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**A Comparative Evaluation of Recent Reports
on the Energy Conservation Potential
from Cogeneration**

R. W. Barnes
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OAK RIDGE NATIONAL LABORATORY
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Engineering Technology Division

A COMPARATIVE EVALUATION OF RECENT REPORTS ON THE
ENERGY CONSERVATION POTENTIAL FROM COGENERATION

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PREFACE

The practice of dual-purpose energy utilization, known as "cogeneration," has the potential to reduce substantially the total energy input required to accomplish certain kinds of energy-consuming tasks. The concept has received much publicity in the last few years. For example, increased cogeneration is now a specified component of the president's "National Energy Plan" recommended for supporting legislation by the Congress. Cogeneration can be implemented in several ways through a variety of mechanisms (modes). The potential for energy conservation depends upon the mode in which cogeneration is accomplished and the degree to which it is installed in each of its forms.

Because of the complex relationships involved in the variety of approaches to cogeneration, it has been difficult to identify the reasons for the rather wide differences observed in various published estimates of the energy conservation potential from cogeneration. The purpose of this report is to describe the primary modes and forms of cogeneration and to define the variables which influence the energy conservation potential from each type of implementation. Using the taxonomy thus developed, several published projections of cogeneration potential are analyzed and compared.

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SUMMARY

Cogeneration as commonly known refers to the simultaneous production of a flow of electricity and a flow of useful heat from a single fuel input. In practice, there are several forms (types of systems) in which cogeneration can be implemented, and there are several modes (technology alternatives) which can be employed within each form. Each feasible combination of form and mode will produce electricity and heat in different proportions, will have different economics, and will be influenced differently by institutional and energy policy variables.

The magnitude of future energy savings from cogeneration will depend on the form and mode of implementation, the demand characteristics for the heat and electricity flows produced, and the extent to which potentially viable applications will be actually implemented. Affecting the degree of implementation will be not only economic considerations but also institutional issues such as exposure to government regulation and the availability of personnel with appropriate skills.

Several investigators have published estimates of the possible future contribution by cogeneration to energy conservation. Each investigator has assumed different values for the magnitude and effect of the various influencing parameters; consequently, we find a wide range of expected energy savings in the reported estimates.

Table 1 lists projections of future energy savings from cogeneration as reported in several different studies. It is important to distinguish between (1) the amount of savings estimated to be technologically feasible, (2) the savings estimated when economic limitations are considered, and (3) the estimated savings from actual implementation when all constraints (including institutional factors) are considered. Also, as shown in the table, energy attributable to industrial steam/power cogeneration should be distinguished from that attributable to district heating and Modular Integrated Utility Systems (MIUS). In general, the former two types of applications do not overlap, and the resulting estimated savings are additive. With this consideration, when appropriate projections are combined, the total technological and economic potential for energy savings estimates ranges from 6 to 10 quads/year (by 1985). Fewer

estimates of expected actual implementation levels have been made, but these range from 0.5 to 4 quads of energy savings within 10 to 35 years.

A COMPARATIVE EVALUATION OF RECENT REPORTS ON THE ENERGY CONSERVATION POTENTIAL FROM COGENERATION

R. W. Barnes

ABSTRACT

Most of the electricity generated in the U.S. and the heat used by industry, buildings, and homes are produced independently from the combustion of separate fuels. Cogeneration, the combined production of electricity and useful heat, could reduce significantly the total amount of fuel required. This report discusses areas of application and alternative technologies for cogeneration. Projections by various investigators indicate potential U.S. energy savings from 1 or 2% up to almost 10%. Several of the published estimates of potential energy conservation benefits from cogeneration are analyzed and reduced to common bases for comparison. Significant differences in the various projections arise from differences in estimating the size of the industrial steam demand and from divergent assumptions concerning the tractability of various implementation problems.

1. SCOPE OF ANALYSIS

The cogeneration studies (reports) that were reviewed in our work can be grouped into two categories: (1) those that developed new or previously unreported basic data, and (2) those that made projections based on such data.

Little basic study has been devoted to the potential for cogeneration in the United States. We have identified and reviewed nine reports covering the first type of study (see Table 1).¹⁻⁹ These basic studies will receive most of the attention in this report; however, a few category 2 reports¹⁰⁻¹² will be discussed, primarily to show their relationship to the basic studies.

Table 1. Estimates of future energy conservation from cogeneration^a [10¹⁵ Btu/year (quads)]

	Indefinite future — based on present energy use			1985			2000/2010		
	Technological potential	Technological and economic potential	Planned or expected (actual)	Technological potential	Technological and economic potential	Planned or expected (actual)	Technological potential	Technological and economic potential	Planned or expected (actual)
<u>Industrial cogeneration</u>									
Dow study ¹					1.5				
Thermo Electron study I ²	1.2-4.6			1.7-6.9	0.6-5.2				
Thermo Electron study II ³						1.5 ^b			
Industry Resource Group (CONAES study) ⁴							6-10		2-4
Ross & Williams study ⁵			2.6						
RPA study ^{6,c}				1.1-1.9	0.5-0.9 ^b	0.5-0.7 ^d			
<u>Utility central station cogeneration (district htg.)</u>									
Brookhaven study I ⁷		3.3-3.8							
Brookhaven study II ⁸		4.7			5.2			5.0	
<u>Modular Integrated Utility Systems (MIUS)</u>									
Ross & Williams ⁵			0.9						
ORNL/HUD ⁹								0.3-0.6 ^e	

^aFuel reduction compared to meeting the same heat and electricity demands without cogeneration. Considers steam generation only (excludes bottoming cycles for waste heat recovery and also topping cycles on direct process heat).

^bWith government action.

^cRPA figures have been increased to include 0.16 quad of energy saving from cogeneration facilities existing in 1975.

^dWithout government action.

^eResidential sector only.

2. COGENERATION CONCEPTS

2.1 Technical Basis for Cogeneration

When energy in the form of heat is released by fuel combustion, it can perform useful work. In general, this work is accomplished by heating a working fluid such as steam or combustion gases and using the energy transported in the fluid to spin a turbine or move a piston. For a given amount of energy released, more work can be obtained from higher temperatures in the working fluid. Thus, it is desirable from the thermodynamic efficiency viewpoint to utilize energy from fuels at the maximum achievable combustion temperature. Unfortunately, there are two factors which constrain the achievement of this objective.

The first constraint is the physical capability of materials (engine components, etc.) to withstand elevated temperatures. Alleviation of this constraint is progressing through advances in metallurgy and through the design of energy transformation systems which can effectively utilize higher-temperature components. At present, we are generally restricted to the use of working fluid temperatures of below 1093°C (2000°F).

