BY THE COMPTROLLER GENERAL

Report To The Congress

OF THE UNITED STATES

Industrial Cogeneration--What It Is, How It Works, Its Potential

Combining industrial process heat production and utility power generation at one site can double the fuel efficiency of electric power generation. Cogeneration does just that.

In the near term, cogeneration can contribute to our Nation's efforts to conserve valuable fossil fuels. In the long term, as the technology develops, cogeneration should encourage coal use with corresponding reductions in oil and natural gas use.

The development of cogeneration as an energy conservation measure depends on the policy and strategy formulated at the Federal level and the cooperative efforts of industry, utilities, and Federal and State agencies. This report presents a framework for achieving this end.

UNITED STATES GENERAL ACCOUNTING OFFICE

EMD-80-7
APRIL 29, 1980

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COMPTROLLER GENERAL OF THE UNITED STATES
WASHINGTON, D.C. 20548

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To the President of the Senate and the
Speaker of the House of Representatives

This is a report on the role that cogeneration can play in our Nation's efforts to conserve valuable energy resources. The cogeneration of power and heat can be employed by both industry and utilities. Since these two sectors account for about half of the fuel consumed in the United States, their acceptance of this technology can assist in accomplishing the national goals of using fuels more efficiently and decreasing the use of imported fuels.

This study was undertaken because of indications that the private sector faces many constraints which limit the acceptance of cogeneration technology. Moreover, the Federal Government is one of the influential forces which can encourage greater acceptance of cogeneration. This report sets forth the characteristics of cogeneration, the factors involved in its application, and the policy option and strategy which we believe should be considered by Federal and State agencies to encourage greater cogeneration development. The report recognizes that cogeneration is very complex and interrelated with other issues such as economics, fuel availability, and environmental considerations.

The report will be useful to the Congress, the executive branch, State agencies, and private industries and utilities in working together to overcome the constraints that cogeneration faces. We are also aware that several Congressmen have expressed interest in the subject, and there is an indication that some are interested in moving forward with legislation in this area.

We are sending copies of this report to the Secretary of Energy; the Secretary of the Treasury; the Administrator of the Environmental Protection Agency; the Chairman of the Federal Energy Regulatory Commission; State agencies; private sector organizations; and to the chairmen of energy-related congressional committees.

Elmer B. Staats
Comptroller General
of the United States

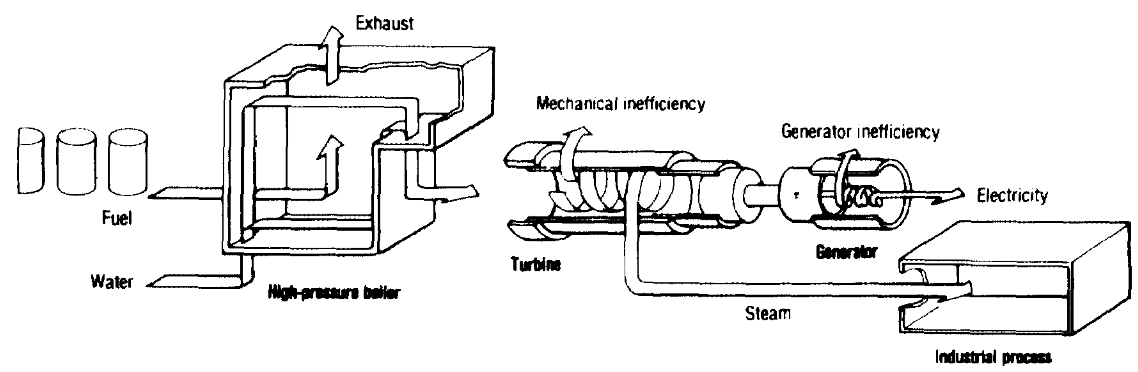
COMPTROLLER GENERAL'S
REPORT TO THE CONGRESS

INDUSTRIAL COGENERATION--WHAT IT IS, HOW IT WORKS, ITS POTENTIAL

D I G E S T

Cogeneration, the combined production of electrical or mechanical power and process heat, can contribute to this Nation's efforts to use fuel more efficiently.

Briefly, in a common cogeneration configuration, fuel is burned to produce high-temperature steam which is expanded through a turbine to generate electricity. After passing through the turbine, the reject steam is then used in industrial applications as process steam.



Because of the energy required to generate electricity, more fuel is consumed in a cogeneration system than in producing process steam alone. However, the total fuel required to produce both power and process steam in one system is less than the total fuel required to produce the same amount of power and steam in separate systems. Cogeneration systems and components must be selected for compatability with the industrial processes which they complement, necessitating selection on a site-by-site basis. (See ch. 2.)

POTENTIAL ROLE IN CONSERVING ENERGY

To determine the possible effects of various levels of cogeneration on our Nation's energy system, GAO analyzed four scenarios for the paper and pulp, chemical, and petroleum refining industries. The scenarios assumed cogeneration development from the status quo to the maximum amount technically possible and showed that the technology could be a valuable conservation measure.

The potential energy savings and the types of fuels which would be saved depend highly on Federal energy policies, the technology used, and the fuel use patterns within industry and utilities. Taking these factors into consideration, it would be reasonable to expect that, for the three industries, the equivalent of 228,000 to 354,000 barrels of crude oil per day would be saved in 1985. The maximum expectation of energy savings in the year 2000 would approximate 945,000 barrels of crude oil per day. (See chs. 3 and 4.)

Interest in cogeneration is increasing; however, there are many risks and uncertainties associated with its acceptance. These risks and uncertainties can be categorized as technical, economic, environmental, regulatory, and institutional. It will take a concerted, cooperative effort on the part of industry, utilities, and State and Federal Governments to settle or at least somehow deal with these issues, if cogeneration is to play a significant role in the Nation's energy conservation efforts. (See chs. 2 and 5.)

HOW TO FOSTER ITS DEVELOPMENT

A coherent Federal policy consistent with State and regional interests should be developed to encourage coal and other alternate fuel use for cogeneration with a controlled shift away from oil and natural gas. This policy should be consistent with the Powerplant and Industrial Fuel Use Act of 1978 which promotes the use of coal and other alternate fuels by major fuel-burning installations, but recognizes that oil and natural gas use may sometimes be desirable, such as with cogeneration applications.

A strategy for carrying out this policy would classify cogenerators by their size and type of fuel use. The objective would be to encourage coal and other alternate fuel based cogeneration by large facilities and provide for some of the freed up oil and natural gas from these facilities to be used for cogeneration by small and medium sized facilities that can only economically use oil or natural gas. By linking the fuel savings from large facilities to the oil and natural gas needs of smaller facilities, cogeneration, with State and regional fuel use monitoring, can be made more universally attractive without fear of increasing imported fuels.

A policy that permits oil and natural gas-based cogeneration in smaller facilities is particularly relevant for the short term, up to 1985. If small-scale coal or alternate fuel based cogeneration technologies become commercially available after the short term, as predicted, the policy could be revised accordingly. This approach would be consistent with the national objectives of decreasing overall energy consumption, burning fuels more efficiently, and decreasing our use of imported fuels.

The development of a policy and strategy that is consistent with State and regional interests must take into consideration several important attributes. It should:

--seek to balance oil and natural gas savings with overall energy savings;

--recognize regional differences regarding fuel use and fuel availability and ensure regional equity in benefits and costs;

--be based upon reasonable expectations of cogeneration development;

--balance Federal expenditures for financial incentives in support of cogeneration and expected national benefits from cogeneration; and

--be based upon the need to get all interested parties--industry, utilities, and Federal and State agencies--actively involved in the development of cogeneration. (See ch. 6.)

RECOMMENDATIONS

The Secretary of Energy should, in consultation with other interested parties:

--Establish a cogeneration policy and strategy as outlined above. This would provide a framework around which responsible bodies, such as the Economic Regulatory Administration and the Federal Energy Regulatory Commission, could promulgate rules and regulations to encourage cogeneration development. Among other things, the policy should encourage coal and alternate fuel use, but recognize that oil and natural gas use may be necessary for small and medium facilities in the short term. To implement this policy, cogenerators should be classified into user classes designated by fuel input rates and by fuel use requirements.

--Specify oil and natural gas use goals within overall energy conservation goals for cogeneration by 1985, 1990 and 2000. These goals should recognize the need for small and medium sized facilities to use oil and natural gas for cogeneration during the transition period to renewable resources, and consider the oil and natural gas savings expected from coal and other alternate fuel based cogeneration.

--Establish guidelines for monitoring oil and natural gas use goals for cogeneration. These guidelines should provide instruction to States for assessing the fuel use of each proposed cogeneration facility. The States could then determine the effects of cogeneration by user classes on State energy consumption. The guidelines should also provide for the Department of Energy regions to collect and aggregate the State energy consumption data. (See pp. 68 and 69.)

RULES AND REGULATIONS TO SUPPORT THE NATIONAL POLICY

The National Energy Act contains several provisions intended to foster cogeneration development. These provisions include authorization for exemption of cogenerators from prohibitions on the use of oil and natural gas, nondiscriminatory utility rates, exemption from public utility regulation, exemption from incremental natural gas pricing, and a possible additional 10-percent investment tax credit.

GAO's analyses indicate that while selective incentives can influence cogeneration's acceptance, the incremental amount of energy savings occurring as a result of these incentives is small. Considering the magnitude of energy savings, GAO believes that Federal expenditures to support cogeneration development should be balanced against the expected national benefits to be derived.

For example, the analyses indicate that tax credits would add to the economic attractiveness of cogeneration. However, a 10-percent tax credit for complete cogeneration systems would not, in itself, be sufficient to encourage general acceptance of cogeneration. Further, the Department of the Treasury has estimated that the 10-percent tax credit, if applied, would cost the Government about $500 million in revenues. Considering the cost, in comparrison to the small additional cogeneration resulting from this financial incentive, GAO believes that the Federal Government should concentrate on the other incentives, such as regulatory and institutional reforms, which are provided for in the National Energy Act.

A Federal policy, such as outlined above, can provide a framework for regulatory bodies to carry out the provisions of the act. The rules and regulations being developed by the Economic Regulatory Administration, the Federal Energy Regulatory Commission, and the Department of the Treasury to carry out the provisions of the act should be structured to support the national cogeneration policy. (See ch. 6.)

RECOMMENDATIONS

The Administrator of the Economic Regulatory Administration should:

--Establish a rule for industrial cogeneration facilities that will set a size limitation, in terms of a fuel input rate, on those facilities eligible for the cogeneration exemption, thus allowing oil and natural gas use by small and medium sized facilities. This rule should be based on the categories of user classes as designated by the Department of Energy in the cogeneration policy. The user classes would be required to use certain types of fuel according to size.

--Expand the cogeneration exemption, in accordance with the categories of user classes, to include also those petitioners with large facilities that cannot use coal or other alternate fuels. This exemption should give recognition to regional differences which include access to coal or alternate fuels and environmental problems. (See p. 69.)

The Commissioners of the Federal Energy Regulatory Commission should:

--Include, as part of their requirements for qualifying cogeneration facilities, a provision which requires industrial cogenerators to provide a means for maintaining fuel-efficient operations to the greatest extent possible. It is particularly important that this rule be made applicable to those industrial cogenerators who will obtain exemptions from the incremental natural gas pricing provisions of the Natural Gas Policy Act of 1978. (See p. 73.)

--Ensure that the rules adopted to establish just and reasonable rates for the sale of power to and the purchase of power from qualifying cogeneration facilities are fully implemented by State regulatory authorities and nonregulated electric utilities. (See p. 75.)

--Clarify the regulatory status of cogeneration facilities by (1) adopting their proposed rules which define a qualifying cogeneration facility as one which is not composed of more than 50 percent electric utility ownership and (2) ensuring that the rules which exempt qualifying facilities from certain Federal and State laws and regulations are properly implemented. (See p. 76.)

--Develop rules which specify, in terms of user classes, the exemption of qualifying cogeneration facilities from the incremental natural gas pricing provision. These rules should be consistent with the rules developed by the Economic Regulatory Administration for the exemption of cogenerators from the Powerplant and Industrial Fuel Use Act. (See p. 77.)

The Secretary of the Treasury should, in consultation with the Secretary of Energy:

--Establish, for the short term, a regulation which specifies that cogeneration systems would not be eligible for the 10-percent investment tax credit under the provision for specially defined property in the Energy Tax Act of 1978.

--Assess the impact and benefits that any Government financial incentives may have on cogeneration development before any such incentives are established for the long term. (See p. 79.)

OFFICE NEEDED TO OVERSEE COGENERATION ACTIVITIES

Because of the many issues affecting the acceptance of industrial cogeneration and the numerous organizations within both the public and private sectors that are involved in these issues, GAO believes an office should be designated within the Department of Energy to serve as an overseer and coordinator for all cogeneration-related activities. (See p. 80.)

RECOMMENDATION

The Secretary of Energy should designate one office to be responsible for overseeing cogeneration-related activities. It should also be responsible for identifying and assessing the efforts being made to eliminate cogeneration constraints. (See p. 82.)

AGENCY AND PRIVATE ORGANIZATION COMMENTS

A draft of this report was provided to the Department of Energy, the Federal Energy Regulatory Commission, the Department of the Treasury, the Environmental Protection Agency, and 12 private organizations and individuals for their review and comment.

The comments received indicated that, generally, the report reflects a comprehensive effort to address and analyze the complex issues affecting industrial cogeneration.

The Department of Energy felt that the policy and the implementing strategy to encourage cogeneration development are reasonable. However, the Department did not agree with all of our recommendations; for example, see pages 70 and 81. The Federal Energy Regulatory Commission staff stated that the report is a useful summary of cogeneration and its analysis of potential fuel consumption changes which could result from several scenarios is a significant addition to previously available information. The Commission felt that the report should be considered in its analysis of the complex issues involved in developing rules for implementing various provisions of the National Energy Act which pertain to cogeneration. In order to comply with the requirements for notice and comment of rulemaking, the Commission requested approval for the draft report to be placed in its public files and made available for public inspection. This request was approved.

Although the Treasury Department had no comment on the tax issue, the Department of Energy stated its preference for a tax credit. Of the six industries who commented on this issue, three favored a tax credit, while the remaining three agreed with GAO's position that a 10-percent tax credit would not encourage general acceptance of cogeneration.

GAO considered the comments and, where appropriate, made changes. Specific comments are also reflected throughout the report.

Contents

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ABBREVIATIONS

bbl/d	barrels per day
Btu	British thermal unit
DOE	Department of Energy
EPA	Environmental Protection Agency
ERA	Economic Regulatory Administration
FERC	Federal Energy Regulatory Commission
FPC	Federal Power Commission
GAO	General Accounting Office
kW	kilowatt
kWh	kilowatt-hour
MEMM	Midterm Energy Market Model
MW	megawatt
NEA	National Energy Act
PIES	Project Independence Evaluation System
QUAD	quadrillion British thermal units
RPA	Resource Planning Associates, Inc.
SIC	Standard Industrial Classification

GLOSSARY

available heat	The amount of heat produced in a combustion process--burning fuel mixed with air.
baseload	The minimum load in a power system over a given period of time.
British thermal unit (Btu)	The amount of heat energy necessary to raise the temperature of 1 pound of water by 1 degree Fahrenheit.
capacity	Maximum power output, expressed in kilowatts or megawatts.
demand	1. In an economic context, the quantity of a product that will be purchased at a given price at a particular point in time. 2. In a public utility context, the rate at which electric energy is delivered to or by a system, expressed in kilowatts, megawatts, or kilovoltamperes over any designated period.
fossil fuels	Coal, oil, natural gas, and other fuels originating from fossilized geologic deposits and depending on oxidation for release of energy.
generator (electric)	A mechanism which converts mechanical energy to electrical energy.
gigawatt	One million kilowatts.
grid	A network of conductors for distribution of electric power.
kilowatt (kW)	One thousand watts.

kilowatt-hour (kWh)	A common unit of electricity consumption representing the total energy developed by a power of 1 kilowatt applied for 1 hour.
load	The amount of electric power delivered to a given point on a system.
megawatt (MW)	A million watts or 1,000 kilowatts, and is used to measure the amount of electricity that can be produced by a facility at any one time.
peaking	Operation of generating facilities to meet maximum instantaneous electrical demands.
peaking capacity	Generating equipment normally operated only during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on a round-the-clock basis.
power	Either mechanical or electrical, generated by the combustion of fuels either under boilers to drive steam turbines or inside an engine such as a diesel or gas turbine.
process heat	Heat transferred from combustion gases applied either in direct contact with the material being transformed, as in ovens and kilns, or indirectly applied through a carrier medium, such as air or steam, as for drying purposes.
reject heat	The energy released after the conversion of energy into useful power or process heat.

thermodynamics	Physics that deals with relations between heat and mechanical energy, and the conversion of one into another.
turbine	An engine that converts energy in the form of heat and pressure into mechanical power of rotating motion.
waste heat	Reject heat which, because of its poor quality or for economic reasons, is not feasible for further use and becomes lost to the environment.

CHAPTER 1

INTRODUCTION

Electric utilities and private industry together consume about half of all the fuel used in the United States. Utilities account for 29 percent of the Nation's energy use, mainly through the combustion of fuels in central power stations generating electricity. Due to the laws of thermodynamics, even the most modern electric generating plant exhausts almost two-thirds of the available energy as low temperature heat. For the most part, this heat is not now productively used, and thus is considered waste heat. At the same time, about 13 percent of the Nation's fuel is consumed to produce industrial process steam. Although industrial energy conversion processes are more efficient, achieving 60 to 80 percent efficiency, they may not effectively use the high temperatures available with combustion. For example, industries can burn fuels exceeding temperatures of 3,000 degrees F for applications that require temperatures of around 400 degrees F. In 1975, waste heat from these two sources, electricity generation and process steam production, amounted to the energy equivalent of over 7 million barrels of oil a day.

One way to use this waste heat is through cogeneration--the combined production of power, either mechanical or electrical, and useful thermal energy such as process steam. Expressed differently, the reject heat of one process becomes the energy input into a subsequent process. The combining of these two normally separate processes through cogeneration is illustrated in figure 1-1. The figure compares conventional and cogeneration systems and their fuel use when producing equal amounts of electricity and industrial process steam. As illustrated, the conventional steam and electrical systems need more fuel than does a cogeneration system to produce the same amount of energy.

Historically, without reliable utility service, most industrial plants generated their own electricity and process steam, although not necessarily by cogeneration. In 1950 industrial generation provided 15 percent of the total U.S. electricity supply. In the last 20 years, however, increasingly efficient and reliable utility powerplants, coupled with the availability of relatively inexpensive oil and gas fired boilers for making industrial process steam, have kept steam production in industry and have shifted electricity generation to utilities. Currently, industrial generation provides only about 4 percent of the Nation's electricity.

Energy considerations have now changed. Industry and utilities are being strongly affected both by the scarcity of fuels and by rising energy prices. Because of its fuel savings potential and other benefits, interest in cogeneration as an energy conservation measure has been renewed. A number of Federal efforts have been directed at assessing and promoting cogeneration in industry. These efforts have included funding studies, 1/ promoting cogeneration through various National Energy Act (NEA) 2/ incentives, creation of an Interagency Cogeneration Task Force and a Department of Energy (DOE) Commercialization Task Force, and sponsoring cogeneration research, development, and demonstration projects.

The three major studies of cogeneration's potential undertaken by private contractors for the Federal Government agree that energy savings is only one of the benefits derived from cogeneration. Additional benefits cited include capital savings and environmental improvements. Capital savings occur because the incremental investment for electricity generation in cogeneration installations can be cheaper per kilowatt than the investment for central utility powerplants. Cogeneration installations achieve these savings through apportioning their capital costs between electricity and process heat. Consequently, the size of the capital savings depends upon how much future central utility generating capacity is replaced by cogenerated capacity.

Environmental improvements attributed to cogeneration result from the fact that, although a cogenerating industry will use more fuel than an industry producing only steam, emissions can be reduced because a cogeneration facility burns about half as much fuel in producing electricity as

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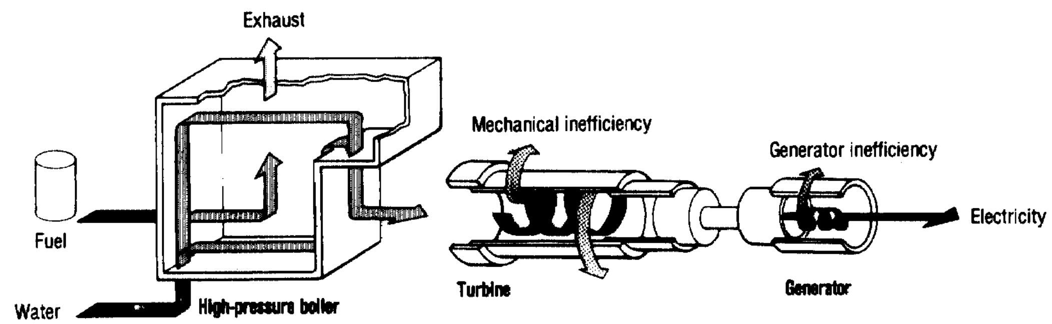
1/Energy Industrial Center Study, National Science Foundation-Dow Chemical Company, June 1975. A Study of Inplant Electric Power Generation in the Chemical, Petroleum Refining and Paper and Pulp Industries, Federal Energy Administration - Thermo Electron Corporation, 1976. The Potential for Cogeneration Development in Six Major Industries by 1985, Department of Energy - Resource Planning Associations, Inc., Dec. 1977.

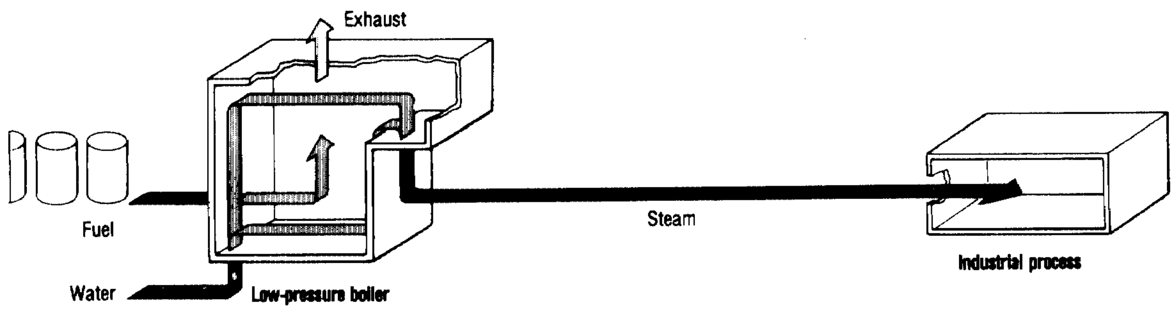
2/For the purposes of this report, the NEA refers to the Powerplant and Industrial Fuel Use Act of 1978, the Public Utility Regulatory Policies Act of 1978, the Natural Gas Policy Act of 1978, and the Energy Tax Act of 1978.

Figure 1-1
CONVENTIONAL ELECTRICAL AND PROCESS STEAM SYSTEMS COMPARED TO A COGENERATION SYSTEM

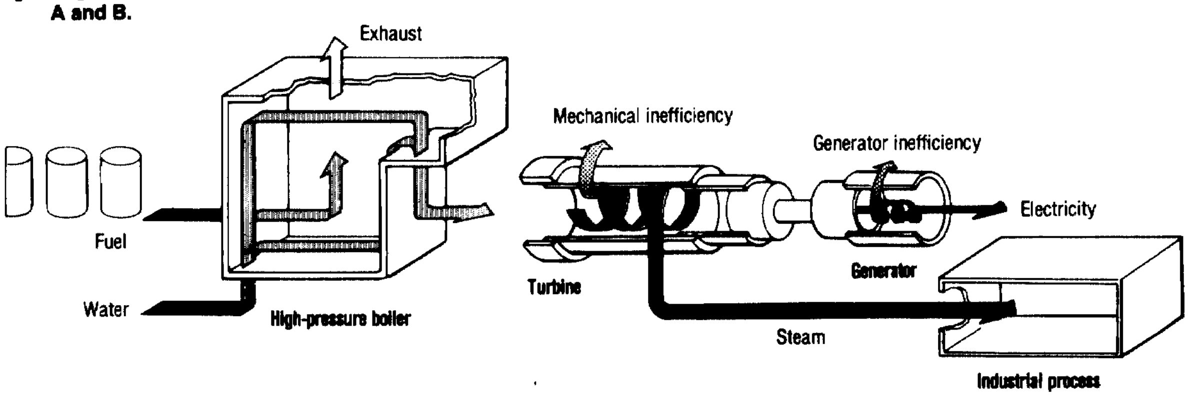
[A] Conventional electrical-generating system requires the equivalent of 1 barrel of oil to produce 600 kWh electricity.



[B] Conventional process-steam system requires the equivalent of 2¼ barrels of oil to produce 8,500 lbs of process steam.



[C] Cogeneration system requires the equivalent of 2¾ barrels of oil to generate the same amount of energy as systems A and B.



Source: Department of Energy-Resource Planning Associates, Inc. Cogeneration: Technical Concepts Trends Prospects, Sept. 1978

does an average central utility plant. Therefore, where industrial cogenerated electricity replaces central powerplant generated electricity, fewer emissions should be produced, even though the emissions' location will be changed. The benefits, impediments, and other issues which affect the acceptance of cogeneration by industry and utilities will be discussed in more detail throughout this report.

SCOPE OF REVIEW

To make an assessment of cogeneration's role in the Nation's conservation efforts, we identified the pertinent issues affecting the development and acceptance of cogeneration and conducted comparative analyses of the effects of various levels of cogeneration on the Nation's energy system. The following issues are addressed in this report:

--What are the technological advantages and disadvantages of cogeneration systems?

--How much energy savings can be achieved through cogeneration?

--What are the benefits and impediments to utility and/or industrial cogeneration?

--What efforts are underway to promote cogeneration, and are those efforts adequate?

We reviewed cogeneration studies, literature, and related information and had discussions with representatives of the chemical, paper and pulp, aluminum, steel, and refining industries, industry trade organizations, electric utility companies, utility trade associations, researchers, and a cogeneration equipment manufacturer. We discussed cogeneration issues with the Department of Energy, Environmental Protection Agency (EPA), Federal Energy Regulatory Commission (FERC), Department of Treasury, and State Government representatives. A list of those contacted during our study is in appendix VI.

A draft of this report was provided to the above 4 Federal agencies and to 12 private sector organizations and individuals for review and comment. The comments received were considered and, where appropriate, changes have been made and specific comments are reflected in this report. The comments received from DOE, EPA, FERC, and Treasury are included in appendixes VII thru X.

CHAPTER 2

HOW COGENERATION WORKS

Utilities and industries burn nonrenewable fossil fuels to meet their energy needs. Combining utility power generation and industrial process heat production at one site can more than double the fuel efficiency of electric power generation. Cogeneration does just that, burning fuels to generate either electricity or mechanical shaft power along with process heat. Technologies are available and are in use for cogenerating at either individual industrial sites or at central utility powerplants. This chapter describes cogeneration technologies and discusses their application to industrial and central powerplant systems. A more detailed discussion of the technical aspects of cogeneration is contained in appendix II.

COGENERATION TECHNOLOGY

Cogeneration systems, using currently available technology, incorporate either a "bottoming cycle" or a "topping cycle" configuration. These terms refer to the point in the cogeneration system at which the electrical or mechanical energy is produced.

Bottoming cycle cogeneration

In a "bottoming cycle" configuration, fuel is burned initially to produce process heat, with the reject heat used to generate either electrical or mechanical power. However, industrial process heat requirements are usually too low (400 degrees F or lower) for the reject heat to be effectively utilized in power generation. Although technology may overcome this problem, at this time no complete, reliable, and problem-free system exists. Therefore, apart from occasional installations the bottoming cycle will not have a major impact upon industrial fossil fuel demand within the next 8 to 10 years. In view of the limited potential applications for this configuration, it was not used in our analyses.

Topping cycle cogeneration

In a "topping cycle" configuration, fuel is burned to produce high-temperature heat, which is expanded through a turbine to generate electrical or mechanical power. After passing through the turbine, the reject heat is then used in industrial applications as process heat. Because of the energy required to generate the electrical or mechanical power, more fuel is consumed in a cogeneration system than in producing process heat alone. However, the total fuel required to produce both power and process heat in one system is less than the fuel required to produce power and heat in separate systems. For example, the overall efficiency of a steam turbine topping cycle cogeneration system is about 79 percent compared with the combined efficiency of about 58 percent for two separate systems.

Topping cycle cogeneration systems are of two types: (1) fuel can be burned in either a gas turbine or a diesel engine directly producing electrical or mechanical power, with the exhaust used to provide process heat or, with the addition of a heat recovery boiler, process steam; or (2) fuel can be burned initially to produce high-pressure steam which is then passed through a steam turbine to produce power, with the exhaust used to provide process steam. Diagram illustrations of these commercially available topping cycle cogeneration systems are shown in figure 2-1.

Cogeneration systems and components must be selected for compatibility with the industrial processes which they complement, necessitating selection on a site-by-site basis. The more important distinguishing features of these alternative systems are the fuels that can be used, the capital investment required, the efficiency in converting fuel to electricity, the electricity produced per unit of steam generated, and the resulting effects on the environment. The advantages and disadvantages of these distinguishing features in topping cycle cogeneration systems are outlined in table 2-1.

As the table indicates, the steam turbine is the only commercially available cogeneration system that can use coal for fuel. However, using coal instead of liquid or gaseous fuel in a steam cogeneration system increases capital costs and could result in making the system uneconomical. As a result, coal-fired steam turbines are usually considered only for large cogeneration applications where economies of scale are possible.

INDUSTRIAL AND UTILITY COGENERATION SYSTEMS

The major difference between industrial and utility cogeneration is which output drives the system. Cogeneration systems can be designed for process steam requirements, with

Table 2-1
Distinguishing Features of Topping Cycle
Cogeneration Systems

	System		
Distinguishing features	Gas turbine	Diesel engine	Steam turbine
1. Type of fuel used	#2 light distillate oil or natural gas	Oil or gas	All types of fuel including coal
Advantage			Supports NEA conversion to coal objective
Disadvantage	Conflicts with NEA conversion to coal objective	Conflicts with NEA conversion to coal objective	
2. Capital investment required 1/	$500 per kW	$550 per kW	$1,250 per kW for coal 875 per kW for oil
Advantage	Low cost	Low cost	
Disadvantage			High cost
3. Efficiency in converting fuel to electricity 2/	5,500 Btu's per kWh	7,000 Btu's per kWh	4,500 Btu's per kWh
Advantage 3/			
Disadvantage 3/			
4. Electricity produced per unit of steam generated 2/	200 kWh per million Btu's of steam	400 kWh per million Btu's of steam	50 kWh per million Btu's of steam
Advantage 4/			
Disadvantage 4/			
5. Environmental effects	Gas produces little pollution	High nitrogen oxide and carbon monoxide emissions	High sulfur dioxide and particulate pollution with some coals
Advantage	No pollution control equipment needed		
Disadvantage		Exhaust may not meet purity requirements of some process heat applications	Expensive pollution control devices needed

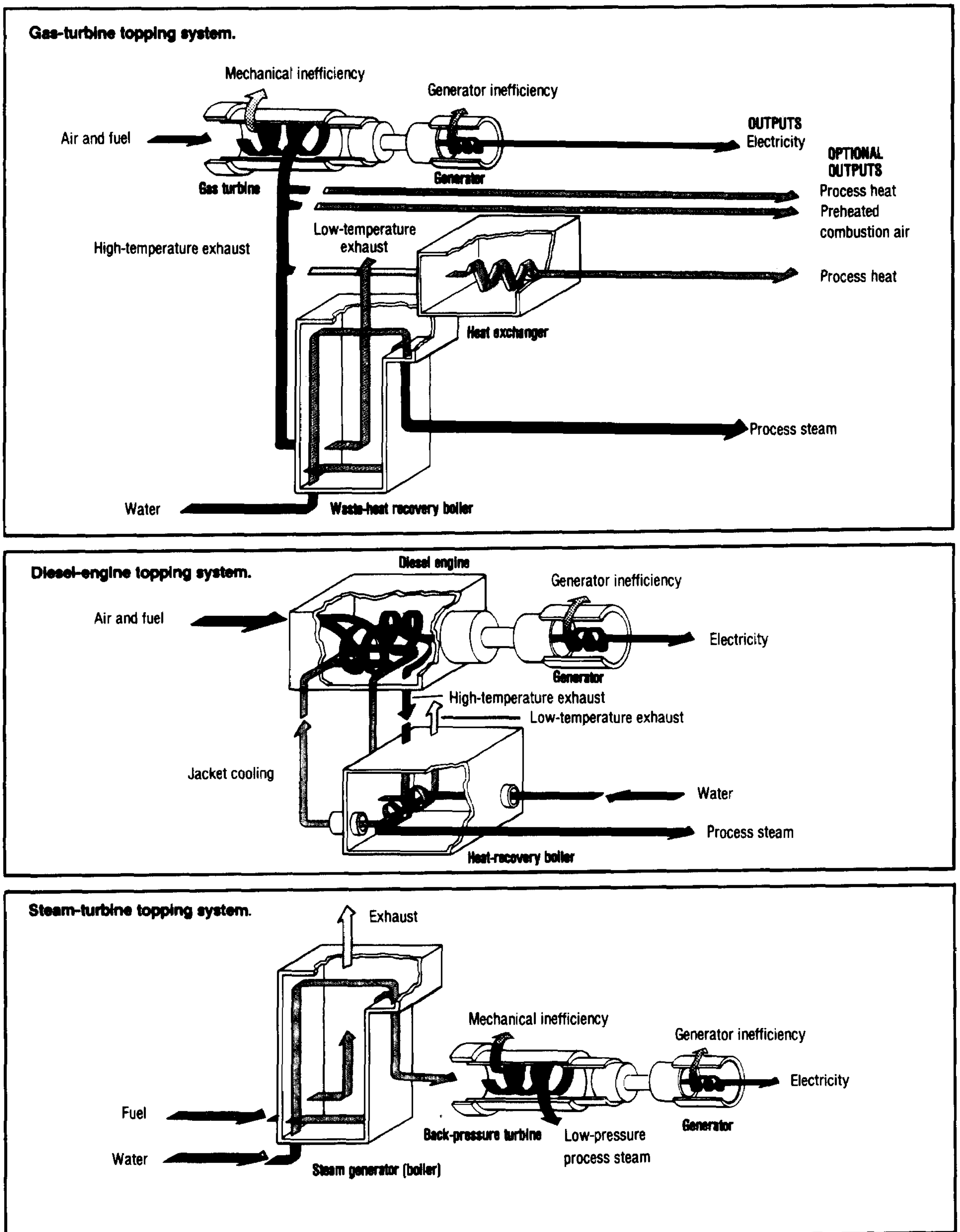
1/ Total installed costs assuming 5-MW capacity.

2/ Federal Energy Administration and Thermal Electron Corporation, A Study of Inplant Electric Power Generation in the Chemical, Petroleum Refining and Paper and Pulp Industries. Final Report, 1976. p.2-1.

3/ While steam and gas turbines are more efficient than diesel engines, their fuel efficiency cannot be universally considered an advantage. For example, in situations with large electricity to steam demands, the diesel, although less efficient, would be the most advantageous to the cogenerator.

4/ Whether the amount of electricity produced is an advantage or disadvantage depends on the cogenerator's needs.

Figure 2-1
DIAGRAM ILLUSTRATIONS OF
TOPPING CYCLE COGENERATION SYSTEMS



Source: Department of Energy-Resource Planning Associates, Inc. Cogeneration: Technical Concepts Trends Prospects, Sept. 1978

electrical production as a secondary consideration, or their design can be reversed, with electrical power as the primary requirement. Although we distinguish between these two systems by referring to them as industrial and utility cogeneration systems respectively, our terms do not necessarily denote ownership. For example, the systems may be jointly owned or utility owned at industrial complexes. The characteristics and considerations of industrial and utility cogeneration are discussed below.

Industrial cogeneration

Most industrial process steam is produced through direct combustion of fossil fuels. Direct combustion results in available heat reaching temperatures as high as 3,600 degrees F. Most industrial processes, however, require steam at much lower temperatures, less than 400 degrees F. Thus, burning fuels to produce only low-temperature process steam is an inefficient use of energy. Substantial fuel savings can be achieved if the high-temperature energy available from combustion is first used to generate power, and then the reject heat, ranging from 200 to 1,000 degrees F depending on the types of fuel and systems involved, is used for industrial process heat applications.

Industrial cogeneration systems are usually located near or within the facility with the process steam serving only one company. The cogeneration equipment generally is operated to meet process heat requirements with electrical production as a secondary consideration. While this permits the systems to operate at optimal efficiency, it may not provide enough electricity for self-sufficiency. The electric utility company serving the industrial site then provides standby electricity when the cogeneration system is unable to generate the required electric power. Conversely, an industrial plant with a large steam demand could install a cogeneration system capable of meeting or even exceeding the plant's electricity needs. In this situation, excess electricity could be sold to the utility. An industry can operate independently from utilities. However, the system requires sufficient backup equipment or over-capacity to ensure reliability. The problems and workability of selling cogenerated power to utilities are discussed in chapters 5 and 6 of this report.

