties in North Carolina have until very recently operated their own air pollution agencies and thus did not report their emissions data to the State Air Quality Section. This is not believed to have had significant impact on the North Carolina cogeneration study because of the use of the boiler registry data, but it could affect studies in other states where boiler registry data are not used or are not available.

A list of boilers identified from the North Carolina boiler registry survey that did not appear in the state emissions data is contained in Exhibit II.2. The list consists of 30 establishments located in 24 counties in all parts of the State. These establishments represent a variety of industries and public sector activities. Many of these plants are very large, which should give cause for alarm.

The use of the North Carolina emissions data in this study is relevant for other studies because all states are required to have data of identical format prepared for use by the U.S. Environmental Protection Agency. Nineteen other states, as listed in Exhibit II.3, have computerized data base systems identical to North Carolina's. Other states may have their own computerized systems or may maintain their files manually. Knowledgeable personnel believe that all of the states with computerized emissions files would have data bases at least as complete as North Carolina's. Those states without computerized systems are required to submit their emissions data to the U.S. EPA, which maintains the data in its computerized National Emissions Data System at the Research Triangle Park, North Carolina. The U.S. EPA makes these data available to other government agencies for study purposes, subject to confidentiality restrictions. Thus, these data would be quite useful for other studies within the limitations noted previously. Within any particular state, it should be possible for an interested energy agency to obtain these data for study from the relevant environmental agency.

The specific areas where these data may be of assistance in cogeneration studies and planning are the following: (1) overall cogeneration potential may be determined reasonably well because most major fuel

Exhibit II-2.

State Plants for Which There Are No Emissions Data Entries

County	Plant Name
Brunswick	E. I. Dupont DeNemours Cape Fear Plant
Buncombe	Akzona Inc. American Enka* + Sayles Biltmore National Distill Beacon Mfg.
Chatham	Allied Chemical
Columbus	Federal Paper, Co. E. I. Dupont DeNemours Textile Fibers
Cumberland	E. I. Dupont DeNemours
Davidson	E. I. Dupont DeNemours Healing Springs
Durham	Duke University
Gaston	Burlington Industries Mayflower Plant Gulf Resources and Lithium Corp.
Guilford	State of N.C. - UNC-Greensboro
Harnett	Campbell College
Haywood	Champion International Paper
Hertford	C & F Ind. Inc. Georgia Pacific *
Hoke	State of N.C. - McCain Hospital +
Lenoir	E. I. Dupont DeNemours - Kinston Plant
Mecklenburg	State of N.C. - UNC-Charlotte
Nash	Akzona Inc., Whitakers Plant
Onslow	Weyerhaeuser Co.
Rockingham	Miller Brewing
Rowan	Cone Mills Corp., Salisbury Plant
Surry	Chatham Mfg. Co., Mill #2
Transylvania	Olin Corp., Ecusta Paper Div.
Wake	State of N.C. - N.C. State University
Washington	Weyerhaeuser Co.
Wilson	Export Leaf Tobacco Imperial Group L American Lead Organization

* - SCC process rate = 0.0

+ - No heat content

Exhibit II-3.

List of States with Computerized Emissions Data System

Massachusetts
Puerto Rico
Delaware
Virginia
Georgia
Kentucky
Mississippi
North Carolina
South Carolina
Tennessee
Indiana
Minnesota
New Mexico
Missouri
Colorado
North Dakota
Montana
Arizona
California
Alaska

SOURCE: Research Triangle Institute
and North Carolina State University

users would be included; the omitted fuel users probably will be small actual users of fuel; (2) industrial patterns of cogeneration candidates may be identified from the Standard Industrial Classification data contained in each plant's emissions data record; (3) amounts and patterns of fuel use can be identified for analysis; (4) the actual amount of fuel burned per year, by fuel type, may be determined. (In some cases the data are included for seasonal and daily operation patterns, which can help in the analysis of steam or process heat load.); and (5) the major fuel users can be identified by name and location for survey or other purposes.

III. THE USE OF NORTH CAROLINA BOILER REGISTRY DATA

All boilers and large hot water heaters (industrial and institutional) in North Carolina are registered with the Boiler and Pressure Vessel Division of the North Carolina Department of Labor. As of January, 1978 there are 125,000 vessels registered.

The information on the vessels are listed in four formats:

- 1) In order of registration number on paper cards which states whether the vessel is high or low pressure, the company name and address, and the dates of inspection.
- 2) In order of registration number listed on computer printout which gives whether high or low pressure (<15psig) and the owners and users name.
- 3) Alphabetical listing of owners name, registration number and location of the vessel.
- 4) Microfilmed inspector reports which give varying amounts of information regarding the vessels specifications such as fuel type, heating surface area, relieving capacity, etc.

Because boilers of relatively large steam capacity (greater than 50,000 lbs/hr) are of interest for co-generation and the larger boilers are all "high pressure," only high pressure vessels were considered. A search was made of the registration number listing (item 2 above) for high pressure vessels. Dry cleaning, automobile tire recapping and other obvious small firms with high pressure vessels were rejected. Given the registration number of the likely high pressure vessels, a search was then made of the microfilmed inspector's reports to determine the steam capacity of the boilers. Many times the capacity had to be calculated from the heating surface of the boiler.

Once a vessel of capacity greater than 50,000 lbs/hr was found, a record was made of the owners and users name, location, fuel type, usage of the boiler, type of boiler, and age. The initial search yielded 226 boilers of capacity greater than 50,000 lbs/hr.

A later comparison of the Boiler Registry data and NEDS data (see Section II, The Use of NC Air Pollution Emissions Data) showed 59 boiler locations that occurred in the NEDS Distribution, and not in the Boiler Registry data. Forty-eight boilers of greater than 50,000 lbs/hr capacity were found at these locations through a second search at the Registry.

Another comparison was made with the revised Boiler Registry data and a listing of electrical utility customers with electrical demand greater than 10 MW. Nineteen customers had demand greater than 10 MW and did not appear in the combined NEDS/Boiler Registry list. A search at the Registry turned up 8 more boilers of greater than 50,000 lbs/hr capacity. Thus, we have found approximately 300 boilers of interest to co-generation in North Carolina at an expense of about 120 man hours.

A variety of lists were compiled from the Boiler Registry data. The boilers were sorted by descending capacity, SIC number, county and city, age and fuel type. An example of the statewide capacity and SIC listing is included. (See Exhibit III, 1 and 2)

We have obtained information about the Boiler Registries or equivalent offices in the remaining 49 states. Questions were asked about filing systems, computerization of files and legal restrictions on dissemination of data in an effort to evaluate the feasibility of our boiler identification method in other states. Addresses of the appropriate state agencies can be obtained by asking for June 1978 Data Sheet from: Uniform Boiler and Pressure Vessel Laws Society, 57 Pratt Street, Hartford, CT 06103.

Every state with the exception of Florida, Missouri, New Mexico, Oklahoma, West Virginia, and South Carolina subscribe to the ASME boiler construction code and has some sort of state inspection agency. Georgia and Wyoming do not have a state inspection agency but rely on inspections by insurance companies. The remaining 42 states have a central file of all the boilers in their state.

The filing system in each state determines the ease of extraction of pertinent data. The filing systems can be divided into three groups. The first group consists of completely automated or computerized systems which include the boiler specifications in the computer file. These systems permit the identification of boilers meeting certain criteria by computer search. This is the least expensive and mind numbing method of locating boilers/firms of interest in cogeneration. Iowa, Kentucky, Minnesota, New Jersey, and Virginia fall in this category.

The second group of filing systems are partially automated. The computer file does not have all of the boiler specifications but usually includes the design pressure. Thus, a list can be compiled of the high pressure boilers (which separates out hot water heaters, etc.) and a manual search made of the

REVISED SIC LISTING
(PRIMARY PRODUCT, SECONDARY PRODUCT)
(CAPACITY IS IN 1000 LBS/HR)

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----- SIC1=28 SIC=CHEMICAL AND ALLIED PRODUCTS SICSEC=-----											
CAPACITY	OWNER	USER	COUNTY	CITY	FUELA	FUELB	YR	PRESS	GT10MW	COGEN	STATERN
63	DUPONT E I DE NE	BREVARD PLANT	TRANSYLVANIA CO	BREVARD	NATURAL GAS	RESIDUAL OIL	67	250	Y	N	93745
62	HERCULES INC	HANOVER PLANT	NEW HANOVER	WILMINGTON	MISC		67	80	N	N	92858
62	HERCULES INC	HANOVER PLANT	NEW HANOVER	MASONITE	MISC		67	80	N	N	92857
60	GULF RESOURCES &	LITHIUM CORP OF	GASTON CO	BESSEMER CITY	NATURAL GAS	RESIDUAL OIL	74	250	N	N	120953
60	DUPONT E I DE NE	KINSTON PLANT	LENOIR CO	KINSTON	RESIDUAL OIL	NATURAL GAS	73	150	Y	Y	124144
51	ALLIED CHEMICAL	ALLIED CHEMICAL	CHATHAM CO		NATURAL GAS	RESIDUAL OIL	76	200	N	N	108289
51	ALLIED CHEMICAL	ALLIED CHEMICAL	CHATHAM CO		NATURAL GAS	RESIDUAL OIL	69	200	N	N	108288
50	HERCULES INC	HERCULES INC	NEW HANOVER	WILMINGTON	MISC		71	80	N	N	105359
4346	TOTAL										.

----- SIC1=28 SIC=CHEMICAL AND ALLIED PRODUCTS SICSEC=TEXTILE MILL PRODUCTS -----											
CAPACITY	OWNER	USER	COUNTY	CITY	FUELA	FUELB	YR	PRESS	GT10MW	COGEN	STATERN
266	AKZCNA INC	BURLINGTON INDUS	BUNCOMBE CO	ASHEVILLE	RESIDUAL OIL	NATURAL GAS	71	500	Y	Y	64459
79	CELANESE CORP	FIBER IND INC	ROWAN CO	SALISBURY	NATURAL GAS		62	425	N	N	90012
54	CELANESE CORP	FIBER IND INC	ROWAN CO	SALISBURY	NATURAL GAS	RESIDUAL OIL	68	300	N	N	90058
54	CELANESE CORP	FIBER IND INC	ROWAN CO	SALISBURY	NATURAL GAS	RESIDUAL OIL	67	300	N	N	49962
54	CELANESE CORP	FIBER IND INC	ROWAN CO	SALISBURY	NATURAL GAS	RESIDUAL OIL	65	300	N	N	49850
54	CELANESE CORP	FIBER IND INC	ROWAN CO	SALISBURY	RESIDUAL OIL	NATURAL GAS	65	300	Y	N	81458
54	CELANESE CORP	FIBER IND INC	ROWAN CO	SALISBURY	RESIDUAL OIL	NATURAL GAS	65	300	Y	N	81459
.	CELANESE CORP	FIBER IND INC	ROWAN CO	SALISBURY	NATURAL GAS		65	425	N	N	49899
.	CELANESE CORP	FIBER IND INC	ROWAN CO	SALISBURY	NATURAL GAS		65	425	N	N	49898
.	CELANESE CORP	FIBER IND INC	ROWAN CO	SALISBURY	NATURAL GAS		65	425	N	N	49883
.	CELANESE CORP	FIBER IND INC	ROWAN CO	SALISBURY	NATURAL GAS		65	425	N	N	49882
.	CELANESE CORP	FIBER IND INC	ROWAN CO	SALISBURY	NATURAL GAS		65	425	N	N	49881
.	CELANESE CORP	FIBER IND INC	ROWAN CO	SALISBURY	NATURAL GAS	RESIDUAL OIL	73	325	N	N	106158
.	CELANESE CORP	FIBER IND INC	ROWAN CO	SALISBURY	NATURAL GAS	RESIDUAL OIL	67	425	N	N	49968
.	CELANESE CORP	FIBER IND INC	ROWAN CO	SALISBURY	NATURAL GAS	RESIDUAL OIL	67	425	N	N	49967
615	TOTAL										.

----- SIC1=28 SIC=CHEMICAL AND ALLIED PRODUCTS SICSEC=PAPER AND ALLIED PRODUCTS -----											
CAPACITY	OWNER	USER	COUNTY	CITY	FUELA	FUELB	YR	PRESS	GT10MW	COGEN	STATERN
424	FEDERAL PAPER CO	PAPER DIV CAROLI	COLUMBUS CO	WILMINGTON	NATURAL GAS	RESIDUAL OIL	68	950	Y	N	99603
343	CHAMPION INTERNA	CHAMPION INTERNA	HAYWOOD CO	CANTON	COAL		29	450	Y	Y	2118
322	CHAMPION INTERNA	CHAMPION INTERNA	HAYWOOD CO	CANTON	COAL		46	500	Y	Y	2115
295	FEDERAL PAPER CO	PAPER DIV CAROLI	COLUMBUS CO	WILMINGTON	RESIDUAL OIL	NATURAL GAS	63	950	Y	N	76387
214	CHAMPION INTERNA	CHAMPION INTERNA	HAYWOOD CO	DUDLEY	COAL	RESIDUAL OIL	45	455	Y	Y	2147
195	CHAMPION INTERNA	CHAMPION INTERNA	HAYWOOD CO	CANTON	COAL	RESIDUAL OIL	41	455	Y	Y	2146
191	FEDERAL PAPER CO	PAPER DIV CAROLI	COLUMBUS CO	WILMINGTON	MISC	NATURAL GAS	57	700	Y	N	39372
180	ULIN CORP.	ECUSTA PAPER DIV	BEAUFORD	AURORA	NATURAL GAS	RESIDUAL OIL	68	725	Y	Y	78551
179	ULIN CORP.	ECUSTA PAPER DIV	TRANSYLVANIA CO	AURORA	COAL		52	675	Y	Y	5507
136	FEDERAL PAPER CO	PAPER DIV CAROLI	COLUMBUS CO	WILMINGTON	NATURAL GAS	RESIDUAL OIL	66	1075	Y	Y	20646
101	FEDERAL PAPER CO	PAPER DIV CAROLI	COLUMBUS CO	WILMINGTON	MISC	NATURAL GAS	51	680	Y	N	2044
2580	TOTAL										.

Exhibit III.1

REVISED STATE LISTING
(CAPACITY IS IN 1000 LBS/HR)

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CAPACITY	OWNER	SIC1	SIC2	COUNTY	CITY	FUELA	FUELB	YR	PRESS	GT10MW	COGEN	STATERN
1173	WEYERHAEUSER CO	26	24	MARTIN CO	PLYMOUTH	RESIDUAL OIL	MISC	74	1040	Y	Y	131926
550	WEYERHAEUSER CO	24	26	CRAVEN	NEW BERN	MISC	RESIDUAL OIL	1520	Y	Y	Y	165806
424	FEDERAL PAPER CO	28	26	COLUMBUS CO	WILMINGTON	NATURAL GAS	RESIDUAL OIL	68	950	Y	N	99603
404	WEYERHAEUSER CO	26	--	CRAVEN CO	NEW BERN	RESIDUAL OIL	MISC	69	1000	Y	Y	82034
378	C F IND INC	28	--	HERTFORD CO	AHOSKIE	NATURAL GAS		68	1650	N	N	82047
368	WEYERHAEUSER CO	26	24	MARTIN CO	PLYMOUTH	RESIDUAL OIL		55	700	Y	Y	9764
343	CHAMPION INTERNA	28	26	HAYWOOD CO	CANTON	COAL		29	450	Y	Y	2118
340	HOERNER WALDORF	26	--	HALIFAX CO	RIEGELWOOD	RESIDUAL OIL	MISC	75	1000	N	N	136881
339	CANNON MILLS CO	22	--	CABARRUS CO	KANNAPOLIS	RESIDUAL OIL	NATURAL GAS	70	1475	Y	Y	72987
322	CHAMPION INTERNA	28	26	HAYWOOD CO	CANTON	COAL		46	500	Y	Y	2115
306	WEYERHAEUSER CO	24	26	WASHINGTON CO	PLYMOUTH	MISC	RESIDUAL OIL	65	800	Y	Y	9818
295	FEDERAL PAPER CO	28	26	COLUMBUS CO	WILMINGTON	RESIDUAL OIL	NATURAL GAS	63	950	Y	N	76387
282	HOERNER WALDORF	26	--	HALIFAX CO	RIEGELWOOD	RESIDUAL OIL	MISC	56	1000	N	N	29408
274	WEYERHAEUSER CO	24	26	CRAVEN CO	NEW BERN	MISC	RESIDUAL OIL	69	990	Y	Y	82035
267	WEYERHAEUSER CO	26	24	MARTIN CO	PLYMOUTH	RESIDUAL OIL	MISC	46	700	Y	Y	9707
266	AKZONA INC	28	22	BUNCOMBE CO	ASHEVILLE	RESIDUAL OIL	NATURAL GAS	71	500	Y	Y	64459
253	HOERNER WALDORF	26	--	HALIFAX CO	RIEGELWOOD	RESIDUAL OIL		48	600	N	N	6631
248	FEDERAL PAPER CO	26	28	COLUMBUS CO	WILMINGTON	RESIDUAL OIL	MISC	56	700	Y	Y	33809
229	FEDERAL PAPER CO	26	28	COLUMBUS CO	WILMINGTON	RESIDUAL OIL		51	680	Y	Y	2061
225	F J REYNOLDS	21	--	FORSYTH CO	WINSTON-SALEM	COAL		50	676	Y	Y	10261
225	HERCULES INC	28	--	NEW HANOVER	WILMINGTON	RESIDUAL OIL		73	800	N	N	89785
225	HERCULES INC	28	--	NEW HANOVER	MORGANTON	RESIDUAL OIL		73	800	N	N	89786
214	CHAMPION INTERNA	28	26	HAYWOOD CO	DUDLEY	COAL	RESIDUAL OIL	45	455	Y	Y	2147
198	R J REYNOLDS	21	--	FORSYTH CO	WINSTON-SALEM	COAL		47	675	Y	Y	3066
198	DUPONT E I DE NE	28	--	LENOIR CO	KINSTON	COAL	RESIDUAL OIL	52	650	Y	Y	18335
197	WEYERHAEUSER CO	24	26	MARTIN CO	PLYMOUTH	RESIDUAL OIL	MISC	40	700	Y	Y	9708
195	CHAMPION INTERNA	28	26	HAYWOOD CO	CANTON	COAL	RESIDUAL OIL	41	455	Y	Y	2146
191	FEDERAL PAPER CO	28	26	COLUMBUS CO	WILMINGTON	MISC	NATURAL GAS	57	700	Y	N	39372
190	DUPONT E I DE NE	28	--	BRUNSWICK CO	WILMINGTON	NATURAL GAS	RESIDUAL OIL	73	1085	Y	Y	126274
180	OLIN CORP.	28	26	BEAUFORD	AURORA	NATURAL GAS	RESIDUAL OIL	68	725	Y	Y	78551
179	OLIN CORP.	28	26	TRANSYLVANIA CO	AURORA	COAL		52	675	Y	Y	5507
175	HERCULES INC	28	--	NEW HANOVER	WILMINGTON	MISC		72	840	N	N	89782
175	HERCULES INC	28	--	NEW HANOVER	WILMINGTON	MISC		72	840	N	N	89780
175	HERCULES INC	28	--	NEW HANOVER	WILMINGTON	MISC		72	840	N	N	89781
171	HOERNER WALDORF	26	--	HALIFAX CO	RIEGELWOOD	MISC	COAL	65	1000	N	N	9837
165	WEYERHAEUSER CO	24	26	MARTIN CO	PLYMOUTH	RESIDUAL OIL	COAL	46	700	Y	Y	9710
158	DUPONT E I DE NE	28	--	LENOIR CO	KINSTON	COAL	RESIDUAL OIL	65	675	Y	Y	73225
157	AKZONA INC	22	28	BUNCOMBE CO	ASHEVILLE	COAL		62	1000	Y	Y	63033
153	R J REYNOLDS	21	--	FORSYTH CO	WINSTON-SALEM	COAL		63	1450	Y	Y	67731
153	R J REYNOLDS	21	--	FORSYTH CO	WINSTON-SALEM	COAL		63	1450	Y	Y	67730
150	BURLINGTON INDUS	22	--	ALAMANCE CO	BURLINGTON	NATURAL GAS	COAL	70	200	N	N	104241
150	DUPONT E I DE NE	28	--	BRUNSWICK CO	WILMINGTON	RESIDUAL OIL		71	800	Y	Y	110325
150	DUPONT E I DE NE	28	--	BRUNSWICK CO	WILMINGTON	RESIDUAL OIL		72	800	Y	Y	110326
150	DUPONT E I DE NE	28	--	BRUNSWICK CO	WILMINGTON	DISTILLED OIL		72	800	Y	Y	110308
150	WEYERHAEUSER CO	24	26	MARTIN CO	PLYMOUTH	MISC		49	700	Y	Y	9702
150	STATE OF N C	--	--	ORANGE CO	CHAPEL HILL	RESIDUAL OIL	NATURAL GAS	72	500	Y	Y	122646
150	WEYERHAEUSER CO	24	26	WASHINGTON CO	PLYMOUTH	MISC	RESIDUAL OIL	37	700	Y	Y	7703
148	CANNON MILLS CO	22	--	CABARRUS CO	KANNAPOLIS	COAL	NATURAL GAS	50	.	Y	Y	1087
145	DUPONT E I DE NE	28	--	LENOIR CO	KINSTON	RESIDUAL OIL	COAL	51	650	Y	Y	18302
145	WEYERHAEUSER CO	24	26	MARTIN CO	PLYMOUTH	RESIDUAL OIL		71	750	Y	Y	82099
140	WEYERHAEUSER CO	24	26	WASHINGTON	PLYMOUTH	MISC		54	725	Y	Y	9665
137	HOERNER WALDORF	26	--	HALIFAX CO	RIEGELWOOD	RESIDUAL OIL		73	1000	N	N	133579
137	HOERNER WALDORF	26	--	HALIFAX CO	ROANOKE RAPIDS	RESIDUAL OIL		73	1000	N	N	133578

Exhibit III.2

boilers. This will usually entail some calculation for the design steam capacity. The work required to locate all the boilers of a given capacity is much greater in this group of filing systems than in the fully automated systems. North Carolina has this type of system. Eight states are in this group.