The second constraint arises from the nature of the task for which the energy is being used. Many industrial process heating applications and all residential and commercial space heating methods require temperatures of less than 149 to 260°C (300 to 500°F). Utilizing a fuel capable of producing 1093 to 1649°C (2000 to 3000°F) temperatures for these applications results in a loss of potential available work. Dual-purpose systems that can utilize the higher-temperature energy component of a working fluid to generate electricity and then exhaust the reduced-temperature fluid for other applications can significantly improve the overall efficiency of energy use. However, the potential improvement is governed by many factors ranging from the technological characteristics of various dual-purpose systems, to the availability of fuels, and to the demand characteristics of the energy flows involved.

The term cogeneration embraces a variety of dual-purpose systems which can produce both electricity and useful output heat flows. To aid in analysis of the various published projections of the potential

for cogeneration, we will use a two-dimensional classification system. One dimension will be the "mode," referring to the technology employed; the other will be the "form," referring to the type of system or the user environment in which the cogeneration system is installed.

2.2 Modes of Cogeneration

There are several technologies which might be used in a cogeneration system; however, only three have practical significance at the present time. These are also the only ones considered in the projections analyzed in this report. The technologies are (1) steam boiler/steam turbine designs, (2) gas turbine designs,* and (3) diesel engine designs.* The pertinent characteristics of each are reviewed below.

2.2.1 Steam turbine designs

Steam technology has been widely used for more than 100 years and is the basis for most of our present electrical power generation. It is also used extensively for industrial process heating and for space heating in buildings; consequently, steam-based systems are the most likely application areas for cogeneration. In a steam-based cogeneration system, steam is produced in a boiler at a temperature (and pressure) substantially higher than that required for the associated process or space heat requirement. The high-temperature steam is passed through a steam turbine which turns a generator to produce electricity, and the exhaust steam from the turbine is utilized for the heating applications.

Steam-turbine-based cogeneration produces the lowest ratio of electricity to heat output of the three modes. Approximately 10 to 15% of the fuel input is converted to electricity, while about 70 to 75% of the fuel energy will appear in the exhaust steam. These proportions are affected by the initial steam temperature and pressure and by the exhaust steam temperature and pressure. For relatively high initial steam pressure

* It should be noted that gas turbines can be operated with clean liquid fuels and diesel engines can be operated with fuels other than diesel oil.

and temperature [i.e., 11,030 kPa (1600 psig) and 538°C (1000°F)] and also a relatively high turbine exhaust pressure [i.e., 4140 kPa (600 psig)], about 8% of the fuel input will be converted to electricity and 77% will be in the exhaust steam. On the other hand, for the same initial steam conditions and for a low exhaust steam pressure of 345 kPa (50 psig), about 16% of the fuel goes into electricity and about 69% to the steam. If the output heat flow can be used in the form of hot water [at 104°C (220°F), for example] such as in district heating systems, as much as 30% of the fuel input can be converted to electricity with about 55% going to the hot water flow.

A convenient parameter in comparing cogeneration systems is the ratio of electrical energy produced (at 3412 Btu/kW/hr) to output heat flow (in Btu's). This ratio has been termed the alpha value and, based on the data given above, can vary from 0.1 to 0.55 for the steam turbine mode, depending on whether the exhaust heat is used in the form of high-pressure steam or hot water, respectively.

An important consideration in cogeneration systems is balancing the two forms of energy output. Since the steam turbine mode normally produces a lower ratio of electricity to heat than the other modes, the operating level of a given system will be controlled by the steam (or hot water) demand. Variable electricity loads are met by providing the capability to directly condense some portion of the exhaust steam from the turbines. By this means the alpha ratio can be increased; however, some efficiency in fuel utilization is sacrificed.

2.2.2 Gas turbine designs

In the gas turbine mode of cogeneration, fuel gas (or a clean distillate oil) is burned in a combustion chamber and the hot combustion gases expand through a turbine coupled to a generator to produce electricity. In nonrecuperated* versions, the exhaust gases exit at high temperatures [above 482°C (900°F)] and can be used directly for heat or

* A heat exchanger (recuperator) can be installed on gas turbines to warm the combustion air with heat from the exhaust, thereby improving the overall thermal efficiency.

passed through a waste heat boiler to produce steam for process use or space heating. In some systems, the steam may be utilized for additional electricity generation, creating what is known as a combined cycle operation. Another variant of this mode is the closed-cycle turbine, wherein pressurized air is heated (within a heat exchanger) in a separate combustion chamber and the hot air is used as the working fluid in the gas turbine. Some energy-use efficiency is sacrificed in this cycle; however, a wider variety of fuels can be used.

For the same process steam (or useful heat) conditions, the gas turbine mode of cogeneration usually generates more power per unit of steam flow than the steam turbine mode. Either open- or closed-cycle gas turbines may have alpha values of up to 0.75, with the fuel economy being inversely proportional to the alpha value. For example, the fuel chargeable to power* from gas turbine cogeneration can range from 3200 to 7000 Btu/kWhr, as compared with 4600 Btu/kWhr for a back-pressure steam turbine mode. It also should be recognized that an open-cycle gas turbine has a sizable advantage in combustor efficiency over a steam boiler furnace. Indirectly heated gas turbine cycles, however, are taxed with about the same furnace efficiency as a steam system and will never show a fuel economy advantage in direct comparison to a steam cogeneration system.

2.2.3 Diesel engine designs

Diesel engines have been available for more than 50 years, and a mature technology producing a widely used and reliable product has evolved. Diesel-powered electricity generation is frequently used in smaller, remote installations not economically serviced by the large central generating stations. Diesel-powered generators have also been used for emergency power or to meet peak demand loads in the larger systems.

* The fuel chargeable to power concept assumes that steam (or useful heat) is the primary desired output and could be produced without cogenerated electricity from a given amount of fuel. When electricity is cogenerated, additional fuel must be supplied above that required for the steam alone, and this additional fuel is charged against the electricity.

Diesel engines primarily use liquid fuels; they will, however, perform well using the heavier and less expensive grades. Fuel consumption for electric power generation is somewhat higher than for the other modes. In a diesel-driven cogeneration system, the fuel chargeable to power will amount to about 6000 to 7000 Btu/kWhr, depending on the extent of waste heat utilization. Although the heat content of the hot exhaust gases can be converted to usable steam, about 30% of the engine heat output is rejected in the engine cooling fluids at temperatures of 121°C (250°F) or lower. In most industrial applications, heat flows at these low temperatures have no utility; however, such low-quality heat would be suitable for space heating applications.