In 1978, industry generated about 80 million megawatthours, or about 4 percent of the Nation's electricity. How much of this electricity was associated with cogeneration is not known; however, estimates of industrial cogeneration capacity in 1977 varied between 4,000 and 11,000 megawatts (MW). 1/ Today, cogeneration is practiced primarily in the paper, steel, petroleum, and chemical industries. The Dow Chemical Company, for example, stated in September 1977 that as the Nation's largest cogenerator, the company saved the equivalent of 17 million barrels of oil per year due to cogeneration efficiency. Dow reportedly generates 80 percent of its own power needs, about two-thirds of it through cogeneration. Dow's commitment to cogeneration dates back many years to when cogeneration was common in U.S. industry.

There are many factors affecting the economic acceptance of industrial cogeneration facilities. 2/ These factors include (1) the size of the installation (unit capital costs diminish as the system's capacity increases), (2) the variability of the steam demand (the most favorable arrangement usually occurs where there is a steady demand for steam, so that the electrical generating capacity can be utilized a large part of the time), (3) whether new steam generating equipment is needed or not, (4) the cost of electric power from alternative sources, (5) the technology chosen, (6) the cost of fuel, (7) the cost of pollution controls, (8) the cost of operation and maintenance, and (9) the competence of the technical personnel charged with operating the facility. Further discussion of some of these factors is included in chapter 5.

Utility cogeneration

With utility cogeneration, fuel savings are possible by supplying steam to industry from central station powerplants. Electric utilities burn fuel in boilers to make high-temperature steam. The steam then flows through a turbine which drives a generator and produces electricity. The exhaust or reject heat is then discharged to the environment through cooling towers or by heating water in rivers or stationary ponds. However, the fuel use efficiency for electrical generation can be increased if the reject heat is used by nearby industries in manufacturing processes.

1/Department of Energy, Unpublished Internal Draft Study of Cogeneration, Washington, D.C., p. 7. "Saving Energy the Cogeneration Way," Business Week, June 6, 1977, p. 99.

2/Robert W. Williams, Industrial Cogeneration, Center for Environmental Studies Report No.66, Princeton University, Princeton, N.J., May 1978, p. 19.

Central powerplant cogeneration overcomes many of the technical factors constraining industrial cogeneration because of the large boilers available and the ability to manage steam and electricity demand. However, utility cogeneration has its own unique problems. For example, central power plants must be located near the industries requiring the steam because steam can be piped economically only short distances. In the ideal situation, a utility is located in the center of a cluster of industries. However, space for siting central powerplants in proximity to industrial plants may be difficult to find. In addition, siting such plants near industrial complexes could aggravate existing environmental problems, resulting in unacceptable air or water quality deterioration.

Although central powerplant cogeneration is not common, a number of such plants are in operation today. One of the oldest and largest in the United States is the Gulf States Utilities Company plant located in the center of a petrochemical complex near Baton Rouge, Louisiana. Since 1929 the plant has produced steam and electric power for Exxon and Ethyl Corporations. The plant was designed to meet the companies' industrial process steam requirements, approximately 3 million pounds per hour. As a result, about 160 MW of electric power are produced. Since the electrical load in the area is over 300 MW, additional power must be brought from the Gulf States Utilities grid into the complex. The sale of cogenerated power under separate contracts with private corporations by the plant, which is wholly owned by Gulf States Utilities, is not subject to State utility regulation. The nonregulated status of such sales was tested and upheld by the Louisiana Supreme Court in 1952. A discussion of the impact of regulatory issues on cogeneration potential is included in chapter 5.

NEW COGENERATION TECHNOLOGY

New advanced technologies can contribute to conservation through cogeneration. A promising new combustion system, using fluidized-bed technology, 1/ is presently under

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1/Fluidized-bed technology has the capability of making coal use an economic alternative to oil or natural gas use. This technology eliminates the need for expensive pollution control equipment by removing sulfur pollutants during the combustion process. Fluidized-bed boilers are also much smaller than conventional coal-fired steam generators. With these and other advantages, fluidized-bed technology can facilitate coal conversion.

demonstration and may be commercially available in the 1980s. A number of industrial applications of this technology have already been successfully tried in Europe. Fluidized-bed combustion technology could lead to a clean-burning process for converting coal, as well as other low-grade fuels, to electricity. This new technology can be readily integrated into steam turbine and gas turbine cogeneration systems. The arrival of reasonably priced, reliable fluidized-bed boilers, with the customary performance guarantees by the manufacturer, should provide a strong incentive to some industries to seriously consider cogeneration together with a shift to coal.

Another technology involves combined cycle configurations. In a standard arrangement, as illustrated in appendix I, fuel is burned in a gas turbine producing electrical or mechanical power. The gas turbine exhaust then passes through a heat-recovery boiler producing steam for use in a steam turbine supplying both power and process steam. One of the attractions of this system is that the gas turbine can be retrofitted to existing plants. However, the system is limited in that all energy has to be supplied by a fuel suitable for gas turbine consumption, either natural gas or a light distillate.

Combined cycle operations have been deployed for power production in central station utilities for a considerable time. Although many of these utilities were designed for power production only, they could lend themselves to cogeneration applications. Where power and steam demands are high enough, such as in the chemical industry, industrial applications may also be attractive.

Other advanced technologies under development but unlikely to effectively contribute before the end of the century to the use of reject heat include closed cycle (external combustion) gas turbines, stirling engines, and fuel cells.

A similar situation prevails with using heat pumps to create process heat by the "upgrading" of low-grade reject heat. Large heat pumps are used for heating and hot water services in Europe based on low-grade reject heat. In general, most industrial processes require process steam of a higher energy content than that required for simple heating purposes. Units to raise process steam to these levels are not commercially available.

CHAPTER 3

POTENTIAL CONTRIBUTION OF COGENERATION AT THE NATIONAL LEVEL IN 1985

What are the possible effects of various levels of cogeneration on our Nation's energy system? In striving to answer this question, we analyzed four scenarios for the paper and pulp, chemical, and petroleum refining industries. The scenarios assume cogeneration development from the status quo to the maximum amount technically possible. Our analyses show that, for the three industries, the implementation of cogeneration could save from .26 to 1.5 quadrillion Btu's (QUADs) of energy or about 123,000 to 719,000 barrels per day (bbl/d) of crude oil equivalent in the year 1985. The attainment of these energy savings and the types of fuels saved are highly dependent on Federal energy policies, the technologies used, the fuel costs, and the fuel use patterns assumed within the industrial and utility sectors. Taking these factors into consideration our analyses show that the most reasonable and likely attainment of energy savings from cogeneration in the year 1985 could be .48 to .75 QUADs or about 228,000 to 354,000 bbl/d of crude oil equivalent.

The types of fuels saved within each scenario varied based on the fuel use patterns assumed for the industrial and utility sectors. Based on historical fuel use patterns, natural gas savings occur in every scenario. Using DOE's econometric model, which forecasts utility and industrial fuel use patterns in 1985, coal and natural gas savings occur in every scenario. In our most likely and reasonable scenario of cogeneration development, the fuel savings occur primarily in natural gas using historical fuel use patterns and oil using forecasted fuel use patterns.

The utility sector could be most affected by growth in cogeneration. Electrical generation declines with increased levels of cogeneration from .5 to as much as 14.8 percent. This decline in generating capacity by the utility sector could result in cumulative capital cost savings from investment in new plants and equipment. Capital cost savings in utility powerplant investments could range from $1.4 billion to $21.6 billion. However, the utility capital cost savings would be offset by the industrial expenditures required for investment in cogeneration equipment.

The above findings and the analytical approach used to arrive at them are discussed in this chapter.

METHODOLOGY, ASSUMPTIONS, AND ANALYTICAL CONSIDERATIONS

The analyses focused on the interaction between energy policy and the implementation of cogeneration technology in determining associated fuel shifts. Government actions which could conceivably assist in implementing cogeneration as a measure for conserving valuable fossil fuels within the 1985 time frame were considered. To maintain some degree of certainty, the analyses were limited to those cogeneration topping cycle configurations which we believe are going to make a sizable contribution towards reducing the national demand for fossil fuels by 1985. This means that the cogeneration technology must be (1) fully proven and commercially available with all warranties, (2) economically attractive in capital and direct costs, and (3) introduced into those industries most likely to implement cogeneration on a scale which makes a significant contribution.

Scenario description

Cogeneration scenarios were developed to (1) establish a realistic national impact, an upper economic limit, and an upper technical limit for cogeneration showing the amount of electricity produced and the resultant fuel shifts in industry and utilities, (2) provide input for econometric models to determine the interaction of different levels of cogeneration with associated fuel shifts, prices and other economic forces, and (3) provide input data for case studies to investigate and illuminate whether such fuel shifts are likely to occur, taking into account the regulatory situations and actual supply and demand patterns at State levels. Each scenario contains cogeneration development by 1985.

The following four scenarios were developed for the paper and pulp, the chemical, and the petroleum refining industries:

1. A no action case assumes that some cogeneration will develop under the status quo without Government incentives or further disincentives. This case assumes the lowest level of cogeneration. Process steam requirements and cogenerated electricity are deemed as economically attractive without tax credits or other incentives. Industries will cogenerate using a composite of coal and residual oil-fired steam turbines, gas and distillate oil-fired gas tubines, and waste fuel and heat recovery steam turbines. This technology mix is assumed to prevail nationwide within each State.

2. An incentives case includes the additional cogeneration resulting from selected Government incentives. This case, with the same type of technology mix as the no action case, increases the amount of cogeneration assuming the existence of the following incentives: a 30-percent investment tax credit for cogeneration equipment, marginal cost pricing of electricity (rate reform), and exemption from Federal Energy Regulatory Commission and Public Utility Commission regulations. The 30-percent investment tax credit consists of an existing 10-percent general investment tax credit with an additional 20-percent for cogeneration.

   Rate reform standards which are established by the Public Utility Regulatory Policies Act of 1978 (Public Law 95-617, Nov. 9, 1978) could be very influential for cogeneration development if adopted by State regulatory authorities or nonregulated electric utilities. However, at the time of our assessment the type of reform to be adopted, if any, was unknown. Thus, we chose to analyze the most dramatic case, namely marginal cost pricing of electricity. The net effect of marginal cost pricing is an average 20-percent rise in industrial electricity rates thereby making cogeneration more economically attractive.

   The exemption of qualifying cogeneration facilities from the Federal Power Act, the Public Utility Holding Company Act, and from State utility laws and regulations is authorized by the Public Utility Regulatory Policies Act of 1978. This exemption should increase the economic attractiveness of cogeneration by alleviating statutory and regulatory constraints.

3. An economic maximum case was developed to provide maximum electricity production under economic conditions. This case assumes that the same process steam produced with fossil fuels in the incentives case will be exclusively produced with exhaust boilers fed only by gas turbines. The gas turbines are fired exclusively by light distillates assuming that the use of natural gas for power generation will be prohibited or of a very low priority in curtailment situations. The steam turbine has not been considered because of its low power-to-steam ratio, while the diesel with its excellent ratio has been

excluded because of its limitations in producing industrial process steam. Process steam cogenerated by waste fuel and heat recovery steam turbines remains unchanged.

4. A technical maximum case addresses the maximum cogeneration technically possible by assuming the cogeneration of all steam identified as technically suitable. Ignoring all economic conditions, we set an upper boundary on the amount of cogenerated electric power that anyone could expect to achieve from the three industries selected. This case assumes that the best possible environment exists for cogeneration development, possibly even a mandatory requirement. Like the economic maximum case, the light distillate fired gas turbine is assumed to be the exclusive cogeneration system. The gas turbine was selected for the two high cogeneration scenarios because it is more easily adaptable for industrial use, and only takes 1-1/2 to 3 years to be operational depending on size.

The national estimates of cogenerated steam and electricity used in our scenarios are based upon a Resource Planning Associates, Inc. (RPA) study, "The Potential for Cogeneration Development in Six Major Industries by 1985." RPA developed its estimates of cogeneration potential using actual industry decisionmaking factors. The following table shows the process steam and electric power estimates for the four scenarios. Detailed information is contained in appendix III, tables III-1 to III-4.

Table 3-1
Amount of Steam and Electricity (note a)
Cogeneration Nationwide
in 1985 by the
Paper and Pulp, Chemical, and Petroleum Refining Industries

	No action case	Incentives case	Economic maximum case (note b)	Technical maximum case
Paper and pulp				
Steam	276.20	313.60	313.60	1059.0
Electricity	38.33	45.00	93.92	211.8
Chemical				
Steam	351.70	443.90	443.90	1396.0
Electricity	21.12	26.78	92.53	279.2
Petroleum refining				
Steam	55.30	81.80	81.80	454.0
Electricity	6.02	10.13	22.61	90.8
Total				
Steam	683.20	839.30	839.30	2909.0
Electricity	65.47	81.91	209.06	581.8

a/Steam figures are in trillion Btu's.
Electricity figures are in billion kWhs.

b/The incentives and the economic maximum cases have the same steam estimates deemed as economically suitable for cogeneration. The difference in electricity estimates occurs because the economic maximum case provides maximum electric power production by assuming that the same steam cogenerates more electrical power using the gas turbine.

Three industrial representatives expressed concern with the above estimates. They felt that the levels of cogenerated electricity were overstated because the amount of steam projected as available for cogeneration was too large. Their concern centered on two points: mechanical shaft power was ignored and growth rates were too high.

The chemical and petroleum trade associations stated that we ignored existing mechanical shaft power, and as such, much of the industrial steam assumed available for new cogeneration may already be used to run equipment such as pumps and compressors. This assertion is not correct; mechanical shaft power was considered in our analyses. In developing the 1985 steam projections, several adjustments were made to account for the steam not suitable for cogeneration. These adjustments included excluding the steam used for existing cogeneration and the steam used for driving condensing and noncondensing turbines, both of which provide mechanical and/or electrical power.

The third representative questioned whether present and anticipated low growth rates for industry will allow the projected cogeneration levels to be attained. At the time of our analyses, we evaluated several projections of cogenerated steam in 1985. We concluded that RPA's forecast was the best available for the purposes of our analyses.

Assumptions and analytical considerations

The fuel shifts in each scenario were computed from the amount of process steam and electricity produced by cogeneration technologies in the three industries. Our analyses considered only topping cycle configurations of currently available technology for cogeneration. We determined that cogeneration would be most economically feasible for boilers with at least 100,000 lbs. per hr. steam capacity. A steam turbine topping cycle configuration of this size will barely command a return on investment in the vicinity of 9 to 10 percent. 1/ A configuration's feasibility in terms of return will increase as capital costs are reduced and efficiencies are improved, such as with economies of scale for larger cogeneration plants. Conversely, a great deal of cogeneration cannot be expected in plants with less than 100,000 lbs. per hr. steam capacity when the return on investment would be less than 10 percent. However, depending on steam conditions, plants with smaller steam needs may be built where local conditions favor cogeneration even at such a low rate of return on investment.

Having established the economic feasibility of cogeneration at 100,000 lbs. per hr., we assessed the actual steam output by industry on the basis of installed boiler capacity for six industries. 2/ In determining the percentage of boiler capacity suitable for cogeneration, we limited our analyses to those boilers installed during the last 12 years. This boundary was established because many boilers which have been idle or retired are still carried on company inventories.

1/Resource Planning Associates, Inc., The Potential for Cogeneration Development in Six Major Industries by 1985, Cambridge, Massachusetts, Dec. 1977. National Science Foundation-Dow Chemical Company et al., Energy Industrial Center Study, June 1975, p. 75.

2/Paper and Pulp, Chemical, Petroleum Refining, Food, Textile, and Steel Industries.

These boilers may be unsuitable to support a cogeneration unit due to either their very small load factor or their inability to produce the high pressures required.

The paper and pulp, chemical, and petroleum refining industries are the ones with the largest percentage of boiler capacity to support a cogeneration unit. (See app. III, table III-12.) The concentration of boiler capacity in these three industries, and the fact that they account for 80 percent of the economically suitable steam for cogeneration, led us to restrict our analyses to these three industries to establish a measure for the impact of cogeneration.

In all scenarios, industrial and utility fuel shifts resulting from cogeneration were computed on a regional basis, based upon RPA's 1985 process steam projections for the three selected industries. In computing industrial fuel use, the cogeneration systems implemented determined the types of fuels used. The fuel savings from cogeneration were computed assuming that the amount of cogenerated steam and electricity would replace equal amounts of industrial process steam and utility electricity generation.

We estimated fuel savings from cogeneration using two major assumptions in the fuel use patterns of industry and utilities. These assumptions are that (1) 1975-76 historical fuel use patterns would prevail through 1985 and (2) fuel use patterns would evolve as forecasted by DOE's Midterm Energy Market Model (MEMM). 1/ The use of these two assumptions enabled us to test the validity of our scenarios and obtain a broad perspective of the types of fuel that could be saved through cogeneration. Comparing the scenario results using both assumptions showed that the total energy savings were very similar at each scenario level; however, the types of fuel to be saved varied.

COGENERATION CAN BE USED TO CONSERVE ENERGY IN THE NEAR TERM

Our four scenarios of cogeneration development for the three industries show that energy savings of fossil fuels will occur in the utility and industrial sectors in 1985. Utilities could save approximately .09 to 1.55 QUADs in oil, and .13 to 1.86 QUADs in coal. Although the industrial sector would use additional fuel to cogenerate, industry still

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1/DOE's econometric model previously was named the Project Independence Evaluation System.

would show natural gas savings ranging from .03 to .8 QUADs. The ranges and variations in fuel savings from cogeneration and their related effect on the national energy system are discussed below.

Using historical fuel use patterns, natural gas savings occur in every scenario

Three scenarios--the no action case, the incentives case, 1/ and the economic maximum case--were analyzed for the three industries using historical fuel use patterns. 2/ Our analyses indicate that cogeneration, when considering displacement of utility-generated power by industrial cogenerated electric power, can contribute national net energy savings of as much as 540,000 bbl/d of crude oil equivalent. In all cases, the largest net fuel savings occur in natural gas, ranging from approximately .58 to 1.28 QUADs in 1985. In the incentives case, which to us represents the most reasonable expectation for cogeneration in 1985, net energy savings of about .75 QUADs, or 354,000 bbl/d of crude oil equivalent, could be achieved, with the largest savings occurring in natural gas. The results of these analyses are discussed below and summarized in table 3-2.

The fuel shifts in industry are the net changes in industrial consumption composed of the differences between the fuel saved under boilers to generate process steam only and the fuel used to cogenerate. In the no action case and the incentives case there is a positive shift to coal resulting from the use of coal-fired steam turbines and a decrease in the use of natural gas and distillate oil. This positive use of coal would be in accordance with NEA legislation to promote alternate fuels. In the economic maximum case the consumption of distillate fuel oil increases because of the exclusive use of gas turbines to cogenerate. Industry use of other fuels, therefore, declines.

Energy savings in coal, oil, and gas occur in the utility sector due to cogeneration in all three scenarios. These savings in the utility sector are attributed to the decrease in utility generation which is now supplied by industrial cogen-

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1/The steam and cogenerated electric power estimates for the incentives case in these analyses include only one incentive, a 30-percent investment tax credit.

2/The technical maximum case was excluded because of the unlikely expectation of achieving this level of cogeneration by 1985.

erated electric power. In all three cases the largest shift in utility consumption occurs in coal, the most significant amount appearing in the economic maximum case. These results are based on the fact that utility coal consumption amounts to approximately 60 percent of total fossil fuels consumed. While utilities save mostly coal, oil savings in the two lower cases, the no action and incentives cases, are large enough to more than offset any increase in oil used by industry to cogenerate. Although this report discusses the effects of cogeneration on a national basis, we recognize that regional fuel shifts will vary. These variations are caused by the amounts and types of cogeneration implemented and regional fuel usage. Appendix III illustrates these regional differences.

Table 3-2
The Effects of Cogeneration in 1985
Summary of National Fuel Consumption
Using Historical Fuel Distribution Patterns
for Three Industries

	No action case	Incentives case	Economic maximum case
Amount of cogeneration:			
Electricity (billion kWhs)	65.47	81.91	209.06
Steam (trillion Btu's)	683.2	839.3	839.3
	QUADs (note a)		
Industrial fuel shift			
Distillate oil	0	0	+1.89
Residual oil	+.09	+.11	-.17
Coal	+.36	+.48	-.20
Gas	-.39	-.51	-.58
Utility fuel shift:			
Oil (note b)	-.16	-.19	-.47
Coal	-.31	-.37	-.92
Gas	-.19	-.25	-.70
Net fuel shift			
Oil	-.07	-.09	+1.25
Coal	+.05	+.10	-1.12
Gas	-.58	-.76	-1.28
Net energy shift:			
QUADs	-.60	-.75	-1.14
bbl/d crude oil equivalent	-282,000	-354,000	-540,000

a/Numbers may not add due to rounding.

b/No distinction can be made between residual and light distillate oils for utilities; no data were available for the utilities breaking the fuel oil down into these two categories.

Using forecasted fuel use patterns, coal and natural gas savings occur in every scenario

The previous analyses focused on the fuel shifts that would occur due to cogeneration in the three industries using a historical fuel mix. As a further step in evaluating cogeneration as an energy conservation measure, the same scenarios were evaluated using forecasted fuel distribution patterns for 1985 as contained in DOE's econometric model. Our analyses indicate that cogeneration can contribute net energy savings of as much as 719,000 bbl/d of crude oil equivalent in 1985. In all cases, net fuel savings occurred in coal, ranging from approximately .08 to 2.97 QUADs. Natural gas savings also occurred in every scenario ranging from .05 to 1.53 QUADs. In the incentives case, net energy savings of about .48 QUADs or 228,000 bbl/d of crude oil equivalent could be achieved, with the largest savings occurring in oil.

The model, MEMM, 1/ considers those economic supply and demand factors that would have a bearing on the impact of cogeneration, enabling us to assess the effects of various levels of cogeneration on fuel consumption, utility generation and capacity, utility capital cost savings, and national fuel prices. The model assumes a level of cogeneration in 1985. For the three industries evaluated we estimated 2/ that level to be 46.75 billion kWhs. Since this level of cogeneration is

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1/The model consists of three main segments. The supply model, subdivided into specific fuel models, such as oil and gas, and electricity, is a linear programming model which shows the prices at which the energy market would be willing to produce and deliver specific fuel quantities. The demand model is an econometric model which predicts regional demands for the various fuels as functions of relative fuel prices and general economic conditions. The third segment of MEMM is the integrating model which takes the demands for fuels from the demand model and fulfills them in a least cost fashion from the supply model. The integrating model determines the energy market conditions which must be satisfied by demand and supply, and controls the process by which a market equilibrium is reached. The point of equilibrium is reached when prices at which producers are willing to supply fuel are identical to the prices which generated the demands.

2/A detailed assessment of this estimate can be found in appendix IV.

implicit in the MEMM base forecast, our estimates of changes in cogeneration levels are adjusted from this base.

Each of the cogeneration levels was introduced to the model as a decline in the industrial demand for electricity, an increase in the demand for the fuels used to cogenerate, and a decrease in the fuels which had previously been burned under boilers to generate process steam. The fuel mix used to generate process steam is different than the fuel mix used for cogeneration. Since cogeneration requires continuous use in order to be economically feasible, we assumed that all declines in industrial electricity demand would come from baseload utility generation.

Based on these inputs, the model provided simulations of predicted changes in national energy demands and supplies. In all four of our scenarios energy savings occurred consistently in coal and natural gas. More specifically, in the two lower cases the net energy savings come mainly in the form of reductions in petroleum, coal, and some natural gas. The reductions in petroleum use are reflected in small reductions in imported oil. While reductions in petroleum demand and imports are one of the desirable goals of the national energy policy, reductions in the demand for coal, our most abundant resource, could be considered counter productive. On the other hand, the efficient use of all fuels, available through cogeneration, is another desirable goal of the national energy policy. In the two maximum cases energy savings are larger. However, because of the exclusive reliance on distillate fired gas turbines, there are substantial increases in the demand for petroleum which result in increased reliance on imported oil. Although small declines occur in natural gas and nuclear demand, the most severe reductions in fuel demand occur in coal use.

When evaluating the fuel changes from the MEMM simulations, one must bear in mind that this is a supply and demand model. A significant assumption in the model is that any highly desirable fuel that is saved or freed up through cogeneration, such as oil or natural gas, will be used to fulfill the demands of other sectors. Thus, the energy savings shown in the MEMM simulations are the net savings after all energy market conditions have been satisfied.

The results of the four scenario cases along with the MEMM base case are presented in tables 3-3 through 3-5. The national fuel consumption statistics presented in table 3-3 show that the fuel savings attributable to cogeneration are small but meaningful, ranging from .26 QUADs in the no action case to 1.52 QUADs in the technical maximum case.

Petroleum demand falls except in the two maximum cases when distillate fuel is used exclusively to cogenerate using gas turbines. Hydro and miscellaneous fuels are unaffected. Natural gas declines in all four cases, up to 1.53 QUADs in the technical maximum case. Of all fuels, the largest savings are in coal, our most abundant energy resource. Coal use falls with increased cogeneration from .08 QUADs in the no action case to 2.97 QUADs in the technical maximum case. Crude oil imports decline slightly in the two lower cases, down 100,000 barrels per day in the incentives case, but increase dramatically in the two maximum scenarios--up 1.72 million barrels per day in the technical maximum case. This is consistent with the fact that a variety of fuels, including coal, are used to cogenerate in the two lower cases, which allows firms to save oil which was formerly used under boilers for steam. However, in the two maximum cases there is a dramatic increase in the demand for distillate fuel to cogenerate. This demand can only be met through increased imports. In the incentives case, fuel consumption decreases by almost one-half QUAD, with the majority of the savings occurring in the utility sector. All types of fossil fuels will be saved and oil imports will decrease by 100,000 barrels per day.

In sectoral terms, industrial fuel demand is virtually unchanged except in the two maximum cases, which indicates an increase in fuel use by as much as 3.2 QUADs. Utility fuel demand declines with increases in cogenerated electric power. In all cases the decline in utility fuel demand more than offsets any increase in industrial fuel demand.

Table 3-3
The Effects of Cogeneration in 1985
Summary of National Fuel Consumption
Using Forecasted Fuel Distribution Patterns
(QUADs)

	MEMM base case	No action case	Incentives case	Economic maximum case	Technical maximum case
		(Changes in consumption)			
Total fuel consumption (note a)	94.61	-.26	-.48	-.93	-1.52
By type of fuel:					
Petroleum	43.86	-.14	-.26	+.64	+3.20
Gas	19.14	-.05	-.08	-.12	-1.53
Coal	21.17	-.08	-.15	-1.39	-2.97
Nuclear	6.22	+.01	0	-0.06	-.23
Hydro and misc.	4.22	0	0	0	0
By sector: (note b)					
Residential-commercial	14.90	-.08	-.07	-.11	-.12
Industrial	26.58	-.02	0	+.73	+3.20
Transportation	21.37	-.02	-.02	-.02	-.11
Utility	31.56	-.14	-.39	-1.52	-4.50
Imports:					
Crude oil (millions of barrels per day)	7.75	-.06	-.1	+.36	+1.72

a/Totals may not agree because of rounding.

b/Excludes the synthetic fuel sector.

Table 3-4 shows the changes in industrial fuel consumption for each scenario. Industrial electricity demand is down .06 QUADs or 1.4 percent in the no action case to 1.58 QUADs or 38 percent in the technical maximum case. For the two lower cases natural gas, distillate, and liquified gas use declines as these fuels are no longer required under boilers. Residual oil and coal demands are correspondingly increased to fire cogeneration turbines. 1/ In the two maximum cases, distillate is used exclusively to fire gas turbines and all other fuels show declines.

In the incentives case industrial electricity consumption is down .15 QUADs, or 3.5 percent. Natural gas, distillate, and liquified gas use also decline. Coal use on the other hand increases in this scenario by .15 QUADs.

Table 3-4
Industrial Fuel Consumption
(QUADs)

Type of fuel (note a)	MEMM base case	No action case	Incentives case	Economic maximum case	Technical maximum case
		(Changes in consumption)			
Electricity	4.18	-.06	-.15	-.56	-1.58
Natural gas	8.19	-.03	-.07	-.14	-.80
Petroleum:					
Distillate	1.53	-.03	-.06	+1.52	+5.53
Residual	1.68	+.02	+.06	-.21	-.67
Liquified gas	1.08	-.02	-.05	-.09	-.19
Coal	5.02	+.05	+.15	-.44	-1.12

a/Does not include refinery oil and gas consumption.

Table 3-5 shows changes in utility fuel consumption under our scenarios. In the no action and incentives cases, coal demand is down, reflecting the loss of baseload demand, which is met primarily by coal and nuclear plants. However, nuclear fuel (uranium) use is not significantly affected, indicating that coal is the least desirable fuel. The declines in coal use occur in low-sulfur, sub-bituminous, and lignite, reflecting the regional effects of cogeneration. There is also a

1/Natural gas is also used to fire some cogeneration turbines, but this use is more than offset by the savings under industrial boilers.

decline in residual fuel use by utilities because some residual-fired base and intermediate plants will be shut down, given the decline in baseload electricity demand. Natural gas, however, in the two lower cases shows a slight increase. In the incentives case the largest fuel savings occur in coal, .3 QUADs, reflecting decreases in baseload capacity. Distillate and residual oil use decline; however, natural gas increases, indicating a desire by the utilities to use more attractive fuels.

In the two maximum cases, the effects noted above are magnified. Coal use is down substantially, and distillate and residual fuel use both decline. Natural gas shows an increase except in the technical maximum case where it declines substantially, by .87 QUADs. Uranium use shows small declines. However, the main result is unchanged; most of the fuel savings occur in coal use by utilities who in effect substitute away from coal into more attractive fuels.

Comments from some industries indicated that they believed utility fuel savings would be more biased towards oil and gas, since they are the most expensive fuels. These comments illustrate the disagreement on the types of fuels utilities would save due to cogeneration. Utility fuel savings depend on the type of electricity production offset by cogeneration. As stated earlier, cogeneration facilities operate as close to 24 hours a day as possible, generating electricity-like baseload facilities. If this electricity replaces utility baseload production, then coal use would most likely decline. However, if this electricity replaces the most expensive generation in peaking and intermediate facilities as the commenters suggest, then more oil and natural gas use should be saved.

We recognize that both assumptions have merit. This was one reason for performing two independent analyses for each case. In the historical analyses, we assumed that all fossil fuels used to generate electric power in base, intermediate and peak load generating units would be offset by cogenerated electricity. On the other hand, the forecasted analyses assumed that only baseload type generation would be affected. Given the two assumptions used, we believe the results in both analyses are reasonable.

Table 3-5
Utility Fuel Consumption
(QUADs)

Utility fuel consumption	MEMM base case	No action case	Incentives case	Economic maximum case	Technical maximum case
		(Changes in consumption)			
Coal:					
High-Sulfur	10.18	+.02	-.01	-.04	-.07
Low-Sulfur	2.10	-.04	-.09	-.25	-.56
Sub-bituminous	2.67	-.11	-.18	-.47	-.93
Lignite	.96	0	-.01	-.20	-.30
Total (note a)	15.90	-.13	-.30	-.96	-1.86
Gas	2.15	+.08	+.09	+.08	-.87
Distillate	.95	-.05	-.09	-.32	-.53
Residual	2.38	-.04	-.09	-.27	-1.02
Uranium	6.22	+.01	0	-.06	-.23

a/Totals may not agree because of rounding.

Historical and forecasted analyses differ in the amount of fuel saved

In previous sections we discussed separately the historical and forecasted analyses of the cogeneration scenarios. This section provides a comparison of the two analyses and an explanation of the different fuel shifts due to cogeneration.

We believe the consideration of supply and demand factors is the major reason for differences between the two analyses. DOE's econometric model, unlike the historical analyses, considers economic supply and demand factors that would affect cogeneration-related fuel shifts within the national energy system. As stated earlier, the energy savings shown in the MEMM simulations are the net savings after energy market conditions have been satisfied.

In comparing the MEMM forecasted analyses and the historical analyses of cogeneration, the results differ by the amount and types of fuel saved. Table 3-6 presents a summary comparison of fossil fuel and total energy savings for the two analyses.

Table 3-6
Summary of Nationwide Changes in Fuel Consumption for Three Industries Due to Cogeneration in 1985 (QUADs)

	No Action case		Incentives case		Economic maximum case		Technical maximum case	
	Historical	Forecasted (note a)	Historical	Forecasted (note a)	Historical	Forecasted (note a)	Historical (note b)	Forecasted (note a)
Type of fossil fuel:								
Oil	-.07	-.14	-.09	-.26	+1.25	+.64	-	+3.20
Gas	-.58	-.05	-.76	-.08	-1.28	-.12	-	-1.53
Coal	+.05	-.08	+.10	-.15	-1.12	-1.39	-	-2.97
Total energy change (note c)	-.60	-.26	-.75	-.48	-1.14	-.93	-	-1.52
bbl/d crude oil equivalent	282,000	123,000	354,000	228,000	540,000	437,000	-	719,000

a/Totals may not agree because of fuel consumption changes in nonfossil fuels.

b/The technical maximum case was not analyzed using historical data because of the unlikely expectation of achieving this level of cogeneration.

c/Totals may not agree due to rounding.

The table shows that total fuel savings are consistently lower when comparing the forecasted to the historical fuel use analyses. These differences can be attributed to supply and demand factors and to the level of cogeneration implicit in the MEMM model. The MEMM model forecast of 94.6 QUADs of total U.S. energy consumption in 1985 includes a level of cogeneration which we estimate to be about 46.75 billion kWhs. To avoid duplication of this implicit cogeneration, 46.75 billion kWhs were subtracted from our 1985 estimates whenever we used the MEMM model. The approximate .2 to .3 QUADs differences in total energy savings between the two analyses can be attributed to this adjustment.

The table also shows that, with the exception of coal, changes in fuel consumption assuming historical or forecasted fuel use patterns consistently increase or decrease within each scenario. The results differ, however, in the magnitude of change. In our most reasonable scenario of cogeneration development, the incentives case, coal consumption shows an increase of .10 QUADs in the historical analyses whereas the forecasted analyses show a decrease of .15 QUADs. This variation is due to supply and demand factors and to the model's assumption of increased utility coal use in the year 1985. The incentives case, however, shows declines in oil and natural gas use for both analyses. The true value of cogeneration's contribution to energy conservation will depend on national energy policies which influence the implementation of cogeneration technology. The policy options available to influence cogeneration and a framework for its encouragement are discussed in chapter 6.

THE RELATED EFFECTS OF COGENERATION

In addition to the fuel shifts that will occur due to cogeneration, there are several other related effects. The utility sector will be most affected by growth in cogeneration. The resulting loss of continuous baseload demand leaves the utilities with a higher ratio of peak demand which is met by less energy efficient peaking capacity. However, the loss of baseload demand allows utilities to reduce their investment in base capacity, which is the most expensive in terms of price per kilowatt, and retain older plants which could otherwise be discarded. The effects of cogeneration on utility generation and capacity, utility and industrial capital investments, and national energy prices are discussed in this section.

Utilities' electric generation and capacity declines

Table 3-7 shows the generation and capacity effects on the utility sector which are predicted to occur as a result of cogeneration. Electrical generation declines with increased levels of cogeneration--utility generation is down 16 billion kWhs, or .5 percent, in the no action case to as much as 449 billion kWhs, or 14.8 percent, in the technical maximum case. With respect to capacity, the largest decline occurs in baseload capacity with much smaller declines occurring in intermediate, daily peak, and seasonal peak capacities. For instance, in the incentives case, total baseload capacity falls by 6 gigawatts. This decline consists of the net effect of an increase of 2 gigawatts in existing baseload capacity that is not retired, and an 8-gigawatt decrease in new plant capacity. Even in the technical maximum case, where existing and new capacity falls by 28 and 30 gigawatts respectively, the largest percentage decline, 24.6, occurs in new capacity.

In assessing the effects of cogeneration on utility generating capacities, baseload falls quite significantly in comparison to the declines in daily and seasonal peak capacity. Utilities respond to the decline in demand by retaining existing plants beyond the time when they would otherwise be retired or replaced and by reducing investment in new plants. Thus older, less efficient baseload and peaking plants are retained while investment in new, more efficient baseload capacity is reduced by cogeneration.