The third group of filing systems can be characterized by the herculean effort required for data compilation. All the information is in hard copy and the only search method is boiler by boiler. Very likely there will be no way of eliminating the small boilers from the initial search list so that all the boiler files will have to be examined. Twenty-seven states are in this group.

Each state is identified by its filing system in Exhibit III - 3.

EXHIBIT III-3.

State Boiler Registry Classification

	Heating Boiler Requires <u>ASME Construction</u>	Automated <u>Filing System</u>	Difficulty of Search	Legal <u>Restriction</u>
Alabama	Y	N	3	NA
Alaska	Y	Y	2	N
Arizona	Y	N	3	NA
Arkansas	Y	N	3	NA
California	Y	Y	2	N
Colorado	Y	N	3	N
Connecticut	Y	N	3	NA
Delaware	Y	N	3	N
Florida*	N			
Georgia*	Y	NA	NA	NA
Hawaii	Y	N	3	N
Idaho	Y	N	3	NA
Illinois	Y	Y	2	N
Indiana	Y	N	3	NA
Iowa	Y	Y	1	Y
Kansas	Y	N	3	N
Kentucky	Y	Y	1	N
Louisiana	Y	N	3	N
Maine	Y	Y	2	Y
Maryland	Y	N	3	N
Massachusetts	Y	N	3	NA
Michigan	Y	Y	1	N
Minnesota	Y	N	3	NA
Mississippi	Y	N	3	N
Missouri*	N			
Montana	Y	N	3	N
Nebraska	Y	N	3	N
Nevada	Y	NA	NA	NA
New Hampshire	Y	N	3	N
New Jersey**	Y	Y	1	N
New Mexico*	N			
New York	Y	N	3	N
North Carolina	Y	Y	2	N
North Dakota	Y	N	3	N
Ohio	Y	N	3	N
Oklahoma*	N			
Oregon	Y	Y	2	N
Pennsylvania	Y	Y	2	Y
Rhode Island	Y	N	3	NA
South Carolina*	N			

IV. SURVEY OF POTENTIAL COGENERATORS

Because the approach of this study called for analysis of each individual plant's potential for cogeneration, it was necessary to collect operating data for each plant. These data were collected by means of mail questionnaires. This section describes the experience of this survey.

A. Survey of Large Fuel Users in North Carolina

Development of an initial list of cogeneration candidates is an essential first step in using primary data to estimate an area's cogeneration potential. Any establishment in the state which uses heat energy is a potential candidate to install a cogeneration plant. In practice, very few heat energy users will find it economical to install cogeneration equipment, however.* Collection of primary data should be concentrated on those establishments with a reasonable probability of being candidates. In order to compile a list of candidates with this reasonable probability of being able to cogenerate, secondary data sources are used.

Two secondary data sets on heat energy usage by North Carolina plants and institutions have been assessed. These were the National Emissions Data System (NEDS) of North Carolina sources and the Boiler Registry of the State of North Carolina. The mailing list to potential candidates was made up of plants and institutions identified from these two data sources.

The NEDS data was the more valuable of the two data sources. NEDS allows major users of heat energy to be identified through the size of heat using capacity of the plant and the amount of fuel consumed. A utilization factor for that capacity can be calculated for the year in which data were collected. Further identifying data, such as a plant's standard industrial classification and the county where it is located, also are available. These data are sufficient to identify major heat energy users that have a reasonable probability of being a cogeneration candidate.

*There were 6,856 manufacturing firms listed in the most recent Directory of North Carolina Manufacturing Firms (1979-1980). This Directory listed 868 plants with at least 250 employees.

The second source used to identify major heat energy users was the North Carolina Boiler Registry. The Boiler Registry contains data collected at the time of installation of a boiler on its specifications and operating characteristics. The owner/user of a boiler and its location also are identified.

The list of industrial and institutional plants from whom further data was sought by survey was drawn from the two sources listed. The criteria for inclusion from the NEDS file was that a plant have a fuel using capacity of at least 30 million Btu's per hour. From this list were excluded utility power plants (Duke, CP&L, and VEPCO), and construction and asphalt paving contractors. The reason for exclusion of power plants is self-evident. Construction and asphalt paving contractors were excluded because plant operation (fuel use) is highly intermittent, an extremely unfavorable operating characteristic for a cogeneration plant. To this list were added plants identified as having steam boilers of over 50,000 pounds per hour of capacity. These were located through use of the Boiler Registry, although most of them also appeared in the NEDS list.

Once the potential candidate plants and institutions were identified, the list was prepared for the primary data collection effort. An attempt was made to identify plant managers and plant mailing addresses from records maintained by the North Carolina State University Industrial Extension Service. Where the records were insufficient, the 1976-77 Directory of Manufacturing Firms was consulted, and the request addressed to an unstipulated Plant Manager. It was believed that a personally addressed inquiry would more rapidly reach the plant managers and then the engineering staff than an inquiry to the plain plant address.*

Materials mailed to each plant or institution included a letter of introduction and explanation (Exhibit IV.1) and an analysis form (Exhibit IV.2). The letter was personally addressed to the Plant Manager or other managerial personnel. The analysis form requested data on managerial policy with respect to investment in energy saving equipment and operating

*This proved to be a poor assumption, personnel changes caused delays and losses of our material.

RESEARCH TRIANGLE INSTITUTE

POST OFFICE BOX 12194

RESEARCH TRIANGLE PARK, NORTH CAROLINA 27709

Dear Sir:

The National Energy Act of 1978 is now law and includes specific incentives to encourage cogeneration, the simultaneous production of steam (or heat energy) and electricity, in order to conserve energy. Businesses that cogenerate can receive investment tax credits, accelerated depreciation, and exemptions from coal conversion orders. Furthermore, electric utilities may not discriminate against customers who engage in cogeneration.

The State of North Carolina also is trying to promote the amount of cogeneration by removing additional barriers. The North Carolina Department of Commerce, through its Energy Institute, is sponsoring this study of the potential for cogeneration by North Carolina State University and the Research Triangle Institute. Your participation in this project will assist us in estimating the potential and may improve the probability of State actions to stimulate cogeneration (e.g., revenue bonds). We can assist you by providing an analysis of cogeneration potential for your firm, by estimating the total potential for your industry, and by inviting you to a workshop on cogeneration at North Carolina State University on March 7-8, 1979.

We need your response to the enclosed form in order to carry out our project. Your firm already has been identified as a major fuel user through examination of the North Carolina Department of Labor boiler registry and the National Emissions Data Set, but we need to verify the data and obtain additional information in order to determine the economic feasibility of cogeneration. The form takes only a few minutes to complete and will be very important for the success of this project. Data from your company will be combined with that from other companies in your industry. The original submissions will be treated confidentially and are not subject to the Freedom of Information Act.

If you have any questions on this study or prefer to transmit your information by phone or a visit, please contact either of the principal investigators for the study: Mr. Jerome Kohl, Nuclear Engineering Extension Specialist, North Carolina State University (919) 737-2303; or Dr. Paul Mulligan, Economist, Research Triangle Institute (919) 541-6419.

Page two

We appreciate your assistance in this important North Carolina project. Be sure to mail your responses to the Research Triangle Institute in the enclosed postage-paid envelope by December 15, 1978.

Very truly yours,

Paul F. Mulligan
Paul F. Mulligan, RTI

Jerome Kohl
Jerome Kohl, NCSU

PFM,JK:jae

Enclosure

23U-1738

Exhibit IV.2

ANALYSIS FORM FOR THE NORTH CAROLINA STUDY OF COGENERATION POTENTIAL

The information requested on this form is being collected as part of a project sponsored by the North Carolina Energy Institute (an agency of the State of North Carolina). All data will be treated confidentially. Data should be for 1977 or the latest completed fiscal year. Limit responses on this form to the plant site indicated on the cover letter. If analysis forms for more than one plant in your firm are received, please complete one form for each plant. Check this box if you desire a summary analysis for this plant based on the information provided herein.

☐

Company Name _____

Address _____

County of Establishment _____ Two-Digit SIC Code _____

Information Supplied by _____ Title _____

Telephone Number _____ Electric Utility Service by _____

A. Business Concerns about Cogeneration Facilities

Please rank your top four impediments (from 1-4) to cogeneration:

- ___ Limited supply of capital
- ___ Unattractive return on investment
- ___ Uncertainty about government energy policy
- ___ Additional health, safety, and environmental problems
- ___ Potential regulation as utility
- ___ Utility charge for standby service
- ___ Other (specify) _____

B. Managerial Policy

1. What is your firm's investment criteria for changes to the steam/power system?
 - a. Payback period: Yes ___ No ___ Maximum # of Years ___
 - b. After tax discounted cash flow return on investment: ___%
 - c. Other criteria: Please specify method and percentage figure _____
2. Have you considered the installation of generating equipment in your plant? Yes ___ No ___
3. Do you plan to install generating equipment in your plant? Yes ___ No ___
4. Do you plan to increase your steam capacity in the next 5 years? Yes ___ No ___
5. If yes, estimate the additional pounds of steam per hour _____

C. Current Boilers						Add extra page if necessary
	1	2	3	4	5	
Capacity (lbs/hr)	_____	_____	_____	_____	_____	
Design pressure (psig)	_____	_____	_____	_____	_____	
Operating pressure (psig)	_____	_____	_____	_____	_____	
Temperature	_____	_____	_____	_____	_____	
Year of installation	_____	_____	_____	_____	_____	
Fuels (Coal: C; Gas: G)						
(Oil: #2, #6,)						
(Other)						

Exhibit IV.2 (Continued)

D. Description of Steam System

	<u>Process</u>	<u>Building Heat & Hot Water</u>	<u>Absorption Air Conditioning</u>	<u>Other</u>
Use of steam	_____	_____	_____	_____
Pressure required for use	_____	_____	_____	_____
Percent of total annual steam production	_____	_____	_____	_____
Total annual steam production (1977 or latest fiscal year)	_____ lbs.			
Total fuel(s) consumed				
Coal _____ tons	Oil _____	gals.		
Gas _____ mcf	Others _____			
Total number of plant operating hours	_____			
<u>Average Steam Load (lbs/hr)</u>	<u>Workday</u>		<u>Weekend</u>	
	<u>Day</u>	<u>Night</u>	<u>Day</u>	<u>Night</u>
Summer	_____	_____	_____	_____
Winter	_____	_____	_____	_____
Fall-Spring	_____	_____	_____	_____

E. Uses of Heat Energy Other than Boilers

	<u>Unit 1</u>	<u>Unit 2</u>	<u>Unit 3</u>	<u>Unit 4</u>	<u>Unit 5</u>
Type of Unit	_____	_____	_____	_____	_____
(Key: 1=Kiln; 2=Dryer; 3=Furnace; 4=Other, Specify _____)					
Energy Used (Btu/hr)	_____	_____	_____	_____	_____
Total Btu/yr	_____	_____	_____	_____	_____
Maximum Operating Temp. (°F)	_____	_____	_____	_____	_____
Year of Installation	_____	_____	_____	_____	_____
Fuels Used					
Coal (tons)	_____	_____	_____	_____	_____
Gas (mcf)	_____	_____	_____	_____	_____
Oil (gals)	_____	_____	_____	_____	_____
Other _____	_____	_____	_____	_____	_____

F. Electric Power Requirements

Average kW Demand in 1977	<u>Workday</u>		<u>Weekend</u>	
	<u>Day</u>	<u>Night</u>	<u>Day</u>	<u>Night</u>
Summer	_____	_____	_____	_____
Winter	_____	_____	_____	_____
Spring-Fall	_____	_____	_____	_____
Peak kW load _____	Average cost of purchased power _____ ¢/kWh			
Total annual electricity purchased _____	kWh (1977)			
Does this plant generate electricity for internal use? _____				
If yes, electricity produced in last year (1977 or last fiscal year) _____ kWh.				
Electric generating equipment	<u>Turbine-Generator</u>		<u>Diesel-Generator</u>	
	(1)	(2)	(1)	(2)
Size (kW)	_____	_____	_____	_____
Year of installation	_____	_____	_____	_____
G. <u>Air Conditioning System</u>	<u>Absorption</u>		<u>Centrifugal</u>	
Capacity in tons	_____		_____	

Please return this form to:

Research Triangle Institute
Cogeneration Project
P.O. Box 12194
Research Triangle Park, NC 27709

data on plant steam and electrical loads.

The initial mailing was made in November 1978 to all plants included in the population of large fuel users. A second mailing to non-respondents followed in late December 1978. Telephone calls to non-respondents among the 50 largest fuel users were initiated on January 15, 1979 continuing until February 16, 1979. The chronology of the survey is presented in Exhibit IV.3.

B. Data Management

A data management and control system was established for logging in Analysis Forms received from plants and institutions. Upon receipt, the form was checked off against the Master List. The date of receipt was noted, and the name of the person providing the data was entered. The Analysis Form was marked with day of receipt and a unique identification number.

Coding-editing instructions were prepared prior to receipt of the data. Appropriate units for entering responses and codes for missing values were established, as well as the format for data entry. Processing of Analysis Forms involved two code-edits in order to control quality. Where essential, call backs were made to fill in missing data. Following coding of the data, it was punched onto cards and then entered onto a disk for analysis.

C. Survey Return Experience

The RTI-NCSU team identified a total of 286 plants and institutions for the Survey of Large Fuel Users (Exhibit IV.4). Of these, 248 were identified by use of the NEDS data. Additional plants (38) were identified by use of the Boiler Registry data and through miscellaneous sources.

One hundred thirty-three plants and institutions responded to our Survey of Large Fuel Users. These responses were either written, by telephone, or the result of site visits. A further 40 plants and institutions responded as being unwilling to participate or as having been shut down.

The completion rate from the survey was 47 percent, which represents 133 responses out of 286 plants initially in the survey. The completion rate was 67 percent for the largest 50 fuel users (capacity of over 150 million Btu's/hr).

Exhibit IV.3.

Survey of Large Fuel Users - Time Line

November 1978: Initial mailing

December 1978: Second mailing to non-respondents

January 15, 1979 - February 15, 1979: Call back to non-respondents in
top 50 of Large Fuel Users

January 29, 1979 - February 15, 1979: Coding and keypunching of
received data

February 16, 1979: Data analysis initiated

February 22, 1979: Second milestone meeting

March 7-8, 1979: Cogeneration in North Carolina Workshop

April 3, 1979: Provision of cogeneration projections to Public Staff
of North Carolina Utilities Commission

Exhibit IV.4.

Summary of Survey Responses

NEDS Data

Plants Total	371
(Power Plants)	-12
(Construction & Asphalt)	<u>-111</u>
	248
Additional Plants	<u>38</u>
TOTAL PLANTS	286
Data Received from	133
Response - Refusal or Shutdown	40
No Response	113
Response Rate	60 percent
Completion Rate	47 percent <u>a/</u>

Source: Analysis of RTI - NCSU data.

a/ Responses were received from plants and institutions that account for about 90 percent of the steam capacity on the master list. The response rate from establishments with a good potential for cogeneration probably was higher than 90%.

V. ANALYSIS PLAN

The analysis plan of this study refers to the model for assessing the feasibility of installing cogeneration equipment in existing plants and institutions in North Carolina. This section presents (1) the elements of this economic feasibility model; (2) the data sources used in the analysis; and (3) the fundamental investment decision analysis used in payback calculations and return on investment calculations. The discussion is general, and presented to familiarize the reader with basic concepts. Further details of the analysis program are presented in Appendix A.

A. Components of Cost-Benefit Analysis

The components selected for the cost-benefit analysis were influenced by prior cogeneration studies. The RPA study, Guidelines for Assessing State Cogeneration Policy Options, prepared for the U.S. Department of Energy, has been studied carefully for use in this exercise. Standard assumptions and figures were used in all cases, in order to simulate as accurately as possible the decision making process of potential cogenerators. This section will discuss the cost elements used in the feasibility calculations. The analysis has been carried out in real 1979 dollars. Prices have been reported at their 1979 level, or where older data are used, have been inflated to their estimated 1979 level.

Appendix A contains a description of the steam topping cycle and detailed calculations of the quantity of power cogenerated. Further discussion on the sizing of the turbine and the computer program used in the plant-by-plant analysis also are presented in the Appendix.

1. Capital expenditures

The two components of capital expenditures are the expense of upgrading a plant's boiler capacity for cogeneration and the purchase and installation of a turbine-generator set. The cost of these two items reflects ancillary equipment as well as installation costs.

Cogeneration of electricity via the steam topping process involves generating high pressure/temperature steam (above the levels required

for process or other uses), expanding the steam through a backpressure turbine and using the exhaust steam which is now at a lower temperature and pressure for process and heating needs. The incremental capital costs for a cogeneration plant are in the boiler capacity and the steam turbine-generator.

Boiler capacity is expensive. Key factors in determining the cost of boiler capacity are the type of fuel burned and the pressure of the steam desired. Oil and gas fired boilers are much less expensive than coal boilers. This is largely due to the expense of the pollution control equipment necessary when coal is used as a fuel. High pressure-temperature boilers cost more than low pressure boilers. Higher pressure-temperature steam contains more useful energy than does low pressure steam (see Appendix A). The installed costs of high pressure boiler capacity as developed by RPA for sample boiler sizes and pressures were used in this study. When adjusted for inflation, oil fired low pressure boilers can cost less than \$20 per pound of steam capacity installed. Coal fired high pressure boilers can cost as much as \$50 per pound of steam capacity installed, with pollution control equipment included.

The entire cost of a boiler plant should not be included in the capital cost of a cogeneration plant. We considered the additional cost of installing high pressure instead of low pressure boilers and the additional boiler capacity needed for cogeneration. The incremental cost is assumed to be \$5 per pound of steam installed capacity which compares to about \$25 per pound of installed high pressure oil-fired boiler capacity and \$45 per pound of installed high pressure coal fired boiler capacity.

To justify use of the incremental cost of boiler capacity, it must be assumed that new high pressure boilers are installed to replace old low pressure boiler capacity which is retired and that the decision on retrofitting a plant for cogeneration is made simultaneously with replacement of old boilers.

There are strong economies of scale in the cost of turbine generators. Small turbines (2-3MW) can cost over \$600/kW installed. In contrast, turbine generators of greater than 15 MW cost \$250/kW installed

capacity. This cost factor heavily weighs against the cost effectiveness of installing small turbine-generators.

2. Annual savings

Cogeneration plants yield savings to their owners when they are able to generate power more efficiently and cheaper than power could be purchased from the utility.

Savings to cogenerators are due to a reduced demand for power from the utility. This will have two components: a demand charge and an energy charge. The demand charge for the cogenerator falls as his peak demand from the utility decreases. The peak over a 12-month period may fall by as much as the capacity of the turbine-generator, but in practice, will decrease less. The 12-month "ratchet" on utility demand charges makes it essential to lower the peak demand as much as possible.

The energy charge is based on a plant's or institution's total demand for energy in kWh. Each kWh generated and substituted for utility power will result in savings in the value of the utility's energy charge, so long as the heat rate and fuel costs of the cogenerator combine to yield a cost lower than that of the utility.

The major component of savings is often in the demand charge. The demand charge can be considered a capacity charge for generating-transmission-and-distribution equipment, which is expensive for utilities, and less expensive for a cogenerator due to the low incremental boiler charges and to the fact that cogenerated electricity is produced at the point of consumption.

Cogeneration plants do incur incremental fuel, operating and maintenance expenses which partially offset their savings on power. Fuel chargeable to power is incurred in producing higher pressure-temperature steam for expansion across the turbine prior to exhausting the steam to process uses.

B. Data Sources

The cost estimates and concepts have been drawn from prior studies and vendors. Prominent among these prior sources are reports by Resource Planning Associates (RPA1 and RPA2) and the Thermo-Electron

Corporation. These reports have provided the basis for calculating capital investment costs and annual savings of cogeneration projects. References were made to articles in journals to assure accuracy in methodology and estimates, and discussions were held with boiler and turbine-generator vendors to obtain up-to-date cost information.

Annual savings due to cogeneration can vary greatly between otherwise similar plants because they are served by different utilities. This study has attempted to model the rate structures of the 3 major utilities serving North Carolina in order to approximate the savings in power charges accruing to a N. C. cogenerating plant. Our figures are intended to reflect the marginal charges cogenerators pay for power, in order to assess the impact of a change to cogeneration by a plant. The following table reports the values used.

<u>Utility</u>	<u>Charge</u>		
	<u>Energy</u> ¢/kWh	<u>Demand</u> \$/kW/mo.	<u>Standby</u> \$/kW/mo
Duke	1.9	2.00	1.59
CP&L	1.5	5.00	1.00
VEPCo	1.8	5.00	5.36

Source: R.T.I. interpretation of Current Rate Schedules filed with and approved by N.C. Public Utilities Commission

The third source of data used in analyzing the feasibility of a plant's cogenerating was the operating data from each plant obtained through our survey of Large Fuel Users described in Section IV.

The data collected were adequate to make rough estimates of the feasibility of a plant's installing and operating cogeneration equipment.

C. Investment Feasibility Criteria

Business decisionmakers base investment decision on the economic feasibility of a project. Two very common measures of economic feasibility are the Payback Period (PB) and Return on Investment (ROI). These measures may be used to rank the economic attractiveness of alternative investment opportunities. Investments with shorter payback periods

or higher returns on investment are better prospects than alternatives with longer payback periods or lower returns on investment.

Payback period analysis concentrates on cash-flow analysis. Roughly defined, the payback period is calculated by dividing the value of capital expenditures for a project by the annual cash-flow savings.

$$(1) \quad PB = CAP \div ANSAV$$

PB: payback period

CAP: capital expenditures

ANSAV: annual cash-flow savings.