The diesel engine mode of cogeneration produces a higher proportion of electricity than either of the other modes. If steam is produced only from the exhaust gases, alpha values of up to 1.5 may be obtained. If the heat content of the cooling fluids is utilized, alpha values are still above 1.0.

2.2.4 Other modes of cogeneration

At least two studies^{2,6} have indicated some potential for cogenerating electricity by the topping of direct process heat. In practice, this would entail the generation of electricity with a gas turbine or a diesel engine and the use of the exhaust gases to heat a process reactor, kiln, or other such industrial equipment. There is no significant use of this technique in industry today. The studies mentioned indicated an economic potential equivalent to 10 to 50% of the steam topping potential. However, because of the lack of experience with such systems, both studies caution against use of their estimates, so they are not included in this report.

Work has been proceeding in recent years on the development of low-temperature Rankine cycle turbines for conversion of waste heat to electricity. Although this would also represent a mode of cogeneration, the technique is still under development and the economics are largely unknown. Some estimates^{2,6} of the potential have been attempted, but they show only a fraction (5-15%) of the steam topping potential, so they have not been included in our analysis.

At least two quite new technologies, fuel cells and solar cells with concentrating collectors, have been suggested for cogeneration systems. In both cases, electricity is produced together with a waste heat stream. Although these technologies might have future cogeneration potential, no studies of such potential have been reported, and consequently they have not been included.

2.3 Forms of Cogeneration

The three basic forms of cogeneration or types of implementation are (1) the industrial cogeneration system, (2) the central utility station cogeneration system, and (3) the smaller MIUS, or total energy system. In the first form, steam will be the nominal principal product and electricity can be considered a by-product. In the second form, electricity is the primary product and the heat flow is a by-product. In the MIUS systems, neither energy flow dominates. Not all modes of cogeneration are feasible within each form; feasibility relationships are shown in Table 2.

2.3.1 Industrial cogeneration systems

The attraction of industrial cogeneration systems results from the facts that U.S. industry produces large quantities of steam for use in various processes and that most of this steam is produced solely for process heat with no associated electrical power generation. It has been estimated⁶ that in 1976, 600×10^{12} Btu of process steam was generated in industrial cogeneration systems (primarily steam turbine mode). This is less than 10% of the total industrial steam production. At a nominal alpha value of 0.2, this represents 35×10^9 kWhr of cogenerated electricity, which is about 4% of industrial electricity use. Thus, from either a total steam or total electricity requirement, it would appear that a several-fold increase in industrial cogeneration is technologically feasible. However, industry uses steam and electricity in widely varying proportions from one plant to another, and there is no assurance that any given industrial plant with the steam capability for additional cogeneration will also have an economic use for the electricity produced.

Table 2. Feasibility of cogeneration alternatives

Form of cogeneration	Current technology				Future technology	
	Basic cycles			Combined cycle	Fuel cell	Solar cells
	Steam turbine	Combustion turbine	Diesel engine			
Industrial plant producing by-product electricity						
Internal use only	<i>a</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>c</i>
External sale	<i>b</i>	<i>a</i>	<i>a</i>	<i>a</i>	<i>b</i>	<i>c</i>
Electrical utility selling by-product heat						
Industrial sales only	<i>a</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>c</i>	<i>c</i>
Residential/commercial sale	<i>a</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>b</i>
Modular Integrated Utility Systems (no external sales)	<i>c</i>	<i>a</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>a</i>

^a Appears feasible.

^b May have limited feasibility.

^c Appears infeasible.

An analysis of a diverse group of ~282 large industrial plants (Appendix A) indicates that about 35% of these plants have an electrical energy requirement equivalent to less than 10% of their steam energy use. Further, 80% of the plants in the group have an electrical energy demand requirement equivalent to less than 25% of their steam energy use. If this sample is representative of the totality of industrial energy use, we can conclude that industrial cogeneration by any mode having alpha values higher than 0.1 to 0.2 will entail substantial export (from the cogenerating plants) of the electricity produced. This means that realization of the full potential for cogeneration from the industrial steam base will require a cooperative effort between private industry and the electrical utilities to distribute and utilize the excess electricity effectively.

Regardless of the mode employed for industrial cogeneration systems, the potential for electricity production and for energy conservation is ultimately dependent upon the industrial requirement for process steam.* Although data on total industrial energy use are regularly collected and compiled by sector and by type of fuel, relatively little survey information is available to establish the energy allocated to steam generation.

Since industrial steam use is an important variable in estimating the potential for industrial cogeneration, we have analyzed the various bases for projecting future total industrial steam requirements. The results, shown in Table 3, indicate that the fuel input for industrial steam generation represents about 10% of total U.S. energy use and was ~7 quads in 1975. Based on historical industrial energy use, the fuel growth rate of 3.5 to 4.0%/year fuel for steam will increase to about 10 quads in 1985. This is substantially lower than the 18.5 quads that would be projected from the steam-use data given in the pioneering analytical study¹³ at Stanford Research Institute (SRI). This work, published in 1972, has been widely used as a reference base in subsequent energy studies and also for some cogeneration projections. We have been unable to reconcile the

* Although electricity could be produced from topping systems installed on direct-fired process heating systems, such applications are rare or nonexistent at present and are not anticipated to increase during the foreseeable future.

Table 3. Estimations and projections of industrial steam use^a (quads)

Source of data or projection	Estimated level of fuel input for industrial steam use in base year				Growth assumed for projection	Projected level of fuel input for industrial steam	
	1968	1972	1973	1975		1980	1985
Stanford Research Inst. ¹³	10.13				3.6%/year		[18.5]
Dow Chemical Company ¹	10.13				3.5%/year to 1980 4.5% thereafter	16.5	[21]
Babcock & Wilcox ¹⁴			6.7		No projections made		
Dow Chemical Company ¹⁵		7.8			No projections made		
Thermo Electron Corp. ² & Amer. Boiler Mfr. Assn. (ABMA) ⁶				[6.7] ^b	50% in 10 years (4.1%/year)		[10]

^aFigures shown in brackets are derived from the data and assumptions reported in the associated study.

^bThe American Boiler Manufacturers Association has a data base covering all industrial boiler sales since before 1963. Tabulations of this data showing boiler purchases by individual industries provided a basis for estimating the total industrial steam capacity and also the distribution of this capacity to specific industries.