Table 3-7
Utility Electrical Generation and Capacity
in 1985

	MEMM base case	No action case	Incentives case	Economic maximum case	Technical maximum case
		(Changes from base case)			
Electrical generation, (billion kWhs)	3,043	-16	-41	-156	-449
Capacity (gigawatts)					
Baseload	397	-2	-6	-20	-58
Existing	275	-1	+2	+1	-28
New	122	-1	-8	-21	-30
Intermediate	103	-1	-2	-5	-15
Existing	78	+1	-4	-2	-9
New	25	-2	+2	-3	-6
Daily Peak	54	0	-1	-3	-8
Existing	52	0	-1	-6	-8
New	2	0	0	+3	0
Seasonal Peak	107	0	0	-5	-17
Existing	49	-1	+1	+2	+7
New	58	+1	-1	-7	-24

The loss of baseload demand is reflected by the overall plant capacity factors presented in table 3-8. Plant capacity factors give the actual amount of plant usage as a proportion of potential full utilization. Although 100-percent utilization is not possible because of routine maintenance and repair, decline in utilization indicates less efficient use of the system's capital stock. Because cogeneration represents a loss of continuous demand which would otherwise be met from baseload capacity, it can cause utilization to fall, or at best stay constant in all regions. The Southwest region, which has the largest potential for cogeneration, will experience the largest decline in plant utilization. Although the model results show this large decline, the Southwest region should have a very high load growth rate, offsetting equipment utilization declines caused by cogeneration.

Table 3-8
Utility Plant Capacity Factors

MEMM Regions	MEMM base case	No action case	Incentives case	Economic maximum case	Technical maximum case
New England	.492	.492	.492	.476	.364
New York/New Jersey	.525	.525	.525	.525	.525
Mid Atlantic	.465	.465	.462	.436	.394
South Atlantic	.500	.500	.500	.500	.500
Midwest	.512	.512	.512	.503	.460
Southwest	.357	.355	.351	.330	.197
Central	.458	.458	.458	.458	.458
North Central	.500	.500	.500	.500	.500
West	.461	.460	.457	.446	.405
Northwest	.517	.517	.517	.517	.517
U.S. average	.472	.472	.471	.463	.417

Utilities can reduce capital investments

Table 3-9 contains the cumulative capital cost savings that would be realized by utilities due to the decline in industrial electricity demand. With a smaller demand, utilities should be able to reduce their investments in new plants and equipment. The savings shown in the table are relative to what would have been the utility investment as indicated in the MEMM base case. However, these savings will be offset by the additional investment costs industry needs to cogenerate.

As expected, the largest savings occur in baseload plant investment, especially sub-bituminous and low-sulfur coal burning plants. In the no action case, there is a slight increase in investment in nuclear plants, an increase which does not persist in the remaining scenarios. There is also a savings in utility investment in distillate turbines. The incentives case increases the savings identified in the no action case and includes additional savings in lignite and combined cycle plants. In the economic maximum case there are substantial capital cost savings in all plant types previously mentioned, with an additional $295 million savings in utility investment in new nuclear plants. In the technical maximum case there are savings in investment in all plant types except high-sulfur coal, gas steam plants, hydro, and pumped storage, which remain unchanged.

Table 3-9
Utility Capital Cost Savings
Computed From The MEMM Base Case
(millions of 1978 dollars)

Plant type	No action case	Incentives case	Economic maximum case	Technical maximum case
Residual steam	$ 0	$ 0	$ 0	$1,051
Coal high-sulfur	0	0	0	0
Coal low-sulfur	612	1,011	1,749	4,175
Sub-bituminous coal	788	1,602	4,229	5,331
Lignite	0	124	2,140	3,308
Distillate turbine	84	412	1,486	4,444
Combined cycle	0	175	1,530	2,108
Gas steam	0	0	0	0
Hydro	0	0	0	0
Pumped storage	0	0	0	0
Nuclear	-47	0	295	1,216
Total	$1,437	$3,323	$11,428	$21,633

In all, utilities save $1.4 billion in the lowest case, $3.3 billion in the incentives case, $11.4 billion in the economic maximum case, and $21.6 billion in the technical maximum case. These capital cost savings, along with reduced generating expenses, can be passed on to consumers in the form of slightly lower utility electric rates.

The capital cost savings utilities accrue as a result of reduced capacity requirements will be offset by industrial cogeneration investments. To examine the relationship between the capital expenditures required by industry and utilities, we computed the investment necessary to install the same amount of electric generating capacity using cogeneration systems and conventional generation systems.

Table 3-10 shows the capital investment required to install the amount of capacity used in the no action, the incentives, and the economic maximum cases. Industrial investment is computed using the mix of cogeneration technologies assumed in each case, while utility investment is computed using either coal or residual oil fired central stations. Both coal and oil fired central stations were evaluated because of the different levels of investment each system requires.

Table 3-10
Comparison of Industrial Cogeneration and Utility Capital Investment Requirements to Install Equal Amounts of Generating Capacity
(1977 dollars)

	No action case	Incentives case	Economic maximum case
Cogeneration capacity in MW (note a)	8,305	10,390	26,517
		(millions)	
Industrial capital investment required to install cogeneration capacity (note b)	$7,827	$9,841	$15,218
Utility capital investment for same capacity using coal-fired central stations (note c)	5,814	7,273	(d)
Additional investment required by industry	2,013	2,568	(d)
Utility capital investment for same capacity using residual oil-fired central stations (note e)	3,737	4,676	11,933
Additional investment required by industry	4,090	5,165	3,285

a/The electricity production in billion kWhs is converted to MW at a 90 percent load factor.

b/Assumes cogeneration units are of an average size of 5 MW. Costs per type of system are contained in table 5-1.

c/Assumes a mean value of $750 per kW installed.

d/Determination was not made because it is unrealistic to assume that oil-fired cogeneration capacity will displace coal-fired central station power capacity in such a large quantity.

e/Assumes a mean value of $450 per kW installed.

The table shows that industrial capital investments for cogeneration capacity exceed utility capital investments in coal-fired central stations and residual oil fired central stations. In the two lower cases, which are predominately composed of coal-fired cogeneration systems, industrial capital investment required for cogeneration equipment exceeded utility investment for coal-fired central stations by $2.0 and $2.6 billion, respectively. Cogeneration, in these cases, requires approximately 35 percent more industrial investment than coal-fired central stations.

When comparing capital investments of mainly oil-fired industrial cogeneration capacity with utility oil-fired central stations, as the economic maximum case indicates, industry needs $3.2 billion, or approximately 28 percent more capital investment for cogeneration.

In developing the utility investment costs, we assumed a direct offset of cogeneration capacity against utility generating capacity. As such, the utility capital investments are much larger in the no action and incentives cases than the utility capital cost savings identified in table 3-9. The difference between tables 3-9 and 3-10 for the two cases is attributable to the assumptions we made and those made by the MEMM model. The cogenerated capacity in these two lower cases is small. These small changes in the additional supply of electric generating capacity are assumed by the MEMM model to be absorbed into the normal utility generating margins. Therefore, as table 3-9 indicates, utility capital cost savings will not amount to that much.

The economic maximum case, however, shows approximately $11.4 billion in utility capital cost savings as a result of cogeneration as indicated in table 3-9. In contrast, when industrial cogeneration investments are compared to utility capital investments for a residual oil fired central station (see table 3-10), the utility investment requirements of $11.9 billion are almost identical to the utility capital cost savings. This means that industrial cogeneration can influence utility capital cost savings when the cogeneration capacity in the utility service area is large enough to replace the capacity of a proposed utility central station powerplant. Cost savings can also occur during the interim time when a utility has enough capacity to meet its demand without having to build a new plant. Usually during this interim period the utility reserves capacity from another utility. The utility, as such, incurs reservation charges. These charges can be avoided when industrial cogeneration capacity decreases or eliminates the need for the utility to reserve the capacity of another utility.

It should be noted that industrial capital investment for cogeneration equipment includes all steam generating equipment. In the case of a new or replacement system much of the steam generation investment costs would be incurred anyway. By adjusting for the capital costs of steam generation capacity in these instances, the capital investment requirements for cogeneration and utility powerplants could be comparable.

Comparing capital costs by themselves only gives an idea of the expenditures required by industry to invest in cogeneration equipment. Of equal importance are the expenditures associated with site preparation, transmission equipment, and the life cycle costs over the lifetime of the facility. For example, life cycle costs tend to favor a central station powerplant when compared to an industrial cogeneration facility when both use oil. Oil-fired central station powerplants burn residual oil, which traditionally is substantially cheaper than the natural gas or light distillates consumed by a cogeneration facility. These types of expenditures were not included in our analyses because they are very site specific and can only be determined on a case by case basis.

National energy prices will not change significantly

The MEMM simulations predicted national average energy price changes from the price levels forecasted in 1985 for each scenario level due to cogeneration. For the no action and incentives cases, energy prices show little movement. All fuels, coals, distillate, residual, and natural gas show small reductions reflecting the overall decline in fuel demand.

In the two maximum cases distillate oil prices increase slightly reflecting the increased distillate demand with gas turbine cogeneration. Coal and natural gas prices decrease accordingly. For all four scenarios electricity rates decline by as much as \$.09 to \$1.48 per megawatt-hour.

CHAPTER 4

COGENERATION DEVELOPMENT AFTER 1985

SHOULD ENCOURAGE COAL UTILIZATION

As a measure of what role cogeneration might have in the Nation's long term conservation efforts, we estimated the maximum level of energy savings expected from cogeneration in the year 2000 as approximately 2 QUADs or the equivalent of 945,000 bbl/d of crude oil. While cogeneration using all types of fossil fuels would be a valuable conservation measure in the near term, after the 1985 time frame the efforts to encourage greater acceptance of cogeneration should be directed towards substantial shifts away from gas and oil, and towards plant options using coal and coal-derived fuels.

ENERGY SAVINGS FROM COGENERATION COULD APPROACH 2 QUADS IN THE YEAR 2000

In recent years, there have been a number of expert pronouncements on the Nation's long-term cogeneration potential. These statements often reflect skepticism and confusion about the energy problem. The simple truth is that no one can predict or "prove" what the world's energy future will be. Any forecast relies on assumptions about supply and demand or Government policies that are subject to vast uncertainties.

Using industrial capital investment trends, we believe it is possible to minimize these uncertainties and to identify a credible scenario for estimating the contribution that cogeneration can make as an energy conservation measure in the long term. In developing this scenario, we first examined the extent to which capital formation would limit the implementation of cogeneration for the paper and pulp, chemical, and petroleum refining industries. Since these industries contain over 80 percent of the economically suitable steam for cogeneration, as determined in our near-term analyses, they were then used as a basis for computing the maximum energy savings expected in the year 2000 for all industries. The major underlying assumption is that capital assigned by industry for cogeneration investment in 1985 to 2000 would not represent a disproportionately larger share than the percentage of capital used for industrial cogeneration investment during the period 1976 to 1985.

One of the many factors that could affect capital investment is the substitutability of labor for capital. This factor was not included in our analysis because of the types of industries with cogeneration potential. The industries included in our study are very energy intensive. Their manufacturing processes are highly automated operations requiring sophisticated control equipment which cannot be substituted for by a large increase in the labor force.

RPA's technology mix with and without incentives was evaluated for the period 1976 to 1985 to determine the expenditures for cogeneration equipment that industrial users are willing to invest with the anticipation of an acceptable rate of return. The value of the cogeneration investment was then related to the total capital investment for the respective three industries to come up with a ratio for cogeneration investment. Assuming that steam demand and income grow at the same rate, we concluded that a 4-percent growth in steam demand would result in a 4-percent growth in capital equipment investment after 1985. This growth rate may appear to be optimistic for some industries; however, it was intentionally set to reflect the best possible growth for cogeneration development in the long term.

The percentage of cogeneration equipment investment is about 6.4 percent per year for the three industries using RPA's mix without incentives for the period 1976 to 1985. Using the same mix with incentives, the rate of investment for the same period is about 8 percent a year. These percentages were used to set an estimate for cogeneration growth in the three industries. We next extrapolated the estimate to include all industries. By taking the estimate for all industries and increasing it for economic driving forces, such as energy prices, we determined that a reasonable estimate of the maximum energy savings from cogeneration in the year 2000 would be approximately 2 QUADs or the equivalent of about 945,000 bbl/d of crude oil. In perspective, this amounts to an approximate 1.7-percent reduction in energy use as forecasted in the National Energy Plan II.

Although capital investment was the major assumption for identifying the annual energy savings estimate of 2 QUADs in the year 2000, we believe that the encouragement of coal-using plant options and the commercial introduction of coal-derived fuels will have a significant bearing on the potential for cogeneration in the long term. The use of coal, its importance, problems, and cogeneration plant options are discussed in the succeeding parts of this chapter.

THE USE OF COAL--ITS IMPORTANCE, PROBLEMS, AND DEVELOPMENT OPTIONS

Increasing our coal use is important because, although coal represents 90 percent of the Nation's total fossil fuel reserves, it currently supplies only approximately 18 percent of the energy needs. The importance of coal use grows as our dependence on foreign energy sources increases. The NEA legislation discourages the use of natural gas and highly refined distillates and encourages the use of coal and other alternative fuels, creating opportunities for replacing and modifying boilers.

The move, however, to coal from oil and gas raises many problems. Potential investors in coal-fired facilities may well hesitate because of environmental, safety, logistical, and regulatory problems associated with coal. The major problem appears to be environmental since the use of coal requires expensive air pollution devices. In a previous report we estimated that electric utilities' cumulative additional capital costs for controlling emissions could be $19.1 billion and $26.4 billion by 1985 and 2000, respectively. 1/ In addition, annual operating costs would be $1.3 billion and $2.3 billion in each respective year.

Coal handling and preparation is expensive and cannot be done easily by small and medium-sized facilities. Boilers burning coal are large in comparision to the small packaged boilers which are cheap, burn oil or natural gas, and thus pose little environmental concern. It appears that the answer to the question of burning coal economically, particularly for the small and medium sized users, rests with the ability of the Federal Government to encourage the introduction of new technology either using coal directly or coal converted to gaseous or liquid fuels. Some of the potential coal-derived fuels which could enter the energy supply picture as clean fuels derived from coal and could be used during the period from 1985 to 2000 are: (1) low-Btu gas, (2) medium-Btu gas, (3) high-Btu gas, and (4) coal-derived oil. The following table summarizes the characteristics of these fuels and their use in a cogeneration system.

1/"U.S. Coal Development--Promises, Uncertainties," EMD-77-43, Sept. 22, 1977.

Table 4-1
Characteristics and Applications of Coal-Derived Fuels in Cogeneration Systems

	Type of conversion			
Characteristics	Coal to low-Btu gas	Coal to mid-Btu gas	Coal to high-Btu gas	Coal-derived oil
Heat content	100 - 200 Btu/standard cubic foot	200 - 500 Btu/standard cubic foot	950-1,050 Btu/standard cubic foot	17,000-19,000 Btu/lb
Conversion efficiency (note a)	72% to 81% (cold gas)	70% to 76%	56% to 68%	b/
Economy of scale	Commercially available at less than 8 tons/hour of coal; large plants operative in Europe	Needs oxygen plants; only large plants economic	Large plants only	Very large plants only; availability estimates of 1/2 million bbl/d in 1990.
Limitations	Transmission limited to short distances	Transmission over several hundred miles	None, full substitution for natural gas	None, full substitution for distillate fuel oil
Applications				
In cogeneration systems	Ideal in combined cycle cogeneration systems	Central gas supply stations; ideal for combined cycle cogeneration systems	Could be used in all commercially available cogeneration systems	Could be used in all commercially available cogeneration systems
As retrofit project	Requires changes to combustion	Some changes may be required to combustion	No changes necessary	No changes necessary

a/Excludes the heat content of other combustibles produced by the conversion process.

b/Conversion efficiency unavailable.

One of the major drawbacks of cogeneration is the availability of fuels and the problems of burning coal in its solid state economically in small boilers--under 100 million Btu's per hour input. The conversion of coal to gaseous or liquid fuels permits further use of natural gas and oil boilers and internal combustion engines. Although some manufacturers claim very high conversion efficiencies, the conversion of coal to coal-derived fuels causes energy losses. To compensate for these losses, the high efficiencies of cogeneration applications offer opportunities to equal or even exceed the efficiencies attained in direct coal-fired operations. Thus, encouraging coal-derived fuel consumption for cogeneration would provide increased amounts of energy from coal in a manner that is more environmentally acceptable and more efficient.

Cogeneration is an issue which cannot be explored by itself, but should be considered in the light of an overall fuel strategy. The Powerplant and Industrial Fuel Use Act of 1978 calls for a strategy based upon the use of coal and other alternate fuels. Therefore, as new technology and coal-derived fuels become available, cogeneration development after 1985 should encourage coal utilization with substantial shifts away from oil and natural gas.

Plant options based on coal utilization

Cogeneration was once a well accepted application until industry could purchase cheap and available electricity to meet their power demands and could burn oil and natural gas in inexpensive packaged boilers to produce process steam. Whether cogeneration can become a well-accepted practice again depends, in part, on the development and availability of coal and coal-derived fuels, and the plant options that are available to industry and utilities to obtain either electricity or steam.

To identify some plant options available to industry and utilities to burn coal, we considered a likely fuel supply structure which is in agreement with the objectives of the Nation's energy goals:

--A modest growth of nuclear power generation by the year 2000.

--A high level of coal production by 2000.

--An effective national energy policy which seeks to burn fuels more efficiently, reduce oil imports, and maintain a constant natural gas usage.

Based on the assumption that coal will provide approximately 34 to 40 percent of the primary fuel consumption by the end of the century, the plant options shown in table 4-2 have been identified as those which may encourage or discourage the use of cogeneration. Cogeneration systems introduced under these plant options by a utility or an industrial end user depend upon or will be influenced by an assured supply of fuel or a range of fuels, the availability of highly reliable cogeneration equipment with low costs for operation and maintenance, the industrial users' access to reasonably priced electricity, and the utility's ability to sell steam at competitive prices. These conditions might occur in parallel with each other, might be mutually exclusive in certain regions, States, or localities, and might be economic in one environment and not in another. The table provides an assessment of plant options that have some likelihood for developing in the next 20 years.

According to the administration, if there is not a modest growth in nuclear power generation, coal by itself cannot displace the total generating capacity that would have been supplied by nuclear power. In the absence of nuclear power, it is highly doubtful that over the long run enough coal-fired plants can be built to meet projected electricity consumption. Coal-fired plants already are somewhat more expensive than nuclear power in many regions. In some areas, new coal-fired plants can be flexibly sited outside the "nonattainment" air quality regions. However, as more such plants are built, there will be fewer areas left where additional plants can be sited. The administration believes that at some point there will probably be a ceiling on the amount of coal-fired power that can be substituted for nuclear electricity. This situation could certainly stimulate the interest by industrial facilities to cogenerate.

In addition to the questions concerning the future role of nuclear power, there are many other issues and uncertainties associated with the acceptance of cogeneration. These issues, such as fuel availability, fuel prices, and environmental concerns, are discussed in the next chapter.

Table 4-2
Plant Options Based on Coal
Utilization After 1985

	Plant option	Potential operational mode	Characteristics: Advantages	Characteristics: Limitations	Technical assessment	Effect on cogeneration	Government actions needed: Incentives 1/	Government actions needed: Regulatory
1.	Large coal burning electric power station w/o cogeneration	Utility-owned	Baseload operation allows best fuel use; grid easily accessible for backup; economies of scale favors large plants	Steam plant requires a large 9,000 Btu/kWh; heat rate can be improved with combined cycle system using oil or gas in addition to coal	Phase out gas and oil burning utility power stations; favorable fuel shifts	Unfavorable if power is cheap; favorable if electricity is expensive provided that oil and gas are available	None	Support rates favoring base load operation; allocate some displaced oil and gas to cogenerators
2.	Large coal burning cogeneration plants near industrial complex	Utility-operated	Baseload operation allows best fuel use; can burn wastes; economies of scale benefits; accessible for grid backup; combined cycle potential	Steam transmission limited; plant could be long distances from coal sources	Limited to a few locations with a high concentration of industries (million lb/hr steam, hundreds MW)	Excellent when economical for the utility; local impact very large; national impact estimated at 0.3 QUADs by 2000	Yes	Allocate some displaced oil and gas to other cogenerators
3.	Coal conversion to high-Btu gas or oil in large central plant	Major investment by large commercial plant	Uses existing transportation system; same energy density flux storable energy form; ideal for combined cycle	High conversion efficiency critical	Can assist to maintain current fuel supply structure	Encourages status quo; favors maintaining package boiler concept	None	Encourage wheeling for cogenerators
4.	Coal conversion to mid-Btu gas in large central plant	Utility as major consumer, sale of mid-Btu gas to industry (concept of an industry-utility combine)	Similar to option 2, but better range of transmissions; storable energy form; baseload potential; ideal combined cycle; central environmental control	Good conversion efficiency required; moderate or no combustion chamber changes	Attractive, in particular if industrial clients cogenerate	Encourages cogeneration if wheeling is possible within combine	Yes	No interference with rate structure within combine; reasonable rate structure between combine and grid

5. Coal conversion to low-Btu gas in large central plant	Utility-owned combined cycle operation; no sale of gas	Best if conversion and boilers at high pressures; economy of scale; central environmental control	Conversion efficiency for sulfurous coal highly critical, small range of gas transmission	Reasonable solution for some coals	Favorable only if utility can sell steam to nearby industry	No	No
6. Coal conversion to low or mid-Btu gas in small plants	Industry-owned for on-site use	Commercial availability claimed by producers	Low and mid Btu gas up to 150 and 200 billion Btu's/ day; access to coal critical; desulfurization problem	Market interest not as strong as predicted; many projects abandoned	High front end expenses; uncertain whether cogeneration will recover additional costs for the prime mover system	Yes	Wheeling essential to recover investment
7. Fluidized-bed boiler, heat exchanger	Utility-owned	Same as option 1 in boiler configuration; better if in combined cycle with closed cycle gas turbine; fuel flexiblity including wastes	Few limitations if properly engineered; disposal or regeneration problems for sulfur stone	Boilers are operating in Europe; heat exchangers in Europe require further investigation	Same as in option 1 or 2 depending on use	(See 1 or 2)	(See 1 or 2)
8. Fluidized-bed boiler, heat exchanger	Industry-owned	Small boiler size; good combined cycle operation with heat exchanger	Temperature limit for closed cycle gas turbine; sulfurstone disposal problems	European plants are operational or under test	Encourage cogeneration via steam turbines or combined cycles	Yes	Wheeling essential, certainly in the combined cycle configuration

1/Incentives can refer to: investment tax credit, accelerated depreciation, loan guarantees, or any combination thereof.

CHAPTER 5

ISSUES AFFECTING COGENERATION

Four major issues affect the acceptance of cogeneration technology: economic, environmental, regulatory, and institutional. It will take a concerted, cooperative effort on the part of industry, utilities, and State and Federal Governments to settle, or at least somehow deal with, these issues if cogeneration is to play a significant role in the Nation's conservation efforts.

ECONOMIC CONSIDERATIONS

Economics is the most significant issue affecting the acceptance of cogeneration. Cogeneration like other business opportunities is adopted or rejected on the basis of its productive capabilities and its earnings potential. Industrial companies have indicated that the economic rate of return on investment is their single most important investment decision criterion. Companies contacted during our review desired a return on investment from a low of 10 percent to a high of 30 percent for cogeneration investments. The major factors affecting the rate of return on investment include the capital costs and the cost savings realized from cogeneration when compared with the alternative costs of separate operations--inhouse steam production and purchased electricity.

High capital investment

Cogeneration systems are expensive, easily requiring millions of dollars for capital investment. As described in chapter 2, capital costs are tied to the type of cogeneration configuration, or technology, selected. Table 5-1 illustrates how the type of system affects capital costs. The table shows that the systems using oil or gas are noticeably cheaper than those using our most abundant fuel, coal.

However, the type of system is not the only factor in determining costs. Capital costs also depend on the size of the cogeneration plant. Due to economies of scale, unit capital costs can diminish as the cogeneration system's capacity increases. Table 5-2 illustrates the economies of scale in facilities generating power with a steam turbine cogeneration system. The table shows that smaller units are more expensive per kW produced than larger units. Although economies of scale reduces costs for larger units, the systems are still very expensive.

Table 5-1
Capital Costs per kW Installed
for Cogeneration Systems
(1977 Dollars)

Type of system	Size of System 1 MW	5 MW	20 MW
	(cost per kW)		
Gas turbine	$ 650	$ 500	$ 400
Steam turbine			
Coal fired	2,500	1,250	1,000
Oil fired	a/	875	575
Diesel	550	550	a/

a/Cost estimates unavailable.

Table 5-2
Capital Costs for
Power Generation Using
a Steam Turbine Cogeneration System (note a)
(1977 Dollars)

Size of generation unit in MW	Cost/kW	Total cost (millions)
5	$353.0	$1.76
10	281.0	2.81
20	223.0	4.46
50	165.0	8.25
100	131.0	13.10
500	77.2	38.60
1,000	61.4	61.40

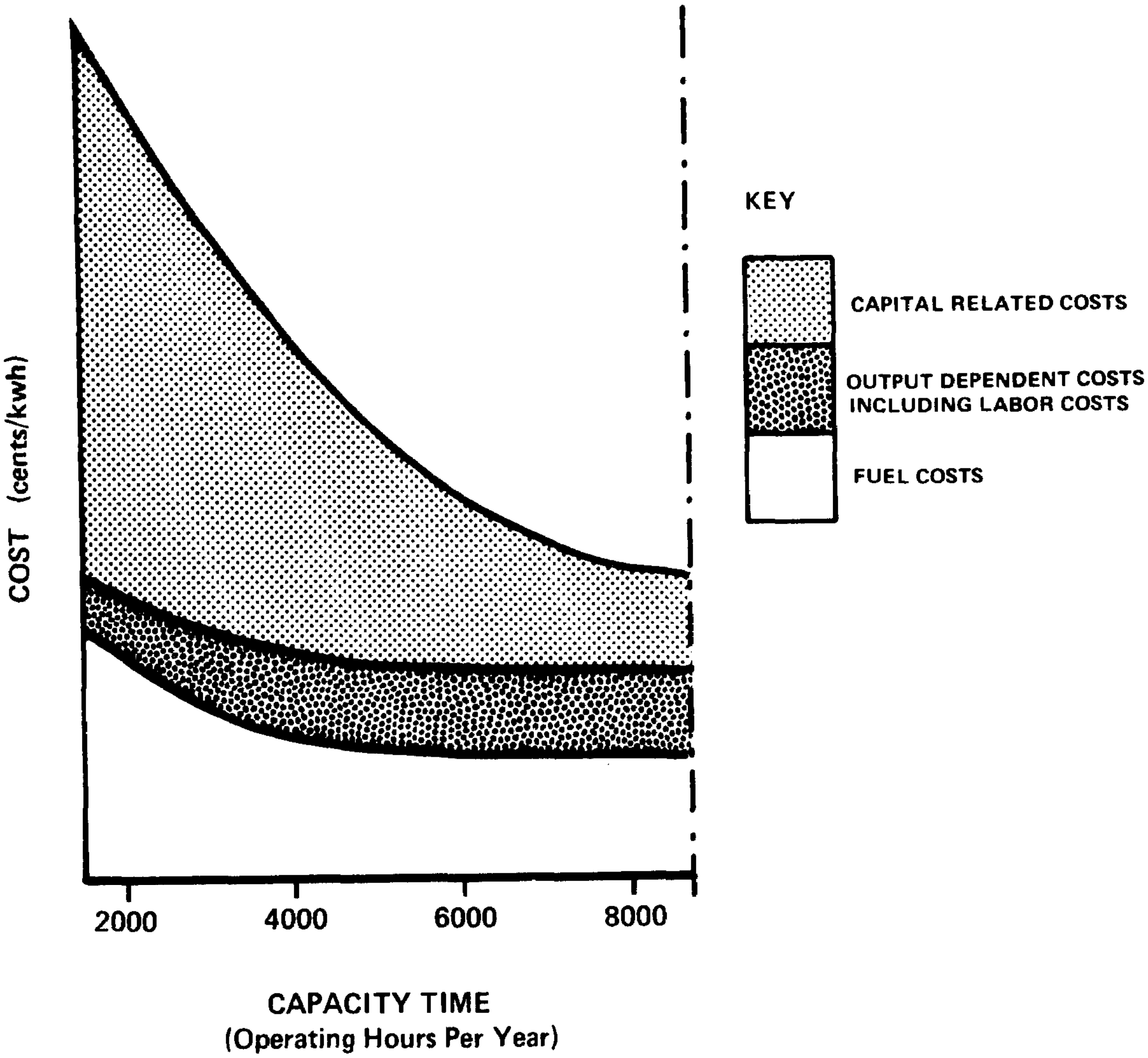
a/Cost figures in tables 5-1 and 5-2 are not comparable. Figures in table 5-1 relate to total cogeneration systems, whereas table 5-2 relates to the power generation components and does not include boilers.

Cost savings depend on plant utilization, and fuel and electricity costs

Cost savings depend on the extent that cogeneration capacity is used, the cost of fuel, and the cost of electricity from alternative sources. The extent that a cogeneration system is used directly affects the opportunities for cost savings. For example, refining and chemical industries normally operating three shifts, 24 hours a day, 365 days a year would benefit more than an industry operating only one shift. The following graph illustrates that as the operational hours increase the cost of electrical generation per kWh decreases.

FIGURE 5-1

TYPICAL DISTRIBUTION OF ELECTRICITY PRODUCTION COSTS



SOURCE: J. A. ORLANDO, H. A. GORGES, "AN ASSESSMENT OF CURRENT ISSUES REGARDING COGENERATION," *ENERGY TECHNOLOGY VI* 1979

Cogeneration equipment is most efficient when operated at design load capacities, producing both steam and electricity. Unbalanced steam and electricity demands will decrease efficiency and thereby reduce the cost savings.

Fuel cost and availability

Cogeneration requires more fuel than does producing only process steam. Cost savings occur when the additional fuel required costs less than what would have been spent on utility supplied electricity. Predicting fuel prices and availability is an integral part of estimating these savings. Uncertainties and risks such as crude oil shortages, future natural gas curtailments, Government requirements to convert from oil and gas to coal, deregulation of gas prices, unstable coal prices, and the future capability of the coal mining and transportation industries to meet demand must be considered. The Powerplant and Industrial Fuel Use Act of 1978 (Public Law 95-620) calls for several actions to promote coal and other alternate fuels as primary energy sources. One of the most significant actions is the prohibition against the use of oil and natural gas in new electric utility generation facilities and in new major fuel-burning boiler installations. According to a DOE official, the prohibition would also apply to existing facilities that retrofit to install cogeneration capability because the retrofit would be considered a major renovation.

The Fuel Use Act also gives the Secretary of Energy authority to prohibit oil or natural gas use in existing electric powerplants and major fuel-burning installations where coal or alternate fuel capability exists. According to Department officials, these fuel use restrictions would not be enforced for cogeneration facilities because they could not foresee when a prohibition order would be issued to an existing cogenerator. Selected provisions of the act along with DOE's interim implementing rules are discussed in more detail in chapter 6.

Considering the above uncertainties and risks, some industrial officials are reluctant to increase fuel demand through cogeneration. In fact, some industries might switch from steam-powered to electrical-powered equipment, thus leaving the fuel problem to the utilities. In industrial operations the demand for process steam is the primary concern. Cogeneration potential, therefore, is directly proportional to the steam demand.

Cost of electricity

Electric power rates also affect cost savings derived through cogeneration. Because cogeneration enables industry to replace purchased electrical power with cogenerated power, cogeneration is more economically attractive when the electric rate is high.

The predominant rate structure used to price electricity by utilities is the declining block rate. This means the price of each additional unit of electricity declines as consumption increases. Declining block rates were introduced to promote electricity consumption so that utilities could expand, enjoy the benefits of economies of scale, and reduce the average price to all users. For years declining block rates worked--consumption rose rapidly and the lower costs of new capacity brought average costs down. From the turn of the century until 1970, U.S. electric power requirements grew at an average annual rate of about 7 percent.

Under the Public Utility Regulatory Policies Act of 1978 (Public Law 95-617), each State regulatory authority and nonregulated electric utility must consider the appropriateness of implementing various standards, such as restricting the use of declining block rates and determining the cost of service. Prior to 1970 there was some economic validity supporting declining block rates. Since 1970, however, because of increasing construction costs for new central powerplants and the absence of further improvements in generating efficiency, the cost of electricity from new plants is higher than the average cost of electricity from existing plants. Thus, rates that promote increased electrical consumption and lead to the need for new generating facilities can raise the average cost of electricity to all users. According to the administration, such rates do not accurately reflect the costs of electricity generation and transmission.

RPA reported that if declining block rates are eliminated, and flat electric rates are established for all customers regardless of consumption, industrial users would incur electricity price increases ranging from 10 to 32 percent. Such a price increase could mean a considerable increase in the cost savings derived through cogeneration. Industrial electricity prices have increased in the last 5 years and are expected to keep increasing faster than the inflation rate.

Utility standby charges can also affect cost savings. An industrial plant, to ensure a high degree of reliability, would maintain a connection with the utility grid system to purchase additional electricity as needed, such as when the cogeneration system provides only a portion of the power required or is not operational. Utilities who charge for this standby service consider these charges necessary to protect their investment in facilities which make backup service possible. Standby charges which are in addition to and generally higher than conventional rates can lower the cost savings from cogeneration. The specific effect of standby charges depends on the amount of electricity required to maintain critical operations and the purchase price negotiated with the utility.

The Public Utility Regulatory Policies Act of 1978 contains provisions which remove disincentives to cogeneration by requiring electric utilities to sell power to qualifying cogeneration facilities at nondiscriminatory rates. The State of California Public Utilities Commission has already moved in this direction by requiring the State's three major utilities to provide specific rate proposals to enhance cogeneration, including revisions to standby rates. Two of the three utilities have already exempted cogenerators from the requirement to pay discriminatory standby charges.

Capital availability

Regardless of how economical cogeneration might prove to be, many companies may not have sufficient capital to finance a cogeneration project. Capital availability can change over time for each company and each industry. However, in many cases, industry has expended available capital on product-oriented investments required to ensure earnings in their primary business area and on government-mandated projects such as pollution control. Many industries have also been plagued by a severe shortage of equity capital since the late 1960s. 1/ Therefore, the capital necessary to finance cogeneration might have to be obtained by increasing debt. However, an already high debt-to-equity ratio due to past borrowing, coupled with additional borrowing for cogeneration, could result in an unacceptable debt level. Also, the cost of borrowed funds increases as the debt-to-equity ratio increases.

1/Thermo Electron Corporation, A Study of Inplant Electric Power Generation in the Chemical, Petroleum Refining, and Paper and Pulp Industries, p. 1-4.

ENVIRONMENTAL CONSIDERATIONS

Another important issue concerning the acceptance of cogeneration is the effect it may have on the environment. At specific locations greater emissions of pollutants could occur because cogeneration facilities must be located near industry due to the inability of steam to travel large distances. The environmental implications of cogeneration must be determined through a case-by-case analysis based on consideration of existing conditions, and on both Federal and State Government environmental policies. However, for the Nation as a whole, increased cogeneration should have a favorable environmental impact. Depending on the fuel used, the higher fuel economy achieved per kWh brings a corresponding reduction in the emission of pollutants from reduced utility electricity generation.

Federal authority over air quality dates back several years to when the Congress enacted a number of laws to enhance and protect air resources. The Clean Air Act of 1970, as amended (42 U.S.C. 7401, et seq.), directed the Environmental Protection Agency to establish minimum national air quality standards. EPA established primary and secondary standards for six classes of pollutants--sulfur dioxide, particulate matter, carbon monoxide, hydrocarbons, nitrogen oxides, and photochemical oxidants. Primary standards were set at levels necessary to protect the public health, and were to be achieved by 1975 in nearly all parts of the country. Secondary standards were designed to protect against such adverse effects as crop damage, reduction in atmospheric visibility, and corrosion of materials, and were to be met in time frames considered reasonable by EPA.

In many areas of the country, neither the primary nor the secondary standards have been attained. These areas are called nonattainment areas. A strict interpretation of the Clean Air Act would prevent the siting of all new air polluting facilities in nonattainment areas. Once existing nonattainment areas came into compliance, new facilities could be sited as long as the new pollutants did not interfere with maintenance of the standards or prevention of significant deterioration of air quality requirements.

However, in December 1976, EPA announced an offset policy setting forth conditions under which new facilities could be sited in nonattainment areas while conforming to the requirements of the Clean Air Act. The policy allows new sources to be located in nonattainment areas as long as, among other things, the new pollutants are more than offset by a reduction in emissions of the same pollutants from existing facilities in the same area. In addition, individual States which have the responsibility to implement Clear Air Act requirements can set stricter new source regulations than those of the Federal Government.

The effect that environmental policies can have on cogeneration is illustrated in a report on issues affecting cogeneration in California prepared by the staff of the California Energy Resources Conservation and Development Commission. The report states that although a potential of about 1,800 MW of cogenerated electric power has been identified in the State, the development of this potential is predicated on the resolution of several important issues, and perhaps the single most pressing issue is the air quality impact.

