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HANDBOOK OF INDUSTRIAL COGENERATION

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INTRODUCTION AND SUMMARY

Cogeneration is the sequential production of electrical or mechanical energy and useful thermal energy from the same fuel source.

In contrast to a conventional system that produces either electricity or thermal energy, a cogeneration system produces both and requires 10 to 30 percent less fuel. Industrial cogeneration saves primary fuels that would otherwise be used by utilities to produce central station power for sale to the industrial plants. Thus, cogeneration offers significant overall energy-saving potential for the nation, as well as significant dollar savings potential for the cogenerator.

In the early 1900s, many industrial plants generated their own electricity, and many practiced cogeneration by using the exhaust steam for process heat. As centrally generated electricity became cheaper, widely available, and more reliable, on-site generation of industrial electricity declined. Other factors contributed to the decline, and by 1979 on-site generation of electricity accounted for less than four percent of U.S. power generation. Now that industrial plants in many regions of the nation face significantly increased purchased electricity costs, the cost-saving potential of cogeneration is becoming more valuable to industrial users. Additionally, the conservation-inspired energy legislation passed in 1978 provides important economic benefits to cogenerators and small power producers who satisfy certain criteria of qualification.

The objective of this handbook is to provide potential cogenerators with sufficient information to permit a preliminary, yet well-considered, decision on the question of whether cogeneration is economically feasible in their particular set of circumstances. This involves many interrelated considerations: technological, economic, environmental, and legal. Added to these analyzable components are such issues as economic uncertainty, changes in plant products and process technologies, availability and future cost of fuels, and changing environmental and energy legislation. Any one of these factors could profoundly influence the outcome of a decision on cogeneration.

This handbook is designed to cover the analyzable issues, though some of the uncertainties are also addressed. The intended audience is not the expert consulting engineer, but the industrial plant manager or company energy coordinator who wishes to make a preliminary assessment of the opportunities for cogeneration at a particular plant prior to making recommendations to management on whether to proceed with a detailed study. Consequently, the material is presented in as generalized and usable a form as possible, concentrating on those technical details that are of economic significance. Some caution should be exercised, however, in the matters of capital cost estimates and equipment characteristics: there is no substitute for vendor-furnished material and competing quotations. Vendor capital cost estimates for some equipment may vary by as much as a factor of two.

Illustrative examples of cogeneration applications, drawn from five industrial plants, are used throughout the text to show the implications of technical, economic, legal, and environmental considerations for specific sites. These examples were drawn from real plant situations, primarily those studied during the "Industrial Cogeneration Optimization Program" (ICOP) sponsored by the Department of Energy in 1978-1979*.

The cogeneration technologies considered in the handbook are limited to those options that have near-term feasibility and those which could be actually implemented on a large scale by 1985.

Although written primarily for potential industrial cogenerators, the handbook can also be used by electric utilities and state regulatory commissions for the development of appropriate institutional relationships.

Organization

The handbook consists of five primary sections. These sections are briefly outlined below.

Chapter 1.0 Cogeneration Systems and Applications

- Presents a compilation of technical and cost data for all cogeneration system options, including topping and bottoming cycles, with near-term feasibility

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*"Industrial Cogeneration Optimization Program", Final Report, DOE/CS/4300-1, Contract No. BM-78C-01-4300, September 1979.

- Describes a range of industrial cogeneration applications to illustrate the use of technical and cost data in synthesizing cogeneration system conceptual designs

Chapter 2.0 Investment and Energy Savings Analysis

- Presents industrial fuel and electricity price forecasts and electric utility fuel use profiles

- Describes and illustrates the methodology for analyzing cogeneration economic and energy-savings performance

Chapter 3.0 Environmental Considerations

- Summarizes the environmental considerations involved in implementing alternative cogeneration systems

- Illustrates preliminary calculations of cogeneration environmental emissions and requirements of the permitting process.

Chapter 4.0 Legal and Regulatory Considerations

- Describes legal and regulatory considerations in implementing cogeneration systems

- Illustrates the application of these considerations for several practical examples

Chapter 5.0 System Implementation Case Study

- Provides a detailed example of how a potential industrial cogenerator uses this information to evaluate the technical, economic, environmental, and institutional factors involved in selecting and implementing an optimum cogeneration system

Complete references and supplementary data to these five sections are presented in appendices to the handbook.*

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*This handbook was prepared by the Energy Engineering Division of TRW, Inc. with assistance from Thermo Electron Corporation.

How to Use This Handbook

The basic steps in a preliminary evaluation of cogeneration alternatives for an industrial plant are illustrated in Figure 1, which also identifies the chapters of the handbook where these steps are discussed. A potential cogenerator need not perform these steps in the order shown. For example, firms which are already familiar with cogeneration economics in their particular situation, and which are primarily concerned with legal and regulatory considerations, may want to proceed to Step 8 and refer to Chapter 4.

The essential content of each step is briefly summarized below.

Step 1 - Define Plant Energy Use

A reasonably accurate plant energy use profile must be defined as a reference case for evaluating cogeneration alternatives. The current or planned future consumption of primary fuels and electricity must be defined together with end use demands for process steam, process heat, hot water, mechanical drive, and electricity. The profile should be documented in the form of schematic diagrams and supporting data showing the plant energy balance and operating characteristics in the absence of any new cogeneration. Chapters 1 and 5 contain several examples of plant energy use profiles and discuss how the relevant data can be obtained.

Step 2 - Identify Corporate Requirements and Constraints

Corporate requirements and constraints should be clearly identified, particularly the decision criteria for investment in a cogeneration project in terms of after-tax return on investment and other relevant measures. Policies or requirements concerning fuels use, equipment operation and maintenance, and reliability of fuel and electric power supplies should also be noted as these may constrain the choice of cogeneration options. These factors are discussed in Chapters 1 and 2 and are illustrated in the Chapter 5 case study.

Step 3 - Determine Cogeneration Options, Technical Characteristics, and Costs

The technical characteristics, installed capital costs, and O&M costs should be determined for a range of cogeneration options which vary in terms of prime mover type, unit size, fuels use, and electrical and thermal output characteristics. Parametric data for this purpose is presented in Chapter 1 and should be supplemented by vendor material and cost quotations for particular designs as discussed and illustrated in Chapters 1 and 5.

Step 4 - Synthesize Cogeneration Conceptual Designs

Based on the preceding steps, conceptual designs for cogeneration systems can be synthesized which are compatible with plant thermal and

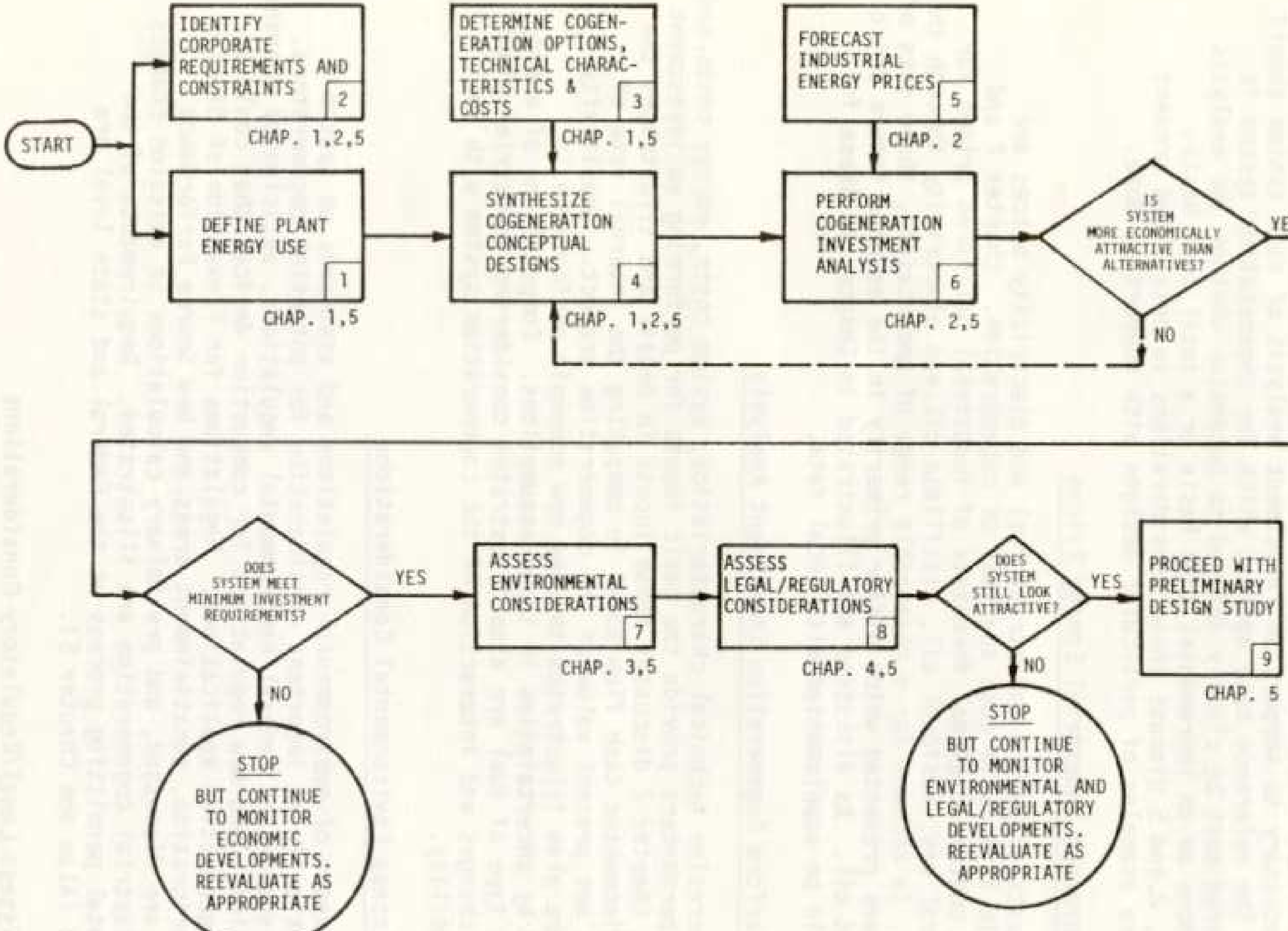


Figure 1. Steps in Cogeneration Evaluation

electrical energy demands, with consideration of supplementary power purchased from, or excess power sold to the utility. Schematics should be prepared showing the plant energy balance with the new cogeneration system, and data necessary to support an investment analysis of each system should be noted. The reference case against which the cogeneration system is being compared must be clearly defined to determine whether the analysis should be done on an incremental cost basis or a total cost basis. Chapters 1, 2,and 5 discuss these considerations in detail and present illustrative examples of particular designs with supporting data.

Step 5 - Forecast Industrial Energy Prices

Forecasts of future industrial fuel and electricity prices are essential in life cycle cost analysis of cogeneration. Chapter 2 and Appendix B contain regional forecasts of industrial delivered prices for coal, natural gas, residual oil, distillate oil,and electricity through the year 1995. To account for a reasonable range of uncertainty, three sets of forecasts are presented which differ primarily in the assumed future price of imported oil. As discussed and illustrated in Chapter 2, these forecasts should be supplemented with local data.

Step 6 - Perform Cogeneration Investment Analysis

Cogeneration technical characteristics, system costs, energy costs,and financial parameters provide the basic inputs for performing an investment analysis. Chapter 2 discusses these inputs in detail and illustrates the use of a discounted cash flow model in computing the internal rate of return and net present value of the cogeneration project. Sensitivity analyses are also illustrated to show how economic performance is influenced by uncertainties in input assumptions. Computations of energy savings by type of fuel are also illustrated considering industrial plant fuels use changes and interaction of the cogeneration system with the electric utility.

Step 7 - Assess Environmental Considerations

The impact of environmental regulations and standards on system implementation is an important consideration for potential cogenerators. Chapter 3 summarizes Federal environmental regulations, anticipated changes to regulations, and new regulations for combustion devices that could be used in cogeneration applications. Regulations for Prevention of Significant Deterioration, nonattainment areas,and New Source Performance Standards are discussed, and preliminary calculations of emission changes due to industrial cogeneration are illustrated. Requirements of the environmental permitting process at the Federal and state level are identified (Also see Chapter 5).

Step 8 - Assess Legal/Regulatory Considerations

Recent Federal energy legislation significantly affects the implementation and economic viability of cogeneration. Potential cogenerators should become familiar with this legislation and pertinent implementing rules so that maximum advantage can be taken of available benefits while minimizing regulatory problems in system implementation.

Chapter 4 summarizes current legal and regulatory provisions relating to cogeneration, discusses requirements and procedures in qualifying for certain benefits, and discusses practical effects on cogeneration including illustrative examples. An additional example is presented in Chapter 5.

Step 9 - Proceed with Preliminary Design Study

If results of the initial evaluation are favorable, prospective cogenerators should proceed with a preliminary design study to provide more detailed data including system schematics and energy balances, site and system layouts, and preliminary specifications of all major components. Revised cost estimates should be prepared covering detailed engineering, site preparation, installation and construction, and operation and maintenance. Fuel and electricity costs and rate structures should be examined in more detail and a revised investment analysis performed to confirm results of the initial evaluation. Chapter 5 discusses these considerations and summarizes the steps in system implementation.

1.0 COGENERATION SYSTEMS AND APPLICATIONS

Cogeneration systems fall into two general categories: topping systems and bottoming systems. In topping systems, the heat exhausted by prime movers is used in an industrial process or to provide space heating or absorption air conditioning. The heat may be used directly in the form of steam from back pressure or extraction steam turbines or in the form of raw exhaust gases from internal combustion engines for drying applications (e.g., wood or building materials) metal heating (e.g., soaking pits), or to heat water, air, oil, Dowtherm®, or some other process heating material. The exhaust gases may also contain sufficient oxygen to permit them to be used as highly preheated combustion air in boilers to reduce fuel consumption.

The technologies currently available for topping applications are: steam turbines, gas turbines, diesels, and spark-ignited engines. Figure 1-1 shows some possible topping configurations using back pressure, extraction non-condensing, and extraction/condensing steam turbines. Topping configurations for gas turbines, diesels, and spark-ignited engines are shown in Figures 1-2 and 1-3; these prime movers can be used in combined-cycle combinations with all types of steam turbines. However, diesels and spark-ignited engines in combined-cycle configurations require fuel to be burned in the heat recovery boilers because their exhaust gas temperatures (typically 500°F to 900°F) are generally lower than gas turbine exhausts (typically 900°F to 1000°F). Figure 1-4 shows a single-ended packaged gas turbine generator.

Bottoming systems use the heat exhausted by heat engines or industrial processes, such as chemical reactions, furnaces, or glass or cement kilns, to produce electric power. Figure 1-5 shows a back-pressure steam turbine operating on steam generated in a heat recovery boiler from the hot gases exhausted by some industrial process. Extraction/non-condensing and extraction/condensing steam turbines can also be used.

If a condensing steam turbine is used (Figure 1-6), the facility may or may not be considered as a cogeneration system for tax and regulatory purposes. In a retrofit situation, a condensing bottoming system will not be considered a cogeneration system under current regulations because the

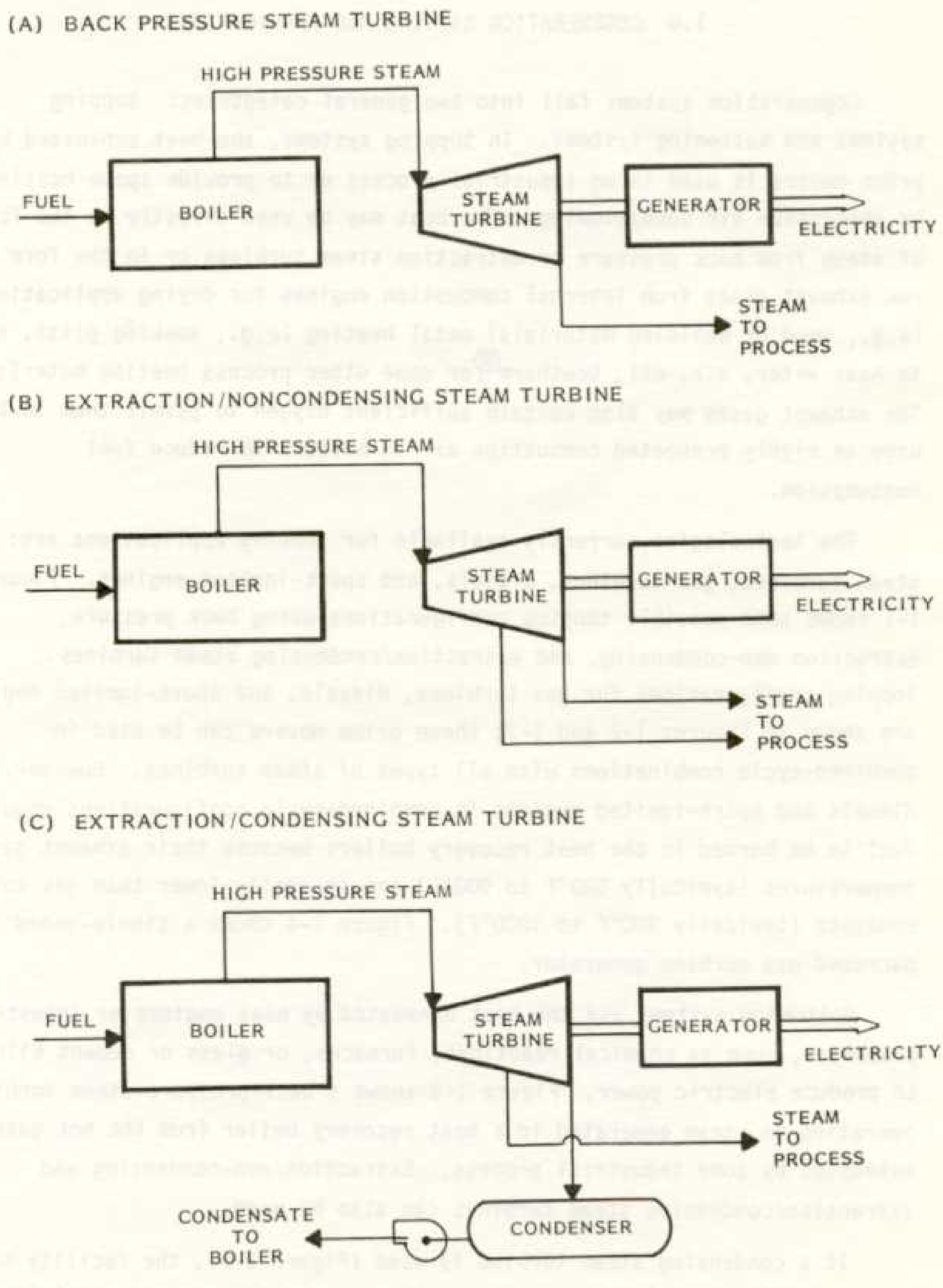


Figure 1-1. Schematic Showing Steam Turbine Cogeneration in the Topping Configuration. Fuel May be Coal, Oil, Natural Gas, Combustible Process Byproducts, Wood, Municipal or Industrial Waste

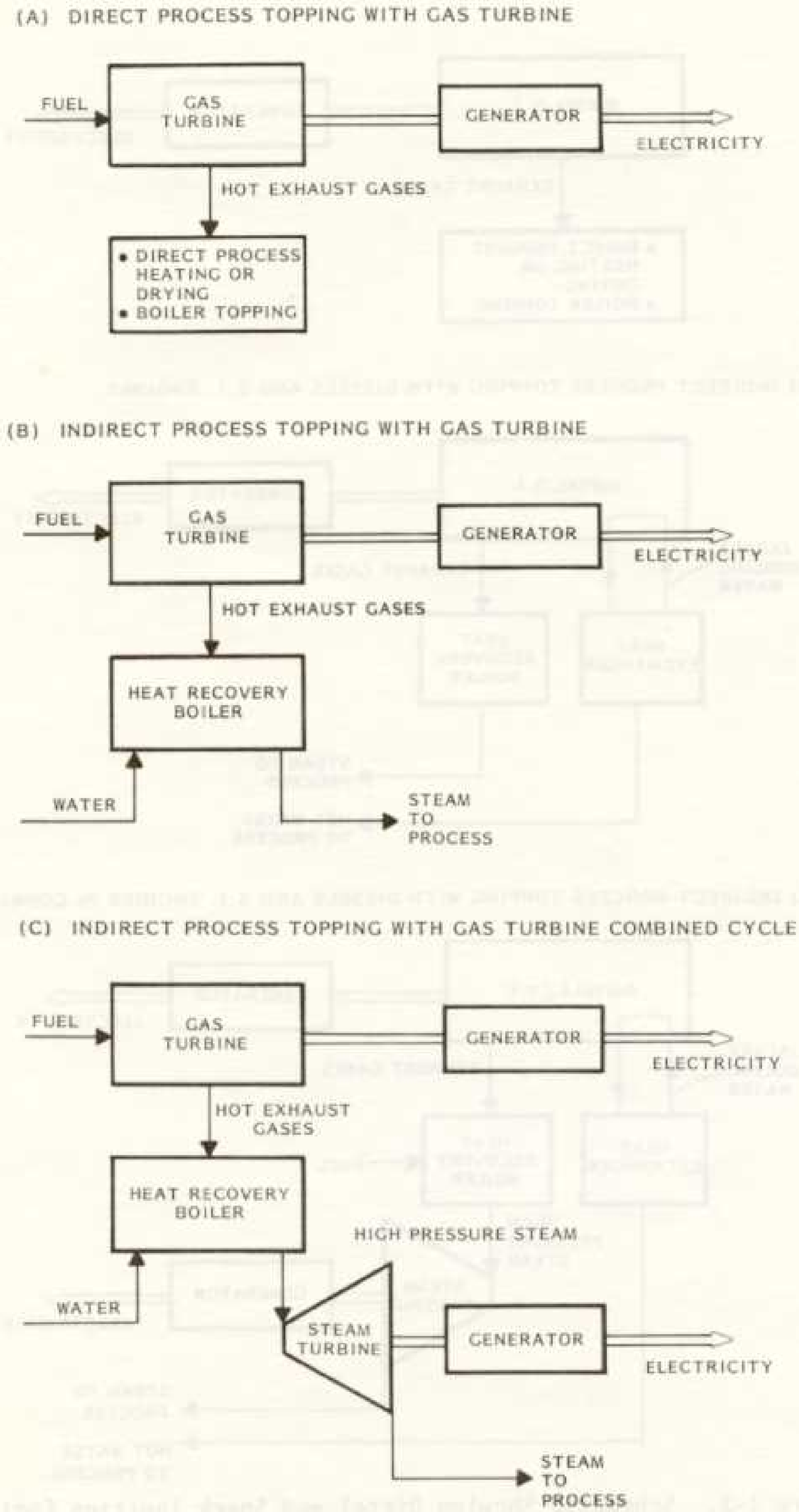
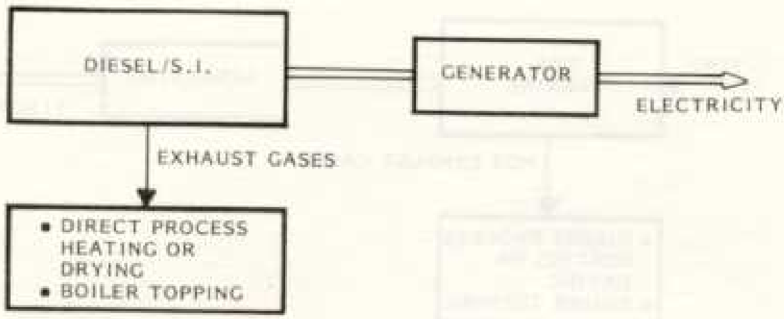
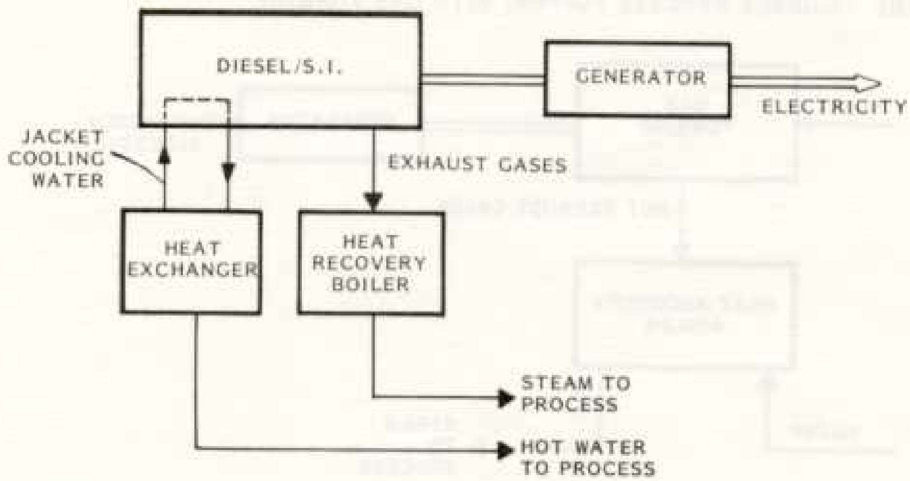


Figure 1-2. Schematic Showing Gas Turbine Cogeneration in the Topping Configuration. Fuel Used May be Oil or Natural Gas or Both.

(A) DIRECT PROCESS TOPPING WITH DIESELS AND SPARK IGNITED ENGINES



(B) INDIRECT PROCESS TOPPING WITH DIESELS AND S.I. ENGINES



(C) INDIRECT PROCESS TOPPING WITH DIESELS AND S.I. ENGINES IN COMBINED CYCLE

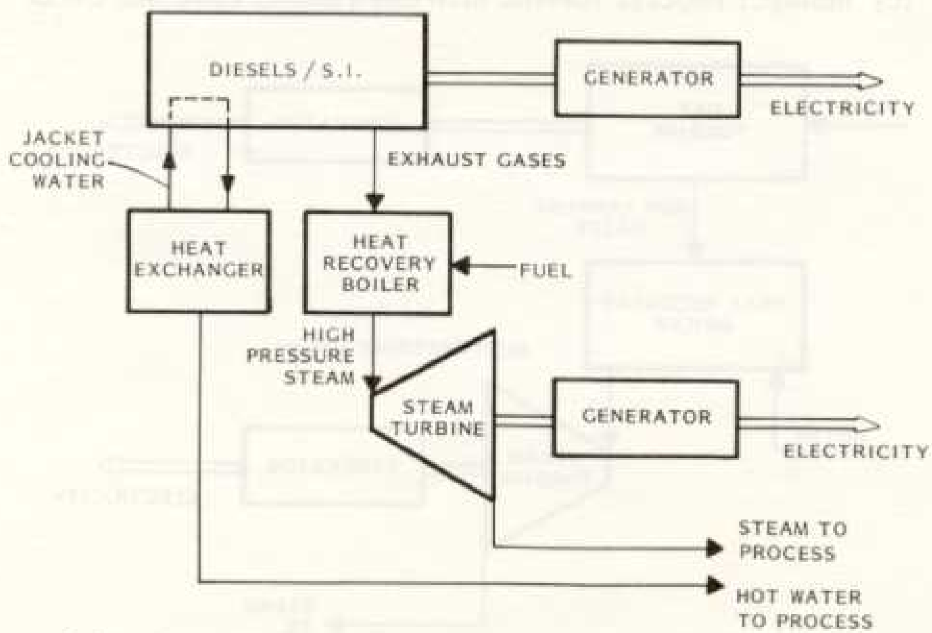


Figure 1-3. Schematic Showing Diesel and Spark Ignition Engine Cogeneration in the Topping Configuration. Fuels Used Can be Oil and Gas or Both. Residual Fuel Oil Can Also be Used in Large Slow Speed 2-Stroke Diesels

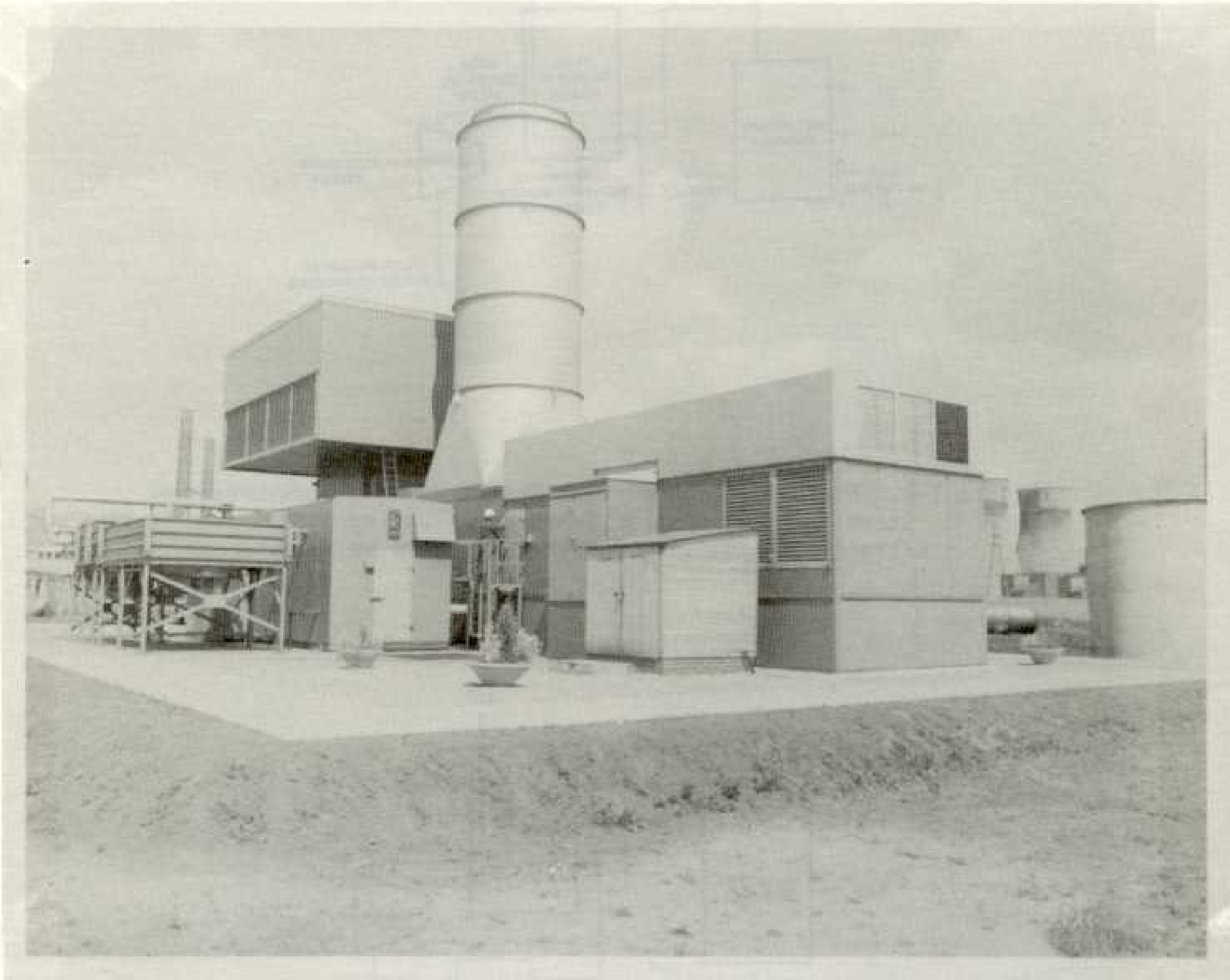


Figure 1-4. Single-Ended Packaged Gas Turbine Generating Set Rated at 22,900 kW. Including Coolers and Accessories and Control Packages, Unit Measures Approximately 85 ft x 41 ft x 53 ft Additional Control Package and Tool Shed by Customer for Special Application. (Courtesy: Rolls Royce, Inc., U.S.A.)

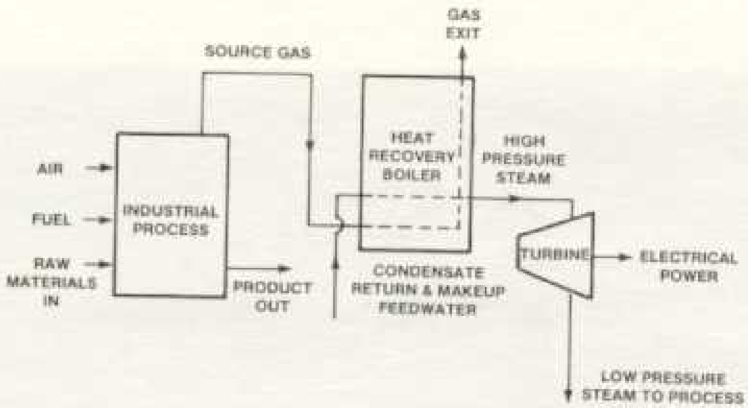


Figure 1-5. Bottoming Cogeneration System Using a Back-pressure Steam Turbine. Extraction/Non-condensing and Extraction/Condensing Turbines can also be Used.

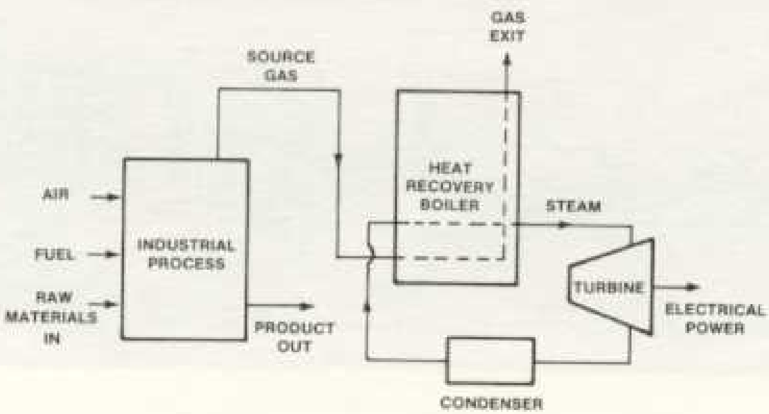


Figure 1-6. Bottoming System Using Steam or Organic Fluids with a Condensing Turbine. Such Systems may or may not be Considered Cogeneration Systems.

requirement of useful heat production is not satisfied. Such a facility, however, could qualify as a "small power production facility" (see Section 4) on the claim that it operates on previously wasted exhaust heat that may be considered in the category of "renewable resources." The same would apply to condensing systems designed to bottom existing gas turbines, diesels or spark-ignited engines. However, a new furnace or kiln equipped with a condensing power system <u>is</u> considered a cogeneration system because the fuel is used to provide both process heat and power.

Another type of system currently being used for bottoming applications uses organic fluids instead of steam. These fluids have low heats of vaporization and can produce more power than steam in certain temperature ranges, depending on the particular type of fluid used. Organic Rankine Cycle Systems (ORCS) are generally available in unit sizes of about 750 W or less. Such units have been used for solar irrigation and the bottoming of kilns and heat engines. The largest organic bottoming system in the world is a 14 MW plant currently under construction in Japan. The turbine for that system is shown in Figure 1-7.

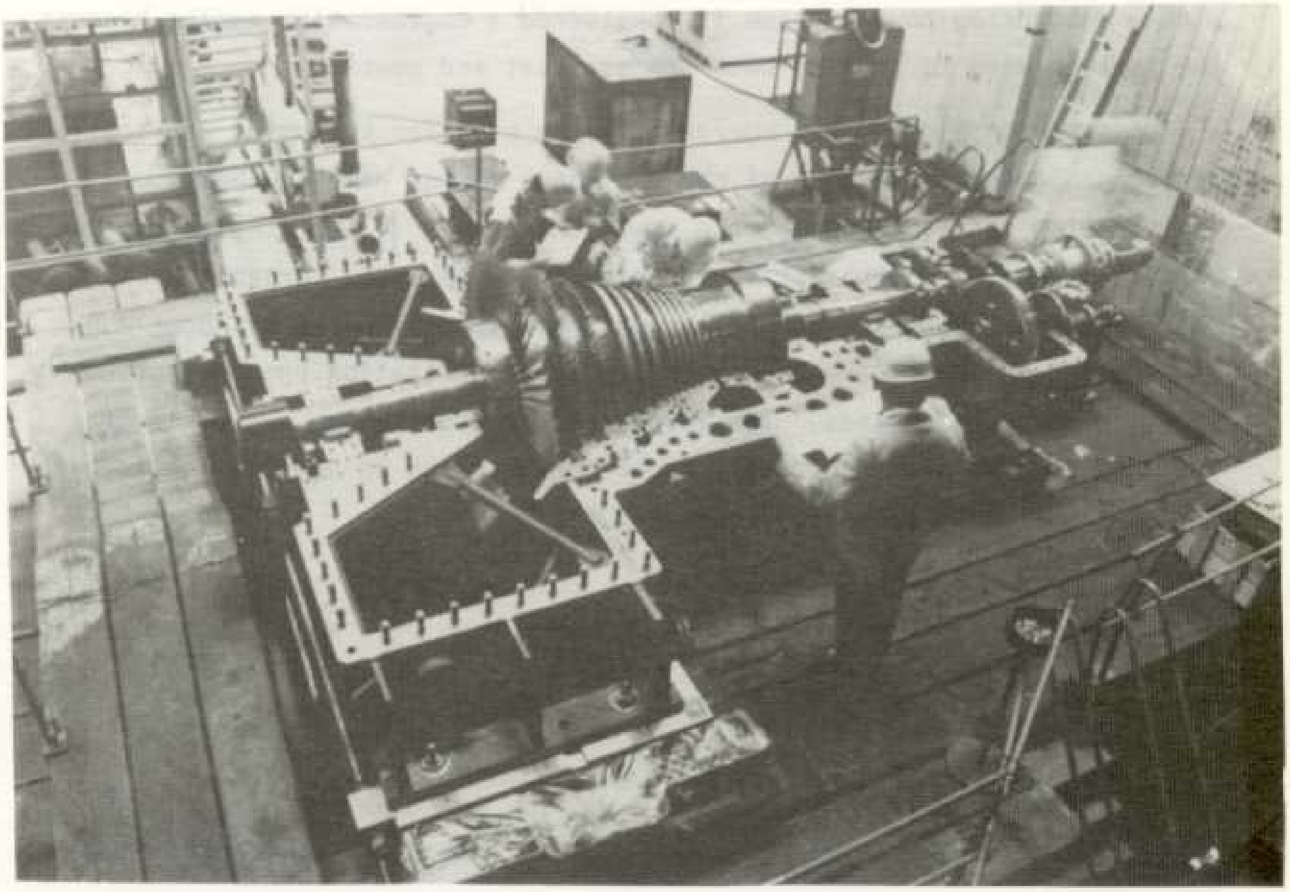


Figure 1-7. 14 MW Organic Turbine Using Fluorinal 85 Working Fluid

1.1 STEAM TURBINE COGENERATION

Steam turbines are available in unit sizes (single casing) from 1 horsepower to 150 MW. Back-pressure units are available in unit sizes up to 50 MW, larger units being rated for straight condensing service. Steam can be obtained from the turbine at one or more extraction points to serve a variety of useful functions, such as process and space heating, boiler feedwater heating, and deaeration. The latter two functions, however, are not legally admissible as bona-fide industrial processes, and consequently, the amount of power generated by expanding the associated steam from the turbine throttle pressure to the extraction pressure is not considered to be cogenerated power. Likewise, if the entire steam flow into the turbine is condensed, the power so produced is not considered to be cogenerated. Thus, the only configurations for which the total power is considered to be cogenerated in topping applications are back pressure, extraction/non-condensing and extraction/condensing turbines delivering steam for process use.

The evaluation of the amount of power obtainable from steam turbines is based on a determination of the Theoretical Steam Rate (TSR) for the particular steam conditions prevailing at the turbine throttle and at the various extraction points or at the condenser. For this purpose, a copy of the Theoretical Steam Rate Tables* is indispensable. Notice that the TSR increases as the pressure at which steam is extracted increases relative to the throttle pressure. This is a natural consequence of the fact that steam is the working medium of the steam turbine and hence its extraction at a high pressure precludes from generation the power that could be obtained if the steam were allowed to expand to a lower pressure. For this reason, back-pressure and extraction/non-condensing steam turbines have low power-to-steam ratios (10 to 60 kWh/1000 lbs) in relation to gas turbines and diesels.

The power conversion efficiency of steam turbines varies in general with load conditions, the steam throttle and exit conditions, the size and

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*See Reference 2

speed of the unit, the number and type of turbine stages and the manufacturer. Small (less than about 100 kW) single- or double-stage turbines usually have a low efficiency, typically 20 to 50 percent; medium units (500 to 5,000 kW) have efficiencies in the 50 to 75 percent range, while very large multi-stage units may have efficiencies exceeding 80 percent. Generator efficiencies may be taken to be 95 to 98 percent. The variation of efficiency with load is shown in Figure 1-8 for non-condensing turbines.

The extraction/condensing configuration is favored in many instances where the steam and electric loads vary significantly. The flexibility of this configuration resides in the fact that more steam can be condensed to give additional power at times when process steam demands are low, or the boiler output can be reduced to give constant or reduced power at different process steam demands. There is a minimum requirement for steam to cool the end stages of turbine.