^cThermo Electron² data for three industries (chemical, petroleum refining, and paper) show a total energy input to steam of 3.8 quads. ABMA data indicate that the three industries have installed 57% of total industrial boiler capacity additions in recent years. On this basis, total industrial steam fuel use would be $3.8/0.57 = 6.7$ quads. This number is probably slightly low, since the three industries analyzed have each grown faster than the average industrial growth in recent years and their boiler purchases in these years were probably a larger fraction of annual boiler sales (in steam capacity) than of total installed industrial steam capacity.

high level of industrial steam production (16.7% of national energy use) estimated by SRI with recent data developed in other independent studies (see Table 3).^{14,15} Consequently, we believe that 10 quads is a realistic expectation for 1985. However, an intensive energy conservation effort could reduce this even further.

2.3.2 Central utility station cogeneration systems

More than 90% of the conventional utility electricity produced in the U.S. is generated with steam-turbine-driven generators. The exhaust steam from these turbines represents in total about 10 quads/year of heat energy that is largely discarded. In theory, much of this discarded heat could be used for industrial process heating or for space heating of buildings.

Industrial utilization of exhaust steam from an electrical utility plant requires the plants concerned to be located in proximity (maximum 5-10 miles) to one another. The difference in criteria for optimal site locations for electrical power plants and private industrial plants represents a significant constraint to this form of cogeneration. Additional constraints arise from the need to match peak demand requirements for the electricity and steam flows and the fact that the industrial user must have a relatively large steam demand to make the project economically viable for the utility.

District heating systems represent another potential use of reject heat from central utility stations. In Sweden, ~20% of the residential and commercial space and water heating requirements are met with hot water produced in central utility stations and circulated to the buildings involved. Steam-based district heating systems exist in many U.S. cities; however, their use has been declining, and in many cases the steam is supplied from a single-purpose boiler rather than from cogeneration. Hot water systems for district heating have technological advantages over steam (e.g., feasibility for longer transmission distances) and also permit higher efficiencies in the associated cogeneration operations.

2.3.3 Modular Integrated Utility Systems (MIUS)

The MIUS concept is alternatively termed the total energy concept. In this form of cogeneration, the total energy requirements (heating, cooling, and electricity) of an activity such as a residential complex, a shopping center, or a community are supplied from a single integrated system. At present, the diesel engine (or a similar gas-fired engine) is the preferred mode for these systems. In general, MIUS installations are most successful when they are incorporated into an activity with reasonably level energy requirements and with a designed balance between heating, cooling, and electricity demand that is optimal with respect to the alpha value of the cogeneration system. In activities and locations with wide variations in energy demand over time, facilities required to meet peak demand loads may be idle much of the time, and MIUS installations may be uneconomic.

3. TECHNOLOGICAL COMPARISON OF COGENERATION STUDIES

In this section of our analysis, each of the several cogeneration projections are characterized as to the mode and form of cogeneration postulated in the study and also as to their estimates of the level* of future use of heat and electricity from cogeneration. Although these characteristics are summarized in Table 4, there are many differences in the basic assumptions of each study, necessitating the discussion which follows.

3.1 The Dow Study¹

This study evaluates only the potential for cogeneration to satisfy the industrial process steam requirement; the only mode of cogeneration examined is the steam turbine topping mode. Projections are made for two forms of cogeneration — individual industrial plant installations and central utility station installations. In addition, a projection is made for a feasible combination of these two forms.

One disadvantage of this study is that projections for the 1985 industrial steam requirement are based on the SRI study¹³ of 1972 using that estimate for 1968 industrial steam use, increased by 3.5%/year until 1980 and by 4.5%/year thereafter until 1985. As discussed previously, the SRI estimate of industrial steam use in 1968 appears to be higher than the actual figure. Since the Dow study projections from the SRI estimate use steam demand growth rates that make no allowance for a stimulated energy conservation effort or for the 1974-75 industrial slowdown, the Dow-projected 1985 total industrial steam demand appears to be substantially larger than that which will actually occur.

Based on economic relationships prevailing in 1975 and assuming an average construction cost escalation of 7.7%/year until 1985, the Dow study estimates that steam turbine cogeneration in industrial plants will

* Because of the differences in their respective bases, many of the entries in Table 4 are derived using the data and assumptions of the associated study.

Table 4. Technological comparison of cogeneration projections^a

Study	Mode of cogeneration			Form of cogeneration		Expected heat and electricity production					Notes
	Steam turbine	Gas turbine	Diesel engine	Industrial steam topping	Central station power generation	Year	Total potential heat demand ^b (quads)	Portion served by cogeneration ^c (%)	Useful heat from cogeneration (quads)	Electricity production from cogeneration (GW)	
Dow ¹	X			X		1985	21	51	10.7	51.5	Includes 18,200 MW electricity and 3.7 quads of steam from existing (1975) industrial steam topping in each case
	X				X	1985	21	32	6.7	[33.4]	
	X			X	X	1985	21	46	9.7	[47.5]	
Thermo Electron I ²											Totals are for petroleum refining, paper, and chemicals, which represent about 50% of U.S. industrial steam use
With utility financing	X			X		1985	4.8	91	4.4	25.6	
		X		X		1985	4.8	81	4.0	89.6	
			X	X		1985	4.8	76	3.7	166.9	
With industrial financing	X			X		1985	4.8	78	3.8	21.9	
		X		X		1985	4.8	77	3.7	83.3	
			X	X		1985	4.8	62	3.0	135.7	
Thermo Electron II ³	?	?	?	X		1985	?	?		40.8	Based on cogeneration in all cases where capital for cogeneration is less than capital for alternate electricity
RPA ⁶											Totals are for six industries which consume more than 50% of all industrial steam
Without government action	X			X		1985	5.9	31	[1.8]	[10]	
	X	X	X	X		1985	5.9	31	[1.8]	[18]	
With maximum government action	X			X		1985	5.9	44	[2.6]	[15]	
(6 industries increased)	X	X	X	X		1985	5.9	44	[2.6]	[23]	
Industry Resource Group (CONAES) ⁴	X			X		2010	28-46	30-40 ^d		45-90	Based on expected levels of implementation in each major steam using industry; assumes 2 and 3%/year gross national product growth
Ross & Williams ⁵	X	X		X		?	12.7	50	[6.3]	[59.]	Based on industrial steam representing 17% of total U.S. energy use and 50% of steam used for cogeneration
Brookhaven I ⁷	X				X	?			2.1		Based on district heating service to 61 MM people at costs competitive with petroleum fuels
Brookhaven II ⁸	X				X	?			3.6		Based on district heating service to 50% of U.S. population at costs competitive with electricity
						1985			4.2		
						2000			5.1		

^aFigures in brackets have been derived from data and assumptions reported in the associated study. Electricity production is shown at 100% capacity factor.

^bTotal heat demand = projected U.S. requirement for industrial steam or residential/commercial space heat as estimated in each study for the year shown.

^cRepresents the percent that is technologically and economically feasible, unless indicated otherwise — as below.