Cash-flow savings on a cogeneration project is composed of the savings on energy no longer purchased from a utility, minus the cost of additional fuel for inplant generation of power and the operation and maintenance costs of the cogeneration plant.

$$(2) \quad ANSAV = SE + SD - FCP - MG - MB$$

SE: savings on energy charge from utility

SD: savings on demand charge from utility

FCP: fuel chargeable to inplant electric generation

MG: operation and maintenance costs of the turbine-generator

MB: incremental operation and maintenance costs of the boiler

The payback period measures the number of years it would take to pay off initial company expenditures with the cash-flow savings, ignoring most tax policy, depreciation, and financing of the investment. The investment tax credit was taken into account in our payback analysis by a proportionate reduction in the capital expenditures.

A sharper analytical tool for studying investment opportunities is the return on investment measure. Return on investment analysis includes the elements of tax policy, depreciation and financing, and offers a method to study the impact of variations in the factors on the feasibility of a project. The return on investment is defined as the rate of discount which equates the present discounted value of the capital expenditures in a project with the present discounted value of the annual savings attributable to the investment over its lifetime.

$$(3) \quad 0 = \sum_{t=1}^T \frac{(CAP_t - AS_t)}{(1 + r)^t}$$

CAP: capital expenditures in year t

AS: annual savings in year t

r: return on investment

T: expected useful lifetime of the investment.

Capital expenditures usually occur before any savings are realized from a project, and savings stretch out over the useful lifetime of a project. The annual savings in the calculation of return on investment reflects the taxes, depreciation, and financial charges on the project.

$$(4) \quad AS_t = SE_t + SD_t - FCP_t - MG_t - MB_t - TX_t - ALP_t$$

TXt: federal taxes in year t

ALP_t: annual loan payment in year t.

The return on investment (r) is solved for in an iterative fashion: successive values of r are substituted into equation (3) until the value of the right term equals zero.

The return on investment is a better measure of an investment's worth to a company than is the payback period analysis. Return on investment demonstrates rigorously what the impact on a project will be of changing depreciation schedules, altering taxes, or varying financial arrangements. It is readily determined how a specific investment compares to the present and past returns on other investments.

The payback period of a project is a valid measure by which to rank investment opportunities, given similar depreciation, tax and financial conditions for each project. It is very easily calculated and understood as well. These factors make payback period analysis widely used, though it is not as refined a tool as is return on investment.

Our analysis calculates both the payback period and return on investment in studying the potential of a plant for cogeneration.

VI. FINDINGS FROM THE SURVEY OF POTENTIAL COGENERATORS

The survey described in Section IV resulted in data that were analyzed with the procedures described in Section V. This section presents the results of the survey and analysis in terms of cogeneration capacity, both actual and potential. The actual status of cogeneration in North Carolina in 1979 is described in subsection A, the potential capacity in existing establishments is described in subsection B, and the situation at public and nonprofit institutions is given a closer examination in subsection C. Subsection D is an analysis of the years to payback vs steam load for various operating periods per year sorted by the utility area in which the companies are located. Subsection E reports on the impediments to cogeneration as perceived by the respondents to the survey. Subsection F is an analysis of the sensitivity of the survey estimates of cogeneration to variation in parameters such as the investment tax credit, the standby charge for power, and the rate of increase of fuel prices and electricity rates. Subsection G is an estimate of the cogeneration potential that will result from new and expanding industries over the next 20 years. Subsection H summarizes the amount of potential cogeneration through the year 2000 based on the above analyses. Subsection J presents preliminary results of an analysis of the potential for cogeneration centers to serve more than one user.

A. Cogeneration in North Carolina - 1979

There are 372 MW of cogeneration capacity in the State of North Carolina (Exhibit VI.1). This represents the capacity in 15 plants, ranging in size from a 95 MW pulp and paper mill down to a 2.3 MW textile mill. Eleven of these plants, with a capacity of 296.3 MW, generated 1,742 million kWh in 1978, for a load factor of 67 percent. The other five plants provided no operating data for 1978, but with similar load factors, an additional 410 million kWh would have been generated in 1978, for a total of 2,155 million kWh.*

Cogeneration has not increased significantly in North Carolina in the last 25 years. Since the middle 1950's only two new plants have installed cogeneration

*These numbers can be compared to the electrical generating capacity located in North Carolina of 15,000 MW or the total capacity owned by the Class A companies serving North Carolina of 29,200 MW and to the total electricity energy sales in North Carolina of 52,500 millions of kWh (source 1975 Report of North Carolina Utilities Commission.)

Exhibit VI.1

Table 1

Existing Establishments that Produce Electricity
Through Cogeneration in North Carolina Classified by Industry,
Capacity and Output (in Most Recent Year)

Industry	SIC	Number of Establishments	MW	MkWh	MkWh	Total MkWh
Food and Tobacco	20,21	2	38.5	<u>a/</u>	190 <u>c/</u>	190
Textiles	22	4	33.3	96		96
Pulp and Paper	26	6	251.0	1551 <u>a/</u> + 147 <u>c/</u>		1698
Chemicals	28	2	37.0	98		98
Institutions	82	<u>1</u>	<u>12.5</u>	<u>a/</u>	<u>73<u>c/</u></u>	<u>73</u>
Total		15	372.3	1745 <u>b/</u>	410	2155

SOURCE: RTI - NCSU Survey of Large Fuel Users.

a/ Information was not available for one of the firms.

b/ Information was not available for three firms.

c/ Estimated at 67 percent capacity utilization.

capacity, totalling 31 MW. The Census of Manufacturers reported 1,742 million kWh cogenerated by industrials in 1971, compared to an estimated 2,155 million kWh produced in 1978.

The pulp and paper industry accounts for more than 67 percent of the installed cogeneration capacity in the state, with 251 MW. Food and tobacco (SIC 20 and 21), textiles (SIC 22 and 23) and chemicals (SIC 28, 29, and 30) each accounted for 35-40 MW of capacity.

Cogeneration capacity is evenly distributed in the utility service areas (Exhibit VI.2.) There are 156 MW in CP&L's area and 98 in Duke's. VEPCo has almost 120 MW of cogeneration in its North Carolina service area, despite the sparse population.

B. Estimation of Cogeneration Potential in Existing Establishments

Estimation of the potential for cogeneration was based on a plant-by-plant analysis of the existing industrial and institutional establishments contacted during the survey. This method required a feasibility study of each plant, analysing the technical feasibility of and economic incentives for the plant to cogenerate. This approach allowed the team to identify specific candidates for cogeneration, test the likelihood of their installing or enlarging cogeneration plants and study the sensitivity of investment decisions to a variety of public policy options and economic scenarios.

Detailed analysis of a plant's potential for cogeneration was carried out on operating data obtained from the plants. The potential from all existing plants and institutions was then summed to yield a total potential for cogeneration in the state from presently existing and operating plants and equipment.

This study identified 130 MW of steam cogeneration potential in North Carolina plants which do not presently cogenerate (Exhibit VI.3.) This potential was based on current conditions of fuel costs, electricity rates, standby charges by the utility in the area in which they are located, and the firms own criteria for payback period and/or return on investment. If the firm did not specify criteria, a 5-year payback period was assumed. A 20 percent federal investment tax credit also was assumed.

Exhibit VI.2

Cogeneration Capacity by Utility Service Area - 1978

	MW	Million kWh
Duke	98	471
CP&L	156	918
VEPCo & Other	118	766
	<hr/> 372	<hr/> 2,155

Source: Analysis of RTI-NCSU survey data.

Most of this 130 MW potential may be realized in the next 10 years. These plants have their best opportunity to retrofit for cogeneration when existing low pressure boiler capacity is ready for replacement. Assuming a 25-year life for boilers, plants accounting for 124 MW out of the total 130 MW potential are due to replace existing boilers by 1990. About 3 years are necessary to plan and install boilers and turbine generator systems. Thus many of these firms probably are thinking about replacement needs at this time. Many of the firms that we judged to have the potential to cogenerate but do not currently do so indicated in the survey that they are studying the feasibility of their plants cogenerating.

The 130 MW of potential cogeneration are concentrated among a small number of plants. About 100 MW is accounted for by four firms in the mining and chemical industries. At least three and possibly all four of these plants are now considering or have considered the installation of cogeneration facilities.

The second portion of the exhibit lists potential increases in cogeneration by establishments which already cogenerate. Several of the pulp and paper mills currently have steam and electrical loads which suggest they have the potential to increase their cogeneration by 40 to 80 MW. Several of these firms are considering the installation of additional generating capacity. Whether the plans are realized depends on the availability of capital and return on investment calculations.

The potential cogeneration capacity of 130 MW is presented in Exhibit VI.4 by the utilities that serve them.

Exhibits VI.3 and VI.4 do not make any allowance for potential cogeneration by firms that did not respond to the RTI-NCSU survey. Analysis of nonrespondents by size (amount of fuel consumed) and industry classification suggests that relatively little potential was overlooked. We estimate that this potential lies in the 20 to 50 MW range. This figure is introduced in Exhibit VI.15 which recapitulates current capacity, existing potential, potential based on new and expanded industry, and potential that surfaced during the sensitivity analysis.

Exhibit VI.3

Estimates of Additional Potential for Cogeneration from Existing Firms in North Carolina^{a/}

Time Period	No. of Plants	MW	MkWh	Steam (000#/hr)	BBT. Oil Equiv. (000) ^{c/}
<u>Noncogenerating Establishments</u>					
1980	4	21	147	457	145
1985	1	12	84	240	83
1990	4	91	638	1469	630
1995 & later	2	6	42	112	41
TOTAL	11	130	911	2278	902
<u>Cogenerating Establishments</u>					
1979	80 ^{b/}				

SOURCE: Analysis of RTI-NCSU survey data.

^{a/} Plants considered to have potential meet the payback or return on investment criteria of the respective firms, or where this data is missing meet a 5-year payback criteria or have a 15 percent return on investment (after inflation). Management may find these unacceptable returns, or view the risk on such an investment as too great, and therefore not carry out the investment.

^{b/} This figure is based on the steam load at 6 paper mills which cogenerate but still have the potential to produce more electricity. If the potential were fully realized, the generating capacity would be approximately equal to their present demand for electricity.

^{c/} These figures represent the energy value of the kilowatts of electricity that are produced. Each kWh was assumed to be equal to 3,412 Btu's. This is a modest estimate of the savings because the heat rate of cogenerators is about 4,200 Btu's per kWh, while the heat rate of central power plants is 9,000 or more.

Exhibit VI.4

Potential Cogeneration by Utility Territory

	MW	MkWh/yr.
Duke	26	177
CP&L	98	692
VEPCO & Other	6	42
TOTAL	130	911

SOURCE: Analysis of RTI-NCSU survey data.

C. Cogeneration Potential at Institutions

1. Past and Current Cogeneration

Institutions refer to nonbusiness activities such as education, health care, military, and general government. Most institutions are either publicly owned or have nonprofit status and these might be better able to utilize cogeneration than private business establishments that have to pay taxes and make an acceptable return on investment. Public institutions usually are subject to investment criteria when making choices among competing approaches to meeting physical needs. For example, a college can make its own electricity or buy it, but it has to justify its decision on the relative costs just like any business enterprise. The only difference is that it may be able to accept a lower return on its investment in generating equipment because the sponsoring agency may make capital available for low return activities because of a commitment to use energy efficiently.

Public institutions in North Carolina have been making decisions on cogeneration in the same manner as businesses, and with similar results. During the last 20 to 30 years, the number of institutions that cogenerate has dropped from a dozen or more to a single facility: the University of North Carolina at Chapel Hill. The reason given to us for dropping cogeneration was that the benefits no longer justified continued operation or replacement of cogeneration equipment. Public utility electricity service is now available everywhere, it is extremely reliable, and much less expensive than it was in the past. Most institutions do not have steam loads and electricity consumption patterns that are favorable to cogeneration. The steam is mainly needed during the winter months; electricity demand is highest during the summer. The daily fluctuations are substantial. The year-round minimum steam production for most institutions is far below 60,000 pounds per hour, which appears to be the minimum economic size for a firm that operates a continuous process.

Insights into barriers to cogeneration were gained from visits to five of these institutions. Many of the visited Institutions had switched from coal to oil for environmental reasons and cannot justify burning more of the high priced oil for producing electricity. Others replaced old boiler capacity with low-pressure oil fired package boilers and thus are unable to cogenerate. Reasons for the decisions to go to low pressure boilers and oil include the expected low return on investment in cogeneration, a shortage of capital, and most importantly uncertainty over government energy policies. The relatively short life of package boilers, their low cost, and the ability to meet air emission standards by burning

oil make package boilers an attractive way to "get by" even though the long run cost per pound of steam is higher than coal fired boilers. Institutions are reluctant to switch back to coal for a variety of reasons. One institution converted its coal yard to a parking lot and thus does not have space for coal. Another dismantled its coal handling equipment and does not want to replace the equipment. Others do not want to bother with ash disposal or the pollution control equipment needed for coal boilers. Some institutions are reluctant to spend scarce capital resources on purposes not directly related to the mission.

2. Future Cogeneration Potential at North Carolina Institutions

Potential cogeneration at North Carolina institutions is a function of their current size because little growth is expected in school enrollments, hospital beds, military installations, and general government. Any improvement in prospects for cogeneration will depend on changes in energy consumption that even out steam loads such as steam absorption air conditioning as a substitute for electrically driven centrifugal compressor air conditioning. Even absorption air conditioning will raise the steam load to acceptable levels for only a few of the larger institutions. Hospitals are better candidates for cogeneration than comparably sized universities because they experience less variation in steam and electricity demand between day and night, weekday and weekend than do universities. The very largest military installations also may have sufficiently large steam loads, though the facilities often are widely dispersed and are not served by a single heating plant.

The payback period is listed in Exhibit VI.5 along with some additional information for the institutions that responded to the survey inquiries. The largest missing institution is the Fort Bragg Army Post in Fayetteville. Telephone contacts indicated that Fort Bragg produces steam in four boiler plants, the largest of which produces an average of 120,000 pounds per hour. This large oil fired boiler was built in 1953 and is due for replacement. Fort Bragg is studying the possibility of replacing this boiler with a high pressure coal, wood and waste boiler designed for cogeneration. An indepth data collection and analysis effort beyond the scope of this project is necessary to make a full determination of the cogeneration potential at Fort Bragg or at the most promising candidates on the list, the Marine Bases at Cherry Point and Camp Lejeune and the University of North Carolina at Chapel Hill. Duke University may become a good candidate as it proceeds with its program of converting buildings from electrical to central heating and if it installs steam absorption air conditioning. North Carolina

Exhibit VI.5

Cogeneration Potential of Selected North Carolina Institutions

Name	FID Number	Steam Load		Electricity		Rec. Turbine Size - MW	Hours of Operation	Payback in Years for ITC	
		Average	Maximum	Max. Dem.	Consumption			20%	10%
N.C. State University	001	46,000	99,000	16.0 MW	403 MWh	2.53	8760	7.9	9.9
Appalachian State Univ.	013	32,190	32,190	NA	282	0.14	8760	72.9	90.0
Baptist Hospital	016	23,290	45,000	NA	114	2.00	8760	9.1	11.0
Cherry Hospital	081	36,870	50,000	4.0	323	2.44	8760	8.7	10.0
Dorothea Dix Hospital	100	14,160	14,160	4.0	124	0.63	8760	12.2	15.3
Duke University	108	58,220	130,000	35.0	510	5.78	2080	8.1	10.6
East Carolina Univ.	114	27,400	45,000	NA	240	0.00	8760	100.0	-
Forsyth Hospital	133	NA	20,000	3.0	NA	0.89	8760	33.1	41.3
McCain Hospital	183	7,990	12,000	NA	70	0.42	8760	23.6	29.4
N.C. A & T University	191	26,600	70,000	3.0	233	0.0	8424	100.0	-
N.C. Central University	193	11,990	22,000	3.0	105	0.0	8760	100.0	-
UNC - Chapel Hill	256	NA	118,000	NA	NA	3.83	8760	6.6	8.3
UNC - Charlotte	257	15,750	40,000	5.6	138	1.92	NA	20.6	25.7
USMC - Cherry Point	258	111,190	200,000	25.0	974	5.60	8760	5.6	7.0
USMC - Camp Lejeune	259	108,110	375,000	10.0	947	3.04	8760	5.7	7.1
Wake Forest University	271	20,780	35,000	3.0	187	1.51	8520	10.7	13.4
Winston-Salem St. Univ.	279	NA	NA	NA	NA	NA	8760	1000.0	-

Source: RTI-NCSU survey

State University could be a candidate, if it can increase its average steam load. None of the other institutions look promising at this time due to their low average steam loads.

D. Years to Payback vs Steam Load for Various Operating Periods, Sorted by Utility

The calculated payback period for each respondent was sorted out by utility, and then into four categories of hourly usage/year of the plant. Each category was ranked in descending order of steam load. The results of these calculations for companies with average steam loads over 20,000 #/hr are shown in Exhibit VI.6.

Preparation of this exhibit revealed anomalies in some calculated paybacks which were explained as follows:

- (a) the company was already cogenerating
- (b) insufficient data was available on average steam load
- (c) low electricity needs resulted in selection of a very small turbine to provide 80% utilization and no sale of electricity to the utility.

The tabular information from exhibit VI-6 has been reproduced in graphical form in exhibit VI-7.

E. Impediments to Cogeneration

The Questionnaire (analysis form) asked respondents to rank the top four impediments to cogeneration from a list of seven. A poor return on investment (ROI) was perceived as the greatest single impediment to cogeneration by the respondents to the analysis form (see exhibit VI-8). Of the 133 respondents, 54 considered a poor ROI to be the biggest impediment. Forty-four other respondents mentioned a poor ROI as an impediment. The second and third ranked impediments were "limited capital" and "uncertainty about government energy policy." More respondents listed the former as the biggest impediment (34 to 11) but "energy policy" was listed more frequently across all rankings (87 to 76).

The next most often ranked impediments were "health, safety, and environmental problems" and "utility charge for standby service," which were ranked by 64 and 60 respondents, respectively. The impediment listed least frequently was "potential regulation as utility," mentioned by 35 respondents as the second, third or fourth biggest impediment. No one considered potential regulation as the biggest impediment.

Exhibit VI.6
Years to Payback vs Steam Load

A. DUKE POWER COMPANY

> 8000 hrs/yr
of operation

FID	SIC	hours/yr	avg. steam load thousands of pounds/hr	calc. payback (yrs.)
116	26	8760	422	2
209	21	8760	163	5
90	22	8640	134	-32*
204	28	8000	84	9
1	24	8760	46	6
176	21	8760	34	10
191	82	8424	26	-32*
178	21	8400	25	14
16	80	8736	23	8
271	82	8520	20	11

7000 - 8000 hrs/yr of operation

186	22	7200	27	12
233	22	7200	24	-32*

6000 - 7000 hrs/yr of operation

309	21	6000	273	
199	22	6000	59	-32*
170	22	6240	57	-32*
252	22	6000	36	-32*
129	22	6000	32	-32*
144	22	6900	22	-32*

Under 6000 hrs/yr of operation

108	82	2080	58	8
88	22	4896	53	7
11	22	2000	29	-32*
34	25	2250	26	13
281	21	4000	22	20

*** LOW ELEC. DEMAND

** ALREADY COGEN.

* INSUFFICIENT DATA FOR CALCULATION

B. CAROLINA POWER AND LIGHT

> 8000 hrs/yr
of operation

FID	SIC	hours/yr	avg. steam load thousands of pounds/hr	calc. payback (yrs.)
78	26	8760	1755	2
122	26	8640	1564	9**
236	28	8760	748	2
110	28	8760	456	2
9	28	8760	228	3
113	28	8760	216	2
155	28	8760	183	3
97	36	8640	134	-32*
258	97	8760	111	5
259	97	8760	108	17***
0	82	8760	46	8
81	80	8760	36	6
182	24	8000	36	7
180	28	8700	31	7
6	28	8760	31	9
210	--	8800	28	-32*

7000 - 8000 hrs/yr operation

205	28	7700	163	5
277	24	7600	68	5
86	22	7344	57	5
232	22	7600	34	-32*
254	24	7200	24	8
439	24	7200	21	53

6000 - 7000 hrs/yr operation

213	22	6000	60	-32*
98	22	6000	57	35

Under 6000 hrs/yr operation

143	20	2000	28	10
-----	----	------	----	----

C. VEPCO
> 8000 hrs/yr of operation

FID	SIC	hours/yr	avg. steam load thousands of pounds/hr	calc. payback (yrs.)
159	26	8688	719	4
140	28	8760	60	8
539	24	8656	24	13
265	24	8200	--	--

7000 - 8000 hrs/yr of operation

255	24	7200	24	8
-----	----	------	----	---

6000 - 7000 hrs/yr of operation

266	22	6480	27	-32*
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D. UTILITIES OTHER THAN CAROLINA POWER & LIGHT, DUKE, OR VEPCO
> 8000 hrs/yr of operation

FID	Util. Ref. No.	SIC	hours/yr	avg. steam load thousands of pounds/hr	calc. payback (yrs.)
226	4	36	8760	1711	11
13	8	82	8760	32	1123**
114	9	82	8760	27	-32*

7000 - 8000 hrs/yr of operation

169	7	30	7488	96	8
488	9	22	7500	48	19
69	7	20	7920	44	--

6000 - 7000 hrs/yr of operation

N O N E

Under 6000 hrs/yr of operation

253	9	28	2000	54	-32*
60	6	28	3800	30	7
270	9	20	4680	26	-32*
120	9	21	2129	21	-32*

COGENERATION PAYBACK VS AVERAGE STEAM LOAD

KEY

SYMBOL	UTILITY
X	CP&L
●	DUKE
■	VEPCO
▲	OTHER

**SOURCE : RESPONDENTS TO NCSU-RTI
QUESTIONNAIRE ON COGEN IN N.C.
(JAN. 79)**

Besides the ranking of impediments by total times mentioned, a weighted ranking was created by which responses were weighted more heavily, if they were ranked more highly. The weighted rankings do not differ significantly from the unweighted rankings except for the reversal of the limited capital and uncertainty categories.