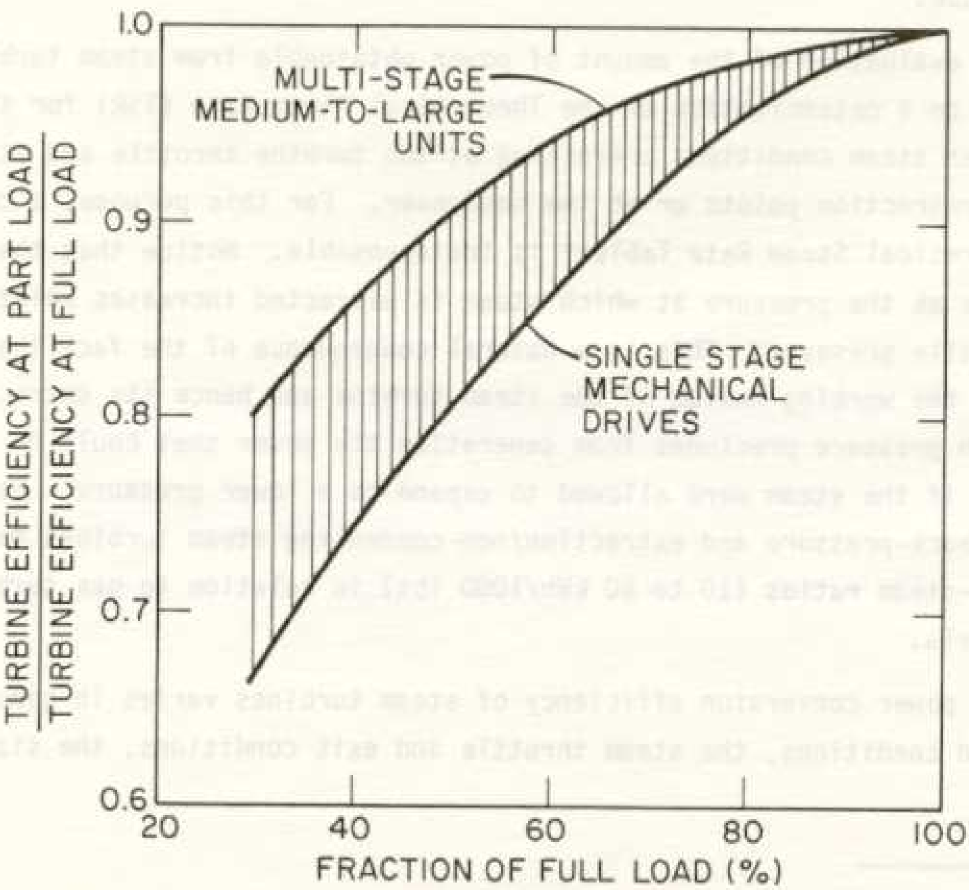

Figure 1-8. Variation of Efficiency with Load

1.2 GAS TURBINE COGENERATION

Gas turbines are commercially available in unit sizes ranging from 6 kW to 100 MW. They can operate on natural gas, No. 2 fuel oil, crude oil, and residual (No. 6) fuel oil. Dual fuel units are also available. The most reliable operation is obtained with natural gas for which forced outages statistically occur less than 1 percent of the operating hours (giving a reliability of 99 percent) and scheduled outages occur 2 to 3 percent of the operating hours (giving an overall availability of 96 to 97 percent). Units operating on oils, particularly residual fuel oil, require more frequent maintenance.

Although closed cycle gas turbines have been designed and tested for bottoming applications, the predominant method of gas turbine cogeneration in existence today uses simple open cycle gas turbines in the topping configuration. Figure 1-9 is a view of a gas turbine with a heat recovery boiler generating steam for process use. Depending on the pressure and temperature of the steam, the power-to-steam ratio of gas turbines in this configuration are typically: 130-265 kWh/1,000 lbs for unfired boilers, 85 to 170 kWh/1,000 lbs for supplementary fired boilers and 27 to 45 kWh/1,000 lbs for fully fired boilers (see Section 1.3). Extraction non-condensing steam turbines can also be used. For moderate process steam pressures (less than 150 psig), the gas turbine typically yields 3 to 4 times the power generated by the steam turbine.

The temperature of the hot gases exhausted by gas turbines typically ranges between 900°F and 1,000°F. When recovering the exhaust gas heat, it is important to recognize that the increase in exhaust gas pressure caused by pressure drops in ducting, heat exchangers, or boilers slightly reduces the turbine power output, but the gain in energy efficiency outweighs the power losses.

1.2.1 Gas Turbine Characteristics

Table 1-1 lists the general characteristics of a modern commercially available gas turbine. The performance characteristics are given in Figures 1-10 to 1-12. Because the amount of power generated is strongly influenced by the ambient temperature, it is important to size the unit according to the highest prevailing ambient temperature. In district

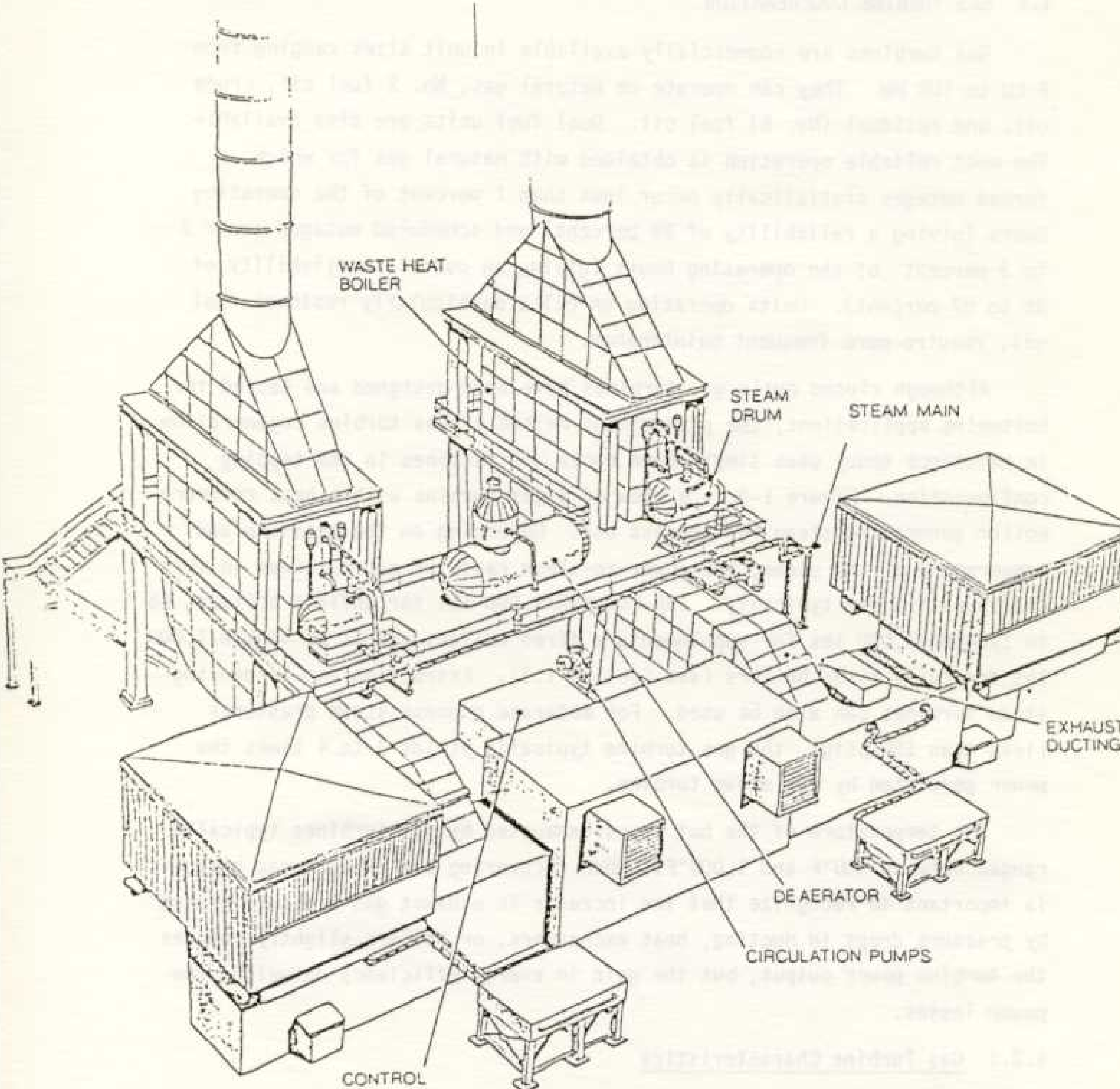

Figure 1-9. View of Double-Ended Gas Turbine with Heat Recovery Boiler Generating Steam for Process Use

Table 1-1. Sample Gas Turbine Characteristics

Turbine Type:	Single-Ended
Normal Base Rating:	22.9 MW (ISO)*
Fuel:	Natural Gas
Required Inlet Gas Pressure:	250 psig

Intake and Exhaust Loss Corrections

Per 1% loss in intake pressure:

Power is reduced by 2.2%
Exhaust temperature is increased by $\delta t = 0.003t + 1.4$ (°F)
Exhaust gas mass flow rate is reduced by 1%
Fuel flow is reduced by 1%
Heat rate is increased by 1.2%

Per 1% increase in exhaust pressure:

Power is reduced by 1.1%
Exhaust temperature is increased by $\delta t = 0.003t + 1.4$ (°F)
Heat rate is increased by 1.1%

Normal Base Rating or Base Continuous: 24,000 hours continuous duty

Electrical Base Rating: Up to 4,000 hours per year, with an average starting frequency of up to 500 starts per year and 2 to 3 years before major inspection.

Maximum Peak Rating: Up to 2,000 hours per year, with an average starting frequency of up to 500 starts per year and 2 to 3 years before major inspection.

*Rating at "International Standards Organization" Conditions of 1 Atmosphere (14.696 psia) and 15°C (59°F).

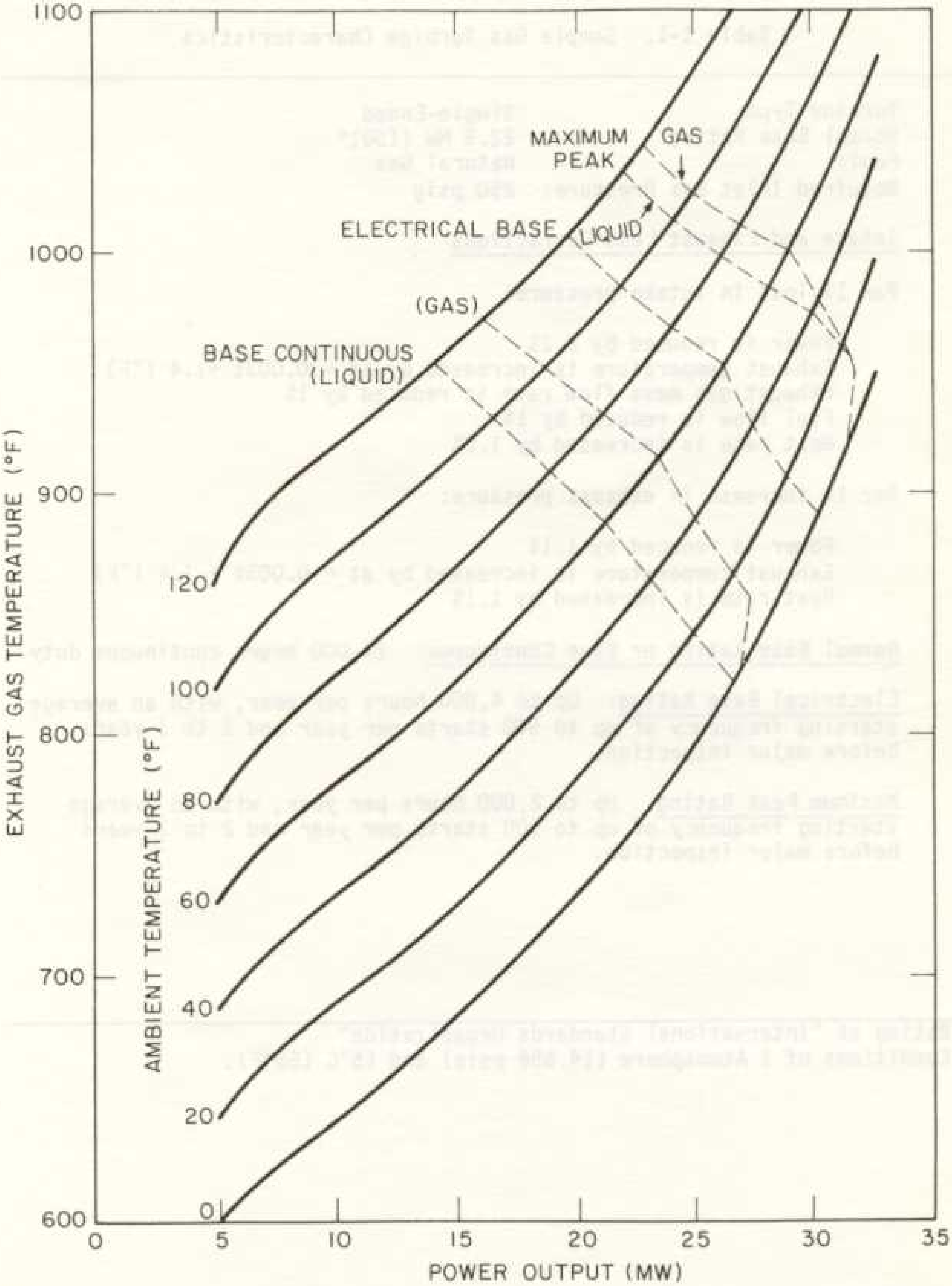

Figure 1-10. Exhaust Gas Temperature versus Power Output and Ambient Temperature - No Loss Conditions

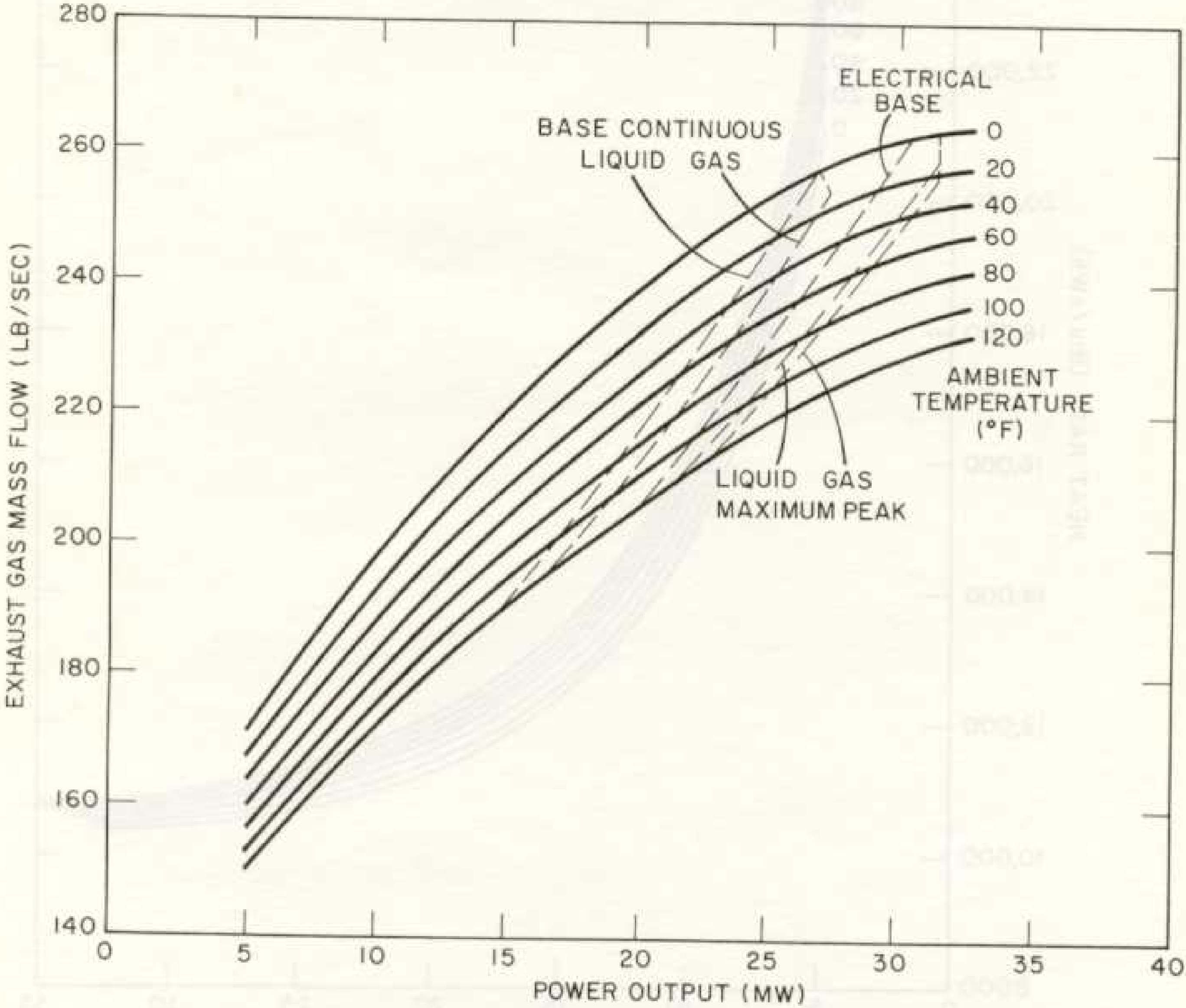

Figure 1-11. Exhaust Gas Mass Flow versus Power Output
and Ambient Temperature - No Loss Conditions

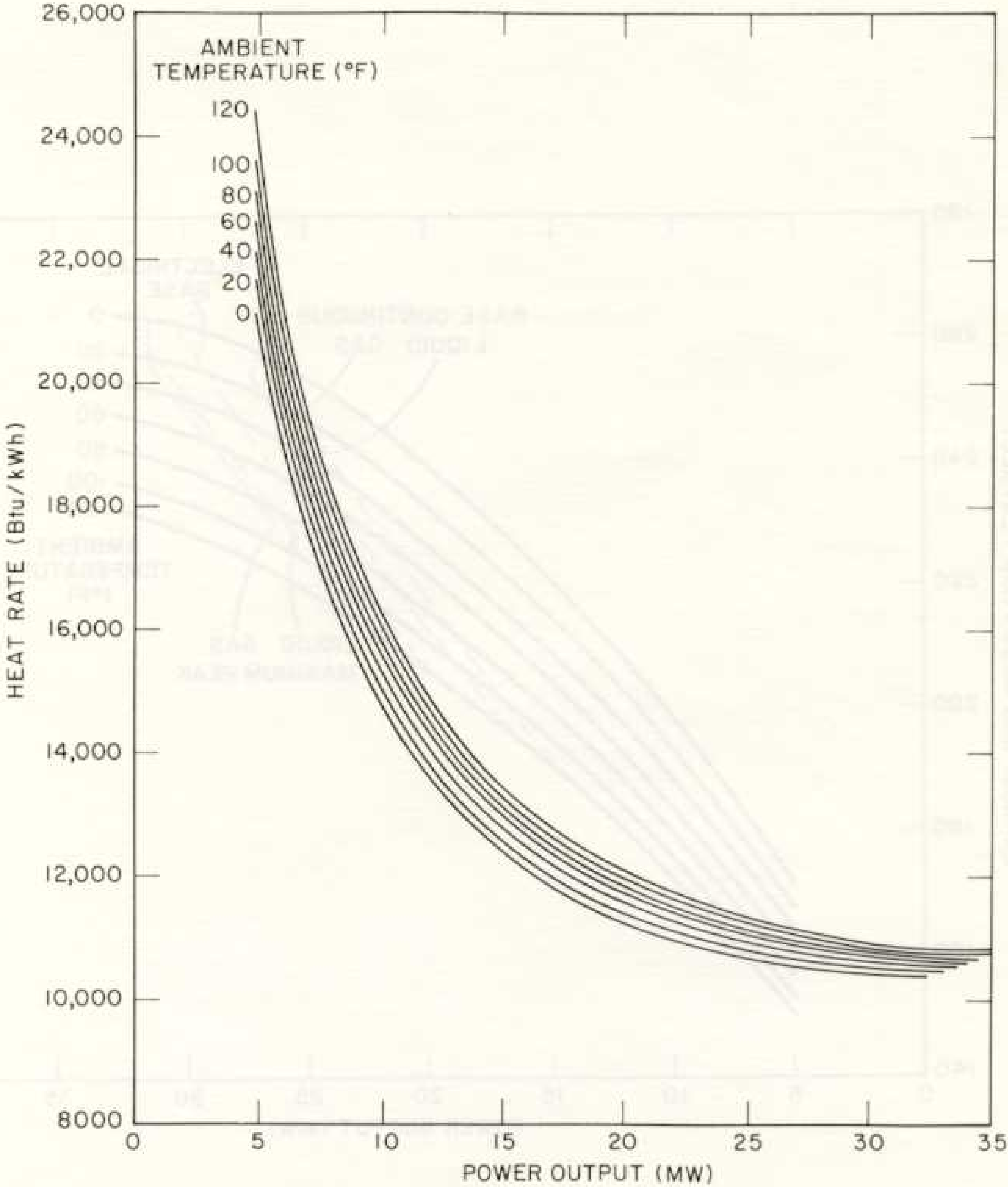

Figure 1-12. Heat Rate versus Power Output and Ambient Temperature
No Loss Conditions

heating applications, this characteristic may be an advantage. Alternatively, inlet air cooling may be used to obtain the desired power at high ambient temperatures.

Another important point is that, when natural gas is used as a fuel, the pressure required for delivery of the gas to the turbine is usually higher than the supply pressure at many plants. Thus, the amount of power required to drive the gas compressor must be taken into account in evaluating the net power output of the facility. A final observation concerns the change in the heat rate with load; the heat rate at part load conditions is significantly higher than it is at full load (Figure 1-12). This is characteristic of all gas turbines. Where thermal demands increase to correspond with decreasing power demand, the effect of the heat rate increase will be nullified by the increase in heat recovery from the turbine exhaust, and the overall fuel utilization will remain the same. If, however, the thermal demands decrease or remain constant as electric demand decreases, then the overall fuel utilization of the facility will decrease.

1.3 THE HEAT RECOVERY BOILER

The heat recovery boiler is used to transfer heat from the hot gases exhausted by gas turbines, diesels and other heat engines, or from stack gases, to produce steam. Several stacks or engines may be connected to a common boiler.

The temperature at which the exhaust gases enter the recovery boiler is usually a few degrees less than the engine exhaust temperature because some heat is lost through the walls of the duct connecting the engine to the boiler. Leakage losses through duct connections will also reduce the flow of gases to the boiler. Both the temperature drop and the flow losses will depend upon the particular placement of the boiler relative to the engine and the length, insulation, and integrity of the ducts connecting them. For estimating purposes, the temperature drop and flow losses may be taken to be 10°F and 2% respectively.

1.3.1 Unfired Heat Recovery Boilers

Unfired heat recovery boilers do not use any fuel to further heat the exhaust gases beyond the temperature at which they enter the boiler. In these boilers, the rate at which heat is transferred from the hot gases to produce steam is substantially influenced by the so-called "pinch-point" temperature difference (ΔT_p), which is the minimum effective temperature difference existing between the exhaust gases on one side of the heat exchange surfaces and the steam on the other side. The surface area (and thus the cost of the boiler) required to produce a given amount of steam will increase as ΔT_p decreases. For estimating purposes, a value for ΔT_p of 59°F (33°C) is adequate.

Two other factors that influence the cost and performance of recovery boilers are the gas outlet temperature (Tgo) and the gas inlet temperature (Tgi). The gas outlet temperature is usually not allowed to fall much below about 300°F, a temperature safely above the "sulfur dewpoint" (the temperature at which sulfuric acid condenses) to minimize metal corrosion; otherwise expensive alloys must be used in the economizer section of the boiler. Thus, the maximum allowable amount of heat that can be transferred to produce steam is proportional to (Tgi - 300).

Not all of that heat, however, goes into generating useful steam: the outlet gas temperature depends on the pressure and temperature of the steam required, the incoming water temperature, and the pinch-point temperature difference. Also, some heat losses (about 2%) occur through the walls of the boiler, and some of the saturated water (about 1.2% of the useful steam production) that is heated to the saturation temperature corresponding to the required steam pressure is "blown down" to limit the accumulation of scaling and corrosive minerals. The amount of blowdown depends on boiler design and the quality and treatment of the water used. In some small installations, blowdown may exceed 5 percent. In addition, some steam may be required for soot blowing if the exhaust gases contain carbon particles or ash, as is the case with the combustion products of diesels or gas turbines operating on liquid petroleum fuels. The amount of steam required for soot blowing depends on the particular fuel used. Normally, no soot blowing is necessary for natural gas.

1.3.2 Estimating Steam Production

The amount of steam produced in a recovery boiler can be quickly estimated using Figure 1-13 and Figure 1-14, which were computed for an inlet water temperature of 230°F. However, the results obtained from the figures are sufficiently accurate for use at different inlet temperatures. The changes in direction of the lines in Figure 1-14 mark the transitions from gas exit temperatures in excess of 300°F to the minimum exit temperature of 300°F. These transitions generally occur when the gas temperatures at the inlet to the boiler exceed about 1000°F.

If the maximum saturated steam flow exceeds the desired quantity, then the steam can be superheated or the design pinch-point temperature difference can be increased, leading to a smaller and less expensive boiler. If the desired steam flow is substantially greater than what can be generated from the source gas, then supplementary firing of the boiler will be necessary (see Glossary for definition of supplementary firing).

Estimates obtained from the above method of computation are accurate to within approximately 5 percent. This is sufficient to gauge the performance and cost of the heat recovery boiler. The main source of error is in the specific heat which changes with temperature and with the composition of the exhaust gases. These in turn, depend on the type of fuel and the fuel/air ratio used in the prime mover.

1.3.3 Single- and Dual-Pressure Boilers

Because water has a high heat of vaporization, its temperature profile cannot closely track the temperature of the exhaust gases. As a result, the temperature differences in the evaporator section of the boiler are larger than necessary. This thermodynamic inefficiency can be considerably reduced by generating steam at two or more pressures so that the temperature profiles track each other more closely resulting in a greater amount of energy transfer and a 10 to 20 percent greater total steam flow.

Dual-pressure boilers can be used to generate steam for direct process use or for powering a bottoming steam turbine.

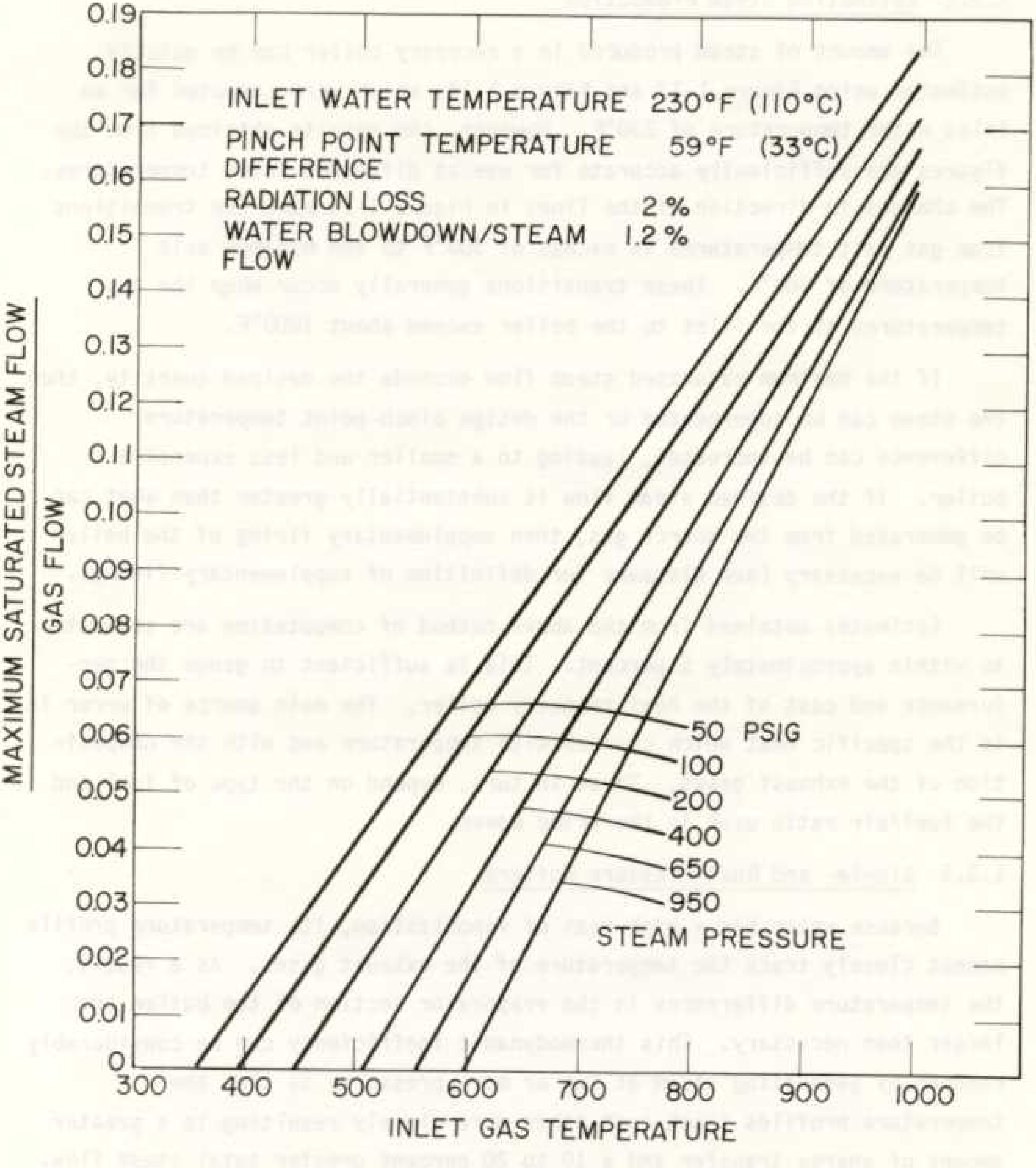

Figure 1-13. Steam Production from Recovery Boilers as a Function of Steam Pressure, Inlet Gas Temperature, and Gas Flow

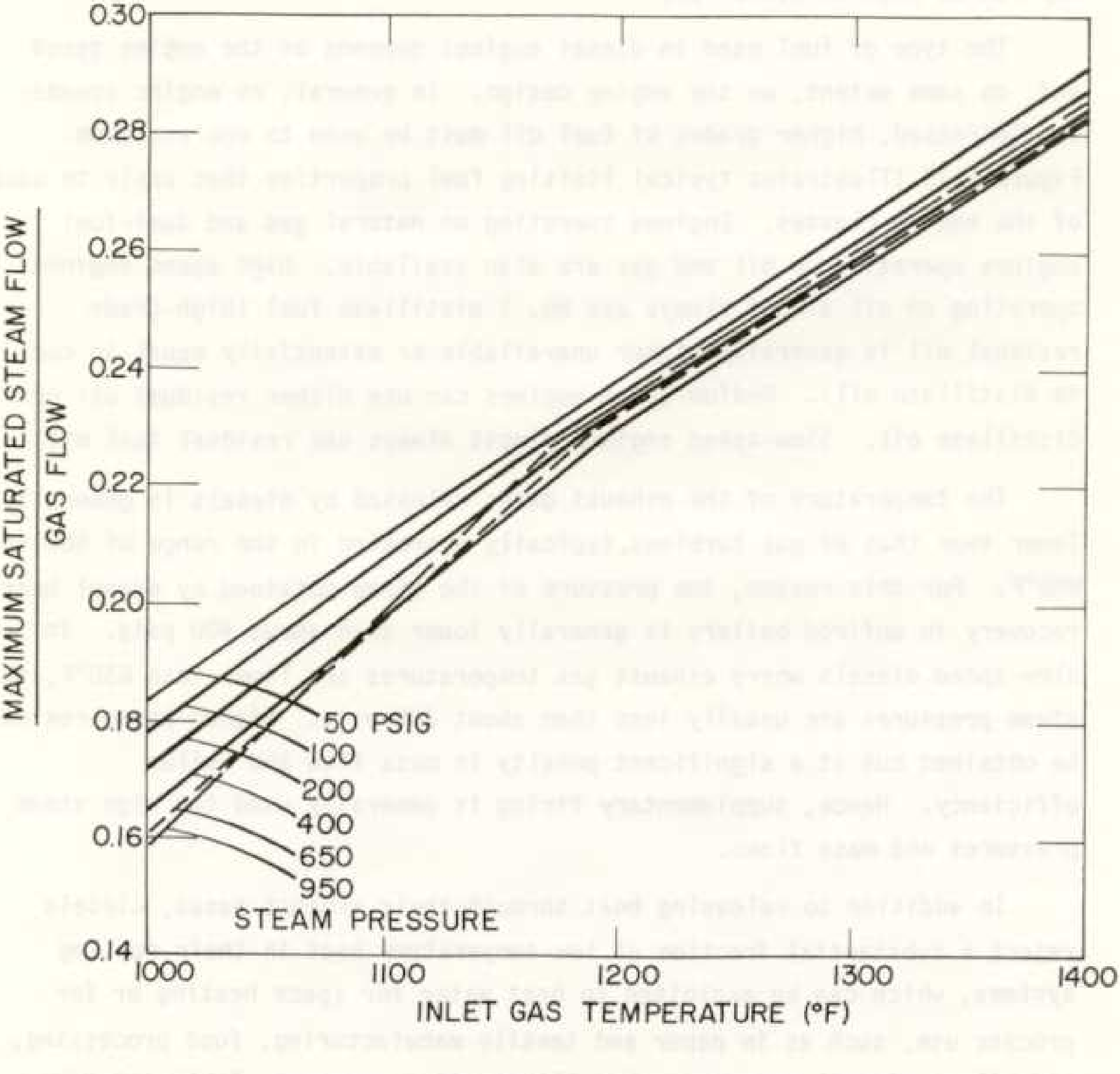

Figure 1-14. Steam Production from Recovery Boilers as a Function of Steam Pressure, Inlet Gas Temperature, and Gas Flow

1.4 DIESEL COGENERATION

Diesel engines can be broadly classified in terms of engine speed in 3 categories: high-speed diesels at 900-1500 rpm with unit sizes up to 3.5 MW; medium-speed diesels with unit sizes from 3 to 9 MW in the 500-600 rpm range and 5 to 20 MW in the 300-450 rpm range; and slow speed diesels with unit sizes of 8 to 28 MW at 120-150 rpm. Some automobile and truck engines may run as high as 5,000 rpm.

The type of fuel used in diesel engines depends on the engine speed and, to some extent, on the engine design. In general, as engine speeds are increased, higher grades of fuel oil must be used to operate them. Figure 1-15 illustrates typical limiting fuel properties that apply to each of the engine classes. Engines operating on natural gas and dual-fuel engines operating on oil and gas are also available. High speed engines operating on oil almost always use No. 2 distillate fuel (high-grade residual oil is generally either unavailable or essentially equal in cost to distillate oil). Medium-speed engines can use either residual oil or distillate oil. Slow-speed engines almost always use residual fuel oil.

The temperature of the exhaust gases released by diesels is generally lower than that of gas turbines, typically operating in the range of 500 to 950°F. For this reason, the pressure of the steam obtained by diesel heat recovery in unfired boilers is generally lower than about 400 psig. In slow-speed diesels where exhaust gas temperatures are lower than 650°F, the steam pressures are usually less than about 200 psig. Higher pressures can be obtained but at a significant penalty in mass flow and boiler efficiency. Hence, supplementary firing is generally used for high steam pressures and mass flows.

In addition to releasing heat through their exhaust gases, diesels reject a substantial fraction of low-temperature heat in their cooling systems, which can be exploited to heat water for space heating or for process use, such as in paper and textile manufacturing, food processing, and oil or mineral recovery. For illustrative purposes, Table 1-2 gives energy balances for representative engines from each speed group. However, the energy balances differ with the design and the manufacturer so that vendor-furnished material should be used whenever possible.

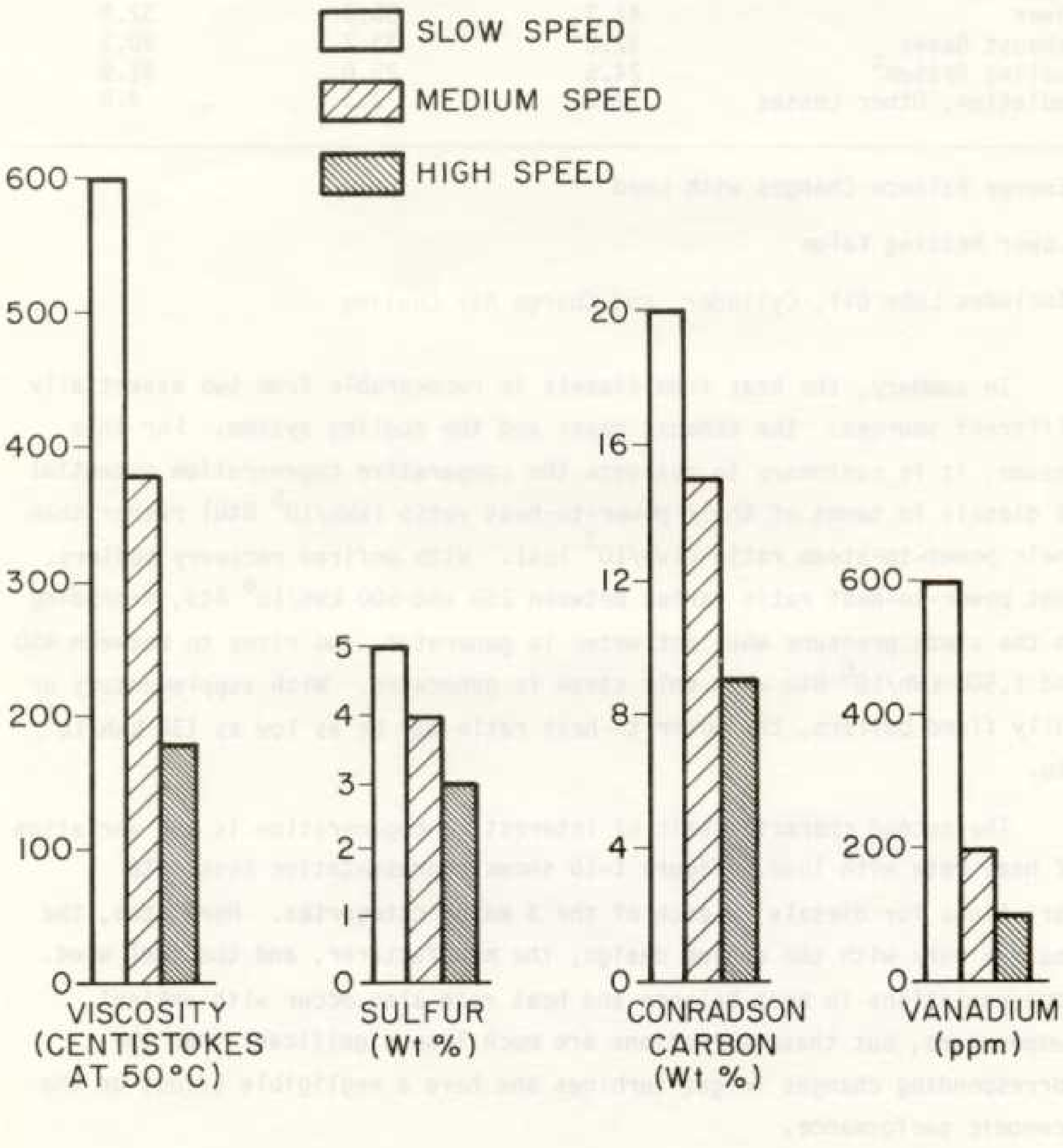

Figure 1-15. Typical Limiting Diesel Fuel Characteristics

Table 1-2. Typical Full Load[a] Diesel Energy Balance for Representative Engines as Fraction of Input

	SLOW SPEED	MEDIUM SPEED	HIGH SPEED
Input (LHV)[b]	100	100	100
Power	41.3	38.0	32.8
Exhaust Gases	32.2	33.7	30.5
Cooling System[c]	24.5	25.0	31.9
Radiation, Other Losses	2.0	3.3	4.8

[a]Energy Balance Changes with Load

[b]Lower Heating Value

[c]Includes Lube Oil, Cylinder, and Charge Air Cooling

In summary, the heat from diesels is recoverable from two essentially different sources: the exhaust gases and the cooling system. For this reason, it is customary to evaluate the comparative cogeneration potential of diesels in terms of their power-to-heat ratio (kWh/10^6 Btu) rather than their power-to-steam ratio (kWh/10^3 lbs). With unfired recovery boilers, that power-to-heat ratio varies between 250 and 500 kWh/10^6 Btu, depending on the steam pressure when hot water is generated, and rises to between 450 and 1,500 kWh/10^6 Btu when only steam is generated. With supplementary or fully fired boilers, the power-to-heat ratio may be as low as 130 kWh/10^6 Btu.

The second characteristic of interest to cogeneration is the variation of heat rate with load. Figure 1-16 shows representative heat rate variations for diesels in each of the 3 major categories. Here, too, the changes vary with the engine design, the manufacturer, and the fuel used. Some variations in heat balance and heat rate also occur with ambient temperature, but these variations are much less significant than the corresponding changes in gas turbines and have a negligible effect on the economic performance.