^dRepresents the estimated feasible level of implementation considering all constraints.

be economically feasible for installations producing 400,000 or more pounds of steam per hour. According to the Dow analysis of industrial steam generation practice, this represents 43% of total U.S. industrial steam production. However, some plants producing less than 400,000 lb/hr and currently cogenerating are expected to continue to do so, and the overall level of technical and economic feasibility for industrial cogeneration will equal 51% of the total industrial steam demand. This results in an estimate of 10.7 quads of industrial steam, 51,500 MW of electricity generation, and 1.5 quads of energy conservation in 1985 from industrial cogeneration.

For central utility station cogeneration, it is estimated in the Dow study (based on discussion with utility company representatives) that 1,000,000 lb/hr of industrial steam demand is the minimum economic level for cogeneration. On this basis, Dow researchers estimate that only 23% of the industrial steam is applicable. However, if existing industrial in-plant cogeneration continues, the combined level of implementation by 1985 would equal 35% of the industrial steam demand, or 6.7 quads/year.

It is assumed in the Dow study that cogenerating central utility stations would each produce 2,000,000 lb/hr of by-product industrial steam on the average, and a steam capacity above this level would be used to produce electricity with condensing turbines. On this basis, the study does not develop a figure for central station electricity production from cogeneration only. However, since the Dow study does consistently use the ratio of 1.0 kWhr of electricity per 20.4 lb of cogenerated steam, we have used this same relationship to obtain the electrical power generation level shown in Table 4 (33,400 MW). Energy saving in 1985 would be 1.1 quads from this form of cogeneration.

Similarly, a scheme of combined industrial plant and central stations cogeneration that in total would satisfy 46% of the industrial steam demand is suggested in the Dow study. This approach would produce 9.7 quads of steam and 47,500 MW of electricity (from cogeneration), with an annual saving of 1.5 quads of energy.

Although major attention is given to the institutional (i.e., legal-regulatory, attitudinal, and other intangible) problems in the Dow study,

no attempt has been made to estimate the extent to which these problems will inhibit cogeneration. The study also fails to evaluate the extent to which dynamic load fluctuation patterns within an industrial plant might produce an imbalance between steam and electricity demands, thereby reducing the potential for dual-purpose steam-electricity generation.

3.2 The Thermo Electron Studies^{2,3}

The primary Thermo Electron study (TE-I)² contains an in-depth analysis of heat use and flows by temperature levels in the chemical, petroleum refining, and paper and pulp industries. The TE-I study presents no data on the relationship of energy use in these three industries to the totality of U.S. industrial energy use. It is known, however, that these industries produce and consume a substantial portion of total industrial steam. Based on data from the American Boiler Manufacturers Association, we estimate that about 50% of industrial boiler capacity (and therefore 50% of steam production) is installed in the three industries.*

Using the data detail obtained from the Thermo Electron analysis, the maximum technological potential[†] for by-product electricity generation is calculated for each of the three industries. This maximum potential represents electricity from both "topping" (cogeneration) and "bottoming" cycles (waste heat recovery). The study then examines the economics of by-product electricity generation under three different sets of financial incentives. Projections of expected 1985 levels of implementation are made for each of the three industries under each alternative incentive plan. The projections do not reflect consideration of institutional constraints or include the effect of industrial operational requirements (i.e., dynamic load balancing) on expected levels of electricity production from cogeneration.

* See footnote b, Table 3.

[†] In the TE-I study, all industrial steam is considered to have potential for cogeneration, and the technological maximum by-product electricity is determined only by the temperature and pressure required in the process steam output.

The TE-I report is concerned only with industrial by-product electricity and makes no separate evaluations or projections for central utility station cogeneration. However, in developing the economics of industrial cogeneration units, two financing alternatives are considered - conventional industrial investment and utility ownership (or financing) of the cogeneration facility. Since utility ownership reduces financing costs and therefore the level of investment required, higher levels of cogeneration are found to meet the economic criteria for acceptability. Although the report shows projections of cogeneration output for both utility and industrial ownership, there is no discussion of the noneconomic factors or conditions which might favor one over the other.

In developing the maximum technological potential for cogeneration, the TE-I report evaluates both the topping of industrial process steam and the topping of process heat within direct-fired operations. The report recognizes, however, that the latter activity has never had significant actual realization, and the potential electricity from such activity is not included in the final projections.

In the projections of industrial electricity generation, the Thermo Electron study included the contribution from bottoming of waste heat in each of the three industries. Since the energy potential from waste heat recovery is relatively small (less than 10% of the process steam energy) and is subject to substantial uncertainties, we have removed this component from the TE-I projections and show only the contribution from industrial steam topping in our tabulations.

Three modes of cogeneration are evaluated in the TE-I report: steam turbine topping power, gas turbine topping power, and diesel engine topping power. For each mode, the relationship between electricity production and output steam characteristics has been determined and then applied to the steam use characteristics developed from the heat utilization analysis of the three industries in the study. From this step, the present (1975) maximum technological potential for cogeneration from each mode is obtained.

Having developed the maximum technological potential for cogeneration from each mode for each of the three industries, a projection to 1985 is made by first assuming an overall 50% (4.1%/year) growth for steam use in each industry between 1975 and 1985. Then, various economic criteria, as

mentioned above, are applied to determine the expected levels of investment in cogeneration facilities. Since the economics of cogeneration facilities are more favorable for new plants than for the retrofitting of old plants, it was assumed that the expected 50% growth represented new plant construction entirely and, in addition, that 25% of the existing plants would be replaced with new capacity because of age and obsolescence.

Table 4 shows the TE-I projections for each mode of cogeneration and for the two types of financing (utility and industrial). The values shown for heat production and electricity generation are the maximum values, based on the most favorable economic incentive.

In general, as shown in Table 4, the TE-I study indicates that it would be economically attractive to cogenerate 62 to 91% of the 1985 industrial steam requirements. At this level, the equivalent electricity production is 22,000 to 167,000 MW, depending on the mode of cogeneration employed. Fuel savings, as shown in Table 1, would range from 0.6 to 5.2 quads/year, again depending on the mode of cogeneration.

Since the TE-I study shows a higher level of economic attractiveness for cogeneration than the Dow study, differences in economic assumptions between the two were reviewed. It was observed that the Thermo Electron study develops more attractive economics for cogeneration because of the effects of assumed financial incentives such as a 25 to 50% investment credit against taxes or 50% government financing for cogeneration facilities. These incentives increase the expected return on investment and therefore induce a higher level of cogeneration investment.