The report states that the additional fuel required for cogeneration will cause the cogeneration installation to come under air pollution regulations such as the New Source Review rules in force in all California air pollution control districts. Under these rules, in areas where pollution levels currently exceed State or national ambient air quality standards, new pollution is allowed only when an existing pollution source can be decreased by an amount which exceeds the additional new pollutants involved. In areas where air pollution regulations dictate stringent controls, such pollution trade-offs can be difficult to obtain. According to the report, even where such emission reductions are possible through in-plant changes, industry might choose to use the trade-off to implement higher priority projects such as increasing production facilities rather than adding cogeneration capability.

The comments received from three industrial sector organizations suggested that cogeneration emission allowances should be based on combined power and thermal energy production, and not on the fuel fired. Such a standard, basing the allowable emissions on a boiler's output versus its input, would provide, according to the commenters, an incentive for cogeneration. An alternative method of removing environmental constraints was proposed in DOE's comments. Their solution would expand the nonattainment "bubble" to include the affected utility. The "bubble" would then show an emission decrease due to cogeneration, even on coal. DOE stated that this solution was formally suggested to them on November 14, 1979, by EPA representatives.

EPA has issued New Stationary Sources Performance Standards for Electric Utility Steam Generating Units, which revised the standards of performance for emissions of sulfur dioxide, particulate matter, and nitrogen oxides. These regulations require new, modified, and reconstructed electric utility steam generating units to use the best demonstrated continuous emissions reduction system. These EPA regulations, effective June 11, 1979, apply to electric steam generating units for which construction commenced after September 18, 1978, and that have the capability of firing more than 73 MW (250 million Btu's/hr.) heat input of fossil fuel. This category will include some industrial cogeneration facilities. Specifically, industrial cogeneration facilities that sell at least one-third or more of their potential electrical output capacity or at least 25 MW of electricity are covered. The standards also apply to large electric utility cogeneration facilities because such units are considered by EPA as electric utility steam generating units.

According to an EPA official, another set of emission standards applicable to industry will soon be issued which will also encompass the majority of cogeneration facilities. Until these industrial standards are established, the effect of EPA's utility emissions standards on cogeneration development is uncertain.

REGULATORY AND INSTITUTIONAL CONSIDERATIONS

Industry management is reluctant to become involved in what is considered a highly regulated and capital intensive activity, electricity generation. Generally, industry representatives do not consider electricity generation as part of their business. As a matter of fact, some view projects such as cogeneration that do not increase production or expand their primary product market as discretionary investments, sometimes requiring a return on investment of as high as 30 percent. The return on investment hurdle is especially true of industries that historically have not generated electrical power.

Industries are also concerned about Federal and State regulation which could require their plants to deliver cogenerated electricity to the grid to meet utility reserve or emergency capability, thus jeopardizing industrial plant operations. The risks and uncertainties of regulation are significant enough to discourage the chemical and petroleum refining industries, having the most potential for cogenerating surplus electricity, from producing and selling excess electricity to the utility.

Through the Public Utility Regulatory Policies Act of 1978, FERC has the authority to exempt qualifying cogeneration facilities from State laws and regulations as well as from the Federal Power Act and the Public Utility Holding Company Act, if it determines such exemption is necessary to encourage cogeneration. Rules have been issued by FERC directed towards removing the regulatory constraints for many cogenerators. A more detailed discussion of these rules is in chapter 6.

CHAPTER 6

A FRAMEWORK FOR RESPONSIBLE COGENERATION POLICY DEVELOPMENT

CONCLUSIONS

In the preceding chapters of this report, we presented a comprehensive overview and examination of cogeneration, its technology and characteristics and the constraints affecting its future application. We also analyzed the possible effects of various levels of cogeneration on our Nation's energy system through four scenarios which assumed cogeneration development from the status quo to the maximum amount technically possible. For each scenario we made certain assumptions with regard to the amount of steam that would be economically suitable for cogeneration, the availability and types of technology that could be used to cogenerate, the amount of utility power that would be displaced by cogenerated power, and the types of incentives that could be use to promote cogeneration.

Based on our assessment, we believe that cogeneration technology is commercially available which can be adopted by both industry and utilities for use at their facilities. Although there are numerous constraints affecting the acceptance of this technology, certain actions can be taken and incentives provided which can encourage cogeneration development. In our opinion, the actions to foster cogeneration must be based upon getting all interested parties involved. On the other hand, the incentives provided should, in our view, be balanced against the national benefits that are expected to be derived. From our analyses, we have concluded that the incentives case, which will require Federal and State actions, represents the most reasonable and likely conditions for cogeneration development in the near term. This case contains a sampling of the types of incentive options which can be used to promote cogeneration.

This scenario, for the three industries which are prime candidates for cogeneration, assumes a heavy concentration of coal and waste fuel based cogeneration. It also takes into consideration those issues which are of prime importance to our national energy policy and to industry and utilities, namely, marginal cost pricing of energy and exemption from, or a relaxation of, Government regulations. These types of issues and actions will, in our view, increase the economic attractiveness of cogeneration and thus add to the amount of cogeneration that will occur under normal conditions. In essence, this case demonstrates that cogeneration can play a role in our Nation's efforts to conserve valuable fossil fuels. Under this scenario, energy savings from cogeneration in the three industries would approximate .48 to .75 QUADs, or the equivalent of 228,000 to 354,000 bbl/d of crude oil in 1985. The maximum energy savings in the year 2000, within the current industrial capital investment structure, would approximate 2 QUADs, or the equivalent of 945,000 bbl/d of crude oil.

Given the potential that exists for cogeneration, the question remains of what needs to be done to foster its development. In our view, the development of cogeneration as a viable conservation measure is highly dependent on the policies and regulations formulated at the Federal and State levels and directed towards removing or alleviating many of the barriers or constraints that cogeneration faces.

The NEA is a step in this direction since it includes provisions which require the consideration of Federal utility rate standards, 1/ authorize exemption of qualifying cogeneration facilities from FERC and State public utility regulation, and authorize exemption of cogenerators from prohibitions on the use of natural gas and petroleum. Some of these provisions were considered in our analyses and demonstrate that the actions which can be taken by the Government can clearly influence the acceptance of cogeneration. It is imperative, however, that the rules and regulations being developed by DOE, FERC and the Treasury Department to carry out the NEA provisions be developed in the full context of an intention of the act--to encourage cogeneration.

In conclusion, we believe that a coherent Federal cogeneration policy that is consistent with State and regional interests can be developed to encourage coal and alternate fuel use for cogeneration with a controlled shift away from oil and natural gas. In the succeeding parts of this chapter, information is presented on the various policy options that are available for consideration in promoting cogeneration and our views and proposals on the policy that should be selected. We also present the framework around which the Federal policy and the pertinent rules and regulations could

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1/With respect to rate standards, in three reports dealing with Government agencies involved in the electricity area, Tennessee Valley Authority, Bonneville Power Administration and Western Area Power Administration, we have suggested that these agencies implement several funding and pricing mechanisms to increase the cost of power and thereby encourage conservation measures such as cogeneration (EMD-78-91, Nov. 29, 1978; EMD-78-76, Aug. 10, 1978; and EMD-79-73, Oct. 16, 1979).

be developed to encourage cogeneration on a local, State, and regional basis and the need for an office within DOE to oversee cogeneration-related activities.

POTENTIAL COGENERATION POLICIES CAN PROMOTE DIFFERENT TYPES OF FUEL SAVINGS

An important consideration in any policy option that is selected as a basis for cogeneration development is the resulting shifts in the types of fuels that would be used to cogenerate. Various policies producing different results include encouraging cogeneration (1) within current industrial fuel use patterns to maintain the existing fuel distribution balance, (2) as an alternative source of electricity power by emphasizing electricity generation, (3) as a means to maximize coal use by restricting oil and natural gas consumption, and (4) as a conservation measure emphasizing coal and alternate fuel use with a controlled shift away from oil and natural gas.

The first policy option would seek to maintain a fuel distribution balance defined by current industry fuel use patterns. Cogeneration technology implemented under this policy would normally use the same types of fuel industry now uses to produce steam. Under this policy, the Government would allow the continued use of oil and gas by industry provided that they adopted the use of cogeneration. Since industries would use more fuels with cogeneration, energy savings clearly would be derived from the utility electricity generation displaced by industrial cogenerated electric power. Federal involvement would be limited to ensuring that industry is cogenerating. Cogeneration, then, would develop without regard to any Federal coal conversion requirements.

The second policy of emphasizing electricity generation requires implementing cogeneration systems which predominantly use oil and natural gas as fuels. These systems that maximize electrical output will also maximize energy savings because of the utility generation offset by cogenerated electricity. This policy is illustrated in our two maximum scenarios assuming the exclusive use of distillate oil fired gas turbines. While energy savings would significantly increase, crude oil imports would also greatly increase. Obviously the role of cogeneration with this policy option would be counterproductive towards decreasing the Nation's use of imported fuels and converting to coal.

The third policy alternative would maximize coal use by restricting oil and natural gas cogeneration. Cogeneration systems implemented under this policy would generally burn coal, with only a few systems able to use oil and natural gas in specific instances. The majority of systems would require the use of steam turbine topping configurations which are capable of using coal or waste fuels. This policy would inhibit cogeneration development by preventing small and medium sized users from considering cogeneration because of the disproportionately higher investment required to use coal.

The fourth policy option would encourage cogeneration as a conservation measure emphasizing coal and alternate fuel use, with a controlled shift away from oil and natural gas. While oil and natural gas would still be used to cogenerate, this policy would use a mix of cogeneration technologies and emphasize the use of coal and other alternate fuels. This approach for implementing cogeneration systems would seek a quantitative balance between oil and gas savings and total energy savings until 1985. This would provide a mechanism for a controlled shift away from imported fuels. This policy option, as indicated in our no action and incentives scenarios, does not save a substantial amount of energy; however, oil imports will decrease. After 1985, oil and gas use should become less important as advanced technologies using coal and coal-derived fuels become commercially available.

GAO'S PROPOSALS FOR ENCOURAGING COGENERATION DEVELOPMENT

A cogeneration policy, in our opinion, which seeks to conserve energy with emphasis on oil and gas savings could establish a role for cogeneration in our Nation's conservation efforts. This approach would be consistent with the national objectives of decreasing overall energy consumption, burning fuels more efficiently, and decreasing our use of imported fuels.

It would be directly in line with the Powerplant and Industrial Fuel Use Act of 1978 which promotes the use of coal and other alternate fuels by major fuel-burning installations but recognizes that oil and natural gas use may sometimes be desirable, such as with cogeneration applications. In essence, the policy should focus on the use of coal and alternate fuels with a controlled shift away from oil and natural gas.

The following sections first discuss the proposed cogeneration policy framework, including a strategy for its implementation, and then relate the pertinent NEA provisions with the policy.

The policy should encourage coal use with a controlled shift away from oil and gas

A Federal cogeneration policy should be based upon fostering those technologies that emphasize coal and alternate fuel use as well as recognizing the need for some oil and natural gas consumption. The level of oil or natural gas fired cogeneration should be linked to the growth of cogeneration technologies which are coal or alternate fuel based. This linkage would allow oil and natural gas use without fear of increasing the level of imported fuels.

For illustrative purposes, we examined the linkage between oil and gas cogeneration and coal use at six complexes in the Gulf States area where large chemical firms cluster. Each complex requires 3 to 4 million pounds of steam per hour and 400 MW of power. We assumed that the steam is cogenerated using coal by utility-operated steam turbines. These steam turbines, producing a total of 24 million pounds of steam at a load factor of 90 percent, will generate about 10.4 billion kWhs annually, or about 55 percent of the actual power demand for the six complexes.

As shown in table 6-1, under these conditions we estimated that cogeneration saves a large amount of natural gas and some oil.

Table 6-1
Energy Savings Due to Cogeneration
at Six Complexes in the Gulf States Area

	Gas	Oil	Coal
	(trillion Btu's per year)		
Industry	-237.6	-12.2	-0-
Utility	- 92.1	- 1.5	+246.7
Energy savings	-329.7	-13.7	+246.7
Net energy savings		-96.7	

The savings in natural gas amount to about 5.2 percent of all 1976 industrial natural gas use nationwide. These savings are achieved with an approximate .8-percent increase in coal use by the utilities. The gas released by these industries and utilities can be used by some small industrial cogenerators for whom coal use is uneconomical because of unfavorable economies of scale. This offset would not be on a one-for-one basis, but one factor among many taken into account in permitting oil and gas use.

Although substantial natural gas savings can be attained in the Gulf States area, other regions may save more oil or even possibly coal. The types of fuel savings from large coal or alternate fuel fired cogeneration facilities will vary by region, depending upon that area's cogeneration potential, access to fuel, and the environmental and economical considerations. If large cogeneration plants using coal or other alternate fuels could be encouraged and made economically attractive, some of the displaced oil and gas could be made available to other small and medium sized industries to make cogeneration more universally attractive.

A coherent Federal cogeneration policy and strategy that is consistent with State and regional interests can be developed to encourage coal and alternate fuel use with a controlled shift away from oil and natural gas. Such a policy and strategy, in our opinion, should

--seek to balance and maximize oil and natural gas savings with overall energy savings;

--recognize regional differences regarding fuel use and fuel availability and ensure regional equity in benefits and costs;

--be based upon reasonable expectations of cogeneration development;

--balance Federal expenditures for financial incentives in support of cogeneration and expected national benefits from cogeneration; and

--be based upon the need to get all interested parties--Federal agencies, industry, utilities, and State agencies--actively involved in the development of cogeneration.

An implementation plan which considers these characteristics and takes into consideration existing NEA legislation is described below.

<u>User classes need to be established and State and regional planning is necessary for implementing the policy</u>

The strategy for implementing our proposed policy includes (1) classifying cogenerators by their size and type of fuel use and (2) using a State and regional planning mechanism to monitor and ensure that cogeneration-related fuel shifts occur consistent with national goals. A cogeneration strategy which emphasizes a controlled shift away from oil and natural gas use would link oil and natural gas cogeneration to coal and alternate fuel based cogeneration. Some of the oil and natural gas freed from coal and alternate fuel based cogeneration could then be used without fear of increasing the use of imported fuels.

To achieve this linkage, user classes should be established by DOE to place cogeneration facilities into categories. User classes 1/ would categorize cogeneration facilities by size and by types of fuels involved. Those facilities that would be expected, with all other factors being equal, to use coal or alternate fuel based cogeneration systems would be in one class. Large plants and utilities more likely to fit in this class (Class A) would be encouraged to use coal fired cogeneration systems. Smaller facilities, for example, with less than 600,000 pounds per hour of steam capacity, including small and medium scale utility-industry partnerships, would be another user class (Class B). Class B oil and natural gas cogenerators would be tied to the regional level of fuel savings by Class A users. In other words, as coal and alternate fuel based cogeneration freed up oil or natural gas within the region, some of those oil or natural gas savings could be used to decide the extent of oil or natural gas fired cogeneration systems.

This approach, encouraging the use of coal and alternate fuels at larger facilities and providing some of the displaced oil and gas to be made available to small and medium sized in-

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1/The actual number of classes and the split between classes would have to be set with the input of utilities, industries, and other interested parties. For the purpose of our description, we assumed two classes and the split between these being facilities with 600,000 pounds of steam per hour capacity.

dustries, would make cogeneration more universally attractive. Thus, cogeneration would be desirable in terms of national energy savings, encouraging the use of coal and alternate fuels, and using fuels more efficiently.

A voluntary State and regional energy planning mechanism could be utilized to monitor the implementation of this strategy. To assess the changes in fuel use patterns caused by the implementation of user classes for cogeneration, existing and projected energy use patterns could be developed at the State level with the voluntary participation of industry, utilities, public utility commissions, State energy commissions, and DOE. Such patterns are already developed in some States, such as Texas. (See appendix V.) States would identify classes of potential cogeneration sites by size of facility and projected fuel consumption. The energy consumption data would be aggregated at the State level to show fuel shifts due to cogeneration and then submitted to the DOE regional office.

The DOE regional office would, on the basis of industry data and in cooperation with appropriate State offices, aggregate the data to determine net regional fuel shifts due to cogeneration. Using this aggregated data, cogeneration development could be assessed primarily on the basis of user classes, projected fuel consumption, and location of the potential cogeneration facility. Oil and natural gas use goals for cogeneration could serve as a measuring device for DOE regional offices to quantify cogeneration-related fuel shifts. If the goals were not being met at the regional level, DOE could then use its regulatory powers under the Powerplant and Industrial Fuel Use Act of 1978 to reassess the appropriateness of granting any further oil and natural gas cogeneration exemptions in that region.

In reviewing the aggregated State data, DOE should consider regional inequities. In some regions, coal use is not developing due to its unavailability or environmental constraints. DOE should recognize these constraints when assessing and developing cogeneration plans. For example, where coal and alternate fuels cannot be used, oil or natural gas fired cogeneration would be allowed on the basis that the conventional system could obtain an exemption to use oil or natural gas.

The guiding principles would set cogeneration policies to first maximize coal and alternate fuel use and then save oil and natural gas. The principles, however, should allow oil and natural gas consumption for cogeneration to the extent that these fuels will be freed up within the region due to coal and alternate fuel based cogeneration. The system we envision should be maintained to reflect the current character of industry and utilities. Regional plans would have to be updated as companies and utilities adjusted their plans to reflect individual situations.

The policy of linking oil and gas based cogeneration capacity to the level of coal and alternate fuel based cogeneration is relevant for the short term, up to 1985. If smaller scale coal-based cogeneration technologies become commercially available after the short term, as predicted, the policy could be revised accordingly.

Interim rules on fuel use should support the policy

The Powerplant and Industrial Fuel Use Act, which restricts the use of oil and natural gas, is already based on user classes, in the sense that the law applies to only those facilities above a certain minimum size. In applying the law, DOE has great latitude in defining when oil and natural gas use exemptions are permissible for cogeneration. We believe that DOE's Economic Regulatory Administration (ERA), through their rulemaking, should set a size limitation on those facilities eligible for the cogeneration exemption based on user classes as discussed above.

One provision in the act prohibits new major fuel-burning boiler installations from using petroleum and natural gas as a primary energy source. However, as an incentive to cogeneration, the act permits exemption of cogeneration facilities from this prohibition provided they demonstrate that the economic and other benefits of cogeneration can only be obtained by using oil and natural gas.

Because of their size, most new industrial cogenerators will have to demonstrate their eligibility for an exemption in order to use oil or natural gas. The act defines major fuel-burning installations as capable of using fuel at an input rate of at least 100 million Btu's per hour, or a combination of two or more units located at the same site and in the aggregate capable of using fuel at an input rate of at least 250 million Btu's per hour. Industrial cogeneration facilities generally need a steam demand of at least 100 million Btu's to be economically attractive. Therefore, most new industrial cogenerators will be classified as major fuel-burning installations and will be required to comply with the act.

Interim rules to carry out the exemption provisions of the act have been issued by ERA. These interim rules, effective May 8, 1979, permit oil and/or natural gas use for cogeneration if a petitioner demonstrates to the satisfaction of ERA that it meets the following criteria: (1) the oil or gas to be consumed will be less than that which would otherwise be consumed in the absence of the cogeneration facility or (2) it would be in the public interest because of specific circumstances such as technical innovations or maintaining industry in urban areas. ERA officials have indicated, however, that the predominant requirement is oil and/or gas savings.

If a petitioner who plans to operate a cogeneration facility cannot qualify to use oil or natural gas under the cogeneration exemption, it, like any other industrial facility, can still petition for exemption status under some other category--such as lack of adequate capital or environmental requirements.

ERA has attempted to encourage cogeneration by generally requiring less eligibility documentation for the cogeneration exemption than that which is required from noncogenerators seeking permanent exemptions. However, ERA's interim rules do not provide any preferential treatment for cogenerators seeking an exemption under some other category. For example, ERA can grant an exemption from the prohibition on petroleum and natural gas use due to the lack of an alternate fuel supply at a reasonable cost, if the cost of using the alternate fuel substantially exceeds the cost of using imported oil. All facilities petitioning exemption status under these conditions must prepare cost comparision data in accordance with ERA specifications. Accordingly, a potential cogenerator would also have to prepare and submit for approval the necessary documentation to obtain an economic exemption to use oil and natural gas.

Thus, petitioners with small facilities that can only economically use oil or natural gas, but cannot show oil or gas savings or otherwise qualify for the cogeneration exemption, are not encouraged to cogenerate. Small facilities, as indicated in chapter 5, require disproportionately higher investments before being able to burn coal. A cogenerator in this situation who seeks a cogeneration exemption but cannot prove oil or natural gas savings, must then seek an exemption under some other category, as explained above.

Another drawback of ERA's interim rules is that large potential cogenerators who can prove oil or natural gas savings are not required to disprove that they could have used alternative fuels in their facility. While ERA's rules recognize that net oil or natural gas savings are beneficial, the potential savings from that same facility using coal or other alternate fuels is even more desirable. We believe the rules should not encourage oil or gas cogeneration in a large facility if that facility could economically and environmentally use coal or alternate fuels.

We also believe that ERA's rules should encourage and not burden potential small cogenerators. ERA has great latitude in defining when oil and natural gas use is permissible for cogenerators. A cogeneration policy and strategy as we have outlined would enable ERA to eliminate some of the eligibility requirements for potential small cogenerators. Further, the development of a cogeneration strategy based on user classes would give recognition to the small industrial facility whose economies of scale for coal burning are infeasible, and simultaneously promote coal at the larger installations, where coal burning is favorable. If ERA, through the rulemaking, set a size limitation for the exemption of cogeneration facilities from the prohibitions of the Powerplant and Industrial Fuel Use Act, larger facilities would be encouraged to cogenerate using coal. At the same time, small and medium sized facilities would be encouraged to cogenerate using oil and natural gas as opposed to continued use of these fuels in inefficient package boilers.

Recommendations

We recommend that the Secretary of Energy, in consultation with other interested parties, including Federal agencies, industry, utilities, and State officials:

--Establish a cogeneration policy and strategy as outlined in the preceding sections. This would provide a framework around which responsible bodies, such as ERA and FERC, could promulgate rules and regulations to encourage cogeneration development. Among other things, the policy should encourage coal and alternate fuel use, but recognize that oil and natural gas use may be necessary for small and medium sized facilities in the short term. To implement this policy, cogenerators should be classified into user classes, designated by fuel input rates and by fuel use requirements.

--Specify oil and natural gas use goals within overall energy conservation goals for cogeneration by 1985, 1990 and 2000. These goals should recognize the need for small and medium sized facilities to use oil and natural gas for cogeneration during the transition period to renewable resources, and consider the oil and natural gas savings expected from coal and other alternate fuel based cogeneration. As such, the goals could be used to provide a measure of the effects of oil and natural gas cogeneration on regional and State energy consumption.

--Establish guidelines for monitoring oil and natural gas use goals for cogeneration. These guidelines should provide instruction to States for assessing the fuel use of each proposed cogeneration facility. The States could then determine the effects of cogeneration by user classes on State energy consumption. The guidelines should also provide for DOE regions to collect the State energy consumption data and determine if the projected fuel shifts will be in accordance with oil and natural gas use goals. This monitoring mechanism can be used to assess, at the national level, the contribution that cogeneration development will make on reducing oil imports.

We recommend that the Administrator of the Economic Regulatory Administration:

--Establish a rule for industrial cogeneration facilities that will set a size limitation, in terms of a fuel input rate, on those facilities eligible for the cogeneration exemption, thus allowing oil and natural gas use by small and medium sized facilities. This rule should be based on the categories of user classes as designated by DOE in the cogeneration policy. The user classes would be required to use certain types of fuel according to size.

--Expand the cogeneration exemption, in accordance with the categories of user classes, to include also those petitioners with large facilities that cannot use coal or other alternate fuels. This exemption should give recognition to regional differences which include access to coal or alternate fuels and environmental problems.

Agency and private organization comments and our evaluation

DOE and two industries commented that the recommendations covering the development of a national cogeneration policy are reasonable and that they concur with the recommendations to encourage large cogeneration facilities to use coal. DOE stated that the Federal Government should not be responsive to arguments from large industrial users to grant exemptions for cogenerators who wish to use imported fuels. Larger users may argue that if they burn scarce fuels in a cogeneration site, they can show a net reduction in imported fuel use for their heat and power. However, if their process heat and power can be generated from abundant domestic fuels (like coal), the imported fuel reduction will be significantly greater since the displacement of imported fuels is 100 percent as opposed to the typical cogeneration fuel savings of 10 to 30 percent.

DOE was concerned with our recommendation that the cogeneration exemption should give recognition to facilities which would incur economic and environmental problems as a result of coal use. DOE stated that sufficient studies of industrial cogeneration using coal in advanced technologies have been sponsored by DOE to suggest that all of the major industries will be able to cogenerate using coal with a return on investment of 10 to 30 percent and show a national emission reduction of 600 kilotons per year.

We recognize that advanced technologies will become available which will enable industries to cogenerate using coal. However, our policy, which is to be implemented for the short term, is based on technologies that are commercially available today. Once advanced technologies which are capable of using coal in an economically sound and environmentally safe way become commercially available, the policy should be revised accordingly.

Three industrial commenters had differing opinions on the policy which encourages coal and alternate fuel-based cogeneration with a controlled shift away from oil and natural gas and its implementing strategy. Some of the concern was that the policy did not encourage high electrical output cogeneration systems which maximize energy savings, or cogeneration systems which would maintain the current industrial fuel use patterns and the existing fuel distribution balance. In addition, there was concern that the establishment of user classes would require loss of flexibility and regimentation of industrial plants alien to U.S. industrial management.

We are recommending a cogeneration policy that is consistent with the Powerplant and Industrial Fuel Use Act of 1978. The act promotes the use of coal and other alternate fuels by prohibiting the use of oil and natural gas in new major fuel-burning installations. The act, however, recognizes the need for some facilities to use oil and natural gas by providing several exemption categories from the prohibition. We propose a cogeneration policy and strategy which supports the goal of greater coal use, but also encourages the more efficient use of oil and natural gas in those facilities that would normally be allowed to use these fuels. While a policy which encourages high electrical output systems would maximize energy savings, this policy would promote oil and gas fired cogeneration systems even when coal or alternate fuel use could be economical. Thus, the policy of encouraging maximum electrical output cogeneration systems in the short term would be counter to the goals of the Powerplant and Industrial Fuel Use Act.

The development of cogeneration, as explained throughout this report, involves many participants to overcome the complex constraints it faces. If cogeneration is to contribute to our Nation's conservation efforts in the short and long terms, we believe it will require a concerted, cooperative effort on the part of industry, utilities, and Federal and State Government agencies to somehow deal with these constraints.

National Energy Act cogeneration provisions should be developed to support the national policy

The administration's National Energy Plan announced in April 1977, included a proposal to eliminate energy waste and encourage more efficient use of fuels through the cogeneration of power and useful thermal energy. The intention of the administration was to achieve energy savings by encouraging industrial acceptance of cogeneration. The NEA, as enacted, contains several provisions which are intended to give impetus to cogeneration. These include authorizations for exemption from public utility regulation and from incremental natural gas pricing provisions.

The impact that the NEA provisions may have on cogeneration development is uncertain. In this respect, as discussed in chapter 3, our analyses show that cogeneration, even with selected incentives, will save only a small amount of energy in the near term. How effective the NEA provisions will be in encouraging cogeneration development and achieving maximum energy savings will depend to a large extent on the nature of the rules and regulations that are developed for their implementation.

We believe the rules and regulations being developed by FERC and the Treasury Department to carry out the NEA provisions should be structured to support the national cogeneration policy. In this light, the rules and regulations should be directed towards balancing Federal expenditures for encouraging cogeneration and removing artificial barriers that tend to constrain cogeneration. The NEA provisions and our views on the rulemaking are discussed below.

Rules defining a qualified cogeneration facility should include provisions to maintain fuel efficiency

The NEA states that only qualifying facilities are eligible for non-discriminatory utility rates, exemption from public utility regulation, and exemption from incremental natural gas pricing. FERC, in accordance with the Public Utility Regulatory Policies Act, has issued proposed rules prescribing requirements for becoming a qualified cogeneration facility. Although the rules set minimum fuel efficiency standards, they do not require that the cogeneration facility include a mechanism to ensure that the fuel efficiency benefits available with cogeneration are maintained.

To obtain the best fuel efficiencies in a cogeneration system, it is important that (1) the power and steam demands change proportionately to each other and (2) the cogeneration system be operated at the point for which it was designed and as close to the maximum hours a year as operation and maintenance requirements permit.

When power and steam demands do not change proportionately, a mechanism or special arrangement is needed to allow the system to continue operating at the design point and thereby maintain fuel-efficient ratios. One arrangement would be for the facility to be connected to the utility grid, thereby enabling it to purchase electricity during periods of low steam demand and selling electricity when steam demands are high.

Another mechanism would be to store energy within the facility. For example, a thermal storage system would help the cogeneration plant to operate at the design point over an extended period. Such a mechanism will, however, add considerably to the cost of the facility.

If the maximum benefits from cogeneration are to be realized, it is important that close attention be given to the design of the system. Natural gas users, in particular, that qualify for exemption from the NEA incremental pricing provision should provide a mechanism to maintain fuel efficiency in order to obtain the price benefits. Therefore, we believe the rules defining a qualified cogeneration facility should require that the cogenerator include in its design a mechanism or arrangement, such as discussed above, to ensure that the fuel efficiency benefits of cogeneration are realized.

Agency comments and our evaluation

In discussions with FERC staff, 1/ they indicated that many commenters on the Commission's proposed rules believe that economic considerations are of paramount importance to cogenerators and that optimizing economics would also provide the most efficient use of resources. As such, cogeneration facilities should be operated efficiently without additional rules. Likewise, DOE said that additional requirements are not necessary--good business practice dictates that a cogeneration system be operated most efficiently. Both the FERC staff and DOE suggested that provisions to maintain fuel efficiency should only be considered for cogenerators who have been granted an exemption from increased natural gas prices or have been given approval to use imported fuels.

We agree with the views expressed by the FERC staff and DOE. It is important, however, that a control mechanism be established to preclude possible abuse from those who may only be seeking lower natural gas prices. Therefore, we believe that a provision to maintain fuel efficiency should apply to those cogenerators who benefit from lower prices through an incremental natural gas pricing exemption.

Recommendation

We recommend that the Commissioners of the Federal Energy Regulatory Commission include, as part of their requirements for qualifying cogeneration facilities, a provision which requires industrial cogenerators to provide a means for maintaining fuel-efficient operations to the greatest extent possible. It is particularly important that this rule be made applicable to those industrial

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1/FERC was unable to officially comment on this report because of two pending Notices of Proposed Rulemakings regarding cogeneration. (See app. IX.)

cogenerators who will obtain exemptions from the incremental natural gas pricing provisions of the Natural Gas Policy Act of 1978.

Rules for just and reasonable rates must be equitable

The Public Utility Regulatory Policies Act of 1978 requires that electric utilities offer to buy power from and sell power to qualifying cogenerators at fair rates. In establishing rules for enforcing this part of the act, FERC is required to ensure that the rates are just and reasonable, in the public interest, and not discriminatory against qualifying cogenerators.

The act prohibits any rule requiring the utility to purchase power from a qualifying cogenerator at a rate which exceeds the cost if the utility were to purchase the electricity from another utility or generate it itself. However, to protect all affected with the purchase of cogenerated electricity, some mechanism needs to be established to outline (1) acceptable methods for determining utility costs for inhouse electricity generation and for acquiring electricity from other utilities and (2) the frequency with which these determinations should be made.

A mechanism to set just and reasonable rates is also needed for selling backup electricity to cogenerators. Utilities use standby charges to protect their investment in facilities which make backup service possible. Standby electricity rates vary throughout the country. Some considerations which may be apparent only at the State and local levels are the conditions of economic growth. In a no-growth situation, utilities may view cogeneration as eroding their baseload demand.

However, in areas where there are expectations of growth, utilities can look upon cogeneration as a realistic solution to their need for capital equipment to meet projected increases in baseload requirements. In this situation utilities would be more willing to sell power to and purchase power from industry. For example, in the State of California, two utilities have exempted cogenerators from the requirement to pay standby charges.

FERC has recently issued final rules, effective March 20, 1980, for utilities to sell and buy power from qualifying cogenerators. The rules, which recognize the diversity within State Public Utility Commissions, establish a mechanism to set just and reasonable rates. As part of this mechanism, the rules specify factors for purchasing electricity which will be considered during the ratemaking. As a minimum, a utility is required to provide certain services upon request, including supplementary power, backup power, and maintenance power to a qualifying cogenerator. From our initial discussion of this matter with the FERC staff and our reading of the final rules, we believe the rules are adequate to carry out the provisions of the act. We also believe that if FERC ensures that the rules are properly implemented, they will make cogeneration more attractive to industrial facilities.

Recommendation

We recommend that the Commissioners of the Federal Energy Regulatory Commission ensure that the rules adopted to establish just and reasonable rates for the sale of power to and the purchase of power from qualifying cogeneration facilities are fully implemented by State regulatory authorities and nonregulated electric utilities.

The regulatory status of cogeneration facilities needs to be determined

From an industrial cogenerator's viewpoint, the most serious consequence of selling electricity is the possibility of being regulated as a utility. Industries want to avoid any organizational structure which will increase the jurisdiction of regulatory agencies over their facility.

A provision is included in the Public Utility Regulatory Policies Act to remove the threat of regulation for some facilities. Under the act, qualifying cogeneration facilities may be exempted from certain provisions of the Federal Power Act, the Public Utility Holding Company Act of 1935, and State utility laws and regulations so as to remain unregulated. In defining a qualifying cogeneration facility, the Public Utility Regulatory Policies Act excludes a facility which is owned by a person primarily engaged in the generation or sale of electric power. However, there was some uncertainty about the degree to which a utility's involvement in a cogeneration facility would preclude the facility's eligibility for exemption under the act.

FERC has proposed rules prescribing requirements which a qualifying cogeneration facility must meet. These rules state that if more than 50 percent of the entity which owns the cogeneration facility is composed of electric utility interests, then the facility may not be granted qualifying status. FERC has also issued rules which specify the exemptions from Federal and State regulations provided to qualifying facilities. We believe the rules clarify the uncertainty of regulation for those cogeneration facilities which have utility ownership interest. In our view, if these rules are adopted and properly implemented, they should remove the threat of utility type regulation for industrial cogeneration facilities.

Recommendation

We recommend that the Commissioners of the Federal Energy Regulatory Commission clarify the regulatory status of cogeneration facilities by (1) adopting their proposed rules which define a qualifying cogeneration facility as one which is not composed of more than 50 percent electric utility ownership and (2) ensuring that the rules which exempt qualifying facilities from certain Federal and State laws and regulations are properly implemented.

Cogeneration exemption from incremental natural gas pricing provisions should be based on user classes

Provisions of the Natural Gas Policy Act of 1978 will incrementally increase gas prices for certain industrial users to the Btu equivalent of substitute fuel oil. FERC is required to develop implementing rules applicable to industrial boiler fuel facilities and other industrial users designated as subject to incremental pricing. The act provides, however, that a qualifying cogeneration facility is exempt from these incremental pricing provisions to the extent allowed by FERC rules.

The exemption of a cogeneration facility from these price increases can contribute to improving its economic attractiveness. In accordance with our proposed cogeneration policy which designates user classes, the small and medium size cogenerators should be allowed to use natural gas as a fuel. FERC should also exempt these cogenerators from the natural gas incremental pricing provisions. By basing the exemption on user classes, FERC can avoid making gas use too economically attractive for those larger cogenerators who could use coal. However, in areas where coal burning is environmentally unacceptable or alternative fuel use is inhibited for any reason, specific exemption for the large qualifying cogeneration facilities from the incremental pricing provisions should be considered.

Recommendation

We recommend that the Commissioners of the Federal Energy Regulatory Commission, after the Department of Energy establishes the user classes recommended earlier:

--Develop rules which specify, in terms of user classes, the exemption of qualifying cogeneration facilities from the incremental natural gas pricing provision. These rules should be consistent with the rules developed by ERA for the exemption of cogenerators from the Powerplant and Industrial Fuel Use Act.

Agency comments and our evaluation

In commenting on this section, FERC staff did not take any position concerning the recommendation. However, they noted that while FERC regulations provide exemption from incremental gas pricing for all qualifying cogeneration facilities, any new facilities defined as major fuel-burning installations will have to secure a prohibition exemption for using natural gas from ERA.

DOE concurred with this recommendation. However, they stated that caution should be exercised in granting exemptions to small industrials who wish to get natural gas at an artificially low price. In particular, DOE said, if it can be shown that coal-burning fluidized-bed combustion is commercially available for small steam generation and there is no negative return on investment for its site specific installation and use, one might reasonably question why an exemption would be granted to stay on natural gas when homeowners would be paying as much for gas as oil.

We agree. As technology makes coal use economically suitable for small cogenerators, the policy basing oil and natural gas use on a facility's size should be reevaluated.

Cogeneration systems should not be eligible for the investment tax credit

The NEA, as originally proposed, contained provisions under which cogeneration property could qualify for an additional 10-percent investment tax credit. However, the final version of the Energy Tax Act of 1978 did not contain the section which specifically defined cogeneration property. Under the specially defined and alternative energy property provisions of the act, however, some components which can be used in a cogeneration system are identified as being eligible for the 10-percent tax credit.