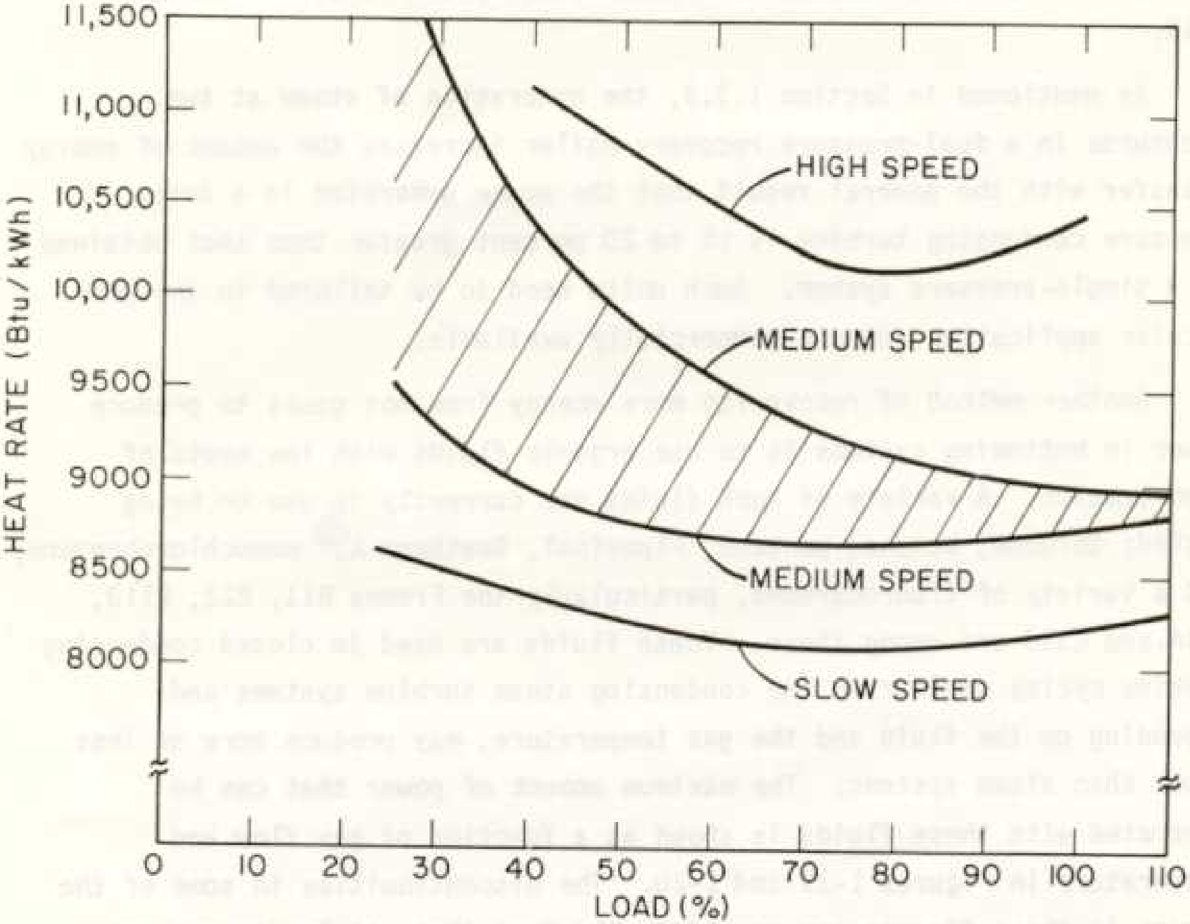

Figure 1-16. Typical Variation of Diesel Heat Rate with Load

1.5 BOTTOMING SYSTEM COGENERATION

Bottoming systems use the heat exhausted by gas turbines, diesels, spark-ignited engines, or industrial processes to generate power. In a steam bottoming system, heat from the exhaust gases is used to produce steam in a recovery boiler. The steam is then expanded in a turbine to generate power. The turbine can be a back-pressure or extraction/condensing machine delivering steam for process use. Figure 1-17 shows the amounts of steam and power that can be generated in a non-condensing system. The power generated in a condensing system is given in Figure 1-18.

As mentioned in Section 1.3.3, the generation of steam at two pressures in a dual-pressure recovery boiler increases the amount of energy transfer with the general result that the power generated in a dual-pressure condensing turbine is 15 to 20 percent greater than that obtained in a single-pressure system. Such units need to be tailored to the particular application and are commercially available.

Another method of recovering more energy from hot gases to produce power in bottoming systems is to use organic fluids with low heats of vaporization. A variety of such fluids are currently in use or being tested; toluene, butane, pentane, Fluorinol, Dowtherm-A®, monochlorobenzene, and a variety of fluorocarbons, particularly the Freons R11, R22, R113, R114, and C318 are among these. These fluids are used in closed condensing Rankine cycles similar to the condensing steam turbine systems and, depending on the fluid and the gas temperature, may produce more or less power than steam systems. The maximum amount of power that can be generated with these fluids is shown as a function of gas flow and temperature in Figures 1-19 and 1-20. The discontinuities in some of the curves in these figures are caused by the fact that, at low source gas temperatures, the limiting temperature difference for organic fluids occurs at the boiler inlet and not at the point of liquid saturation. Organic bottoming systems are commercially available but are generally custom-designed for particular applications.

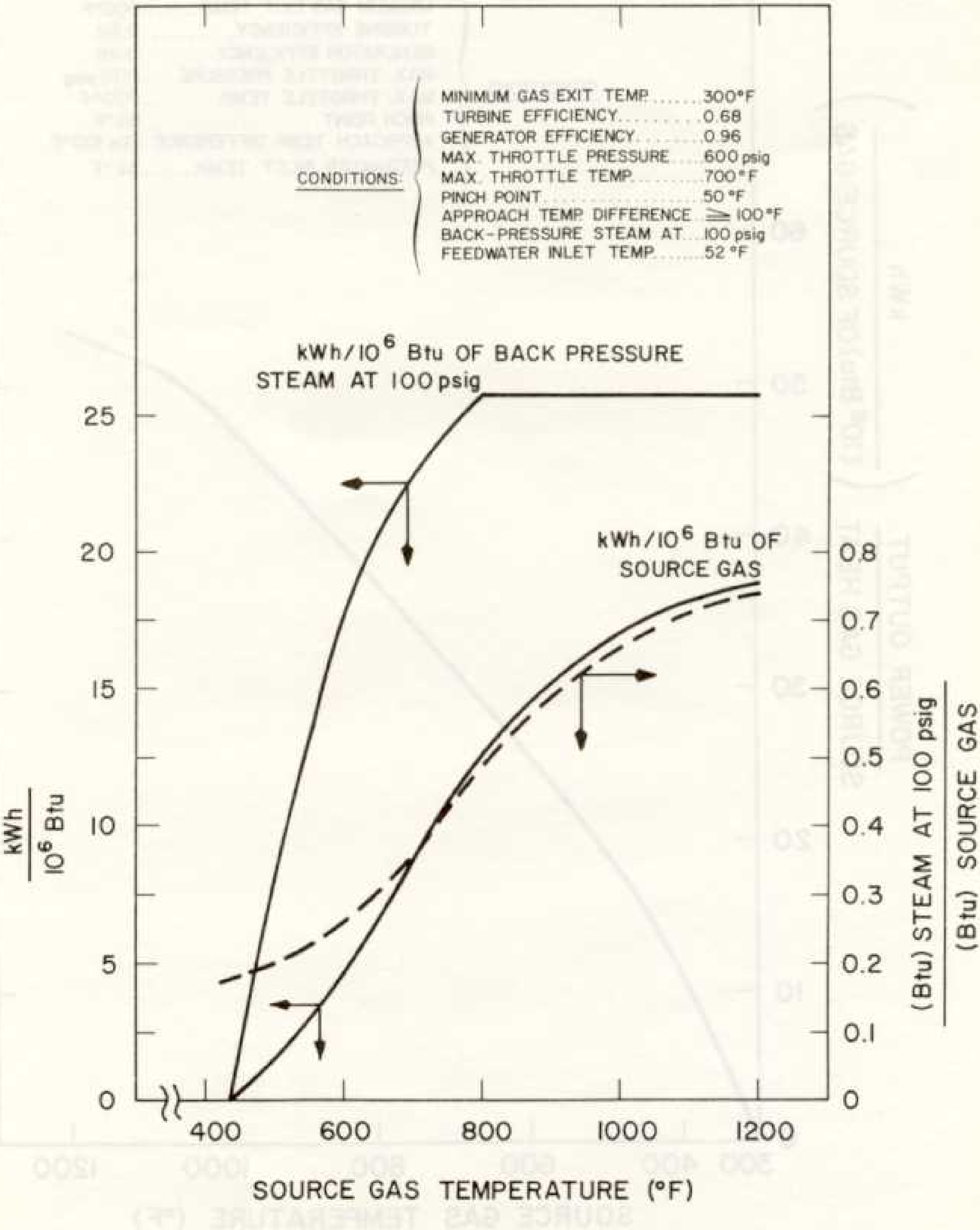

Figure 1-17. Power and Steam Generation by Noncondensing Steam Turbine Bottoming of Waste Heat

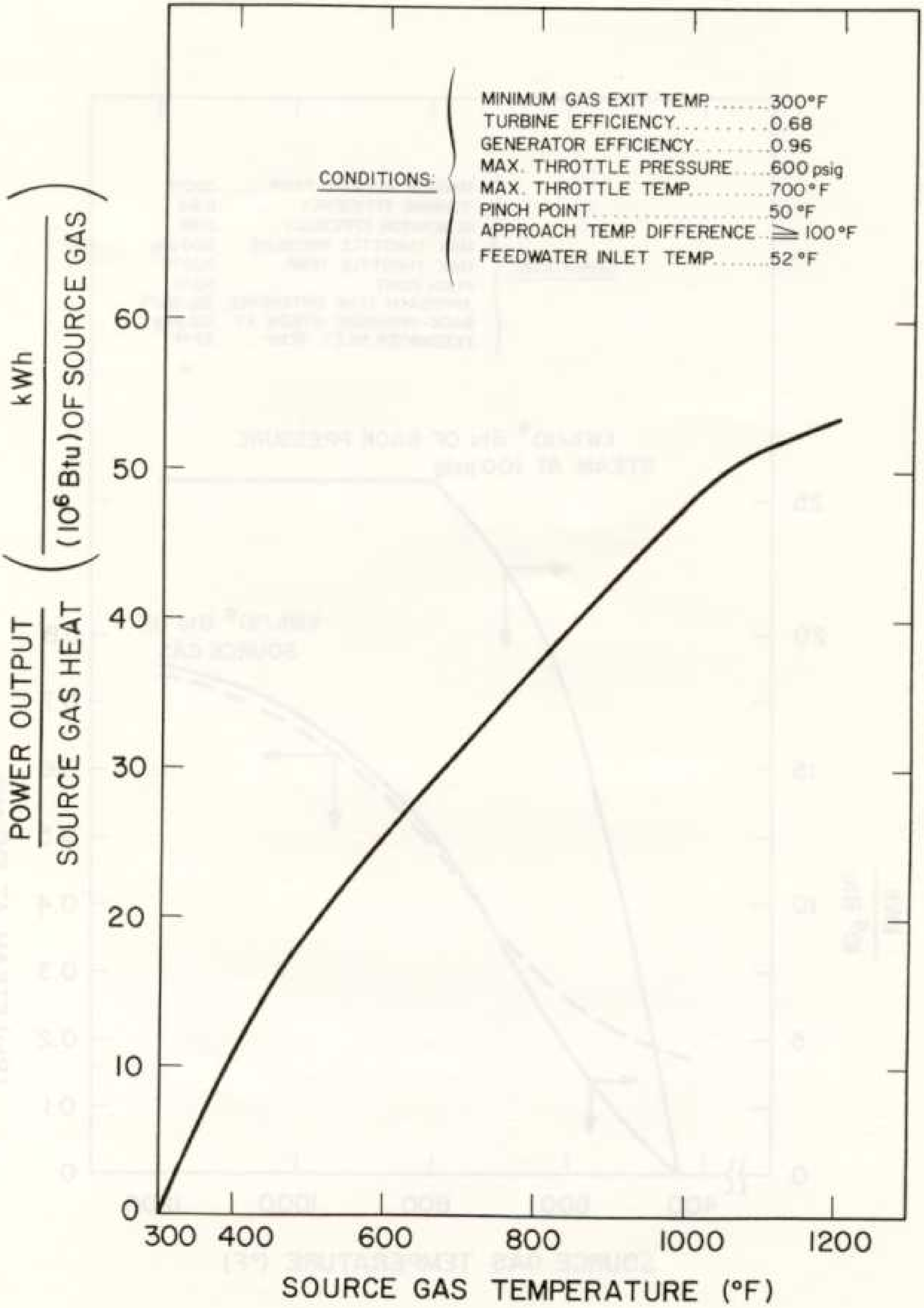

Figure 1-18. Power Generation by Condensing Steam Rankine Bottoming of Waste Heat

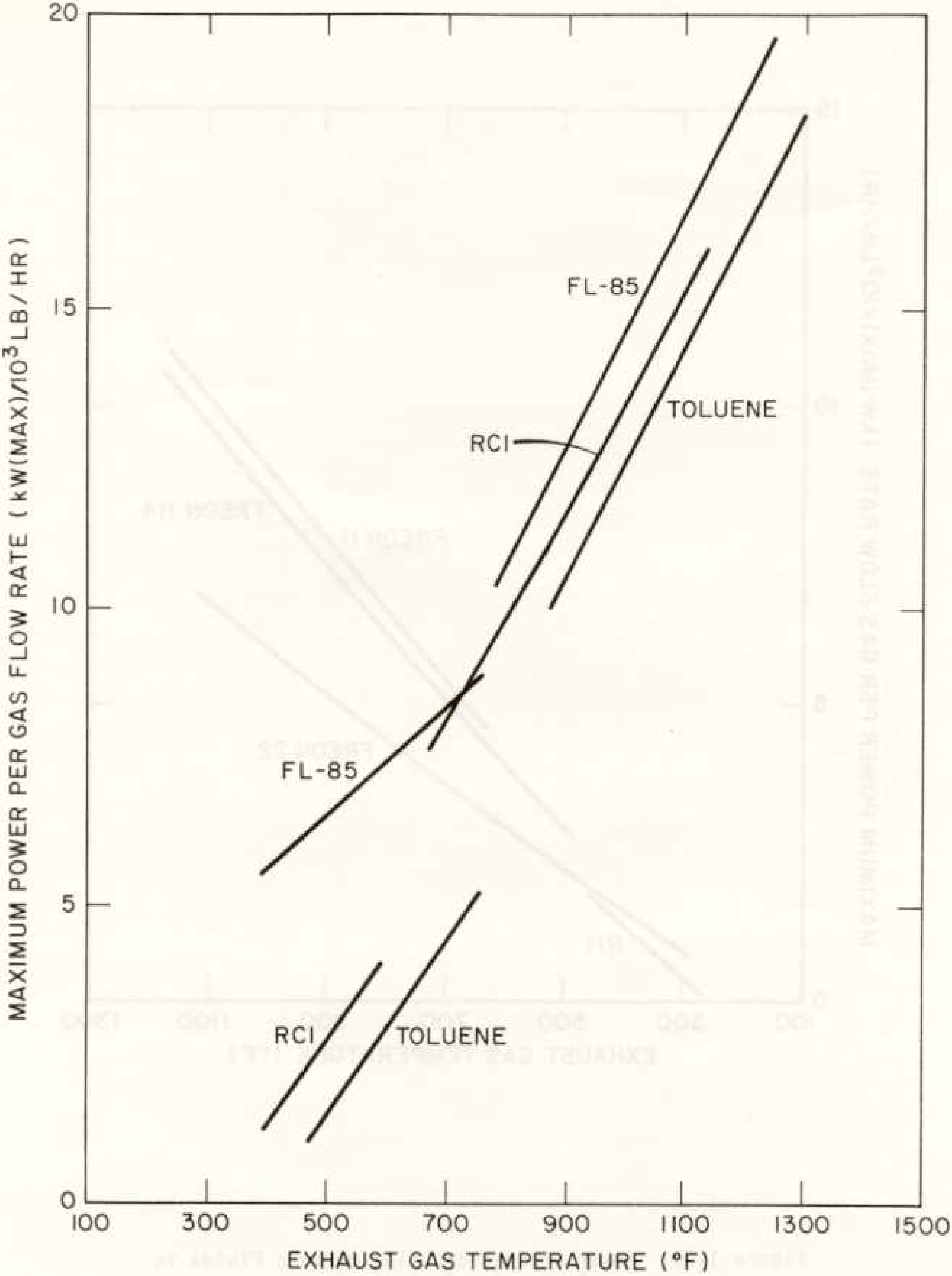

Figure 1-19. Power Generation Using Organic Fluids in Condensing Systems

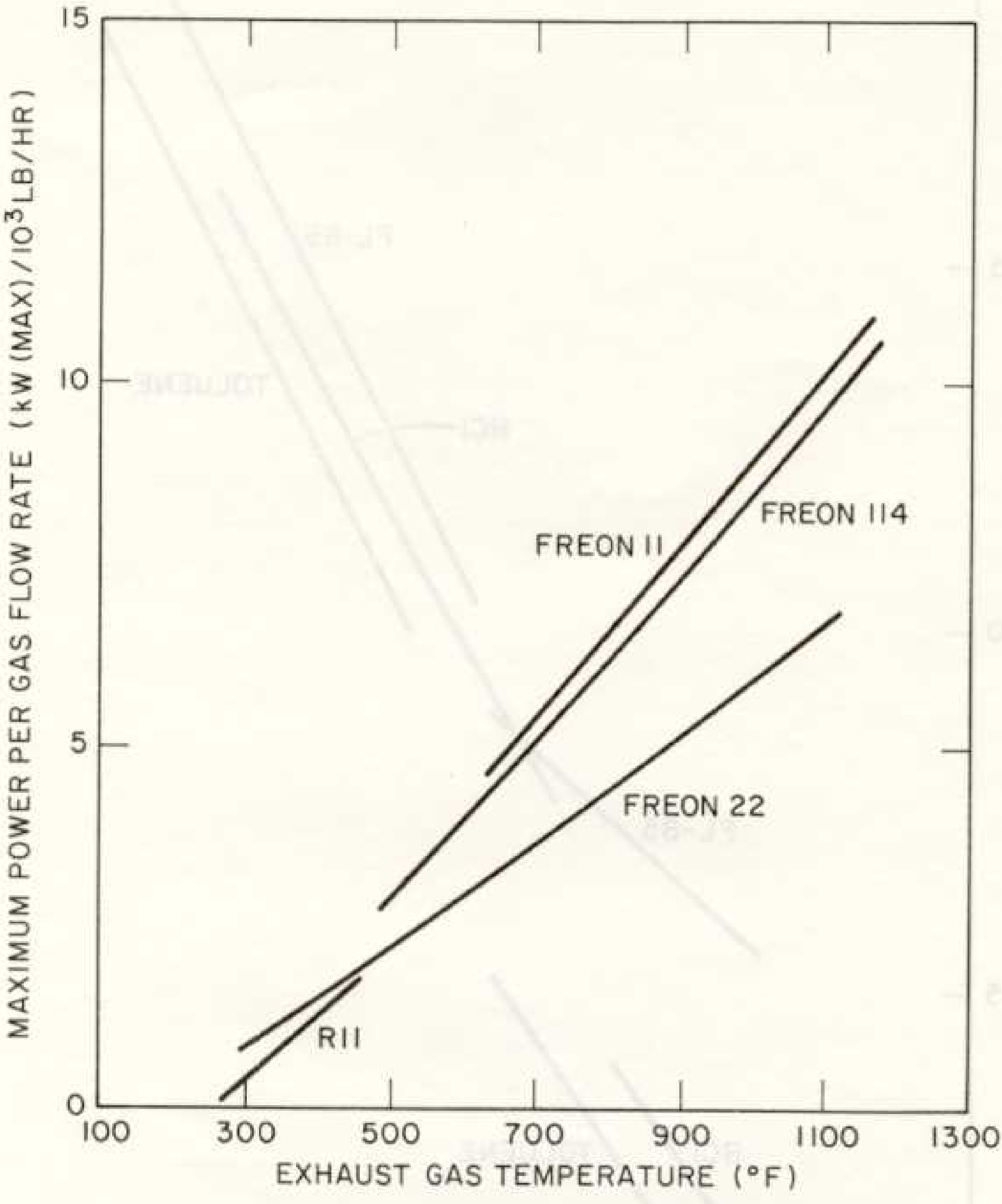

Figure 1-20. Power Generation Using Organic Fluids in Condensing Systems

1.6 COST DATA

Capital Costs

Data on total installed costs for gas turbines, steam turbines, and diesels are given in Figure 1-21. In new plants where steam is required, the economic analysis is generally based on the merit of installing a cogeneration system relative to that of installing steam generating equipment alone. Such an "incremental economic analysis" considers the increase in capital investment (i.e., cost of cogeneration system minus cost of equivalent steam generating capacity) and proceeds to evaluate the marginal return on investment on the difference in capital costs. To aid in this assessment, Figure 1-22 gives the incremental costs directly. It is seen that the total cost of steam turbine cogeneration using oil or coal generally exceeds that of most other systems, while in terms of incremental costs, oil-fired steam turbine cogeneration competes with diesels in the larger sizes. This is largely because the cost of noncondensing turbine generators is generally dwarfed by boiler costs (especially coal-fired boilers). The cost of boilers is properly given in dollars per pound of steam per hour. Total installed costs for coal-fired boilers are in the range of \$40 to \$80 per lb/hr. At high back-pressures, the steam rates of noncondensing steam turbines may be 40 to 60 lbs/kWh or more. Thus, the unit cost of the boiler would be \$1600 to \$4000/kW. The capital costs of economically attractive cogeneration systems are now generally below about \$1000 to \$1500/kW depending on the local costs of fuel and purchased electricity.

While the cost format given here is based on convenience for quick estimating purposes, some caution must be exercised in the use of these figures. There are several reasons for this, perhaps the most important of which is the interpretation of what is meant by "installed costs." Different vendors include different costs under this general heading. For example, a coal-fired boiler may be quoted at \$20 per lb/hr of steam with installation costs at \$540/day. This type of quotation does not give a clear indication of the total installed cost. It also does not include the cost of buildings, coal handling, or pollution abatement equipment,

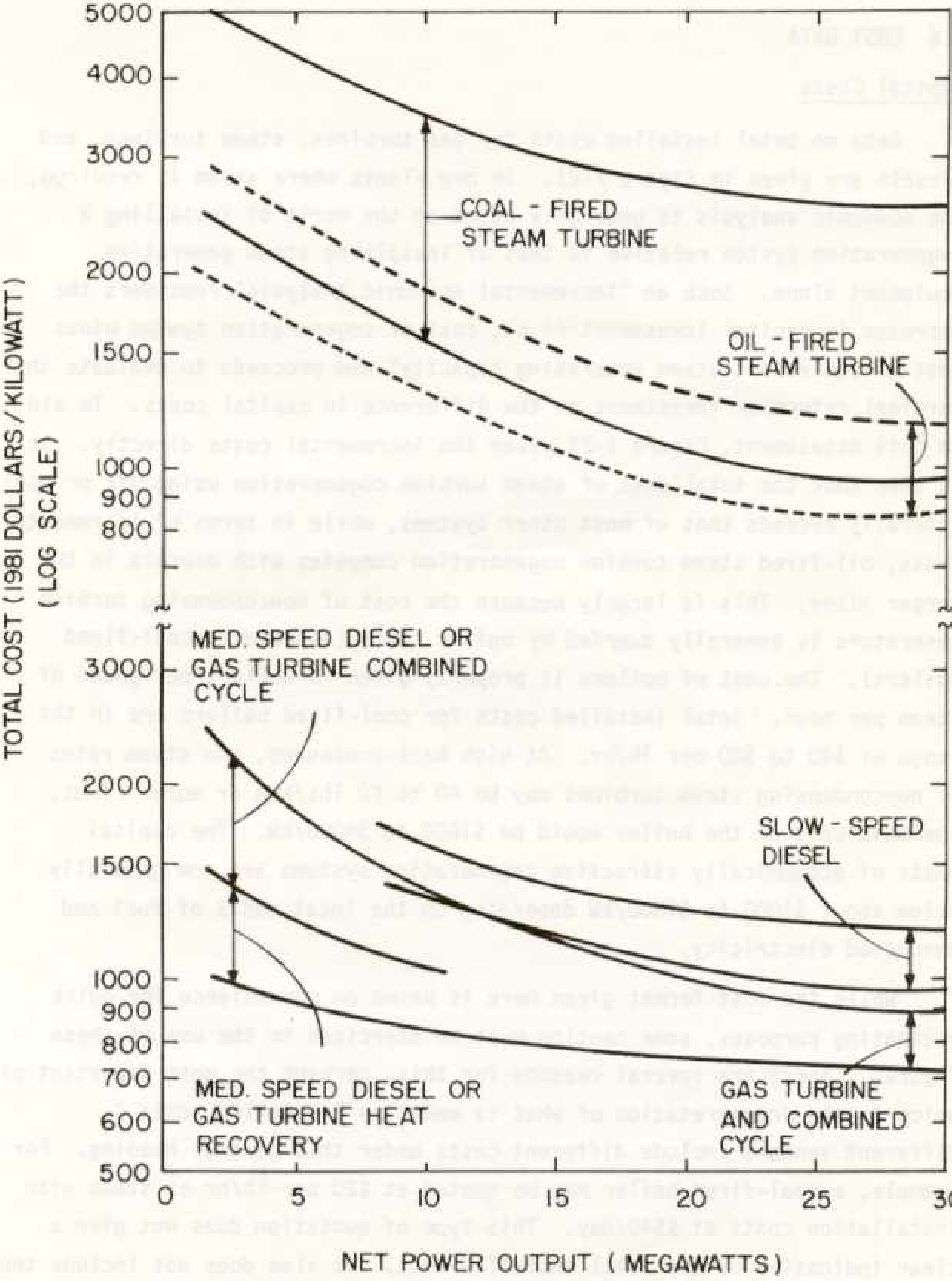

Figure 1-21. Typical Total (Turnkey) Costs of Industrial Cogeneration Systems, including Equipment, Installation, Engineering, and Construction

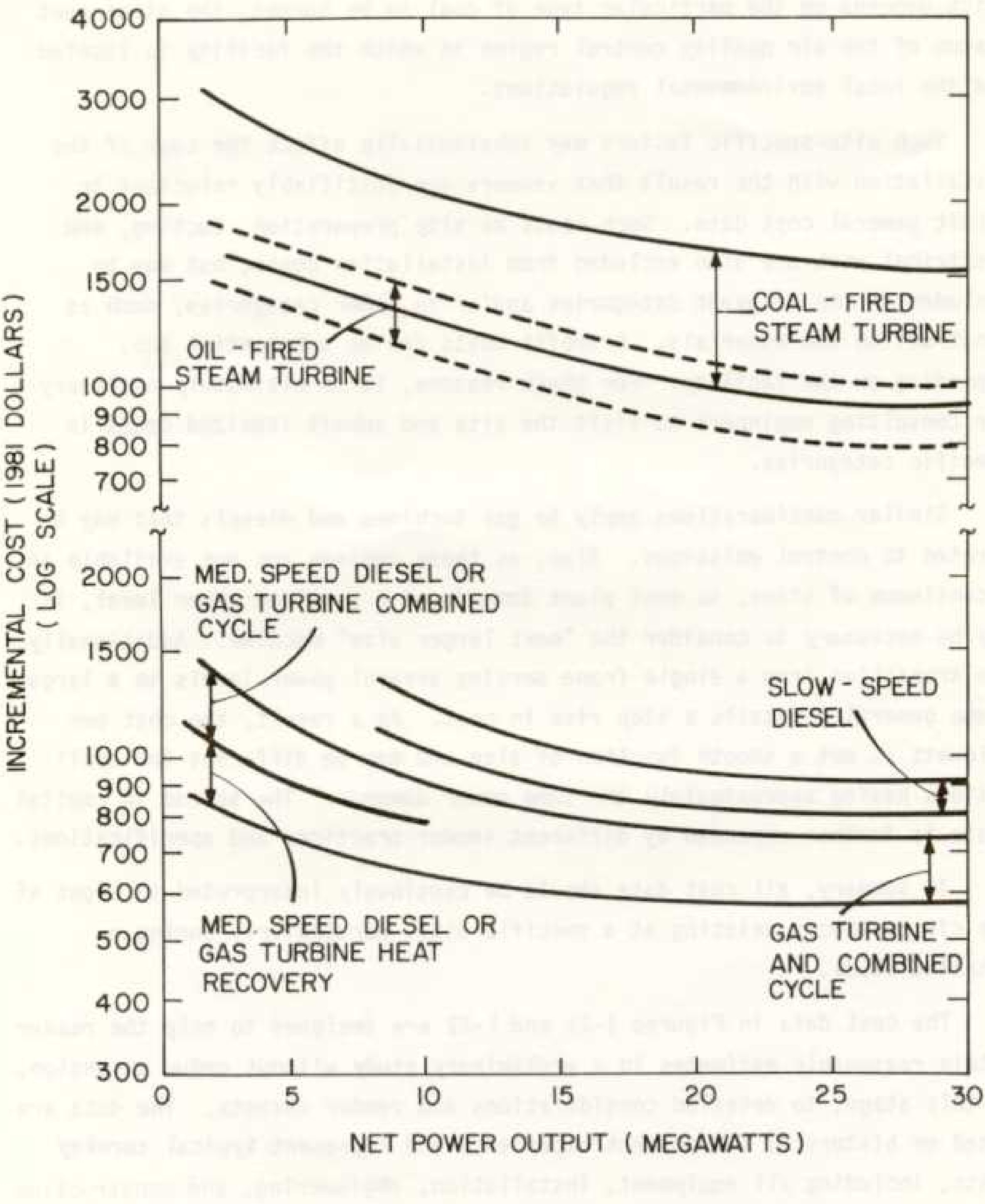

Figure 1-22. Typical Incremental (Turnkey) Costs of Industrial Cogeneration Systems, including Equipment, Installation, Engineering, and Construction

which depends on the particular type of coal to be burned, the attainment status of the air quality control region in which the facility is located and the local environmental regulations.

Such site-specific factors may substantially affect the cost of the installation with the result that vendors are justifiably reluctant to submit general cost data. Such costs as site preparation, ducting, and electrical work are also excluded from installation costs, but may be included in the relevant categories and/or in other categories, such as construction and materials. Retrofit costs can be substantial too, depending on the facility. For these reasons, it is ultimately necessary for consulting engineers to visit the site and submit itemized costs in specific categories.

Similar considerations apply to gas turbines and diesels that may be derated to control emissions. Also, as these engines are not available in a continuum of sizes, to meet plant demands at a required power level, it may be necessary to consider the "next larger size" machine. Additionally, the transition from a single frame serving several power levels to a larger frame generally entails a step rise in cost. As a result, the cost per kilowatt is not a smooth function of size and may be different for applications having approximately the same power demands. The spread in capital costs is further expanded by different vendor practices and specifications.

In summary, all cost data should be cautiously interpreted in light of the circumstances existing at a specific site, particularly during a detailed study.

The cost data in Figures 1-21 and 1-22 are designed to help the reader obtain reasonable estimates in a preliminary study without undue attention, at this stage, to detailed considerations and vendor caveats. The data are based on historical and current experience and represent typical turnkey costs, including all equipment, installation, engineering, and construction. All costs include provisions for escalation during construction of projects initiated in mid-1981. Some cost spread is inevitable because of the reasons outlined above and also to accommodate a variety of possible configurations within an equipment category. Consider, for example, the case of a low back-pressure (e.g., 50 psig) steam turbine generating power from steam produced by a coal-fired boiler at medium pressure (e.g., 400 psig). Such a system could generate the same amount of power as that generated by a moderate back-pressure (e.g., 200 psig) turbine operating with steam produced from a coal-fired boiler at higher pressure (e.g., 1000 psig). The capital costs of the two systems, however, are not the same, even at identical steam flows. High-pressure boilers cost more per pound of steam than low pressure boilers. In addition, water treatment requirements are more stringent at high pressures, so that the water treatment system for the high-pressure boiler is also more costly. As examples of the use of these curves, the total cost in 1981 dollars of a 23 MW gas turbine combined cycle ranges between \$740/kW and \$950/kW and the total cost of a 23 MW slow-speed diesel with heat recovery ranges between \$1,000/kW to \$1,250/kW. These figures may be checked with the values given respectively in Example I-A and Example IV (See Section 1.8).

Operating and Maintenance Expenses

Operating and maintenance expenses include the costs of insurance and property tax, the average annual cost of spare parts and expendables (such as lube oil and filters), and the cost of maintenance or supervising personnel. The cost of spare parts and expendables depends on the type of unit and varies throughout its life; as a rough guide, they may be taken to be about 1.5 percent of capital cost. Closer estimates may be obtained from manufacturers or from literature articles based on user experience (Appendix E). The size of the labor force required to maintain the unit will also vary with the type and size of the equipment but is frequently dependent to a greater extent on the particular manufacturing facility and the governing laws of the state. These laws specify the experience and credentials required of the personnel in charge of different types of equipment.

For small plants that are not generating their power or do not have the required labor, the acquisition of a small power system entails a significant investment in personnel and is frequently a deciding factor. For example, if a 1 MW plant operating 8000 hours/yr requires 3 people per shift to run it at a burdened cost of \$30,000 per person, the incremental running cost will be about 3.4¢/kWh which may be higher than the local cost of purchased electricity. On the other hand, the same personnel investment for a 20 MW plant would result in a more acceptable running cost of

0.17¢/kWh. In larger plants that have an experienced maintenance crew, the incremental investment in additional personnel may be negligibly small. Such is the case in the chemical plant treated in Section 1.7.3 and Section 1.8 (See Example III Table 1-12.)

Because labor costs could directly affect the economic performance of some cogeneration systems, it becomes necessary to carefully consider the operation of these systems and their intended objectives. For example, if the cogeneration system is to operate in parallel with currently existing boilers, then additional personnel will generally be required to operate and service the cogeneration system, and the system should therefore bear the attendant costs. However, if the existing boilers are primarily on standby when the cogeneration system is operating, the crew normally operating the boilers could be assigned to the cogeneration system with little or no incremental labor burden.

As another example, consider the case of a coal-fired steam turbine cogeneration system to be installed in a plant burning residual oil in its process steam boilers. Here, the cogeneration system simultaneously provides two benefits: (1) it provides a shift in fuel from residual oil to less expensive coal, and (2) it provides electric power in addition to process steam (cogeneration). Each of these benefits is obtained at a certain cost and economic return. Hence it is necessary to separate out the costs of cogeneration from the costs of fuel shifting. One way to do this is to determine the capital, and O & M costs for a transition to coal-fired boilers at the process steam pressure and subtract them from the costs of the total cogeneration system to obtain the capital and O & M costs attributable to cogeneration. As shown in the treatment of Example I-C (Table 1-10, Section 1.8) and Example I-D (Table 2-22, Section 2.4) the bulk ($870,000/yr) of the total O & M costs in this case ($1,070,000/yr) is attributable to fuel shifting, leaving a small labor burden ($200,000/yr) on cogeneration.

In summary, the O & M costs of industrial cogeneration systems are largely dependent on site-specific factors, on the type and operation of the particular system,and on the benefits derived from it. Hence it is not possible to cite general values for O & M costs that would be meaningful to all potential cogenerators. Each situation should be assessed on an individual basis. Where the installation of a cogeneration system would yield benefits other than those directly related to the cogeneration function, care should be taken not to unduly burden the cogeneration system with costs attributable to the other benefits.

1.6.1 Construction Times and Cash Flow Profiles

The time needed to construct the facility and bring it to an operational status depends on the particular cogeneration technology and on site-specific factors, such as retrofit equipment modification, degree of site preparation, and building requirements. Small diesel and gas turbine installations may require less than a year to install and operate. Larger units could be operational in 2 to 3 years, while coal-fired boiler installations usually take longer. Licensing requirements also tend to elongate the period of construction, installation, and operation. Thus it is necessary to evaluate the period of construction on a case-by-case basis.

The rate at which expenditures are made during the construction period depends on the type of project, the conditions of sale, the work contract negotiated and the particular financing instrument adopted. For "turnkey" projects, the rate of the expenditure may be small at the beginning of construction and increase steadily as construction proceeds. "S-shaped" curves of various forms, such as that illustrated in Figure 1-23, are characteristic of utility installations or large projects whose construction period exceeds 3 or 4 years. The curve may be symmetric or skewed to one side or another. Left-skewed curves are characteristic of projects requiring heavy front-end cash flows. Right-skewed curves are characteristic of many coal-fired and nuclear power plant projects. The aim of a construction strategy is to bring the facility to commercial operation at the desired date with minimum total cost. Such variables as construction delays, inflation, and the interest rates of borrowed funds should be taken into account when devising the optimum financing and construction strategy.

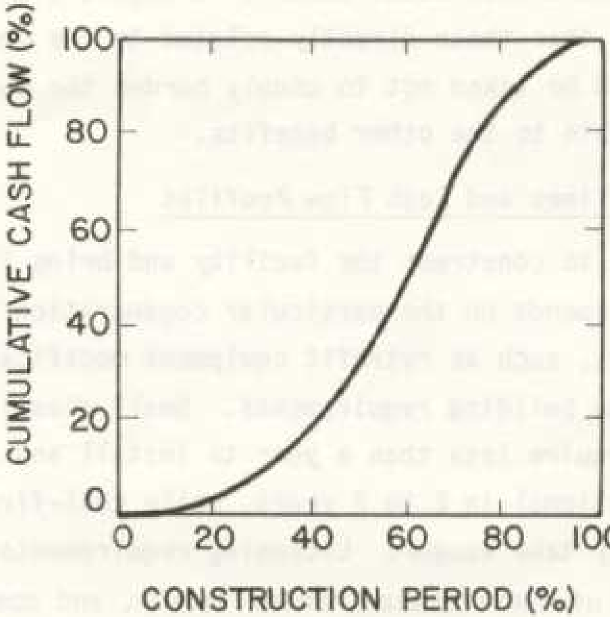

Figure 1-23. Construction Cash Flow Profile

1.7 TYPICAL INDUSTRIAL APPLICATIONS

Four illustrative examples are treated in this section to illustrate the use of the parametric data given in Sections 1.0 through 1.6 and show how a cogeneration system can be assembled and evaluated.

1.7.1 Example I: Synthetic Textile Facility

The annual average pattern of energy use at a synthetic fiber facility is shown in Figure 1-24. The facility consists of two adjacent processing plants. One plant produces intermediates which are used in the second plant to produce textile fibers. Waste heat recovery boilers at the intermediate plant provide 175 psig steam for use in the textile fiber plant. Neither plant generates electricity. Residual fuel oil is used in the boilers to produce process steam.

Cogeneration Option A

The fiber plant requires 93,000 lbs/hr of steam at moderate pressures and 22,900 kW of electric power, giving a power-to-steam ratio of about 245 kWh/1000 lbs. This ratio is compatible with a gas turbine combined cycle system using an extraction/noncondensing steam turbine (see Section 1.2). A heat balance for the installation is shown in Figure 1-25. The computations required to obtain the performance of the gas turbine are shown in Table 1-3. For purposes of illustration, the ambient temperature is assumed to remain constant at 59°F, and the rise in exhaust pressure caused by the heat recovery boiler and associated ducting is 3 percent of atmospheric pressure. The power required to compress the fuel gas may be estimated from the enthalpy-entropy chart of methane or obtained from a compressor manufacturer.

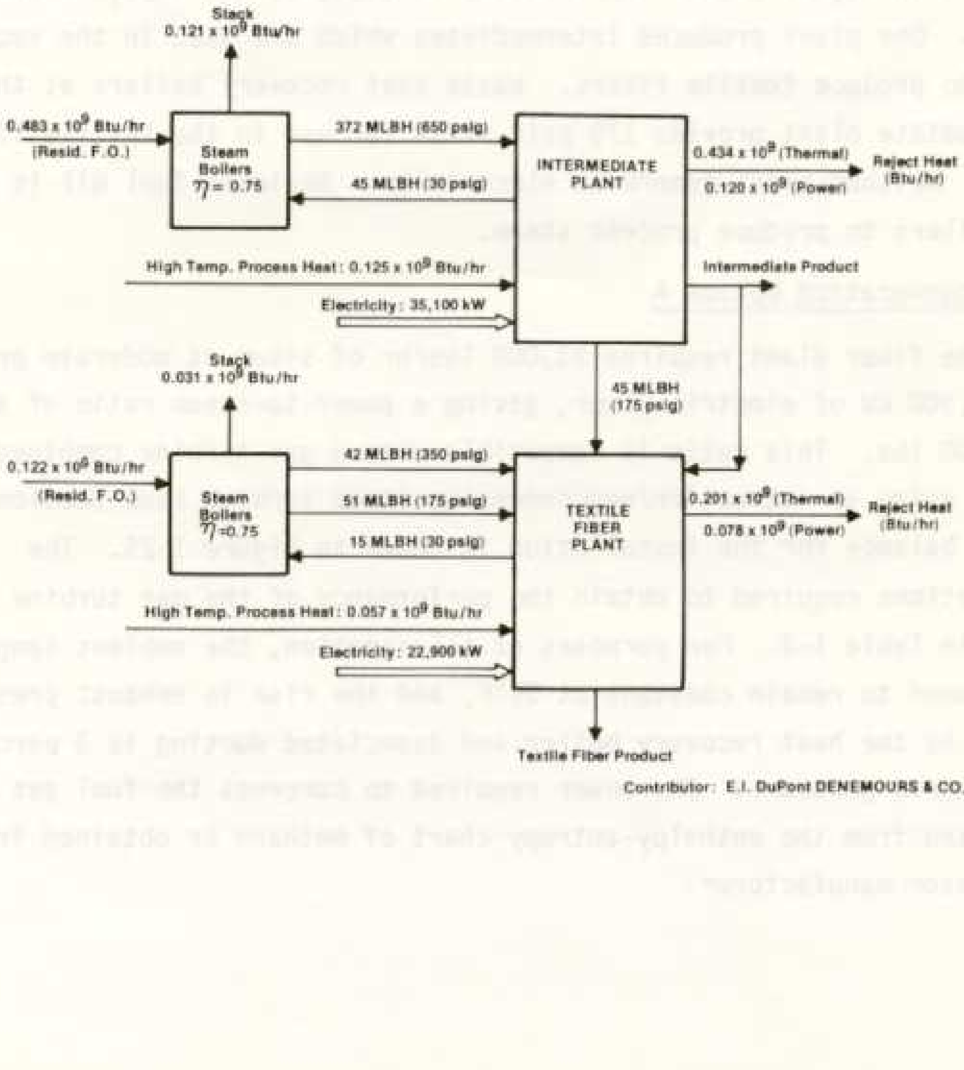

Figure 1-24. Annual Average Energy Profile of Adjacent Intermediate and Synthetic Textile Fiber Plants in Southeast (1 MLBH = 1,000 lb/hr)

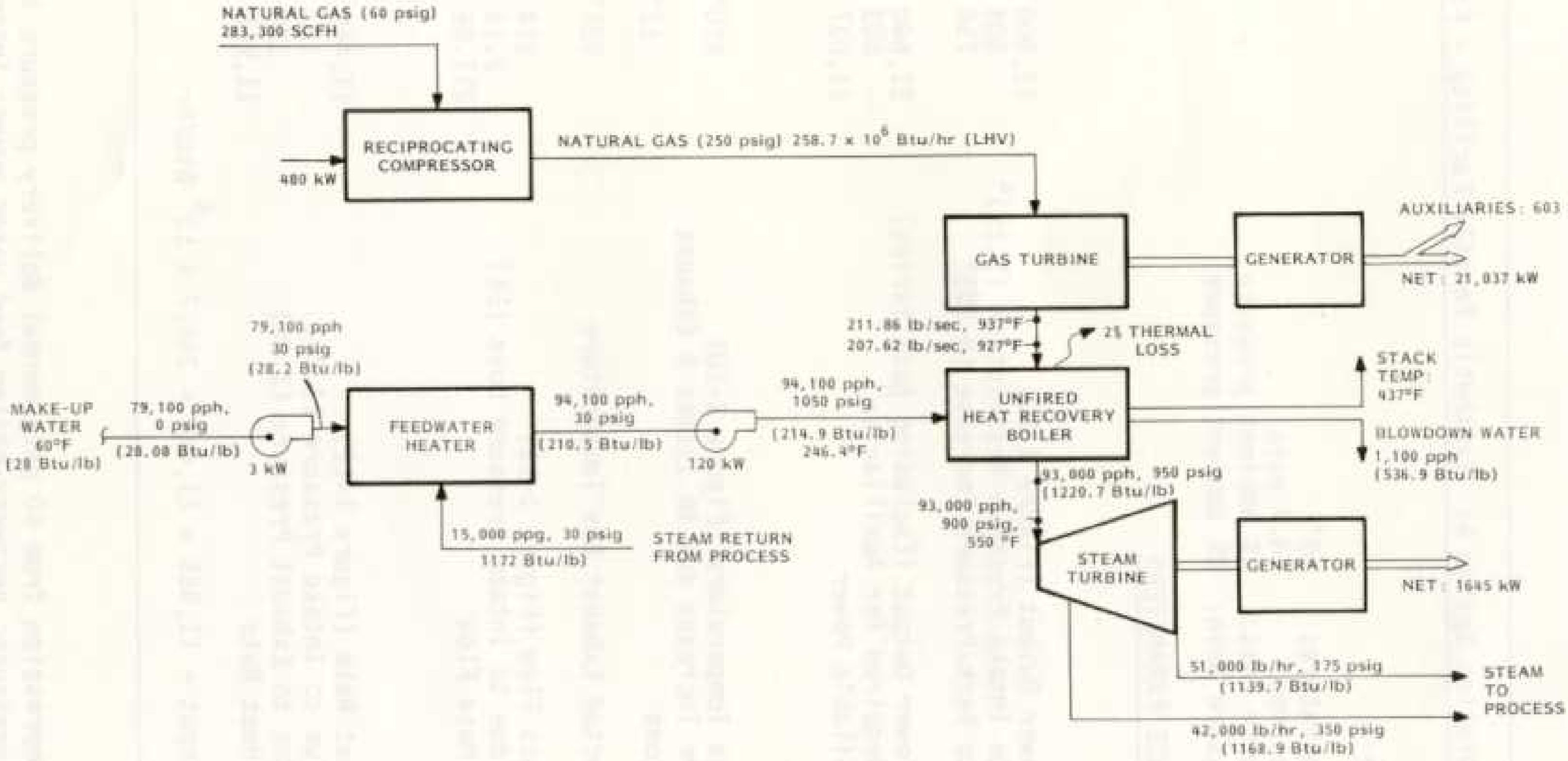

Figure 1-25. Heat Balance Schematic, Example I Cogeneration Option A
(1 pph = 1 lb/hr)

Table 1-3. Sample Gas Turbine Performance Evaluation

Example I: Cogeneration Option A: Synthetic Textile Facility - Fiber Plant

DESIGN CONDITIONS

Ambient Temperature:	59°F
Ambient Pressure:	14.7 psia
Intake Pressure Loss:	1% ambient pressure
Exhaust Pressure Gain:	3% ambient pressure

TURBINE PERFORMANCE PARAMETERS

Power:	
No Loss Power Output (Figure 1-10)	22,900 kW
Loss Due to Intake Pressure Restriction (2.2%)[a]	504 kW
Loss Due to Back-Pressure Increase (3.3%)[a]	756 KW
Gross Power Output (Excluding Auxiliaries)	21,640 kW
Power Required for Auxiliaries[b]	603 kW
Net Available Power	21,037 kW
Exhaust Gas:	
No Loss Gas Temperature (Figure 1-10)	920°F
Temperature Increase due to Intake & Exhaust Conditions	17°F
Corrected Exhaust Gas Temperature	937°F
No Loss Mass Flow (Figure 1-11)	214 lbs/sec
Reduction due to Intake Pressure Loss (1%)	2.14 lbs/sec
Corrected Mass Flow	211.86 lbs/sec
Heat Rate:	
No Loss Heat Rate (Figure 1-12)	11,440 Btu/kWh
Increase due to Intake Pressure (1.2%)	137 Btu/kWh
Increase due to Exhaust Pressure (3.3%)	378 Btu/kWh
Corrected Heat Rate	11,955 Btu/kWh

Total Fuel Input = 11,955 x 21,640 = 258.7×10^6 Btu/hr

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[a]From Table 1-1

[b]Power for gas compression from 60 psig normal delivery pressure to 250 psig combustion pressure; recovery boiler feed water pumps; instrumentation and controls.