"Other" responses to the ranking are listed at the bottom of exhibit VI.8. No "other" response was listed by more than seven respondents. The two responses mentioned seven times each were "the availability and cost of fuel" and the infeasibility of the "modification of the plant and operational reliability."

F. Sensitivity Analysis

The feasibility of investing in cogeneration equipment is subject to numerous influences including current prices for fuel and power, the cost of installing cogeneration plant, the rates for stand-by service, the current business climate, expectations with respect to the business cycle and inflation, and managerial criteria for investment decisions. Some of these factors are out of a plant's or institution's hands, some are subject to impact by government policy.

The public policies which have been modeled, and their impact studied are:

- investment tax credits; and utility standby-by rates

In addition to these policy variables changes in the following economic factors that would affect investment decisions have been studied:

- the price of fuels; inflation of fuel and power rates;
and alternative investment decision criteria.

Factors held constant for the study include:

- cogeneration mode;
- fuel used;
- structure of power rates for cogenerators
(no provision for peak load pricing);
- output level of the plant;
- price of cogeneration equipment; and
- the steam and electrical load profiles.

Exhibit VI.9 presents the key factors in our model, with the variations from present values used to test sensitivity.

Exhibit VI.8.

Perceived Impediments to Cogeneration from the
Survey of Potential Cogenerators in North Carolina

Impediment	Ranking				Sum Total	Weighted Sum Total
	1st	2nd	3rd	4th		
Limited Capital	34	19	6	17	76	222
Poor Return on Invest- ment	54	29	9	6	98	327
Uncertain Energy Policy	11	16	34	26	87	186
Health, Safety, and Environmental Problems	1	22	26	15	64	137
Potential Regulation		5	14	16	35	59
Charge for Standby Service	5	16	20	19	60	127
(WEIGHT FACTOR)	(4)	(3)	(2)	(1)		
Other	15	7	4	8	33	
No Response	13	19	20	26	78	

Other Impediments	Times Mentioned
Availability of fuel and cost	7
Modification of plant and operational reliability	7
Finding qualified personnel	5
Have not considered the econo- mics or feasibility	5
Very low steam pressure needed	4
Irregular and low demands for steam and electric power; boiler shutdowns; impractical	2
Already cogenerating	1
Total electric plant - no steam	1
Demand for manufactured product	1
Government regulation	1

SOURCE: RTI-NCSU
survey

Exhibit VI.9.

Policy and Economic Variations

	<u>Base Conditions</u>	<u>Favoring Cogeneration</u>	<u>Discouraging Cogeneration</u>
Investment Tax Credit	20 percent	30 percent	10 percent
Utility Stand-by Charges	actual	\$1.00/kW/mo.	\$5.36/kW/mo.
Inflation of Fuel Price	0 percent/yr.	0 percent/yr	2 percent/yr.
Inflation of Power Rates	0 percent/yr.	2 percent/yr	0 percent/yr.
Price of fuel used	\$1.25/MBtu	\$1.25/MBtu	\$1.75/MBtu \$1.50/MBtu

The base value used for the investment tax credit (ITC) is 20 percent. The ITC effectively decreases the cost of the capital project by the given percentage by allowing that fraction to be written off against the firm's tax liability. This variable is an effective proxy for varying the investment cost of the project. As a more favorable ITC we used a rate of 30 percent, as a less favorable ITC we used 10 percent.

Standby rates for utility service to cogenerators was modeled at the current approximate values for each of the 3 class A utilities serving North Carolina. Vepco has a stand-by rate which is appreciably higher than those of the other two. The favorable scenario has all utilities applying the same relatively low stand -by charge of CP&L. The pessimistic run imposes the high standby charge of Vepco on all potential cogenerators.

Inflation is expected to have an impact on the feasibility of cogeneration plants, if the inflation rates for fuel and power differ. Current projections call for both fuel and power rates to increase at about the general inflation rate. Neither rate is expected to be lower than the general rate, though either might be greater. For our sensitivity tests, the base assumption is that the price of fuel and power inflate at the same rate. A situation encouraging cogeneration arises when power rates increase faster than the price of fuel (we allow 2 percent over the general rate). A situation unfavorable to cogeneration arises when fuel prices escalate faster than do power rates (again by 2 percent).

The initial assumption on fuel is that it is obtainable at \$1.25 per million Btu. Other rates used are less favorable to the feasibility of cogeneration: \$1.50 per million Btu and \$1.75 per million Btu.

The analysis which is reported in this section focuses on survey respondents that do not presently cogenerate, and includes no provision for potential increases by present cogenerators or by non-respondents to the survey.

As the sensitivity results are read, it is important to note two things: present cogenerators have steam and electrical loads which can support 40-80 MW of additional cogeneration; and survey non-respondents make up an additional 25 to 30 percent of cogeneration potential. These two allowances should be made in discussing the sensitivity of total present potential in North Carolina.

The results of basic sensitivity runs are presented in Exhibit VI.10. For each run we list the critical assumptions, and the MW of potential cogenerating capacity, with a payback of under 6 years.

Run number 1 is the scenario providing the strongest incentives for cogeneration. In this analysis, there is a maximum of 175 MW of potential cogenerating capacity with a payback of 6 years or better in plants which do not cogenerate. This contrasts with the base run which projects 130 MW of potential cogeneration capacity meeting the 6 year payback criteria. The increase of 45 MW between the most favorable run and the base run is due to three factors: a higher ITC, a common low stand-by charge for power, and the price of electricity inflating faster than that of fuel.

Changing only the ITC to 30% from 20% yields 13 MW more of cogenerating capacity with a payback of at least 6 years. Lowering the ITC to 10 percent causes 15 MW of capacity to no longer meet the 6 year payback criterion.

A major impact on feasible capacity is made by imposing a uniformly high charge for stand-by power. If all of the potential candidates were charged as much as \$5.36 per kilowatt per month for stand-by service, only 88 mW of cogenerating capacity would meet a 6 year payback criterion.

Using \$1.50 per million Btu causes the cogenerating capacity with a payback of better than 6 years to drop to 121 MW, and using \$1.75 per million Btu, lowers potential capacity to 108 MW.

The combination of \$1.75 per million Btu, a \$5.36/kW/mo. standby charge with only a 10 percent ITC on cogenerating equipment would make it financially unattractive for any of the plants in our survey to cogenerate (i.e., of those that do not presently cogenerate).

Exhibit VI.11 presents the MW of cogeneration capacity that can meet different payback criteria for different policy and economic assumptions. For the base (run 1), 130 MW meet a 6 year payback criterion, and 76 MW of that cogeneration capacity has a payback of 3 years or better. A 4 year payback is met by 99MW of capacity and 108 MW meet a 5 year payback. The most favorable conditions (run 1) yields 175 MW of capacity meeting the 6 year criterion, 167 MW meeting the 5 year level, 141 MW having a payback of 4 years or better, and 124 MW with a payback of better than 3 years.

Exhibit VI.10.

Major Parameters and Results of Sensitivity Analysis

Run Number	Investment Tax Credit	Standby Charge	Differential Inflation		Fuel Price \$/MBtu	MW Capacity 6 Yr. Payback
			Fuel	of Electricity		
1	.3	1.00 kW/mo	0	2%	\$1.25	175
2	.1	actual	0	0	1.25	115
3	.2	actual	0	0	1.25	130
4	.3	actual	0	0	1.25	143
5	.2	actual	2%	0	1.25	124
6	.2	actual	0	2%	1.25	166
7	.2	1.59/kW/mo	0	0	1.25	130
8	.2	5.36/kW/mo	0	0	1.25	88
9	.2	actual	0	0	1.50	121
10	.2	actual	0	0	1.75	108
11	.1	5.36/kW/mo	2%	0	1.75	0
12	.3	1.00/kW/mo	0	2%	1.25	175

Source: Analysis of RTI-NCSU survey data.

Exhibit VI.11

Projected Installation of Cogeneration
By Non-Cogenerators with Alternative Scenarios^{a/}

Computer Analysis	Cogeneration in MW			
	Payback Criterion			
	<u>6 Yr.</u>	<u>5 Yr.</u>	<u>4 Yr.</u>	<u>3 Yr.</u>
Run 1	130	108	99	76
Run 2	115	108	99	76
Run 3	175	167	141	124
Run 4	143	130	108	88
Run 5	124	108	89	76
Run 6	165	141	124	94
Run 7	130	108	99	76
Run 8	88	76	0	0
Run 9	121	108	99	76
Run 10	108	99	88	0
Run 11	0	0	0	0

Source: Analysis of RTI-NCSU survey data.

^{a/} This analysis is based on the cogeneration potential at existing plants in North Carolina that do not cogenerate at the present time. The estimate of capacity under the most likely conditions is 130 MW.

G. New and Expanded Industry

Forecasts of the cogeneration potential from new and expanded industry in North Carolina must be based on a combination of methods and must allow for a very large margin of error, since the potential for cogeneration in North Carolina with a continuation of present conditions, is limited to a few industries and a small number of plants with a large steam loads, almost continuous operation, complementary electric demand, and the ability to burn coal. Only a few individual plants in food and tobacco, pulp and paper, and chemicals, including mining and petroleum refining, meet these conditions and can justify installing new cogeneration equipment. The textile and furniture industries generally are not good candidates because the individual plants are too small. Thus we were required to predict approximately how many specific plants will open or expand.

The first step in the approach was to look at the records maintained by the State Industrial Development Agency of new and expanded plants in North Carolina for the last 12 years. The record listed the location, industry, employment size, and investment cost for each firm. During this time only 3 or 4 large firms began operations and not all of them were suitable for cogeneration. Past history offered no pattern that could be extrapolated.

The next step was to look at estimates of national growth in each industry offering potential for the next five and past 10 years (U.S. Industrial Outlook). Due to resource constraints, regional markets, plant indivisibilities, and the lack of acceptable projections for more than 5 years, application of these growth percentage rates to the current industry in North Carolina does not appear to be acceptable.

The final solution was to estimate the range of future cogeneration potential shown in Exhibit VI.12 based on average annual growth rates for the high side estimate and judgment about minimal growth for the low side. The judgment is based on knowledge of the state's economy, recent industrial growth, and trends in the national economy. The percentage figures that were used were applied to energy growth rather than growth in output and the energy growth assumes some progress in energy conservation. Our estimates of potential also assume that economic growth in the remainder of the century will approximate 3 percent per year.

The pulp and paper industry in North Carolina consists of six large mills that cogenerate with an estimated capacity of 251 MW. The resource

Exhibit VI-12.

Cogeneration Potential in New and Expanded Industries
in North Carolina by 2000 A.D.*

Industry	Installed MW	Potential at Current Plants	Projected Annual Increase	Judgment			
				New Plants	Expansion	Total	Trend
Pulp and Paper	251.0	40-80	2%	30	30	60	170
Chemicals	37.0	100	2%	40	-	40	70
Food and Tobacco	38.5	10	1.5%	10	-	10	15
Total	326.5	150-180		80	30	110	255

Source: RII-NCSU survey.

*No special government actions are assumed, but it is expected that some firms will make investments in projects that have payback periods as long as 4-1/2 years.

base and demand appear adequate to support a new mill with a capacity of 30 MW and expansion at several others for another 30 MW. The estimated national growth of 2 percent through 2000 yields a figure of 170 MW. This figure is calculated on the basis of the existing 251 MW plus the existing potential for another 80 MW, which is based on the available steam load. The wide spread in possibilities for pulp and paper accounts for much of the range in the total estimates.

The chemical industry in North Carolina has substantial unexploited cogeneration potential, but more limited growth prospects. The synthetic textile industry is a large part of the present chemical industry and is unlikely to experience much growth due to market saturation. The phosphate and lithium industries are based on exploiting natural resources. The most likely growth in cogeneration from new and expanded industry will come from a petrochemical complex and/or an additional phosphate mine. These two plants could easily result in 40 MW of capacity. A 2 percent annual growth rate applied to the present capacity of 37 MW and the potential capacity of existing plants of about 100 MW results in a maximum figure of 70 MW. This upper figure probably is more likely to be achieved than the upper figure of 170 MW in the pulp and paper industry.

The food and tobacco industries are likely to experience energy consumption growth of about 1.5 percent per year. When this figure is applied to the current level of 38.5 MW, a maximum figure of 15 MW is reached. Another brewery and installation of generating equipment at one or more of the cigarette factories could result in this figure being reached. A more likely figure is 10 MW.

The expected amount of cogeneration from new and expanded industry between now and the year 2000 is predicted to be between 110 and 255 MW. Although the range is large, it is not really excessive when looking at the total potential from all sources in the year 2000. Of course, substantial increases in real electricity rates relative to fuel costs could change the picture, but otherwise, these estimates are not unduly conservative.

H. Summary of Future Potential

The current cogeneration capacity in North Carolina was described in subsection A. The unexploited potential for cogeneration in existing firms was estimated under current conditions in subsection B. This

means that establishments in this category probably will have an economic incentive to install cogeneration equipment as their boilers need replacement. In the previous section (VI.G), we looked at the cogeneration potential in industries that will locate in or expand in North Carolina by the year 2000. We also subjected the data from the survey to a sensitivity analysis to determine the degree to which existing firms will be more or less likely to cogenerate, if various policies are implemented or if the relative prices of electricity and fuel change. These four components are combined in this section to estimate the total cogeneration capacity by the year 2000. Of course, this potential may not be realized for a variety of reasons such as the unavailability of capital, changes in technology, and so forth.

Exhibit VI.13 is a summary of the four types of estimates that have been made for cogeneration capacity through the year 2000. No effort was made to determine whether existing capacity (372MW) will continue to be used for the next 20 years. It is likely that some of the smaller cogenerators with old equipment will not replace it, if it needs replacement. It also is likely that the paper companies will replace old equipment. Thus, this component may be a little high for 2000 but not very much. The potential found in existing firms has a range of 190 - 260 MW. Any of this potential that is realized should still be operative by 2000. The new and expanded industry has a range of 110 to 255 MW, which depends on industrial location decisions at which we can only speculate. These figures do not consider cogeneration centers, with more than one process heat user from a single turbine, nor do they consider any potential from diesel engines or combustion turbines -- we have confined our analysis to coal fired systems on the premise that gas and petroleum products will not be available for electrical generation. Appendix C reports on one analysis of gas turbine potential and Section VI-I discusses possible cogeneration centers. These three categories yield a total of 672 - 887 MW of capacity, representing a doubling of current capacity.

Lowering standby charges has a minimal effect on cogeneration potential although raising them does reduce the potential greatly. The size of the investment tax credit does not greatly affect the amount of cogeneration potential. The range is broadened by 45 MW when the ITC is raised to 30%, electricity prices are assumed to inflate at 2%/year compared to coal and a \$1/month per Kw

Exhibit VI. 13.

Actual, Potential and Possible Cogeneration
In North Carolina by 2000 AD*

Cogeneration Capacity	MW	
	Min.	Max.
Existing and in place	372	- 372
Potential in existing firms		
Pulp and paper	40	- 80
Other firms		
Respondents	130	- 130
Nonrespondents	<u>20</u>	<u>- 50</u>
	190	- 260
New and Expanded Industry		
Pulp and paper	60	- 170
Chemicals	40	- 70
Food and tobacco	<u>10</u>	<u>- 15</u>
	110	- 255
GRAND TOTAL	672	- 887
Variability due to sensitivity analysis	<u>±</u>	45
Adjusted Grant Total	627	- 932**

*No special government actions are assumed except for those considered in the sensitivity analysis, but it is expected that some firms will make investments in projects that have payback periods as long as 4-1/2 years.

**These figures do not consider cogeneration centers, with more than one process heat user from a single turbine, nor do they consider any potential from Diesel Engines or Combustion Turbines -- we have confined our analysis to coal fired systems on the premise that gas and petroleum products will not be available for electrical generation. Appendix C reports on one analysis of Gas Turbine Potential and Section VI-I discusses possible cogeneration centers.

standby is assumed.

The major stumbling blocks to greater use and cogeneration in North Carolina are the low cost of electricity and the scarcity of firms with large steam loads. Pooling of steam for a group of firms and institutions in a small area might make a substantial difference to the total. The only other factors that would produce a major increase in the use of cogeneration would be a large increase in the price of electricity relative to the price of fuel or a significant drop in the reliability of electricity. Section VII elaborates on Barriers to Cogeneration.

I. Possible Cogeneration Centers

Our study concentrated on the prospect for cogeneration by individual companies and institutions, since we did not have adequate funding to also examine the prospects for cogeneration centers where more than one user would share the output of the cogeneration equipment. However we have looked at the geographical distribution of companies that might be part of cogeneration centers and we are recommending that further study be made of the prospects for cogeneration centers in North Carolina. Exhibit VI-14 presents our geographical distribution data in map form.

Forty locations are shown on the attached map where industries could perhaps share a cogeneration facility.

We suggest a detailed study of selected centers and have submitted proposals to DOE and the North Carolina Energy Inst. for such a study.

GEOGRAPHICAL DISTRIBUTION OF POTENTIAL COGENERATION CENTERS IN N.C.

SYMBOL	CLUSTERS OF COMPANIES WITH TOTAL AVG. STEAM LOAD IN THE RANGE
●	GREATER THAN 300
■	135-300
▲	70-135
⬡	40-70

IN 1000 LBS./HR.

VII. N. C. UTILITY PRACTICES AND BARRIERS TO COGENERATION

A. Introduction

The analysis of cogeneration potential in North Carolina and its sensitivity to economic and policy parameters indicates that there is sufficient untapped cogeneration potential to warrant further study by the electric utilities and the North Carolina Utilities Commission. Detailed studies on a site-by-site basis can be made pursuant to the mandates of the Public Utility Regulatory Policies Act as a regular component of the electric utility capacity expansion approval process. These studies should address the specific impact of barrier removal.

Carolina Power and Light Company (CP&L), Duke Power Company, and the Virginia Electric Power and Light Company (VEPCo) have all indicated their possible interest in cogeneration as a means of reducing the scope and costs of future construction programs. These savings would flow primarily from reduced construction programs and shorter construction periods. However, the current and foreseeable North Carolina future cogeneration potential is not so large that it can be viewed as a panacea to capacity expansion problems.

B. Broad Limitations to Potential

The North Carolina cogeneration potential is primarily limited by the relatively small size and major fluctuations in institutional and industrial steam loads. The predominant North Carolina industry, textiles, employs over 250,000 people but is less of a cogeneration prospect now than it was in the past since many mills have cut back to one shift. The current industrial structure and new industrial growth is dominated by light industry with relatively low base steam loads. Institutional steam loads are generally low and highly seasonal, since this steam is primarily used for heating purposes and few institutions have absorption chiller air conditioning units.

Another limitation to North Carolina cogeneration is the relatively low cost of power in North Carolina as compared with other states. This limitation may be relaxed, if the cost of electric power relative to fossil fuels begins to rise.

Implementation of peak-load pricing schemes and load management initiatives may stimulate the cogeneration potential if the high price time periods coincide with high industry steam loads.

At least one survey respondent indicated concern over the future reliability of electric power service. Manufacturers with high-value inventories of goods-in-process that are subject to spoilage, or that have large costs associated with process interruption and restart are especially concerned with the reliability issue and thus are potential cogeneration candidates. These manufacturers are mainly concentrated in the food processing, pulp and paper, chemicals, glass, and textile finishing industries.

C. Electric Utility Rates and Service Practices

In North Carolina rate and service practice barriers are more a case of restricted service practices to cogenerators and demand that prevail as if no cogeneration were present, rather than high penalty rates applied only to cogenerators. Limited provisions for emergency plant load coverage offered by the electric utilities often require an industrial user to contract for more power demand than he might otherwise need, and billing demands typically have several minimum provisions, at least one of which is keyed to contract demand. While the cost of service availability is high, the cost of service use (energy charge) is low. The net effect is both to discourage new cogeneration and to encourage existing cogenerators to use power from the electric utility, since he has effectively paid for most of it through the demand charge.

Of the three major electric utility companies, VEPCo service practices seem to be the most favorable toward industrial cogeneration. VEPCo's Large General Service schedule, filed in September 1978, contains a provision for breakdown, relay, or parallel operation service. Duke's Industrial Service, Parallel Operation schedule, also filed in September 1978, does not provide for auxiliary or breakdown service. Carolina Power and Light's Standby and Supplementary Service Rider No. 7C, filed in November 1962, provides for supplementary service and for standby service to cover either scheduled maintenance or breakdown; however, standby service is limited to

a maximum of 7.5 megawatts and has been phased out by CP&L in South Carolina. The degree of difficulty in understanding the CP&L rider is greater than the other schedules, but efforts are currently underway to file a new rider and, it is to be hoped, simplify the language.

The VEPCo and CP&L schedules do not provide for utility buyback of excess power from the cogenerator, and the Duke schedule expressly forbids buyback and industry resale of utility power. North Carolina Statutes require that all companies seeking to generate power for sale must obtain a Certificate of Public Convenience and Necessity and be regulated as a public utility. This binding requirement, could be relaxed to allow perfunctory review of applications from cogenerators or to allow exemptions for small power producers, including cogenerators*.

All rate and service schedules pertinent to cogeneration provide for protective apparatus with the costs borne by the cogenerator. On the rate side of the schedules, Duke Power partially compensates for its relatively low service practice flexibility (with correspondingly high contract and billing demands) with low demand charges -- 5¢ per kW of billing demand or per kW nameplate capacity of the customer's generating plant, whichever is larger; the total bill cannot fall below \$1.59 per kW. The effective demand charge for large customers on the CP&L system is \$5.03 per kW and the effective energy charge is 1.486¢ per kWh. Standby charges for CP&L are graduated into blocks, but they average \$1.00 per kW. For VEPCo, the demand charge is \$5.36 per kW for cogenerators (the second demand block in the industrial schedule) and the tail block energy charge only declines to 1.770¢ per kWh.