In addition to the types of property specifically cited in the act, the Secretary of the Treasury has broad authority to specify other energy conservation equipment as eligible for this tax credit under the category of "specially defined energy property." Additional equipment may be specified provided that it is installed in connection with an existing industrial or commercial facility and its principal purpose is reducing the amount of energy consumed in any existing industrial or commercial process. Cogeneration equipment could meet these criteria.

DOE has described two options for including certain cogeneration systems under the regulations for specially defined energy property pursuant to the act. Option 1 would restrict the credit to ancillary equipment used in connection with alternative (coal) fuel fired systems. This would exclude tax credits for boilers or burners and for all cogeneration systems which use oil or gas. Option 2 would expand the coverage by allowing cogeneration systems which use oil or gas, but would exclude the tax credits for boilers or burners used in connection with such systems.

According to the Treasury Department, the tax credit, if applied, could cost the Government $500 million in revenues over the period 1979-1984. In discussions with Treasury officials, they have expressed a position that cogeneration systems will not be eligible for the tax credit. Treasury interprets the act and its legislative history to preclude such action.

We support this position from a policy standpoint. We recognize that return on investment is an important consideration for industry in evaluating a potential cogeneration application. Although a tax credit would improve the rate of return, our analyses show that a 10-percent tax credit for complete cogeneration systems would not, in itself, be sufficient to encourage general acceptance of cogeneration. For example, we evaluated several actions to encourage cogeneration in the incentives case, including a 20-percent tax credit--double the NEA's proposal. Our analyses showed that these incentives resulted in little additional cogeneration over the status quo. Thus we believe a 10-percent tax credit is insufficient to sway industry towards cogeneration.

In essence, the tax credit would only reward those who were planning to cogenerate regardless of a tax credit. To become a meaningful incentive for inducing cogeneration, we believe a large tax credit would be needed, possibly even 40 to 50 percent. Therefore, considering the cost in lost revenue to the Government and the small additional cogeneration resulting from proposed financial incentives, we believe cogeneration systems should not be eligible for the additional 10-percent tax credit.

Recommendations

We recommend that the Secretary of the Treasury, in consultation with the Secretary of Energy:

--Establish, for the short term, a regulation which specifies that cogeneration systems would not be eligible for the 10-percent investment tax credit under the provision for specially defined property in the Energy Tax Act of 1978.

--Assess the impact and benefits that any Government financial incentives may have on cogeneration development before any such incentives are established for the long term.

Agency and private organization comments and our evaluation

The Department of the Treasury had no comment on these recommendations. Of the six industries who commented on this issue, three stated their preference for a tax credit, while the remaining three agreed with our position that a 10-percent tax credit would not encourage general acceptance of cogeneration. DOE also disagreed with the recommendation prohibiting a tax credit for cogeneration systems. Every favorable action helps, DOE said, and can have a positive impact. We agree that a tax credit can be beneficial in some cases; however, even DOE acknowledges that the sensitivity of return on investment to tax credits is low. We therefore maintain that a tax credit, when the benefits are weighed against the costs, is not now merited. This situation may change, as recognized in our second recommendation, in which DOE concurs.

Office needed to oversee cogeneration activities

Because of the many issues affecting the acceptance of industrial cogeneration and the numerous organizations within both the public and private sector that are involved in these issues, an office should be designated within DOE to serve as an overseer and coordinator for all cogeneration-related activities.

The term "cogeneration" has attracted much attention since the National Energy Plan proposal in 1977. Interest has come from industry, utilities, State and local officials, and various Federal agencies, as well as individual cogeneration proponents. For example, in July 1977, a task force, consisting of representatives from ten Federal departments and commissions, was established and charged with coordinating Federal activities in this area. However, responsibility and authority for any agency action remained with that agency and not with the task force. Given these restrictions, the task force perceived its role as simply providing an information exchange for Federal and State governments and private concerns.

Another DOE cogeneration task force was established in August 1978, to determine the marketing or commercialization capability of cogeneration. The task force proposed a commercialization strategy of Federal marketing initiatives which would focus on three major areas--(1) a technical efforts program to stimulate industry interest, and to develop and demonstrate the latest technology, (2) a national commercialization program which will include the development and maintenance of a national cogeneration inventory and information system, and (3) a State and regional commercialization program which would be oriented toward development of actions to overcome cogeneration constraints.

In response to the above task force report, an implementation plan for cogeneration commericialization was proposed in October 1978 by DOE's Office of Conservation and Solar Applications. The plan emphasized the importance of State policies for creating a favorable environment for cogeneration development. The two major program elements designed to facilitate the coordination and integration of various Federal and State efforts to stimulate industrial cogeneration development are composed of a Research Technology Development and Demonstration Program, and a Planning, Policy, and Technical Assistance Program. These programs, based on improving the technology mix and market penetration of cogeneration, have an estimated budget authorization of $43 million from fiscal year 1979 to 1981 allocated among five separate DOE organizations.

As explained in chapter 5, there are many issues affecting the acceptance of industrial cogeneration. The constraints are primarily economic with institutional, regulatory, and technical overtones. Overcoming these constraints is complicated by the many different groups concerned with and affecting cogeneration. Beyond DOE, the Environmental Protection Agency, the Securities and Exchange Commission, Public Utility Commissions, State Energy Commissions, electric utilities, the International Cogeneration Task Force, and other parties, such as equipment manufacturers and trade organizations, all have some interest in cogeneration issues.

DOE has previously been made aware of the necessity for an office to coordinate and integrate cogeneration activities. In this respect, the Cogeneration Commercialization Plan proposed a program office to serve as a focal point for all cogeneration activities. The office would assign responsibilities to the appropriate DOE organizational units and see that the responsibilities are carried out. The office would also serve as a primary liaison with State energy offices and other non-Federal cogeneration-related organizations.

We believe such an office can be a useful tool to evaluate the efforts being made, both inside and outside DOE, to promote cogeneration. Based upon these assessments, the office can provide direction to the individual DOE divisions, other Government agencies, and the private sector on prioritizing which issues need to be addressed to eliminate cogeneration constraints. Further, the office can serve as a technical advisor to all interested parties.

Agency comments and our evaluation

DOE stated that while the problems being addressed are appreciated and understood, it does not seem reasonable to create a special office to service just one utilization approach for fuels. We concur with DOE that creating a special office to service cogeneration activities may not be warranted. We are aware that organizational changes are being made within DOE so that all of the functions related to a single technology are grouped together in order to improve the technology development and speed the transition of the technology to the private sector. In line with these changes, we believe an existing office, such as the Commercialization

Office within the Division of Conservation and Solar Applications, could be assigned with the responsibility to follow cogeneration activities both in the Federal and private sectors. Whatever office is assigned this responsibility, the coordination and the overseeing of cogeneration activities must become an important function.

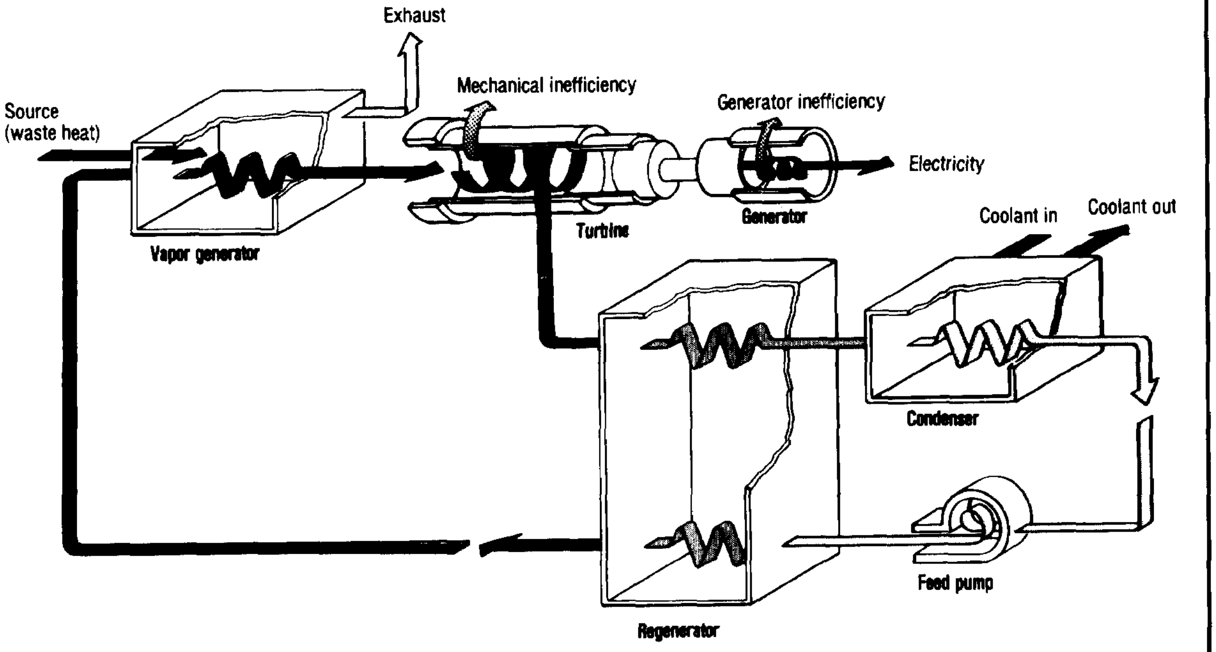
Recommendation

We recommend that the Secretary of Energy designate one office to be responsible for overseeing cogeneration-related activities. It should also be responsible for identifying and assessing the efforts being made to eliminate cogeneration constraints.

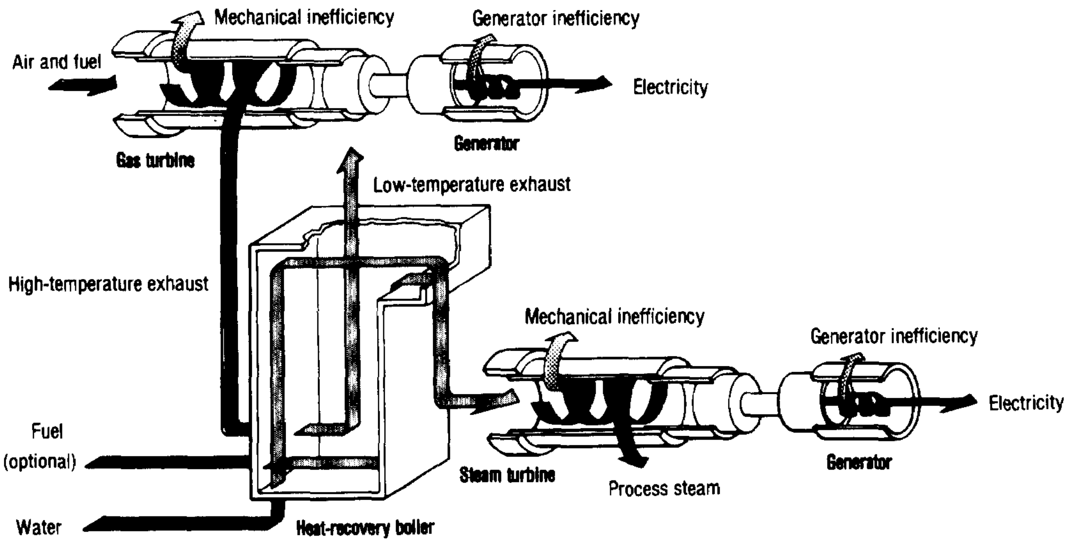
APPENDIX I

DIAGRAM ILLUSTRATIONS OF BOTTOMING AND COMBINED CYCLE COGENERATION SYSTEMS

Rankine bottoming system.



Combined-cycle topping system.



Source: Department of Energy-Resource Planning Associates, Inc. Cogeneration: Technical Concepts Trends Prospects, Sept. 1978

TECHNICAL ASPECTS

OF

COGENERATION

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INTRODUCTORY REMARKS

Cogeneration offers itself as an effective measure by which industrial users can significantly contribute to the conservation of valuable fossil fuels. This paper will discuss the predominant technical factors which enter into the matching of cogeneration systems to specific industrial requirements in power and process heat. It will concern itself primarily with thermodynamic parameters and not with the economics of various systems. It will also not deal with questions of ownership, institutional constraints and the like.

All data presented in the tables for the various prime movers are average values and have been selected in a manner which permits easy comparison between various configurations of cogeneration systems.

INDUSTRIAL USE OF ENERGY

Industrial manufacturing processes require energy in the form of power and process heat; their operation depends on the input of energy, generally in the form of electricity and of fossil fuels.

Figure II-1 presents in schematic form, how energy is applied in the form of power or heat in the manufacturing process. Common to the industrial generation of power and heat is a combustion process in which a fossil fuel (solid, liquid, gaseous) is burned in the presence of air, creating hot combustion gases.

Power is then generated by prime movers such as turbines or reciprocating engines. They can be in an open cycle configuration (example: internal combustion engines) or a closed cycle configuration (example: steam turbine).

SOME FUNDAMENTAL THERMODYNAMICS

The combustion of a fuel generates hot combustion gases; heat is transferred from these combustion gases to a working medium or to a work piece. Whatever the transfer mechanism (radiation, convection, conduction) the temperature of the combustion gases will decrease as heat is withdrawn.

Available heat is that heat content which can be converted to work by reducing the temperature of the combustion gas from its high initial value to ambient temperature. The heat content of the gas at ambient temperature is unavailable and cannot be converted to work.

In an ideal conversion process, an equivalent exists between work and available heat:

1 kWh = 3413 Btu

In practice all conversion processes are subject to losses; they do not utilize to the fullest the available heat. Thus an internal combustion engine will only convert one third of the available energy into useful work at the coupling, one third will be expelled as exhaust gases, and one third will be dissipated through the cooling system. Thus, two-thirds of the available heat is released into the environment as reject heat.

Figure II-1 shows the generation of power and process heat as two completely independent processes. The question then presents itself whether the reject heat emanating from a prime mover can be put to use as process heat.

The quality of the reject heat depends on the specific heat content of the medium in Btu/lb. In many cases the specific heat content of the reject heat is high, as for instance, in the exhaust gases of a combustion turbine at high temperatures. It can also be quite low as in the cooling water released from a central power station; large mass flows are released into the environment at small temperature differentials above ambient.

Reject heat at high temperature can be utilized as industrial process heat. Then (unlike as shown in Figure II-1), one and the same combustion process supports sequentially the generation of power and of process heat. This is called cogeneration. The reject heat of one process becomes the input for a subsequent process.

Expressed differently, cogeneration refers to "cascading" the heat content of a medium by reducing its temperature from an initial high value to a low value by withdrawing heat alternatingly generating power or process heat.

CHARACTERISTICS OF COGENERATION

Where power generation precedes heat application, this is called topping. This is shown in Figure II-2 in some typical configurations. Where power generation follows a process heat application, this is called bottoming. This is shown in Figure II-3 in typical configurations.

A special case of cascading is the combined cycle where the exhaust gases of a combustion turbine raise steam in an exhaust heat boiler which is then expanded through a steam turbine. A combined cycle can be followed by the extraction of process heat thus becoming part of a cogeneration system.

A very convenient vehicle to transport heat from a source to the application offers itself in the form of steam. Process steam is very extensively used as a transfer medium by many industries. Therefore, the following considerations will restrict themselves to systems which cogenerate steam in a topping configuration. A prime mover extracts heat from a combustion gas and the reject heat of the prime mover is utilized as process steam.

Restricting the discussion to the topping of process steam and excluding the cogeneration of process heat is justified if only fully proven technologies are to be considered (see e.g. ref 1).

INDUSTRIAL POWER AND STEAM REQUIREMENTS

Access to and availability of process steam is a critical factor in industrial operations. Cogeneration units must therefore be geared to produce process steam in the quantities (lb/hr) and heat content (Btu/lb) required. The heat content of the steam is given, if its pressure (psig) and temperature (degrees F) are specified.

The power demand for a given steam demand is described in the power/steam ratio. The power requirements vary not only from industry to industry, but also from one plant to another.

Table II-1 gives some average values for the power/steam ratios for some industries. 2/

Table II-1
Average Values For The Power/Steam Ratios

Industry	Number of samples	Power/steam demand ratio kWh/million Btu steam average	highest sample
paper and pulp	12	35.4	96.5
chemical	13	51.4	117.3
refineries	16	31.2	53.8

Thus in a typical paper mill with a steam demand of 500,000 lb/hr (or 500 million Btu/hr for an average latent heat of steam at 1,000 Btu/lb) the power demand will be 17,700 kWh/hr or (at a 100% load factor) a generating capacity of 17.7 MW will be required to meet the power demand.

CHARACTERISTICS OF VARIOUS PRIME MOVERS AS TOPPING UNITS

A cogeneration plant can be designed to generate power and steam for a number of supply conditions:

* It can be operated to match power and steam demand at all times; no electricity has to be imported except for plant maintenance or in emergencies,

* the steam demand is met at all times, but additional electricity still has to be purchased, or

* the steam load is always matched, but power generated is in excess of the power demand. Power demand must then be exported and will either be wheeled or purchased by the utility.

Whether electricity will be imported or exported depends on the selection of the prime mover or of a prime mover mix.

The performance of a prime mover in a topping configuration is characterized by two parameters:

* the power/steam ratio, which can be achieved in topping a given amount of steam, and

* the incremental heat rate which is required to generate that power in addition to the heat required to produce the steam.

Both power/steam ratio and incremental heat rate are functions of the inlet conditions of the working medium at the prime mover and the properties of the steam (pressure, temperature) to be produced.

The incremental heat rate is lower than the heat rate required in central power station generation. It reaches a minimum when steam and power demand are matched. Expressed differently this means that for a given power output of the prime mover, the steam demand is at a maximum. If the steam demand decreases and the power demand remains constant, then the incremental heat rate will increase. In fact, if the steam demand drops to zero the incremental heat rate approaches the central power station heat rate.

Thus the matching of steam and power demand is an important consideration; operation of the plant at design point will maximize the benefits to be derived from cogeneration.

Table II-2 gives some typical ranges for the operating charcteristics for four prime movers in a steam topping configuration.

Table II-2
Ranges of Operating Characteristics of Prime Movers

	power/steam ratio $kWh/10^6$ Btu	incremental heat rate Btu/kWh	steam pressure psig
steam turbine (backpressure)	30 - 70	4500 - 6000	15 - 600
gas turbine	125 - 220	5500 - 6500	150 - 600
combined cycle (backpressure)	200 - 320	5000 - 6000	15 - 600
Diesel	400 - 500	6500 - 6700	15 - 150

Table II-2 illustrates that for the industries listed in Table II-1 the installation of prime movers other than the steam turbine will produce electricity in excess of their demand.

Table II-3 will compare the four prime movers regarding their fuel utilization and their energy savings potential. Average values are assumed for the power/steam ratio and the incremental heat rates. When the cogeneration of power and steam is compared to separate cogeneration of power and steam, it is assumed that the central station heat rate is 10,000 Btu/kWh and that boilers operate at an efficiency of 83%. The same efficiency is also assumed for the heat exchangers in the exhaust stream of gas turbines and Diesels.

Table II-3 illustrates a few important points of interest to the industrial end user, whose energy demands are largely dictated by his demand for process steam.

Fuel savings attainable through cogeneration are highest for the diesel and lowest for the steam turbine. The share of the fuel used to generate power is lowest for the steam turbine and highest for the diesel. In fact, in the case of the steam turbine the larger portion of the heat content of the fuel leaves the system in the form of steam; in the case of the diesel the opposite holds.

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Table II-3
Characteristics of Cogeneration Technology

Cogeneration characteristics	Units	Steam turbine (backpressure)	Gas turbine	Combined cycle (backpressure)	Diesel
Power/steam ratio	kWh/million Btu steam	50	200	250	400
	Btu power/Btu steam	.171	.683	.853	1.365
Incremental heat rate	Btu/kWh	4700	5800	5500	6500
	Btu fuel/Btu steam	.235	1.160	1.375	2.600
Cogeneration					
fuel consumption	Btu fuel/Btu steam	1.488	2.365	2.375	3.805
power/fuel ratio	Btu power/Btu fuel	.115	.289	.359	.359
steam/fuel ratio	Btu steam/Btu fuel	.672	.423	.421	.263
fuel utilization	%	78.7	71.2	78.0	62.2
Separate generation					
fuel consumption	Btu fuel/Btu steam	1.705	3.205	3.705	5.205
Savings by cogeneration					
fuel consumption	Btu fuel/Btu steam	.22	.84	1.33	1.4
	%	12.9	26.2	35.9	26.9

This makes the diesel an excellent power source, but a poor steam generator. Thus to obtain 100,000 lb/hr of steam will require the installation of a large and expensive diesel with a capacity of 4 MW.

The choice of a prime mover will always be affected by their dependency on specific fuels:

steam turbines: all fuels, solid, liquid, gaseous including waste

combustion turbines: currently limited to natural gas and light distillates up to #2 oils

diesels: natural gas and diesel fuels up to #4 oils; large diesel also #6 oils.

SOME FUTURE DEVELOPMENTS ON COGENERATION

In order to increase the savings potential of cogeneration systems the following options present themselves:

* increase inlet temperatures for specific prime movers. This applies particularly to combustion turbines.

* simplify the combustion of solid fuels and reduce the environmental impact of "dirty fuels"; fluidized bed boilers show considerable promise in this direction.

* substitute or introduce closed cycle operations such as the Stirling cycle, for open cycles. This will permit the use of solid fuels instead of valuable gaseous or liquid fuels.

* introduce the heat pump as a means to elevate low quality reject heat to industrial process steam.

The following table utilizes some of the information of the General Electric Cogenèration Technology Alternatives Study (CTAS) and indicates some of the characteristics of advanced concepts. 3/

Table II-4
Characteristics of Advanced Cogeneration Configurations

Configuration	Advancement	Power/Fuel Ratio Btu/Btu	Steam/Fuel Ratio Btu/Btu	Overall Efficiency Btu/Btu	Other characteristics
Steam turbine	-atmospheric fluidized bed	0.11	0.75	0.86	400 degrees F steam
Gas turbine	-2200 degrees F inlet temperature	0.31	0.48	0.79	invariant with steam temperature
Helium closed cycle	-closed cycle gas turbine -atmospheric fluidized bed heater -regenerator	0.31	0.14	0.45	350 degrees F steam
Stirling cycle	-Stirling engine -coal fired heat exchanger	0.28	0.45	0.73	process at 228 degrees F
Diesel plus heat pump	-vapor compressor heat pump (diesel jacket outlet at 250 degrees F)	0.31	0.44	0.75	400 degrees F steam

APPENDIX II

Pollution control measures and economic considerations may in many instances discourage the industrial end user to burn coal as the primary fuel in cogeneration plants.

Large centralized conversion plants, which produce liquid or gaseous (high or mid BTU gas) fuels from coal will eliminate many of the problems associated with coal handling and pollution control and may promote the introduction of cogeneration systems.

EFFICIENCY AND OPERATING CONDITIONS

Efficiency - and consequently economics - are best

* When the prime mover operates at design point where its efficiency reaches a maximum,

* Where power and steam demand are balanced at all times,

* When the load factor is high, that means that the plant runs at design point at close to 8760 hours a year, as maintenance requirements permit.

In practice these conditions can not always be met: partial load conditions or overloads (as well as mismatched power/ steam demands) will reduce the efficiency of the overall system.

If power and steam demand do not change proportional to each other, special arrangements must be made to maintain high efficiency. This may involve purchases of electricity during periods of low steam demand and sale of electricity when the steam demand is high. Energy storage (e.g. thermal storage) could alleviate some of the problems. Installation of a number of small modules rather than a few large units has similar effects.

Where the load factor is too low, then capital related costs will outweigh fuel related costs and render a system uneconomical. 4/

Power and steam generation are rather rigidly coupled where the working medium in the prime mover is also steam, as in the case of a back pressure or extraction turbine. In the case of combustion turbines or internal combustion engines, the coupling is less rigid; thus changes in steam demand will be reflected in changes in the exhaust stack temperatures.

Efficient power generation is the driving force in a utility; therefore, base load operation is the most desirable modus operandi. By contrast in industrial operations, meeting the steam demand is the dominant consideration. But even then the efficiency of a cogeneration system is highest if it operates as close as possible to base load conditions (design conditions) in a well balanced power steam demand situation.

SUMMARY

The choice of a cogeneration system depends on a number of highly plant and site specific factors if it is to be efficient both in technical performance and in economic terms.

The main technical and economic factors to be considered in the design of a cogeneration system are:

* Power demand, daily and seasonal variations;
* Steam demand, daily and seasonal variations;
* Annual load duration curves for steam and power;
* Load factors for power and steam;
* Process steam properties;
* Fuel availability and costs (including waste material);
* Electricity availability and cost;
* Life cycle costs;
* Life cycle energy savings;
* Environmental constraints.

References

1/ Resource Planning Associates, Inc., Potential for Cogeneration Development in Six Major Industries by 1985, Cambridge, Massachusetts, December 1977, p. 5.

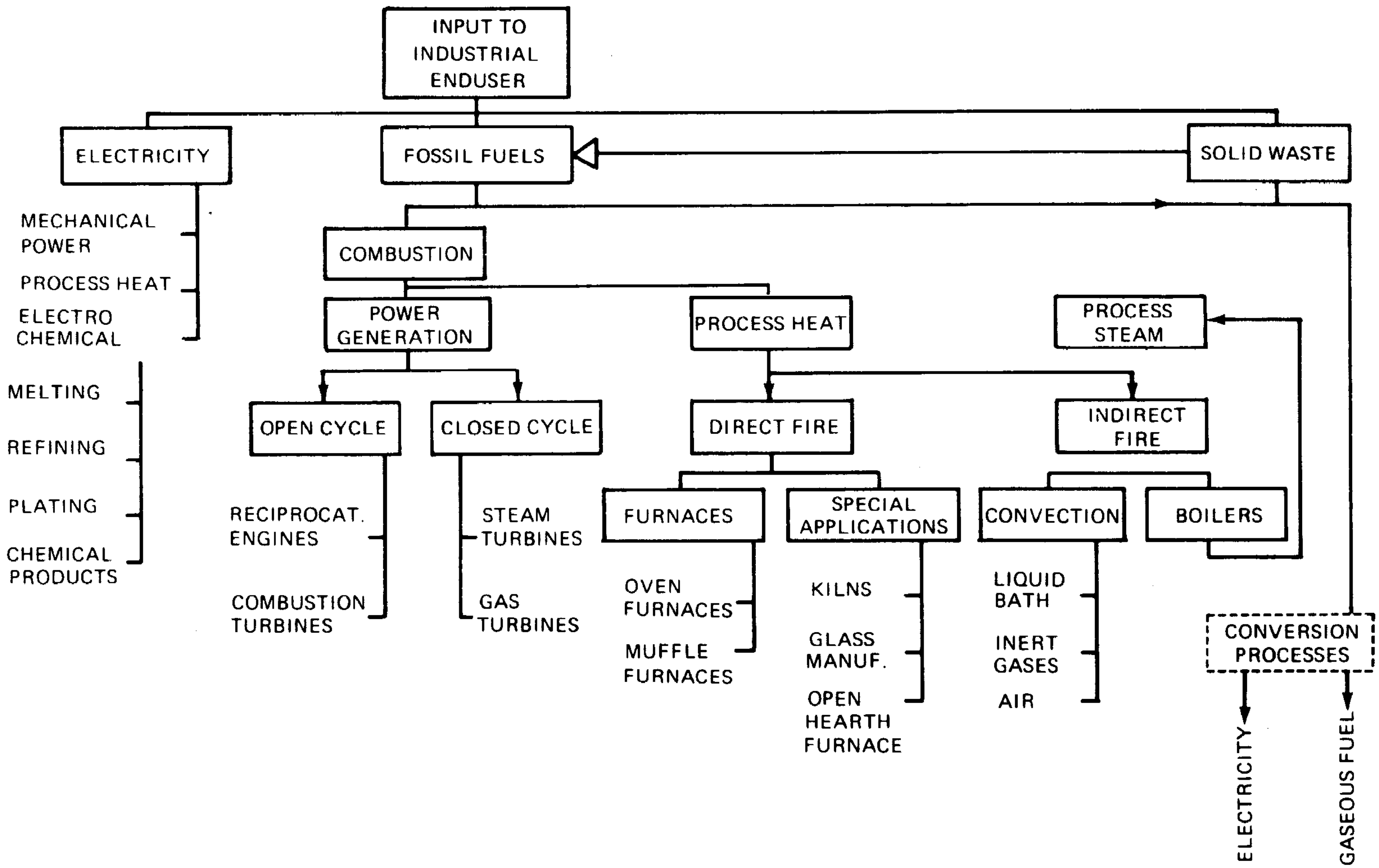
2/ Resource Planning Associates, Inc., A Technical Overview of Cogeneration - The Hardware, The Industries, The Potential Development, December 1977, pgs. 3.2, 3.3, and 3.4.

3/ General Electric, Cogeneration Technology Alternatives Study, final Briefing in Washington, D.C., April 27, 1979, pgs. 3.7, 3.10, 3.11, 3.13, and 3.15.

4/ J. A. Orlando, H. A. Gorges, An Assessment of Current Issues Regarding Cogeneration, Energy Technology VI, 1979, p. 157.

FIGURE II-1

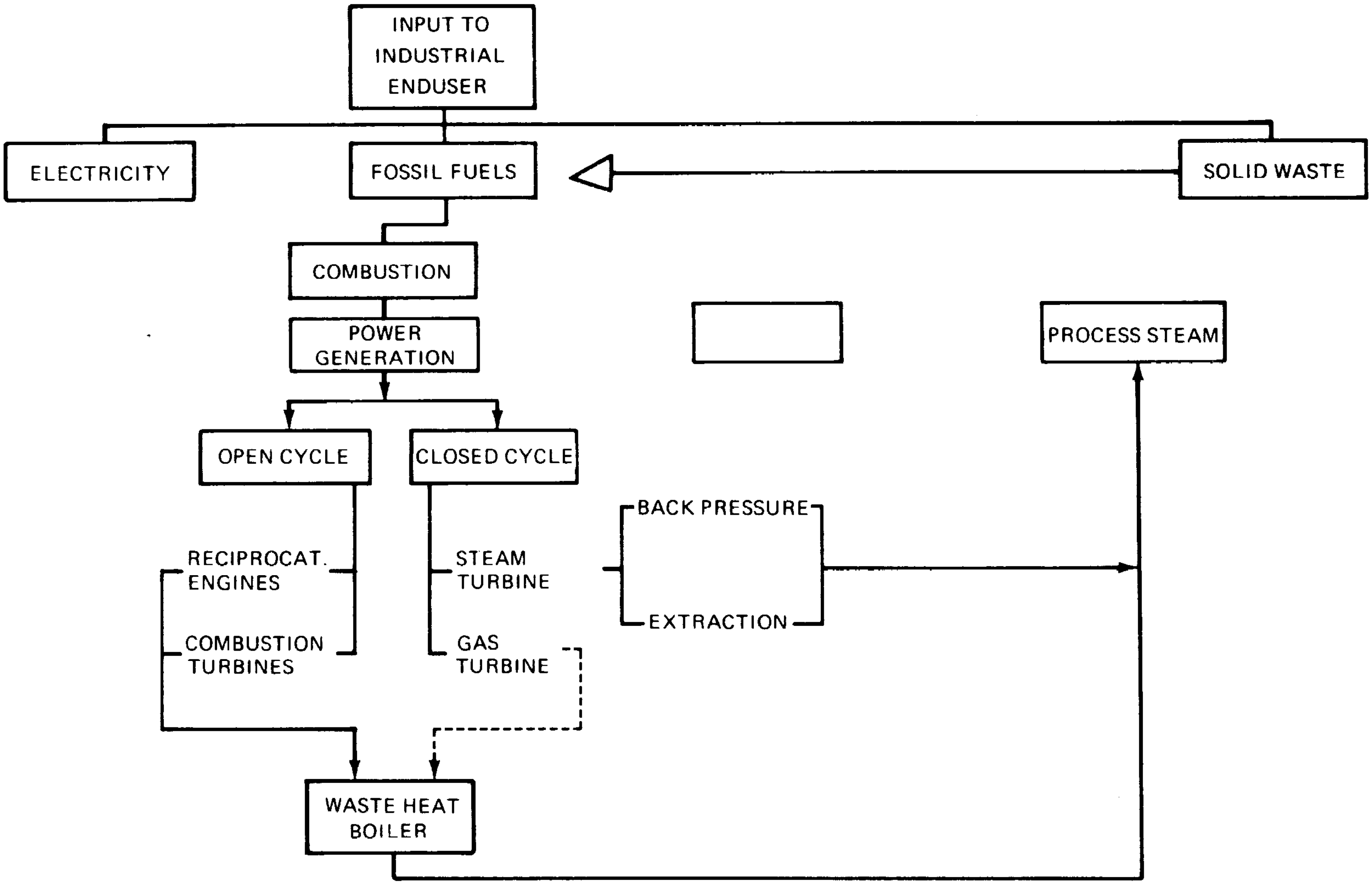
INDUSTRIAL ENERGY CONVERSION WITHOUT COGENERATION



APPENDIX II

FIGURE II-2

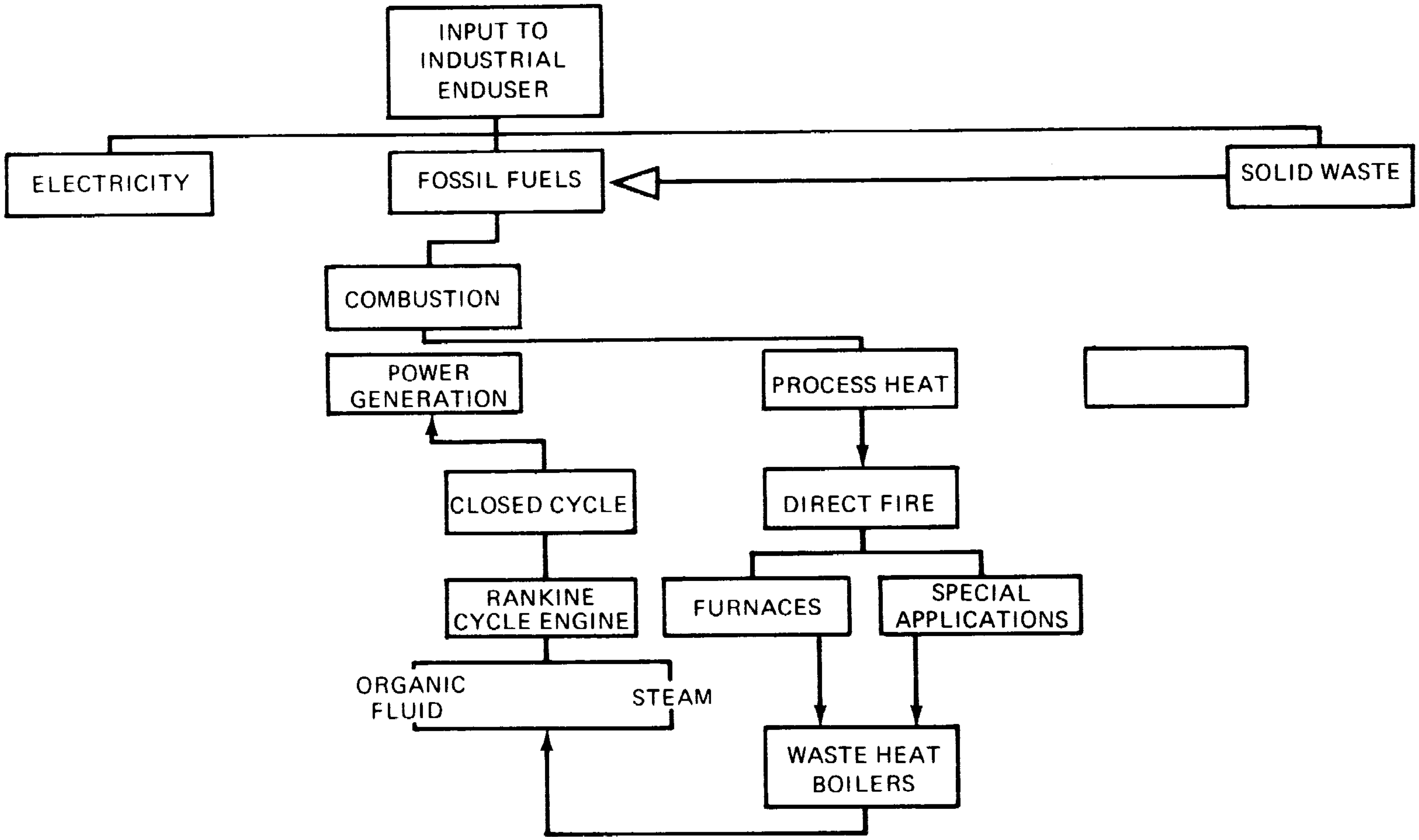
INDUSTRIAL ENERGY CONVERSION WITH TYPICAL TOPPING CONFIGURATIONS



APPENDIX II

FIGURE II-3

INDUSTRIAL ENERGY CONVERSION WITH TYPICAL BOTTOMING CONFIGURATIONS



APPENDIX II

DESCRIPTION OF SCENARIO DATA

DEVELOPMENT

In chapter 3 we describe the objectives, assumptions, and methodology for four cases of potential cogeneration development by 1985. The purpose of this appendix is to further describe the methodology employed in determining the amount of steam and electricity cogenerated and the resultant industrial and utility fuel shifts.