Because of thermal losses through the ducts connecting the boiler to the turbine (Section 1.3), the gas temperature at the boiler inlet is 927°F, or 10°F less than the gas temperature at the turbine exit.

The maximum saturated steam output from the recovery boiler at 950 psig and a gas temperature of 927°F is easily obtained from Figure 1-13 as 0.13 times the exhaust gas flow, or $0.13 \times 747{,}442 \approx 97{,}000$ lbs/hr. This flow rate is higher than the requirement for process steam (93,000 lbs/hr); thus, it is possible, in principle, to provide for some superheating in the recovery boiler without firing. Table 1-4 shows how the performance of the boiler and its different sections can be computed in the case where superheated steam is required. The temperature profile is shown in Figure 1-26.

The computation of the power obtained from the steam turbine is shown in Table 1-5.

The steam exit enthalpies depend in part on the turbine efficiency. Also, wet steam conditions, as obtained in this option, will reduce the turbine efficiency. Depending on the temperature, some wetness (less than about 7 percent) can generally be tolerated without significant deterioration of the turbine performance or corrosion of the blades. If the process steam is required to be dry and saturated, then a greater amount of superheat is needed at the turbine throttle. In this example, this means that the heat recovery boiler requires some supplementary firing.

Cogeneration Option B

The process steam at the intermediate plant is at high pressure (650 psig) and the power-to-steam ratio is approximately 95 kWh/1000 lbs. This value is lower than what can be obtained from a gas turbine and unfired heat recovery boiler. Thus, a fired heat recovery boiler is required. In this case, two gas turbines similar to the one considered above can be used. The heat balance for this plant is shown in Figure 1-27. The computations required for the heat recovery boiler are shown in Table 1-6. Note that at high inlet gas temperatures, the pinch-point temperature

Table 1-4. Steam Production From An Unfired Recovery Boiler - Example I-A

Given:

Gas Turbine Exhaust Flow : 211.86 lbs/sec
Exhaust Gas Temperature: 937°F
Inlet Water Enthalpy : 214.9 Btu/lb
Inlet Water Temperature: 246°F
Required Steam Pressure: 950 psig

Compute:

(1) Maximum Saturated Steam Flow and Exit Gas Temperature
(2) Outlet Steam Conditions for a Flow of 93,000 lbs/hr, Exit Gas Temperature and Duty of Each Boiler Section

Solution:

From Steam Tables at 950 psig (964.7 psia):

Steam Saturation Temperature = 540.4°F
Saturated Water Enthalpy = 536.9 Btu/lb
Saturated Steam Enthalpy = 1193.7 Btu/lb
Latent Heat of Vaporization = 656.8 Btu/lb

Gas Turbine Exhaust Flow = 211.86 x 3600 = 762,696 lb/hr
Duct Losses (2%) = 15,254 lb/hr
Gas Flow at Boiler Inlet = 747,442 lb/hr

Exhaust Gas Temperature = 937°F
Duct Losses = 10°F
Gas Temperature at Boiler Inlet = 927°F

Pinch-Point Temperature Difference = 59°F
Gas Temperature at Evaporator Exit = 540.4 + 59 = 599.4°F

Assume a gas specific heat of 0.265 Btu/lb°F and a radiation loss of 2%.
Heat Transferred by Gas in Evaporator
$= 0.98 \times 747{,}442 \times 0.265 \times (927 - 599.4) = 63.59 \times 10^6$ Btu/hr

Maximum Saturated Steam Flow $= \dfrac{63.59 \times 10^6}{656.8} = 96{,}819$ lbs/hr

Blowdown Water (1.2%) = 1,162 lbs/hr
Water Flow in Economizer = 96,819 + 1,162 = 97,981 lbs/hr
Enthalpy Gained by Water in Economizer
$= 97{,}981 \times (536.9 - 214.9) = 31.55 \times 10^6$ Btu/hr
Enthalpy Lost by Gas in Economizer
$= 0.98 \times 747{,}442 \times 0.265 \times (599.4 - T_{go}) = 31.55 \times 10^6$ Btu/hr
Outlet Gas Temperature $T_{go} = 437°F$

Table 1-4. Steam Production From An Unfired Recovery Boiler - Example I-A (Continued)

For a steam flow of 93,000 lbs/hr:

Enthalpy gained by steam in superheater and evaporator

$$= \frac{63.59 \times 10^6}{93{,}000} = 683.8 \text{ Btu/lb}$$

Outlet Steam Enthalpy = 536.9 + 683.8 = 1220.7 Btu/lb
Corresponding Temperature at 950 psig (From Steam Tables) = 567°F

Water Flow in Economizer = 93,000 x 1.012 = 94,116 lb/hr
Enthalpy Gained by Water in Economizer = 94,116 x (536.9 - 214.9)

$$= 30.31 \times 10^6 \text{ Btu/hr}$$

Enthalpy Lost by Gas in Economizer

$$= 0.98 \times 747{,}442 \times 0.265 \times (599.5 - T_{go}) = 30.31 \times 10^6 \text{ Btu/hr}$$

Outlet Gas Temperature: $T_{go} = 443°F$

Total Enthalpy Lost by Gas = 0.98 x 747,442 x 0.265 x (927 - 443)

$$= 93.90 \times 10^6 \text{ Btu/hr}$$

Duty of Boiler Sections:

$$\text{Economizer: } \frac{\text{Enthalpy Gained by Water in Economizer}}{\text{Total Enthalpy Lost by Gas}} = \frac{30.31 \times 10^6}{93.90 \times 10^6} = 0.32$$

$$\text{Evaporator: } \frac{\text{Enthalpy Gained by Steam in Evaporator}}{\text{Total Enthalpy Lost by Gas}} = \frac{93{,}000 \times 656.8}{93.9 \times 10^6} = 0.65$$

$$\text{Superheater: } \frac{\text{Enthalpy Gained by Steam in Superheater}}{\text{Total Enthalpy Lost by Gas}} = \frac{93{,}000 \times (1220.7-1193.7)}{93.9 \times 10^6} = 0.03$$

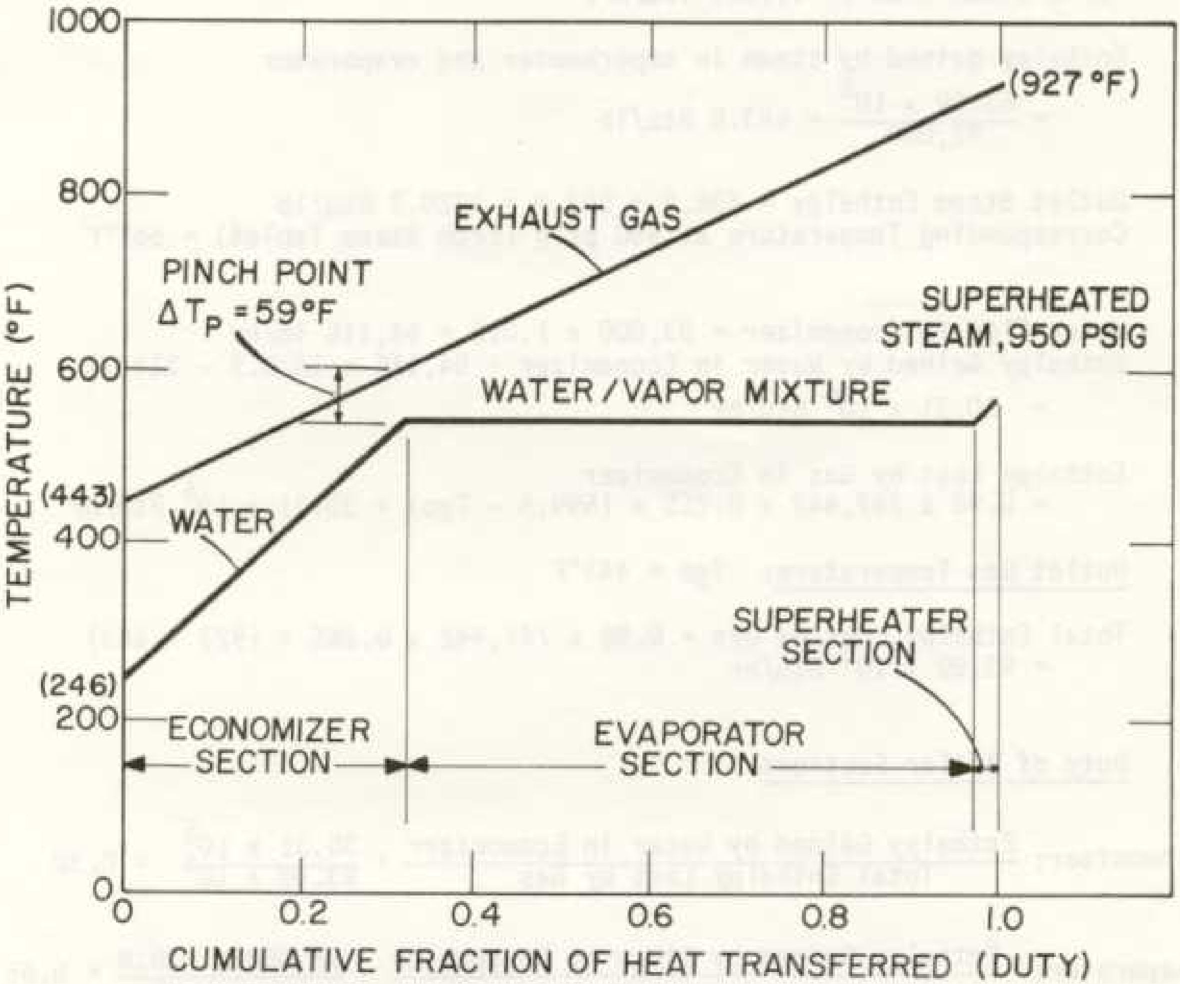

Figure 1-26. Temperature Profile in Gas Turbine Heat Recovery Boiler Operating at Full Load (Example I - Cogeneration Option A)

Table 1-5. Computation of Steam Turbine Power Output

Example I: <u>Cogeneration Option A: Synthetic Textile Facility - Fiber Plant</u>

Boiler Exit Steam Conditions (from Table 1-4):

Steam Flow: 93,000 lbs/hr
Pressure: 950 psig
Temperature: 567°F

Allowing pressure and temperature drops of 50 psi and 17°F respectively between boiler and turbine the steam conditions at the turbine throttle are:

Steam Flow = 93,000 lbs/hr
Pressure = 900 psig
Temperature = 550°F
Enthalpy = 1213.2 Btu/lb

From Theoretical Steam Rate Tables:

TSR for expansion to 175 psig = 27.19 lbs/kWh

TSR for expansion to 350 psig = 45.07 lbs/kWh

Assume:

Steam Turbine Efficiency = 0.61
Generator Efficiency = 0.96

Actual Steam Rates (ASR):

$$\text{ASR (175 psig)} = \frac{27.19}{0.61} = 44.57 \text{ lbs/kWh}$$

$$\text{ASR (350 psig)} = \frac{45.07}{0.61} = 73.89 \text{ lbs/kWh}$$

<u>Power</u>:

$$\text{From expansion of 51,000 lbs/hr} = \frac{51{,}000}{44.57} = 1{,}144 \text{ kW}$$

$$\text{From expansion of 42,000 lbs/hr} = \frac{42{,}000}{73.89} = 568 \text{ kW}$$

Total Power = 1,712 kW

Generator Output Power = 1,712 x 0.96 = 1,645 kW

Table 1-5. Computation of Steam Turbine Power Output (Continued)

Process Steam Enthalpies:

$$\text{Enthalpy at 175 psig} = 1213.2 - \frac{3412}{44.57} = 1136.6 \text{ Btu/lb}$$

$$\text{Enthalpy at 350 psig} = 1213.2 - \frac{3412}{73.89} = 1167.0 \text{ Btu/lb}$$

Process Steam Quality

From Steam Tables:

	At 175 psig	At 350 psig
Evaporation Enthalpy	846.8 Btu/lb	790.1 Btu/lb
Saturated Steam Enthalpy	1197.6 Btu/lb	1204.2 Btu/lb

$$\text{Quality at 175 psig} = \frac{1197.6 - 1136.6}{846.8} \approx 0.072$$

$$\text{Quality at 350 psig} = \frac{1204.2 - 1167.0}{790.1} \approx 0.047$$

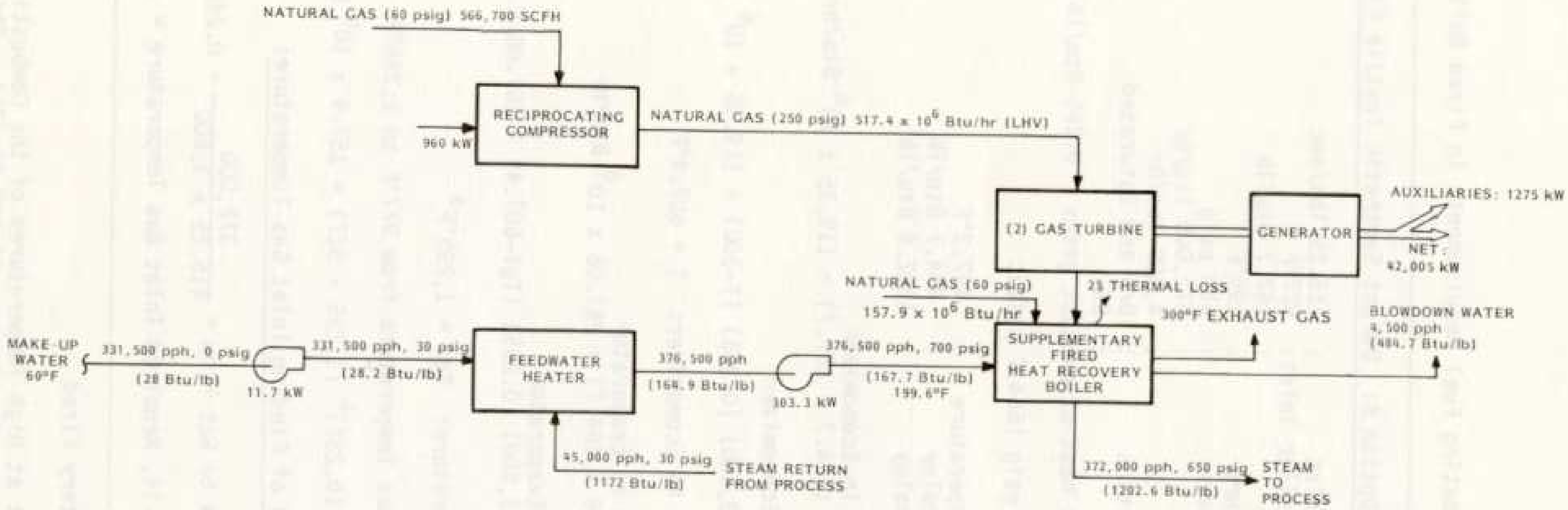

Figure 1-27. Heat Balance Schematic, Example I - Cogeneration Option B
(1 pph = 1 lb/hr)

Table 1-6. Estimating Fuel Requirements in Fired Boilers

Example I: Cogeneration Option B: DuPont Synthetic Textile Plant

Gas Flow at Boiler Inlet	:	415.25 lbs/sec
Gas Temperature at Boiler Inlet	:	927°F
Inlet Water Enthalpy	:	167.7 Btu/lb
Inlet Water Temperature	:	199°F
Required Steam Pressure	:	650 psig
Required Steam Flow	:	372,000 lbs/hr
Blowdown Water	:	4,500 lbs/hr
Required Steam Condition	:	Dry and Saturated
Radiation Loss	:	2%

Assume mean specific heat of exhaust gases = 0.265 Btu/lb°F

From Steam Tables at 650 psig (664.7 psia):

Steam Saturation Temperature	:	497.3°F
Saturated Water Enthalpy	:	484.7 Btu/lb
Saturated Steam Enthalpy	:	1202.6 Btu/lb

Enthalpy Gained by Water in Economizer
$= (372,500 + 4,500)\ (484.7 - 167.7) = 119.35 \times 10^6$ Btu/hr

Enthalpy Lost by Gas in Economizer

$= (0.98)\ (415.25)\ (3,600)\ (0.265)\ (T-300) = 119.35 \times 10^6$ Btu/hr

Gas Temperature at Inlet to Economizer: T = 607.4°F

Enthalpy Gained by Steam in Evaporator
$= (372,000)\ (1,202.6 - 484.7) = 267.06 \times 10^6$ Btu/hr

Enthalpy Lost by Gas in Evaporator
$= (0.98)\ (415.25)\ (3,600)\ (0.265)\ (Tgi-607.4) = 267.06 \times 10^6$ Btu/hr

Required Inlet Gas Temperature: Tgi = 1,295°F[a]

Fuel Required to Raise Gas Temperature from 927°F to 1,295°F

$= (415.25)\ (3,600)\ (0.287)^b\ (1,295 - 927) = 157.9 \times 10^6$ Btu/hr

Alternative Method of Finding Inlet Gas Temperature:

$$\text{Ratio of Steam to Gas Flow} = \frac{372,000}{415.25 \times 3,600} = 0.249$$

From Figure 1-14, Required Inlet Gas Temperature = 1,265°F.

---

[a]Unit is Supplementary Fired

[b]Mean Specific Heat at High Temperatures of the Combustion Products of Natural Gas (Lower Heating Value = 21,520 Btu/lb). This value can also be used for other fuels.

difference is not a limiting factor (in the case study shown, ΔTp = 607.4 - 497.3 $\approx$ 110°F); the limiting factor is the minimum outlet gas temperature. For clean low-sulfur fuels, the outlet gas temperature can be reduced to 250°F resulting in less fuel consumption in the boiler.

Estimates obtained by the method of Table 1-6 are accurate to within approximately 5 percent, the main source of error being the variations in specific heat with temperature and fuel noted earlier.

Cogeneration Option C

This option involves the installation of new, high-pressure pulverized coal-fired boilers and steam turbines as shown schematically in Figure 1-28. This configuration provides the steam for both the intermediate and the fiber plants. The computation of the power output from the turbines is given in Table 1-7.

1.7.2 Example II: Large Petroleum Refinery, Norco, Louisiana

Figure 1-29 shows the annual average pattern of energy use in a typical large refinery. Some steam turbine cogeneration capacity is included as is generally the case in refineries of that size.

Cogeneration Option A.

This particular cogeneration option is that of a gas turbine topping the existing boilers. In this case, the raw exhaust gases from the turbine are directed into the boilers as highly preheated combustion air. These gases contain sufficient oxygen for combustion because of the large amount of excess air used in the gas turbine to maintain moderate turbine blade temperatures. The result is that less fuel is consumed in the boiler.

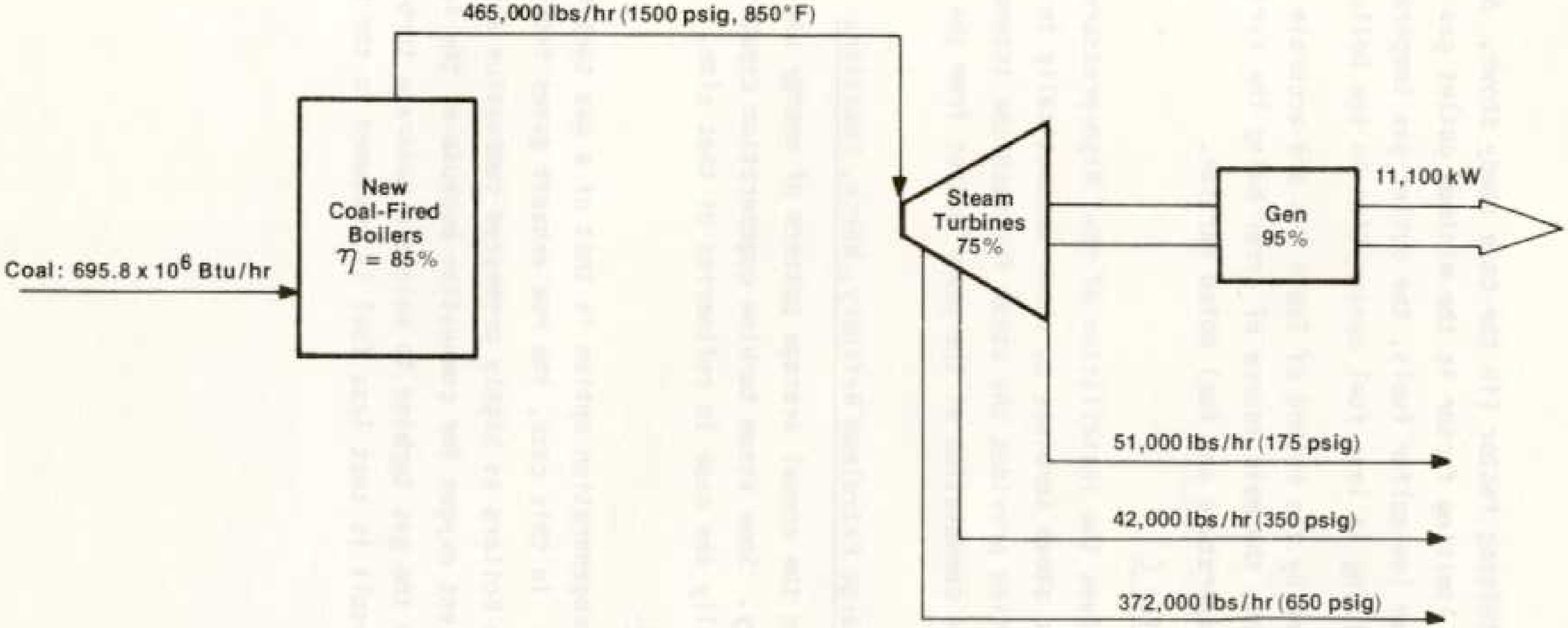

Figure 1-28. Textile Fiber Plant, Example 1, Cogeneration Option C

Table 1-7. Computation of Steam Turbine Power Output

Example I-C: Coal-Fired Boiler Option, Textile Fiber Facility (Figure 1-28)

Steam Turbine Throttle Conditions:

Steam Flow = 465,000 lbs/hr
Pressure = 1,500 psig
Temperature = 850°F
Enthalpy = 1,396.7 Btu/lb

Theoretical Steam Rates:

TSR (to 175 psig) = 15.927 lbs/kWh
TSR (to 350 psig) = 21.75 lbs/kWh
TSR (to 650 psig) = 35.3 lbs/kWh

Assume:

Turbine Efficiency = 0.74
Generator Efficiency = 0.96

Actual Steam Rates are:

ASR (175 psig) = 21.52 lbs/kWh
ASR (350 psig) = 29.39 lbs/kWh
ASR (650 psig) = 47.70 lbs/kWh

Power:

From expansion of 51,000 lbs/hr $= \frac{51,000}{21.52} = 2,370$ kW

From expansion of 42,000 lbs/hr $= \frac{42,000}{29.39} = 1,429$ kW

From expansion of 372,000 lbs/hr $= \frac{372,000}{47.70} = 7,798$ kW

Total Power = 11,597 kW

Generator Output Power = 11,597 x 0.96 ≈ 11,130 kW

Process Steam Enthalpies:

Enthalpy at 175 psig $= 1396.7 - \frac{3412}{21.52} = 1238.2$ Btu/lb

Enthalpy at 350 psig $= 1396.7 - \frac{3412}{29.39} = 1280.6$ Btu/lb

Enthalpy at 350 psig $= 1396.7 - \frac{3412}{47.70} = 1325.2$ Btu/lb

All process steam is superheated

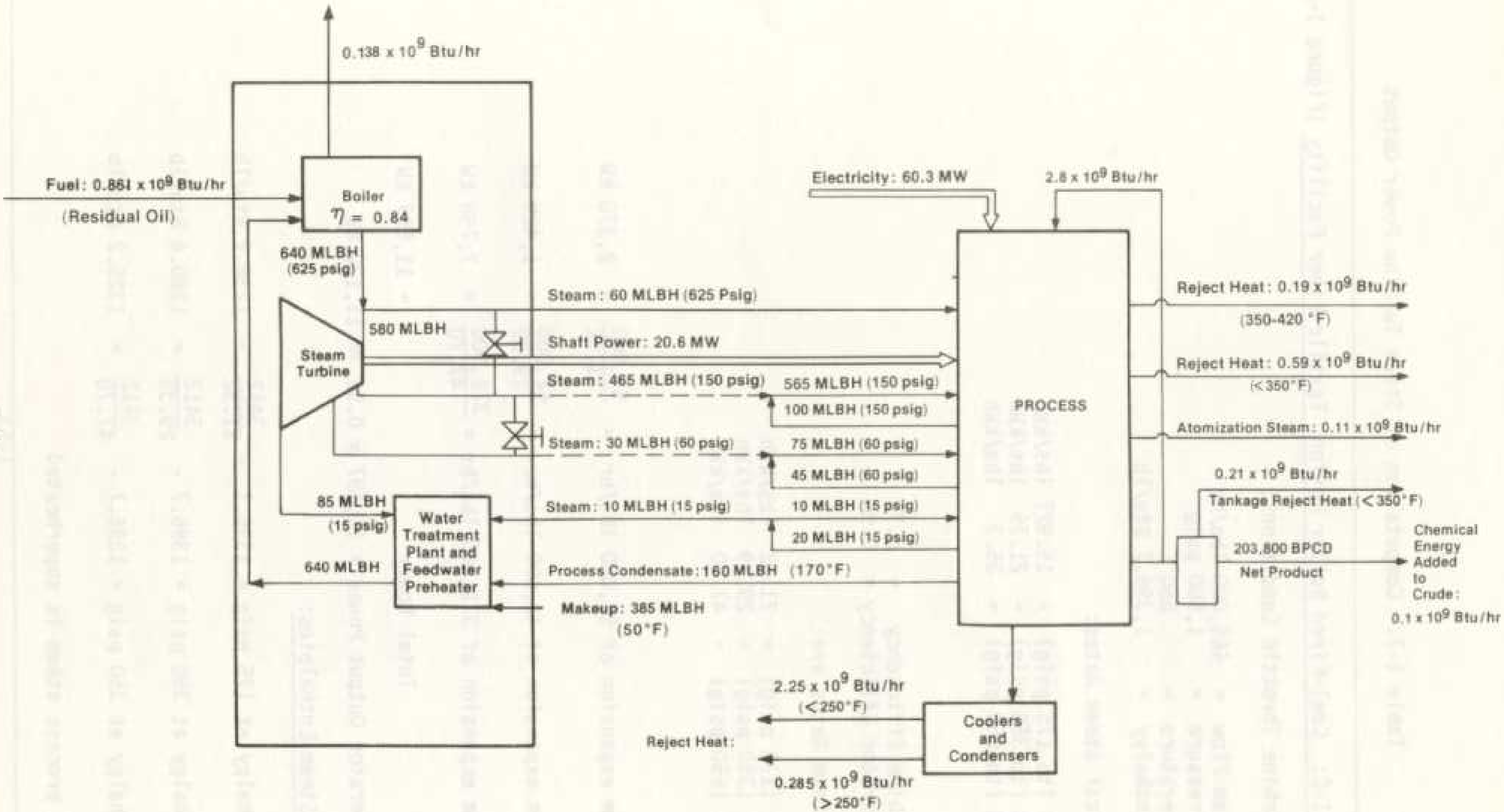

Figure 1-29. Annual Average Energy Profile of Typical Large Refinery -- Base Case Example II (1 MLBH = 1,000 lb/hr)

The performance computations and heat balance for this example are shown in Table 1-8 and Figure 1-30 respectively. The computation starts with a determination of the gas flow rate required to operate the boiler without additional air. This involves calculations of the amount of oxygen in the turbine exhaust gases. A boiler input heat balance then determines the fuel and gas flows. The boiler efficiency in this example is assumed to be constant but may change in practice in several ways. The gas flow rate is greater than the amount of air normally used by the boiler and hence tends to reduce the flame temperature. This reduction in flame temperature is counteracted by the higher inlet air temperature so that detailed combustion and heat transfer calculations are required to determine the relative effects on flame temperature and on the competing processes of convective and radiative heat transfer for a particular boiler. If a lower flame temperature is obtained, then some boiler modifications may be necessary. The higher flow rate will also produce larger pressure drops and may require larger fans.

The computations of Table 1-8 permit a preliminary evaluation to be made of the size and performance of the topping facility. A more accurate assessment of the performance, boiler compatibility, and extent of required modification should be obtained from boiler and turbine manufacturers.

Cogeneration Option B

This option involves installing a pulverized coal-fired boiler and back-pressure steam turbines (Figure 1-31). It is essentially the same as Option C of Example I, except that the back pressure is very high in this case.

1.7.3 Example III: Agricultural Chemicals Plant - Turbine Cogeneration Option

One of the most economically attractive opportunities for cogeneration with back-pressure or extraction/noncondensing steam turbines is in applications where a significant amount of steam is throttled to a lower pressure for process use. Such situations are not uncommon. They may occur in old plants that have undergone substantial changes in product structure, process technology, and/or energy use. Figure 1-32 illustrates one such situation in a Union Carbide Agricultural Chemicals Plant where substantial amounts of steam are throttled down to process pressures of

Table 1-8. Boiler Topping Cogeneration With Gas Turbines - Example II, Cogeneration Option A

Step 1: Compute fuel flow (M_f lbs/hr) and minimum exhaust gas flow for residual oil-fired boiler operation without ambient air

For residual oil assume:

Density = 18.3°API at 60°F
Heating Value = 19,000 Btu/lb
Theoretical Air Requirement[a] = 7.46 lbs air/10^4 Btu fuel

$$= \frac{7.46 \times 19{,}000}{10{,}000} = 14.17 \frac{\text{lb air}}{\text{lb fuel}}$$

Excess Air = 10%

For gas turbine assume:

Exhaust Gas Temperature at Boiler = 927°F
Excess Oxygen in Exhaust Gas = 0.17[b]
Ambient Air Temperature = 59°F

Solution

Actual air requirement for M_f lbs fuel/hr = $1.1 \times 14.17 \times M_f$ = $15.59\ M_f$ lbs/hr

Corresponding oxygen requirement = $0.23^c \times 15.59\ M_f = 3.59\ M_f$ lb/hr

Turbine exhaust flow rate corresponding to oxygen requirement

$$= \frac{3.59}{0.17} M_f = 21.09\ M_f \text{ lb gas/hr}$$

Boiler input heat balance (Figure 1-31):

$$21.09\ M_f \times 0.265^d \times (927 - 59) + M_f \times 19{,}000 = 0.86 \times 10^9 \text{ Btu/hr}$$

$$M_f = 36{,}100 \text{ lbs/hr}$$

---

[a] "Steam," Babcock and Wilcox (see References) p. E-1.

[b] Varies to some extent with turbine, manufacturer, and operating conditions.

[c] Air contains 23% oxygen by weight.

[d] Mean specific heat of exhaust gases (see Table 1-4).

Table 1-8 (Continued)

Corresponding exhaust gas flow at boiler	= 36,100 x 21.09
	= 761,450 lbs/hr
Duct losses (2%)	= 15,540 lbs/hr
Minimum turbine exhaust gas flow	= 776,990 lbs/hr

Step 2: Select Most Compatible Turbine from Manufacturers' Data and Repeat above Computation if Exhaust Gas Temperature is Different[e]

If the previous gas turbine is selected (Table 1-4) we have:

Gas turbine exhaust flow	= 211.86 x 3600	= 762,696 lbs/hr
Duct losses (2%)[f]		= 15,254 lbs/hr
Gas flow at boiler inlet		= 747,442 lbs/hr

From Boiler Input Heat Balance:

$$\text{Boiler Fuel Consumption} = 0.861 \times 10^9 - 747{,}442 \times 0.265 \times (927 - 59)$$

$$= 0.689 \times 10^9 \text{ Btu/hr}$$

$$= \frac{0.689 \times 10^9 \text{ Btu/hr}}{19{,}000 \text{ Btu/lb}}$$

$$= 36{,}300 \text{ lbs/hr}^{g}$$

[e]Notes: (1) Optimum choice of maximum power at matching exhaust flow may not always be obtainable.

(2) Boiler efficiency will decrease if turbine exhaust flow is greater than the amount required because the amount of excess air (and excess oxygen) will increase.

(3) Some ambient air may be required for better boiler control at different load conditions.

[f]Losses in ducts connecting turbine to boiler.

[g]Because of the smaller contribution of exhaust gas sensible heat, the fuel consumption is approximately 200 lbs/hr greater than the optimum consumption.