The billing demands are figured differently in each schedule; all rely on minimum demands as a percentage of contract demand and other considerations, and on maximum demand measured in 15-minute intervals for Duke and CP&L, and 30-minute intervals for VEPCo. The VEPCo and CP&L billing demands explicitly reflect time of use ratchets; VEPCo establishes billing demand minima based on time of day and season of year, and CP&L on season of year only. The Duke schedules reflects load factor costs through declining energy charges within kWh/kW blocks and across these blocks as kWh/kW increases. Another wrinkle of interest

* Legislation of this type is under consideration in the 1979-1980 General Assembly.

appears in the CP&L rider: minimum kWh/kW ratios are established differently for steam turbine versus other cogenerators. As mentioned earlier, the CP&L rider is more difficult to understand than the others; one reason for this is the separation of total contract demand into separate contracts for supplementary and standby services, with provisions for transfer of service between the two.

To summarize, note the following table:

<u>Services Practices</u>	<u>Demand Charge</u>	<u>Tail Block Energy Charge</u>
VEPCo	CP&L	VEPCo
CP&L	Duke	Duke
Duke	VEPCo	CP&L

In this table, utilities are arranged by how favorable their service practices, demand charges, and tail block energy charges are for cogeneration, relative to one another. Thus VEPCo, which has more flexible service practices for cogenerators and the highest tail block energy charge, appears to be the most attractive service area for cogenerators from strictly a rate and service practices standpoint. CP&L and Duke have the lowest demand charge by a wide margin; low demand charges are favorable to cogeneration. These comparisons are not to suggest that any utility is remiss in any one of these areas; they are presented in terms of the extent each is favorable for cogeneration, and the individual rate and service practices that result in these comparisons may simply reflect differences in individual utility costs of service.

Lowering the standby charges to the \$1.00 per kW average on the CP&L system had little effect on the statewide cogeneration potential. This charge falls far below the VEPCo rate, but the impact there is small because the VEPCo service area in North Carolina is small and relatively unindustrialized.

D. Financial Barriers

The recently passed Energy Tax Act of 1978 provides for business energy tax credits for industrial investment in alternative energy property, including cogeneration equipment using alternate fuels. This is a 10 percent credit that can be added to the regular 10 percent

investment tax credit to provide an overall tax credit of 20 percent on investments in cogeneration equipment using alternative fuels. This additional 10 percent credit is reduced to 5 percent, if industrial revenue bond financing is used to purchase and install this equipment. A separate cogeneration tax credit did not pass the Congress in 1978.

The 1978 Act also provides for rapid writeoff of existing oil and gas boilers; the book value of such property, termed the "basis" for tax purposes, can now be depreciated over a shorter remaining life than the remaining life permitted under the old depreciation schedule. Only straight-line depreciation can be used over the shortened life. In order to qualify for this rapid depreciation treatment, the company must establish to the satisfaction of the Secretary of Energy that there is a reasonable foundation for the conclusion that the combustion unit will, in fact, be retired or replaced at the end of the shortened useful life.

These measures were designed to encourage reduced dependence on scarce fossil fuels rather than to promote cogeneration but their effect may be to move a few North Carolina cogeneration prospects over the threshold of economic feasibility.

Industrial revenue bond financing can cover manufacturing sector cogeneration projects in North Carolina, but only in new and expanded facilities, and only when other criteria -- such as job creation or job savings that have a measurable impact on the local community, and wages that exceed the average community wage -- are met.

Additional tax and financing measures available for implementation by the North Carolina Legislature and local units of government -- such as corporate income tax credits and ad valorem property tax exemptions -- are more limited in their effect on cogeneration potential than the national measures. A tax credit for absorption air conditioning might help to levelize seasonal steam loads but we would not expect this change to have a major impact on cogeneration potentials in North Carolina.

E. Buyback Credits and Wheeling Charges

The Federal Energy Regulatory Commission (FERC) is currently engaged in rulemaking related to buyback credits and wheeling charges to cogenerators. Buyback is expressly forbidden in the Duke Power Industrial Parallel Schedule.

No agreements for utility buyback of power from industrial cogenerators currently exist in North Carolina.

Wheeling is currently practiced by the Class A utilities in North Carolina, but it is primarily limited to transferring power between public generating and transmission customers at one end and public distribution companies on the other end. Wheeling for industrial customers is uncommon practice and as far as we know is not carried out in North Carolina, and no general schedules currently apply to wheeling rates. Wheeling is an area that the North Carolina Utilities Commission may want to pursue in conjunction with facilitating buyback practices under the mandates of the Public Utility Regulatory Policies Act of 1978.

F. Summary

The barriers to cogeneration potential in North Carolina are primarily technical -- related to the size and variability of industrial and institutional steam loads -- and the low cost of purchased power. Those measures that are most likely to make a sizeable impact on this potential are electricity rates that escalate faster than fossil fuel costs, stretched out payback period requirements, and investment tax credits. Electricity rates could escalate more rapidly than fossil fuel costs if conversion and availability problems with electric utility base load units arise, if electricity is priced on a long run incremental cost basis, or if peak load pricing and other load management measures are implemented. These latter measures could increase the cogeneration potential in one-and two-shift operations, but could decrease it for continuous process industries if the three-shift industries received lower rates overall.

The financial measure most likely to influence cogeneration potential in North Carolina is the availability of low-cost loans that could effectively eliminate the need for company financing. A second measure with promise is the availability of additional investment tax credits, especially if these credits are high by typical standards (e.g., 30 as opposed to 10 percent).

Exhibit VII.1 is a matrix presentation in which the major impediments to cogeneration are shown for major North Carolina industries.

Exhibit VII.1

Rank Order of Major Impediments to Cogeneration
in North Carolina by Industry Group^{1/}

Major Impediment	Industry Group			
	Food and Tobacco	Textiles	Pulp & Paper	Chemicals & Petroleum
Poor Return on Investment ^{2/}	1	2	1	1
Limited Capital	2	1	2	4
Uncertain Energy Policy	3	3	4	2
Health, Safety, and Environmental Problems	4	4	5	5
Potential Regulation	6	6	6	6
Charge for Standby Service	5	5	3	3

^{1/}As revealed by survey responses and results of sensitivity analyses; only industry groups near cogeneration threshold are included.

^{2/}Includes steam load conditions and match between steam and electrical loads implicitly.

SOURCE: Research Triangle Institute

VIII. MARCH 7-8, 1979 CONFERENCE
COGENERATION AND NORTH CAROLINA

As a concluding part of our study of the potential for cogeneration in North Carolina we presented a conference to acquaint those who might be affected by or help implement our recommendations with our findings and recommendations. The workshop was attended by over 100 individuals including 5 members of the North Carolina Utilities Commission. Proceedings of the Conference have been published thanks to special funding from the North Carolina Energy Institute and copies are available from J. Kohl, Dept. of Nuclear Engineering, NCSU.

The program planning committee for the conference included:

- Mr. Jerome Kohl, Chairman
- Dr. James C. Bresee, N. C. Energy Institute
- Mr. Richard L. Cowles, Department of Energy
- Dr. Robert Fischbach, Commissioner, N. C. Utilities Commission
- Dr. Leigh Hammond, Commissioner, N. C. Utilities Commission
- Ms. Linda McDaniels, N. C. Energy Institute
- Dr. Paul Mulligan, Research Triangle Institute
- Mr. Henry Walker, Division of Continuing Education, NCSU
- Mr. Andrew W. Williams, Public Staff, N. C. Utilities Commission

Much of the success of this conference resulted from the excellent cooperation and support provided by Robert K. Koger, Chairman of the N. C. Utilities Commission and Hugh Wells, Director of the Public Staff of the N. C. Utilities Commission.

The Conference program, as presented, is included as Exhibit VIII.1.

EXHIBIT VIII.1.

COGENERATION AND NORTH CAROLINA

MARCH 7, 1979

- 8:00 - 9:00 am Registration
- 9:00 - 9:10 Welcoming Remarks, Dr. Larry K. Monteith, Dean of School of Engineering, North Carolina State University
- 9:10 - 9:20 Introduction of the Conference Subject
The Energy Institute's Interest in Cogeneration, Dr. James C. Bresee, Director, North Carolina Energy Institute
- 9:20 - 9:30 Program for and Mechanics of this Conference, Jerome Kohl, Conference Chairman

Session I

Cogeneration An Assessment

Chairman: Rep. J. P. Huskins, Co-Chairman Utility Review Committee, 1979 North Carolina General Assembly

- 9:30 - 10:15 **The Role of Cogeneration—Past and Future**, J.C. Franklin, Turbine Applications Engr., G.E., Atlanta
- 10:15 - 10:30 Coffee Break
- 10:30 - 11:15 **The Federal Government's Role in Implementing Cogeneration**, Richard L. Cowles, Program Manager, Cogeneration, Office of Industrial Applications and Commercialization, D.O.E.
- 11:15 - 11:45 **Cogeneration From a North Carolina Utility's Point of View**, Donald H. Denton, Jr., Vice President, Duke Power Co.
- 11:45 - 12:15 Discussion and Questions
- 12:30 - 2:00 pm Lunch Session
Chairman: Honorable Hugh Wells, Director Public Staff, Utilities Commission, State of North Carolina
Price and Availability 1980 - 2000 Industrial Electricity and Fossil Fuels, Dr. Robert Spann, Prof. of Economics, V.P.I.

Session II

Report on NCSU-RTI Study of Cogeneration Potential for North Carolina

Chairman: Andrew W. Williams, Director Electric Division, Public Staff, North Carolina Utilities Commission

- 2:00 - 3:00 **Developing Basic Data on Cogeneration Prospects for North Carolina**, Jerry Kohl, Principal Investigator, Kevin Vaughn, Research Associate, Richard Paddock, RTI
- 3:00 - 3:45 **The Cogeneration Potential for North Carolina through the Year 2000 as a Function of Impediment Elimination**, Dr. Paul Mulligan, RTI Project Leader, and Rick Harwood, Research Economist
- 3:45 - 4:00 Afternoon Break
- 4:00 - 4:45 **Implications of the Study to Federal Regulations, the NC General Assembly and Utility Commission**, J. Kohl and P. Mulligan
- 4:45 - 5:15 Discussion
- 5:30 - 6:30 Social Hour

Exhibit VIII.1 Continued

MARCH 8, 1979

Session III Federal and State Impediments and Encouragements to Cogeneration
Chairman: Dr. Robert Fischbach, Commissioner, North Carolina Utilities Commission

- 8:30 - 9:15 am **The 1978 Energy Act. Its Impact on Federal Regulatory Barriers to Cogeneration**, Roger D. Feldman, Le Boeuf, Lamb, Leiby, and MacRae, Washington, DC
- 9:15 - 9:45 **North Carolina Regulatory Barriers to Cogeneration**, Dwight Allen, Attorney, Public Staff, North Carolina Utilities Commission
- 9:45 - 10:15 Discussion and Questions
- 10:15 - 10:30 Coffee Break
- 10:30 - 11:15 **California P.U.C. Actions Designed to Encourage Cogeneration**, Hon. Claire Dedrick, Member California P.U.C.
- 11:15 - 12:00 **Experiences in Encouraging Cogeneration**, Ray Kulvicki, P.E., Cogeneration Consultant, Flintridge, California
- 12:00 - 12:30 pm Discussion and Questions
- 12:30 - 2:00 Lunch Session
Chairman: Senator Jack Childers, Co-Chairman Utility Review Committee, 1979, North Carolina General Assembly
The North Carolina Utility Commission and Cogeneration, Robert K. Koger, Chairman, North Carolina Utility Commission

Session IV Implementing Cogeneration
Chairman: Brian Flattery, Head, North Carolina Energy Division

- 2:00 - 2:30 **Experiences With Cogeneration in the Tobacco Industry**, Robert A. Vogler, Manager, Power and Steam Unit, R.J. Reynolds Tobacco Corp., Winston Salem
- 2:30 - 3:00 **A Recent Examination of the Payout for Cogeneration in Fiber Plants**, J. Entwistle, Fiber Industries, Charlotte
- 3:00 - 3:30 Coffee Break
- 3:30 - 4:00 **The Proposed King's Mountain Cogeneration Installation**, H. M. DeBoe, Campbell, DeBoe & Associates—Arthur G. McKee
- 4:00 - 4:30 **Cogeneration in the Pulp and Paper Industry**, Edgar C. Fox, Chief Engineer, Federal Paper Board Co., Riegelwood, NC
- 4:30 - 5:00 Discussion
- 5:00 - 5:15 Closing Remarks, Jerome Kohl, Conference Chairman

Appendix A

METHODOLOGICAL CONSIDERATIONS

Appendix A

METHODOLOGICAL CONSIDERATIONS

This appendix contains discussions of three aspects of the methodology that were discussed only briefly in the text. These three aspects are:

(1) Description of the Steam Topping Cycle, which is the usual mode of cogeneration in North Carolina; (2) Discussion of the Procedures Used to Select the Size Turbine Used in the Analysis of Each Plant's Potential; and, (3) The Computer Program that was Used to Assess the Potential for Cogeneration in Each Plant Based on that Plant's Operating Conditions and the Standard Assumptions.

1. Description of the Steam Topping Cycle

This study focused on the economic feasibility of retrofitting plants for cogeneration of power by use of the steam topping cycle.* Cogeneration via steam topping involves generation of high pressure/temperature steam, expansion of the steam through a back pressure steam turbine, and use of the back-pressure steam for process heat needs. Expansion of the steam through the turbine converts some of the heat energy in the steam into mechanical energy. Most of the heat energy is exhausted from the turbine as steam. Only a small proportion of the steam's initial heat energy can be captured as mechanical energy.

The steam topping cycle is used to cogenerate power by extracting energy from the steam before it goes to the process. The pressure and temperature of the boiler (and therefore enthalpy value (H_1) of the steam entering the turbine) is usually determined by the maximum steam load of the plant. Large steam loads mean large turbines, where the enhanced efficiency due to high temperature/pressure can be justified.

Typical Boiler Specifications

Maximum Steam Load (000 lbs/hr)	Pressure (psig)	Temperature (°F)	Enthalpy(H_1) (Btu/lb)
≤ 149	600	750	1,379
$\geq 150, \leq 299$	900	825	1,410
≥ 300	1,500	950	1,460

Our analysis is based on the plants's current load. The steam is exhausted (or extracted) at the pressure at which it is to be used in process, and the temperature is assumed to be at the saturation point for the given pressure. The following non-linear functional approximation was estimated to determine the enthalpy of the exhaust steam.

$$H_2 = 1,329 - \frac{211}{(P)^{(.09)}}$$

H_2 = enthalpy of saturated exhaust steam at pressure P.

P = pressure of steam required in process.

The difference (H) between the enthalpy of steam entering the turbine (H_1) and steam exhausted from the turbine is the useful heat energy given off by each pound of steam crossing the turbine.

$$H = H_1 - H_2$$

H = useful heat energy (Btu) per pound of steam given off in turbine.

H_1 = enthalpy of steam entering turbine (Btu/lb)

H_2 = enthalpy of steam leaving turbine (Btu/lb)

Given the steam load (SL) in pounds per hour and the value of H for a specific period of time (HRS) the useful energy (UE) extracted by steam and the turbine can be calculated as:

$$UE = SL \times H \times HRS$$

2. Selection of Turbine Size

Given the energy extracted from the steam by the turbine, the power produced is

$$kW = \frac{SL \times H}{HR}$$

kW = kilowatts generated per hour

SL = steam load: pounds per hour

H = heat energy released to the turbine: Btu/lb

HR = heat rate: conversion of heat energy to electrical energy by turbine-generator, (Btu/kW)

Given the pressure/temperature of the boiler, heat rate of the turbine-generator, and the steam load profile (over the hours of the week and weeks of the year), the capacity of the turbine generator can be chosen in order to achieve

a desired capacity utilization factor. Capacity utilization is defined as the total kWh actually cogenerated over a period of time (a year) divided by the maximum kWh the turbine-generator could produce if it ran at 100 percent capacity for the year. A high utilization rate of the turbine-generator, spreads the fixed cost of the cogeneration plant over more kWh.

In practice the cogeneration of power will be at less than maximum capacity. Constraints on cogeneration are imposed by system parameters such as H and HR, and by the steam load and the capacity of the turbine-generator. The turbine generator will have a maximum capacity (corresponding to a certain steam load) beyond which more power cannot be cogenerated with the turbine-generator even though the process steam load may increase. The capacity of the turbine generator will be a constraint on the maximum level of cogeneration when the process steam load is higher than the capacity of the turbine. Sizing the turbine to the steam load is important in order to keep utilization of the turbine-generator up and the cost of power generated down and yet to minimize the waste in energy that occurs when process steam is produced by reducing the pressure of high pressure steam. The problem is to select the turbine size that minimizes the payback period. Due to economies of scale, it pays to have a turbine with a larger capacity than the minimum steam load in order to take advantage of the steam loads above the minimum, but without having to pay for capacity that will be idle for long periods.

In this analysis, the turbine-generator was sized to maintain at least an 80 percent utilization rate for the operating hours of the plant. No studies were made to look at the impact of variation in utilization rate.

3. Computer Program for Analysis of Economic Feasibility

The model described in Section V of this report was written as a computer program in order to assess the economic feasibility of cogeneration for each plant. The variables used in this program are listed in Exhibit A.1 along with the symbols that represent each variable. The program itself is reproduced as Exhibit A.2. The program was written using the Statistical Analysis System. The code includes adjustments for missing values where necessary and possible, selects the turbine-generator size, and calculates capital expenditures, annual savings, and the payback period for various investment tax credits.

Exhibit A.1

Selected Variables used in Analysis Program

FID	Firm identification number
SIC	Standard Industrial Classification of plant
PRESSP	Pressure of steam used in plant process
SL1-SL12	Steam load in each of 12 typical periods
HRS	Plant operating hours per year
ANNAST	Annual steam generated
E1-E12	Electrical demand in each of 12 typical periods
EG	Whether the plant presently cogenerates
TAE	Total kWh purchased from utility in a year
OkWh	Total kWh generated in plant in a year
Peak	Peak demand of plant for power
A - F,K	Parameters
H1	Enthalpy of steam from boiler
H2	Enthalpy of steam leaving turbine to process
HR	Heat rate of turbine-generator
CE	Utility charge for power: per kWh.
ASH1-ASH12	Level of steam load necessary to cogenerate full plant electrical load in periods of time
kW1-kW12	Plant cogeneration of power in typical periods
DC	Utility demand charge per kW
PR1	Peak electrical demand in plant without cogeneration
PR2	Planned electrical demand in plant with cogeneration
SBC	Utility standby charge for power
DD	Price of fuel per million Btu's
SLMAX	Steam load for which the turbine is sized
kW	Capacity of turbine generator
kW1	Power cogenerated
GEN	Price of turbine generator per kW of capacity
PGEN	Total cost of turbine generator
SE	Savings on utility energy charge
SD	Savings on utility demand charge
BL	Incremental boiler cost for higher pressure
MG	Maintenance and operating costs of turbine generator
FCP	Fuel chargeable to cogeneration of power
MB	Maintenance and operating costs of boiler
ANSA	Annual savings due to cogeneration