Four cases or scenarios were developed for the paper and pulp, the chemical, and the petroleum refining industries:

--a no action case assuming that some cogeneration will develop under the status quo without government incentives or further disincentives,

--an incentives case which includes the additional cogeneration resulting from government incentives such as a 30-percent tax credit, and exemption from regulations,

--an economic maximum case based upon the incentives case, providing an upper economic cogeneration limit, and

--a technical maximum case addressing the maximum cogeneration technically possible.

The amount of steam and electricity cogenerated in each case was based on the RPA study, "The Potential for Cogeneration Development in Six Major Industries by 1985." In the no action and the incentives cases (see tables III-1 and III-2) the amounts of steam and electricity are distinguished by the types of systems used to cogenerate. These types of systems, gas and steam turbines, are also separated by the fuels used--coal, oil, natural gas, and others.

In the economic maximum case (see table III-3) we assume that the same amount of steam cogenerated in the incentives case is also economically attractive in this case. However, instead of using RPA's mix of coal, oil, and natural gas-fired gas and steam turbines for producing steam, this steam is assumed to be cogenerated exclusively by distillate-fired gas turbines which produce electricity at the rate of 200 kWhs per million Btu's of steam. In order to represent an economically feasible situation, we also assume that cogeneration with waste fuel and heat recovery steam turbines will continue as in the incentives case.

In the technical maximum case, we assume that all technically suitable process steam in 1985 1/ will be cogenerated by distillate-fired gas turbines. (See table III-4.) The amount of electricity produced, determined at the 200 kWhs per million Btu's steam rate, is very similar to Thermo Electron's figures 2/ for the potential for inplant generation by gas turbine topping: for the paper and pulp industry 210 billion kWhs; for the chemical industry 274.19 billion kWhs; and for the petroleum refining industry 140.385 billion kWhs per year.

The effects of cogeneration in terms of industrial and utility fuel shifts were computed on a State level so that the results could be compiled into various regional totals for use in further analyses. The same methodology for apportioning cogenerated steam and electricity and computing resultant fuel shifts was used consistently for each industry within each scenario. Throughout the methodology, steam and the fuels used to produce steam are interchangeable because they are expressed in the common factor of trillion Btu's. The methodology is divided into three major sections: 1) the fuel saved by industry, 2) the fuel saved by utilities, and 3) the fuel used to cogenerate.

In the first section, we assume that industry will save fuel since conventionally produced steam is replaced by cogeneration. Industrial fuel savings are computed using the steam cogenerated with the fuels, oil, coal, and natural gas. To convert the replaced steam into the fuel used to produce it, cogenerated steam is multiplied by 1.2 to reflect industries' 83-percent fuel use efficiency. The fuel is then allocated by the State, based on each industry's total purchased fuel use in 1975, 3/ by dividing each State's fuel use by the U.S. total.

The next step determines the types of fuels industry uses to produce steam. We used two sources for the allocation, Thermo Electron's regional figures for the average fuel mix industry uses to produce steam 4/ and the Census Bureau data of industrial fuel use by State. 5/ By multiplying together the percentages of fuel use from both sources, we were able to develop, by State, the industrial fuel use patterns for residual oil, distillate oil, coal, and natural gas. These patterns, in percentage form, were multiplied by the fuel savings allocated for each State. The result is the oil, coal, and natural gas fuel savings for industry stated in trillion Btu's.

The second section computes utility fuel savings assuming cogenerated electricity replaces an equal amount of utility generation. The amount of cogenerated electricity, being directly related to steam, is allocated among the States using the same proportioning method as described in the first section, that is, based upon each industry's total purchased fuel use in 1975. The electricity is then converted to fuel saved by assuming that utilities require 10,000 Btu's of fuel for each kWh of electricity produced. These fuel savings by State are finally allocated to the types of fuel saved in the same proportion as utilities used fuels to produce electricity in 1976. 6/ We assumed that utilities would maximize their savings with fossil fuels; residual oil, coal, and gas; while nuclear and hydro generating would not be affected by cogeneration. Distillate oil was not considered to have a large impact and therefore was included within residual oil figures. Average utility fuel use percentages for all types of fuels versus for fossil fuels only can be compared in tables III-5 and III-6.

The last section computes the fuel industry needs to cogenerate by multiplying the amount of electricity cogenerated in each State, computed in the second section, by a factor which converts the electricity into the amount and the types of fuel projected as producing it. The first step in developing this factor is to determine what types of fuels are used. RPA's data on electricity generation identifies the methods used to cogenerate: coal-fired steam turbine, residual oil-fired steam turbine, distillate oil-fired gas turbine, natural gas steam and gas turbines, waste fuel steam turbine, and heat recovery steam turbine. The proportion each method contributes was computed by dividing the total cogenerated electricity into the amount each method provided. Waste fuel and heat recovery steam turbines were excluded in this section because they do not use imported fuels.

After computing the mix of fuels used, the next step determines the amount needed to produce steam and electricity. Steam and gas turbines are assumed to generate on an average of 50 and 200 kWhs per million Btu's respectively. Therefore, when generating 1 million kWhs, cogeneration facilities would also produce either 20 billion Btu's of steam with steam turbines or 5 billion Btu's of steam with gas turbines. Assuming fuel is burned at an 83-percent efficiency level, steam and gas turbines would need 24 billion Btu's and 6 billion Btu's of fuel respectively to produce this steam. To generate electricity, fuel is required at the incremental heat rate of 4,710 Btu's per kWh for steam turbines and 5,630 Btu's per kWh for gas turbines. By combining the fuel needed to produce steam and electricity, we determined that for every million kWhs of electricity generated, steam turbines would require 28.7 billion Btu's of fuel, and in gas turbines, 11.63 billion Btu's. When these requirements were multiplied by the percentages of utility fuel use by type, we obtained the factors, which were then multiplied by each State's cogenerated electricity. The resulting numbers showed the amounts and types of fuel industry uses to cogenerate. By subtracting the fuel saved by industry from these numbers, we obtained the net fuel shift of industry. Tables III-7 to III-11 highlight our results.

1/ Resource Planning Associates, Inc., "The Potential for Cogeneration Development in Six Major Industries by 1985," Dec. 1977, exhibits B.11, B.12, B.13.

2/ Thermo Electron Corporation, "A Study of Inplant Electric Power Generation in the Chemical, Petroleum Refining and Paper and Pulp Industries," tables 6.2, 6.6, 6.10.

3/ U.S. Department of Commmerce, Bureau of the Census, "Annual Survey of Manufacturers 1975, Fuels and Electric Energy Consumed," Sept. 1977, table 3.

4/ Thermo Electron Corporation Study, tables 4.3, 4.18, 4.40.

5/ U.S. Department of Commerce Survey.

6/ Federal Power Commission, News Release. "FPC Release Preliminary 1976 Power Production, Capacity, Fuel Consumption Data," Mar. 23, 1977, p. 5.

Table III-1
Potential Nationwide Steam and Electricity
Cogeneration in 1985 for Selected Industries

No Action Case

Cogeneration system type	Paper and pulp		Chemical		Petroleum refining	
	Steam (trillion Btu's)	Electricity (billion kWhs)	Steam (trillion Btu's)	Electricity (billion kWhs)	Steam (trillion Btu's)	Electricity (billion kWhs)
Coal-fired steam turbine	187.1	8.05	197.5	8.49	41.8	1.80
Residual-fired steam turbine	71.3	3.07	108.5	4.67	12.3	.53
Distillate-fired gas turbine	0	0	22.4	3.92	.6	.11
Natural gas turbine	17.8	.77	23.3	1.62	.6	.11
Waste fuel steam turbine	(a)	26.44	(a)	1.21	(a)	2.86
Heat recovery steam turbine	(a)	0	(a)	1.21	(a)	.61
Total	276.2	38.33	351.7	21.12	55.3	6.02

a/These figures were excluded because industry would use other types of fuels to produce this steam than those included in our analyses of fuel shifts. In determining utility generation offset by cogeneration all electricity was included regardless of the source.

Source: Resource Planning Associates, Inc.

Table III-2
Potential Nationwide Steam and Electricity
Cogeneration in 1985 for Selected Industries

Incentives Case

Cogeneration system type	Paper and pulp		Chemical		Petroleum refining	
	Steam (trillion Btu's)	Electricity (billion kWhs)	Steam (trillion Btu's)	Electricity (billion kWhs)	Steam (trillion Btu's)	Electricity (billion kWhs)
Coal-fired steam turbine	213.3	9.18	268.7	11.55	63.2	2.72
Residual-fired steam turbine	80.3	3.46	126.7	5.45	15.9	.68
Distillate-fired gas turbine	2.2	.39	25.2	4.41	2.1	.37
Natural gas turbine	17.8	.77	23.3	1.62	.6	.11
Waste fuel steam turbine	(a)	31.20	(a)	1.98	(a)	5.09
Heat recovery steam turbine	(a)	0	(a)	1.77	(a)	1.16
Total	313.6	45.00	443.9	26.78	81.8	10.13

a/These figures were excluded because industry would use other types of fuels to produce this steam than those included in our analyses of fuel shifts. In determining utility generation offset by cogeneration, all electricity was included regardless of the source.

Source: Resource Planning Associates, Inc.

APPENDIX III

Table III-3
Potential Nationwide Steam and Electricity Cogeneration in 1985 for Selected Industries

Economic Maximum Case

Cogeneration system type	Paper and pulp: Steam (trillion Btu's)	Paper and pulp: Electricity (billion kWhs)	Chemical: Steam (trillion Btu's)	Chemical: Electricity (billion kWhs)	Petroleum refining: Steam (trillion Btu's)	Petroleum refining: Electricity (billion kWhs)
Distillate-fired gas turbine	313.6	62.72	443.9	88.78	81.8	16.36
Waste fuel steam turbine	(a)	31.20	(a)	1.98	(a)	5.09
Heat recovery steam turbine	(a)	0	(a)	1.77	(a)	1.16
Total	313.6	93.92	443.9	92.53	81.8	22.61

a/These figures were excluded because industry would use other types of fuels to produce this steam than those included in our analyses of fuel shifts. In determining utility generation offset by cogeneration, all electricity was included regardless of the source.

Table III-4
Technical Maximum Case

Cogeneration system type	Paper and pulp: Steam (trillion Btu's)	Paper and pulp: Electricity (billion kWhs)	Chemical: Steam (trillion Btu's)	Chemical: Electricity (billion kWhs)	Petroleum refining: Steam (trillion Btu's)	Petroleum refining: Electricity (billion kWhs)
Distillate-fired gas turbine	1059	211.8	1396	279.2	454	90.8
Total	1059	211.8	1396	279.2	454	90.8

APPENDIX III

Table III-5
Average Utility Fuel Use
for All Fuels
Percentages by Region
for 1976

Region	Percent of Fuel Use (note a)					
	Oil	Coal	Nat. Gas	Hydro	Nuclear	Other
New England	56.9	2.6	.4	6.9	33.2	0
New York/New Jersey	48.0	15.1	1.0	21.3	14.5	0
Mid Atlantic	14.9	71.1	.1	1.9	11.9	0
South Atlantic	15.6	63.0	3.7	8.6	9.0	0
Midwest	4.3	78.7	2.0	.8	14.2	0
Southwest	5.9	10.7	80.2	1.8	1.4	0
Central	4.7	66.1	17.3	2.9	9.0	0
North Central	.9	58.7	5.1	35.2	0	.0
West	41.5	13.6	20.4	19.4	2.9	2.2
Northwest	.2	4.2	1.0	91.6	2.9	0
U.S. weighted average	15.7	46.3	14.5	13.9	9.4	.2

a/Percentages within each region may not add to 100 because of rounding.

Table III-8
Net Industrial and Utility Fuel Shifts
by 1985

Region	No action case	Incentives case	Economic maximum case
	(trillion Btu's)		
New England			
Distillate	- 1.74	- 1.69	73.40
Residual	-56.69	-66.33	-123.77
Coal	20.63	23.93	- 6.45
Natural gas	2.20	2.17	- .49
Net shift	-35.60	-41.84	- 57.31
New York/New Jersey			
Distillate	- 7.72	- 9.27	87.96
Residual	-30.89	-37.44	- 98.74
Coal	11.32	14.71	- 36.19
Natural gas	- 3.90	- 5.76	- 10.98
Net shift	-31.19	-37.76	- 57.95
Mid Atlantic			
Distillate	- 2.11	- 2.44	164.68
Residual	-12.10	-15.55	- 70.60
Coal	-35.71	-41.71	-182.14
Natural gas	- 2.45	- 4.54	- 10.88
Net shift	-52.37	-64.24	- 98.94
South Atlantic			
Distillate	- 9.03	- 9.33	363.50
Residual	- 28.54	- 34.04	-133.31
Coal	- 54.05	- 63.15	-390.32
Natural gas	- 48.99	- 61.48	- 85.08
Net shift	-140.61	-168.00	-245.21
Midwest			
Distillate	- 1.01	- .45	271.12
Residual	21.42	23.87	- 26.12
Coal	- 84.15	- 99.20	-361.91
Natural gas	- 37.40	- 45.98	- 61.08
Net shift	-101.14	-121.76	-177.99

Table III-8 (cont.)

Region	No action case	Incentives case	Economic maximum case
	(trillion Btu's)		
Southwest			
Distillate	20.42	25.44	753.32
Residual	50.42	57.54	-102.83
Coal	180.13	244.31	- 45.25
Natural gas	-427.81	-568.47	-997.51
Net shift	-176.84	-241.18	-392.29
Central			
Distillate	1.25	1.32	50.97
Residual	5.32	6.05	- 4.04
Coal	.83	2.10	-36.28
Natural gas	-18.17	-23.81	-35.32
Net shift	-10.77	-14.35	-24.67
North Central			
Distillate	09	.17	7.06
Residual	.63	.77	- .12
Coal	-.07	- .34	-7.27
Natural gas	-.98	-1.26	-1.73
Net shift	-.33	- .66	-2.06
West			
Distillate	- .44	- .34	62.34
Residual	-7.80	-11.68	-48.17
Coal	17.30	22.99	- .57
Natural gas	-28.75	-37.52	-53.09
Net shift	-19.69	-26.55	-39.49
Northwest			
Distillate	- 4.12	- 4.35	56.87
Residual	- 9.64	-11.37	-33.08
Coal	.60	- .94	-49.49
Natural gas	-14.19	-16.92	-20.51
Net shift	-28.55	-33.58	-46.21
U.S. Total			
Distillate	- 4.41	- .86	1891.22
Residual	- 67.87	- 88.18	- 640.78
Coal	+ 55.63	+102.70	-1115.89
Natural gas	-580.44	-763.57	-1276.67
Net shift	-597.09	-749.91	-1142.12

Table III-13
Industry Capital Investments
for Cogeneration
(1977 dollars)

No Action Case

	Coal-fired steam turbine	Residual-fired steam turbine	Distillate-fired gas turbine	Gas-fired gas turbine	Waste fuel steam turbine	Heat recovery steam turbine	Total
Paper and pulp:							
Cogenerated electricity (trillion Btu's)	8.05	3.07	-	.77	26.44	-	38.33
Capacity required (thousand MW)	1.02	.39	-	.10	3.35	-	4.86
Capital investment (millions)	$1,277	$341	-	$ 49	$2,934	-	$4,601
Chemical:							
Cogenerated electricity (trillion Btu's)	8.49	4.67	3.92	1.62	1.21	1.21	21.12
Capacity required (thousand MW)	1.08	.59	.50	.21	.15	.15	2.68
Capital investment (millions)	$1,346	$518	$249	$103	$ 134	$134	$2,484
Petroleum refining:							
Cogenerated electricity (trillion Btu's)	1.80	.53	.11	.11	2.86	.61	6.02
Capacity required (thousand MW)	.23	.07	.01	.01	.36	.08	.76
Capital investment (millions)	$ 285	$ 59	$ 7	$ 7	$ 317	$ 68	$ 743

APPENDIX III

Table III-10
Fuel Shifts in the
Incentives Case
in 1985

Region	Net Industrial Fuel Shifts Distillate	Residual	Coal	Natural gas
	(trillion Btu's)			
New England	-1.61	-26.10	26.95	2.39
New York/New Jersey	-9.27	-7.73	25.23	-4.79
Mid Atlantic	-2.44	4.23	9.18	-4.38
South Atlantic	-9.33	-.73	75.29	-53.64
Midwest	-.45	31.11	19.34	-41.71
Southwest	25.44	90.34	260.19	-346.55
Central	1.32	7.37	12.28	-18.80
North Central	.17	.81	2.71	-1.06
West	-.34	7.38	23.16	-28.11
Northwest	-4.35	-.05	22.03	-16.26
Total	-.86	106.63	476.36	-512.91

Region	Utility Fuel Shifts Distillate	Residual	Coal	Natural gas
	(trillion Btu's)			
New England	-	-40.23	-3.02	-.22
New York/New Jersey	-	-29.71	-10.51	-.94
Mid Atlantic	-	-19.77	-50.89	-.17
South Atlantic	-	-33.31	-138.44	-7.84
Midwest	-	-7.24	-118.54	-4.27
Southwest	-	-32.80	-15.88	-221.92
Central	-	-1.32	-10.17	-5.01
North Central	-	-.03	-3.05	-.20
West	-	-19.06	-.16	-9.41
Northwest	-	-11.33	-22.97	-.66
Total		-194.80	-373.63	-250.64

a/Any differences between these numbers and those in table III-8 are due to rounding.

Table III-15
Industry Capital Investments
for Cogeneration
(1977 dollars)

Economic Maximum Case

	Distillate-fired gas turbine	Waste fuel steam turbine	Heat recovery steam turbine	Total
Paper and pulp:				
Cogenerated electricity (trillion Btu's)	62.72	31.20	-	93.92
Capacity required (thousand MW)	7.96	3.96	-	11.92
Capital investment	$3,978	$3,463	-	$7,441
Chemical:				
Cogenerated electricity (trillion Btu's)	88.78	1.98	1.77	92.53
Capacity required (thousand MW)	11.26	.25	.23	11.74
Capital investment (millions)	$5,630	$ 220	$196	$6,046
Petroleum refining:				
Cogenerated electricity (trillion Btu's)	16.36	5.09	1.16	22.61
Capacity required (thousand MW)	2.08	.65	.15	2.88
Capital investment (millions)	$1,038	$ 565	$129	$1,732

Table III-12
Distribution of Industrial
Boiler Steam Capacity Since 1965

	Boiler sizes more than			
	100,000 lbs/hr	150,000 lbs/hr	250,000 lbs/hr	400,000 lbs/hr
INDUSTRY	(percent)			
Paper and pulp	26.0	31.0	41.7	46.7
Chemical	24.6	24.8	21.7	22.0
Petroleum refining	16.1	18.3	18.0	15.4
Subtotal	66.7	74.1	81.4	84.1
Food	10.2	6.6	3.1	0.5
Textile	1.7	0.7	0.2	0
Steel	6.2	6.7	8.0	8.3
Subtotal	18.1	14.0	11.3	8.3
Total	84.8	88.1	92.7	92.9

INDUSTRIAL GENERATION OF ELECTRICITY IN 1985: A REGIONAL FORECAST

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Table III-14
Industry Capital Investments
for Cogeneration
(1977 dollars)

Incentives Case

	Coal-fired steam turbine	Residual-fired steam turbine	Distillate-fired gas turbine	Gas-fired gas turbine	Waste fuel steam turbine	Heat recovery steam turbine	Total
Paper and pulp:							
Cogenerated electricity (trillion Btu's)	9.18	3.46	.39	.77	31.20	-	45
Capacity required (thousand MW)	1.16	.44	.05	.10	3.96	-	5.71
Capital investment (millions)	$1,455	$384	$25	$49	$3,463	-	$5,376
Chemical:							
Cogenerated electricity (trillion Btu's)	11.55	5.45	4.41	1.62	1.98	1.77	26.78
Capacity required (thousand MW)	1.47	.69	.56	.21	.25	.23	3.41
Capital investment	$1,831	$605	$280	$103	$220	$196	$3,235
Petroleum refining:							
Cogenerated electricity (trillion Btu's)	2.72	.68	.37	.11	5.09	1.16	10.13
Capacity required (thousand MW)	.35	.09	.05	.01	.65	.15	1.30
Capital investment (millions)	$ 431	$ 75	$ 23	$ 7	$565	$129	$1,231

APPENDIX III

Table III-9
Fuel Shifts in the
No Action Case
in 1985

Region	Net Industrial Fuel Shifts			
	Distillate	Residual	Coal	Natural gas
	(trillion Btu's)			
New England	-1.74	-22.57	23.20	-2.39
New York/New Jersey	-7.72	-6.25	20.02	-3.10
Mid Atlantic	-2.11	4.24	5.68	-2.32
South Atlantic	-9.03	-.58	61.68	-42.41
Midwest	-1.01	27.43	14.34	-33.83
Southwest	20.42	76.60	191.60	-263.77
Central	1.25	6.29	8.80	-14.47
North Central	.09	65	1.88	-.83
West	-.44	6.42	17.43	-21.73
Northwest	-4.12	-.03	18.90	-13.66
Total	-4.41	92.20	363.53	-393.73

Region	Utility Fuel Shifts			
	Distillate	Residual	Coal	Natural gas
	(trillion Btu's)			
New England	-	-34.12	-2.57	-.19
New York/New Jersey	-	-24.64	-8.70	-.79
Mid Atlantic	-	-16.35	-41.39	-.13
South Atlantic	-	-27.96	-115.73	-6.59
Midwest	-	-6.00	-93.50	-3.57
Southwest	-	-26.18	-11.48	-164.04
Central	-	-.97	-7.98	-3.70
North Central	-	-.02	-1.95	-.15
West	-	-14.23	-.13	-7.02
Northwest	-	-9.61	-19.49	-.52
Total		-160.08	-307.92	-186.70

a/Any differences between these numbers and those in table III-8 are due to rounding.

APPENDIX III

Figure III-1

DEPARTMENT OF ENERGY REGIONS USED
IN THE MIDTERM ENERGY MARKET MODEL (MEMM)

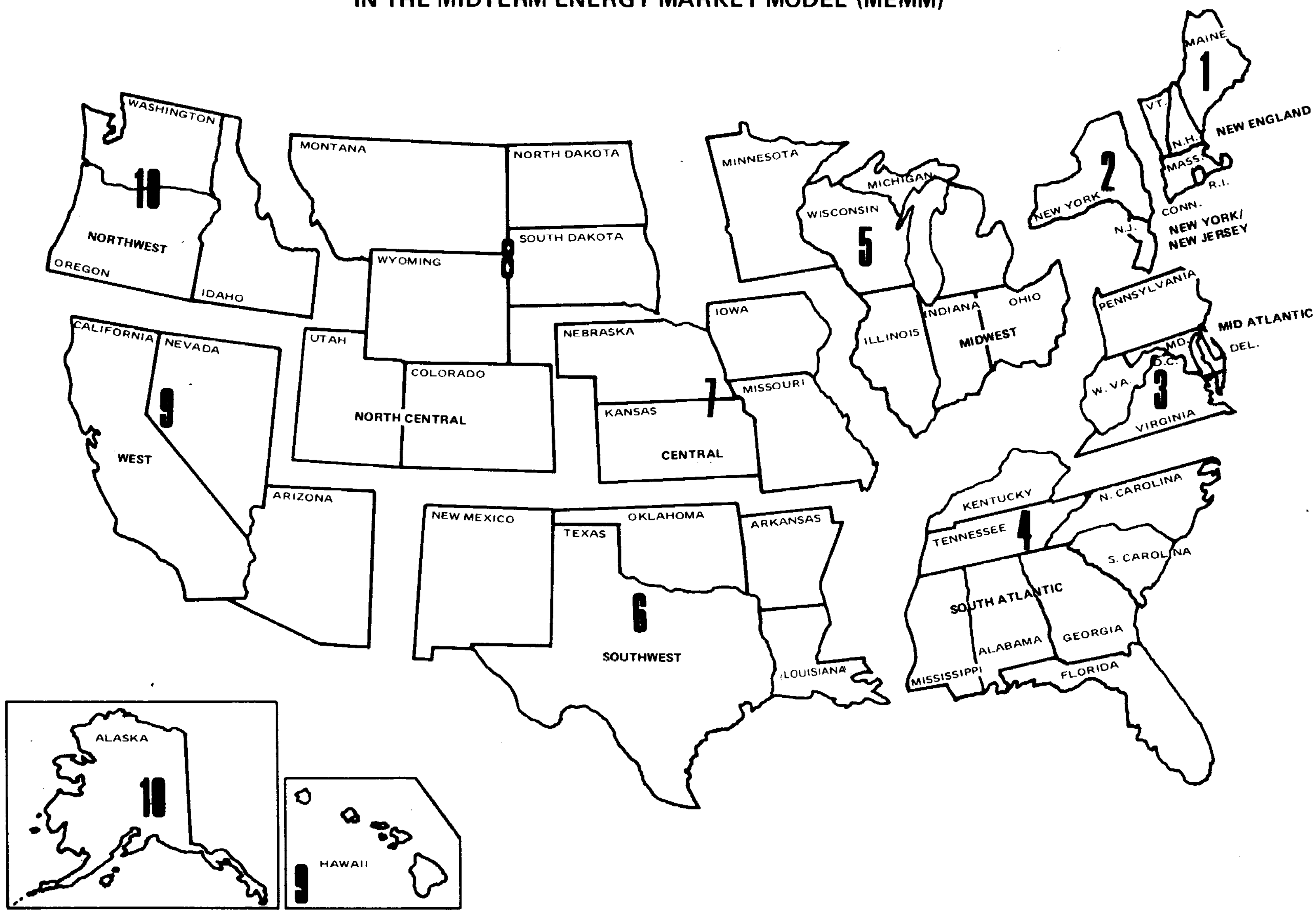

Table III-11
Fuel Shifts in the
Economic Maximum Case
in 1985

Region	Net Industrial Fuel Shifts			
	Distillate	Residual	Coal	Natural gas
	(trillion Btu's)			
New England	73.40	-36.58	.09	0
New York/New Jersey	85.69	-22.29	-8.70	-8.38
Mid Atlantic	64.68	-20.56	-49.51	-10.39
South Atlantic	63.50	-55.11	-56.46	-66.66
Midwest	71.12	-8.36	-76.89	-51.09
Southwest	53.32	-15.69	0	-370.97
Central	50.97	-.17	-5.03	-20.65
North Central	7.06	-.03	0	-1.19
West	62.34	-1.20	0	-29.89
Northwest	56.87	-8.63	0	-18.22
Total	1891.22	-168.62	-196.68	-577.44

Region	Utility Fuel Shifts			
	Distillate	Residual	Coal	Natural gas
	(trillion Btu's)			
New England	-	-87.19	-6.36	-.49
New York/New Jersey	-	-76.46	-27.49	-2.60
Mid Atlantic	-	-50.03	-132.62	-.49
South Atlantic	-	-78.20	-333.86	-18.42
Midwest	-	-17.76	-285.02	-9.99
Southwest	-	-87.13	-45.27	-626.54
Central	-	-3.88	-31.25	-14.67
North Central	-	-.09	-7.27	-.54
West	-	-46.97	-.57	-23.20
Northwest	-	-24.45	-49.49	2.29
Total		-472.16	-919.20	-699.23

a/Any differences between these numbers and those in table III-8 are due to rounding.

Introduction

Industrial demand for electricity is a large fraction of the total demand for electric power, accounting for 37 percent of all electricity consumption in 1975 [8]. This demand is important for the utilities since it is a more continuous source of demand than residential or commercial and hence satisfied from efficient baseload plants. However, the industrial sector also has the most elastic demand for electricity since these large users have the option of generating their own electricity.

While several studies have been done estimating the industrial demand for electricity [4], this paper explicitly estimates the relationship between industrial generation of electricity and electricity prices. Further, this study recognizes the regional differences that characterize energy systems, including utility electric systems. We use this regional model to forecast industrial generation in 1985 under the Department of Energy Reference Scenario and under an electricity rate reform scenario which would charge marginal cost prices for electricity.

2. The Regression Model

We hypothesize that the amount of industrial electrical generation is dependent primarily on the price of electricity, the price of alternative fuels which could be used to generate electricity, the level of industrial activity and the industrial composition. With respect to industrial composition, certain industries, specifically paper and pulp (SIC 26), chemicals and related products (SIC 28) and petroleum products (SIC 29) generate a great deal of their own electricity.

For our preliminary analysis we collected data on average fuel prices, value added by manufacturing and value added by industries 26, 28 and 29 by state from the 1972 Census of Manufactures [6], the latest Census available.[1] Using this data we estimated the following preliminary regression (in logarithms):

$$(1) \quad GS/ELQ = a_0 + a_1\ PDIST_i + a_2\ PRES_i + a_3\ PGAS_i + a_4\ PELEC_i + a_5\ PCT\ 2629_i + a_6\ VAM_i$$

Where GS = industrial electricity generated loss sold

ELQ = purchased electricity

PDIST = average price of distillate fuel

PRES = average price of residual fuel

PGAS = average price of gas

PELEC = average price of electricity

PCT2629 = percentage of value added by manufacturing 26, 28 and 29

VAM = value added by manufacturing

The regression results are reported in Table 1.

As Table 1 shows, the only variables which are significantly related to the ratio of electricity generated less sold to purchased electricity are the price of electricity and the proportion of value added originating in industries 26, 28 and 29. All other variables are insignificant at the .05 significance level. This is a reasonable result in that fuels are substitutes for each other and that, as a result, fuel prices will tend to move together. Thus, high electricity prices will occur coincidentally with high oil and gas prices. The decision to generate electricity will therefore be determined primarily by available technology and the price of electricity. In this analysis the available technology is captured by the industrial composition variable PCT 2629 which describes the relative importance of large industrial electricity users in each state.

With these preliminary results analyzed, we turned to the collection of more recent data. Using the Annual Surveys of Manufactures [5] we collected data on purchased electricity (ELQ), value added by manufacturing (VAM) and value added in industries 26, 28 and 29. In addition we collected data on net generation of electricity by industrial establishments (GEN) [7]. This data was collected across states for the years 1975 and 1976.[2]

In order to most effectively use this data, the samples were pooled to form a single sample of two cross sections with two observations on each state corresponding to the two years 1975 and 1976. With more than one observation on each state, we can do a more detailed study by allowing each state to have its own intercept while estimating the coefficients on the price of electricity and the industrial composition of each state.

The econometric technique employed is Analysis of Covariance (ACV) and has certain desirable econometric properties including reduction of any simultaneous equation bias, as well as reduction of any multicollinearity and autocorrelation that may be present in the data. Of special interest here is the fact that the ACV technique, by including a dummy variable for each state and each year allows for State-specific characteristics which could affect the amount of industrial generation and cogeneration in that State. We are therefore capable of doing an explicitly regional analysis for eventual use in forecasting regional generation levels.[3]

We therefore propose the following regression

$$(2) \quad (GEN/ELQ)_{it} = \sum_{t=1}^{2} \alpha_t + \sum_{i=1}^{50} \beta_i + \gamma \ln(PELEC)_{it} + \delta \ln(PCT2629)_{it}$$

where t refers to the two years, 1975 and 1976, and i = 1, . . ., 50 is the index for States. We have 100 observations and 54 explanatory variables (two year dummies, 50 State dummies and the two continous variables, PELEC and PCT2629). This procedure allows us, in effect, to estimate a forecasting equation for each state but restricts the coefficients on the continuous variables (γ and δ) to be equal across States. Our maintained hypothesis is therefore that the responsiveness of the ratio of generated to purchased electricity to changes in the price of electricity or the industrial composition is constant across states.

In order to insure numerical accuracy, we modified regression (2) by including an overall intercept term and eliminating two dummy variables (the year dummy variable for 1975 and the state dummy variable for Maine). Thus the computed overall intercept term will estimate the intercept for Maine in 1975. All other State coefficients will estimate the difference between the Maine intercept and the corresponding State intercept. The final estimated equation has the form

$$(3) \quad \ln(GEN/ELQ) = A + \alpha' + \sum_{i=2}^{50} \beta_i' + \gamma \ln(PELEC)_{it} + \delta \ln(PCT2629)_{it}$$

where A is the overall intercept, t = 1975, 1976 and i = 1, . . ., 50. The final estimated equation is reported in Table 2.

Examination of Table 2 reveals that we have explained virtually all of the variance of the dependent variable (R^2 = .998) and almost all of the State and year coefficients are significantly different from zero at the customary levels indicating that there are significant differences among states with respect to the importance of self generated electricity even after allowing for differences in the price of electricity and industrial composition. This verifies the often stated hypothesis that generation and cogeneration of electricity is site specific, and therefore one cannot easily generalize across regions. With respect to the price of electricity, the coefficient on ln(PELEC) is .82 with a highly significant t ratio of 2.25. Thus a 10 percent increase in the price of industrial electricity will lead to an 8.2 percent increase in the GEN/ELQ ratio. A similar effect is found with respect to PCT2629. The coefficient on ln(PCT2629) is .19 with a t ratio of 1.61 which indicates significance at the .10 level. Therefore, a 10 percent increase in the proportion of value added in industries 26, 28, and 29 will lead to 1.9 percent increase in GEN/ELQ.

3. Industrial Generation in 1985--Base Case

In order to forecast industrial generation in 1985, we need to consider three variables: the proportion of value added by manufacturing due to industries 26, 28 and 29, the real price of electricity in 1985, and the time trend. We have only two time periods in our data base, but the coefficient on 1976 is negative and significant, which indicates a downward trend in GEN/ELQ, everything else being the same. Since this is consistent with Surveys of Manufactures data [5] we projected the observed trend into the future. Since we have no information on projected industrial mix in 1985 by State, we assumed that PCT2629 would take its 1975-1976 average value. The real price of electricity to industrial users in 1985 is taken from the Department of Energy Reference forecast [8]. This forecast is made on a regional level rather than by State, so we assumed that the DOE regional price is constant across all States within a region. The forecast values of the ratio of generated to purchased electricity in 1985 for the base case is presented in Table 3, column 2, with the corresponding values for 1976 presented in column 1 for comparison. Comparing columns one and two, we can see that the strong negative trend more than offsets the effect of rising real electricity prices for most States. The States of Indiana, Missouri, South Dakota, Nebraska, Oklahoma, Montana, New Mexico, Nevada, Alaska and Hawaii show increases in generated to purchased industrial electricity and most of these states are relatively insignificant with respect to either total industrial energy use or the actual change in the ratio. The important exceptions are Louisiana and Texas which are large energy users and where a small change in the ratio of generated to purchased electricity could have a significant effect on the electric and energy systems in that region.

In order to predict total industrial generation in 1985, we need a forecast of purchased electricity to which we can apply the ratios in Table 3. The Department of Energy Reference case was again used for this purpose. As before, the DOE forecasts only on the basis of ten energy demand regions. Thus, we applied the average GEN/ELQ ratio for States in each region, weighted by purchased electricity in 1976, to the DOE forecast for purchased electricity in 1985. The results are reported in Table 4. According to our baseline forecast, industrial generation will amount to 157 billion kilowatt - hours in 1985 with the largest proportion being produced in the Midwest and Southwest regions (which together are forecast to account for 58 percent of all industrial generation).

This result is interesting in that while the ratio of generated to purchased electricity is forecast to decline in the base case for most states, the level of industrial generation is forecast to increase substantially. Thus, the rise in industrial electricity prices which is expected over the next several years is forecast to reverse the downward trend in industrial generation. (In 1972 industrial generation was 104.5 billion kwh; by 1977 it had fallen to 87.0 billion kwh [7])

4. Industrial Generation in 1985 Under Electricity Rate Reform

Included in the proposed National Energy Plan is an electricity rate reform program which could have a significant impact on the level of industrial generation. While there is much disagreement as to the final form that rate reform will take, if passed, we chose to analyze the most dramatic case--namely, marginal cost or replacement cost pricing of electricity. Under this scheme electricity consumers will have to pay a price of electricity determined by cost of the last kilowatt-hour generated. In a period of rising fuel and capital costs, this means that the price of electricity will be substantially higher than the price which would have been charged under current regulatory practice, which is a price based on the average cost rather than the marginal cost of production. Results of a run of DOE's PIES model to simulate such a regulatory change are reported in [1]. It was assumed for the purposes of this run that the reform improved the load factor for utilities from the current average of 60 percent to a 1985 average of 65 percent nation-wide. The improvement in load factor occurs because marginal cost pricing includes peak load pricing since the cost of generating for peak demand is higher than the cost of generating for baseload demand. The net effect is an average 20 percent rise in the price of electricity to industry, a rise which would have been even higher had the load factor not improved.