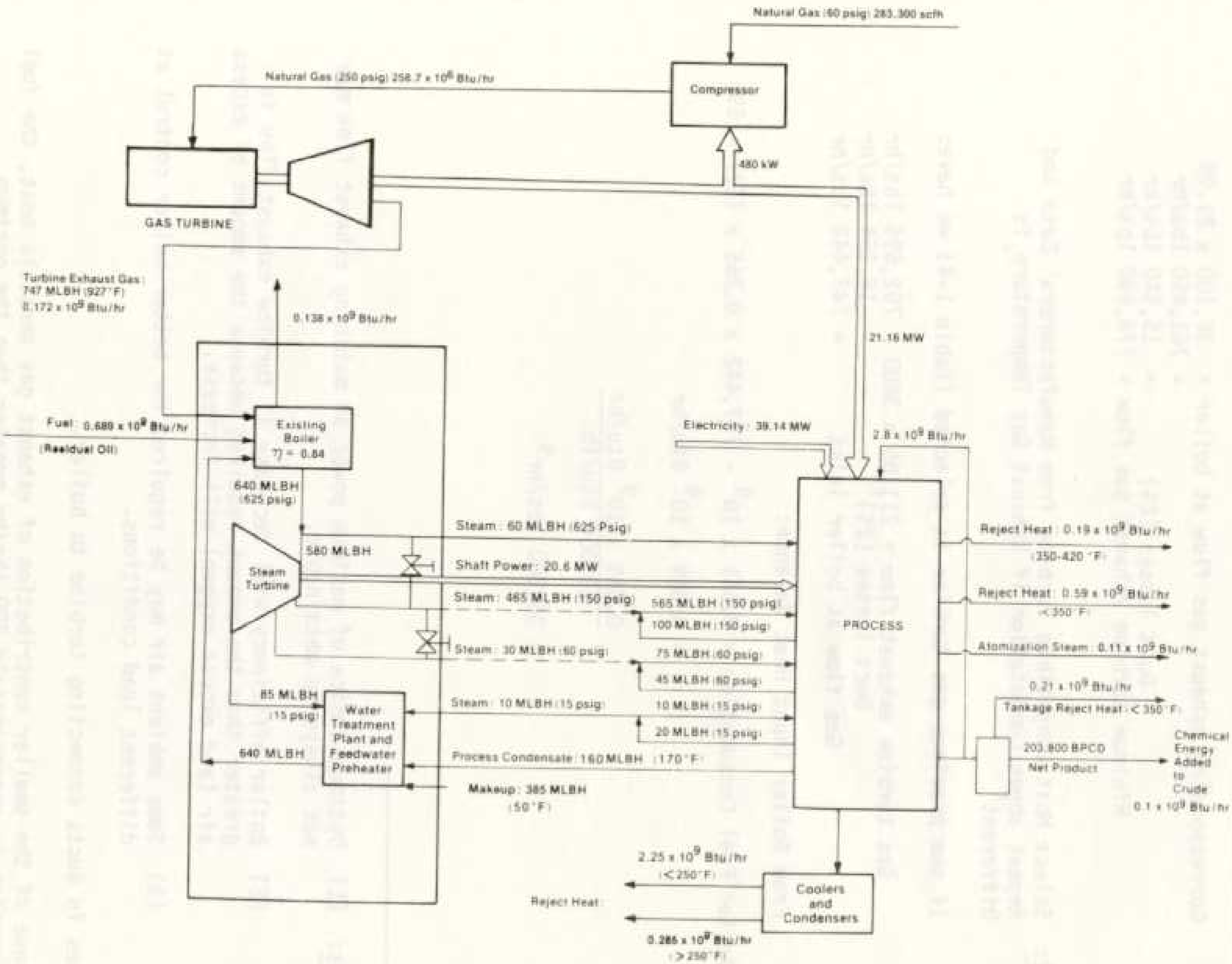

Figure 1-30. Cogeneration with Gas Turbine Topping Existing Boilers -- Heat Balance Schematic, Example II, Cogeneration Option A
(1 MLBH = 1,000 lb/hr)

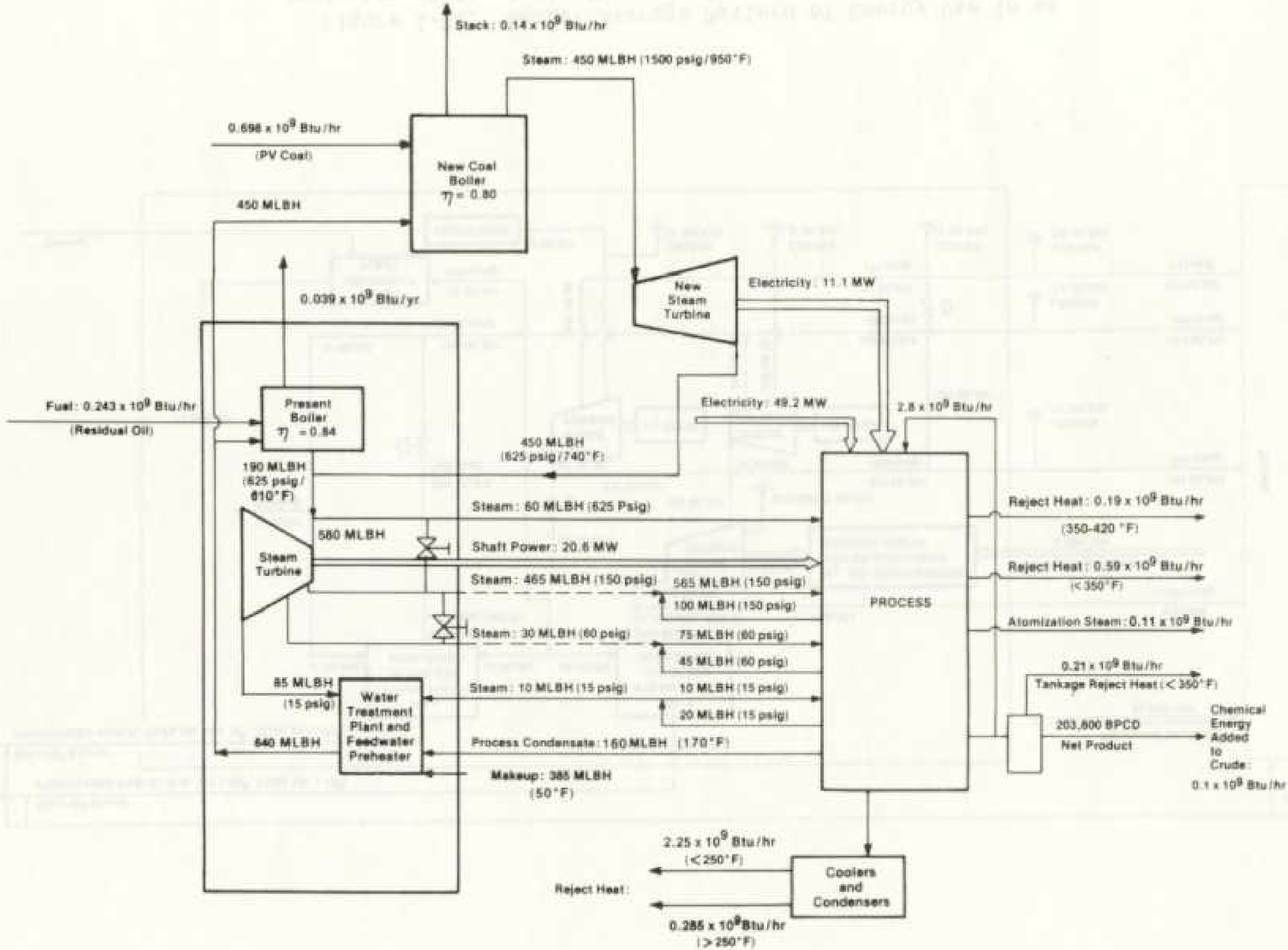

Figure 1-31. Cogeneration Option for Large Refinery using a Coal-Fired Boiler and Back-Pressure Steam Turbines - Example II, Cogeneration Option B
(1 MLBH = 1,000 lb/hr; BPCD = barrels per calendar day)

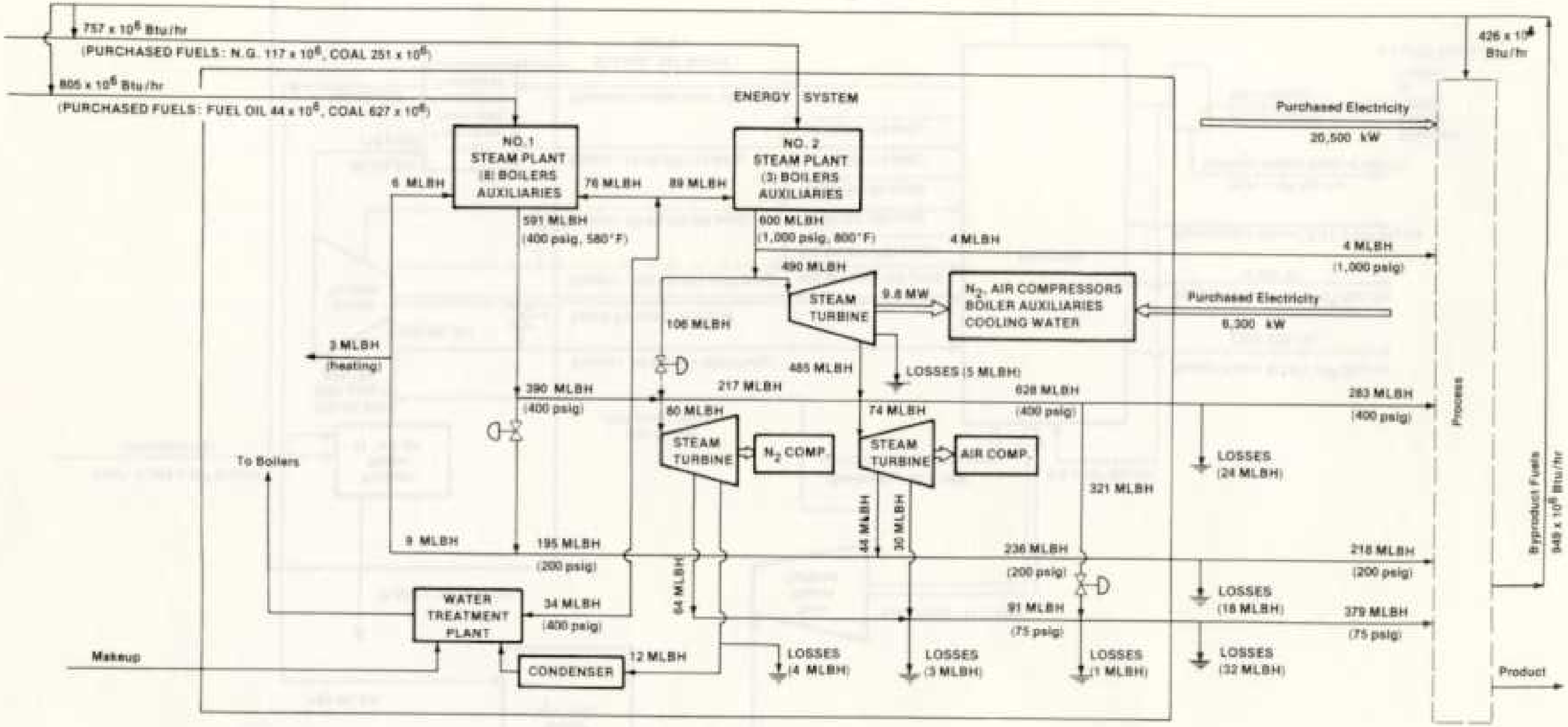

Figure 1-32. Annual Average Pattern of Energy Use in an Agricultural Chemicals Plant in Institute, W.Va. - Example III (1 MLBH = 1,000 lb/hr)

200 psig and 75 psig from a header pressure of 400 psig. Taking seasonal variations into account, the average base load flows to the two process pressures are 125,000 lbs/hr and 200,000 lbs/hr as shown in Figure 1-33.

1.7.4 Example IV - A Fine Chemicals Plant: Diesel Cogeneration Option

The electrical load for a fine chemicals plant is 20,000 to 23,000 kW. Approximately 900 kW of mechanical drive power is currently cogenerated in the plant, using noncondensing steam turbines. Steam is produced in residual oil-fired boilers at 650 psig and 200 psig. Process steam is used at 200 psig and 85 psig. With the existing boiler and process steam pressures, the plant is operating close to its maximum steam turbine generating capacity and must purchase power from the local utility. The total average steam output of the plant's boilers is 430,000 lb/hr with about 65 percent generated at 650 psig/700°F and 35 percent at 200 psig. The 650 psig/700°F steam is utilized in existing back-pressure turbines that supply mechanical power to the plant, reducing the steam to 200 psig, 85 psig, and 25 psig. The 200 psig and 85 psig steam flows are utilized for process purposes and 25 psig primarily for deaeration. A slow-speed diesel cogeneration system is designed to integrate with the existing plant and is currently under construction. The system heat balance and performance summary are given in Figure 1-34 and Table 1-9.

Waste heat from the diesel is recovered from the exhaust gases, air cooler, and engine water-cooling circuits. To maximize overall thermal efficiency, the temperature levels of the waste heat are matched to the plant's thermal requirements. The exhaust gas, at a temperature of 550°F is used to raise 225 psig saturated steam in a supplementary-fired boiler. The boiler is supplementary fired because of the plant's requirement for 150 to 160,000 lb/hr 200 psig steam, much greater than the amount that can be obtained without additional fuel input. Additional oxygen for combustion beyond that already contained in the flue gases is not necessary, a result of the large amount of excess air used in the diesel engine cycle.

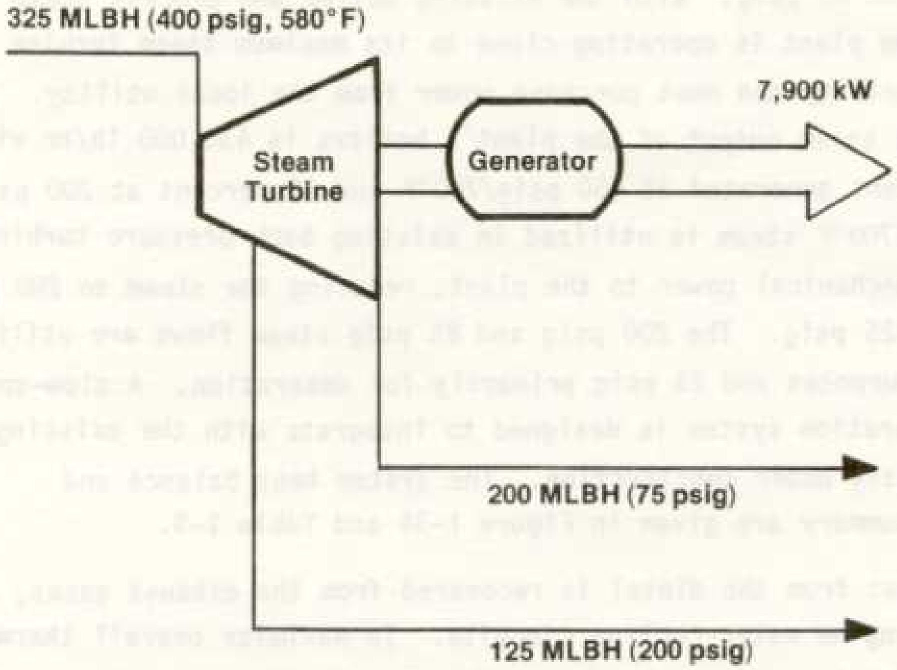

Figure 1-33. Extraction/Noncondensing Steam Turbine Cogeneration for Agricultural Chemicals Plant - Example III (1 MLBH = 1,000 lb/hr)

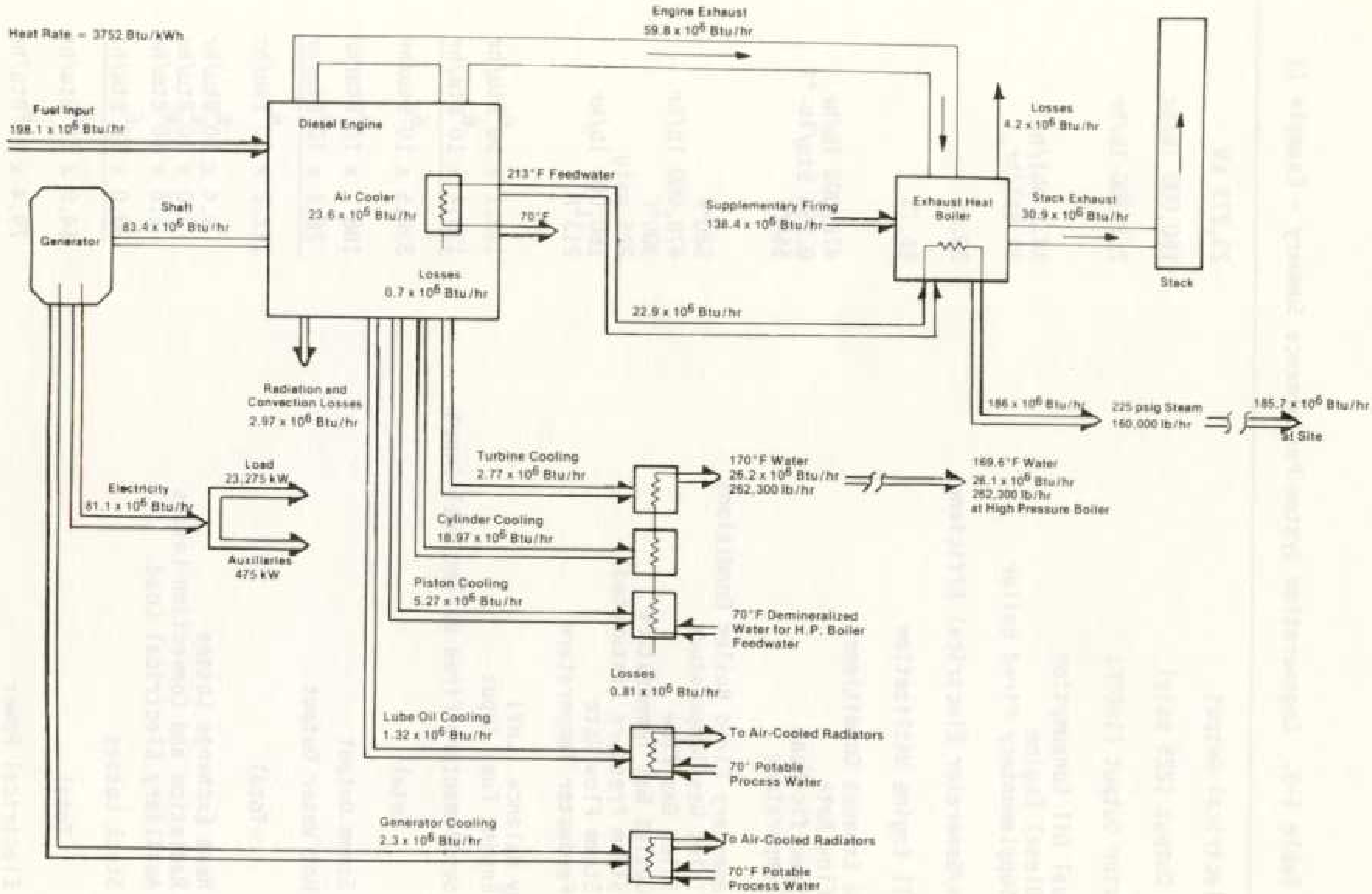

Figure 1-34. Energy Balance for a Slow-Speed Diesel Cogeneration System - Example IV

Table 1-9. Cogeneration System Performance Summary - Example IV

Net Electrical Output	23,275 kW
Steam Output (225 psig)	160,000 lb/hr
Hot Water Output (180°F)	262,300 lb/hr
Residual Oil Consumption	
Diesel Engine	34.5 bbl/hr
Supplementary Fired Boiler	24 bbl/hr
Engine/Generator Electrical Efficiency	39.3%
Overall Engine Utilization	86.7%
Engine Exhaust Conditions	
Flow Rate	478,000 lb/hr
Specific Heat	0.254 Btu/lb-°F
Temperature	550°F
Supplementary Fired Boiler Conditions	
Inlet Gas Temperature	550°F
Inlet Gas Flow	478,000 lb/hr
Outlet Gas Temperature	300°F
Steam Pressure (saturated)	225 psig
Steam Flow Rate	160,000 lb/hr
Feedwater Temperature	213°F
Energy Balance (LHV)	
Engine Fuel Input	198.1 x 10^6Btu/hr
Supplementary Fired Boiler Fuel Input	138.4 x 10^6Btu/hr
Total	336.5 x 10^6Btu/hr
Steam Output	186 x 10^6Btu/hr
Hot Water Output	26.2 x 10^6Btu/hr
Total	212.2 x 10^6Btu/hr
Heat Exchange Losses	9.4 x 10^6Btu/hr
Radiation and Convection Losses	3.0 x 10^6Btu/hr
Auxiliary Electrical Load	1.6 x 10^6Btu/hr
Stack Losses	30.0 x 10^6Btu/hr
Total	44.0 x 10^6Btu/hr
Electrical Power	79.4 x 10^6Btu/hr
Total Useful Energy Output	291.6 x 10^6Btu/hr

The air temperatures entering and leaving the diesel air cooler are about 300°F and 100°F, respectively. This waste heat source is used to preheat the feedwater for the supplementary fired boiler in an air-to-water heat exchanger from a nominal 70°F to about 200°F prior to entering the deaerator for oxygen scavenging. Of the sources of waste heat from the engine cooling circuits, the turbocharger is at the highest temperature, about 180°F, and the lube oil is at the lowest, about 120°F. To maximize the amount of waste heat recovered from the engine cooling system and to maintain a reasonable pinch point in the heat exchanger, only the turbocharger, jacket, and cylinder water circuits are used. From these sources, about 260,000 lb/hr of 70°F water is heated to 170°F for use as feedwater in existing high-pressure 650 psig boilers. Additional low-temperature heat, as well as the low-temperature heat from the lube oil cooler, is dissipated in a rooftop cooler.

As shown in Figure 1-34 the continuous electrical output rating of the system is approximately 23,300 kW (net). Residual fuel oil consumption is approximately 34.5 bbl/hr (198.3 x 10^6 Btu/hr) in the diesel engine and 24 bbl/hr (138.4 x 10^6 Btu/hr) for supplementary firing. The energy content of the steam and hot water produced is 212 x 10^6 Btu/hr. If this process heat were produced in a separate boiler, an additional 43 bbl/hr of fuel oil would have to be consumed. The total energy utilization is 86 percent of the energy input. In terms of electrical generation, the effective cogeneration heat rate is 3752 Btu (LHV)/kWh.

1.8 SUMMARY OF ILLUSTRATIVE SYSTEM EXAMPLES

Cost summaries of the 4 illustrative examples given in this chapter are shown in Tables 1-10 through 1-13. The diesel and gas turbine systems do not include emission control equipment. The pulverized coal-fired boiler for the textile plant (Example I-C) includes wet limestone scrubbers. The pulverized coal-fired boiler for the refinery (Example II-A) includes electrostatic precipitators and wet limestone scrubbers because of the high ash content of the coal expected to be used in that facility. The ash that falls to the bottom of the boiler is removed by a water sluicing system in both boilers. The remaining ash passes out with the flue gas where it is removed by the precipitators and/or scrubbers. Both boilers include feedwater economizers and regenerative air preheaters and are equipped with steam soot-blowers. The ash is removed from the boiler hoppers and from the precipitators and/or scrubbers by a water sluicing system. The ash is then separated from the water and removed off-site.

The economically relevant parameters for all the illustrative examples are summarized in Table 1-14. The capital costs were based on vendor quotations and past experience with similar projects. All costs are in 1981 dollars and include provisions for escalation during construction. The projects are assumed to be initiated in mid-1981. Fuel consumptions were obtained from figures supplied by the Company. These parameters are used to determine the returns on investment and energy savings in Section 2.4.

Table 1-10. Example I - Cost Summary (Cogeneration Options for Textile Fiber Plant)

	I-A (Gas Turbine Combined Cycle)	I-B (Gas Turbine with Heat Recovery)	I-C (Coal-Fired Steam)
CAPITAL COSTS			
Installed Equipment	$16,080,000	$30,400,000	$28,700,000
Engineering and Construction Supervision	990,000	1,870,000	1,800,000
General and Administrative Costs	1,130,000	2,160,000	2,000,000
Total	$18,200,000	$34,430,000	$32,500,000
Total Cost per Kilowatt ($/kW)	802	820	2,920
ANNUAL OPERATION AND MAINTENANCE COSTS			
Insurance	$ 35,000	$ 70,000	$ 70,000
Maintenance and Expendables	430,000	740,000	700,000
Burdened Labor (10 x $30,000)	300,000	300,000	300,000
Total	$765,000	$1,110,000	$1,070,000

Table 1-11. Example II - Cost Summary (Cogeneration Options for Refinery)

	II-A (Coal Boiler/ Steam Turbine)	II-B (Gas Turbine)
CAPITAL COSTS		
Installed Equipment	$27,800,000	$13,500,000
Engineering & Construction Supervision	1,800,000	1,000,000
General and Administrative Costs	2,000,000	1,000,000
Total	$31,600,00	15,500,000
Total Cost per Kilowatt ($/kW)	2,850	733
ANNUAL OPERATING & MAINTENANCE COSTS		
Insurance	$ 65,000	$ 35,000
Maintenance & Expendables	650,000	400,000
Burdened Labor (10 x $30,000)	300,000	300,000
Total	$1,015,000	$735,000

Table 1-12. Example III - Cost Summary (Extraction/Noncondensing Steam Turbine for Chemical Plant)

CAPITAL COSTS	
Installed Equipment	$1,650,000
Engineering and Construction Supervision	1,400,000
General and Administrative Costs	250,000
Total	$3,300,000
Total Cost per Kilowatt ($/kW)	418
ANNUAL OPERATING AND MAINTENANCE COSTS	
Insurance	$ 5,000
Maintenance and Expendables	40,000
Burdened Labor[a]	0
Total	$ 45,000

[a]This plant has sufficient power and maintenance personnel to service the steam turbine.

Table 1-13. Example IV - Diesel Cogeneration Cost Summary[a]

CAPITAL COSTS	
Installed Equipment	$19,017,000
Engineering and Construction Supervision	1,171,000
General and Administrative Costs	1,332,000
Total	$21,520,000
Total Cost per Kilowatt ($/kW)	925
ANNUAL OPERATION AND MAINTENANCE COSTS	
Property Tax and Insurance (2% Capital Cost)	$439,400
Maintenance and Expendables (1 1/2% Capital Cost)	322,800
Burdened Labor (8 x $25,000/yr)	200,000
Total	$962,200

[a]Thermo Electron estimates, March 1981.

Table 1-14. Summary of Cogeneration System Parameters for Illustrative Examples

Plant	Example Number	Cogeneration System Type	Annual Hours of Operation	Net Power Output (kW)	Purchased Power Requirement (kW)	Fuel Type	Fuel Consumption (10^9 Btu/hr)	Incremental Fuel Consumption (10^9 Btu/hr)	Capital Cost (Thousands 1981$)	Annual O&M Costs (Thousands 1981$)	Construction Time (Years)
	Base Case	---	8,000	---	58,000	Resid	0.605	---	---	---	---
Textile	IA	Gas Turbine/ Combined Cycle	8,000	22,682	35,318	Resid N.G.	0.483 0.259	-0.122 (Resid) 0.259 (N.G.)	18,200	765	1.5
Fiber	IB	Gas Turbine/ Heat Recovery	8,000	42,005	15,995	Resid N.G.	0.122 0.669	-0.483 (Resid) 0.669 (N.G.)	34,430	1,110	1.5
Plant	IC	Coal-Fired Steam Turbine	8,000	11,130	46,870	Resid Coal	0 0.696	-0.605 (Resid) 0.696 (Coal)	32,500	1,070	2.5
	Base Case	---	8,000	---	60,300	Resid	0.861	---	---	---	---
Petroleum	IIA	Coal-Fired Steam Turbine	8,000	11,100	49,200	Resid Coal	0.243 0.698	-0.618 (Resid) 0.698 (Coal)	31,600	1,015	2.5
Refinery	IIB	Gas Turbine Topping Boiler	8,000	21,160	39,140	Resid N.G.	0.689 0.259	-0.172 (Resid) 0.259 (N.G.)	15,500	735	1.5
	Base Case	---	8,000	---	26,800	Coal	1.5620	---	---	---	---
Chemicals Plant	III	Extraction/ Noncondensing Steam Turbine	8,000	7,900	18,900	Coal	1.5976	0.0356 (Coal)	3,300	45	1.0
	Base Case	---	8,400	---	23,000	Resid	0.601	---	---	---	---
Fine Chemicals Plant	IV	Diesel/ Supplementary- Fired Recovery Boiler	8,400	23,275	-275	Resid	0.694	0.0931 (Resid)	21,520	962	1.25

2.0 INVESTMENT AND ENERGY SAVINGS ANALYSIS

This section presents the data and methodology necessary for performing investment and energy-savings analyses of alternative cogeneration systems. Section 2.1 presents recent industrial fuel and electricity price forecasts that can be used in cogeneration economic analyses. Section 2.2 contains electric utility fuel use profiles that are used to estimate the types and quantities of utility fuels that would be displaced by cogeneration in specific regions. Section 2.3 describes the methodology for performing an economic and energy savings analysis of cogeneration systems, and Section 2.4 illustrates the use of a computer model to analyze the seven examples of cogeneration options defined in Section 1.7. The computer model is available from the Argonne Code Center, Argonne National Laboratory, 9700 South Cass Avenue, Argonne, Illinois 60439.

2.1 INDUSTRIAL FUEL AND ELECTRICITY PRICE FORECASTS

2.1.1 Introduction

Forecasts of industrial fuel and electricity prices are essential for analyzing the economic feasibility of cogeneration systems. The price of fuel is the dominant factor in cogeneration operating costs, and the price of purchased electricity largely determines dollar savings. Forecasts of these prices are necessary for two reasons. First, cogeneration systems typically require from one to four years from the time of investment decision to initial operation. Second, such investments are best analyzed in terms of life cycle costs with explicit consideration of fuel and electricity prices and their escalation rates over the economic life of the system. Some cogeneration systems have been technical successes but economic failures because energy price forecasts were either not made, or the forecasts failed to account for a reasonable range of uncertainty.

Because several of the most important factors influencing the future prices of fuels and electricity are highly uncertain (e.g., general economic conditions and the price of imported oil), it is not judicious to rely solely on a single price forecast. This handbook, therefore, presents a set of three price forecasts which attempt to account for the range of uncertainty of the most important factors determining energy prices. The user of these forecasts has the option of choosing from any one forecast, or a combination or variation thereof, depending on which forecast he believes is most in accord with his own perception of future price changes. Confidence in an investment decision will be increased, however, if the investment is attractive under a wide range of energy price assumptions.

Although energy price forecasts have been developed for 13 regions of the nation, users should augment or replace these forecasts with their own price forecasts as necessary to reflect local conditions. Intraregional variations in fuel and electricity prices can be significant, further reinforcing the need to employ a projection for a smaller geographical area if such a projection is available to the user. In particular, a user may want to use his own local, current year, energy prices as a starting point and then apply the future year energy price escalation rates contained herein as a way of generating his own forecasts.

2.1.2 Scope

This section presents three forecasts of delivered industrial fuel and electricity prices: best case, low case, and high case. These forecasts differ primarily because of the assumed price of world oil and its effect on economic growth and inflation. Policy assumptions that affect fuel prices (e.g., Natural Gas Policy Act) are also incorporated into the three price scenarios. The fuel and electricity price forecasts were made using the Energy Core Model* of Data Resources, Inc. (DRI). The best case forecast, which DRI produced and presented in their summer 1981 Energy Review, is taken to be the best estimate of future energy prices. The low-case forecast, which was also produced by DRI, assumes that the current soft oil market continues in the future and that a lower rate of oil price increase occurs. The high-case forecast was produced by TRW using DRI's energy model. The low and high price forecasts assume low and high imported oil prices, respectively, relative to the best-case, and incorporate the direct effects of those prices on other energy commodities and economic growth in general.

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*U.S. Energy Model developed by Data Resources, Inc., Lexington, MA 02173, June 1981.

Prices have been forecast for the following industrial energy resources, by geographical region, for the years 1981-1995:

- Distillate oil
- Residual oil
- Natural gas
- Coal
- Electricity

The regions defined in the DRI model are shown in Table 2-1; Figure 2-1 presents a map showing the geographical demarcations.

Table 2-1. Regional Definitions for the DRI Energy Model

Region	Abbreviation	States
New England	NENG	MA, ME, VT, RI, NH, CT
Middle Atlantic	MATL	PA, NJ, NY
South Atlantic	SATL	DE, MD, DC, VA, WV, GA, FL, SC, NC
East North Central	ENC	OH, WI, IN, MI, IL
West North Central	WNC	KS, NE, ND, SD, MN, IA, MO
East South Central I	ESC1	KY, TN
East South Central II	WSC2	AL, MS
West South Central I	WSC1	OK
West South Central II	WSC2	TX, AR, LA
Mountain I	MTN1	NM
Mountain II	MTN2	MT, CO, WY, ID, UT
Mountain III	MTN3	NV, AZ
Pacific	PAC	CA, OR, WA, AK, HI

2.1.3 Forecast Assumptions

The key assumptions that were used to make the three fuel price forecasts--low case, best case, and high case--are presented in Table 2-2. These assumptions include the projected price of imported oil, the general economic conditions resulting from these oil prices, and the manner in which two of the Acts [the Natural Gas Policy Act (NGPA) and the Powerplant and Industrial Fuel Use Act (FUA)] contained in the National Energy Act of 1978 are assumed to be implemented at the time this forecast was prepared. Internal consistency between the macroeconomic assumptions (i.e., rate of economic growth and inflation) and the price (and quantity) of imported oil was maintained by either generating or using a macroeconomic scenario that included the imported oil costs to the economy.

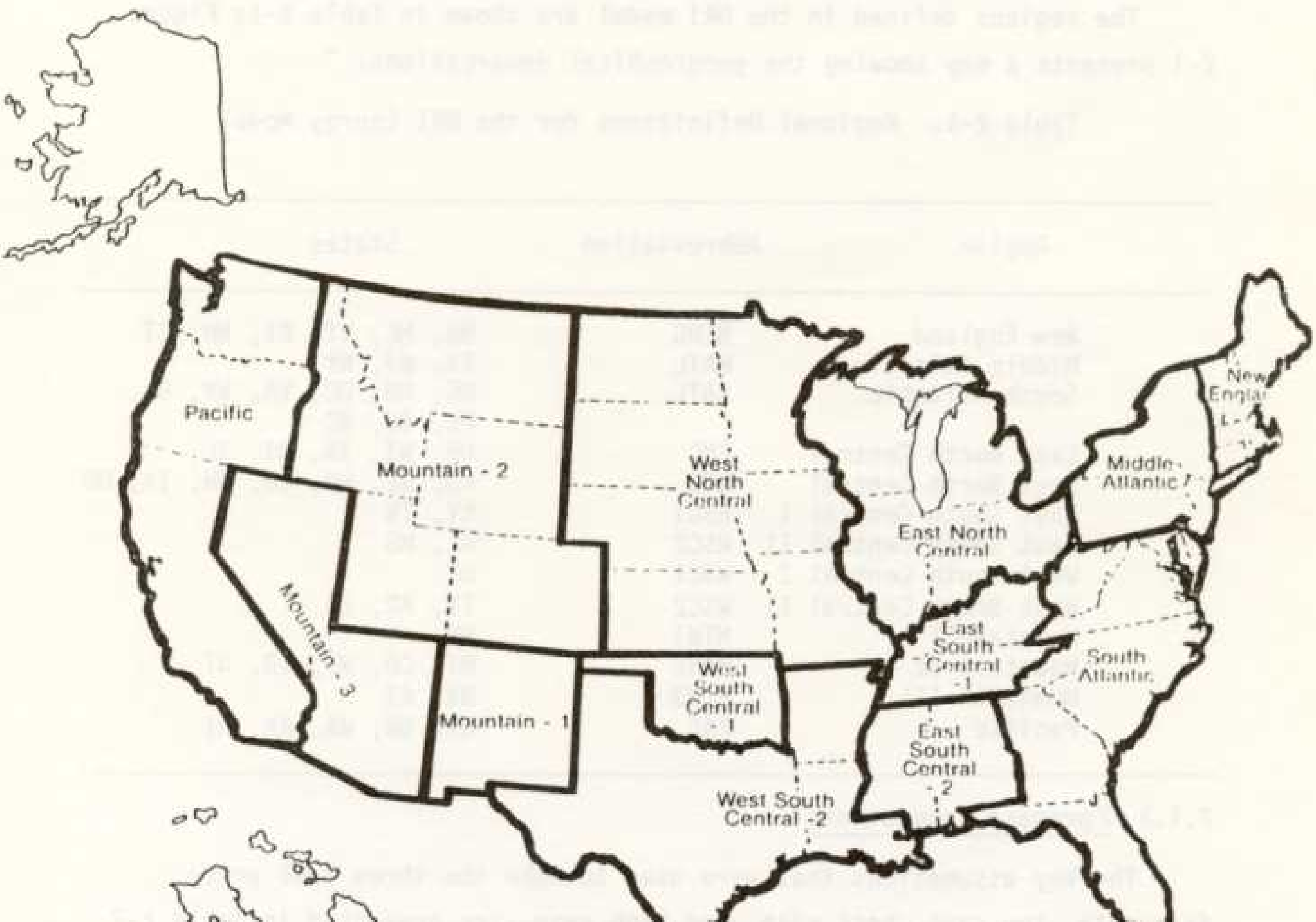

Figure 2-1. DRI Energy Demand Regions

Table 2-2. Fuel Price Forecasting Assumption

Key Assumption	Low Case	Best Case	High Case
Imported Oil Prices ($/bbl)			
1980	$ 34.00	$ 34.00	$ 34.00
1981	$ 37.00	$ 38.75	$ 38.75
1995 Current Dollar Price	$129.55	$172.41	$397.86
1995 Real Price (1980 dollars)	$ 44.26	$ 53.46	$ 84.69
Price Escalation Rates			
Nominal Escalation rate to 1995	8.7%	10.5%	18.1%
Real Escalation rate to 1995	1.8%	3.1%	6.5%
Macroeconomic[a]			
Real GNP Growth rate (1981 to 1995)	2.5%	2.5%	2.1%
Inflation Rate (1981 to 1995)	6.8%	7.4%	10.9%
Natural Gas Policy Act	Accelerated Phased Decontrol 1983-1986	Accelerated Phased Decontrol 1983-1986	Total Decontrol in 1982 except for "old interstate gas"
Powerplant and Industrial Fuel Use Act	System compliance not enforced	System compliance not enforced	System compliance not enforced

[a]Assumptions were based on the following DRI macroeconomic forecasts: Low Case — TRENDLONG 0681; Best Case — TRENDLONG 2006; High Case — PESSIMLONG 2006

Price of Oil

The price assumptions for imported oil in the three forecasts are shown in constant 1980 dollars in Figure 2-2. In the high and best case forecasts, imported oil prices are assumed to remain constant in real terms for 1982-83. This assumes that the current high level of Saudi production continues, maintaining an oversupply in the market that results in slow price rises. The low case assumes, based on the recent round of price cuts by foreign oil producers, that an average price of $37/bbl occurs in 1981 rather than the $38.75 price, which is assumed in both the best and high cases. In this case, the real price of imported oil actually declines through 1984, remains flat in 1985, and finally grows at a real annual rate of 3.2 to 4.0 percent above inflation. The overall average annual real price increase from 1981 to 1995 is 1.8 percent as compared with 3.1 percent in the best-case, and 6.5 percent in the high case.

The reason for the much higher rate of increase in the real price of oil (6.5 percent above inflation) in the high case was caused by the assumption that another oil supply disruption was probable in the next 15 years with a consequent sharp increase in the real price of oil. Because the timing and magnitude of this price increase as a result of a supply disruption is not predictable, it was represented by assuming a continual steep rise in real prices over the forecast interval. This high case is intended to provide a reasonable upper bound on the future prices of imported oil.

In all cases the price of domestically produced oil, in accordance with the advent of price decontrol, reaches parity with world oil prices by 1982 with slight price variations due to quality differentials.

Economic Growth

The rate of economic growth is a primary determinant of the growth in energy demand and, therefore, of energy prices. This rate of economic growth is also strongly affected by energy prices in general and oil import prices in particular. Therefore, when making long-term energy price forecasts it is important to use an economic growth forecast that is generally consistent with these forecasted energy prices.

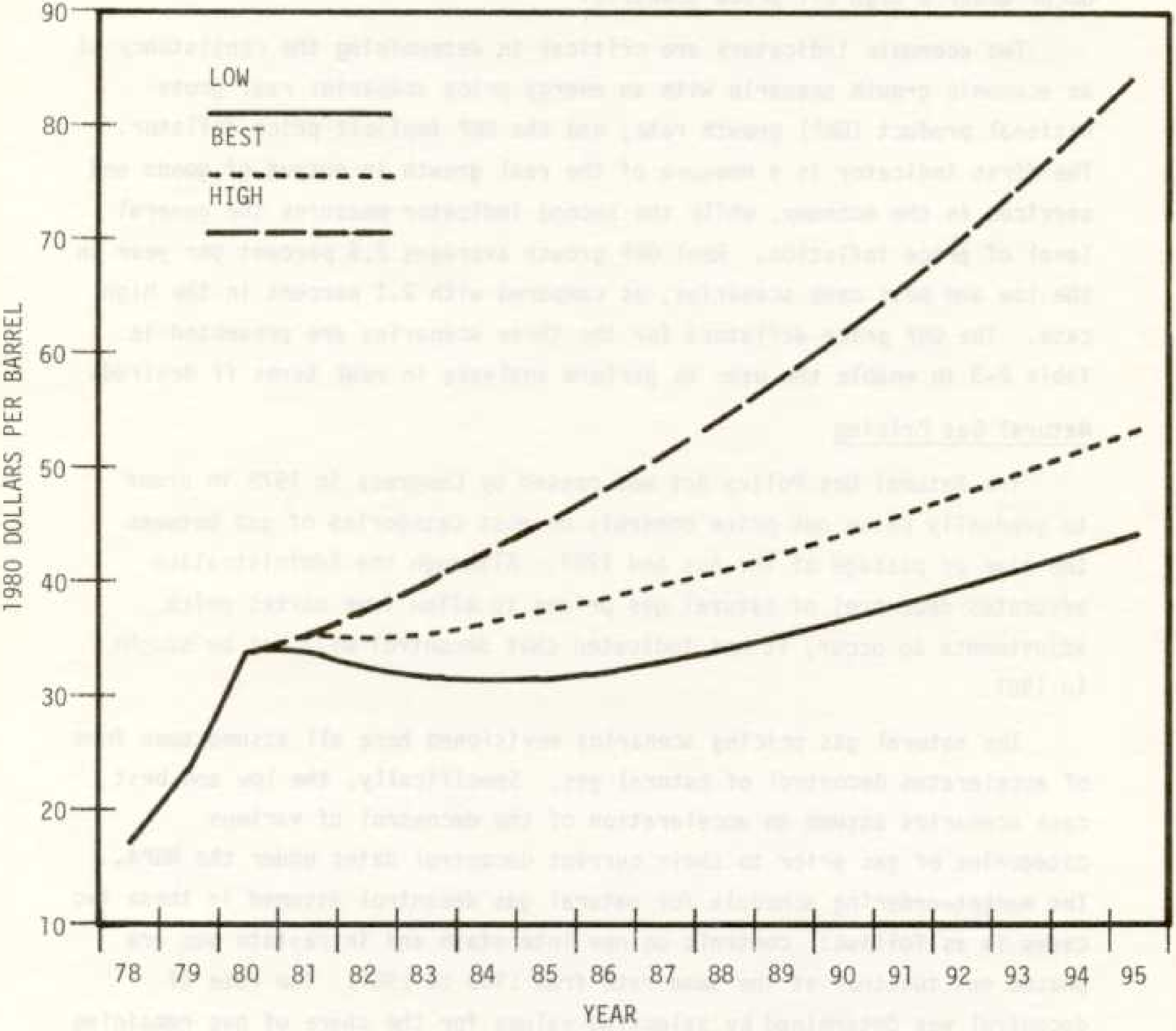

Figure 2-2. Price of Imported Crude Oil for Low, Best, and High Price Scenarios

For the low and best case scenarios DRI generated and used consistent macroeconomic projections to make their energy price forecasts. For the high price case, TRW chose a more pessimistic DRI long-term forecast, which is believed to be consistent with the lower economic growth rate that would occur under a high oil price scenario.

Two economic indicators are critical in determining the consistency of an economic growth scenario with an energy price scenario: real gross national product (GNP) growth rate, and the GNP implicit price deflator. The first indicator is a measure of the real growth in output of goods and services in the economy, while the second indicator measures the general level of price inflation. Real GNP growth averages 2.5 percent per year in the low and best case scenarios, as compared with 2.1 percent in the high case. The GNP price deflators for the three scenarios are presented in Table 2-3 to enable the user to perform analyses in real terms if desired.

Natural Gas Pricing

The Natural Gas Policy Act was passed by Congress in 1978 in order to gradually phase out price controls on most categories of gas between the time of passage of the Act and 1987. Although the Administration advocates decontrol of natural gas prices to allow free market price adjustments to occur, it has indicated that decontrol will not be sought in 1981.

The natural gas pricing scenarios envisioned here all assume some form of accelerated decontrol of natural gas. Specifically, the low and best case scenarios assume an acceleration of the decontrol of various categories of gas prior to their current decontrol dates under the NGPA. The market-ordering schedule for natural gas decontrol assumed in these two cases is as follows: controls on new interstate and intrastate gas are phased out together at the same rate from 1983 to 1987. The rate of decontrol was determined by selecting values for the share of gas remaining under controls that would smooth the price transition to complete

Table 2-3. Year-End GNP Price Deflator Index for the High, Best, and Low Case Scenarios (1980=1.00)

	1978	1979	1980	1981	1982	1983	1984	1985	1986
High	0.846	0.918	1.000	1.105	1.233	1.383	1.557	1.767	2.001
Best	0.846	0.918	1.000	1.100	1.210	1.318	1.429	1.560	1.703
Low	0.846	0.918	1.000	1.095	1.192	1.290	1.389	1.500	1.618
	1987	1988	1989	1990	1991	1992	1993	1994	1995
High	2.251	2.507	2.775	3.061	3.361	3.668	3.988	4.326	4.698
Best	1.852	2.006	2.165	2.334	2.507	2.680	2.853	3.034	3.225
Low	1.743	1.874	2.011	2.159	2.308	2.459	2.611	2.766	2.927

decontrol. In other words, it was assumed that the decontrol plan that is ultimately passed by Congress would be constructed so as to avoid price discontinuities.

In contrast to the low and best case scenarios, the high case scenario assumes decontrol in 1982 of all natural gas except for "old interstate" gas (volumes committed to the interstate market prior to passage of the NGPA). While it is unlikely that the Administration and Congress would agree to nearly immediate decontrol, this case is useful in providing an upper bound on near-term natural gas prices.

Fuel Use Act

The Administration prefers operation of the forces of a free market to regulatory provisions in the Powerplant and Industrial Fuel Use Act (FUA). These provisions (1) prohibit oil or gas use in new large boilers and powerplants unless exemptions are obtained and (2) permit the government to order conversion of existing plants. Reflecting the high likelihood of both Administration and Congressional proposals to streamline the exemption procedure and ultimately to dismantle most, if not all, of the Act's provisions, all three scenarios assume no enforcement of compliance with the FUA. This assumption also reflects enactment of the Omnibus Reconciliation Act of 1981, which repealed the utility "off-gas" provisions of the FUA. While this assumption can lead to a slightly higher demand projection of gas use by utilities and industry in the next few years, it is expected to have little effect on delivered industrial natural gas prices.