Exhibit A.2

**Computer Program used in the Analysis of the Economic Feasibility
of Cogeneration for Each Plant**

```

00020 //STEAM JOB NCS,NE,C5275,HJH,PTY=1,T=1,COMPRESS=YES,COPIES=2
00030 // EXEC SAS
00040 //CGG1 DD DSN=RTI,C44,P014177,HJH,CCC,DATA,DISP=SHR
00045 //BLL DD DSN=RTI,C44,P014177,HJH,CGG5,DISP=SHR
00050 //SYSIN DD *
00051 DATA; INFILE BLL;
00052 INPUT FID 1-3 YR 22-23;
00053 IF YR>79 THEN YR=.; IF YR<54 THEN YR=54; IF YR=, THEN YR=54;
00054 YRS=25-(79-YR); YRA=79-YR; DATE=1979+YRS; PROC SORT; BY FID YRA;
00060 DATA;
00070 INFILE CGG1;
00080 INPUT FID 1-3 SIC 12-13 UTIL 14 PBY 25-26 ROI 27-28 PRESSP 42-45
00090 PRESSAC 56-59 (SL1-SL12) (#123 12*4,) HRS 119-122 ANNAST 79-83
00100 (E1-E12) (#173 12*5,1) EQ 246 TAE 242-245 QKWH 247-250 PEAK 233-237
00110 PBP 24 CE 238-241;
00111 PROC SORT; BY FID;
00112 DATA; UPDATE DATA2 DATA1; BY FID;
00120 A=1030;
00130 B=-.5128;
00140 D=1.25*EXP(.00*11);
00150 E=.025;
00155 SICNEW=SIC;
00160 F=.025;
00161 IF SICNEW<20 THEN SICNEW=50; IF SICNEW=21 THEN SICNEW=20;
00162 IF SICNEW=23 THEN SICNEW=22; IF SICNEW=25 THEN SICNEW=24;
00163 IF SICNEW=29 THEN SICNEW=28; IF SICNEW=30 THEN SICNEW=28;
00164 IF SICNEW>30 THEN SICNEW=50; IF SICNEW=, THEN SICNEW=50;
00170 IF PRESSP>900 THEN PRESSP=150;
00180 IF PRESSP<15 THEN PRESSP=15;
00190 IF PRESSP=, THEN PRESSP=150;
00200 H1=1379;
00210 HR=4200;
00220 POTENT=9;
00230 <=5;
00240 IF UTIL=, THEN UTIL=4;
00250 CE=.015;
00260 IF UTIL=1 THEN CE=.019;
00270 IF UTIL=3 THEN CE=.018;
00275 CE=CE*EXP(.02*11);
00280 PB=100;
00290 IF ANNAST>90000 THEN ANNAST=;
00295 BTU=ANNAST*1.15/.80;
00300 AVE=ANNAST/8.76;
00310 IF SL1>9000 THEN SL1=.;
00320 IF SL2>9000 THEN SL2=.;
00330 IF SL3>9000 THEN SL3=.;
00340 IF SL4>9000 THEN SL4=.;
00350 IF SL5>9000 THEN SL5=.;
00360 IF SL6>9000 THEN SL6=.;
00370 IF SL7>9000 THEN SL7=.;
00380 IF SL8>9000 THEN SL8=.;
00390 IF SL9>9000 THEN SL9=.;
00400 IF SL10>9000 THEN SL10=.;
00410 IF SL11>9000 THEN SL11=.;
00420 IF SL12>9000 THEN SL12=.;
00430 IF SL1=, THEN SL1=AVE;
00440 IF SL2=, AND HRS>4500 THEN SL2=AVE;
00450 IF SL3=, AND HRS>6500 THEN SL3=AVE;
00460 IF SL4=, AND HRS>7000 THEN SL4=AVE;
00470 IF SL5=, THEN SL5=AVE;
00480 IF SL6=, AND HRS>4500 THEN SL6=AVE;
00490 IF SL7=, AND HRS>6500 THEN SL7=AVE;
00500 IF SL8=, AND HRS>7000 THEN SL8=AVE;
00510 IF SL9=, THEN SL9=AVE;

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00520 IF SL10=. AND HRS>4500 THEN SL10=AVE;
00530 IF SL11=. AND HRS>6500 THEN SL11=AVE;
00540 IF SL12=. AND HRS>7000 THEN SL12=AVE;
00550 SLMAX=MAX(SL1,SL2,SL3,SL4,SL5,SL6,SL7,SL8,SL9,SL10,SL11,SL12);
00560 SLMAX10=SLMAX;
00570 IF SLMAX>149 THEN H1=1410;
00580 IF SLMAX>299 THEN H1=1460;
00590 H2=1329-211/(PRESSP**09);
00600 IF H2=. THEN H2=230; H=H1+H2;
00610 IF SL1=. THEN SL1=0;
00620 IF SL2=. THEN SL2=0;
00630 IF SL3=. THEN SL3=0;
00640 IF SL4=. THEN SL4=0;
00650 IF SL5=. THEN SL5=0;
00660 IF SL6=. THEN SL6=0;
00670 IF SL7=. THEN SL7=0;
00680 IF SL8=. THEN SL8=0;
00690 IF SL9=. THEN SL9=0;
00700 IF SL10=. THEN SL10=0;
00710 IF SL11=. THEN SL11=0;
00720 IF SL12=. THEN SL12=0;
00730 IF HRS>8800 THEN HRS=2000;
00740 IF 1AE>900 THEN TAF=.; IF PEAK>90 THEN PEAK=.;
00750 AVV=TAE/8.760;
00760 IF E1>90 THEN E1=AVV;
00770 IF E2>90 THEN E2=AVV;
00780 IF E3>90 THEN E3=AVV;
00790 IF E4>90 THEN E4=AVV;
00800 IF E5>90 THEN E5=AVV;
00810 IF E6>90 THEN E6=AVV;
00820 IF E7>90 THEN E7=AVV;
00830 IF E8>90 THEN E8=AVV;
00840 IF E9>90 THEN E9=AVV;
00850 IF E10>90 THEN E10=AVV;
00860 IF E11>90 THEN E11=AVV;
00870 IF E12>90 THEN E12=AVV;
00880 IF E1=. THEN E1=AVV;
00890 IF E2=. THEN E2=AVV;
00900 IF E3=. THEN E3=AVV;
00910 IF E4=. THEN E4=AVV;
00920 IF E5=. THEN E5=AVV;
00930 IF E6=. THEN E6=AVV;
00940 IF E7=. THEN E7=AVV;
00950 IF E8=. THEN E8=AVV;
00960 IF E9=. THEN E9=AVV;
00970 IF E10=. THEN E10=AVV;
00980 IF E11=. THEN E11=AVV;
00990 IF E12=. THEN E12=AVV;
01000 ASH1=E1*HR/H;
01010 ASH2=E2*HR/H;
01020 ASH3=E3*HR/H;
01030 ASH4=E4*HR/H;
01040 ASH5=E5*HR/H;
01050 ASH6=E6*HR/H;
01060 ASH7=E7*HR/H;
01070 ASH8=E8*HR/H;
01080 ASH9=E9*HR/H;
01090 ASH10=E10*HR/H;
01100 ASH11=E11*HR/H;
01110 ASH12=E12*HR/H;
01120 SHIFT=1;
01130 IF HRS>3000 THEN SHIFT=2;
01140 BQIL=SLMAX*8760;
01150 ANS=(SL1+SL5+2*SL9)*520*SHIFT+(SL2+SL6+SL10*2)*520*SHIFT+
01160 (SL3+SL7+SL11*2)*208*SHIFT+(SL4+SL8+SL12*2)*208*SHIFT;
01170 AAAA=ANS/HQIL;

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01180 SLMAXH=SLMAX10;
01190 CAPUTIL=,80*HRS/8760;
01200 SLMAXL=0;
01210 ABOVE2: SLE1=MIN(SL1,ASH1,SLMAX);
01220 SLE2=MIN(SL2,ASH2,SLMAX);
01230 SLE3=MIN(SL3,ASH3,SLMAX);
01240 SLE4=MIN(SL4,ASH4,SLMAX);
01250 SLE5=MIN(SL5,ASH5,SLMAX);
01260 SLE6=MIN(SL6,ASH6,SLMAX);
01270 SLE7=MIN(SL7,ASH7,SLMAX);
01280 SLE8=MIN(SL8,ASH8,SLMAX);
01290 SLE9=MIN(SL9,ASH9,SLMAX);
01300 SLE10=MIN(SL10,ASH10,SLMAX);
01310 SLE11=MIN(SL11,ASH11,SLMAX);
01320 SLE12=MIN(SL12,ASH12,SLMAX);
01330 BUIL=SLMAX*8760;
01340 ANS=(SLE1+SLE5+2*SLE9)*520*SHIFT+(SLE2+SLE6+SLE10*2)*520*2/SHIFT+
01350 (SLE3+SLE7+SLE11*2)*208*SHIFT+(SLE4+SLE8+SLE12*2)*208*2/SHIFT;
01360 AAA=ANS/BUIL;
01370 XX=CAPUTIL-AAA;
01380 YY=XX/CAPUTIL;
01390 IF YY=. THEN GO TO DOWN;
01400 IF YY<-.001 AND SLMAX=SLMAXH THEN GO TO DOWN;
01410 IF YY<-.001 THEN GO TO ONE2;
01420 IF YY>.001 THEN GO TO TWO2;
01430 GO TO DOWN;
01440 ONE2: SLMAXL=SLMAX;
01450 SLMAX=(SLMAX+SLMAXH)/2;
01460 GO TO ABOVE2;
01470 TWO2: SLMAXH=SLMAX;
01480 SLMAX=(SLMAX+SLMAXL)/2;
01490 GO TO ABOVE2;
01500 DOWN:
01510 SLE1=MIN(SL1,ASH1,SLMAX);
01520 SLE2=MIN(SL2,ASH2,SLMAX);
01530 SLE3=MIN(SL3,ASH3,SLMAX);
01540 SLE4=MIN(SL4,ASH4,SLMAX);
01550 SLE5=MIN(SL5,ASH5,SLMAX);
01560 SLE6=MIN(SL6,ASH6,SLMAX);
01570 SLE7=MIN(SL7,ASH7,SLMAX);
01580 SLE8=MIN(SL8,ASH8,SLMAX);
01590 SLE9=MIN(SL9,ASH9,SLMAX);
01600 SLE10=MIN(SL10,ASH10,SLMAX);
01610 SLE11=MIN(SL11,ASH11,SLMAX);
01620 SLE12=MIN(SL12,ASH12,SLMAX);
01630 SHIFT=1; IF HRS>3000 THEN SHIFT=2;
01640 KW1=SLE1*H/HR;
01650 KW2=SLE2*H/HR;
01660 KW3=SLE3*H/HR;
01670 KW4=SLE4*H/HR;
01680 KW5=SLE5*H/HR;
01690 KW6=SLE6*H/HR;
01700 KW7=SLE7*H/HR;
01710 KW8=SLE8*H/HR;
01720 KW9=SLE9*H/HR;
01730 KW10=SLE10*H/HR;
01740 KW11=SLE11*H/HR;
01750 KW12=SLE12*H/HR;
01760 PE1=E1-KW1;
01770 PE2=E2-KW2;
01780 PE3=E3-KW3;
01790 PE4=E4-KW4;
01800 PE5=E5-KW5;
01810 PE6=E6-KW6;
01820 PE7=E7-KW7;
01830 PE8=E8-KW8;

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01840 PE9=E9-KW9;
01850 PE10=E10-KW10;
01860 PE11=E11-KW11;
01870 PE12=E12-KW12;
01880 PK1=MAX(E1,E2,E3,E4,E5,E6,E7,E8,E9,E10,E11,E12);
01890 PK2=MAX(PE1,PE2,PE3,PE4,PE5,PE6,PE7,PE8,PE9,PE10,PE11,PE12);
01900 DPK=PK1-PK2;
01910 SLH1=8*5*13*SHIFT*SLF1;
01920 SLH5=8*5*13*SHIFT*SLF5;
01930 SLH9=8*5*13*SHIFT*2*SLF9;
01940 SLH2=8*5*13*2/SHIFT*SLF2;
01950 SLH6=8*5*13*2/SHIFT*SLF6;
01960 SLH10=8*5*13*2/SHIFT*SLF10*2;
01970 SLH3=8*2*13*SHIFT*SLF3;
01980 SLH7=8*2*13*SHIFT*SLF7;
01990 SLH11=8*2*13*SHIFT*2*SLF11;
02000 SLH4=8*2*13*2/SHIFT*SLF4;
02010 SLH8=8*2*13*2/SHIFT*SLF8;
02020 SLH12=8*2*13*2/SHIFT*2*SLF12;
02030 DC=5;
02040 IF UT1L=1 THEN DC=2;
02050 SBC=1;
02060 DC=DC-SBC;
02065 DC=DC*EXP(.02*11);
02070 PRE=CE;
02080 IF PRY>10 THEN PRY=.;
02090 IF ROI>90 THEN ROI=18;
02100 IF KUI=., THEN ROI=18;
02110 IF PRY=., THEN PRY=5;
02120 IF PRY=0 THEN PRY=5;
02130 IF ROI=0 THEN ROI=18;
02140 PRY=.;
02150 ASLH=SLH1+SLH2+SLH3+SLH4+SLH5+SLH6+SLH7+SLH8+SLH9+SLH10+SLH11+SLH12;
02160 ASLH=ASLH*1000;
02170 DD=0/1000000;
02180 SLMAX=3LMAX*1000;
02190 DPK=DPK*1000;
02200 KW=SLMAX*H/HR;
02210 KWH=ASLH*H/HR;
02220 GEN =A*(SLMAX*H/(HR*1000))*B;
02230 IF KW>15000 THEN GEN=250;
02240 PGEN=3LMAX*H/HR*GEN;
02250 SE=PRE*KWH;
02260 SD=DC*DPK*12;
02270 BL=K*SLMAX*1,500;
02280 MG=L*PGEN;
02290 FCP=DD*ASLH*H;
02300 MB=F*BL;
02310 ANSAV=(SE+SD-FCP-MG-MB); IF ANSAV=0 THEN GO TO NEXT;
02315 GPB=PB;
02315 GPB=(PGEN+BL)/(ANSAV);
02320 PB=(.7)*(PGEN+BL)/(SE+SD-FCP-MG-MR);
02330 NEXT;
02340 IF ANNAST<400 AND ANNAST NE . THEN POTENT=0;
02350 IF HRS<5000 AND HRS NE . THEN POTENT=0;
02360 IF SL1<50 AND SL1 NE . THEN POTENT=0;
02370 KW=KW/1000; KWH=KWH/1000000;
02380 IF PB<PB1 AND PB NE . AND PB>0 THEN POTENT=1;
02390 DROP SL1-SL12 E1-E12 KW1-KW12 PE1-PE12 ASH1-ASH12 SLH1-SLH12
02400 PRESSP PRESSAC CE A B D E F M1 HR K M2 SBC PRE DD SLE1-SLE12
02410 PRP SHIFT DPK DC ASLH;
02420 DATA;
02430 SET DATA3;
02440 G=.05;
02450 TX=.50;
02460 T=25;

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02470 N=.0;
02480 R=.04;
02490 RH=1;
02500 RL=-1;
02510 R1=.00;
02520 R2=.02;
02530 R3=.03;
02540 CAP=(.7)*(PGEN+BL);
02550 LOAN=N*CAP;
02560 ALP=(LOAN*R3)/(1-EXP(-R3*T));
02570 DEP=G*CAP;
02580 ABOVE1CAP1=(.25)*CAP+(.5)*CAP*EXP(-R1)+(.25)*CAP*EXP(-R2);
02590 DCF=((1-TX)*(SD-MG-MB)+(TX-1)*ALP+TX*DEP)*
02600 (EXP(-R3)-EXP(-R*T))/R +
02610 (1-TX)*SE*(EXP((R1-R)*T)-EXP((R1-R)*3))/(R1-R) -
02620 (1-TX)*FCP*(EXP((R2-R)*T)-EXP((R2-R)*3))/(R2-R) -
02630 TX*R3*LOAN*(EXP((R3-R)*T)-EXP((R3-R)*3))/(R3-R);
02640 IF UCF= THEN GO TO BELOW;
02650 IF DCF=0 THEN GO TO BELOW;
02660 X=CAP1-DCF;
02670 Y=X/CAP1;
02680 IF Y>0 AND R=.04 THEN GO TO BELOW;
02690 IF Y<-.0001 THEN GO TO ONE;
02700 IF Y>.0001 THEN GO TO TWO;
02710 GO TO BELOW;
02720 ONE: RL=R;
02730 R=(R+RH)/2;
02740 GO TO ABOVE;
02750 TWO: RH=R;
02760 R=(R+RL)/2;
02770 GO TO ABOVE;
02780 BELOW: R=R*100; R=R*6;
02790 IF R>90 THEN POTENT=1;
02800 ORDP G TX T N RH RL R1 R2 R3 LOAN ALP DEP DCF X Y;
02810 IF PB<0 THEN PB=1000; IF PB<0 THEN PB=1000;
02820 DATA; SET; IF EG=1 THEN POTENT=2;
02830 PROC FREQ; TABLES SIGNEW*POTENT;
02840 PROC FREQ; TABLES SIGNEW*POTENT; WEIGHT KN;
02850 PROC FREQ; TABLES SIGNEW*POTENT; WEIGHT KNH;
02860 DATA ; SET; KEEP AVE PB R KN POTENT FID SLMAX10 EG GPB;
02870 PROC SORT; BY PB;
02880 PROC PRINT;

```

HARMUJO PRINT 5-PAGES 304-LINES 0-PLNTS # NC8,NE,C5275
123456789012345678901234567890123456789012345678901234567890123456789012345678901
123456789012345678901234567890123456789012345678901234567890123456789012345678901
123456789012345678901234567890123456789012345678901234567890123456789012345678901
123456789012345678901234567890123456789012345678901234567890123456789012345678901

Appendix B

SAMPLES OF ANALYSIS PROGRAM RESULTS

- Exhibit B.1 Crosstabulation of Potential by Industry
- Exhibit B.2 Ranking of Plants by Payback
- Exhibit B.3 Sample of Data from Calculations for 16
Plants Used in Analysis

1	----- TOP - OF - FORM -----	1
2		2
3		3
4		4
5		5
6		6
7		7
8		8
9		9
10		10
11		11
12		12
13		13
14		14
15		15
16		16
17		17
18		18
19		19
20		20
21		21
22		22
23		23
24		24
25		25
26		26
27		27
28		28
29		29
30		30
31		31
32		32
33		33
34		34
35		35
36		36
37		37
38		38
39		39
40		40
41		41
42		42
43		43
44		44
45		45
46		46
47		47
48		48
	STATISTICAL ANALYSIS SYSTEM	18:03 WEDNESDAY, MAY 16, 1979
	2	
	TABLE OF SICNEW BY POTENT	
	SICNEW POTENT	
	FREQUENCY	
	PERCENT	
	ROW PCT	
	COL PCT	
	0	1
	2	9
	TOTAL	
20	10	17
	2.13	3.62
	16.13	27.42
	23.81	9.09
	14.83	0.00
22	16	19
	3.40	4.04
	38.10	45.24
	38.10	10.16
	0.85	100.00
24	10	12
	2.13	2.55
	45.45	54.55
	23.81	6.42
	0.00	0.00
26	0	0
	0.00	0.00
	0.00	0.00
	0.00	0.00
	0.00	0.00
28	4	118
	0.85	25.11
	2.72	80.27
	9.52	63.10
	10.59	0.00
50	2	21
	0.43	4.47
	7.69	80.77
	4.76	11.23
	1.27	0.00
TOTAL	42	187
	8.94	39.79
	50.21	1.06
	470	100.00

31	-----TOP OF FORM-----										41
32											42
33											43
34											44
35	STATISTICAL ANALYSIS SYSTEM										45
36	18:03 WEDNESDAY, MAY 16, 1979 4										46
37	OBS	FID	EG	POTENT	PB	AVE	SLMAX10	KW	GPB	R	47
38											48
39	1	110	0	1	1.65657	456.621	500.000	31.3761	2.3665	26.2744	49
40	2	236	0	1	1.68342	748.744	749.000	45.0750	2.4049	26.0635	50
41	3	125	.	1	1.86271	.	240.000	11.9641	2.6610	24.6748	51
42	4	155	0	1	2.25161	183.333	198.000	10.1551	3.2166	22.2285	52
43	5	209	0	1	2.50183	163.242	275.000	9.4648	3.5740	20.9878	53
44	6	214	.	1	3.05093	.	80.000	3.6774	4.3585	18.7422	54
45	7	140	0	1	3.26581	60.959	65.000	2.6322	4.6654	18.1211	55
46	8	126	.	1	3.35986	.	75.000	3.0903	4.7998	17.7314	56
47	9	277	0	1	3.41404	68.493	70.000	3.1190	4.8772	17.5806	57
48	10	69	0	1	3.42358	44.064	65.000	2.8540	4.8908	17.5381	58
49	11	258	0	1	3.50687	111.187	200.000	5.5963	5.0098	17.2187	59
50	12	259	0	1	3.59590	108.105	375.000	3.0432	5.1370	17.0957	60
51	13	205	0	1	3.81251	84.589	140.000	6.1470	5.4464	16.3779	61
52	14	1	0	1	4.04321	65.868	80.000	3.1870	5.7760	15.8857	62
53	15	1	0	1	4.04321	65.868	80.000	3.1870	5.7760	15.8857	63
54	16	109	0	1	4.07705	6.621	81.000	3.5208	5.8244	15.8125	64
55	17	169	0	1	4.21408	96.347	95.000	4.0682	6.0201	15.5430	65
56	18	86	.	1	4.27510	57.078	94.000	4.1771	6.1073	15.3232	66
57	19	60	0	1	4.59121	30.137	50.000	2.1693	6.5589	14.7871	67
	20	641	.	1	4.69120	33.676	34.000	1.5237	6.7017	14.5410	68
	21	108	0	1	4.77744	58.219	130.000	5.7768	6.8249	14.4019	69
	22	138	0	1	4.84423	52.854	90.000	3.8844	6.9203	14.2466	70
	23	0	0	1	4.86863	46.005	99.000	2.5300	6.9552	14.1924	71
	24	539	.	1	4.96891	24.658	25.000	1.0977	7.0984	14.1455	72
	25	182	0	1	4.98072	36.530	40.000	1.8039	7.1153	13.9961	73
	26	176	.	1	5.03563	34.018	70.000	2.0880	7.1938	13.9360	74
	27	232	.	1	5.06378	34.703	70.000	2.3171	7.2340	13.9492	75
	28	254	.	1	5.20746	24.658	24.000	1.2306	7.4392	13.6562	76
1	29	88	.	1	5.25238	53.653	73.000	3.2526	7.5034	13.5625	1
2	30	16	0	1	5.27804	23.288	45.000	1.9997	7.5401	13.5156	2
3	31	81	0	1	5.28428	36.872	50.000	2.4436	7.5490	13.4307	3
4	32	180	0	1	5.53911	31.963	38.000	1.6931	7.9130	13.0981	4
5	33	252	0	1	5.58079	36.644	55.000	2.4149	7.9726	13.0820	5
6	34	185	0	1	5.58266	17.123	35.000	1.5595	7.9752	13.0527	6
7	35	170	0	1	5.60539	57.306	100.000	3.7476	8.0077	13.0498	7
8	36	170	0	1	5.60539	57.306	100.000	3.7476	8.0077	13.0498	8
9	37	271	0	0	6.05708	20.776	35.000	1.5108	8.6530	12.4126	9
10	38	36	0	0	6.15473	.	64.000	2.7551	8.7925	12.2881	10
11	39	120	0	0	6.16098	21.119	85.000	3.7771	8.8014	12.3130	11
12	40	98	0	9	6.18092	57.078	100.000	2.8457	8.8299	12.3145	12
13	41	11	0	0	6.33368	29.566	80.000	3.5126	9.0481	12.0654	13
14	42	178	0	1	6.38255	25.685	52.000	1.4314	9.1179	12.0215	14
15	43	488	.	9	6.39793	48.174	90.000	3.3146	9.1399	11.8354	15
16	44	129	0	0	6.75475	32.192	50.000	2.2218	9.6496	11.5952	16
17	45	6	0	0	6.94355	31.963	45.000	1.6092	9.9194	11.2759	17
18	46	238	0	0	6.96965	14.384	15.000	0.6866	9.9566	11.3506	18
19	47	112	0	0	7.03769	14.840	16.000	0.6955	10.0538	11.2744	19
20	48	139	.	0	7.22422	11.758	10.000	0.4481	10.3203	11.1924	20
21	49	239	.	0	7.24116	14.954	15.000	0.6508	10.3445	11.0737	21
22	50	100	0	0	7.34324	14.155	14.155	0.6307	10.4903	10.9727	22
23	51	230	0	0	7.69094	17.694	23.000	1.0099	10.9871	10.7207	23
24	52	186	0	0	7.69511	27.397	45.000	1.5154	10.9930	10.6387	24
25	53	143	0	0	7.88530	28.082	45.000	1.9997	11.2647	10.3896	25
26	54	281	0	0	7.95173	22.032	47.000	2.1344	11.3596	10.4277	26
27											27