We use the PIES forecast regional industrial price of electricity and our equation (2) to predict the ratio of generated to purchased electricity by state in 1985. Again we assumed that the regional price is constant across all States in that region. The results are reported in Table 3, column 3. Comparing the base case to the marginal cost case, we see that the ratio of generated to purchased electricity increased in most States although eleven showed no change or even a tiny decline.[4] However, it is also true that we find the downward trend of GEN/ELQ in many States is forecast to be reversed under marginal cost pricing of electricity. For seventeen States the ratio of generated to purchased electricity will be higher under this rate reform than it was in 1976.[5]

The corresponding level of generation implied by these electricity prices and the implied demand for industrial purchased electricity under rate reform is presented in Table 4, column 2. Examination of Table 4 reveals that forecast industrial generation will increase in all regions with the largest increases occurring in the South Atlantic and Southwest (La. and Texas). Overall, we expect a 15 percent increase in industrial generation under marginal cost pricing of electricity.

Industrial Cogeneration in 1985.

In order to forecast the level of cogeneration in 1985 in the three industries of interest (Paper and Pulp, Chemicals and Refining) we took the predicted ratio of their cogeneration in 1985 to total cogeneration in 1985 (from RPA [9]) and multiplied by the ratio of cogeneration to industrial generation in 1976 (from [7] and [9]). Applying this ratio (.296) to the forecast value of industrial generation in 1985 from Table 4 under the base case (157.4 billion kwh) yields a base case forecast of cogeneration by these three industries of 46.75 billion kwh. This is the level of cogeneration that we forecast will take place if the downward trend in industrial generation continues but electricity prices continue to rise as forecast by the Department of Energy. This means that if these assumptions are correct, cogeneration will grow in these three industries from 22.5 billion kilowatt hours in hours in 1976 [9] to 46.75 billion kwh in 1985 as a result of rising electricity prices only. We take this level (46.75 billion kwh) as the level of cogeneration that is implicit in the DOE Reference Forecast for these three industries. Any changes in cogeneration will be taken from this base.

In order to forecast the corresponding change in cogenerated electricity in the three industries of interest we apply the same ratio as before and derive our estimate of 53.8 billion kwh, an increase of 7 billion kwh of cogenerated electricity due to rate reform. This represents an increase of 15 percent in cogeneration as a result of a 20 percent rise in industrial electricity price.

Summary and Conclusions

We have derived a regression equation based on recent time series and cross section data which tests the hypothesis that industrial generation is responsive to electricity prices and the industrial output mix. We found that in fact the ratio of generation to purchased electricity, hence the level of generation, is sensitive to price but it also varies widely across regions and has been declining over time. With this regression model we forecast the ratio of generation to purchased electricity by State for 1985 using the PIES reference forecast of electricity prices. We found that while some States showed small increases in the ratio of generated to purchased electricity, the expected rise in electricity prices failed to reverse the downward trend in GEN/ELQ for most States. The exception occurs in Texas and Louisiana where GEN/ELQ is forecast to go up by 1985. We used the corresponding PIES reference forecast of industrial purchased electricity to predict the level of generation by region in 1985. The forecast rise in electricity prices was found to predict an increase in the level of industrial generation, a reversal of the strong downward trend observed in the period 1972-1976.

We also analyzed an electric rate reform case based on marginal cost pricing of electricity. Under this scenario the ratio of generated to purchased electricity increases over the base case and even reverses the downward trend in several States. The PIES model was used to generate the industrial prices and purchase electricity amounts for this case. We find that the level of industrial generation increases by a factor of 15 percent over the base case with the largest increases coming in the South Atlantic and Southwest PIES regions.

FOOTNOTES

[1] Only 32 States had data on all relevant variables: these States are Maine, New Hampshire, Vermont, Massachusetts, Pennsylvania, Ohio, Indiana, Illinois, Michigan, Wisconsin, Minnesota, Iowa, Maryland, West Virginia, North Carolina, South Carolina, Georgia, Florida, Tennessee, Alabama, Mississippi, Arkansas, Louisiana, Texas, Oklahoma, Colorado, Arizona, Nevada, Washington, Oregon, California and Alaska.

[2] Because of the results of the preliminary analysis, we knew we did not need data on the price of gas, distillate and residual fuel. We used the preliminary analysis to determine the list of variables in order to avoid any pretesting bias which occurs when a data set is used to both generate and test hypotheses. These data were available for all fifty States.

[3] Justification for the use of ACV over other pooling techniques can be found in [2,3].

[4] Specifically: PA, MD, VA, WVA, ARZ, CAL, NJ, DEL, NEV, ALSK, AND HI.

[5] These States are: ID, MD, SD, KA, NC, SC, KY, TN, ALA, ARK, LA, TX, COLO, ARZ, WASH, ORE, ND, NEB, MISS, OK, MON, IDA, NM, UTAH, NEV, ALSK, AND HI.

 APPENDIX IV

TABLE 1

Dependent Variable GS/ELQ*

VARIABLE	COEFFICIENT	T SCORE
PDIST*	0.58	0.44
PRES*	-0.62	0.47
PGAS*	-0.75	1.52
PELEC*	1.42	2.75
PTC2629*	1.09	4.22
VAM*	-0.16	1.35
INTERCEPT	7.69	0.92

R^2 = .57
$\bar{R}^2$ = .48
F = 5.69
n = 32
* Measured in natural logarithms

APPENDIX IV

TABLE 2

Dependent Variable: GEN/ELQ*

Var.	Coeff.	T score	Var.	Coeff.	T score
RPELEC*	.818	2.25	ALA	-2.014	-18
PCT2629*	.189	1.61	ARK	-1.279	-11.83
INT	4.129	2.33	LA	-0.305	- 1.47
Y1976	-0.089	- 3.66	TX	-0.937	- 6.06
NH	-1.597	- 9.03	COL	-2.247	-12.58
VT	-2.224	-14.02	ARZ	-0.740	- 3.89
MA	-2.537	-11.47	WASH	-2.744	- 5.35
RI	-4.521	-10.63	OR	-2.554	- 7.28
CT	-3.211	-15.11	CAL	-2.97	-22.07
MY	-2.414	-18	NJ	-3.374	-17.36
PA	-2.181	-15.86	DEL	-2.64	-16.06
OH	-2.642	-20.28	ND	0.065	0.08
IND	-1.157	- 8.51	NEB	-6.838	-50.3
ILL	-2.798	-22.76	MISS	-2.142	-19.25
MICH	-1.874	-11.26	OK	-3.305	-20.77
WIS	-1.808	-13.78	MON	-4.94	- 9.22
MIN	-0.721	- 5.76	IDA	-2.752	- 9.22
ID	-2.476	-17.77	WYD	0.089	0.60
MO	-2.918	-25.19	NM	-0.144	- 1.08
SD	-0.958	- 1.20	UTAH	0.356	2.00
KA	-3.641	-32.63	NEV	-1.76	-10.67
MD	-1.908	-14.17	ALSK	1.915	2.41
VA	-1.551	-12.12	HI	1.593	1.91
WVA	-1.392	-11.08			
NC	-2.703	-22.82			
SC	-2.029	-18.76			
GA	-1.682	-13.16			
FL	-1.565	- 9.97			
KY	-6.638	-39.2			
TN	-2.938	-21.92			

$R^2 = .9979$ $\bar{R}^2 = .9956$ $F = 433.8$

*Measured in natural logarithms

TABLE 3

RATIO OF GENERATED TO PURCHASED ELECTRICITY
1985

State		1976 (1)	Base Case (2)	Marginal Cost Case (3)
ME	1	0.961	0.869	0.948
NH	2	0.242	0.172	0.188
VT	3	0.116	0.091	0.1
MA	4	0.109	0.067	0.073
RI	5	0.015	0.009	0.009
CT	6	0.053	0.034	0.037
NY	7	0.076	0.067	0.067
PA	8	0.121	0.096	0.096
OH	9	0.059	0.053	0.063
IND	10	0.23	0.236	0.283
ILL	11	0.057	0.045	0.055
MICH	12	0.153	0.114	0.137
WISC	13	0.163	0.123	0.148
MINN	14	0.48	0.366	0.439
IO	15	0.070	0.069	0.078
MO	16	0.044	0.044	0.050
SD	17	0.099	0.229	0.28
KA	18	0.023	0.021	0.024
MD	19	0.131	0.127	0.127
VA	20	0.226	0.183	0.183
WVA	21	0.265	0.222	0.222
NC	22	0.059	0.050	0.065
SC	23	0.123	0.101	0.13
GA	24	0.201	0.141	0.182
FLA	25	0.238	0.159	0.206
KY	26	0.000	0.000	0.001
TN	27	0.041	0.040	0.052
ALA	28	0.104	0.102	0.131
ARK	29	0.263	0.216	0.275
LA	30	0.561	0.616	0.785
TX	31	0.291	0.314	0.4
COL	32	0.070	0.063	0.078
ARZ	33	0.351	0.371	0.37
WASH	34	0.016	0.023	0.031
ORE	35	0.028	0.028	0.037
CA	36	0.050	0.040	0.040
NJ	37	0.051	0.026	0.026
DEL	38	0.087	0.061	0.061
ND	39	0.405	0.638	0.779
NEB	40	0.000	0.000	0.001
MISS	41	0.114	0.089	0.116
OK	42	0.022	0.027	0.031
MON	43	0.001	0.004	0.005
IDA	44	0.032	0.023	0.031

TABLE 3 (cont.)

State		1976 (1)	Base Case (2)	Marginal Cost Case (3)
WYO	45	0.96	0.706	0.861
NM	46	0.609	0.658	0.737
UTAH	47	1.04	0.865	1.05
NEV	48	0.085	0.136	0.135
ALSK	49	2.44	5.23	5.22
HI	50	1.63	3.79	3.78

TABLE 4

INDUSTRIAL GENERATED ELECTRICITY
1985
(millions of kilowatt - hours)

Region*	Base Case (1)	Marginal Cost Case (2)	Difference (3)	Percent (4)
1 NE	5615	6065	450	8.01
2 NY/NJ	3960	4046	86	2.17
3 MA	17400	17816	416	2.39
4 SA	19928	23760	3832	19.23
5 MW	31506	35800	4294	13.63
6 SW	59670	73555	13885	23.27
7 CEN	2316	2540	224	9.67
8 N.CEN	6288	7082	794	12.63
9 WEST	7576	7714	138	1.82
10 NW	3163	3394	231	7.30
U.S.	157422	181772	24350	15.47

* The FEA regions are defined as follows:

1 NE: ME, NH, UT, MA, CT, RI
2 NY/NJ: NY, NJ
3 MA: PA, DEL, MS, VA, WVA
4 SA: NC, SC, GA, FL, KY, TN, MISS, AL
5 MW: OH, IND, MICH, IL, WISC, MINN
6 SW: RAK, AL, TX, OK, NM
7 CEN: ID, MD, NEB, KA
8 N.CEN: ND, SD, MON, WYO, UT, COL
9 WEST: NEV, ARZ, CAL, HI
10 NW: WASH, ORE, ID, AK

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 APPENDIX V

EXCERPTS FROM THE

EVALUATION OF THE POTENTIAL FOR

COGENERATION IN TWO STATES :

OHIO AND TEXAS

A Report Submitted to the

U.S. General Accounting Office

Center for Energy and Natural Resource Management

UNIVERSITY CITY SCIENCE CENTER
Philadelphia, Pa.

The focus of this report is upon cogeneration as it might be applied to the energy needs of industries in the states of Ohio and Texas. More specifically, this report addresses a wide range of factors that could have a significant influence upon how widespread cogeneration could become among industries in these states, each of which occupies an important position in the national economy.

II. *Projections of Energy Consumption*

The second task addressed in Ohio was to evaluate, insofar as possible, trends in energy consumption and industrial growth in order to assess their effects on the potential development of cogeneration. In order to evaluate whether trends found in energy consumption would aid or hinder this development, GAO provided us with total projected 1985 fuel shifts for Ohio which a projected level of cogeneration would be expected to produce. Our aim was to find Ohio's projected 1985 energy consumption figures and compare these with the GAO shifts to see if projections of trends in energy consumption, including electric load trends, will impact the development of cogeneration in Ohio.

DATA SOURCE

In order to find Ohio's projection of its own 1985 energy consumption, we asked ODOE, [the Ohio Department of Energy] where we found that state-level, long-term energy forecasting models did not exist, although ODOE is currently developing a model to forecast natural gas consumption. Faced with this lack of data from Ohio, we turned to the U. S. Department of Commerce [DOC] (6), which has recently prepared highly detailed state level energy production and consumption forecasts for the years 1985 and 2000 (Table 4). When we asked ODOE officials for an informal response, they considered these data to be quite reasonable.

SHIFTS

Comparison of the GAO shifts with the U.S. DOC data shows that forecast trends in Ohio's oil and gas consumption for 1985 are consistent with the GAO shifts, with oil consumption increasing and gas consumption decreasing. Furthermore, the GAO shifts represent only a small portion of projected changes in consumption for these fuels, with the GAO shift for oil representing 14% of the total oil shift between 1976 and 1985, while the GAO shift for natural gas represents only 2% of the total shift for natural gas. For coal, the GAO shifts run counter to the state trend, but this is not a problem for two reasons: first, the GAO shift for coal is a negative shift representing fuel conservation, something very desirable; and second, the shift represents only about 1% of the total coal consumption in 1985 and hence is an insignificant perturbation of the system.

Another very interesting conclusion can be drawn from the U.S. DOC data. These data predict that Ohio's electric power consumption will increase from 119 billion Kwh in 1976 to 150 billion Kwh in 1985, a growth of 25% over 9 years, yielding an annual linear rate of growth of only 2.9%. In contrast with this forecast, Dayton Power & Light's 1977 annual report projects its load to increase over the next ten years at an annual rate of 5.25%. Conversations with ODOE officials have indicated that a 2.9% growth rate is a much more reasonable figure, particularly in view of what is perceived to be a low rate of industrial and population growth in Ohio. The low rate of electrical load growth in Ohio could create a significant resistance by utilities and utility customers in Ohio to the development of cogeneration, particularly if significant capacity surpluses should arise. Cogeneration development, in this case, would serve to aggravate an increasing spiral in electricity rates caused by the capacity surplus.

III. *Logistical Constraints*

Our third task for investigation in Ohio was to ascertain whether or not the shifts in energy consumption projected by GAO for 1985 as a result of cogeneration could be accommodated by Ohio's energy storage and transportation systems. For the most part, this question was answered by the shifts themselves. As shown in Table 3, the shifts for coal, gas and distillate fuels are negative, and Ohio's energy storage and transportation systems cannot possibly be strained by a reduction in demand for these fuels. On the other hand, Ohio could reap an environmental benefit from cogeneration resulting from an annual reduction in coal consumption of more than 9 million tons.

Although the shift for residual fuels is positive, it represents only about 0.5% of Ohio's total consumption of oil in 1985. This shift could be easily accommodated by any of the refineries in Ohio. Consequently, we have concluded that Ohio's energy storage and transportation systems will not inhibit the level of development of cogeneration projected by GAO.

IV. *Local Industrial Attitudes*

Our final task was to assess local industrial attitudes toward cogeneration as an opportunity for investment. Interviews were conducted with representatives from the pulp and paper, chemicals, and oil refining industries, which are likely candidates for cogeneration. Comment was also solicited from the Ohio Manufacturers Association. Although opinion varied widely, consensus was found on three points:

- The industrial geography of Ohio is not particularly favorable to multi-plant cogeneration projects. Industries whose operating characteristics would make them attractive candidates for cogeneration have not tended to cluster within the roughly 4 square mile areas such a facility could serve.
- Broad, general statements about the economic environment for cogeneration cannot be made with confidence. Each project must be evaluated on its own merits.
- In general, industry will <u>not</u> invest when uncertainty over government regulations and policy could have an effect on the investment.

The range of necessary ROI [Return on Investment] levels for cogeneration investments extended from a low of 10% to a high of 30%. The degree of familiarity with the concept of cogeneration also varied widely. Some representatives had had personal experience with cogeneration projects, while others were barely conversant with the concept.

TABLE 3
PROJECTED SHIFTS IN FUEL CONSUMPTION
RESULTING FROM PROJECTED 1985 COGENERATION
IN OHIO
SOURCE: GENERAL ACCOUNTING OFFICE

	Trillion BTU	Natural Units
Distillate	-0.6991	-0.1188 (10^6 Bbl)
Residual	+7.2951	+1.1672 (10^6 Bbl)
Coal	-25.9390	-9.2463 (10^6 Ton)
Gas	-2.1116	-2.1116 (BCF)
Total	-21.4547	

Total Cogenerated Electricity : 2.344 Billion Kwh

TABLE 4

OHIO'S ENERGY SUPPLIES AND CONSUMPTION FOR 1976, 1985, 2000

NO. 35

AREA (SQ. MI.) 41,222

	Units	1976	1985	2000
Population	thousands	10,690	11,216	12,058
Energy Consumption	trillion BTU's			
Oil	"	1,242	1,289	842
Natural Gas	"	1,034	933	870
Coal	"	1,816	2,115	3,942
Other - Nuclear, Hydro, Geo, Solar, etc.	"	0	260	1,136
Total	"	4,085	4,597	6,790
Electric Power Input (10,400 BTU/KWH)	"	1,238	1,560	3,186
Energy Produced				
Oil, Includes NGL	thousand B/D	27.3	23	15
Natural Gas	billion cubic ft/yr	90	50	0
Coal	thousand short tons	48,089	53,841	112,490
Electric Power Energy Source	megawatts	28,426	32,047	58,132
Oil	"	894	909	0
Natural Gas	"	253	200	701
Coal	"	23,814	23,408	39,241
Nuclear	"	0	4,250	12,345
Hydro/Geo	"	330	366	545
Peak Shaving/Unknown	"	3,095	3,038	3,038
Other	"	40	176	2,262
Water	million gals/day	144.41	188.88	347.04
Facilities				
LNG (includes number and amount of GAS/YR (Bcf)		0	0	0
Power Plants (Number--assuming each is a nominal plant capable of generating 1100 megawatts)		26		
Oil	"	1	1	0
Natural Gas	"	0	1	1
Coal	"	22	21	36
Nuclear	"	0	4	11
Hydro/Geo	"	1	1	2
Other	"	0	1	2
Petroleum Refining	barrels per day	524,895	524,895	424,895
Coal Gasification -- High BTU	billion cubic ft/yr	0	0	0

APPENDIX V

The Houston area has historically been an attainment area and, therefore, is covered under PSD [prevention of significant deterioration] regulations. A great amount of concern among industrials in this area is that all of the incremental emissions permitted under these rules already exists, largely as a result of previous conversions from gas to fuel oil. If this is the case, additional industrial growth and conversions to coal in this area could be slowed or halted. A study commissioned by a private industry association, the Texas Chemical Council, is currently investigating this question.

II. *Texas Projections to 1985*

The analyses in this section are based primarily upon two major studies prepared by or under contract to the Texas Energy Advisory Council (TEAC). The first of these, Texas Energy Outlook: The Next Quarter Century, focuses upon the overall energy and economic situation projected in Texas. The second, Provision of Electric Power in Texas: Key Issues and Uncertainties, focuses specifically upon the prospects of electric power generation.

The first of these studies evaluates the impact of three alternative combinations of energy policies: a Business as Usual scenario, a Maximum Government Regulation scenario, and a Free Market Scenario. The analyses in this section of our report are based upon the Business as Usual projections since (1) available quantitative TEAC analyses of the impacts of specific policy options are based upon this set of projections and (2) the assumptions upon which these projections are based lead to moderate rather than extreme expectations concerning future Texas energy supply and demand. Specifically, the assumptions underlying the projections are:

- "No future embargoes will occur; the price of imported crude will continue at $13 per barrel adjusted annually for United States inflation rates."

- "Texas Railroad Commission (TRC) restrictions on the use of natural gas as a boiler fuel (Docket 600) will be continued and enforced."
- "Domestic crude oil prices will increase as scheduled under the Energy Policy and Conservation Act; similar controls will be continued after EPCA termination."
- "Natural gas prices for interstate gas will continue as scheduled in the Federal Power Commission Docket 770; market clearing intrastate prices will be allowed to continue."
- "Surface mining regulation in Texas and the west will be enforced approximately as currently required in Texas (not so restrictive as to prevent maximum coal and lignite development)."
- "No political restrictions on nuclear power development will be created but continuation of current regulatory procedures will prevent maximum development."
- "No energy conservation practices will be government enforced except those resulting from price."
- "The government will not enforce utility rate structure changes."
- "Significant contributions (defined as 0.01 quadrillion BTU (Quads) per year or greater) from 'developing technologies' will begin to occur as follows:

solar, wind and biomass	1985
geothermal	1990
tertiary oil and gas recovery	1975
synthetic fuels	1990
breeder reactor	1990

Government will participate in the development of these technologies through research and development funding plus supports during the commercialization phase."

- "Existing environmental standards for air and water will continue."

Selected projections provided by the Texas Energy Advisory Council under the assumption outlined above are contained in Appendix A to this chapter.

The projections included in Appendix A answer several specific questions posed by GAO, each of which is addressed in succeeding portions of this report.

GROWTH

BAU Table 10 in Appendix A provides an index of projected economic growth in Texas. This index shows an increase of 27% between 1975 (1.2867) and 1985 (1.6333;) (Base year 1967 = 1.0000). In addition, Tables 11 and 12 provide projections of population, employment, income, and state and local tax revenues. With the exception of employment, all of these projections show continuing increases in the 1976-85 period. Employment declines slightly in 1979 (because of a recession anticipated by the model under the BAU scenario), but increases annually after that year.

CHANGES IN INDUSTRIAL ENERGY DEMAND

Projected Texas demand is provided in BAU Table 1. Total demand is expected to increase by 24.7% (1.7843 Quads) from 7.2288 Quads in 1976 to 9.0131 Quads in 1985. Nearly half of this total increase is the result of a 0.8702 Quad increase in industrial energy demand. Furthermore, the chemical industry, which accounted for 33% of Texas' total energy demand and 67.7% of Texas' industrial energy demand in 1976, is projected to account for a .8183 Quad increase between 1976 and 1985, which is 94% of Texas' projected increase in industrial demand.

PROJECTIONS OF TOTAL ENERGY CONSUMPTION

BAU Table 8 gives annual fuel consumption by type of fuel. Note that only electricity produced by nuclear and hydropower is included; power generated by fossil fuels is represented by including volumes of fuel used to generate that power with the volumes of fuel consumed directly. These data show total energy demand increasing by 24.7% from 7.2 Quads in 1976 to 9.0 Quads in 1985. All fuels show an increase in utilization except hydropower, which remains constant, and natural gas which declines by 33% from 3.9 Quads in 1976 to 2.6 Quads in 1985. These trends are consistent with those reflected in the fuel shifts developed by GAO. Furthermore, the magnitude of the GAO net state fuel shifts is small in comparison except for natural gas and, to a lesser extent, for coal:

	GAO Shift	Texas Projected Change (1976-85)	GAO as % Texas
Oil (ref. prod.)	.0604	1.5019	4.02%
Coal (coal & lig.)	.1014	.9384	10.8 %
Gas	-.2638	-1.3193	20.00%

The significance of the GAO shift as a component of the reduction in gas consumption is not unexpected because of the close connection among mandatory reduction in gas consumption as a boiler fuel, conversion of boilers to coal, and the market for cogeneration. This interaction and the major current issues (i.e. TRC Docket 600) are discussed elsewhere in the report.

Assessing the magnitude of the GAO shifts with total anticipated energy consumption in 1985 for those fuels whose consumption is expected to increase because of the development of cogeneration capability reveals the same pattern:

	GAO Shift	Texas Projected 1985 Demand	GAO as % Texas Projected
Oil (ref. prod.)	.0604	3.9841	1.56%
Coal (coal & lig.)	.1014	1.1516	8.81%

The importance of plant conversions to coal is again shown by the significance of the shift projected by GAO as a component of the total Texas demand for coal estimated for 1985.

STATE AND FEDERAL PROJECTIONS

The following table compares projections of the U.S. Department of Commerce, Office of Ocean, Resource and Scientific Policy Coordination, Series F with those contained in BAU Table 8, made by the Texas Energy Advisory Council. The complete Commerce data upon which this table is based in included as Appendix B.

1985 Total Texas Energy Consumption (Quads)

	Commerce	BAU Table 8	Difference
Oil (ref. prod. & NGL)	3.494	4.920	-1.426
Natural Gas	4.110	2.598	1.512
Coal (coal & lig.)	.758	1.152	-0.394
Other (nuc. & hydro)	.263	.344	-0.081
Total (Quads)	8.625	9.014	-0.389

While the total energy consumption projected is fairly close, two major differences are evident. First is the magnitude of the differences in oil and natural gas. These differences, which are offsetting to a large degree, reflect Commerce anticipations of a continually high level of natural gas consumption in Texas. It is worth noting that the GAO shift projections for coal are 13.4% of the total coal projected by Commerce and 8.8% of that projected by Texas.

Department of Commerce and Texas state supply projections (from BAU Table 2, which should be interpreted as total domestic state supply) show the following 1985 components:

1985 Production of Fuels (Quads)

	Commerce	BAU Table 2	Difference (Commerce less Texas)
Oil (Crude)	7.145	5.244	1.901
Gas	7.451	6.085	1.366
Coal (Lignite)	.292	.700	-0.408

It is evident from these data that Commerce anticipates a considerably higher level of Texas oil and gas production than does Texas and a lower level of coal (lignite) production. These projections can also explain a large part of the discrepancies in the projections of fuel consumption.

INDUSTRIAL ENERGY PER UNIT OUTPUT

BAU Table 9 gives projections of the energy consumption per dollar of output for gross Texas product, Texas manufacturing, and transportation. These data show that, between 1976 and 1985, Texas gross product will increase its energy consumption per unit of output from 74,400 BTU/dollar to 75,500 BTU/dollar with fluctuations in individual years. After 1985, a clear trend of increasing energy-intensity is evident. The manufacturing and transportation sectors on the other hand are expected to show a 1976-85 trend toward lower energy consumption per unit output. For manufacturing, the energy required goes from 86,000 to 77,100 BTU/dollar of output. For transportation, this value goes from 73,300 to 69,000 BTU/dollar of output.

PROJECTIONS OF ELECTRIC POWER CONSUMPTION

Projections of electric power consumption in BAU Table 6 show an increase in total industrial demand of 0.091 quads between 1976 and 1985. Of particular significance is the fact that electricity generated and consumed by industry is distinguished from electricity consumed by industry but generated by utilities. The following table summarizes these projections in light of the GAO projection of cogeneration. The quantity of cogenerated electricity projected by GAO is 1.7 times the Texas projected increase in all industrially generated electricity by 1985. Furthermore, the GAO projection exceeds 40% of the total increase in industrial electricity consumption and 10% of the total industrial electricity consumption projected by Texas for 1985.

Texas Industrial Electric Power Consumption (quads)

	Ind. Self Generated	GAO Proj. as % of:	Other Ind. Consumption	GAO Proj. as % of:	Total Ind.	GAO Proj. as % of:
1976	0.0564	-	0.1871	-	0.2435	-
1985	0.0791	49.05	0.2554	15.19	0.3345	11.59
Change	0.0227	170.93	0.0683	56.81	0.0910	42.64

GAO Cogeneration Projections = 11.3774×10^9 Kwh

$$11.3774 \times 10^9 \text{ Kwh} \times \frac{3.412 \times 10^9 \text{ BTU}}{10^6 \text{ Kwh}} = .0388 \times 10^{15} \text{ BTU's}$$

APPENDIX V

A.4. SELECTED FORECASTING RESULTS

A.4.1. BAU RESULTS

BAU TABLE 1. TOTAL ENERGY DEMAND, 1960-2000

YEAR	ELECT. POWER LOSS	RES. AND COMM.	TRANS-PORTATION (QUADS)	OTHER INDUSTRY	CHEMICAL INDUSTRY	TOTAL
1960	.3132	.4260	.8530	1.6988	1.3364	4.6274
1961	.3168	.4280	.8799	1.6629	1.3788	4.6664
1962	.3648	.4780	.8975	1.7036	1.4730	4.9169
1963	.4088	.4996	.8975	1.7039	1.5450	5.0548
1964	.4434	.5243	.9528	1.7090	1.6610	5.2905
1965	.4631	.5258	1.0061	1.7126	1.5325	5.2401
1966	.5061	.5638	1.0512	1.4956	1.5272	5.1419
1967	.5546	.5877	1.1236	1.6091	1.7080	5.5830
1968	.6165	.6391	1.1960	1.5975	1.8546	5.9037
1969	.6940	.6972	1.2183	1.6175	1.9556	6.1826
1970	.7492	.7403	1.2483	1.6863	2.1090	6.5331
1971	.8298	.7551	1.2855	1.7857	2.3804	7.0365
1972	.9094	.7966	1.3839	1.6663	2.4304	7.1666
1973	.9905	.8815	1.5072	1.7844	2.6245	7.7881
1974	1.0411	.8552	1.4815	1.6658	2.5700	7.6136
1975	1.0635	.8558	1.5364	1.3680	2.2297	7.0534
1976	1.1244	.8423	1.5288	1.3411	2.3922	7.2288
1977	1.1600	.8430	1.5375	1.3214	2.5265	7.3884
1978	1.2373	.8483	1.5518	1.2855	2.4876	7.4104
1979	1.2788	.8468	1.5530	1.2553	2.4641	7.3980
1980	1.3486	.8419	1.5530	1.2719	2.6268	7.6422
1981	1.4134	.8518	1.5810	1.2990	2.8829	7.9480
1982	1.4887	.8717	1.6280	1.3238	2.9133	8.2256
1983	1.5695	.8932	1.6769	1.3499	2.9998	8.4893
1984	1.6499	.9120	1.7231	1.3752	3.1139	8.7741
1985	1.7247	.9268	1.7580	1.3930	3.2105	9.0131
1986	1.7709	.9410	1.7880	1.4172	3.3658	9.2830
1987	1.8062	.9545	1.8171	1.4422	3.5296	9.5496
1988	1.8473	.9682	1.8478	1.4667	3.7012	9.8311
1989	1.8893	.9827	1.8805	1.4926	3.8817	10.1267
1990	1.9186	.9925	1.9115	1.5120	4.0701	10.4047
1991	1.9600	1.0030	1.9427	1.5329	4.2676	10.7062
1992	1.9912	1.0118	1.9745	1.5538	4.4753	11.0066
1993	2.0280	1.0203	2.0128	1.5777	4.6937	11.3325
1994	2.0612	1.0285	2.0510	1.6024	4.9235	11.6665
1995	2.0963	1.0366	2.0887	1.6274	5.1647	12.0138
1996	2.1317	1.0448	2.1268	1.6534	5.4184	12.3752
1997	2.1737	1.0542	2.1661	1.6813	5.6853	12.7575
1998	2.2130	1.0645	2.2071	1.7111	5.9662	13.1620
1999	2.2592	1.0765	2.2505	1.7428	6.2618	13.5908
2000	2.3095	1.0900	2.2964	1.7766	6.5728	14.0455

BAU TABLE 2. TOTAL ENERGY SUPPLY, 1955-2000

YEAR	CRUDE OIL	NATURAL GAS	LIGNITE	URANIUM	HYDRO-POWER	TOTAL
			(QUADS)			
1955	6.1090	4.8820	0	0	.0091	11.0001
1956	6.4250	5.1600	0	0	.0049	11.5899
1957	6.2280	5.3210	0	0	.1324	11.6814
1958	5.4530	5.3440	0	0	.0122	10.8092
1959	5.6370	5.9020	0	0	.0105	11.5495
1960	5.3790	6.0810	0	0	.0110	11.4710
1961	5.4470	6.1540	0	0	.0123	11.6133
1962	5.4710	6.2750	0	0	.0080	11.7540
1963	5.6710	6.4040	0	0	.0048	12.0798
1964	5.7390	6.7340	0	0	.0045	12.4775
1965	5.8040	6.8490	0	0	.0074	12.6604
1966	6.1350	7.1760	0	0	.0079	13.3189
1967	6.4960	7.4190	0	0	.0058	13.9208
1968	6.5740	7.7350	0	0	.0133	14.3223
1969	6.6800	8.1050	0	0	.0127	14.7977
1970	7.2480	8.6250	0	0	.0101	15.8830
1971	7.0930	8.8240	0	0	.0088	15.9258
1972	7.5500	8.9350	.0280	0	.0083	16.5213
1973	7.5090	8.7860	.0280	0	.0170	16.3400
1974	7.3200	8.4320	.0280	0	.0163	15.7963
1975	7.0880	7.7250	.0980	.2400	.0192	15.1702
1976	6.7226	7.4050	.1540	.2928	.0192	14.5936
1977	6.4442	7.1276	.2100	.4320	.0192	14.2330
1978	6.1599	6.8086	.2660	.6400	.0192	13.8937
1979	5.9395	6.5415	.3220	.9968	.0192	13.8191
1980	5.7655	6.3461	.3780	1.0656	.0192	13.5745
1981	5.6147	6.1785	.4424	1.1616	.0192	13.4085
1982	5.5161	6.0749	.5068	1.1616	.0192	13.2787
1983	5.6147	6.1785	.5712	1.1616	.0192	13.5373
1984	5.4059	6.0354	.6356	1.1616	.0192	13.2578
1985	5.2435	6.0853	.7000	1.1616	.0192	13.2096
1986	5.0173	6.1404	.7336	1.1616	.0192	13.0721
1987	4.8085	6.1581	.7672	1.1616	.0192	12.9145
1988	4.5765	6.1071	.8008	1.1616	.0192	12.6652
1989	4.3560	6.0396	.8344	1.1616	.0192	12.4109
1990	4.1530	5.9035	.8680	1.1616	.0192	12.1053
1991	3.9152	5.7517	.9016	1.1616	.0192	11.7494
1992	3.6948	5.5637	.9352	1.1616	.0192	11.3745
1993	3.4744	5.3434	.9688	1.1616	.0192	10.9674
1994	3.2772	5.0919	1.0024	1.1616	.0192	10.5523
1995	3.0800	4.8123	1.0360	1.1616	.0192	10.1091
1996	2.8886	4.5484	1.0696	1.1616	.0192	9.6874
1997	2.7146	4.2980	1.1032	1.1616	.0192	9.2965
1998	2.5463	4.0610	1.1368	1.1616	.0192	8.9250
1999	2.3839	3.8387	1.1704	1.1616	.0192	8.5738
2000	2.2389	3.6277	1.2040	1.1616	.0192	8.2514

BAU TABLE 6. ELECTRIC POWER ENERGY CONSUMPTION, 1955-2000

YEAR	INDUSTRY SELF GENERATION	INDUSTRY (QUADS)	RES. AND COMM.	TOTAL
1955	.0425	.0300	.0407	.1132
1956	.0473	.0352	.0465	.1289
1957	.0509	.0393	.0508	.1410
1958	.0422	.0396	.0564	.1382
1959	.0474	.0445	.0624	.1543
1960	.0479	.0496	.0692	.1667
1961	.0468	.0498	.0910	.1876
1962	.0546	.0594	.0864	.2004
1963	.0580	.0652	.0978	.2210
1964	.0612	.0721	.1054	.2387
1965	.0632	.0799	.1150	.2581
1966	.0650	.0915	.1240	.2805
1967	.0673	.1009	.1368	.3050
1968	.0679	.1137	.1507	.3323
1969	.0713	.1271	.1713	.3697
1970	.0703	.1368	.1882	.3953
1971	.0695	.1456	.2027	.4178
1972	.0706	.1589	.2260	.4556
1973	.0734	.1717	.2404	.4854
1974	.0755	.1790	.2444	.4988
1975	.0528	.1783	.2597	.4908
1976	.0564	.1871	.2601	.5036
1977	.0595	.1952	.2654	.5201
1978	.0596	.1954	.2720	.5270
1979	.0597	.1952	.2750	.5299
1980	.0633	.2054	.2769	.5456
1981	.0674	.2176	.2847	.5698
1982	.0705	.2274	.2964	.5943
1983	.0732	.2365	.3080	.6177
1984	.0764	.2466	.3186	.6416
1985	.0791	.2554	.3274	.6619
1986	.0818	.2644	.3349	.6811
1987	.0846	.2737	.3421	.7004
1988	.0876	.2834	.3497	.7206
1989	.0906	.2936	.3577	.7419
1990	.0938	.3037	.3654	.7629
1991	.0971	.3144	.3731	.7846
1992	.1005	.3253	.3803	.8062
1993	.1041	.3368	.3875	.8283
1994	.1079	.3487	.3946	.8512
1995	.1118	.3612	.4018	.8748
1996	.1159	.3742	.4091	.8992
1997	.1202	.3880	.4168	.9250
1998	.1247	.4026	.4249	.9522
1999	.1294	.4181	.4336	.9811
2000	.1344	.4344	.4429	1.0117