2.1.4 Fuel-Specific and Regional Forecast Assumptions

In addition to the major forecast assumptions that differ between the low, best, and high case forecasts, a large number of fuel-specific assumptions are generally common for all three price forecasts. These assumptions relate to the domestic crude oil supply as a function of world oil price; the supply and price of Alaskan, Canadian, and Mexican natural gas and imported LNG; regional coal supplies and coal production and transportation costs; and electric utility plant capacities, capital costs, and allowable rate of return on invested capital. [The interested user is referred to the DRI Energy Review (summer, 1981) for more detail.]

The DRI Energy Core Model forecasts delivered prices of residual and distillate oil on a national average basis only, and regional delivered coal prices are forecasted for electric utilities but not for industry. Consequently, TRW developed regional prices for residual and distillate oil based on the national average prices using Department of Commerce* state data for 1976-78. These data were used to calculate weighted average price rates for each of the 13 DRI regions. In general, regional residual and distillate oil price variations are small. In developing regional industrial coal prices, TRW assumed that the percentage difference between the regional coal prices delivered to utilities and the regional coal prices delivered to industry remains constant over time. The percentage difference between utility and industrial delivered coal prices was determined from Department of Commerce* data and applied to the utility regional coal prices as forecast by the DRI model. The higher prices of coal delivered to industry reflect purchases in smaller quantities, generally higher transportation costs and shorter term contracts or more spot market purchases, as compared with utilities. Regional and

*Annual Survey of Manufacturers, U.S. Department of Commerce, Fuels and Electric Energy Consumed, Table 3, Washington, D.C. (1976-1978).

intraregional differences in coal prices are significant and the user should obtain supplementary price quotations, if possible, reflecting local conditions and specific coal characteristics.

2.1.5 Forecast Results

For making energy price comparisons, the forecast of the national average fuel and electricity prices for the best, low, and high scenarios is presented graphically in Figures 2-3, 2-4, and 2-5. These graphs present the forecast estimates in current dollars per million Btu. When comparing the three scenarios, note that the underlying implicit price deflator for each scenario is different. Note also that the price scale for the graph in the high case scenario is compressed compared with that in the best and low cases.

An examination of the best case results presented graphically in Figure 2-3 reveals results as expected. Coal prices increase at a slower rate as a result of the elasticity of supply of coal compared with the other fuels. Natural gas prices under accelerated decontrol have the widest disparity when compared with residual oil in 1982, but gradually approach residual oil prices in 1988 to 1992. Distillate and residual fuel oil follow crude oil prices; however, distillate follows crude prices more closely than residual. This might be anticipated as residual fuel oil prices would be expected to be driven by demand and the price of substitutes (e.g., coal). In the later periods of the forecast, the difference in the prices of coal and residual oil becomes more pronounced. This could cause some depression of residual fuel oil prices.

The results of the forecasts in the low scenario presented in Figure 2-4 are similar to that of the best case, except that the general prices are lower. The prices for distillate and residual fuel are relatively flat through 1985 because crude oil prices remain flat. In real dollars, distillate and residual fuel prices decline over that period. Coal prices increase over the forecast period, but, as in the best case, at a lesser rate than the other fuels. Electricity prices increase at a rate less than that in the best case and, as expected, are affected by the price of coal and the price of capital (reflected through inflation-based interest rates).

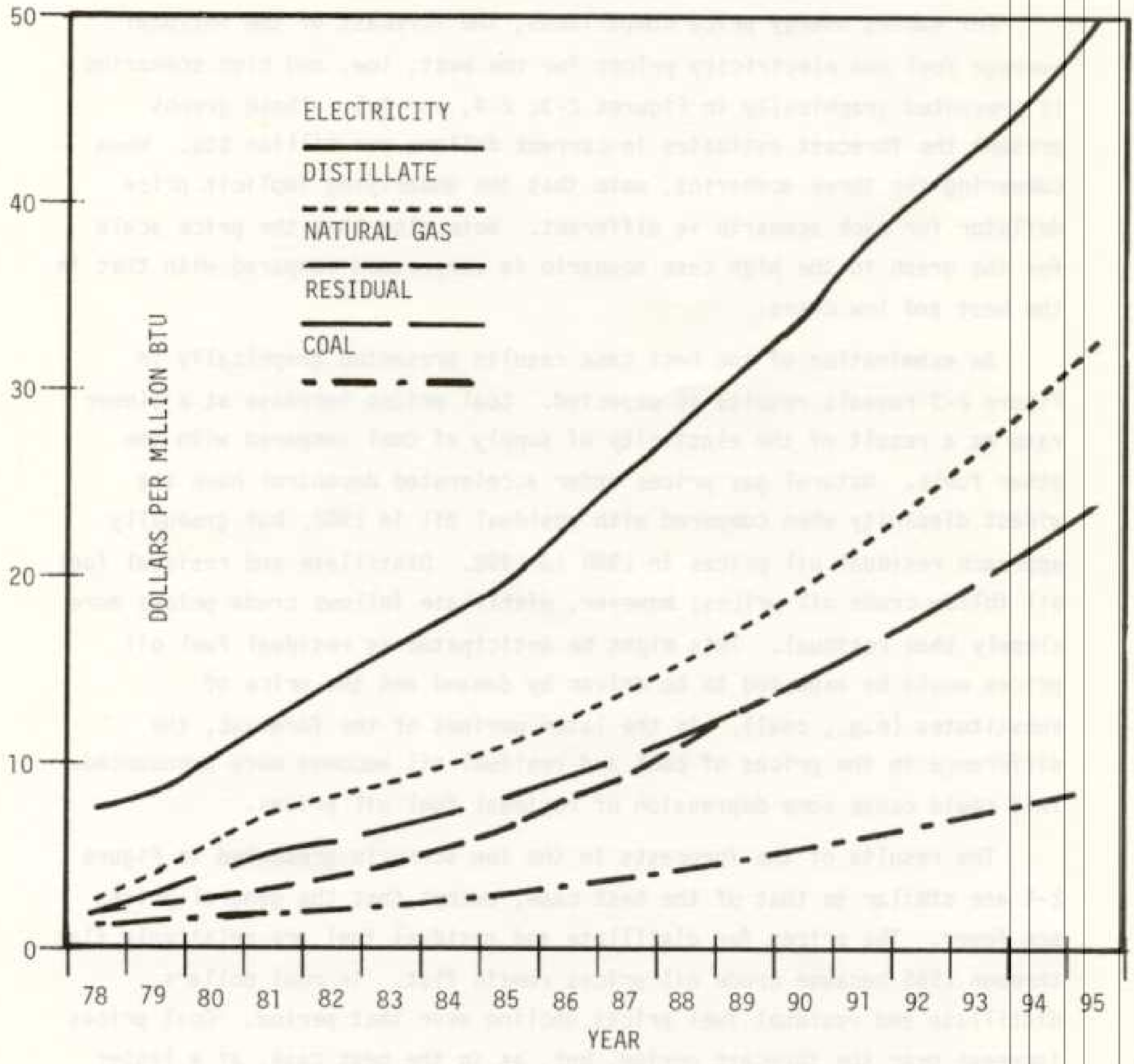

Figure 2-3. National Average Industrial Fuel and Electricity Price Forecast for the Best Case Scenario

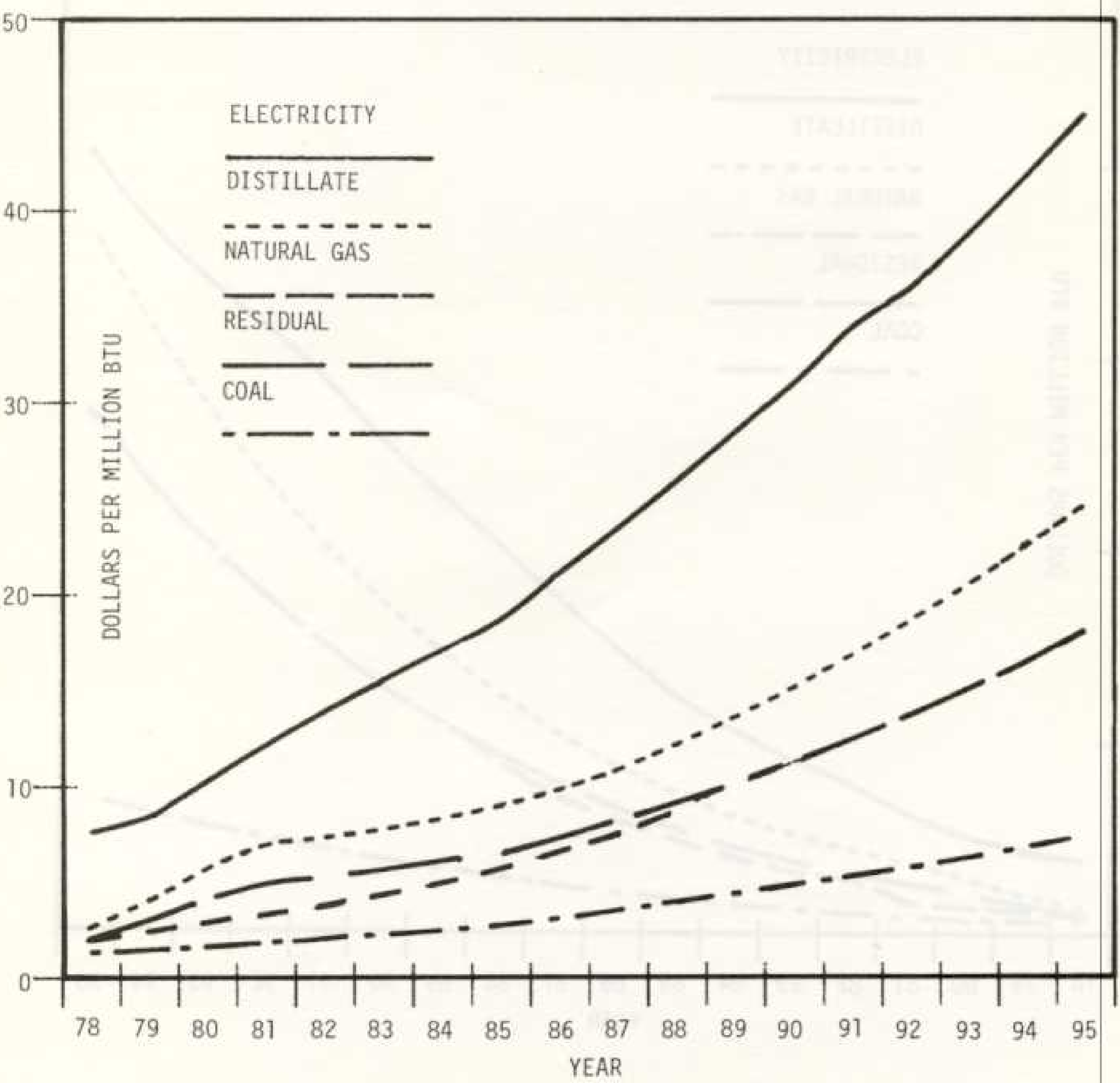

Figure 2-4. National Average Industrial Fuel and Electricity Price Forecast for Low Case Scenario

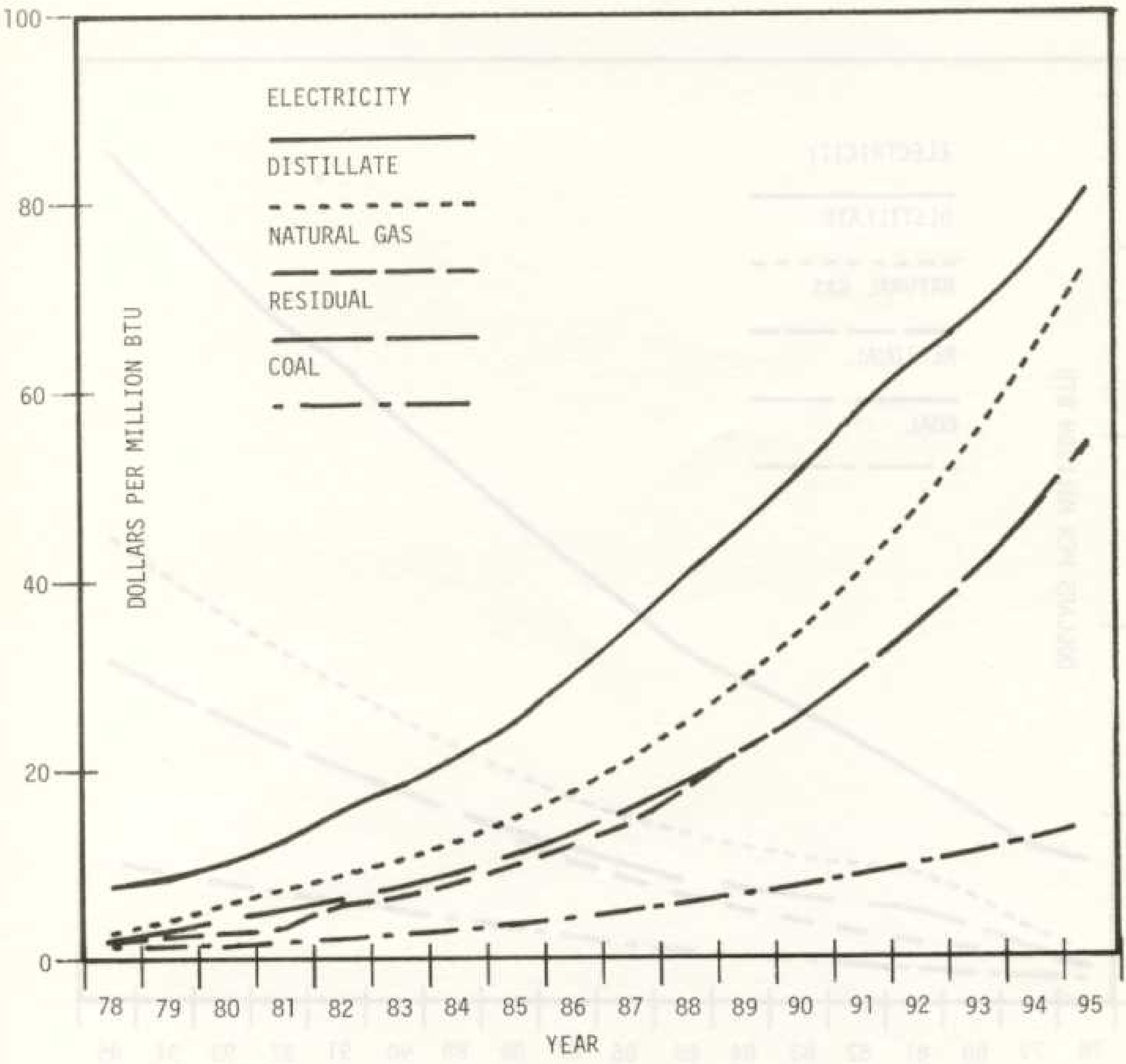

Figure 2-5. National Average Industrial Fuel and Electricity Price Forecast for High Case Scenario

Results of the high case forecast (Figure 2-5) exhibit slightly different trends from the two other scenarios. Residual and distillate fuel oil prices increase at a much higher rate than the other cases because of the high rate of increase in crude oil prices (6.5% real price increase). Natural gas is decontrolled in 1982 in this scenario, which is illustrated by the upward shift in natural gas in 1982. Due to the tremendous price increase in residual oil and the effect of old gas contracts, natural gas does not reach absolute parity with residual fuel until 1989. Coal prices, as in the other scenarios, increase at a rate less than that of the other fuels. Note that on a Btu basis, distillate fuel prices begin to approach parity with the price of electricity in 1995. This phenomenon reflects the increased use of coal and nuclear fuels in the generation of electricity and the trend away from petroleum and natural gas, all of which act to bring the prices of electricity and distillate closer together.

Appendix B contains complete tabulations of annual regional values for the forecast prices of electricity, distillate, residual fuel, natural gas and coal for the best, low, and high case scenarios. For visualizing price trends, Appendix B also presents graphically the best case forecasts of fuel and electricity prices for each region.

The user of this handbook can employ these values as they are presented or, alternatively, use them as reference values to be modified by more recent judgment or by other mathematical-statistical methods.

2.2 UTILITY FUELS DISPLACED

Industrial cogeneration saves electric utility primary fuels by displacing central station electricity that the industrial plant would otherwise purchase. Whether cogenerated electricity is consumed in-plant or exported to the utility grid, load demands on the utility will be reduced and therefore consumption of fuels at central powerplants will be reduced.

While the types and quantities of fuels displaced at the utility are not directly used in computations of cogeneration economic performance, utility fuel savings are of interest to the potential cogenerator for several reasons. A cogeneration system that displaces premium fuels (oil and natural gas) within a utility or power pool is more likely to be economically successful than a system that displaces lower-cost primary energy sources (coal, nuclear, and hydro). This is because utility fuels use is reflected in utility rates, and utility rates directly affect the economics of cogeneration. In addition, for a potential cogenerator seeking an exemption from the FUA prohibitions on oil or natural gas firing on the grounds that the cogeneration system would realize a net savings of oil or gas, estimating utility fuel displacement by type of fuel is essential (see Chapter 4).

2.2.1 Utility-Cogenerator Interactions

When a cogeneration system begins operation at an industrial plant, the utility serving the plant will experience a reduction in power demands. Under the principles of economic dispatch, the normal utility response to a small reduction in load would be to reduce the output of the currently operating plant that has the highest operating cost.* Because fuel is the dominant component of operating costs, the plant that is providing the marginal, incremental unit of power would normally be the one using the most expensive fuel of those currently operating and would be the least

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*Certain units on a system must sometimes operate even if their running costs exceed the running costs of units not operating at full capacity because of technical constraints (e.g. area protection, reserve to cover forced outages, and maintenance scheduling).

efficient plant of those operating with that fuel. This implies that plants using oil and gas would be the first units backed down when a cogenerating facility came on line.

Many utilities operate together in power pools to improve the economy and reliability of supply to customers. The power pools are further aggregated into the 9 National Electric Reliability Council (NERC) Regions (Figure 2-6). Thus, if a utility is located in a region that predominantly uses oil and gas, it would be expected that oil and gas would be displaced by cogeneration. The following section illustrates techniques to estimate utility overall fuel savings and oil/gas savings.

2.2.2 Computation of Utility Fuel Displacement

Utility fuel displacement through cogeneration can be computed from the following equation:

$$\begin{array}{c}\text{Total Fuel}\\ \text{Displaced}\\ \text{at Utility}\\ \text{(Btu/year)}\end{array} = \left(\begin{array}{l}\text{Power Produced}\\ \text{by Cogenerator}\\ \text{(kW)}\end{array}\right) \times \left(\begin{array}{l}\text{No. of Hours of}\\ \text{Operation per}\\ \text{year of Cogen-}\\ \text{eration System}\end{array}\right) \times \left(\begin{array}{l}\text{System*}\\ \text{Heat Rate}\\ \text{of Utility}\\ \text{(Btu/kWh)}\end{array}\right) \times 1.07 \qquad (1)$$

In Equation (1) the power produced by the cogenerator and the number of hours of operation of the system depend on the cogeneration system design and operating characteristics. Heat rates of utilities are available from a number of sources, such as Electrical World, Directory of Electric Utilities, 1979-1980, and are reported annually on a plant-by-plant basis to the Federal Energy Regulatory Commission (FERC), on FERC Form 1. An example of this data is shown in Table 2-4. In the absence of local or regional data, a nominal value of 10,500 Btu/kWh can be used.

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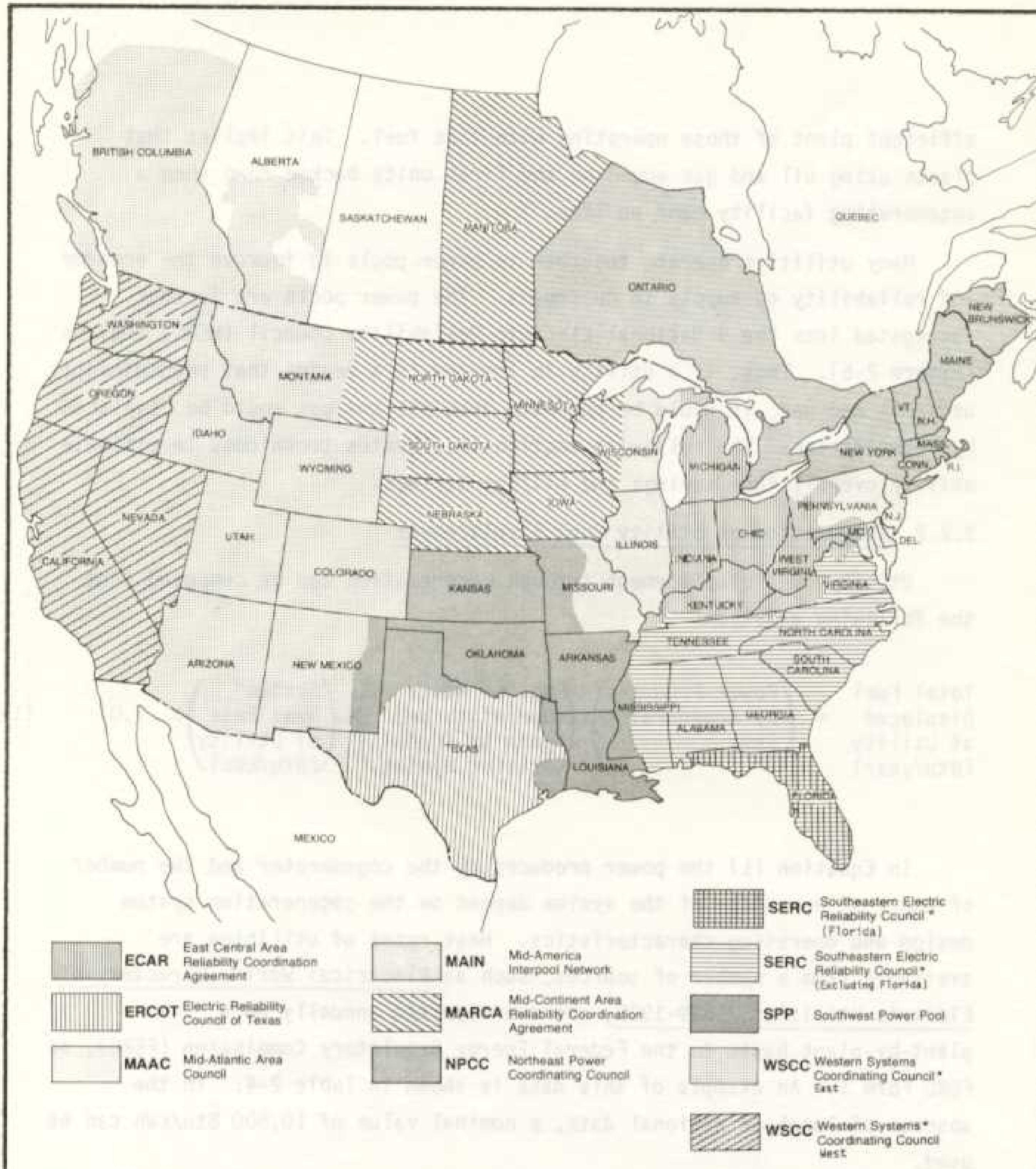
*Use of an overall system weighted average heat rate will give a conservative estimate of utility fuel displaced because actual fuel displacement will usually take place at one of the utility's least efficient plants.



*This split was necessary owing to large differences in utility fuel mix between Florida and the rest of SERC, as also between the eastern and western portions of WSCC.

Source: National Electric Reliability Councils, 1979 Annual Report.

Figure 2-6. National Electric Reliability Council (NERC) Regions

Table 2-4. Data Available from FERC: Portion of FERC Form I[a]

Annual report of .... Year ended December 31, 19....

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants for the purpose of this schedule are steam plants of 25,000 kw or more of installed capacity (name plate rating). Include gas-turbine and internal combustion plants of 10,000 kw and more in this schedule. Include nuclear plants.
2. If any plant is leased or operated as a joint facility, indicate such facts by the use of asterisks and footnotes.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. If gas is used and purchased on a therm basis, the B.t.u. content of the gas should be given and the quantity of fuel burned converted to M cu. ft.
6. Quantities of fuel burned (line 38) and average cost per unit of fuel burned (line 41) should be consistent with charges to expense accounts 501 and 547 (line 42) as shown on line 21.
7. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
8. The items under cost of plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production expenses do not include Purchased Power, System Control and Load Dis-

Line No.	Item (a)	Plant Name (b)	Plant Name (c)
1	Kind of plant (steam, internal combustion, gas turbine or nuclear)		
2	Type of plant construction (conventional, outdoor boiler, full outdoor, etc.)		
3	Year originally constructed		
4	Year last unit was installed		
5	Total installed capacity (maximum generator name plate ratings in kw.)		
6	Net peak demand on plant—kw. (60 minutes)		
7	Plant hours connected to load		
8	Net continuous plant capability, kilowatts:		
9	(a) When not limited by condenser water		
10	(b) When limited by condenser water		
11	Average number of employees		
12	Net generation, exclusive of plant use		
13	Cost of plant:		
14	Land and land rights	$	$
15	Structures and improvements		
16	Equipment costs		
17	Total cost	$	$
18	Cost per kw. of installed capacity (Line 5)		
19	Production expenses:		
20	Operation supervision and engineering	$	$
21	Fuel		
22	Coolants and water (nuclear plants only)		
23	Steam expenses		
24	Steam from other sources		
25	Steam transferred (Cr.)		
26	Electric expenses		
27	Misc. steam (or nuclear) power expenses		
28	Rents		
29	Maintenance supervision and engineering		
30	Maintenance of structures		
31	Maintenance of boiler (or reactor) plant		
32	Maintenance of electric plant		
33	Maint. of misc. steam (or nuclear) plant		
34	Total production expenses	$	$
35	Expenses per net kwh. (Mills—2 places)		
36	Fuel: Kind (coal, gas, oil or nuclear)		
37	Unit: (Coal—tons of 2,000 lb.) (Oil—barrels of 42 gals.) (Gas—M cu. ft.) (Nuclear, indicate)		
38	Quantity (units) of fuel burned		
39	Average heat content of fuel burned (B.t.u. per lb. of coal, per gal. of oil, or per cu. ft. of gas) *		
40	Average cost of fuel per unit, as delivered f.o.b. plant during year		
41	Average cost of fuel per unit burned		
42	Avg. cost of fuel burned per million B.t.u.		
43	Avg. cost of fuel burned per kwh. net gen.		
44	Average B.t.u. per kwh. net generation		

* Nuclear, indicate unit.

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[a]Plant heat rates are reported on Line 44

The factor of 1.07 in Equation (1) accounts for transmission and distribution (T&D) inefficiencies (estimated at 7 percent), which reflect losses to the utility if the cogenerator were not in operation. This assumes that the industrial plant is situated within a utility load center, at some distance from the serving utility (Figure 2-7). The T&D losses occur only when the industrial plant is accepting power from the utility. Negligible T&D losses are assumed when the industrial plant cogenerates and consumes power internally or exports power for consumption by other customers within the load center. If the industrial plant is not situated within a load center, this transmission credit cannot be taken for that portion of exported power because the cogenerator and utility are then assumed to accept the same T&D losses.

Equation (1) gives the total fuel displaced at the utility. To estimate oil and gas displacement, a separate analysis is required. Equation (1) can again be used, but in this instance the heat rate for the utility must reflect the average annual incremental (or marginal) oil and gas displacement heat rate. For cogeneration systems that cause constant reductions in demand to electric utilities, an estimate of this heat rate can be taken from Table 2-5, which shows average annual values for incremental oil and gas displacement for the nine NERC regions. These values are forecasts for 1989 and reflect a considerable transition from oil and gas toward coal and nuclear power on the part of utilities. The derivation of these values is described in Appendix C. If the cogeneration system has a variable power output, then estimates of utility oil and gas displacement heat rate by time of day and season of year from Appendix C should be used instead of the annual average value.

However, use of the values of incremental oil and gas displacement in Table 2-5 [developed by the Economic Regulatory Administration (ERA)] may not give an accurate measure of the oil and gas displaced at the utility. This is because potential oil and gas displacement can vary (1) within a single region, (2) between power pools, and (3) between utilities. For example, the TVA power pool, within the SERC region, is heavily dependent on coal and nuclear power for its generation. Negligible displacement of oil and gas is expected for this power pool, although SERC overall shows some potential for oil and gas displacement. Conversely, Louisiana Power

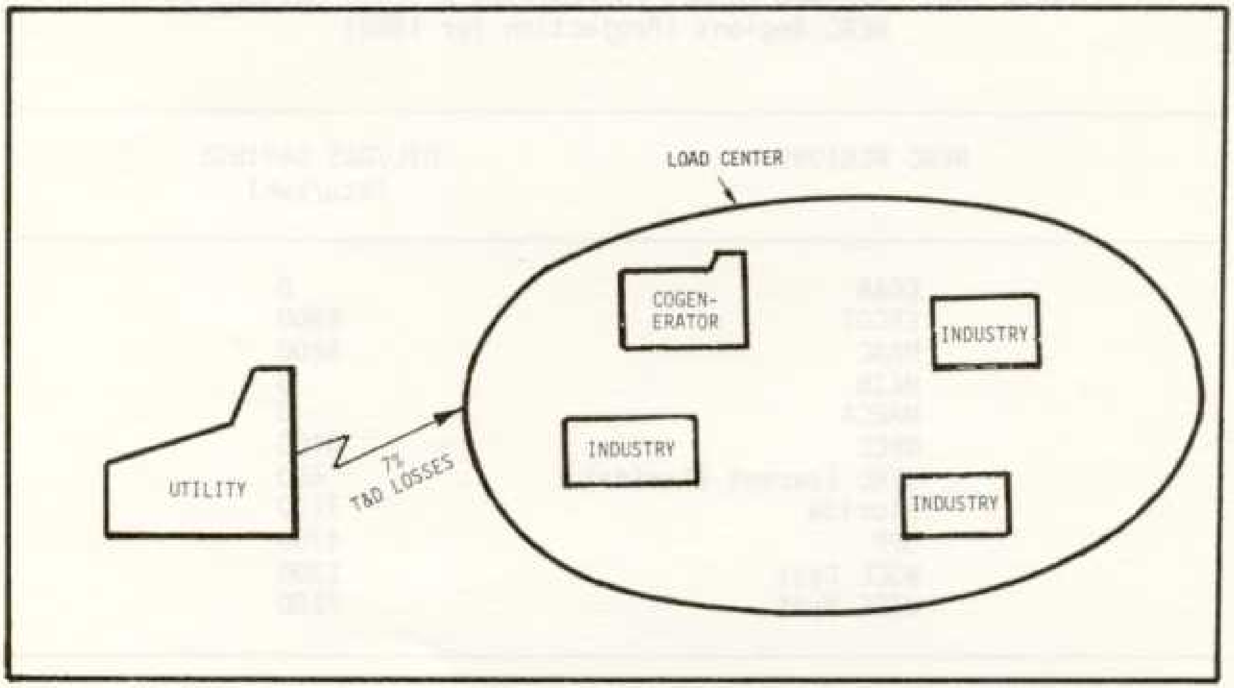

Figure 2-7. Example of Cogenerator as Part of Load Center, in Relation to Utility

and Light, within the Middle South Utilities power pool of the SPP region, is currently entirely dependent on natural gas and oil, and most other utilities in this pool are also heavily dependent on these fuels. Although SPP shows only a moderate incremental oil/gas savings of 4700 Btu/kWh, savings in this particular utility and power pool would be considerably greater.

Calculation of oil/gas displacement is further complicated by interpool transfers. Utilities can purchase power from pools other than their own. For example, in 1980, the American Electric Power (AEP) power

Table 2-5. Average Annual Incremental Oil/Gas Savings by NERC Regions (Projection for 1989)

NERC REGIONS	OIL/GAS SAVINGS (Btu/kWh)
ECAR	0
ERCOT	8900
MAAC	5200
MAIN	0
MARCA	0
NPCC	6400
SERC (except Florida)	600
Florida	7100
SPP	4700
WSCC East	1300
WSCC West	7100

Source: Regional Electric Utility Fuel Use Tables for Scarce Fuel Displacement Determination, Draft Chapter for "Electric Power Supply and Demand for the Contiguous United States 1980-1989. U.S. Department of Energy Economic Regulatory Administration. Division of Power Supply and Reliability. DOE/RG-0036 (Rev. 1). Revised and Reprinted July 1980.

Note: The SERC and WSCC regions have each been divided into two subregions to account for the differences in fuel mixes being used in power generation among utilities located in these regions.

pool* was able to sell low-priced coal-based power to utilities outside of AEP, replacing the higher-priced oil-based power at these utilities. On the other hand, the Middle South Utilities power pool[+] notes that in 1980, 22 percent of their power was purchased from outside utilities. These examples show that potential cogeneraters must consider the characteristics of their particular power pools and utilities in determining the expected oil and gas savings for their specific cases. The complete FERC Form 1 for each utility provides a significant portion of the information and data required for this determination.

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*1980 AEP Annual Report

[+]1980 Middle South Utilities Annual Report

2.3 CALCULATION OF SYSTEM ECONOMIC PERFORMANCE AND ENERGY SAVINGS

Thus far, a range of cogeneration system options has been defined, and typical industrial applications have been illustrated. Basic information necessary to calculate system economic performance and energy savings has been discussed, including technical and cost data, fuel and electricity prices, and utility fuels displacement. This information provides the basis for a preliminary investment analysis of proposed cogeneration systems and alternatives.

2.3.1 Methodologies for Estimating Economic and Energy Savings Performance

The objective of the preliminary financial analysis is to determine whether the installation of a cogeneration system is justified economically for the potential cogenerator. Specifically, the analysis should identify those systems which meet or exceed the after-tax ROI required by an industrial firm. Based on the economic results, an optimum system can be selected.

The long-term nature of the investment and the interaction of fuel costs, electricity prices, capital costs, and other cost factors require a sound economic approach to identify and discount each set of annual cash flows. A general overview of an appropriate analysis methodology is shown in Figure 2-8. While the financial analysis can be performed using any methodology consistent with user practices, this section illustrates the use of a discounted cash flow (DCF)/internal rate of return (IRR) model.*

The DCF model identifies and discounts all relevant cash flows and computes the IRR of the proposed cogeneration system. Each element of the methodology is described in the following section. Although the discussion focuses on this particular DCF model, it is written as generally as possible, noting that this analysis can be performed by other models or even by hand calculations.

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*The model, which is basically a general purpose DCF model uses methods similar to those used by industrial firms in evaluating energy conservation investment alternatives. The model is available from the Argonne Code Center, Argonne National Laboratory, 9700 Cass Avenue, Argonne, Illinois 60439.

METHODOLOGY OVERVIEW

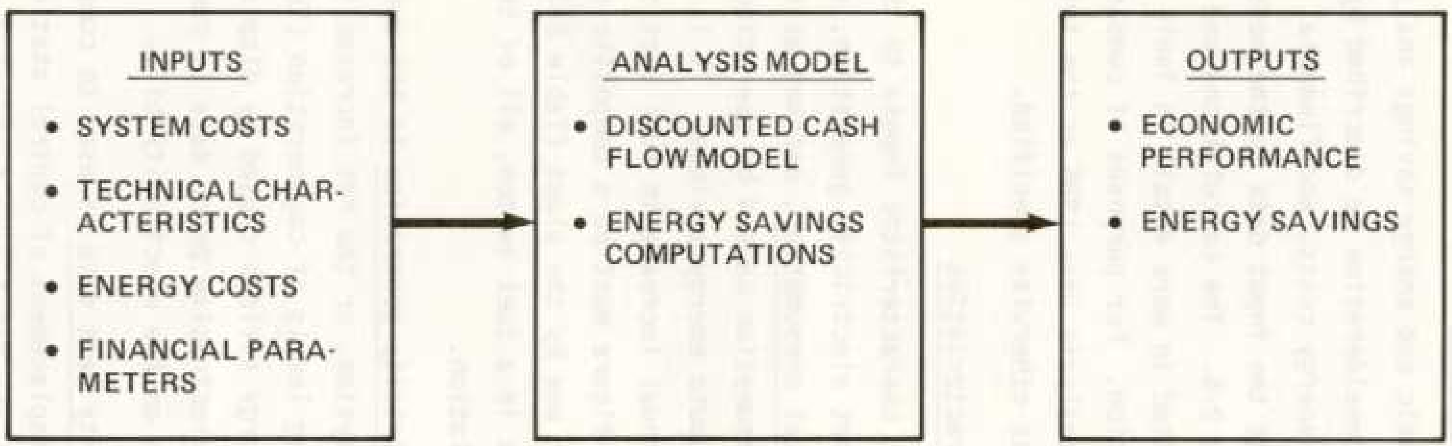

Figure 2-8. Methodology Overview

2.3.1.1 Model Inputs

The economic and energy savings analysis first requires that the system under consideration be described by its technical characteristics, system costs, energy costs, and financial parameters. These characteristics constitute the input data to the model, as shown in a sample model run sheet in Table 2-6. The calculations and sources of information for these inputs are listed in more detail in Table 2-7 and are described in the following section. For purposes of comparing alternative cogeneration systems, the analysis uses 1985 as the initial year of operation for all systems, unless otherwise specified.

Technical Characteristics

Technical characteristic inputs to the model are incremental fuel consumption, net electricity generation, and the utility heat rate. Incremental fuel consumption, defined as the annual increase in industrial plant fuel consumption caused by operation of the new cogeneration system, is used to compute energy savings. It is also used with fuel price data to compute the annual increase in fuel cost to the industry for operating the system. This figure must be a composite of all fuel types previously used or planned for use by the plant (Table 2-7, entry 1). If the cogeneration system results in a fuel switch, all of the fuels replaced must be included in this calculation.

Net electricity generation is the annual kWh output of the cogeneration system, or the net increase in electric output for plants having existing levels of cogeneration (Table 2-7, entry 2). It is used to compute energy savings caused by displacement of utility electricity and is used with electricity price data to compute the industrial plant's annual savings on the electricity bill.

The utility heat rate is used to compute primary energy savings that result from displacement of central station power. The utility heat rates should include the T&D losses (estimated at 7 percent) that the utility must accept in serving an industrial customer (Table 2-7, entry 3). For that portion of the cogenerated electricity that is sold back to the utility, no T&D adjustment is made if it is assumed that the electricity is consumed outside the load center containing the industrial plant.