The differences between the Thermo Electron and the Dow studies, such as scope of industrial coverage and size of the estimated industrial steam base, preclude a meaningful comparison of the actual magnitude of future cogeneration outputs projected in each study. However, we can compare the effect of the financial incentives incorporated in the TE-I study with the Dow analysis by showing the fraction of maximum technological potential for cogeneration projected for each economic alternative. As shown in Table 5, both studies project a level of implementation of about half their respective estimates of the maximum technological potential. For the various additional economic incentives, the Thermo

Table 5. Projected level of cogeneration based on alternative economic incentives^a

	Percent of maximum technological potential					
	Industrial financing			Utility financing		
	Base case	With 50% investment credit	With 50% government financing	Base case	With 25% investment credit	With 50% government financing
Dow study	51					
TE-I study	47	78	70	78	86	91

^aBase case = present corporate tax rate (50%) and 10% investment tax credit.

Electron study shows the expected level of implementation increasing up to a high of 91% of the maximum potential.

A more recent report (TE-II),³ by the Thermo Electron Corporation presents an estimate of the feasible level of industrial cogeneration activity in 1985. Although no basis for the estimate is identified, the projections are quite likely derived from the previous work discussed above. The TE-II report estimates a fuel saving of 1.5 quads (Table 1) and a by-product electricity generation of 42,800 MW. These values are near the lower end of the ranges presented in the TE-I study and appear to represent the estimated potential for the steam turbine topping mode. Although the projected level of fuel saving is somewhat high (about 20%) with respect to the estimated level of by-product electricity generation, the projections are compatible with the Dow and the TE-I studies.

3.3 The Resource Planning Associates (RPA) Study

This study, which is the newest of those analyzed, represents the most comprehensive investigation performed to date on the potential for industrial cogeneration. The RPA study parallels the TE-I study in that industrial steam topping potential was the major consideration, and the three primary modes of cogeneration (steam turbine, gas turbine, and diesel engine) were evaluated. In addition to the chemical, paper, and petroleum refining industries discussed in the TE-I study, the RPA work

also covered the steel, food, and textile industries. Both studies analyzed the effect of various possible government incentive programs on the attractiveness of cogeneration investments. The RPA study did not, however, consider utility company financing, as did the Thermo Electron study.

The major difference between the RPA and the Thermo Electron projections is the distinction made by RPA between technically "suitable" and "unsuitable" portions of the total steam use. Based on discussions held in the field with more than 50 industrial companies, it was concluded that about 46% of the steam use in the six industries studied was technically unsuitable for cogeneration.* Reasons for this ranged from the small size of some individual steam requirements to the mismatch between the dynamic fluctuations in steam and electricity demand loads for a given establishment.

To evaluate the economically attractive portion of the technically suitable process steam load, RPA developed estimates of the return-on-investment (ROI) required by each industry for investment in cogeneration projects. An accumulative distribution plot of cogeneration investment potential vs ROI was prepared for each industry. The expected ROI was calculated for each type of cogeneration activity for each industry, and the expected economic level of implementation was then obtained from the distribution plots.

A very similar procedure was used in the TE-I study to determine the economic level of cogeneration investment. However, the Thermo Electron group used only one composite investment probability distribution curve for the three industries considered. It was based on the industry-wide average after-tax rates of ROI and was subjectively scaled to show the effect of higher and lower rates of return. In contrast, the RPA study developed separate investment vs ROI distribution curves for each of six industries and established the functional relationships from extensive discussions with investment decision makers in each industry. However, when we compared the distribution curves from both

*The RPA group did not study process steam use outside the six industries of interest; however, they estimate that only 5% of such steam is technically suitable for cogeneration.

studies, the single Thermo Electron distribution was found to lie quite close to the centerline of the six RPA distributions.

The RPA study does not have a separate projection for each mode of cogeneration, and only two cases are developed: (1) the "low electricity" case for steam turbine topping only and (2) the "high electricity" case for a mix of 75% steam turbine, 15% gas turbine, and 10% diesel engine modes. The "high electricity" case is estimated to represent the maximum extent to which the gas turbine and diesel engine modes could be utilized by 1985.

As shown in Table 1, the RPA analysis projects a minimum energy saving in 1985 of 0.5 quads and a maximum saving (with strong government programs) of 0.9 quads* for the six industries studied. This is a lower level of energy saving than is projected by the other studies reviewed. This smaller energy saving is primarily a consequence of the small industrial process steam load considered suitable for cogeneration in the RPA study. Also, RPA estimates that only 25% of the process steam demand will be served by the gas turbine and diesel engine modes of cogeneration (which further restricts the potential for energy conservation).

In the RPA analysis, the use of industrial steam is projected to increase at 4.1%/year from 1976 on, giving a "technically suitable" steam base of 3.5 quads† in 1985. Without government programs to stimulate cogeneration, half of this steam would be obtained from new and presently existing industrial cogeneration systems. With maximal government programs, three-fourths of the technical potential would be utilized. These levels of implementation would produce from 10 to 23 GW of electricity (see Table 4), depending on the mode of cogeneration employed.

The RPA estimates for 1985 levels of cogenerated electricity are significantly lower than the Thermo Electron estimates not only because

* The RPA study actually presents only the estimated energy savings from "additional" cogeneration by 1985. We have added 0.16 quad of energy savings attributable to presently existing industrial cogeneration.

† This represents only the six industries studied. However, all other industry is estimated to have only a total of 0.4 quad of steam demand technically suitable for cogeneration.

of the lower industrial steam base considered suitable for cogeneration, but also because of the limited expectations for gas turbine and diesel engine applications.

3.4 The CONAES Industry Resource Group (IRG) Study[†]

This study is still unpublished and has been included in our discussion because of this author's participation in the CONAES work.

As part of a larger program studying major energy alternatives for the U.S., a group of industrial energy specialists was assembled to evaluate the potential for industrial energy conservation activity.[†]

Industrial cogeneration was one of the conservation activities examined. Using the basic data developed in the Dow study and the TE-I study, an evaluation was made of the effect of operational and institutional constraints on the expected level of industrial cogeneration. This included consideration of factors such as operational load balancing for steam and electricity use in industrial plants, economic cost of standby facilities to backup cogeneration operations, willingness of industrial managers to commit to firm contracts for surplus electricity sales, and the expected ratio of private sale price for surplus industrial electricity to the purchase price of displaced electricity. Much of this evaluation was necessarily subjective.