28	----- T O P - O F - F O R M -----										36
29											37
30											38
31											39
32											40
33	S T A T I S T I C A L A N A L Y S I S S Y S T E M										41
34	18:03 WEDNESDAY, MAY 16, 1979										42
35	5										43
36	OBS	FID	EG	POTENT	PB	AVE	SLMAX10	KW	GPB	R	44
37	55	281	0	0	7.95	22.03	47.000	2.13441	11.360	10.4277	45
38	56	233	0	0	7.98	24.43	45.000	1.74970	11.406	10.3208	46
39	57	34	0	0	8.35	26.37	40.000	1.77747	11.925	10.0732	47
40	58	226	0	0	8.52	1711.30	23.000	0.98612	12.177	10.0000	48
41	59	111	0	0	8.62	17.35	22.000	0.99589	12.309	10.0000	49
42	60	266	0	0	8.66	27.97	39.000	1.73304	12.369	10.0000	50
43	61	227	0	0	8.74	14.27	21.000	0.93317	12.481	10.0000	51
44	62	137	0	0	8.87	14.38	25.000	0.85149	12.676	10.0000	52
45	63	22	0	0	8.89	17.81	25.000	1.06901	12.699	10.0000	53
46	64	82	0	0	9.06	9.13	30.000	1.04523	12.943	10.0000	54
47	65	204	0	0	9.15	13.93	20.000	0.88874	13.071	10.0000	55
48	66	253	0	0	9.39	54.79	70.000	3.11058	13.409	10.0000	56
49	67	144	0	0	9.47	22.95	35.000	1.42242	13.532	10.0000	57
50	68	117	0	0	9.86	17.92	21.000	0.94703	14.088	10.0000	58
51	69	130	0	0	10.02	13.24	20.000	0.88874	14.314	10.0000	59
52	70	257	.	0	10.89	15.75	40.000	1.91800	15.550	10.0000	60
53	71	192	0	0	11.42	16.10	29.000	0.73243	16.308	10.0000	61
54	72	439	.	0	11.64	21.35	26.000	1.14677	16.630	10.0000	62
55	73	73	0	0	12.38	13.01	28.000	0.62674	17.683	10.0000	63
56	74	124	0	0	12.38	.	28.000	0.58203	17.691	10.0000	64
57	75	183	0	0	13.05	7.99	12.000	0.41822	18.646	10.0000	65
58	76	133	0	0	14.73	.	20.000	0.88874	21.040	10.0000	66
59	77	18	0	0	17.40	16.78	25.000	1.11092	24.850	10.0000	67
60	78	264	0	0	18.49	6.51	12.000	0.41772	26.408	10.0000	68
61	79	163	0	0	19.44	4.57	10.000	0.43466	27.768	10.0000	69
62	80	275	0	0	19.61	5.94	20.000	0.88874	28.017	10.0000	70
63	81	171	0	0	19.65	0.57	100.000	4.50967	28.071	10.0000	71
64	82	168	0	0	20.65	18.61	40.000	1.37824	29.501	10.0000	72
65	83	270	.	0	21.01	26.71	26.712	1.17287	30.019	10.0000	73
66	84	77	0	0	21.72	11.42	11.416	0.52249	31.030	10.0000	74
67	85	179	0	0	25.66	3.65	3.653	0.16233	36.651	10.0000	75
68	86	131	0	0	29.89	5.71	14.000	0.20223	42.693	10.0000	76
69	87	13	0	0	30.51	32.19	32.192	0.14230	43.593	10.0000	77
70	88	251	0	0	30.86	.	25.000	1.12742	44.090	10.0000	78
71	89	166	0	0	31.47	.	6.000	0.26344	44.956	10.0000	79
72	90	255	0	0	31.74	1.37	1.370	0.06178	45.345	10.0000	80
73	91	269	0	0	60.22	11.99	70.000	2.33293	86.024	10.0000	81
74	92	217	0	0	61.83	.	28.000	1.28156	88.326	10.0000	82
75	93	97	0	0	100.00	.	0.000	0.00000	.	10.0000	83
76	94	105	0	0	100.00	2.85	10.000	0.00000	.	10.0000	84
77	95	114	0	0	100.00	27.40	45.000	0.00000	.	10.0000	85
78	96	134	0	0	100.00	.	0.000	0.00000	.	10.0000	86
79	97	136	0	0	100.00	5.37	6.000	0.00000	.	10.0000	87
80	98	147	0	0	100.00	10.05	15.000	0.00000	.	10.0000	88
81	99	173	0	0	100.00	.	12.000	0.00000	.	10.0000	89
82	100	177	0	0	100.00	.	0.000	0.00000	.	10.0000	90
83	101	191	0	0	100.00	26.60	70.000	0.00000	.	10.0000	91
84	102	193	0	0	100.00	11.99	22.000	0.00000	.	10.0000	92
85	103	210	0	0	100.00	28.54	90.000	0.00000	.	10.0000	93
86	104	240	0	0	100.00	0.00	0.000	0.00000	.	10.0000	94
87	105	274	0	0	100.00	0.00	0.000	0.00000	.	10.0000	95
88	106	282	0	0	100.00	.	0.000	0.00000	.	10.0000	96
89	107	23	.	0	1000.00	.	.	.	.	10.0000	97
90	108	79	0	0	1000.00	11.30	11.301	0.57950	-40.000	10.0000	98

25	----- TOP - OF - FORM -----										32
26											33
27											34
28											35
29	STATISTICAL ANALYSIS SYSTEM 18:03 WEDNESDAY, MAY 16, 1979 6										36
30											37
31	OBS	FID	EG	POTENT	PB	AVE	SLMAX10	RW	GPB	R	38
32											39
33	109	85	0	0	1000	.	0.0000	0.00000	.	10	40
34	110	107	0	0	1000	.	10.0000	0.41309	-283.48	10	41
35	111	118	0	0	1000	16.5525	35.0000	1.53676	.	10	42
36	112	127	0	0	1000	11.3014	11.3014	0.57950	-40.00	10	43
37	113	156	.	0	1000	3.0822	3.0822	0.14558	-147.28	10	44
38	114	165	0	0	1000	0.0000	0.0000	0.00000	.	10	45
39	115	167	.	0	1000	.	22.0000	0.97761	.	10	46
40	116	200	0	0	1000	.	0.0000	0.00000	.	10	47
41	117	228	0	0	1000	0.2283	0.2283	0.01078	-86.71	10	48
42	118	265	0	0	1000	.	.	.	.	10	49
43	119	279	0	0	1000	.	0.0000	0.00000	.	10	50
44	120	323	.	0	1000	.	.	.	.	10	51
45	121	368	0	0	1000	.	.	.	.	10	52
46	122	423	.	0	1000	.	.	.	.	10	53
47	123	523	.	0	1000	.	.	.	.	10	54
48	124	769	0	0	1000	.	.	.	.	10	55
49											56
50	----- TOP - OF - FORM -----										57
51											58
52											59
53											60
54											61
55											62
56											63
57											64

PROGRAMMER=HJH

ACCOUNT=NCS.NE.C5275

STATISTICAL ANALYSIS SYSTEM

17:35 SUNDAY, MARCH 25, 1979 1

ORS	FID	SIC	UTIL	PBY	ROI	HRS	ANNAST	EG	TAE	OKWH	PEAK	POTENT	PH	PB2	AVF	SLMAX	SLMAX10	H
1	0	82	2	5	15	8750	403	0	75	0	16.0	0	7.383	6.898	46.00	57621	99.00	184.411
2	1	24	1	5	15	8400	577	0	38	0	5.0	0	6.821	5.968	65.87	80000	80.00	167.316
3	1	24	1	5	15	8400	577	0	38	0	5.0	0	6.821	5.968	65.87	80000	80.00	167.316
4	6	28	2	5	15	8760	280	0	66	0	9.0	0	11.671	10.212	31.96	37090	45.00	182.223
5	9	28	2	5	15	8760	2000	0	90	60	21.0	0	3.352	2.933	228.31	250000	250.00	205.542
6	11	22	1	5	15	8760	259	0	26	0	5.0	0	100.000	100.000	29.57	0	80.00	184.411
7	13	82	8	5	15	8760	282	0	1	0	0	0	72.578	63.506	32.19	3156	32.19	189.406
8	16	87	1	5	8	8736	204	0	27	0	6.0	0	9.095	7.958	23.29	45000	45.00	186.635
9	18	22	2	5	10	5880	147	0	22	0	0	0	35.834	31.355	16.78	25000	25.00	186.635
10	22	22	1	5	15	8760	156	0	46	9998	11.0	0	15.031	13.152	17.81	20801	25.00	179.594
11	23	25	1	5	15	2000	0	0	27	0	8.3	0	15.123	13.232	26.37	40000	40.00	186.635
12	34	25	1	3	15	2250	231	0	22	0	5.0	0	10.902	9.540	0	62000	64.00	186.635
13	36	25	1	3	15	6700	0	0	37	0	8.0	0	7.335	6.418	30.14	50000	50.00	182.223
14	60	28	6	5	20	3800	264	0	18	0	4.0	0	5.427	4.748	44.06	65000	65.00	184.411
15	69	20	7	3	15	7920	386	0	0	0	3.0	0	22.564	19.744	13.01	12223	28.00	215.361
16	73	83	9	5	15	8760	114	0	8	0	0	0	0	0	0	0	0	0

ORS	AVV	B01L	ANS	AA1A	SLMAXH	CAPUTIL	SLMAXL	AAA	XX	YY	PK1	PK2
1	8.5616	504761	404141	0.602014	58.01	0.800000	57.23	0.800659	-0.00066	-0.0008	16.0000	14.1998
2	4.3377	700800	607152	0.866370	80.00	0.767123	0.00	0.866370	-0.09925	-0.1294	5.0000	2.8488
3	4.3377	700800	607152	0.866370	80.00	0.767123	0.00	0.866370	-0.09925	-0.1294	5.0000	2.8488
4	7.5342	324907	260092	0.703623	37.27	0.800000	36.91	0.800513	-0.00051	-0.0006	9.0000	8.2190
5	10.2740	2190000	1954680	0.892548	250.00	0.800000	0.00	0.892548	-0.09255	-0.1157	19.0000	8.9676
6	2.9680	0	0	0.545377	0.00	0.800000	0.00	0	0	0	5.0000	5.0000
7	0.1142	27442	22114	0.997260	3.16	0.800000	3.15	0.799998	0.00000	0.0000	0.1142	0.0000
8	3.0822	394200	318552	0.808097	45.00	0.797808	0.00	0.808097	-0.01029	-0.0129	6.0000	4.6669
9	2.5114	219000	138904	0.634265	25.00	0.536986	0.00	0.634265	-0.09728	-0.1812	2.5114	2.5114
10	5.2511	182215	145893	0.708055	20.90	0.800000	20.70	0.800664	-0.00066	-0.0008	11.0000	10.4869
11	3.0822	0	0	0	0	0.192648	0.00	0	0	0	8.0000	8.0000
12	2.5114	350400	204886	0.620320	40.00	0.205479	0.00	0.584722	-0.37924	-1.8456	5.0000	4.1113
13	4.2237	543120	332280	0.596390	64.00	0.611872	60.00	0.611798	0.00007	0.0001	7.0000	5.2225
14	2.0544	438000	348729	0.847196	50.00	0.347032	0.00	0.796186	-0.44915	-1.2943	4.0000	1.8307
15	0	567400	567840	0.997260	65.00	0.723298	0.00	0.997260	-0.27397	-0.3788	3.0000	0.1460
16	0.9132	107070	85642	0.465558	12.25	0.800000	12.20	0.800055	-0.00006	-0.0001	21.0000	20.7436

ORS	KW	KWH	GEN	PGEN	SE	SD	RL	MG	FCP	MB	ANSAV	R	CAP
1	2.5300	17.745	639.91	1619962	266172	86410	432150	40474	93160	10804	208143	13.5625	1640896
2	3.1870	24.187	568.47	1811486	455556	10584	600000	45292	126983	15000	282865	15.7187	1929349
3	3.1870	24.187	568.47	1811486	455556	10584	600000	45292	126983	15000	282865	15.7187	1929349
4	1.6092	11.284	807.03	1298666	169267	37486	274174	32467	59244	6954	108089	9.9062	1261472
5	12.2347	95.659	285.18	3489087	1434990	491556	1975000	97227	502211	46875	1280132	29.0312	4291270
6	0.0000	0.000	0.00	0	0	0	0	0	0	0	0	4.0000	0
7	0.1423	3.977	2799.42	399368	14959	5479	23666	9959	5236	592	4652	4.0000	337627
8	1.9997	14.155	721.95	1443652	268953	6559	337500	36091	74316	8437	156667	12.0156	1424922
9	1.1109	6.172	975.91	1584161	92587	0	187500	27104	32435	4687	28390	4.0000	1017329
10	0.8895	6.239	1093.77	972959	118531	2525	156305	24321	32752	3900	60082	7.2344	903092
11	0	0.000	0	0	0	0	0	0	0	0	0	4.0000	0
12	1.7775	9.104	766.90	1363142	172993	4373	300000	34079	47799	7500	87981	7.1406	1330514
13	2.7551	14.765	612.54	1687605	280544	9745	465000	42190	77519	11625	157955	10.0234	1722084
14	2.1693	15.130	622.42	1502085	226552	104128	375000	37552	79433	9375	204719	13.6562	1501668
15	2.8540	24.932	601.56	1716951	372985	136391	447500	42921	130895	12187	324972	18.6719	1763481
16	0.6267	4.492	1308.86	326357	64887	12306	21670	20568	23060	2292	32333	4.9609	729582

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SICNEW POTENT

FREQUENCY PERCENT ROW PCT COL PCT	0	1	2	9	TOTAL
20	7 5,30 58,33 7,95	4 3,03 33,33 13,79	1 0,76 8,33 9,09	0 0,00 0,00 0,00	12 9,09
22	26 19,70 70,27 29,55	4 3,03 10,81 13,79	3 2,27 8,11 27,27	4 3,03 10,81 100,00	37 28,03
24	21 15,91 80,77 23,86	5 3,79 19,23 17,24	0 0,00 0,00 0,00	0 0,00 0,00 0,00	26 19,70
26	1 0,76 20,00 1,14	0 0,00 0,00 0,00	4 3,03 80,00 36,36	0 0,00 0,00 0,00	5 3,79
28	8 6,06 36,36 9,09	12 9,09 54,55 41,38	2 1,52 9,09 18,18	0 0,00 0,00 0,00	22 16,67
50	25 18,94 83,33 28,41	4 3,03 13,33 13,79	1 0,76 3,33 9,09	0 0,00 0,00 0,00	30 22,73
TOTAL	88 66,67	29 21,97	11 8,33	4 3,03	132 100,00

Exhibit B.1

STATISTICAL ANALYSIS SYSTEM										20:15 MONDAY, APR	
OBS	FID	EG	POTENT	PB	AVE	SLMAX10	KW	GPB	R		
1	110	0	1	1,57078	456,62	500	31,3761	2,2440	27,0654		
2	236	0	1	1,63923	748,74	749	45,0750	2,3418	26,4531		
3	125	1	1	1,91366	719,18	240	11,9641	2,7338	24,2998		
4	159	0	2	2,04458	183,33	880	35,8401	2,9208	23,4414		
5	155	1	1	2,07610	422,37	198	10,1551	2,9659	23,2964		
6	116	1	2	2,39928	216,89	462	27,4609	3,4275	21,2368		
7	113	1	2	2,53026	1755,71	235	13,2250	3,6147	20,6230		
8	78	1	2	2,60067	1563,93	1750	93,8725	3,7152	20,3125		
9	122	0	1	2,60617	68,49	1670	16,4379	3,7231	20,3008		
10	277	1	1	2,67254	163,24	70	3,1190	3,8179	20,3564		
11	214	0	1	2,80816	84,59	80	3,6774	4,0117	19,7002		
12	209	0	1	2,87612	44,06	275	9,4648	4,1087	19,3076		
13	205	0	1	2,87696	228,31	140	6,1470	4,1099	19,4687		
14	69	1	2	2,90106	273,97	65	2,8540	4,1444	19,3867		
15	9	1	2	2,93318	65,87	250	12,2347	4,1903	18,9180		
16	309	0	1	3,47683	24,66	500	35,2811	4,9669	17,2070		
17	1	1	1	3,50869	33,68	80	3,1870	5,0124	17,3535		
18	254	0	1	3,71064	60,96	24	1,2306	5,3009	16,9111		
19	641	0	1	3,73721	96,35	34	1,5237	5,3389	16,7793		
20	140	1	1	3,75303	24,66	65	2,6322	5,3615	16,6416		
21	169	0	1	3,76397	24,66	95	4,0682	5,3771	16,6797		
22	539	0	1	3,97849	30,14	25	1,0977	5,6836	16,2578		
23	126	0	1	3,99709	36,53	75	3,0903	5,7101	15,9004		
24	60	0	1	4,09907	6,62	50	2,1693	5,8558	15,8828		
25	182	0	1	4,18354	52,85	40	1,8039	5,9765	15,6543		
26	109	0	1	4,45225	21,12	81	3,5208	6,3604	14,9453		
27	138	0	1	4,56771	23,29	90	3,5208	6,3604	14,9453		
28	120	0	1	4,60874	141,19	85	3,8844	6,5253	14,7988		
29	16	0	1	4,60874	96,715	200	3,7771	6,5839	14,8691		
30	258	0	1	4,69080	108,11	45	1,9997	6,7011	14,5937		
31	259	0	1	4,91260	34,70	375	5,5963	7,0180	13,8057		
32	232	0	1	4,96715	17,12	70	3,0432	7,0959	13,8950		
33	185	0	1	5,06378	31,90	35	2,3171	7,2340	13,9492		
34	180	0	1	5,10401	14,38	38	1,5595	7,2914	13,8467		
35	238	1	2	5,37378	31,96	15	1,6931	7,6768	13,3647		
36	256	0	1	5,80592	51,96	118	0,6866	8,2942	12,8418		
37	6	0	1	5,81780	14,95	45	3,8289	8,3111	12,4111		
38	239	0	9	5,93239	57,08	15	1,6092	8,4748	12,5693		
39	86	0	0	6,02428	14,84	94	0,6506	8,6061	12,5488		
40	112	0	0	6,03572	17,69	16	4,1771	8,6225	12,1328		
41	230	0	0	6,03519	58,22	23	0,6955	8,6231	12,5151		
42	108	0	0	6,60266	46,00	130	1,0099	9,4324	1,8926		
43	0	0	0	6,72257	14,27	99	5,7768	9,6037	1,4224		
44	227	0	0	6,89806	7,00682	21	2,5300	9,8544	11,1660		
45	175	0	0	7,00682	14,27	21	0,9332	10,0097	11,4287		

Exhibit B.2

60%

39	86	0	9	6,03572	57,08	94	4,1771	8,6225	12,1328
4	112	0	0	6,03619	14,84	16	0,6955	8,6231	1,151
41	230	0	0	6,60266	17,69	23	1,0099	9,4324	11,8926
42	108	0	0	6,72257	58,22	130	5,7768	9,6037	11,4224
43	0	0	0	6,89806	46,00	99	2,5300	9,8544	11,1660
44	227	0	0	7,00682	14,27	21	0,9332	10,0097	11,4297
45	176	0	0	7,11749	34,02	70	2,0880	10,1678	10,9888
46	88	0	0	7,21206	53,65	73	3,2526	10,3029	10,8936
47	111	0	0	7,32219	17,35	22	0,9959	10,4603	11,0137
48	81	0	0	7,58732	36,87	50	2,4436	10,8390	10,3911
49	253	0	0	7,65219	54,79	70	3,1106	10,9317	11,0488
50	22	0	0	7,80330	17,81	25	1,0690	11,1476	10,5874
51	252	0	0	7,93791	36,64	55	2,4149	11,3399	10,2256
52	170	0	9	7,97100	57,31	100	3,7476	11,3871	10,2036
53	178	0	0	8,26453	25,68	52	1,4314	11,8065	10,0176
54	271	0	0	8,38640	20,78	35	1,5108	11,9806	10,0000

T O P - O F - F O R M - - - - -

Exhibit B.2. (Continued)

S T A T I S T I C A L A N A L Y S I S S Y S T E M

20:15 MONDAY, APR 1

OBS	FID	EG	POTENT	PB	AVE	SLMAX10	KW	GPB	R	FID
55	204	0	0	8,562	13,93	20,000	0,88874	12,2312	10	
56	439	0	0	8,707	21,35	26,000	1,14677	12,4382	10	
57	186	0	0	8,780	27,40	45,000	1,51536	12,5429	10	
58	98	0	9	8,806	57,08	100,000	2,84570	12,5798	10	
59	36	0	0	8,836		64,000	2,75508	12,6223	10	
60	266	0	0	8,902	27,97	39,000	1,73304	12,8025	10	
61	488	0	9	9,059	48,17	90,000	3,31460	12,9415	10	
62	11	0	0	9,115	29,57	80,000	3,51259	13,0213	10	
63	73	0	0	9,322	13,01	28,000	0,62674	13,3172	10	
64	129	0	0	9,752	32,19	50,000	2,22184	13,9314	10	
65	143	0	0	10,061	28,08	45,000	1,99966	14,3730	10	
66	139	0	0	10,361	11,76	10,000	0,44813	14,8008	10	
67	100	0	0	10,701	14,16	14,155	0,63071	15,2871	10	
68	199	1	2	10,845	59,70	115,000	2,68929	15,4923	10	
69	144	0	0	10,915	22,95	35,000	1,42242	15,5935	10	
70	281	0	0	11,660	22,03	47,000	2,13441	16,6573	10	
71	233	0	0	11,848	24,43	45,000	1,74970	16,9262	10	
72	257	0	0	12,124	15,75	40,000	1,91800	17,3205	10	
73	137	0	0	12,227	14,38	25,000	0,85149	17,4673	10	
74	34	0	0	12,349	26,37	40,000	1,77747	17,6417	10	
75	226	0	0	12,740	1711,30	23,000	0,98612	18,1993	10	
76	124	0	0	12,824		28,000	0,58203	18,3203	10	
77	192	0	0	13,296	16,10	29,000	0,73243	18,9947	10	

EXHIBIT B-2. (continued)

72	251	0	0	12,124	15,75	40,000	1,91800	17,3205	10
73	137	0	0	12,227	14,38	25,000	0,85149	17,4673	10
74	34	0	0	12,349	26,37	40,000	1,77747	17,6417	10
75	226	0	0	12,740	1711,30	23,000	0,98612	18,1993	10
76	124	0	0	12,824	,	28,000	0,58203	18,3203	10
77	192	0	0	13,296	16,10	29,000	0,73243	18,9947	10
78	82	0	0	13,516	9,13	30,000	1,04523	19,3079	10
79	117	0	0	14,856	17,92	21,000	0,94703	21,2228	10
80	130	0	0	15,090	13,24	20,000	0,88874	21,5567	10
81	133	0	0	15,907	,	20,000	0,68874	22,7242	10
82	179	0	0	20,379	3,65	3,653	0,16233	29,1124	10
83	183	0	0	20,607	7,99	12,000	0,41822	29,4389	10
84	163	0	0	22,141	4,57	10,000	0,43466	31,6296	10
85	270	0	0	25,851	26,71	26,712	1,17287	36,9303	10
86	77	0	0	28,910	11,42	11,416	0,52249	41,3006	10
87	251	0	0	30,863	,	25,000	1,12742	44,0904	10
88	18	0	0	31,355	16,78	25,000	1,11092	44,7927	10
89	166	0	0	31,469	,	6,000	0,26344	44,9564	10
90	264	0	0	31,507	6,51	12,000	0,41772	45,0097	10
91	171	0	0	31,585	0,57	100,000	4,50967	45,1219	10
92	275	0	0	34,790	5,94	20,000	0,88874	49,6993	10
93	168	0	0	36,684	18,61	40,000	1,37824	52,4057	10
94	131	0	0	62,442	5,71	14,000	0,20223	89,2024	10
95	13	0	0	63,506	32,19	32,192	0,14230	90,7231	10
96	255	0	0	65,234	1,37	1,370	0,06178	93,1918	10
97	90	1	2	100,000	134,36	190,000	0,00000	,	10
98	97	0	0	100,000	,	0,000	0,00000	,	10
99	105	0	0	100,000	2,85	10,000	0,00000	,	10
100	114	0	0	100,000	27,40	45,000	0,00000	,	10
101	134	0	0	100,000	,	0,000	0,00000	,	10
102	136	0	0	100,000	5,37	6,000	0,00000	,	10
103	147	0	0	100,000	10,05	15,000	0,00000	,	10
104	173	0	0	100,000	,	12,000	0,00000	,	10
105	177	0	0	100,000	,	0,000	0,00000	,	10
106	191	0	0	100,000	26,60	70,000	0,00000	,	10
107	193	0	0	100,000	11,99	22,000	0,00000	,	10
108	210	0	0	100,000	28,54	90,000	0,00000	,	10

111

T O P - O F - F O R M - - - - -

S T A T I S T I C A L A N A L Y S I S S Y S T E M

20:15 MONDAY, APR.