TABLE 2-6. Sample Model Run Sheet

RUN SHEET

RUN NO. ____________________

____

____

PARAMETERS	VARIABLE NAME	VALUE	OR DEFAULT
TECHNICAL CHARACTERISTICS:			
INCREMENTAL FUEL CONSUMPTION, (10^6 Btu/yr)	FUELCN	________	0.0
NET ELECTRICITY GENERATION (10^6 kWh/yr)	NETGEN	________	0.0
UTILITY HEAT RATE (INCLUDING T&D LOSSES) (Btu/kWh)	HTRATE	________	0.0
SYSTEM COSTS:			
CAPITAL INVESTMENT ($ In 1985)	CAPINV	________	0.0
CONSTRUCTION COST DISTRIBUTION -			
PERIODS OF CONSTRUCTION	NPER	________	0
PERIODS PER YEAR	IPER	________	0
CONSTRUCTION FRACTION PER PERIOD	FCONST	________	0.0
OPERATIONS & MAINTENANCE COST, INITIAL ($/yr In 1985)	OANDM	________	0.0
O&M COST ESCALATION RATE (Fraction)	OMRATE	________	0.0
SALVAGE VALUE ($)	SALVAG	________	0.0
ENERGY COSTS:			
INCREMENTAL FUEL COST, INITIAL ($/yr In 1985)	FUEL	________	0.0
INCREMENTAL FUEL COST ESCALATION RATE (Fraction)	FRATE	________	0.0
ELECTRICITY COST, INITIAL ($/yr In 1985)	ELECT	________	0.0
ELECTRICITY COST ESCALATION RATE (Fraction)	ERATE	________	0.0

TABLE 2-6. SAMPLE MODEL RUN SHEET (CONTINUED)

RUN SHEET (Continued)

FINANCIAL PARAMETERS:

DISCOUNT RATE (Fraction)	DISRTE	____________	0.2
DOWNPAYMENT (Fraction)	DWNPMT	____________	1.0
LOAN LIFE (Up To 40 Years)	LIFLON	____________	12
SYSTEM LIFE (Up To 40 Years)	LIFSYS	____________	12
INTEREST RATE (Fraction)	IRATE	____________	0.2
INCOME TAX RATE (Fraction)	TXRATE	____________	0.48
TAX CREDIT RATE (Fraction)	TAXCRD	____________	0.20
INSURANCE RATE (Fraction)	INS	____________	0.005
INSURANCE ESCALATION RATE (Fraction)	INSRAT	____________	0.0
PROPERTY TAX RATE (Fraction)	PCTAX	____________	0.025
PROPERTY TAX ESCALATION RATE (Fraction)	PCRATE	____________	0.0
DEPRECIATION LIFE (Up To 40 Years)	DEPYRS	____________	5
DEPRECIATION MODE = 1 - SUM-OF-YEARS-DIGITS = 2 - STRAIGHT LINE = 3 - DOUBLE DECLINING BALANCE = 4 - 150% DECLINING BALANCE CHANGING TO STRAIGHT LINE = 5 - 175% DECLINING BALANCE CHANGING TO SUM-OF-YEARS-DIGITS = 6 - 200% DECLINING BALANCE CHANGING TO SUM-OF-YEARS-DIGITS	MODDEP	____________	1

Table 2-7. Calculations and Sources for Model Inputs

TECHNICAL CHARACTERISTICS

	PARAMETER	CALCULATIONS	VALUE OR DATA SOURCE	COMMENTS
1.	Incremental Fuel Consumption (10^6 Btu/yr)	Total Incremental Fuel Consumption = (new-original) oil consumption + (new-original) NG consumption + (new-original) coal consumption + Etc.....	System Designer, Energy use profile	• "Original" refers to existing consumption at the plant • If fuel-switch has occurred, <u>all</u> replaced fuels should be included in the calculation
2.	Net Electricity Generation (kWh)	Net Electricity Generation $= \left(\begin{array}{c}\text{Continuous Net} \\ \text{Rated Capacity} \\ \text{x Hrs of} \\ \text{Operation}\end{array}\right)_{\text{New}} - \left(\begin{array}{c}\text{Continuous Net} \\ \text{Rated Capacity} \\ \text{x Hrs of} \\ \text{Operation}\end{array}\right)_{\text{Original}}$	System Designer	• "Original" refers to existing electricity production at the plant
3.	Utility Heat Rate (Btu/kWh)	Utility Heat Rate = System Heat Rate x 1.07	Local Utility Data	• Local utility data corrected for T&D losses of 7 percent

Table 2-7. Calculations and Sources for Model Inputs (Continued)

PARAMETER	CALCULATIONS	VALUE OR DATA SOURCE	COMMENTS
SYSTEM COSTS			
4. Capital Investment ($ in 1985)	$(\text{Capital Investment})_{1985\$} = (\text{Vendor Estimates})_{\text{Quote Year\$}} \times \left(\frac{(\text{GNP Deflator})_{\text{startup year}}}{(\text{GNP Deflator})_{\text{Quote year}}}\right)$	• Vendor quotes • GNP deflators in Section 2.1, Table 2-3	• Year & period of vendor quote should be noted • Vendor quote includes escalation during construction • Escalation carried through to quarter in which construction begins
5. Construction Cost Distribution - Periods of Construction - Periods Per Year - Construction Fraction per Period	 ----- ----- 1/Periods of Construction	• System Designer	• Model uses these inputs to compute burdened investment
6. Incremental Operations & Maintenance Cost, Initial ($/yr in 1985)	$(\text{O\&M Costs})_{1985\$} = \left(\begin{array}{c}\text{Incremental} \\ \text{Annual O\&M} \\ \text{Costs}\end{array}\right)_{\text{Quote Year \$}} \times \left(\frac{(\text{GNP Deflator})_{\text{startup year}}}{(\text{GNP Deflator})_{\text{Quote year}}}\right)$	• System Designer • GNP Deflators in Section 2.1, Table 2-3	-----

Table 2-7. Calculations and Sources for Model Inputs (Continued)

SYSTEM COSTS (Continued)

	PARAMETER	CALCULATIONS	VALUE OR DATA SOURCE	COMMENTS
7.	O&M Escalation Rate (Fraction)	-----	• Economic Projections, Sect. 2.1	• Can be assumed equal to inflation rate
8.	Salvage Value ($)	-----	0	• Alternatively, can be estimated by user

Table 2-7. Calculations and Sources for Model Inputs (Continued)

ENERGY COSTS

	PARAMETER	CALCULATIONS	VALUE OR DATA SOURCE	COMMENTS
9.	Incremental Fuel Cost, Initial (in 1985)	$(\text{Incremental Fuel Cost})_{1985}$ $= (\text{Incr. Oil Consumption})_{1985}$ $\times (\underline{\quad}\ \$/10^6 \text{ Btu Oil})_{1985}$ $+ (\text{Incr. NG Consumption})_{1985}$ $\times (\underline{\quad}\ \$/10^6 \text{ Btu NG})_{1985}$ + etc.....	• Previous Consumption Calculations Entry 1 • Fuel Price Projections for Geographic Region, Sect. 2.1; Initialize with Local Data	-----
10.	Fuel Cost Escalation Rate (Fraction)	Fuel Cost Escalation Rate $= \left(\dfrac{\text{1995 Incr. Fuel Cost}}{\text{1985 Incr. Fuel Cost}}\right)^{1/10} - 1$	• 1985 Incr. Fuel Costs from Entry 9. • 1995 Incr. Fuel Costs using Equation in Entry 9, with 1985 Incr. consumption and 1995 fuel price projections, Sect. 2.1	• If incr fuel costs change sign between 1985 and 1995, escalation rate can not be used. Discrete values must be entered.

Table 2-7. Calculations and Sources for Model Inputs (Continued)

ENERGY COSTS (Continued)

PARAMETER	CALCULATIONS	VALUE OR DATA SOURCE	COMMENTS
11. Electricity Cost ($/yr in 1985)	Electricity Cost $= \left(\begin{array}{c}\text{Elect Gen for}\\ \text{On-Site Use,}\\ \text{kWh/yr}\end{array}\right) \times \left(\begin{array}{c}\text{Cost of}\\ \text{Purchased}\\ \text{Elec, \$/kWh}\end{array}\right)$ $= \left(\begin{array}{c}\text{Elect Sold}\\ \text{to Utility,}\\ \text{kWh/yr}\end{array}\right) \times \left(\begin{array}{c}\text{Price of Elect}\\ \text{Sold}\end{array}\right)$ + Capacity Payments	• kWh/yr of Cogeneration • System Designer • Elect Price Projections for Region, Sect. 2.1; Initialize with Local Data • Price of Elect sold + Capacity Payments from State PUC's (Section 4.0)	-----
12. Electricity Cost Escalation Rate (Fraction)	Elect Cost Escalation Rate $= \left(\frac{\text{\$/kWh in 1995}}{\text{\$/kWh in 1985}}\right)^{1/10} - 1$	• Regional Elect Price Projections, Sect. 2.1	-----

Table 2-7. Calculations and Sources for Model Inputs (Continued)

FINANCIAL PARAMETERS

PARAMETER	CALCULATIONS	VALUE OR DATA SOURCE	COMMENTS
13. Discount Rate (Fraction)	-----	• Industry Requirements	• IRR hurdle rate
14. Down Payment (Fraction)	-----	• Industry Input	• 1.00 for 100 Percent Equity Financing
15. Loan Life (Years)	-----	• Industry Input	-----
16. System Life (Years)	-----	• Industry Input	-----
17. Interest Rate (Fraction)	-----	• Industry Input	-----
18. Income Tax Rate (Fraction)	-----	• 48 percent	• By law; includes state & local tax
19. Tax Credit Rate (Fraction)	-----	• Energy Tax Act of 1978; Crude Oil Windfall Profits Tax Act of 1980.	See Sect. 4.0 for more details • 10% oil/gas-fired units • 20% coal-fired units • 0% oil/gas-fired boilers

Table 2-7. Calculations and Sources for Model Inputs (Continued)

FINANCIAL PARAMETERS (Continued)

PARAMETER	CALCULATIONS	VALUE OR DATA SOURCE	COMMENTS
20. Insurance Rate (Fraction)	-----	• 2.5 Percent	-----
21. Insurance Escalation Rate (Fraction)	-----	• Inflation Rate, Economic Projections, Sect. 2.1	-----
22. Property Tax Rate (Fraction)	-----	• From Local Data	• Set by Law
23. Property Tax Escalation Rate (Fraction)	-----	• Local Data	-----
24. Depreciation Life (Years)	-----	• 5 Years	• Per the Accelerated Cost Recovery System (ACRS) of the Economic Recovery Tax Act of 1981.

Table 2-7. Calculations and Sources for Model Inputs (Continued)

FINANCIAL PARAMETERS (Continued)

PARAMETER	CALCULATIONS	VALUE OR DATA SOURCE	COMMENTS
25. Depreciation Mode	-----	• SYD, SL, DDB, 150% DB/SL, 175% DB/SYD, or 200% DB/SYD	• SYD - Sum of Years Digits SL - Straight Line DDB - Double Declining Balance 150% DB/SL - 150 percent declining balance (DB) changing to SL per the Economic Recovery Tax Act (ERTA) of 1981 for systems placed in service between 1981 and 1984. • 175% DB/SYD - 175 percent DB changing to SYD per the ERTA for property placed in service in 1985. • 200% DB/SYD - 200 percent DB changing to SYD per the ERTA for property placed in service after 1985. • Accelerated depreciation denied to oil/gas fired boilers (Sect. 4.0).

System Costs

The initial capital investment is the primary system cost (Table 2-7, entry 4). This is the capital cost above that for comparable alternatives. For example, if the potential cogenerator is currently using conventional steam boilers, the alternative is simply to continue operating the existing boilers, and the initial capital investment is the total cost of the retrofit cogeneration system. If the user is contemplating replacement of oil- or gas-fired conventional boilers with new boilers burning coal or alternative fuels (with no new cogeneration), then the latter may be considered the alternative, and only incremental cogeneration capital costs above and beyond this alternative cost need be considered. Where the installation of cogeneration is accompanied by a switch from oil or gas to coal or alternative fuels, the economics of fuel switching alone should be considered in addition to the fuel switching/cogeneration combination. The third possibility is in the case of a new facility, with no existing system, and the cogeneration option is again compared on an incremental basis with the cost of new steam boilers. Estimates of system capital investment are obtained from vendor quotes and should include escalation during construction. These estimates should be further escalated to dollar figures for the year and period in which construction begins. GNP deflators (Section 2.1, Table 2-3) may be used for this escalation.

The construction cost distribution spreads the capital investment over the construction period to account for interest or burden during construction. Although construction times for industrial cogeneration systems are short compared with utility plants, the effect of the construction burden is by no means negligible. Applying this burden accounts for the fact that if a company were not making an investment in the cogeneration project, the funds would still be invested internally where they would be expected to earn a return at the IRR rate. This distribution consists of (1) the number of periods of construction per year, (2) the total number of construction periods, and (3) a construction fraction per period (Table 2-7, entry 5). The model will accept any distribution of construction costs as percentages per quarter for up to 20 quarters (5 years) although a uniform distribution of construction cash outlays has been assumed.

Other system cost inputs include the incremental O&M costs for the start-up year and an O&M escalation rate (Table 2-7, entries 6 and 7). These are used by the model to generate O&M costs for subsequent years of operation. Initial incremental O&M costs are provided by the system designer and are based on the additional expenditures necessary for O&M of the cogeneration system. Typically, these are given in dollars per year and are escalated to a dollar figure for the first year of operation. The O&M escalation rate can be assumed equal to the inflation rate.

The system salvage value at the end of the analysis period can be estimated by the user (Table 2-7, entry 8).

Energy Costs

The energy cost inputs are (1) the incremental fuel costs in the start-up year, (2) the fuel cost escalation rate, (3) the electricity cost savings, (4) the electricity escalation rate, and (5) the price of electricity sold to the utility. Note that the energy price forecasts used in the model are in current dollars. That is, they include the effects of inflation. The incremental fuel costs in the start-up year are obtained for each fuel type by multiplying the incremental fuel consumption (from cogeneration) by the price for that type of fuel (Table 2-7, entry 9). Calculations of incremental fuel consumption were shown previously (Table 2-7, entry 1). Projected prices for each type of fuel are shown in Appendix-B (Tables B-1 through B-15). These projected prices should be initialized using local data, if available. An example of this initialization is shown in Section 2.4.

The fuel cost escalation rate is calculated using the incremental fuel cost in the start-up year (Table 2-7, entry 9) together with the incremental fuel cost in 1995. Incremental fuel costs in 1995 are calculated like those in entry 9 using 1995 fuel price projections. Where the fuel mix changes with the installation of cogeneration, the fuel cost is thus a composite number reflecting the cost of the fuel used for cogeneration less the cost of one or more other fuels that are replaced.

In such cases, the fuel cost escalation rate is also a composite. Calculations of these composite numbers are shown in Table 2-7, entry 10. Normally, the fuel cost increase is characterized by a power curve, and the fuel cost escalation rate is calculated from this. In the case where composite fuel costs change sign over the analysis period, however, incremental fuel costs are calculated as discrete annual values. These discrete values must be tabulated for each year of the analysis period.

The model uses both incremental fuel costs and the fuel cost escalation rates to calculate incremental fuel costs for subsequent years of system operation.

The <u>electricity cost</u> in the start-up year is calculated as follows:

```
Electricity Cost = (Electricity generated for on-site use)
                   x (price of purchased electricity)
                   + (Electricity sold to utility)
                   x (Price of electricity sold)
                   + Capacity payments
```

The first term is the product of the electricity generated for use on-site and the electricity price (the start-up year electricity price projection tabulated in Appendix-B). This term accounts for the savings the cogeneration system realizes by not purchasing this power from the utility. If local data are available, those data should be used to initialize the price projections.

The second term accounts for the revenue realized by the system through sale of power to the utility. A cogenerator is not restricted to the sale of excess power only. Under the provisions of the Public Utility Regulatory Policies Act (PURPA), all of the power produced by the new capacity may be sold to the utility at the full avoided cost (see Chapter 4), and the cogenerator can purchase back electric power for internal needs at non-discriminatory retail rates. The prices of electricity sold under these provisions are available from the State Regulatory Commission (SRC) of each state. The SRC contacts are listed in Table 4-2, Chapter 4.

The third-term accounts for savings the system realizes through the utilities avoided capacity costs, which are the costs avoided by the utility as a result of not having to generate this power itself or purchase it from another source. Capacity payments by utilities are also subject to the provisions of PURPA (Section 4).

The overall electricity cost is indicated as a negative number (i.e., negative costs) for input to the ICOP model.

The electricity cost escalation rate is calculated using electricity price projections for 1995 and 1985 (Table 2-7, entry 12). The electricity cost escalation rate and the electricity cost in the startup year are used to calculate electricity cost from cogeneration in subsequent years. Both the price of electricity sold to the utility and the capacity payments are assumed to escalate at the same rate as the price of electricity purchased.

Financial Parameters

Financial parameters include the discount rate, (Table 2-7, entry 13) or the IRR hurdle rate, defined as the rate of return which the project must earn to equal alternative investments. This rate of return includes some implied expectation of inflation.

Three financial parameters relate to the system capital cost if the investment is not entirely equity funded. These are the down payment as a percentage of total capital cost, the loan life, and the interest rate on borrowed capital (Table 2-7 entries 14, 15, and 17, respectively).

The investment tax credit (Table 2-7, entry 19) for non-boiler oil- or gas-fired systems is 10 percent. Coal-fired systems are allowed an additional 10 percent energy tax credit under the Energy Tax Act as amended by the Crude Oil Windfall Profits Tax Act. (This calculation involves more detail as described in Chapter 4. For example, oil- or gas-fired boilers are not allowed any tax credit or accelerated depreciation.)

Other financial parameters include the income tax rate (48 percent to include both state and Federal taxes), and selection of a depreciation method (Table 2-7, entries 18 and 25 respectively). The depreciation method may be the sum-of-years-digits (SYD), straight line (SL), double-declining balance (DDB), 150 percent declining balance (DB) changing to SL (150% DB/SL), 175 percent DB changing to SYD (175% DB/SYD), and 200 percent DB changing to SYD (200% DB/SYD). The latter three methods are in accordance with the Accelerated Cost Recovery System (ACRS) under the Economic Recovery Tax Act (ERTA) of 1981. For property placed in service between 1981 and 1984, the 150% DB/SL method is permitted. The 175% DB/SYD method applies to property placed in service in 1985, and the 200% DB/SYD method is for property in service after 1985. These three methods use a half-year convention and no salvage value limitation. The depreciation life (Table 2-7, entry 24) is generally 5 years in accordance with the ERTA.

System life (Table 2-7, entry 16), which is the period over which the firm desires to view the economic performance of the system must be specified. The system life is not necessarily related to the actual physical life of the equipment. Insurance, property taxes, and their escalation rates (Table 2-7, entries 20 through 23) must be estimated. The model can accommodate projected changes in the property tax rate, if these are likely.

2.3.1.2 Analysis and Model Outputs

The economic and financial analysis includes calculation of (1) the capital investment, (2) discounted and undiscounted cash flows, (3) the project IRR, (4) the net present value, and (5) energy savings.

The economic analysis may be further illustrated by referring to a sample printout of the ICOP model (Table 2-8). The printout starts with an identification header and a summary of inputs. Next, undiscounted cash flows are calculated and tabulated.

The unburdened capital investment (principal) is spread over the construction period; O&M and insurance costs (increasing at the inflation rate) and fuel costs (increasing at the fuel escalation rate) are calculated for each year of system operation. Fuel cost is usually a positive number as in the sample, because extra fuel must be burned to cogenerate electricity not being generated previously. If, however, cogeneration is accompanied by a switch to lower cost fuels (e.g., coal or wood waste), fuel cost can be negative, even though more fuel is being consumed.

In most runs, the fuel cost increase is characterized by a power curve (i.e., using an initial value and an average annual escalation rate). The model has the capability, however, to accept discrete annual values. As noted earlier, discrete annual values must be used in cases where the composite fuel cost changes sign over the analysis period because this cannot be accommodated by a power curve.

ICOP MODEL - VERSION 3.5 (08/17/81)

ICOP RUN NO. U- 1- 2 (08/17/81)
UNION CARBIDE, INSTITUTE, WV
7900 KW STEAM TURBINE SYSTEM
DEPRECIATION ON 1985 SCHEDULE

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

CAPITAL INVESTMENT = $ 4142286	EQUITY = $ 4142286	ANALYSIS PERIOD = 12 YEARS
INITIAL O AND M = $ 54438	INITIAL FUEL COST = $ 945536	INITIAL ELECT. COST = $ -4247040
O AND M ESC. RATE = 7.10 PERCENT	FUEL COST ESC. RATE = 10.98 PERCENT	ELECT. ESC. RATE = 10.20 PERCENT
INITIAL INSURANCE = $ 0.00/$1000.	PROPERTY TAX RATE = 2.50 PERCENT	LOAN INTEREST RATE = 000.00 PERCENT
INSURANCE ESC. RATE = 7.10 PERCENT	PROP. TAX ESC. RATE = 7.10 PERCENT	LOAN PERIOD = 0 YEARS
DISCOUNT RATE = 20.00 PERCENT	INCOME TAX RATE = 48.00 PERCENT	INV. TAX CREDIT RATE= 20.00 PERCENT
DECLINING BALANCE DEPRECIATION	DEPRECIATION LIFE = 5 YEARS	SALVAGE VALUE = $ 0
	ANNUAL LOAN PAYMENT = $ 0	

YEAR	PRINCIPAL	INTEREST ON CAPITAL	O AND M	INSURANCE	REPLACEMENT COST	FUEL COST	ELECTRICITY COST	DEPREC- IATION	TAX ON CAPITAL	DELTA INCOME TAX	NET COST *
-1	4142286										4142286
1	0	0	54438	0	0	945536	-4247040	1449800	103557	-15477	-3158986
2	0	0	58303	0	0	1049356	-4680238	1076994	110910	1144644	-2317025
3	0	0	62443	0	0	1164575	-5157622	807746	118784	1441956	-2369865
4	0	0	66876	0	0	1292445	-5683700	538497	127218	1756158	-2441002
5	0	0	71624	0	0	1434356	-6263437	269249	136250	2088940	-2532267
6	0	0	76710	0	0	1591848	-6902308	0	145924	2442156	-2645669
7	0	0	82156	0	0	1766633	-7606343	0	156285	2688609	-2912660
8	0	0	87989	0	0	1960610	-8382190	0	167381	2959781	-3206430
9	0	0	94236	0	0	2175884	-9237174	0	179265	3258138	-3529650
10	0	0	100927	0	0	2414797	-10179365	0	191993	3586391	-3805257
11	0	0	108093	0	0	2679941	-11217661	0	205624	3947521	-4276481
12	0	0	115767	0	0	2974199	-12361862	0	220224	4344803	-4706869
TOT.	4142286	0	979562	0	0	21450181	-91918940	4142286	1863416	29643621	-33839875

* FIRST OPERATIONAL YEAR NET COST INCLUDES TAX CREDIT.

UTILITY HEAT RATE X	NET GENERATION -	INCR FUEL CONS =	ENERGY SAVED
BTU / KWH	MIL. KWH / YR	MIL. BTU / YR	MIL. BTU / YR
10018	63.20	284800	348338

INTERNAL RATE OF RETURN IS 50.42 PERCENT.

Table 2-8. Sample Model Printout

The electricity cost is always a negative number, as shown in the sample printout, since it represents the savings from cogeneration (reduced electricity bills plus any revenues from sales of electricity). In the sample run, these yearly savings are calculated using an escalation rate of 10.2 percent per year.

The printout also shows depreciation calculated according to the 175% DB/SYD schedule. The depreciation is used to determine the income tax. Capital property tax and income tax are also calculated. The income tax is small the first year as a result of the investment tax credit taken. (In many cases, the first year income tax is negative and is thus an income tax credit that could be used to offset income taxes elsewhere in the firm.)

Net cost is calculated by algebraically summing all the columns except for depreciation.

The energy-savings computation is shown in the lower portion of the table. The utility heat rate, corrected for T&D losses as described earlier, is multiplied by the net generation to compute primary energy savings in the utility system. Subtracting the incremental fuel consumption at the industrial plant gives the overall net energy savings.

While not an output of the ICOP computer model itself, the net savings of oil and gas can be easily determined through hand calculations based on the model inputs. Utility fuels displaced require estimates of the type(s) of primary energy saved at the utility (e.g., oil/gas or coal/nuclear). These inputs can be based on local utility data concerning current and projected fuel use (Section 2.2).

The IRR (bottom of Table 2-8) is calculated as the discount rate that results in a net present value (NPV) of zero [i.e., the discount rate that equates the present value (PV) of dollar savings to the PV of costs]. For cases where the PV of savings is less than the PV of costs for all positive discount rates, the IRR is taken to be zero.

Table 2-9 presents the discounted cash flows. Note that in these calculations, the construction capital burden is included in the burdened capital cost in the principal and net cost columns. The burden on the construction cash flows is not subject to depreciation, because the burden

SYSTEM COST ANALYSIS

PRESENT VALUE COSTS

YEAR	PRINCIPAL	INTEREST ON CAPITAL	O AND M	INSURANCE	REPLACEMENT COST	FUEL COST	ELECTRICITY COST	DEPREC-IATION	TAX ON CAPITAL	DELTA INCOME TAX	NET COST *
-1	4648278										4648278
1	0	0	45365	0	0	787947	-3539200	1208167	86298	-12898	-2632488
2	0	0	40480	0	0	728719	-3250165	747913	77021	794892	-1609045
3	0	0	36136	0	0	673944	-2984735	467445	68741	834465	-1371449
4	0	0	32251	0	0	623286	-2740982	259692	61351	846913	-1177181
5	0	0	28784	0	0	576436	-2517135	108205	54756	839498	-1017661
6	0	0	25690	0	0	533107	-2311569	0	48870	817873	-886029
7	0	0	22928	0	0	493035	-2122791	0	43616	750341	-812870
8	0	0	20463	0	0	455975	-1949430	0	38927	688350	-745713
9	0	0	18264	0	0	421701	-1790226	0	34743	631449	-684070
10	0	0	16300	0	0	390003	-1644024	0	31008	579222	-627491
11	0	0	14548	0	0	360608	-1509762	0	27675	531289	-575563
12	0	0	12984	0	0	333576	-1386465	0	24700	487299	-527907
TOT.	4648278	0	314202	0	0	6378416	-27746484	2791422	597705	7788694	-8019189

* FIRST OPERATIONAL YEAR NET COST INCLUDES TAX CREDIT.

NET PRESENT VALUE IS $ -8019189 AT DISCOUNT RATE OF 20.00 PERCENT.

Table 2-9. Sample Model Printout
(Discounted Cash Flows)

does not represent an actual capital expenditure. Calculations are basically the same as those described previously except that discounted dollars are used. The final total at the bottom of the net cost column is the NPV. Where the PV of savings is less than the PV of costs for the IRR hurdle rate used, the NPV will be a positive number. Conversely, if the PV of savings exceeds that of costs, the NPV will be negative. This is because costs in the model are represented by positive values and savings by negative values.

2.4 ILLUSTRATION OF METHODOLOGIES

This section illustrates the use of the methodologies discussed earlier to calculate the IRR and energy savings associated with cogeneration alternatives. These will be described for the typical cogeneration applications developed in Chapter 1. Seven cogeneration configurations are considered for the following four industrial facilities:

- o Union Carbide Agricultural Chemicals Plant, Institute, West Virginia
  - Coal-fired steam turbine system
- o Dupont Textile Fiber Plant and Intermediate Plant, South Carolina
  - Natural gas fired combustion turbine combined cycle system
  - Natural gas fired combustion turbine topping existing process heaters
  - Coal-fired steam turbine system
- o Large Oil Refinery, Norco, Louisiana
  - Coal-fired steam turbine system
  - Natural gas fired combustion turbine system
- o Fine Chemicals Plant, New Jersey
  - Diesel with supplementary fired recovery boiler

The methodologies described will utilize data pertaining to cogeneration system characteristics, fuel and electricity price projections, and other pertinent information, in conjunction with relevant relationships from Tables 2-7, to derive the inputs necessary to compute IRR and energy savings through the ICOP model. Unless otherwise noted, capital costs and O&M costs used in all of these examples were obtained in mid-1981 dollars.

These computations will be performed systematically and in detail for the case pertaining to the Union Carbide facility. For cogeneration systems in the other plants, these computations will only be shown if they differ in nature from those for the Union Carbide plant. In such instances explanations will also be provided to clarify these differences.

2.4.1 Union Carbide Agricultural Chemicals Plant, Institute, W.Va.

The agricultural chemicals plant is located in the SERC region of the National Electric Reliability Council and is served by the Appalachian Power Co. For the SERC region overall (excluding Florida), utilities will retain some marginal dependence on oil and gas for central station generation, at least through 1989 (Tables 2-5). However, it can be determined* that APCO is 100 percent dependent on coal and hydro for power generation. Moreover, APCO operates within the American Electric Power (AEP) system which is also heavily dependent on coal. Evidently coal would be the utility fuel displaced as a result of any new cogeneration at the Institute.

The general pattern of energy use at the plant is shown in Figure 1-32, Section 1.7. Although the plant presently cogenerates shaft power using back-pressure and extraction steam turbines, throttling valves are also used in the steam distribution system.

As illustrated in Section 1.7, one cogeneration option for this plant is the interposition of a 7900 kW single-extraction non-condensing steam turbine between the 400 psig and 75 psig headers, replacing the throttling valves (Figure 1-33). Such a system would partially offset the electricity requirements of the plant. No new boilers would be required for this system but additional coal firing is required in the existing boilers. Table 2-10 indicates the major characteristics of the proposed cogeneration system and that of the utility serving the agricultural chemicals plant. It should be noted that the incremental fuel consumption is obtained as the product of the hourly incremental fuel consumption (Table 1-14) and the annual hours of operation of the system.

The economic viability of this system is based on the condition that the IRR on this investment would either equal or exceed the hurdle rate of 20 percent imposed by Union Carbide. Illustration of the methodology to determine the IRR is shown in the next section and is followed by a determination of energy savings.

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*Electrical World Directory of Electric Utilities, 1980-81.

Table 2-10. Cogeneration System and Utility Characteristics

COGENERATION SYSTEM	
• Continuous Power Rating	7,900 kW (net)
• Annual Operating Hours	8,000
• Incremental Fuel (coal) Consumption (i.e., increase in consumption over current use)	$284{,}800 \times 10^6$ Btu/year
• Net Generation (7,900 kW x 8,000 hrs)	63.2×10^6 kWh/year
UTILITY (Appalachian Power Co.)[a]	
• System Heat Rate	9,363 Btu/kWh
• Transmission and Distribution Losses	7% (assumed)
• Fuels Used for Power Generation (in 1980)	
- coal	98.5%
- hydro	1.5%

[a]Based on Electric World Directory of Electric Utilities 1980-81

Computation of the IRR

The IRR is computed using the ICOP Model discussed in Section 2.3.1. The specific inputs to the model are as shown in Table 2-11, and the manner in which each is obtained is discussed in the following sections.

Estimates of capital investment were obtained from vendor quotes for an installed system and thus implicitly include the vendor's estimate of escalation during construction. The quote, which amounted to $3,300,000 was, however, for a mid-1981 start of construction (and included a 1-year construction period). As construction would not actually begin until early 1984 for a 1985 startup date, this quote needs to be escalated to reflect

TABLE 2-11. UNION CARBIDE - MODEL RUN SHEET

RUN SHEET

RUN NO. U-1-1
UNION CARBIDE, INSTITUTE, W.VA.
7900 kW STEAM TURBINE SYSTEM

PARAMETERS	VARIABLE NAME	VALUE	OR DEFAULT
TECHNICAL CHARACTERISTICS:			
INCREMENTAL FUEL CONSUMPTION, (10^6 Btu/yr)	FUELCN	284,800	0.0
NET ELECTRICITY GENERATION (10^6 kWh/yr)	NETGEN	63.2	0.0
UTILITY HEAT RATE (INCLUDING T&D LOSSES) (Btu/kWh)	HTRATE	10,018	0.0
SYSTEM COSTS:			
CAPITAL INVESTMENT ($ in 1985)	CAPINV	4,142,286	0.0
CONSTRUCTION COST DISTRIBUTION -			
PERIODS OF CONSTRUCTION	NPER	4	0
PERIODS PER YEAR	IPER	4	0
CONSTRUCTION FRACTION PER PERIOD	FCONST	0.25	0.0
OPERATIONS & MAINTENANCE COST, INITIAL ($/yr in 1985)	OANDM	54,438[a]	0.0
O&M COST ESCALATION RATE (Fraction)	OMRATE	0.071	0.0
SALVAGE VALUE ($)	SALVAG	0	0.0
ENERGY COSTS:			
INCREMENTAL FUEL COST, INITIAL ($/yr in 1985)	FUEL	945,536	0.0
INCREMENTAL FUEL COST ESCALATION RATE (Fraction)	FRATE	0.1098	0.0
ELECTRICITY COST, INITIAL ($/yr in 1985)	ELECT	-4,247,040	0.0
ELECTRICITY COST ESCALATION RATE (Fraction)	ERATE	0.1020	0.0

RUN SHEET (Continued)

FINANCIAL PARAMETERS:

DISCOUNT RATE (Fraction)	DISRTE	0.20	0.2
DOWNPAYMENT (Fraction)	DWNPMT	1.0	1.0
LOAN LIFE (Up To 40 Years)	LIFLON	0	12
SYSTEM LIFE (Up To 40 Years)	LIFSYS	12	12
INTEREST RATE (Fraction)	IRATE	0	0.2
INCOME TAX RATE (Fraction)	TXRATE	0.48	0.48
TAX CREDIT RATE (Fraction)	TAXCRD	0.20	0.20
INSURANCE RATE (Fraction)	INS	0	0.005
INSURANCE ESCALATION RATE (Fraction)	INSRAT	0.071	0.0
PROPERTY TAX RATE (Fraction)	PCTAX	0.025	0.025
PROPERTY TAX ESCALATION RATE (Fraction)	PCRATE	0.071	0.0
DEPRECIATION LIFE (Up To 40 Years)	DEPYRS	5	5
DEPRECIATION MODE	MODDEP	5	5

= 1 - SUM-OF-YEARS-DIGITS
= 2 - STRAIGHT LINE
= 3 - DOUBLE DECLINING BALANCE
= 4 - 150% DB CHANGING TO SL
= 5 - 175% DB CHANGING TO SYD
= 6 - 200% DB CHANGING TO SYD

a. O&M costs from Table 1-12, include only maintenance and expendables, and burdened labor components.

its value in 1984. This is calculated by applying a GNP deflator (from Table 2-3) to the capital cost:

Capital Investment = (vendor quote for mid-1981) x (GNP deflator from mid-1981 to January 1984)

$$= (\$3,300,000) \times \frac{(1.318)}{(1.05)}$$
$$= \$4,142,286.$$

GNP deflators based on the DRI model are tabulated in Section 2.1.

The <u>construction cost distribution</u> for this system consists of four equal quarterly installments. A 20 percent annual burden (equal to the hurdle rate) is applied to these outlays. As financing is based on 100 percent equity, there are no loan payments.

The <u>O&M costs</u> are estimated by the system designer at $40,000/year (in mid-1981). For the first year of operation (i.e., 1985) the value is calculated using information from Table 2-7 in conjunction with the data given in Table 2-3 as follows:

O&M costs in 1985 = (1981 O&M cost estimate)

x (GNP deflator for 1981-85 period)

$$= (40,000) \times \frac{(1.429)}{(1.05)}$$
$$= \$54,438.$$

The <u>O&M escalation rate</u> is assumed to be the same as the inflation rate (7.1%) annually during the 12-year analysis period considered.

The <u>incremental fuel cost</u> for the first year of operation (1985) of the system is $945,536. This is obtained from the incremental fuel consumption (in this case, coal) of 284,800 $\times 10^6$Btu/year (Table 2-11) and the projected price of coal in 1985 for this region, $3.32/$10^6$Btu (Appendix-B, Table B-5):

Incremental Fuel Cost in 1985 = (284,800 $\times 10^6$Btu/year) x (3.32 \$/10^6Btu) = $945,536.

and using 1995 coal prices,

Incremental fuel cost in 1995 = (284,800$\times 10^6$Btu/yr)x(9.41 \$/10^6Btu) = $2,679,968

The incremental fuel cost escalation rate is then determined using a power curve approximation to represent the coal price data in Appendix-B, Table B-5:

$$\text{Incremental Fuel Cost Escalation rate} = \left(\frac{\text{1995 incremental coal costs}}{\text{1985 incremental coal costs}}\right)^{1/10} - 1$$

$$= \left(\frac{2,679,968}{945,536}\right)^{1/10} -1 = 10.98\%$$

The value of electricity saved in 1985 as a result of cogeneration is calculated as $4,247,040 (Table 2-7, entry 11). Using information from Table 2-11 and the projected price of electricity from Appendix-B, Table B-1:

$$\text{Value of electricity savings in 1985} = (\text{net generation, kwh/year}) \times (\$/\text{kwh in 1985})$$

$$= (63.2\text{x}10^{6}\text{kWh/yr})\text{x}(0.0672\ \$/\text{kWh})$$

$$= \$4,247,040$$

and, using 1995 electricity prices,

$$\text{Value of electricity savings in 1995} = (63.2\text{x}10^{6}\ \text{kWh/yr})\text{x}(0.1731\$/\text{kWh})$$

$$= \$11,218,000.$$

The electricity price escalation rate is also determined using a power curve (Table 2-7, entry 12):

$$\begin{array}{c}\text{Electricity price}\\ \text{escalation rate}\end{array} = \left(\frac{\text{1995 incremental electricity cost}}{\text{1985 incremental electricity cost}}\right)^{1/10} - 1$$

$$= \left(\frac{11,218,000}{4,247,040}\right)^{1/10} - 1$$

$$= 10.20\%.$$

For this cogeneration system, all of the electricity generated is used on site.

The income tax rate for this investment is assumed to be 48 percent and includes State taxes. An investment tax credit of 20 percent (allowed under provisions of the Crude Oil Windfall Profits Tax Act because this system is coal-fired) is taken during the first year of operation. Depreciation of equipment is taken over a 5-year period, and the model uses a 175% declining balance (DB) changing to a sum-of-years-digits (SYD) depreciation schedule to compute the annual depreciation.

Taxes on capital stock are assessed at 2.5 percent per annum of the capital investment and is assumed to remain unchanged during the analysis period. Union Carbide claims that adequate insurance provisions currently exist at the plant so that no additional insurance is required to accommodate this cogeneration retrofit.

Model Outputs and Discussion of Results

The model uses the inputs described in the preceding section first to generate streams of undiscounted cash flows. These are then used to calculate the IRR. For this cogeneration system, the IRR is determined to be over 50 percent. This value is considerably greater than the hurdle rate set by the company. Hence, the system is cost-effective under the particular economic assumptions used.

The reasons for this high IRR may be attributed to three major factors. First, the simplicity of the design permits a relatively modest capital investment, which requires no new boilers, but only a turbo-generator and its associated auxiliaries. Secondly, because the fuel used is coal (the cheapest fuel available), fuel costs are maintained at a minimum. Finally, the value of electricity savings is considerably in excess of the incremental fuel costs during each year of the analysis period.

The net energy savings that would be realized through this cogeneration system is the difference between the utility fuels displaced and the industrial plant's incremental fuel consumption. The utility fuel displacement is the product of net annual electricity generation of the cogeneration system and the utility heat rate corrected for T&D losses.

Using the information from Table 2-11, the net energy saved is calculated by the model as:

$(63.2\text{x}10^6$ kWh/yr$)\text{x}(10{,}018$ Btu/kWh$)-(284{,}800\text{x}10^6$ Btu/yr$)$

$= 348{,}338\text{x}10^6$ Btu/yr.

As the utility and the cogeneration system are both coal-fired, the altered energy use patterns produce a net reduction in the use of coal. The industrial plant will, however, burn more coal while meeting a significant portion of its electricity needs. These results are as shown in Table 2-12.

Table 2-12. Energy Savings Resulting from Cogeneration at Union Carbide (10^{12} Btu/year)

Industry Energy Savings	Utility Energy Savings	Net Energy Savings
Coal: - 0.28	Coal: + 0.63	+ 0.35

Modifications of Inputs for Local Energy Prices

In the foregoing illustrative example, fuel prices (obtained from the DRI forecast) represent regional prices. For this example, local coal and electricity prices are also available. Coal prices, which vary from $1.09 to $1.24 per million Btu (in 1981), are the actual prices paid for coal purchased by Union Carbide. Electricity prices, amounting to 3.1¢/kWh, are those charged by AEP* to its industrial customers, of which the Institute plant is one.

Two model inputs are affected by these new prices--the incremental fuel cost, and the electricity cost, both in 1985. The incremental fuel and electricity cost escalation rates are not different from those calculated previously.

For illustrative purposes, the $\$1.09/10^6$ Btu local price for coal is considered in this example. Using DRI regional coal price forecasts from Table B-5 (Appendix B), this value is escalated to reflect its estimated value in 1985 as follows:

$$(1.09) \times \left(\frac{3.32}{2.05}\right) = \$1.77/10^6 \text{ Btu.}$$

*1980 AEP Annual Repoprt.

The incremental fuel cost in 1985 is then:

$$(284{,}800 \times 10^6 \text{ Btu/yr}) \times (1.77 \text{ \$}/10^6 \text{ Btu}) = \$504{,}096.$$

The incremental value of electricity saved in 1985 is calculated likewise. Using DRI Regional electricity price forecasts (Table B-1), the local (1980) electricity price is escalated to reflect its value in 1985:

$$(0.031)\left(\frac{0.0672}{0.0355}\right) = \$0.0587/\text{kWh}$$

The incremental value of electricity saved in 1985 is then:

$$(63.2\times10^6 \text{ kWh})(0.0587 \text{ \$/kWh}) = \$3{,}709{,}840.$$

Using these new inputs in the model, the IRR is determined to be 49.6 percent. Evidently this figure is hardly different from that obtained using regional energy prices. This occurs despite the fact that local coal prices are almost one-half that for the region. The main reason for this closeness in the two results may be attributed to the value of electricity savings far outweighing the incremental fuel costs in both cases.

Sensitivity Analysis--Effects of Energy Prices

For the two price scenarios considered, the preceding analyses indicate that the IRR is virtually insensitive to relatively strong fuel and electricity price variations. To explore this further, model runs were made using coal and electricity prices derived for the "low" and "high" price scenarios (Section 2.1). Results from these runs are shown plotted alongside those obtained using the "best case" and "local" fuel and electricity price forecasts in Figure 2-9.

The results indicate that the IRR of about 48 percent obtained for the "low" price scenario does not differ appreciably from those obtained using "best" and "local" prices. However, under the "high" price scenario,the IRR is observed to increase to over 57 percent. This increase may be attributed to the rapid escalation rate (13.2 percent) of electricity prices under this latter scenario (as compared to the 9.6 to 10.2 percent rates under the other price scenarios). Although fuel prices also increase rapidly under this scenario, incremental fuel costs are relatively small compared to the electricity savings. Electricity savings thus weigh

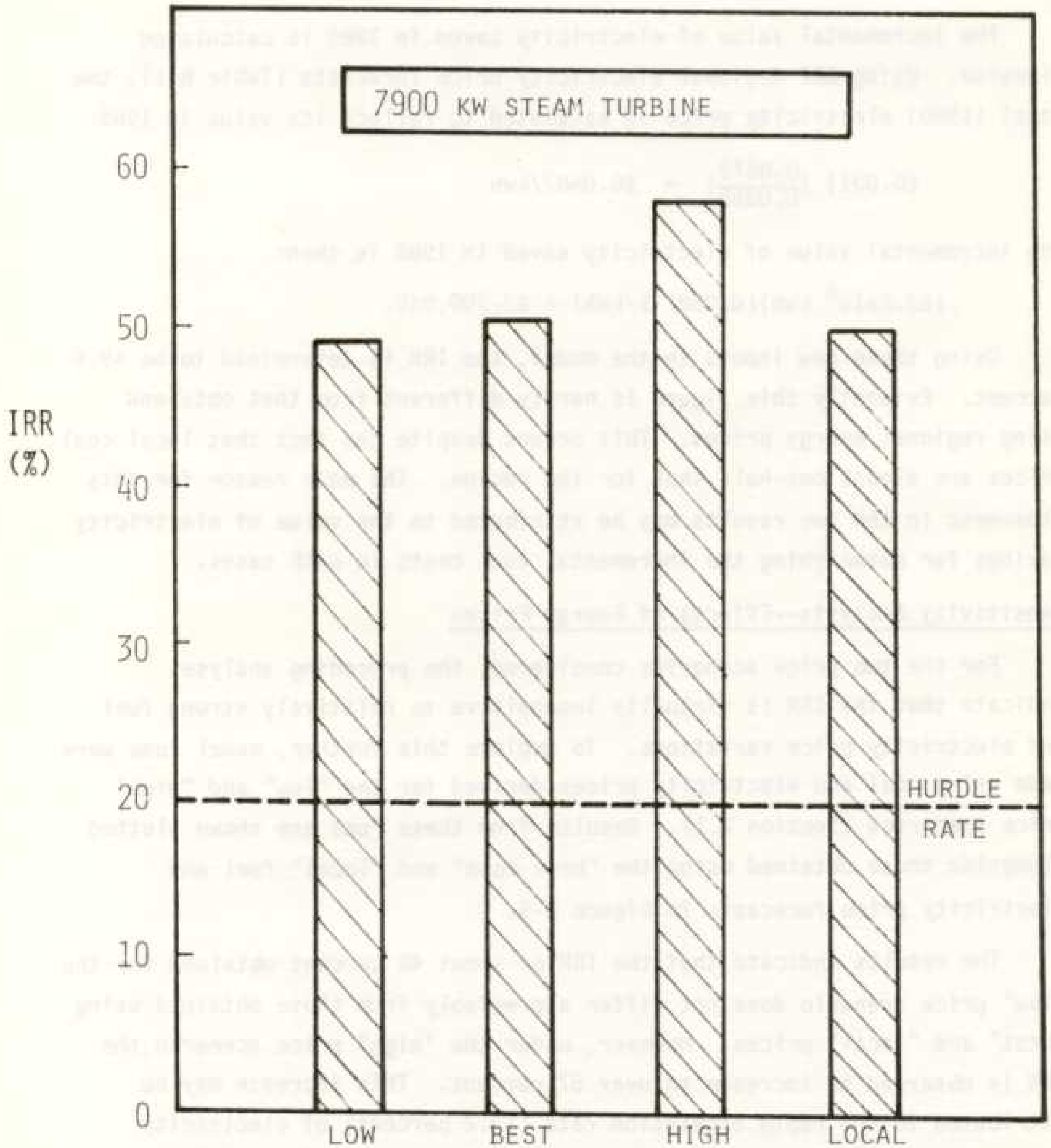

Figure 2-9. Effect of Energy Prices on IRR at Union Carbide

heavily toward producing this high IRR. It is thus evident that this cogeneration system is cost-effective under a variety of price scenarios.