The IRG study concluded that expected implementation of cogeneration would be about 30 to 40% of the maximum technological potential. The IRG study evaluated several alternative "scenarios" for future energy prices and economic growth. Within these scenarios, the expected annual fuel saving from cogeneration by the year 2010 would be 2 to 4 quads (Table 1). This represents a by-product electricity generation of 45,000 to 90,000 MW (Table 4). When interpolated back to 1985, this is a lower

[†]The Committee on Nuclear and Alternative Energy Systems (CONAES) was set up by the National Research Council to evaluate the future need for nuclear energy. As part of the study, an Industry Resource Group (IRG) was assembled to identify and evaluate industrial energy conservation options. The IRG was composed of representatives from the aluminum, cement, chemical, food, glass, paper, and steel industries.

estimated level of implementation than shown in any of the other studies reviewed.

3.5 The Ross and Williams (R&W) Study⁵

This study also contains no new independent evaluation of the technical basis for cogeneration and relies upon the data presented in the Dow and the TE-I reports. Ross and Williams estimate that industrial steam production represents 17% of the total U.S. energy use. This is the same fraction of total energy use previously reported in the SRI study,¹³ and it appears to be substantially larger than the actual level of industrial steam use. With the further assumption that cogeneration from 50% of the steam base is feasible and the cogeneration saves half the fuel otherwise required for electricity generation, the R&W study estimates a potential fuel saving of 2.6 quads (Table 1).

If we use the R&W estimate that cogeneration saves half the fuel input normally required for electricity generation and a value of 10,000 Btu/kWhr for the normal fuel requirement, we find that R&W projects approximately 59,000 MW of by-product electricity from cogeneration. This indicates an alpha value of about 0.3 and suggests that the estimate is based on steam turbine cogeneration or a combination of steam turbine and gas turbine modes.

The R&W study also presents estimates for fuel savings from total energy systems (MIUS) cogeneration. The study estimates a feasible potential of half of all multifamily housing units to be equipped with total energy systems for a fuel saving of 0.31 quad. Additionally, it is estimated that half of all commercial building units could be so equipped for a fuel saving of 0.64 quad. No data are presented showing the absolute magnitudes of heat and electricity generation resulting from these cogeneration applications, nor is the basic source for the estimate given.

3.6 The Brookhaven Studies^{7,8}

The Brookhaven reports discuss the potential for central utility station cogeneration to supply by-product heat for district heating. The

cost of district heating systems is evaluated for several U.S. cities. The potential for district heating is assumed to be that portion of the U.S. residential and commercial heating demand which can be served at a cost that is less than the cost of heat derived from imported petroleum in one case⁷ and from utility electricity in the other.⁸ It is estimated on these bases that 61 million and 103 million people, respectively, would find district heating to be economically attractive. This represents a total present heat demand of 2.1 quads in the first case and 3.6 quads in the second. The second study also presents projections showing the economically attractive potential for district heating growing to 4.2 quads in 1985 and 5.1 quads in the year 2000 (Table 4).

Assuming that these district heating loads are met with by-product heat from utility central station power plants, the first study projects a total U.S. fuel savings of ~3.3 to 3.8 quads/year (Table 1). This projection represents the primary fuel that otherwise would have been required for space and water heating, minus the additional fuel required by the utility to maintain constant electricity production.

The second Brookhaven study projects fuel savings (Table 1) of 4.7 (1972), 5.2 (1985), and 5.0 (2000) quads while serving district heating loads of 3.6, 4.2, and 5.1 quads, respectively. Again, these are net savings with the increased fuel used by the utilities deducted from the fuel saved by the consumers. This study assumes that the average thermal efficiency for conventional home heating systems will increase from about 58% in 1972 to 74% in 2000.

The energy conservation potential for district heating as reported in these Brookhaven studies may be overestimated. This writer is aware of recent unpublished work at Oak Ridge and Argonne National Laboratories which indicates that the retrofit (or new system) costs to a utility for the production and distribution of district heat may be higher than estimated in the Brookhaven work. At the higher cost the potential market (and energy savings) would be about half the size reported by Brookhaven.

3.7 The ORNL/HUD Study⁹

To our knowledge, this study is the only one containing a national projection of potential for the MIUS form of cogeneration that has been

developed from basic data. The study indicates that MIUS installations are economically competitive with conventional heating and electricity supply systems for large multifamily housing developments (i.e., 200 or more dwelling units per project). The authors estimate that 28 to 50% of multifamily housing built after the year 1980 would represent a feasible market for MIUS installation. If retrofit installations are considered, the total annual market could be from 400,000 to 750,000 dwelling units per year. By the year 2000, 8,000,000 to 15,000,000 dwelling units could be using MIUS at a primary fuel saving of ~25% per unit. At the projected usage levels for conventional heat and electricity in the absence of MIUS, this represents an annual saving of 0.3 to 0.6 quad (Table 1).

3.8 Secondary Studies

In the last one to two years, several investigators have published estimates of the potential energy savings from cogeneration according to their interpretation of the original work discussed previously. Each of these estimates will be reviewed briefly.

In two published reports,^{10,11} Amory Lovins makes three statements respecting the energy saving potential of cogeneration:

Cogeneration and more efficient use of electricity could together reduce our use of electricity by a third and our central station generation by 60 percent. (p. 74, Ref. 10)

Utility owned industrial cogeneration by 1985 could be profitably generating 26-42% more than all U.S. utility sales of electricity in 1975. (p. 26, Ref. 11)

It appears that cogeneration in 2000 could provide electricity conservatively equivalent to over two-thirds of the total 1975 electrical demand, directly displacing over 200 GW(e) of projected nuclear capacity. (p. 33, Ref. 11)

In the first quotation, since cogeneration and unspecified other electricity conservation measures are lumped together, it is not possible to identify the estimated potential savings for cogeneration alone. As a basis for this statement, Lovins cites the work of Ross and Williams⁵ that was discussed previously.

The second and third quotes above are somewhat inconsistent and may have been reconciled in the final paper, which has not yet been published. As the basis for the first of these two statements, Lovins cites the study by Thermo Electron² that was discussed previously (TE-I). The Thermo Electron study does not show a case projecting this high level of implementation. The maximum economic level (with federal tax incentives) projected for cogeneration in three industries equals 79% of 1975 utility electricity generation. If these three industries (chemicals, petroleum refining, and paper) are assumed to represent about 55% of total industrial steam use, one could estimate an overall level in the range shown by Lovins as "profitable." However, the difference between the economic maximum potential and the truly "profitable" level can be very substantial and is dependent upon many assumptions with respect to federal financing incentives, electricity pricing alternatives, and the removal of institutional constraints.

The last statement quoted above from Lovins was based on a report by Von Hippel and Williams,¹² which is discussed below. The ultimate source for this estimate was also the Thermo Electron (TE-I) report and is subject to the considerations just discussed.