OBS	FID	EG	POTENT	PB	AVE	SLMAX10	KW	GPB	R
09	213	1	2	100,00	60,6164	105,000	0,00000	,	10
110	274	0	0	100,00	0,0000	0,000	0,00000	,	10
...	263	0	0						

102	150	0	0	100,000	5.37	5,000	0,00000	.	10
103	147	0	0	100,000	10.05	15,000	0,00000	.	10
104	173	0	0	100,000	.	12,000	0,00000	.	10
105	177	0	0	100,000	.	0,000	0,00000	.	10
106	191	0	0	100,000	26.60	70,000	0,00000	.	10
107	193	0	0	100,000	11.99	22,000	0,00000	.	10
108	210	0	0	100,000	28.54	90,000	0,00000	.	10

TOP - OF - FORM - - - - -

STATISTICAL ANALYSIS SYSTEM										20:15 MONDAY, APR
OBS	FID	EG	POTENT	PB	AVE	SLMAX10	KW	GPB	R	
109	213	1	2	100,00	60,6164	105,000	0,00000	.	10	
110	274	0	0	100,00	0,0000	0,000	0,00000	.	10	
111	282	0	0	100,00	.	0,000	0,00000	.	10	
112	217	0	0	280,23	.	28,000	1,28156	400,33	10	
113	269	0	0	290,72	11,9863	70,000	2,33293	415,31	10	
114	23	.	0	1000,00	.	.	.	.	10	
115	79	0	0	1000,00	11,3014	11,301	0,57950	.	10	
116	85	0	0	1000,00	.	0,000	0,00000	.	10	
117	107	0	0	1000,00	.	10,000	0,41309	-114,78	10	112
118	118	0	0	1000,00	16,5525	35,000	1,53676	.	10	
119	127	0	0	1000,00	11,3014	11,301	0,57950	-40,00	10	
120	156	.	0	1000,00	3,0822	3,082	0,14558	-89,90	10	
121	165	0	0	1000,00	0,0000	0,000	0,00000	.	10	
122	167	.	0	1000,00	.	22,000	0,97761	.	10	
123	200	0	0	1000,00	.	0,000	0,00000	.	10	
124	228	0	0	1000,00	0,2283	0,228	0,01078	-110,52	10	
125	240	0	0	1000,00	0,0000	0,000	0,00000	.	10	
126	265	0	0	1000,00	.	.	.	.	10	
127	279	0	0	1000,00	.	0,000	0,00000	.	10	
128	323	.	0	1000,00	.	.	.	.	10	
129	368	0	0	1000,00	.	.	.	.	10	
130	423	.	0	1000,00	.	.	.	.	10	
131	523	.	0	1000,00	.	.	.	.	10	
132	769	0	0	1000,00	.	.	.	.	10	
JOB CONSOLE LOG										

1522 -- STEAM -- JCL INTERPRETED; TUCC CPU #1
 1522 -- STEAM -- BEGINNING EXEC - INIT 1 - CLASS
 1522 ++++S=255,I=01,J=STEAM 20:15:15 RJH
 1522 END EXECUTION;

TOP - OF - FORM - - - - -

OBS	FID	SIC	UTIL	PBY	ROI	HRS	ANNAST	EG	TAE	QKWH	PEAK	POTENT
1	0	82	2	6	15	8760	403	0	75	0	16.0	0
2	1	24	1	6	15	8400	577	0	38	0	5.0	1
3	1	24	1	6	15	8400	577	0	38	0	5.0	1
4	6	28	2	6	15	8760	280	0	66	0	9.0	0
5	9	28	2	6	15	8760	2000	1	90	60	21.0	1
6	11	22	1	6	15	2000	259	0	26	0	5.0	0
7	13	82	8	6	15	8760	282	0	1	0	1	0
8	16	80	1	6	8	8736	204	0	27	0	6.0	1
9	18	22	2	6	10	5880	147	0	22	0	1	0
10	22	22	1	6	15	2000	156	0	46	9998	11.0	0
11	23	25	1	6	15	2000	1	1	27	1	8.3	0
12	34	25	1	6	15	2250	231	0	22	0	5.0	0
13	36	25	1	6	15	6700	1	0	37	0	8.0	0
14	60	28	6	6	20	3800	264	0	18	0	4.0	0
15	69	20	7	6	15	7920	386	0	1	0	3.0	1
16	73	83	9	6	15	8760	114	0	8	0	1	0

OBS	BOIL	ANS	AAAA	SLMAXH	CAPUTIL	SLMAXL	AAA
1	504761	404141	0.602014	58.01	0.800000	57.23	0.8000
2	700800	607152	0.866370	80.00	0.767123	0.00	0.866
3	700800	607152	0.866370	80.00	0.767123	0.00	0.866
4	324907	260092	0.703623	37.27	0.800000	36.91	0.8000
5	2190000	1954680	0.892548	250.00	0.800000	0.00	0.8920
6	700800	382200	0.545377	80.00	0.182648	0.00	0.545
7	27642	22114	0.997260	3.16	0.800000	3.15	0.799
8	394200	318552	0.808097	45.00	0.797808	0.00	0.8080
9	219000	138904	0.634265	25.00	0.536986	0.00	0.634
10	219000	155064	0.708055	25.00	0.182648	0.00	0.7080
11	1	0	1	1	0.182648	0.00	1
12	350400	204886	0.620320	40.00	0.205479	0.00	0.584
13	543120	332280	0.596390	64.00	0.611872	60.00	0.611
14	438000	348729	0.847196	50.00	0.347032	0.00	0.796
15	569400	567840	0.997260	65.00	0.723288	0.00	0.997
16	107070	85662	0.465558	12.25	0.800000	12.20	0.8000

OBS	KWH	GEN	PGEN	SE	SD	BL	MG	I
1	17744776	639.91	1618962	266172	86410	432158	40474	931
2	24187178	568.47	1811686	459556	25814	600000	45292	126
3	24187178	568.47	1811686	459556	25814	600000	45292	126
4	11284490	807.03	1298666	169267	37486	278174	32467	59
5	95659313	285.18	3489087	1434890	481556	1875000	87227	502
6	16781385	540.80	1899620	318846	23710	600000	47491	88
7	997260	2799.42	398368	14959	5479	23666	9959	5
8	14155431	721.95	1443652	268953	15997	337500	36091	74
9	6172454	975.91	1084161	92587	0	187500	27104	32
10	6630623	995.35	1064040	125982	6158	187500	26601	34
11	0	1	1	0	0	0	0	0
12	9104498	766.90	1363142	172985	10665	300000	34079	47
13	14765460	612.54	1687605	280544	21330	465000	42190	77
14	15130147	692.42	1502085	226952	104128	375000	37552	79
15	24932343	601.56	1716851	373985	136991	487500	42921	130
16	4392465	1308.86	820307	65887	12306	91670	20508	23

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PEAK	POTENT	PB	AVE	SLMAX	SLMAX10	H	AVV
16.0	0	6.90	46.00	57621	99.00	184.411	8.5616
5.0	1	5.66	65.87	80000	80.00	167.316	4.3379
5.0	1	5.66	65.87	80000	80.00	167.316	4.3379
9.0	0	10.21	31.96	37090	45.00	182.223	7.5342
21.0	1	2.93	228.31	250000	250.00	205.542	10.2740
5.0	0	9.11	29.57	80000	80.00	184.411	2.9680
.	0	63.51	32.19	3156	32.19	189.406	0.1142
6.0	1	7.51	23.29	45000	45.00	186.635	3.0822
.	0	31.35	16.78	25000	25.00	186.635	2.5114
11.0	0	13.27	17.81	25000	25.00	179.594	5.2511
8.3	0	1000.00	.	.	.	189.406	3.0822
5.0	0	12.35	26.37	40000	40.00	186.635	2.5114
8.0	0	8.84	.	62000	64.00	186.635	4.2237
4.0	0	6.42	30.14	50000	50.00	182.223	2.0548
3.0	1	4.75	44.06	65000	65.00	184.411	.
.	0	19.74	13.01	12223	20.00	215.361	0.9132

SLMAXL	AAA	XX	YY	PK1	PK2	KW
57.23	0.800659	-0.00066	-0.0008	16.0000	14.1998	2.5300
0.00	0.866370	-0.09925	-0.1294	5.0000	2.8488	3.1870
0.00	0.866370	-0.09925	-0.1294	5.0000	2.8488	3.1870
36.91	0.800513	-0.00051	-0.0006	9.0000	8.2190	1.6092
0.00	0.892548	-0.09255	-0.1157	19.0000	8.9676	12.2347
0.00	0.545377	-0.36273	-1.9859	5.0000	3.0242	3.5126
3.15	0.799998	0.00000	0.0000	0.1142	0.0000	0.1423
0.00	0.808097	-0.01029	-0.0129	6.0000	4.6669	1.9997
0.00	0.634265	-0.09728	-0.1812	2.5114	2.5114	1.1109
0.00	0.708055	-0.52541	-2.8766	11.0000	10.4869	1.0690
0.00	.	.	.	8.0000	8.0000	.
0.00	0.584722	-0.37924	-1.8456	5.0000	4.1113	1.7775
60.00	0.611798	0.00007	0.0001	7.0000	5.2225	2.7551
0.00	0.796186	-0.44915	-1.2943	4.0000	1.8307	2.1693
0.00	0.997260	-0.27397	-0.3788	3.0000	0.1460	2.8540
12.20	0.800055	-0.00006	-0.0001	21.0000	20.7436	0.6267

BL	MG	FLP	MB	ANSAV	R	CAP	CAP1
2158	40474	93160	10804	208143	10.3750	1435784	1297775
0000	45292	126983	15000	298096	11.9219	1688180	1503782
0000	45292	126983	15000	298096	11.9219	1688180	1503782
8174	32467	59244	6954	108089	8.0078	1103788	1020479
5000	87227	502211	46875	1280132	18.3437	3754861	3151928
0000	47491	88102	15000	191964	8.1953	1749734	1614765
3666	9959	5236	592	4652	4.0000	295424	283954
7500	36091	74316	8437	166106	9.6484	1246807	1134767
7500	27104	32405	4687	28390	4.0000	890163	855601
7500	26601	34811	4687	66040	5.9570	876078	826146
0000	.	0	.	.	4.0000	.	.
0000	34079	47799	7500	94273	6.3203	1164199	1093987
5000	42190	77519	11625	170540	8.4062	1506823	1387783
5000	37552	79433	9375	204719	10.4336	1313960	1187000
7500	42921	130895	12187	324972	13.3516	1543046	1356213
1670	20508	23060	2292	32333	4.4687	638384	610789

INDUSTRIAL

SALES

DIVISION

GENERAL ELECTRIC COMPANY 3565 PIEDMONT ROAD, N.E., P.O. BOX 4659
ATLANTA, GEORGIA 30302, Phone (404) 262-6000

May 1, 1979

Mr. Jerry Kohl
North Carolina State University
Department of Nuclear Engineering
Box 5636
Raleigh, North Carolina 27650

Subject: Gas Turbine Cogeneration Feasibility

Dear Jerry:

In accordance with Kevin Vaughn's April 5, 1979 letter and our subsequent telephone conversations, I have prepared the attached broad brush feasibility study for the most promising set of data which was provided. The data which I used was identified by your Reference #258. My evaluation consists of the following:

Attachment 1 represents an interpretation of the data which was provided, along with assumptions used for this brief analysis.

Attachment 2 shows the addition of cogeneration to a base case facility consisting of a low pressure boiler to supply process steam only. The turbine and boiler ratings can be seen in this figure. The proposed turbine-generator is a Model 5341 Combustion Gas Turbine-Generator which utilizes a supplementary fired heat recovery steam generator to produce the required process steam at 250 psig.

Attachment 3 represents a simplified economic analysis. It shows that cogeneration, based on the data provided and assumptions made, would result in an annual operating loss when compared to the base case. However, it is interesting to note that the incremental total installed cost between the coal fired low pressure boiler and the gas turbine with HRSG is only \$390,000. With the present relationship of purchased power at 2.87¢/kWh, coal at \$1.70/MM Btu, and natural gas at \$2.77/MM Btu cogeneration does not seem feasible.

Attachment 4 represents a sensitivity analysis which plots gross payout versus purchase power cost. If we assume that the coal and natural gas costs remain constant then this project would achieve a gross payout of 3 years or less at a purchased power cost of approximately 3.46¢/kWh. If this study could be compared on the marginal cost of new generating capacity, rather than the average cost of power, it might well have a very attractive payout.

Continued

Mr. Jerry Kohl

Page 2.

May 1, 1979

Of the other sets of data which were mailed to me, nearly all had steam loads or plant operating periods which were too low for consideration. Your analysis forms identified by reference numbers 86 and 177 might prove economic if the cost of purchase power could be compared on the marginal cost of new generating capacity and excess power generated could be sold back to the utility at an attractive level, however, it would take both of these incentives before these two industrials would become even marginally attractive.

Please feel free to give me a call if you have any questions concerning the attached broad-brush feasibility study.

Very truly yours,

J. C. Franklin
Turbine Sales Engineer
Industrial Sales Division
Atlanta, Georgia

cc: Mr. Kevin Vaughn - North Carolina State University - Raleigh, North Carolina
Mr. W. L. Richbourg - ISD - Greensboro, North Carolina

attachments

JCF:jas

Appendix C

ATTACHMENT NO. 1

STUDY DATA AND ASSUMPTIONS

- ° Steam Demand 103,000 lb/hr Average, 200,000 lb/hr Peak at 250 psig.
- ° Plant Electrical Load 16,000 kW Average, 23,000 kW Peak.
- ° Conversion to Coal is Mandatory unless Plant Cogenerates, then Natural Gas is available.
- ° Base Case Process Steam Requirements Supplied by Single Coal-Fired Boiler with Existing Boilers for Back-Up.
- ° Fuels - Low Sulphur Coal @ \$1.70/MM Btu
- Natural Gas @ \$2.77/MM Btu
- ° Operation 8400 hr/yr.
- ° Average Purchased Power Cost 2.87¢/kWh.
- ° Differences in Powerhouse Auxiliaries with Cogeneration are being neglected.
- ° Size Gas Turbine-Generator and Boilers based upon Peak Steam Requirements.
- ° Gas Turbine-Generator Performance at 500 ft. Altitude, 59°F, 4" H₂O Inlet and 14" H₂O Exhaust Pressure Drops.
- ° HRSG and Low Pressure Boiler Performance with 3.0% Blowdown and 228°F Feedwater.

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Appendix C

Base Case

With Cogeneration

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ESTIMATED ANNUAL OPERATING COST DEVELOPMENT

	<u>BASE</u>	WITH COGENERATION
Average Power Purchased -- kW	16000	-0-
Energy Purchased -- MM kWh/yr	134.4	-0-
Incremental Fuel -- G Btu/yr	Base	1224.72
Estimated Total Installed Cost -- \$Millions	8.88	9.27

Δ Total Installed Cost = .39

Annual Costs (\$Millions)

Fuel	1.77	6.28
Purchased Power	3.86	-0-
Operating Labor	Base	-0-
Maintenance	Base	.01
	<hr/>	<hr/>
Total	5.63	6.29

Annual Loss with Cogeneration = .66

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APPENDIX D

COGENERATION AND THE N. C. BRICK INDUSTRY

The North Carolina brick industry produces about a billion bricks per year. This amounts to about 20% of the total United States production. Average consumption of fuel in North Carolina ranges from about 4,000 to 6,500 BTU per brick, which is usually in the form of natural gas, propane or distillate. The total annual N. C. fuel usage (in the brick industry) is thus the equivalent of a million bbl. of oil, and cogeneration would save the equivalent of 0.5 million bbl. of oil every year.

Although there are over thirty locations in N. C. where brick and clay products are manufactured, most of the North Carolina production is concentrated in five locations, and it is in these locations that prospects for the installation of cogeneration systems appear to be the brightest.

From information available⁽¹⁾, it can be concluded that the brick industry in North Carolina and elsewhere in the U. S., typically has the following characteristics when compared with other industries:

1. It consumes large amounts of fuel.
2. Heat losses and energy inefficiencies appear to be high, owing to little or no modernization of plants in recent years.
3. Brick properties (such as color, strength, ceramic nature) are sensitive to system variations.
4. The brick kilns operate 24 hours/day (thus continuously needing process heat) without needing a significant amount of supervision.

Process heat is necessary in brick manufacture for the following operations:

- (a) for kiln (to change chemical state of brick)
- (b) for clay dryer

Since significant amounts of moisture have to be removed from the bricks during the manufacture, hot dry gases are preferred to steam as the medium for process heat. Potential brick plant cogeneration systems would therefore be of the combustion turbine type (as opposed to the steam turbine). In such a configuration, the exhaust gases from the exit of the combustion turbine (which still have a significant amount of heat even after "cooling

down" in the turbine) are used to provide the process heat in a "bottoming" type of cycle.

Bradstock⁽²⁾ has reported studies of heat balance in brick kilns, and has discussed methods for thermal analysis of heat kilns along with corrections and improvements possible in their designs. Robinson⁽³⁾ has conducted studies on brick kilns in the Southeastern United States, and found little correlation between kiln design and its operating efficiency. Thus, it would appear that cogeneration designs, as well as modifications for increasing energy efficiencies of brick plants would have to be considered on a plant-by-plant basis.

The amount of heat needed in a brick kiln exceeds that which would be produced from a combustion turbine-generator producing the amount of electricity needed for operation of the brick plant. This lack of energy balance can be concluded from the information obtained during the visits to the brick kilns and from figures quoted in standard references^(4,5) on gas turbine cogeneration. A visit to a representative brick company generated the following information about its energy usage:

fuel consumed (nat'l gas): 13×10^6 BTU/hr

kiln exhaust temperatures in the range: 300 - 600°F

daytime power consumption: 1.6 MW

nighttime power consumption: 0.8 MW

process heat usage: 24 hours/day

If the entire amount of process heat in a brick plant was used to cogenerate electricity through a gas turbine-generator system, about ten times the power needed by the plant would be available. It would thus appear that cogeneration in the brick industry would be fully feasible only if adequate tie-up arrangements exist with either the utility (to absorb the excess power in the electric grid, as for example, has been suggested by Sherry⁽⁶⁾) or neighboring industrial electric consumers.

The brick industry has typically chosen not to cogenerate. However, Burns Brick Company in Macon, Georgia has two combustion turbine generators producing about 2200 kVA of electricity which meets all of their demand, and they have no backup arrangements with the neighborhood utility, Georgia Power

Company. In fact, it is interesting to note that the primary reason for Burns cogeneration (over ten years ago) was to become self-reliant in power, and not for cost or energy savings. Burns does not generate excess electricity, and thus their cogenerating potential has not been fully utilized. They are generally satisfied by the performance of the system, and easily keep up with maintenance and repair of their system.

As fuel and electricity prices rise, cogeneration in the brick industry should become much more attractive as compared to the present situation.

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