APPENDIX V

BAU TABLE 7. ENERGY USE IN ELECTRIC POWER GENERATION, 1960-2000

YEAR	NATURAL GAS	FUEL OIL	COAL AND LIGNITE (QUADS)	NUCLEAR	HYDRO-POWER	TOTAL
1960	.5569	.0037	0	0	.0110	.5716
1961	.5679	.0030	0	0	.0123	.5833
1962	.6630	.0163	0	0	.0080	.6773
1963	.7374	.0052	0	0	.0048	.7474
1964	.8001	.0031	0	0	.0045	.8077
1965	.8397	.0029	0	0	.0074	.8500
1966	.9093	.0038	0	0	.0079	.9210
1967	.9911	.0030	0	0	.0058	.9999
1968	1.0722	.0046	0	0	.0133	1.0901
1969	1.2083	.0059	0	0	.0127	1.2269
1970	1.2947	.0009	0	0	.0101	1.3056
1971	1.4038	.0021	0	0	.0088	1.4147
1972	1.5280	.0105	.0314	0	.0083	1.5781
1973	1.5158	.0392	.0662	0	.0170	1.6383
1974	1.5933	.0333	.0727	0	.0163	1.7157
1975	1.5467	.0111	.1266	0	.0192	1.7037
1976	1.5077	.0118	.2036	0	.0192	1.7424
1977	1.4665	.0260	.2842	0	.0192	1.7959
1978	1.3882	.0407	.3721	0	.0192	1.8202
1979	1.2947	.0568	.4594	0	.0192	1.8301
1980	1.2184	.0758	.5665	0	.0192	1.8799
1981	1.1629	.0896	.6392	.0491	.0192	1.9600
1982	1.0959	.1049	.7172	.1060	.0192	2.0431
1983	1.0122	.1214	.7997	.1706	.0192	2.1231
1984	.9131	.1397	.8880	.2439	.0192	2.2040
1985	.7934	.1586	.9769	.3247	.0192	2.2727
1986	.8008	.1583	1.0069	.3524	.0192	2.3376
1987	.8081	.1582	1.0351	.3822	.0192	2.4028
1988	.8151	.1578	1.0655	.4134	.0192	2.4710
1989	.8224	.1573	1.0972	.4466	.0192	2.5427
1990	.8273	.1566	1.1287	.4816	.0192	2.6134
1991	.8314	.1555	1.1627	.5173	.0192	2.6859
1992	.8344	.1539	1.1957	.5550	.0192	2.7582
1993	.8367	.1521	1.2301	.5942	.0192	2.8323
1994	.8384	.1500	1.2652	.6355	.0192	2.9084
1995	.8394	.1477	1.3020	.6788	.0192	2.9871
1996	.8401	.1450	1.3400	.7214	.0192	3.0687
1997	.8406	.1421	1.3801	.7725	.0192	3.1545
1998	.8413	.1389	1.4224	.8236	.0192	3.2454
1999	.8423	.1354	1.4669	.8781	.0192	3.3420
2000	.8433	.1317	1.5141	.9361	.0192	3.4445

BAU TABLE 8. COMPOSITION OF ENERGY CONSUMPTION - 1960 to 2000

YEAR	REFINERY PRODUCTS	NATURAL GAS LIQUIDS	NATURAL GAS	COAL AND LIGNITE	NUCLEAR	HYDRO-POWER	TOTAL
			(QUADS				
1955	0	0	0	0	0	0	0
1956	0	0	0	0	0	0	0
1957	0	0	0	0	0	0	0
1958	0	0	0	0	0	0	0
1959	0	0	0	0	0	0	0
1960	1.2003	.2272	3.1594	.0281	0	.0124	4.6274
1961	1.2175	.2370	3.1781	.0202	0	.0137	4.6665
1962	1.2613	.2586	3.3671	.0212	0	.0088	4.9170
1963	1.2635	.2813	3.4847	.0201	0	.0052	5.0548
1964	1.3524	.3405	3.5651	.0275	0	.0050	5.2905
1965	1.1798	.3730	3.6500	.0294	0	.0080	5.2402
1966	1.3291	.3926	3.3845	.0274	0	.0084	5.1420
1967	1.4165	.4096	3.6603	.0241	0	.0062	5.5167
1968	1.5445	.4802	3.8406	.0246	0	.0138	5.9037
1969	1.5519	.5727	4.0211	.0234	0	.0135	6.1826
1970	1.6268	.5895	4.2772	.0289	0	.0107	6.5331
1971	1.7690	.6072	4.6283	.0224	0	.0093	7.0362
1972	1.8674	.7637	4.5233	.0235	0	.0086	7.1865
1973	2.1268	.7760	4.7573	.1102	0	.0179	7.7882
1974	2.1309	.7505	4.5953	.1206	0	.0163	7.6136
1975	2.2227	.6614	4.0521	.0980	0	.0192	7.0534
1976	2.3722	.7072	3.9170	.2132	0	.0192	7.2288
1977	2.5382	.7479	3.7763	.3067	0	.0192	7.3884
1978	2.6768	.7553	3.5600	.3991	0	.0192	7.4104
1979	2.7986	.7631	3.3336	.4915	0	.0192	7.3980
1980	2.9969	.8153	3.2172	.5936	0	.0192	7.6422
1981	3.1771	.8724	3.1290	.7013	.0491	.0192	7.9480
1982	3.3555	.9181	3.0168	.8131	.1060	.0192	8.2256
1983	3.5294	.9589	2.8907	.9204	.1706	.0192	8.4893
1984	3.7132	1.0055	2.7567	1.0355	.2439	.0192	8.7741
1985	3.8741	1.0458	2.5977	1.1516	.3247	.0192	9.0131
1986	3.9682	1.0836	2.6523	1.2072	.3524	.0192	9.2830
1987	4.0554	1.1230	2.7058	1.2639	.3822	.0192	9.5496

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APPENDIX V

APPENDIX V

BAU TABLE 8. (CONTINUED)

YEAR	REFINERY PRODUCTS	NATURAL GAS LIQUIDS	NATURAL GAS	COAL AND LIGNITE	NUCLEAR	HYDRO-POWER	TOTAL
			(QUADS)				
1988	4.1519	1.1641	2.7606	1.3220	.4134	.0192	9.8311
1989	4.2538	1.2071	2.8185	1.3815	.4466	.0192	10.1267
1990	4.3527	1.2519	2.8570	1.4422	.4816	.0192	10.4047
1991	4.4636	1.2986	2.9032	1.5042	.5173	.0192	10.7062
1992	4.5726	1.3474	2.9448	1.5676	.5550	.0192	11.0066
1993	4.6993	1.3987	2.9885	1.6326	.5942	.0192	11.3325
1994	4.8274	1.4522	3.0329	1.6993	.6355	.0192	11.6665
1995	4.9608	1.5081	3.0789	1.7679	.6788	.0192	12.0138
1996	5.0994	1.5665	3.1271	1.8385	.7244	.0192	12.3752
1997	5.2465	1.6277	3.1802	1.9114	.7725	.0192	12.7575
1998	5.4019	1.6917	3.2388	1.9868	.8236	.0192	13.1620
1999	5.5669	1.7588	3.3031	2.0647	.8781	.0192	13.5908
2000	5.7425	1.8291	3.3731	2.1454	.9361	.0192	14.0455

BAU TABLE 9. ENERGY EFFICIENCY PER UNIT OF OUTPUT, 1960-2000

YEAR	GROSS STATE PRODUCT	MANUF.	TRANS.
	(MILLION BTU PER DOLLAR)		
1960	.0970	0	0
1961	.0950	0	0
1962	.0950	0	0
1963	.0940	0	0
1964	.0940	.1000	0
1965	.0870	.0890	0
1966	.0800	.0760	0
1967	.0820	.0780	0
1968	.0820	.0760	0
1969	.0830	.0780	0
1970	.0870	.0880	0
1971	.0900	.0950	0
1972	.0850	.0870	.0800
1973	.0890	.0870	.0799
1974	.0830	.0870	.0746
1975	.0740	.0870	.0740
1976	.0744	.0860	.0733
1977	.0742	.0844	.0725
1978	.0735	.0819	.0719
1979	.0731	.0803	.0714
1980	.0741	.0802	.0708
1981	.0748	.0799	.0702
1982	.0750	.0789	.0698
1983	.0748	.0780	.0695
1984	.0753	.0775	.0693
1985	.0755	.0771	.0690
1986	.0763	.0776	.0689
1987	.0771	.0782	.0688
1988	.0780	.0789	.0686
1989	.0789	.0796	.0685
1990	.0800	.0802	.0683
1991	.0810	.0808	.0681
1992	.0822	.0817	.0679
1993	.0840	.0830	.0679
1994	.0858	.0843	.0679
1995	.0875	.0855	.0679
1996	.0893	.0867	.0678
1997	.0911	.0880	.0678
1998	.0929	.0892	.0677
1999	.0946	.0904	.0677
2000	.0963	.0916	.0677

BAU TABLE 10. TEXAS ECONOMIC GROWTH INDEX, 1955-2000

YEAR	(1967 = 100)
1955	.5860
1956	.6310
1957	.6460
1958	.6120
1959	.6530
1960	.6560
1961	.6720
1962	.7050
1963	.7550
1964	.8030
1965	.8500
1966	.9320
1967	1.0000
1968	1.0580
1969	1.1180
1970	1.1370
1971	1.1270
1972	1.1930
1973	1.2510
1974	1.2810
1975	1.2540
1976	1.2867
1977	1.3222
1978	1.3394
1979	1.3481
1980	1.3809
1981	1.4275
1982	1.4778
1983	1.5328
1984	1.5825
1985	1.6333
1986	1.6761
1987	1.7191
1988	1.7617
1989	1.8068
1990	1.8598
1991	1.9119
1992	1.9641
1993	2.0127
1994	2.0637
1995	2.1178
1996	2.1746
1997	2.2340
1998	2.2964
1999	2.3618
2000	2.4301

BAU TABLE 11. TEXAS POPULATION AND EMPLOYMENT, 1955-2000

YEAR	ENERGY INDUSTRY EMPLOYMENT	NO. OF HOUSE-HOLDS	TOTAL EMPLOY-MENT	TOTAL POPU-LATION
		(MILLIONS)		
1955	.2104	2.5440	3.2030	8.7860
1956	.2174	2.5600	3.3320	8.9580
1957	.2185	2.6150	3.3740	9.1270
1958	.2083	2.6700	3.3440	9.2950
1959	.2066	2.7250	3.4210	9.4620
1960	.1987	2.7780	3.4350	9.6210
1961	.1954	2.8510	3.4410	9.8160
1962	.1902	2.9300	3.5170	10.0300
1963	.1834	2.9830	3.5780	10.1550
1964	.1821	3.0330	3.6700	10.2650
1965	.1816	3.0830	3.8010	10.3740
1966	.1789	3.1340	3.9690	10.4870
1967	.1769	3.1870	4.1170	10.6060
1968	.1773	3.2670	4.2860	10.8100
1969	.1776	3.3530	4.4710	11.0330
1970	.1806	3.4340	4.5100	11.2400
1971	.1805	3.5100	4.5630	11.4240
1972	.1833	3.5960	4.6510	11.5910
1973	.1889	3.6830	4.7760	11.8190
1974	.2030	3.7630	4.9200	12.0120
1975	.2182	3.7660	4.9970	12.2260
1976	.2109	3.7768	5.0404	12.2610
1977	.2098	3.8093	5.1039	12.3666
1978	.2065	3.8571	5.1308	12.5218
1979	.2030	3.8778	5.1196	12.5890
1980	.2041	3.8696	5.1597	12.5624
1981	.2052	3.8995	5.2553	12.6594
1982	.2064	3.9713	5.3694	12.8925
1983	.2103	4.0574	5.4836	13.1721
1984	.2107	4.1437	5.5830	13.4521
1985	.2113	4.2190	5.6585	13.6966
1986	.2090	4.2762	5.7232	13.8824
1987	.2065	4.3252	5.7849	14.0414
1988	.2034	4.3719	5.8471	14.1929
1989	.2004	4.4189	5.9127	14.3455
1990	.1973	4.4684	5.9765	14.5064
1991	.1930	4.5167	6.0372	14.6631
1992	.1882	4.5626	6.0943	14.8121
1993	.1830	4.6058	6.1501	14.9523
1994	.1780	4.6480	6.2065	15.0892
1995	.1729	4.6906	6.2639	15.2275
1996	.1680	4.7340	6.3232	15.3685
1997	.1635	4.7788	6.3859	15.5138
1998	.1594	4.8262	6.4534	15.6677
1999	.1555	4.8771	6.5259	15.8330
2000	.1521	4.9319	6.6040	16.0110

BAU TABLE 12. TEXAS PERSONAL INCOME AND TAXES, 1965-2000

YEAR	ENERGY TAXES	STATE & LOCAL REVENUES	PERSONAL INCOME
	(1975 DOLLARS	IN BILLIONS)	
1965	.6900	4.9300	42.6730
1966	.7040	5.1430	45.8440
1967	.7280	5.2850	48.7000
1968	.7530	5.4790	51.8020
1969	.7460	5.9980	54.1600
1970	.7700	6.4850	56.1560
1971	.8480	6.9090	56.8410
1972	.8540	7.5080	60.9850
1973	.8740	7.9280	65.2940
1974	.9930	8.1130	64.2080
1975	1.0620	8.4130	65.9030
1976	1.0960	8.4948	67.3237
1977	1.1356	8.6266	68.9775
1978	1.1737	8.7504	70.1072
1979	1.2065	8.8059	70.7777
1980	1.2431	8.8956	72.1919
1981	1.2838	9.0991	74.3015
1982	1.3385	9.3752	76.6667
1983	1.4191	9.7061	79.0998
1984	1.4636	9.9599	81.3499
1985	1.5195	10.1903	83.3028
1986	1.5358	10.3601	85.0813
1987	1.5484	10.5181	86.8306
1988	1.5541	10.6653	88.5904
1989	1.5585	10.8199	90.4127
1990	1.5565	10.9583	92.2153
1991	1.5502	11.0671	93.9741
1992	1.5406	11.1535	95.6868
1993	1.5289	11.2261	97.3888
1994	1.5151	11.2979	99.1166
1995	1.4963	11.3664	100.8740
1996	1.4777	11.4362	102.6758
1997	1.4618	11.5162	104.5533
1998	1.4470	11.6102	106.5263
1999	1.4336	11.7190	108.6042
2000	1.4230	11.8459	110.7996

APPENDIX B

TEXAS' ENERGY SUPPLIES AND CONSUMPTION FOR 1976, 1985, 2000

NO. 43

AREA (SQ. MI.) 267,338

	Units	1976	1985	2000
Population	thousands	12,487	14,233	17,554
Energy Consumption	trillion BTU's			
Oil	"	3,134	3,494	2,590
Natural Gas	"	4,213	4,110	4,195
Coal	"	135	758	2,593
Other - Nuclear, Hydro, Geo, Solar, etc.	"	22	263	1,233
Total	"	7,486	8,625	10,611
Electric Power Input (10,400 BTU/KWH)	"	1,822	2,520	4,052
Energy Produced				
Oil, Includes NGL	thousand B/D	4,030	3,375	2,000
Natural Gas	billion cubic ft/yr	7,220	6,020	4,150
Coal	thousand short tons	11,391	20,835	43,531
Electric Power Energy Source	megawatts	41,840	51,773	73,922
Oil	"	657	971	-
Natural Gas	"	33,462	27,301	900
Coal	"	4,271	15,691	51,760
Nuclear	"	0	4,262	15,026
Hydro/Geo	"	383	409	1,731
Peak Shaving/Unknown	"	3,002	2,946	2,446
Other	"	65	193	2,059
Water	million gals/day	1,103.16	1,013.61	886.87
Facilities				
LNG (amount of GAS/YR Bcf)		0	0	2 800
Power Plants (Number--assuming each is a nominal plant capable of generating 1100 megawatts)		38		
Oil "		1	1	-
Natural Gas "		30	25	1
Coal "		4	14	47
Nuclear "		-	4	14
Hydro/Geo "		1	1	2
Other "		1	1	2
Petroleum Refining	barrels per day	3,539,379	3,539,379	2,839,379
Coal Gasification -- High BTU	billion cubic ft/yr	-	-	-

APPENDIX V

ACKNOWLEDGEMENTS

During our assessment we conducted interviews with eight industrial cogeneration candidate companies, five utilities, nine trade associations, three research organizations, five Federal agencies and departments, three State agencies, and one equipment manufacturer. These organizations are listed below.

INDUSTRY

Alcoa
Dow Chemical
Gulf Oil Chemicals Company
Gulf Refining and Marketing Company
International Paper Corporation
Shell Oil Company
Union Carbide Corporation
U.S. Steel

UTILITIES

Gulf States Utilities Company
Houston Lighting and Power
Public Service Gas & Electric of New Jersey
San Diego Gas & Electric
Southern California Edison Company

TRADE ASSOCIATIONS

Aluminum Association of America
American Iron and Steel Institute
American Petroleum Institute
American Public Power Association
Chemical Manufactures Association
Edison Electric Institute
Electricity Consumers Resource Council
National Association of Manufacuters
National Association of Regulatory
Utility Commissioners

GOVERNMENT DEPARTMENTS AND AGENCIES

Department of Energy
Economic Regulatory Administration
Environmental Protection Agency
Federal Energy Regulatory Commission
Department of the Treasury

RESEARCH ORGANIZATIONS

Electric Power Research Institute
Resource Planning Associates, Inc.
Thermo Electron Corporation

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California Public Utilities Commission
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EQUIPMENT MANUFACTURER

Solar Turbines

U.S. Department of Energy
Washington, D.C. 20585

JAN 8 1980

J. Dexter Peach, Director
Energy and Minerals Division
U.S. General Accounting Office
Washington, D.C. 20548

Dear Mr. Peach:

We appreciate the opportunity to review and comment on the GAO draft report EMD 80-7, "Cogeneration--What It Is, How It Works, And Its Potential Development As An Energy Conservation Measure."

The recommendations of this draft report, which appear in Chapter 6, are concerned with the promulgation of policy guidance for the development of rules and regulations to implement provisions of the 1977 National Energy Act (NEA) in the area of cogeneration. This concern is not clearly evident in the Digest section nor in the introduction. This matter should be clarified in the final report; otherwise the reader may misinterpret the purpose of the report to be to recommend new policy. The policy exists and the GAO recommendations, supported by detailed analytic backup, are focused on its use as guidance to implement NEA.

The comments on the related effects of cogeneration in Chapter 3, are questionable. It is unlikely that electric utilities will lose baseload demand as a result of certain industrial operations converting to cogeneration. With even a modest growth in system demand, the baseload may be expected to continue to increase, although perhaps at a lower rate. The comment on the expense of base capacity is also misleading. Baseload is met by the most cost-effective plants within a given utility grid, with older facilities being brought on line to meet peak demand. The paragraph needs rewriting to eliminate ambiguities. a/

We believe that the recommendations concerning development of a national cogeneration policy which appear in Chapter 6 under the topic "Establishing user classes and state and regional planning are necessary for implementing the policy," are reasonable.

As to the recommendations concerning the topic "Cogenerators coal conversion exemption should be based on user classes:"

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a/See GAO note 1 on p. 174.

-- We concur in the first recommendation regarding encouraging large industrials to cogenerate on coal because industrial consumption of imported fuels (for heat) is up to eight times higher than that of utilities (for power). Because of this high industrial imported type fuel consumption, the Federal government should not be responsive to arguments from large industrial users to grant exemptions for cogenerators who wish to use imported fuels. The areas to be on the alert for this argument are those where oil or gas is currently used by utilities for power generation and by industrials for heat/ steam generation. The applicant's argument will correctly be that if he burns scarce fuels in a cogeneration site he can show a net reduction in imported fuel use for his heat and power. However, if his process heat and power can be made to come from abundant domestic fuels (like coal) the imported fuel reduction is expected to be significantly greater than cogeneration on imported fuels. This is because in conversions or new construction using coal, the displacement or non-use of imported fuels is 100% and not just the typical cogeneration fuel savings of 10-30%.

-- We do not concur in the second recommendation. Sufficient studies of industrial cogeneration using coal in advanced technologies have been sponsored by DOE to suggest that all of the major industries will be able to cogenerate on coal and get at least a 10-30% ROI and show a national emission reduction of 600 kilotons/year. Increase in on-site emissions through burning more on-site fuel would be more than offset by utility fuel burning reductions, which EPA acknowledges. A solution to the on-site emission increase is to extend the non-attainment "bubble" to include the impacted utility. The "bubble" would then show an emission decrease due to cogeneration, even on coal. This solution was suggested to DOE formally on November 14, 1979, by EPA representatives from Washington, Triangle Park and Cincinnati when DOE presented the above to them. a/

We do not agree with the recommendation under the topic "Rules defining a qualified cogeneration facility should include provisions to maintain fuel efficiency." Good business practice dictates that a cogeneration system be operated most efficiently, so as to realize the most effective use of capital and operating funds. Hence the GAO's recommendation would result in a redundant requirement. GAO appears to believe that there is a one for one correspondence between electricity generation and steam production, with changes in one resulting in corresponding changes

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a/See GAO note 2 on p. 174.

in the other. Cogeneration systems may be designed to provide electricity, with steam as a by-product, or to generate steam with electricity as the by-product. There may thus be considerable variation in either steam production or electricity generation without substantial variation in the cogenerated product. We also suggest that the discussion under this topic, concerning thermal energy storage be deleted. This would be an expensive and questionable plant feature at best. As a further response to this topic we believe the recommendation should only be considered for cogenerators who have been granted an exemption so they can use imported fuels; under no circumstances should it apply to cogenerators where domestic coal is the primary fuel. a/

On the topic "Rules for just and reasonable rates must be equitable," we concur with both recommendations, providing the adoption of such guidelines is left up to the discretion of the State Public Utility Commissions.

We do not concur with the recommendations under the topic "The regulatory status of cogeneration facilities needs to be determined" because it implies that the Federal Energy Regulatory Commission (FERC) would be given the authority to impose restrictive regulations in areas of the public sector where it has given up authority. It would seem more reasonable for FERC to: (1) Define clearly what constitutes a non-exempt ownership status. By definition, this leaves the balance as exempt. (2) In granting an exemption or exception, FERC should make every effort to keep large shareholders in a cogeneration facility from taking on extensive new responsibilities to the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935. The intent of the above is to promote cogeneration in industry by removing Federal authority to regulate both by FERC and SEC. b/

We concur in the recommendation under "Cogeneration exemptions from incremental natural gas pricing provisions should be based on user classes." This recommendation is very much in keeping with the first GAO recommendation on cogenerator's coal conversion exemption, discussed above. The comments in support of that recommendation apply here as well. However, caution should be exercised in granting exemption to small industrials who wish to get natural gas at an artificially low price. In particular, if it can be shown that coal burning fluidized bed combustion is commercially available for small steam generation and there is no negative return on investment for its site specific installation and use, one might reasonably question why an exemption would be granted to stay on natural gas when homeowners would be paying as much for gas as oil.

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a/See GAO note 3 on p. 174.

b/See GAO note 4 on p. 174.

Two recommendations are made under the topic "Cogeneration systems should not be eligible for the investment tax credit." a/

-- We do not concur in the recommendation concerning investment tax credit eligibility of cogeneration systems. DOE sponsored studies have suggested that while very few single actions are sufficient to push a decision in favor of cogeneration, every favorable action helps and can have a positive impact. The sensitivity of ROI to tax credits is acknowledged to be low, 5% ROI for 10% additional tax credit. However, with existing technology, a 5% reduction in minimum acceptable ROI (hurdle rate) from 15% down to 10% is sufficient to raise the emission savings due to cogeneration by a factor of 4. Advanced coal burning technologies project even better economics and less environmental sensitivity to ROI. The implication here is that an interim tax credit, until the advanced technology is available, would be highly beneficial to the environment.

-- We do concur in the second recommendation. The recommended impact and benefit assessment should extend beyond economic and cover the other barrier areas identified by GAO--namely, environmental, regulatory and institutional.

We do not concur in the recommendation for establishment of a program office to oversee cogeneration activities. While the problems being addressed by the GAO recommendation are appreciated and understood it does not seem reasonable to create a special office to service just one utilization approach for fuels. This perspective comes from the observation that there are no less than four utilization sectors (transportation, utilities, industrials, and commercial/residential) and in each sector there are three approaches for the utilization of fuels (power generation, heat generation and cogeneration). The recommendation as stated by GAO is basically too powerful to be given to one of three approaches to fuels utilization. We suggest that some review be made of functional organizational charts of other Federal departments who have the responsibility of being responsive to a usage/mission sector and implementing their needs via a coordinated effort in technical and non-technical, current, near term and far term efforts, for a more feasible model. b/

The report makes little mention of the nature and extent of DOE-supported work that bears on cogeneration. This includes development of improved cogeneration concepts, district heating assessments, improved coal combustion technology, and strategy studies, such as for the use of

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a/See GAO note 5 on p. 174.

b/See GAO note 6 on p. 174.

commercial-scale heat pumps. We suggest that some coverage be added to the report to identify the major DOE projects that bear on cogeneration. Otherwise, the reader will have the impression that little relevent work is in progress.

Appendix II of the draft report is a discussion of technical aspects of cogeneration. The time available for review of the report did not permit a thorough evaluation of the data in this appendix. We noted, however, that Appendix II draws attention to certain factors which should be considered in the body of the report to a greater extent than they appear to be. In the limited time available for our review of this draft, it was not possible to determine if the projected savings of oil (or of energy), resulting from implementation of the NEA in accordance with the policy guidance recommended in this report, was critically dependent upon the assumed operating conditions for the variously fuel-fired cogeneration systems projected. The technical issue of concern is whether maximum design efficiencies have been used in the scenarios developed or whether lower operating efficiencies which would result from variations, during plant operation, of demands for steam or electricity have been used. Altering the electricity/steam production ratio from the optimum design one will affect operating efficiency. Its sensitivity to change in the electricity/steam ratio for the different kinds of cogeneration plants identified was touched on in appendix II; how it was taken into account in the body of the report and presentation of the analytical results is not apparent.

We will be pleased to provide any additional information you may desire in this matter.

Sincerely,

Jack E. Hobbs
Controller

GAO'S RESPONSE TO DOE'S COMMENTS

1/We believe the report's discussion on cogeneration's related effects is valid and clear as discussed in chapter 3. In our analyses, we recognize that declines in capacity caused by cogeneration may be offset in areas with high growth rates, such as in the Southwest region. Our analyses also recognize that electric utilities are likely to lose baseload type demand because the cogeneration facilities analyzed would probably operate 24 hours a day like a baseload facility. The question of whether cogenerated electricity would offset utility baseload production or higher cost intermediate or peaking production is subject to debate as discussed on page 29. We recognize both situations and performed two independent analyses for each scenario. We believe that given the assumptions used, the results in both analyses are reasonable.

2/This comment is reflected and discussed on pages 55 and 70.

3/We concur with DOE's suggestion for changing the recommendation for maintaining fuel efficiency and have modified it as discussed on page 73. In their comments, however, DOE incorrectly implied that we believe that there is a one for one correspondence between electricity generation and steam production. On pages 72 and 73, we discuss how variations in either steam or electricity can affect fuel efficiency. The information shows that steam and electricity demands are not on a one for one basis, but that nonproportional changes in either of these demands can affect the fuel efficiency benefits of cogeneration.

4/The sections of the report to which these comments pertain have been revised to reflect our discussions with the Federal Energy Regulatory Commission staff and their rulemaking to carry out the provisions of the NEA which pertain to cogeneration. The Commission staff's rules identify specific factors which should be considered during the ratemaking process for establishing just and reasonable rates for qualifying cogeneration facilities. The rules, which recognize the diversity within State Public Utility Commissions, further specify the exemptions provided to qualifying cogeneration facilities from the Federal and State laws and regulations which pertain to utilities. Based on our discussions with the Commission staff and after reviewing their rules, we believe the rules, if properly implemented, will make cogeneration more attractive.

5/This comment is reflected and discussed on page 79.

6/This comment is reflected and discussed on page 81.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

13 [illegible] 1980

OFFICE OF
PLANNING AND MANAGEMENT

Mr. Henry Eschwege
Director
Community & Economic Development Division
United States General Accounting Office
Washington, D.C. 20548

Dear Mr. Eschwege:

The Environmental Protection Agency (EPA) has reviewed the General Accounting Office (GAO) revised draft report entitled "Cogeneration--What It Is, How It Works, And Its Potential Development As An Energy Conservation Measure." The Environmental Protection Agency thought the report was very good overall - thorough in its coverage of the issues and rigorous in its analysis.

We do have some reservations about the implication in the report that industrial cogeneration would always provide positive environmental benefits (see, for example, the first paragraph on page 1-5). In general, emissions savings would occur because the same quantity of electricity and process steam could be generated with less fuel by an on-site industrial cogeneration system than by separate facilities for electricity generation at the utility and steam production at the factory. Since less fuel is burned, fewer air pollution emissions might be produced.

While a reduction in emissions is possible, it is not assured. Key to actual measurement of such savings is a clear understanding of how the utility would have generated electricity and how the factory would have produced steam in the absence of cogeneration. Differences in the type of fuel or equipment used at the utility and the factory or differences in applicable air pollution regulations could preclude savings. Indeed, under some circumstances, emissions could increase.

In general, cogeneration with new industrial boilers would slow growth projections for the utility and therefore preclude the construction of new plants rather than displace existing units. If this can be assumed, it narrows the possible range of characteristics for the utility base case. Furthermore, if steam generation is the primary concern, the industrial cogeneration should probably be considered to preclude baseload or intermediate load utility operation. These broad assumptions are important for at least two reasons. First, coal and nuclear fuel can be viewed as the most likely fuels to be precluded. And second, the utility plants not built would have had to meet recently promulgated new source performance standards (NSPS) for electric powerplants.

As noted, cogeneration would shave electricity demand growth and would thereby eliminate the need for new coal and nuclear powerplants. These new plants would not only have been used to meet new electricity demand, but also to lessen the use of existing facilities. These existing units, operating generally under less stringent emissions requirements, would generate more pollution than the new, strictly regulated units. Because it could prolong the use of these existing powerplants, industrial cogeneration could indirectly increase utility emissions. Furthermore, since many existing utility plants burn oil, cogeneration might also lead to greater oil use than would otherwise be the case.

The assumption concerning applicable air pollution regulations are of equal importance. The recently promulgated NSPS for utilities sets a 1.2 lbs. per mmBtu limit on SO_2 emissions for coal-fired facilities. In addition, no matter what emissions would be without controls, the utility must reduce emissions by 70 to 90 percent. With a low sulfur western coal, this standard could result in emissions of about 0.4 lbs. per mmBtu at the utility while a 1.2 lbs. standard might still apply at the factory. So with these assumed levels in factory and utility SO_2 regulations, there would be no emissions savings with cogeneration; indeed, emissions would increase.

I would like to make one further comment on the air quality implications of industrial cogeneration concerning the location of emissions. Fuel use, and therefore emissions, would increase at the factory site with cogeneration; emissions would, however, decline overall for an area encompassing both the factory and the utility by which it is served. Emissions from different sites could have different effects on air quality. Modelling would reveal the effect of the shift in location on measured, area-wide air quality.

The issue of where emissions occur will be especially important for non-attainment areas. Many factories will be within such areas while the electric utility by which they are served lies outside the non-attainment boundaries. A tradeoff between emissions in non-attainment and other areas would be especially difficult to evaluate.

We appreciate the oppportunity to review and comment on this draft prior to its issuance to Congress.

Sincerely yours,

William Drayton, Jr.
Assistant Administrator for
Planning and Management

GAO's response to EPA's comments

The EPA comments highlight some of the many environmental concerns and problems which confront cogenerators. In our report, we recognize that these issues are important to cogenerators and that their implications must be determined through a case-by-case analysis, given the site specificness of cogeneration. (See p. 54.) While cogeneration may increase the level of emissions in specific situations as outlined, our analysis of the available literature addressing this issue indicates that, generally, less emissions should be produced. This would occur because, as recognized in EPA's comments, the same quantity of electricity and process steam could be generated with less fuel.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF THE CHAIRMAN

JAN 21 1980

J. Dexter Peach
Director
United States General Accounting Office
Energy and Minerals Division
441 G Street, N.W.
Room 5120
Washington, D.C. 20548

Dear Mr. Peach:

Thank you for providing me with the opportunity to review and comment on the draft report, "Cogeneration--What It Is, How It Works, And Its Potential Development As An Energy Conservation Measure", EMD-80-7, (Code 003240).

At my request, selected staff members of the Commission reviewed the report and met with your representatives to discuss their observations on the report on January 10, 1980.

Insofar as the Commission presently has pending two Notices of Proposed Rulemakings with regard to cogeneration, I am not able to directly comment to you on this report. However, I hope that the comments of the staff have been helpful and that your staff feels free to consult with the staff of the Commission with regard to any technical or other review they might request concerning preparation of the final report.

Sincerely yours,

Charles B. Curtis

Charles B. Curtis
Chairman

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON 20426

DEC 26 1979

Honorable Elmer Staats
Comptroller General
General Accounting Office
Washington, D. C.

Dear Mr. Staats:

I am writing to you with regard to the draft report which you recently provided to the Chairman of the Federal Energy Regulatory Commission, entitled "Cogeneration -- What It Is, How It Works, And Its Potential Development As An Energy Conservation Measure" (EMD-80-7, Code 003240). At this time, the Commission is preparing final rules implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), which concerns the interconnection of cogeneration facilities with electric utilities, the rates for exchanges of electricity between such facilities and utilities, and the exemption of cogeneration facilities from state and federal regulation as electric utilities.

I have reviewed your draft report on cogeneration and I believe that the Commission should consider it in its analysis of the complex issues involved in determining national policy with respect to cogeneration. The CAO report contains an overview of the issues involved in cogeneration, and sets forth a framework for a responsible cogeneration policy development. However, in order to comply with the requirements for notice and comment of rulemakings the document must be placed in the Commission's public files and be made available for public inspection. I, therefore, request that you authorize the Commission's Staff to undertake those actions.

In addition, as part of the rulemaking process, in compliance with the National Environmental Policy Act of 1969 (NEPA), the Commission is preparing an Environmental Impact Statement (EIS) on its proposed rules implementing sections 201 and 210 of PURPA. SRI International is assisting the Commission in this project. In order to predict the environmental effects of the proposed rules, SRI is attempting to project the growth rate of cogeneration and other technologies under various regulatory alternatives. Appendix IV of the GAO report contains a study ("Industrial Generation of Electricity in 1985: A Regional Forecast") prepared by C. E. Moody as a consultant to the GAO. This forecast is very similar to forecasts being prepared for the Commission by SRI International, and would be most useful to them in their work for the Commission.

I would, therefore, also request that the Commission be permitted to provide this forecast to SRI International.

If you do not believe it appropriate to make these documents part of the Commission's official record in its rulemaking proceedings, it would nevertheless be useful if the above-mentioned forecast could be furnished to SRI International, under the condition that SRI be required to prevent its publication or disclosure.

Thank you for providing the Commission with this document, and for your consideration of these requests.

Sincerely yours,

Robert R. Nordhaus
General Counsel

UNITED STATES GENERAL ACCOUNTING OFFICE
WASHINGTON, D.C. 20548

ENERGY AND MINERALS
DIVISION

Jan. 7, 1980

Mr. Robert Nordhaus
General Counsel
Federal Energy Regulatory Commission
Washington, D.C. 20426

Dear Mr. Nordhaus:

We have reviewed your December 26, 1979, request to place a copy of our draft report "Cogeneration--What It Is, How It Works, And Its Potential Development As An Energy Conservation Measure" in the Commission's public files concerning sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). We understand this request, made in order to comply with the requirements for notice and comment of rulemakings, would make our draft report available for public inspection. Although it is unusual to release a draft report for public consumption, you have clearly pointed out that releasing this report for the Commission's files would be in the public interest.

Considering the benefits, we authorize the Commission's staff to undertake those actions outlined in your request. We would like you to note in the public files, however, that the report is a draft being reviewed by other agencies and interested concerns, and is subject to change. We would also appreciate you including in the public record a copy of your December 26, 1979, request and this response.

You also noted that appendix IV ("Industrial Generation of Electricity in 1985: A Regional Forecast") of our report would be helpful to SRI International who is assisting the Commission in preparing an Environmental Impact Statement on sections 201 and 210 of PURPA. We agree again that it would be in the public interest to provide this appendix to SRI International for their internal use.

We are happy that our draft report can be beneficial to the Commission and assist SRI International with its study.

Sincerely yours,

J. Dexter Peach
Director

DEPARTMENT OF THE TREASURY
WASHINGTON, D.C. 20220

ASSISTANT SECRETARY

JAN 0 2 1980

Dear Mr. Voss:

Thank you for the opportunity to comment on the General Accounting Office draft report entitled "Cogeneration -- What It Is, How It Works, And Its Potential Development As An Energy Conservation Measure."

We have no comment with respect to this report.

Sincerely,

Donald C. Lubick

Mr. Allen Voss
Director
General Government Division
United States General Accounting Office
Washington, D.C. 20548

(003240)

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