The Von Hippel and Williams report includes an analysis of the effect that implementation of cogeneration might have on the growth of nuclear power. This report projects a level of electricity generation from cogeneration in the year 2000 equivalent to 230 GW of central station power. The report uses the ERDA-48 projection¹⁶ for industrial process heat (18 quads), coupled with a fraction for steam (0.75) from the SRI study¹³ to obtain an estimate for industrial steam use in the year 2000. Although this quantity is not explicitly stated, by following their assumptions we calculate it to be about 13.5 quads. From our earlier discussion of future industrial steam use, this projection appears to be conservatively low.

Von Hippel and Williams deduct from this steam demand a portion assumed to be derived from solar energy (2.1 quads per ERDA-48) and further assume that only 60% of the remaining steam could be economically obtained from cogeneration. It is also assumed that all this steam will be produced from the gas turbine mode of cogeneration ($\alpha = 0.7$). With a

final assumption that central station power plants operate at a capacity factor of about 70%, the annual electricity generation from cogeneration is estimated to equal 230 GW of central station generation capacity.

It should be noted that all the studies projecting the higher levels (i.e., above 100,000 MW) of economically attractive electricity production from cogeneration assume that the gas turbine mode will be employed and that the problem of obtaining a clean burning fuel to replace gas and distillate oil will be solved. Also, there is a general assumption that all operational, attitudinal, regulatory, and other institutional problems associated with cogeneration will be solved completely so that the economic maximum level of cogeneration will be installed.

4. CONCLUSIONS

Cogeneration of electricity and useful heat probably represents the largest single opportunity for energy conservation in the United States. However, like most opportunities, it may be so fraught with problems that to many observers it appears largely unachievable. Thus, we find that the energy-savings potential projected for cogeneration is largely dependent on the optimism of the forecaster with respect to the tractability of the problems involved. Some, like Lovins,^{10,11} indicate a potential annual savings as high as 13 quads (10^{15} Btu) by the year 2000. Others, such as Resource Planning Associates (RPA),⁶ expect about 1 quad* by 1985 and (by inference) only a modest increase by 2000. The difference between these two estimates appears to be more closely related to the extent to which each forecaster has examined the problems involved than to differences in basic data.

Lovins' projections are based on full utilization of the industrial steam base for cogeneration, employing almost exclusively a technology (combustion turbines) that produces a high electricity yield. However, his estimate does not represent an original investigation but is derived from the studies of other analysts.

Conversely, during the RPA study, researchers had many discussions with, and obtained basic data from, a substantial number of industrial people who are or would be involved in the cogeneration activity. As a result, the RPA researchers expect only a portion of the industrial steam base to be "suitable" for cogeneration; they also expect the bulk of the implementation to use the conventional steam turbine technology, which yields less cogenerated electricity.

Other projections of potential energy savings from industrial cogeneration range between the extremes quoted above and vary in their assumptions concerning the appropriate steam base and the technology to be employed. All studies agree that the maximum potential (whatever it may be) will be attained only with governmental programs that increase the

* In addition to presently existing cogeneration savings (about 0.6 quad).

incentive for cogeneration and solve the problems associated with the economic use of surplus electricity from industrial cogeneration plants.

Other forms of cogeneration (such as district heating and total energy systems) also have significant energy-savings potential but have major implementation problems. If these can be fully resolved, another 5 or more quads of energy saving could be obtained.

In total, it appears that cogeneration, in its various forms could, under ideal conditions, reduce our national energy consumption by almost 10%. In practice, however, actual energy savings are likely to be much smaller, depending largely on the extent to which the implementation problems are solved.

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Appendix

ANALYSIS OF INDUSTRIAL POWER/STEAM RATIOS

It is expected that the real (deflated) price of electricity sold to industry by electrical utilities will continue to increase. As this occurs, it will become increasingly attractive for industrial plants to produce their own electricity using cogeneration systems. However, since all industrial plants do not use steam and electricity in fixed proportions, there is a question about how effectively the total steam base can be used. Some plants could produce far more electricity than they use and would need to sell the surplus at a satisfactory price to justify the additional cogeneration. Others might consume more electricity than they could produce using their total steam base and thus still need to purchase some electricity.

The data needed to answer the above question are almost unavailable; however, a study* sponsored by Oak Ridge National Laboratory furnishes some pertinent data. This study presents steam and electricity consumption for almost 300 large U.S. industrial plants in the major process industries. Table A.1 shows the following distribution of steam and electricity use by individual industrial plants obtained from an analysis of the data from this study. From Table A.1, it appears that 80% of the plants have an electricity to steam use ratio ("alpha") of less than 0.25.

The implication of this analysis is that for the majority of U.S. industrial plants (if the sample analyzed is representative), electrical energy use is small with respect to steam energy use. If these plants were to install cogeneration only to satisfy their own steam and electricity needs, they would likely install steam turbine topping systems with alpha values in the range 0.1 to 0.25. Choice of another mode of cogeneration such as a gas turbine or a diesel engine, both of which normally have alpha values above 0.5, would depend upon having an attractive market for sale of the surplus electricity, which in many cases would be five or ten times larger than the internal use.

**The Potential Industrial Market for Process Heat from Nuclear Reactors*, ORNL/TM-5516 (July 1976), prepared for Oak Ridge National Laboratory by Dow Chemical Company, Midland, Mich.

Table A.1. Distribution of steam and electricity

Electricity/steam ratio ^a	Number of plants	Total steam use (10 ⁶ lb/hr)	Percent of steam use
<0.05	35	40.3	13.8
0.05-0.1	67	68.0	23.3
0.11-0.15	85	90.9	31.2
0.16-0.2	30	31.2	10.7
0.21-0.25	8	8.6	3.0
0.26-0.3	10	9.3	3.2
0.31-0.35	12	11.0	3.8
>0.35	35	32.2	11.0
Total	282	291.5	100.0

^aElectricity/steam ratio = Btu's used as electricity/
Btu's used as steam.

Internal Distribution

1. T. D. Anderson	32. H. Postma
2. M. Baker	33. M. W. Rosenthal
3-12. R. W. Barnes	34. Dunlap Scott
13. R. S. Carlsmith	35. M. R. Sheldon
14. T. E. Cole	36. M. J. Skinner
15. H. Falkenberry	37. I. Spiewak
16. L. C. Fuller	38. H. E. Trammell
17. J. F. Harvey	39. D. B. Trauger
18. J. E. Jones	40-41. Central Research Library
19. M. A. Karnitz	42. Document Reference Section
20-29. O. H. Klepper	43-45. Laboratory Records Dept.
30. M. Levenson	46. Laboratory Records (RC)
31. M. L. Myers	

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