2.4.2 DuPont Textile Fiber Manufacturing Facility in Southeast U.S.

The DuPont textile fiber manufacturing facility is located in the SERC region of the National Electric Reliability Council and is served by the Carolina Power and Light Co. Referring to Table 2-13 it can be determined that the utility generates 97 percent of its power using coal and nuclear power; oil and hydro account for the remainder. Carolina Power & Light operates within the Virginia-Carolinas Reliability Group (VACAR) power pool, which is also heavily dependent on coal and nuclear energy. Coal will thus be displaced as a result of cogeneration at the DuPont plant.

The average profile of energy use at the DuPont plant is as shown in Figure 1-24, and described in Section 1.7. The facility consists of two adjacent processing plants. Presently, steam requirements are met using residual oil-fired boilers, and waste heat recovery boilers provide 175 psig steam for use in the textile fiber plant. The three cogeneration configurations (for this facility) discussed in Section 1.7, will be evaluated for their economic and energy-savings performance. Where appropriate, the results of sensitivity analyses will be presented to illustrate the effects of changes in key parameters on the economic performance.

Example I-A: Synthetic Textile Facility-Fiber Plant

As discussed in Section 1.7, one cogeneration option for this plant is the use of a combustion turbine combined cycle configuration with a single extraction noncondensing steam turbine (Figure 1-25). This system, which is natural gas-fired, would replace the existing residual oil-fired boilers serving this plant. It would meet all of the steam requirements previously met by these boilers and would meet almost all of the electricity demands of this plant. Table 2-13 indicates the major characteristics of the proposed cogeneration system and that of the utility serving the DuPont plant.

The hurdle rate for this investment has been set at 20 percent by DuPont. The methodology to determine if the IRR from this investment meets this hurdle rate is described in the next section and is followed by a

Table 2-13. Cogeneration System and Utility Characteristics

COGENERATION SYSTEM	
• Gas Turbine/Generator Continuous Rated Output	21,037 kW (net)
• Steam Turbine/Generator Continuous Rated Output	1,645 kW (net)
• Annual Operating Hours	8,000 hrs.
• Incremental Fuel Consumption	
Natural Gas	$2,072,000 \times 10^6$ Btu/year
Residual Fuel Oil	$-976,000 \times 10^6$ Btu/year
	$1,096,000 \times 10^6$ Btu/year
• Net Generation (22,682kWx8000hr)	181.46×10^6 kWh/year
UTILITY - (CAROLINA POWER & LIGHT CO.)	
• Overall System Heat Rate[a]	10,322 Btu/kWh
• Transmission and Distribution Losses	7% (assumed)
• Fuels Used for Power Generation (in 1980)[b]:	
- coal	69%
- oil	1%
- nuclear	28%
- hydro	2%

[a]Based on Electrical World, Directory of Electric Utilities 1980-81

[b]Based on Carolina Power & Light Co. Annual Report (1980)

computation to determine the net energy savings. Table 2-14 presents the inputs to the ICOP model.

Computation to Determine the IRR

The parameters input to the ICOP model to compute the IRR are as shown in Table 2-14. A discussion of these inputs follows.

Computation of model inputs for this example differ from those for the Union Carbide System only in that the incremental fuel costs and fuel cost escalation rates now reflect composite values. Also, as the system uses premium fuels, tax credits are treated differently.

The incremental fuel cost (in 1985) is calculated using Table 2-7, entry 9; that is,

Incremental fuel cost in 1985 = (annual increase in NG consumption) x ($\$/10^6$Btu of NG in 1985) - (annual decrease in resid. consumption) x ($\$/10^6$Btu of resid. in 1985),

$= (259 \times 10^6 \text{Btu/hr}) \times (8000 \text{ hr/yr}) \times (6.37\$/10^6\text{Btu}) - (122 \times 10^6\text{Btu/hr}) \times (8000 \text{ hr/yr}) \times (8.14\$/10^6\text{Btu}),$

$= 5,254,000.$

The incremental fuel cost escalation rate is a composite quantity based on the price components for natural gas and residual oil in a given year. This value is computed using Table 2-7, entry 9: that is,

$$\text{Fuel Cost Escalation Rate} = \left(\frac{\text{1995 incremental fuel costs}}{\text{1985 incremental fuel costs}}\right)^{1/10} - 1$$

The 1995 incremental fuel cost is:

(Increase in NG consumption) x ($\$/10^6$Btu of NG in 1995) - (decrease in resid. consumption) x ($\$/10^6$Btu of resid. in 1995)

$= (259 \times 10^6\text{Btu/hr}) \times (8000 \text{ hr/yr}) \times (24.68\ \$/10^6\text{Btu}) - (122 \times 10^6\text{Btu/hr}) \times (8000 \text{ hr/yr}) \times (23.70\ \$/10^6\ \text{Btu}) = \$28,006,000.$

TABLE 2-14. DUPONT SOUTHEAST MODEL RUN SHEET

RUN SHEET

RUN NO. D-1-2
22,682 kW COMBINED CYCLE

PARAMETERS	VARIABLE NAME	VALUE	OR DEFAULT
TECHNICAL CHARACTERISTICS:			
INCREMENTAL FUEL CONSUMPTION, (10^6 Btu/yr)	FUELCN	1,096,000	0.0
NET ELECTRICITY GENERATION (10^6 kWh/yr)	NETGEN	181.46	0.0
UTILITY HEAT RATE (INCLUDING T&D LOSSES) (Btu/kWh)	HTRATE	11,045	0.0
SYSTEM COSTS:			
CAPITAL INVESTMENT ($ in 1985)	CAPINV	21,909,333	0.0
CONSTRUCTION COST DISTRIBUTION -			
PERIODS OF CONSTRUCTION	NPER	6	0
PERIODS PER YEAR	IPER	4	0
CONSTRUCTION FRACTION PER PERIOD	FCONST	0.167	0.0
OPERATIONS & MAINTENANCE COST, INITIAL ($/yr in 1985)	OANDM	993,495[a]	0.0
O&M COST ESCALATION RATE (Fraction)	OMRATE	0.071	0.0
SALVAGE VALUE ($)	SALVAG	0	0.0
ENERGY COSTS:			
INCREMENTAL FUEL COST, INITIAL ($/yr in 1985)	FUEL	5,254,000	0.0
INCREMENTAL FUEL COST ESCALATION RATE (Fraction)	FRATE	0.1821	0.0
ELECTRICITY COSTS, INITIAL ($/yr in 1985)	ELECT	-12,194,112	0.0
ELECTRICITY COST ESCALATION RATE (Fraction)	ERATE	0.1020	0.0

RUN SHEET (Continued)

FINANCIAL PARAMETERS:

DISCOUNT RATE (Fraction)	DISRTE	0.20	0.2
DOWNPAYMENT (Fraction)	DWNPMT	1.0	1.0
LOAN LIFE (Up To 40 Years)	LIFLON	0	12
SYSTEM LIFE (Up To 40 Years)	LIFSYS	12	12
INTEREST RATE (Fraction)	IRATE	0	0.2
INCOME TAX RATE (Fraction)	TXRATE	0.48	0.48
TAX CREDIT RATE (Fraction)	TAXCRD	0.10	0.20
INSURANCE RATE (Fraction)	INS	0.003[b]	0.005
INSURANCE ESCALATION RATE (Fraction)	INSRAT	0.071	0.0
PROPERTY TAX RATE (Fraction)	PCTAX	0.025	0.025
PROPERTY TAX ESCALATION RATE (Fraction)	PCRATE	0.071	0.0
DEPRECIATION LIFE (Up To 40 Years)	DEPYRS	5	5
DEPRECIATION MODE	MODDEP	5	5

= 1 - SUM-OF-YEARS-DIGITS
= 2 - STRAIGHT LINE
= 3 - DOUBLE DECLINING BALANCE
= 4 - 150% DB CHANGING TO SL
= 5 - 175% DB CHANGING TO SYD
= 6 - 200% DB CHANGING TO SYD

a. O&M costs from Table 1-10, include only maintenance and expendables, and burdened labor components.

b. From Table 1-10, as fraction of capital costs

The 1985 incremental fuel cost has been already calculated as $5,254,000.

Then,

$$\text{Fuel Cost Escalation Rate} = \left(\frac{28,006,000}{5,254,000}\right)^{1/10} - 1 = 18.21\%$$

The two fuel cost components that cause this rapid escalation are shown in Figure 2-10. Initially, the incremental cost of fuel for cogeneration is slightly less than the cost of fuel for continuing to operate the existing system (i.e., the value of fuel saved). Even though more total fuel is required for cogeneration, the incremental cost is initially less because cheaper natural gas is substituted for more expensive residual oil. As natural gas prices escalate at a higher rate than residual oil prices, however, the incremental fuel cost increases rapidly and becomes greater than the value of fuel saved.

The investment tax credit for this case has been limited to 10 percent of the capital investment because this cogeneration system uses natural gas. Under provisions of the Crude Oil Windfall Profits Tax Act, an additional 10 percent energy tax credit is therefore disallowed.

Model Outputs and Discussion of Results

Using the above inputs in the DCF model the IRR for this system is determined to be 13.1%. This IRR does not meet DuPont's 20 percent hurdle rate and would not therefore be an acceptable investment to this company.

This may be attributed mainly to the incremental fuel costs being high and escalating at a rate that surpasses the electricity cost increase (i.e., 18.2% annually for incremental fuel cost escalation versus 10.2% for electricity). This example shows that it may be uneconomical to operate a premium fuel-fired cogeneration system in a region served by a coal or nuclear powered utility generating relatively cheap electricity.

This cogeneration system results in fuel substitution. The existing residual oil-fired system is replaced with a system burning natural gas. Cogenerated electricity displaces the use of coal at the utility. Table 2-15 presents the net energy savings realized through this cogeneration system.

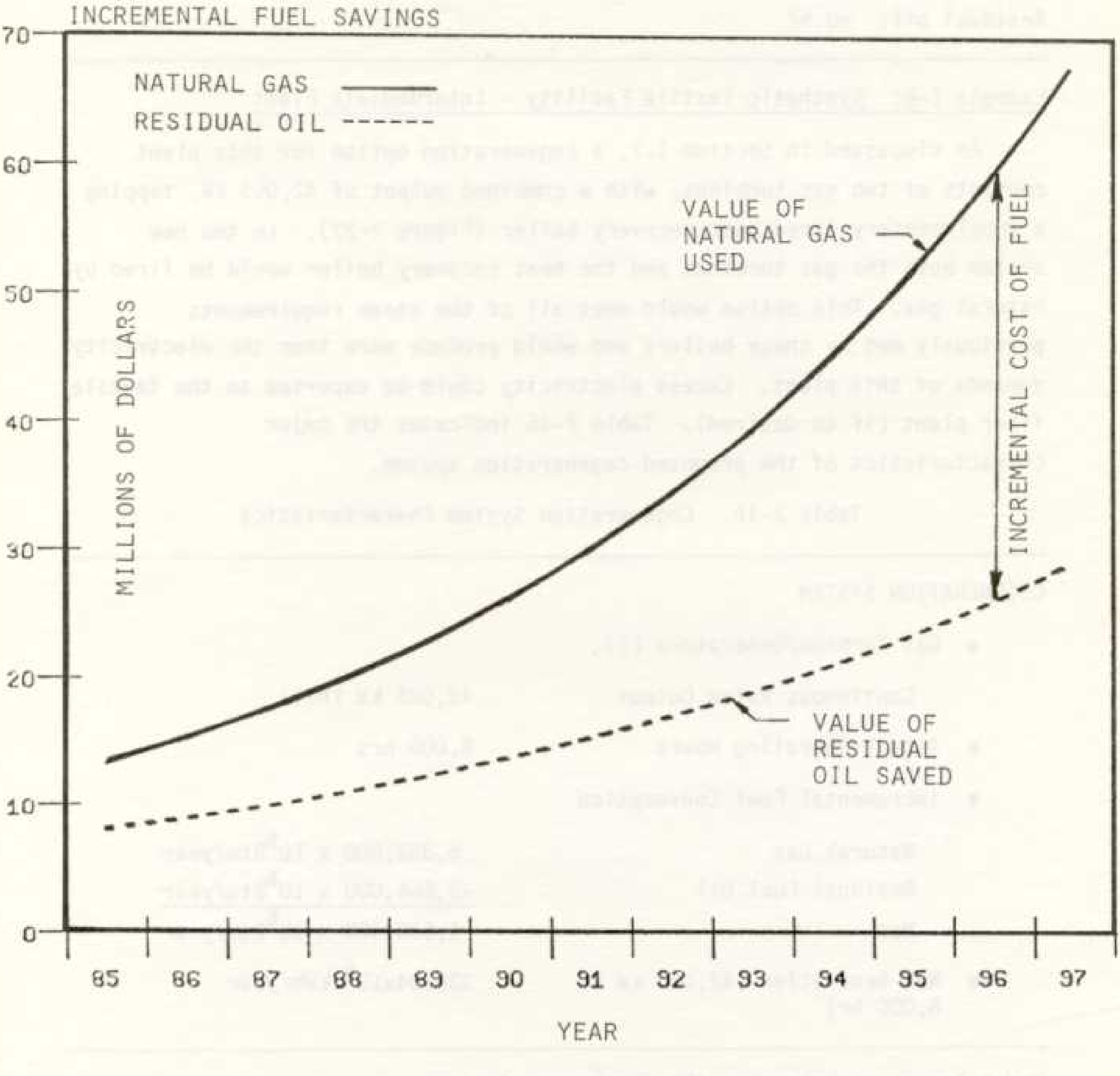

Figure 2-10. Incremental Value of Fuels During Analysis Period for DuPont 22,682 kW Combined Cycle System

Table 2-15. Energy Savings (10^{12} Btu/year)

INDUSTRY ENERGY SAVINGS	UTILITY ENERGY SAVINGS	NET ENERGY SAVINGS
Natural gas: -2.07	Coal: +2.01	+0.91
Residual oil: +0.97		

<u>Example I-B: Synthetic Textile Facility - Intermediate Plant</u>

As discussed in Section 1.7, a cogeneration option for this plant consists of two gas turbines, with a combined output of 42,005 kW, topping a supplementary fired heat recovery boiler (Figure 1-27). In the new system both the gas turbines and the heat recovery boiler would be fired by natural gas. This option would meet all of the steam requirements previously met by these boilers and would produce more than the electricity demands of this plant. Excess electricity could be exported to the textile fiber plant (if so desired). Table 2-16 indicates the major characteristics of the proposed cogeneration system.

Table 2-16. Cogeneration System Characteristics

COGENERATION SYSTEM	
• Gas Turbine/Generators (2),	
Continuous Rated Output	42,005 kW (net)
• Annual Operating Hours	8,000 hrs
• Incremental Fuel Consumption	
Natural Gas	5,352,000 x 10^6Btu/year
Residual Fuel Oil	-3,864,000 x 10^6Btu/year
Net	1,538,400 x 10^6Btu/year
• Net Generation (42,005 kW x 8,000 hr)	336.04x10^6 kWh/year

<u>Model Inputs to Determine IRR and Energy Savings</u>

The inputs to the model are derived in the same manner as for the cases discussed previously. These inputs are shown in Table 2-17.

TABLE 2-17. DUPONT SOUTHEAST - MODEL RUN SHEET

RUN SHEET

RUN NO. D-2-2
42,005 kW GAS TURBINE WITH
SUPPLEMENTARY FIRED RECOVERY BOILER

PARAMETERS	VARIABLE NAME	VALUE	OR DEFAULT
TECHNICAL CHARACTERISTICS:			
INCREMENTAL FUEL CONSUMPTION (10^6 Btu/yr)	FUELCN	1,488,000	0.0
NET ELECTRICITY GENERATION (10^6 kWh/yr)	NETGEN	336.04	0.0
UTILITY HEAT RATE (INCLUDING T&D LOSSES) (Btu/kWh)	HTRATE	11,045	0.0
SYSTEM COSTS:			
CAPITAL INVESTMENT ($ in 1985)	CAPINV	41,447,162	0.0
CONSTRUCTION COST DISTRIBUTION -			
PERIODS OF CONSTRUCTION	NPER	6	0
PERIODS PER YEAR	IPER	4	0
CONSTRUCTION FRACTION PER PERIOD	FCONST	0.167	0.0
OPERATIONS & MAINTENANCE COST, INITIAL ($/yr in 1985)	OANDM	1,415,391[a]	0.0
O&M COST ESCALATION RATE (Fraction)	OMRATE	0.071	0.0
SALVAGE VALUE ($)	SALVAG	0	0.0
ENERGY COSTS:			
INCREMENTAL FUEL COST, INITIAL ($/yr in 1985)	FUEL	2,639,280	0.0
INCREMENTAL FUEL COST ESCALATION RATE (Fraction)	FRATE	0.3140	0.0
ELECTRICITY COST, INITIAL ($/yr in 1985)	ELECT	-22,581,888	0.0
ELECTRICITY COST ESCALATION RATE (Fraction)	ERATE	0.1020	0.0

RUN SHEET (Continued)

FINANCIAL PARAMETERS:

DISCOUNT RATE (Fraction)	DISRTE	0.20	0.2
DOWNPAYMENT (Fraction)	DWNPMT	1.0	1.0
LOAN LIFE (Up To 40 Years)	LIFLON	0	12
SYSTEM LIFE (Up To 40 Years)	LIFSYS	12	12
INTEREST RATE (Fraction)	IRATE	0	0.2
INCOME TAX RATE (Fraction)	TXRATE	0.48	0.48
TAX CREDIT RATE (Fraction)	TAXCRD	0.10	0.20
INSURANCE RATE (Fraction)	INS	0.002[b]	0.005
INSURANCE ESCALATION RATE (Fraction)	INSRAT	0.071	0.0
PROPERTY TAX RATE (Fraction)	PCTAX	0.025	0.025
PROPERTY TAX ESCALATION RATE (Fraction)	PCRATE	0.071	0.0
DEPRECIATION LIFE (Up To 40 Years)	DEPYRS	5	5
DEPRECIATION MODE	MODDEP	5	5

= 1 - SUM-OF-YEARS-DIGITS
= 2 - STRAIGHT LINE
= 3 - DOUBLE DECLINING BALANCE
= 4 - 150% DB CHANGING TO SL
= 5 - 175% DB CHANGING TO SYD
= 6 - 200% DB CHANGING TO SYD

a. O&M costs from Table 1-10, include only maintenance, expendables, and burdened labor components.

b. From Table 1-10, as fraction of capital costs.

Model Outputs and Discussion of Results

The IRR for this system is determined to be almost 27 percent. This IRR meets DuPont's hurdle rate (20 percent) and might therefore be considered a cost-effective investment. The system has relatively low incremental fuel costs and high electricity cost savings.

The net energy savings is calculated as 2.22 trillion Btu/year. Table 2-18 summarizes these energy savings.

Table 2-18. Energy Savings (10^{12} Btu/year)

INDUSTRIAL ENERGY SAVINGS	UTILITY ENERGY SAVINGS	NET ENERGY SAVINGS
Natural gas: -5.35	Coal: +3.71	+2.22
Residual oil: +3.86		

Since the system uses a supplementary fired boiler, it may require an exemption from FUA prohibitions on natural gas firing in boilers. Because this system displaces coal in the utility (see Table 2-5 for the SERC region excluding Florida), it appears unlikely that such an exemption would be granted.

Sensitivity Analysis

In the preceding example, it was assumed that the system was allowed a 10 percent investment tax credit. The additional 10 percent energy tax credit was denied because of the use of natural gas. This assumption is not strictly accurate, because other provisions of the Energy Tax Act tend to minimize these credits even further. For example, the use of supplementary firing with natural gas in the heat recovery boiler would not only disqualify that item of equipment from the 10 percent energy tax credit, but would perhaps also result in denial of the regular 10 percent tax credit. Moreover, depreciation of this equipment on an accelerated schedule may be disallowed for the same reason. The gas turbine/generator would, however, be still permitted the 10 percent tax credit.

To analyze a case when such a possibility exists, a model run was made using the following assumptions:

(1) Tax credit on overall capital investment--7% [this figure is compatible with the proportion of tax credit allowed on the gas turbine/generator (10%) and the denial of the tax credit on the heat recovery boiler].

(2) Straight-line depreciation on all equipment.

Although these assumptions do not describe the economic penalties exactly, they are sufficient for purposes of illustration. All other inputs to the model remain unchanged.

These new inputs to the model result in a computed IRR of almost 26 percent. Although this value represents a slightly lower IRR than that calculated previously, it nevertheless meets DuPont's hurdle rate, and the system may be considered cost-effective. Evidently the smaller tax credit and the slower depreciation schedule have a small effect on the economic performance of this system.

Example I-C: Coal-Fired Steam Turbine Cogeneration Option for Textile Fiber and Intermediate Plants

The final cogeneration option considered for these plants entails the use of a double extraction noncondensing steam turbine powered by coal-fired boilers (Section 1.7). These boilers would replace the residual oil-fired boilers currently in use at the plants. Table 2-19 and Figure 1-28 present the major characteristics of this cogeneration system.

The new system would meet all process steam requirements of the two plants and would generate 11,130 kW of electric power for on-site use. The electricity produced would meet almost 20 percent of the electrical demand of the two plants.

Model Inputs to Determine IRR and Energy Savings

The inputs to the model are derived as for the cogeneration options discussed previously. These inputs are presented in Table 2-20.

Table 2-19. Cogeneration System Characteristics

COGENERATION SYSTEM	
• Steam turbine/Generator Continuous Rated Output	11,130 kW (net)
• Annual Operation	8,000 hours
• Incremental Fuel Consumption	
Coal	5.568×10^{12} Btu/year
Residual Oil	-4.840×10^{12} Btu/year
Net	0.728×10^{12} Btu/year
• Net Electricity Generation (11,130 kW) (8,000 hr/yr)	89.04×10^{6} kWh/year

TABLE 2-20. DUPONT SOUTHEAST - MODEL RUN SHEET

RUN SHEET

RUN NO. D-3-2
11,130 kW COAL-FIRED
STEAM TURBINE

PARAMETERS	VARIABLE NAME	VALUE	OR DEFAULT
TECHNICAL CHARACTERISTICS:			
INCREMENTAL FUEL CONSUMPTION (10^6 Btu/yr)	FUELCN	728,000	0.0
NET ELECTRICITY GENERATION (10^6 kWh/yr)	NETGEN	89.04	0.0
UTILITY HEAT RATE (INCLUDING T&D LOSSES) (Btu/kWh)	HTRATE	11,045	0.0
SYSTEM COSTS:			
CAPITAL INVESTMENT ($ in 1985)	CAPINV	35,750,000	0.0
CONSTRUCTION COST DISTRIBUTION -			
PERIODS OF CONSTRUCTION	NPER	10	0
PERIODS PER YEAR	IPER	4	0
CONSTRUCTION FRACTION PER PERIOD	FCONST	0.10	0.0
OPERATIONS & MAINTENANCE COST, INITIAL ($/yr in 1985)	OANDM	1,360,952[a]	0.0
O&M COST ESCALATION RATE (Fraction)	OMRATE	0.071	0.0
SALVAGE VALUE ($)	SALVAG	0	0.0
ENERGY COSTS:			
INCREMENTAL FUEL COST, INITIAL ($/yr in 1985)	FUEL	-20,911,840	0.0
INCREMENTAL FUEL COST ESCALATION RATE (Fraction)	FRATE	0.1154	0.0
ELECTRICITY COST, INITIAL ($/yr in 1985)	ELECT	-5,983,488	0.0
ELECTRICITY COST ESCALATION RATE (Fraction)	ERATE	0.1020	0.0

RUN SHEET (Continued)

FINANCIAL PARAMETERS:

DISCOUNT RATE (Fraction)	DISRTE	0.20	0.2
DOWNPAYMENT (Fraction)	DWNPMT	1.0	1.0
LOAN LIFE (Up To 40 Years)	LIFLON	0	12
SYSTEM LIFE (Up To 40 Years)	LIFSYS	12	12
INTEREST RATE (Fraction)	IRATE	0	0.2
INCOME TAX RATE (Fraction)	TXRATE	0.48	0.48
TAX CREDIT RATE (Fraction)	TAXCRD	0.20	0.20
INSURANCE RATE (Fraction)	INS	0.002[b]	0.005
INSURANCE ESCALATION RATE (Fraction)	INSRAT	0.071	0.0
PROPERTY TAX RATE (Fraction)	PCTAX	0.025	0.025
PROPERTY TAX ESCALATION RATE (Fraction)	PCRATE	0.071	0.0
DEPRECIATION LIFE (Up To 40 Years)	DEPYRS	5	5
DEPRECIATION MODE	MODDEP	5	5

= 1 - SUM-OF-YEARS-DIGITS
= 2 - STRAIGHT LINE
= 3 - DOUBLE DECLINING BALANCE
= 4 - 150% DB CHANGING TO SL
= 5 - 175% DB CHANGING TO SYD
= 6 - 200% DB CHANGING TO SYD

a. O&M costs from Table 1-10, include only maintenance, expendables, and burdened labor components.

b. From Table 1-10, as fraction of capital costs.

Model Outputs and Discussion of Results

The IRR for this system is determined to be almost 39 percent. This IRR meets DuPont's hurdle rate (20 percent) and could therefore be considered a cost-effective investment under the particular economic assumptions made.

The major reason for this relatively high IRR may be attributed to the significant savings in fuel costs that result from substitution of a coal-fired system for the existing residual oil-fired system. The differences in the prices of residual oil and coal are so large, that despite greater energy consumption by the cogeneration system, fuel expenditures are significantly less than those for the existing system. These savings with those resulting from a reduction in electricity purchased by the plants tend to produce this favorable return on investment.

The energy use changes resulting from cogeneration at the DuPont plant are presented in Table 2-21.

Table 2-21. Energy Savings (10^{12} Btu/year)

INDUSTRY ENERGY SAVINGS		UTILITY ENERGY SAVINGS	NET ENERGY SAVINGS
Residual oil:	+4.84	Coal: +0.98	+0.25
Coal:	-5.57		

Example I-D: Coal-Fired Boiler to Replace Existing Residual Oil-Fired Boilers at Textile Fiber and Intermediate Plants

This option does not represent a cogeneration system; rather, it examines the effects of fuel substitution. This system merely replaces the existing residual oil-fired boilers with a coal-fired unit. It would meet all process steam requirements of the two plants. However, no electric power is generated in this instance. Technical and cost data pertaining to this boiler are described in Table 2-22.

Table 2-22. Coal-Fired Boiler--Technical and Cost Data

TECHNICAL	
• Incremental Fuel Consumption	
- Coal	5.568×10^{12} Btu/year
- Residual oil	$- 4.840 \times 10^{12}$ Btu/year
Net	0.728×10^{12} Btu/year
COST DATA	
• Capital cost (mid-1981)	$26,500,000
• O&M Costs (mid-1981)	$870,000/year

The inputs to the model are derived as for the cogeneration options discussed previously. These inputs are presented in Table 2-23.

TABLE 2-23 DUPONT FIBER & INTERMEDIATE PLANTS - MODEL RUN SHEET

RUN SHEET

RUN NO. D-3-2 - BOILER - 1
COAL BOILER FOR REPLACEMENT
NO POWER GENERATION

PARAMETERS	VARIABLE NAME	VALUE	OR DEFAULT
TECHNICAL CHARACTERISTICS:			
INCREMENTAL FUEL CONSUMPTION (10^6 Btu/yr)	FUELCN	-198,400	0.0
NET ELECTRICITY GENERATION (10^6 kWh/yr)	NETGEN	0	0.0
UTILITY HEAT RATE (INCLUDING T&D LOSSES) (Btu/kWh)	HTRATE	0	0.0
SYSTEM COSTS:			
CAPITAL INVESTMENT ($ in 1983)	CAPINV	25,710,300	0.0
CONSTRUCTION COST DISTRIBUTION -			
PERIODS OF CONSTRUCTION	NPER	10	0
PERIODS PER YEAR	IPER	4	0
CONSTRUCTION FRACTION PER PERIOD	FCONST	0.1	0.0
OPERATIONS & MAINTENANCE COST, INITIAL ($/yr in 1985)	OANDM	1,184,029	0.0
O&M COST ESCALATION RATE (Fraction)	OMRATE	0.071	0.0
SALVAGE VALUE ($)	SALVAG	0	0.0
ENERGY COSTS:			
INCREMENTAL FUEL COST, INITIAL ($/yr in 1983)	FUEL	-23,987,488	0.0
INCREMENTAL FUEL COST ESCALATION RATE (Fraction)	FRATE	0.1147	0.0
ELECTRICITY COST, INITIAL ($/yr in 1983)*	ELECT	0	0.0
ELECTRICITY COST ESCALATION RATE (Fraction)	ERATE	0	0.0

*Includes sales of 275 kW to utility grid.

RUN SHEET (Continued)

FINANCIAL PARAMETERS:

DISCOUNT RATE (Fraction)	DISRTE	0.20	0.2
DOWNPAYMENT (Fraction)	DWNPMT	1.0	1.0
LOAN LIFE (Up To 40 Years)	LIFLON	0	12
SYSTEM LIFE (Up To 40 Years)	LIFSYS	12	12
INTEREST RATE (Fraction)	IRATE	0	0.2
INCOME TAX RATE (Fraction)	TXRATE	0.48	0.48
TAX CREDIT RATE (Fraction)	TAXCRD	0.20	0.20
INSURANCE RATE (Fraction)	INS	0.002	0.005
INSURANCE ESCALATION RATE (Fraction)	INSRAT	0.071	0.0
PROPERTY TAX RATE (Fraction)	PCTAX	0.025	0.025
PROPERTY TAX ESCALATION RATE (Fraction)	PCRATE	0.071	0.0
DEPRECIATION LIFE (Up To 40 Years)	DEPYRS	5	5
DEPRECIATION MODE	MODDEP	5	5

= 1 - SUM-OF-YEARS-DIGITS
= 2 - STRAIGHT LINE
= 3 - DOUBLE DECLINING BALANCE
= 4 - 150% DB CHANGING TO SL
= 5 - 175% DB CHANGING TO SYD
= 6 - 200% DB CHANGING TO SYD

Model Outputs and Discussion of Results

The IRR for this system is almost 44 percent, which exceeds DuPont's hurdle rate by a significant margin. Although no electricity is generated by this system, the substitution of a cheaper fuel (coal) for the residual oil currently being used at DuPont results in substantial savings in fuel costs. The magnitude of these savings (as reflected in the IRR) appears to justify the replacement of the existing residual oil-fired boilers with a new coal-fired one.

The IRR for this system exceeds that for the coal-fired cogeneration case (Example I-C). This can partially be attributed to the fact that electricity purchased by DuPont is relatively cheap owing to the fuel mix (97% coal and nuclear) employed by Carolina Power to generate its electricity. Also, as the cogeneration system uses a higher pressure boiler, its associated capital costs are significantly larger than for the non-cogeneration case. Furthermore, the incremental fuel consumption is significantly greater with cogeneration.

If this example had however been considered in a predominantly oil and gas burning region, electricity prices would be significantly higher, and the cogeneration system may well be the more favorable option.

Fuel substitution may not produce such high IRRs in all instances. However, this example illustrates that although a cogeneration system may be desirable for a number of applications, fuel substitution (without cogeneration) should be considered as a viable alternative.

2.4.3 Large Oil Refinery, Norco, Louisiana

Energy use data pertaining to a typical large refinery was obtained from the Exxon Research and Engineering Co. The refinery is located in the SWPP region of the National Electric Reliability Council and is served by the Louisiana Power and Light Co. Louisiana Power and Light, which is currently 100 percent dependent on oil and gas for power production (Table 2-24), operates within the Middle South Utilities System power pool which is also heavily dependent on oil and natural gas (81% oil and gas, 17% nuclear, and the remaining 2% coal). It would thus be expected that oil and natural gas would be the primary fuels displaced at the utility as a result of cogeneration at the refinery.

The average profile of energy use at the refinery is as shown in Figure 1-29, Section 1.7. Presently, residual oil-fired boilers supply all of the steam requirements of the refinery. Some shaft power (although no electricity) is also cogenerated using extraction turbines. The two cogeneration options for this refinery discussed in Chapter 1 will be evaluated for their economic performance.

Example II-B: Coal Fired-Steam Turbine

The cogeneration alternative considered here is a coal-fired steam turbine system (Figure 1-31). In this option, steam is generated in a new coal-fired boiler and is fed to the throttle of a back-pressure turbine producing 11.1 MW of electrical power. Steam at the back pressure of the turbine is then fed directly into the existing high-pressure steam main and combines with that generated in the existing but derated residual oil-fired boiler. The combined steam flow then enters the existing back-pressure/extraction steam turbines and produces the same amount of power as in the base case. As a result of the added amount of cogenerated power, purchased electricity is reduced from 60.3 to 49.2 MW. Table 2-24 illustrates the major characteristics of this cogeneration system and that of the utility serving the plant.

For analysis of this option, the inputs to the model are derived as in the previous cases. These inputs are shown in Table 2-25.

Table 2-24. Cogeneration System and Utility Characteristics

COGENERATION SYSTEM	
• Steam turbine/generator Continuous Rated Output	11,100 kW (net)
• Annual Operation	8,000 hrs
• Incremental fuel consumption	
Coal	5.584×10^{12} Btu/year
Resid.	$- 4.944 \times 10^{12}$ Btu/year
Net	0.64×10^{12} Btu/year
• Net Electricity Generation (11,100 kW)(8,000 hr/yr)	88.8×10^{6} kWh/year
UTILITY (LOUISIANA POWER & LIGHT CO.)	
• Overall system heat rate[a] (1980)	10,753 Btu/kWh
• Transmission & Distribution losses	7% (assumed)
• Fuels used for power generation (in 1979)[b]	
- Oil & natural gas	100%

[a] Based on Louisiana Power & Light Co. Annual Report (1980)
[b] Based on Electrical World, Directory of Electric Utilities, 1980-81.

TABLE 2-25. LARGE OIL REFINERY - MODEL RUN SHEET

RUN SHEET

RUN NO. S-1-2

11,100 kW COAL-FIRED STEAM TURBINE SYSTEM

PARAMETERS	VARIABLE NAME	VALUE	OR DEFAULT
TECHNICAL CHARACTERISTICS:			
INCREMENTAL FUEL CONSUMPTION (10^6 Btu/yr)	FUELCN	640,000	0.0
NET ELECTRICITY GENERATION (10^6 kWh/yr)	NETGEN	88.8	0.0
UTILITY HEAT RATE (INCLUDING T&D LOSSES) (Btu/kWh)	HTRATE	11,506	0.0
SYSTEM COSTS:			
CAPITAL INVESTMENT ($ in 1985)	CAPINV	34,760,000	0.0
CONSTRUCTION COST DISTRIBUTION -			
PERIODS OF CONSTRUCTION	NPER	10	0
PERIODS PER YEAR	IPER	4	0
CONSTRUCTION FRACTION PER PERIOD	FCONST	0.10	0.0
OPERATIONS & MAINTENANCE COST, INITIAL ($/yr in 1985)	OANDM	1,292,905[a]	0.0
O&M COST ESCALATION RATE (Fraction)	OMRATE	0.071	0.0
SALVAGE VALUE ($)	SALVAG	0	0.0
ENERGY COSTS:			
INCREMENTAL FUEL COST, INITIAL ($/yr in 1985)	FUEL	-18,860,480	0.0
INCREMENTAL FUEL COST ESCALATION RATE (Fraction)	FRATE	0.1007	0.0
ELECTRICITY COST, INITIAL ($/yr in 1985)	ELECT	-6,207,120	0.0
ELECTRICITY COST ESCALATION RATE (Fraction)	ERATE	0.1206	0.0

RUN SHEET (Continued)

FINANCIAL PARAMETERS:

DISCOUNT RATE (Fraction)	DISRTE	0.20	0.2
DOWNPAYMENT (Fraction)	DWNPMT	1.0	1.0
LOAN LIFE (Up To 40 Years)	LIFLON	0	12
SYSTEM LIFE (Up To 40 Years)	LIFSYS	12	12
INTEREST RATE (Fraction)	IRATE	0	0.2
INCOME TAX RATE (Fraction)	TXRATE	0.48	0.48
TAX CREDIT RATE (Fraction)	TAXCRD	20	0.20
INSURANCE RATE (Fraction)	INS	0.002[b]	0.005
INSURANCE ESCALATION RATE (Fraction)	INSRAT	0.071	0.0
PROPERTY TAX RATE (Fraction)	PCTAX	0.025	0.025
PROPERTY TAX ESCALATION RATE (Fraction)	PCRATE	0.071	0.0
DEPRECIATION LIFE (Up To 40 Years)	DEPYRS	5	5
DEPRECIATION MODE	MODDEP	5	5

= 1 - SUM-OF-YEARS-DIGITS
= 2 - STRAIGHT LINE
= 3 - DOUBLE DECLINING BALANCE
= 4 - 150% DB CHANGING TO SL
= 5 - 175% DB CHANGING TO SYD
= 6 - 200% DB CHANGING TO SYD

a. O&M costs from Table 1-11, include only maintenance and expendables, and burdened labor components.

b. From Table 1-11, as fraction of capital costs.

Model Outputs and Discussion of Results

The IRR for this system is determined to be over 37 percent. It could therefore be considered a cost-effective investment under the particular economic assumptions made.

As in the case of the DuPont coal-fired cogeneration system, this system again shows large fuel cost savings through fuel substitution (in this case from residual oil to coal). These savings, together with the large electricity cost savings, produce a relatively high rate of return.

Cogeneration at this refinery will be reflected in a decrease in residual oil use combined with the use (for the first time) of coal.

At the utility, the decrease in electricity purchased by the industrial plant will bring about a corresponding reduction in utility power generation. As Louisiana Power and Light is currently 100 percent oil and gas fired, these units will be backed down to the extent necessary to accommodate this decrease in power demand. The net energy savings through this cogeneration option are presented in Table 2-26.

Table 2-26. Energy Savings (10^{12} Btu/year)

INDUSTRY ENERGY SAVINGS	UTILITY ENERGY SAVINGS	NET ENERGY SAVINGS
Residual oil: + 4.94	Oil & gas: + 1.02	+0.38
Coal: - 5.58		

Example II-A. Natural Gas-Fired Combustion Turbine Topping Existing Boiler

The technical characteristics of this system have been discussed in detail in Section 1.7. The system consists of a 21,160 kW gas turbine topping the existing residual oil-fired boilers (Figure 1-32). The exhaust gas stream from the gas turbine is used as combustion air in the boilers. The existing back-pressure/extraction steam turbine system remains unchanged in the new configuration. This cogeneration system meets over 35 percent of the electrical requirements of the refinery. Table 2-27 summarizes the major characteristics of this cogeneration system.

Table 2-27. Cogeneration System Characteristics

COGENERATION SYSTEM	
• Gas Turbine/Generator Continuous Rated Output	21,160 kW (net)
• Annual Operation	8,000 hours
• Incremental Fuel Consumption	
Natural Gas	$2,072,600 \times 10^6$ Btu/yr
Residual Fuel Oil	$-1,376,000 \times 10^6$ Btu/yr
Net	$696,000 \times 10^6$ Btu/yr
• Net Generation	
(21,160 kW) (8,000 hr)	169.28×10^6 kWh/yr

The inputs to the ICOP model to perform the economic and energy-savings analysis are presented in Table 2-28.

TABLE 2-28 LARGE OIL REFINERY - MODEL RUN SHEET

RUN SHEET

RUN NO. S-2-2
21,160 kW GAS TURBINE TOPPING
EXISTING BOILER

PARAMETERS	VARIABLE NAME	VALUE	OR DEFAULT
TECHNICAL CHARACTERISTICS:			
INCREMENTAL FUEL CONSUMPTION, (10^6 Btu/yr)	FUELCN	696,000	0.0
NET ELECTRICITY GENERATION (10^6 kWh/yr)	NETGEN	169.28	0.0
UTILITY HEAT RATE (INCLUDING T&D LOSSES) (Btu/kWh)	HTRATE	11,506	0.0
SYSTEM COSTS:			
CAPITAL INVESTMENT ($ in 1985)	CAPINV	18,659,048	0.0
CONSTRUCTION COST DISTRIBUTION -			
PERIODS OF CONSTRUCTION	NPER	6	0
PERIODS PER YEAR	IPER	4	0
CONSTRUCTION FRACTION PER PERIOD	FCONST	0.167	0.0
OPERATIONS & MAINTENANCE COST, INITIAL ($/yr in 1985)	OANDM	952,667[a]	0.0
O&M COST ESCALATION RATE (Fraction)	OMRATE	0.071	0.0
SALVAGE VALUE ($)	SALVAG	0	0.0
ENERGY COSTS:			
INCREMENTAL FUEL COST, INITIAL ($/yr in 1985)	FUEL	3,312,960	0.0
INCREMENTAL FUEL COST ESCALATION RATE (Fraction)	FRATE	0.1792	0.0
ELECTRICITY COST, INITIAL ($/yr in 1985)	ELECT	-11,832,672	0.0
ELECTRICITY COST ESCALATION RATE (Fraction)	ERATE	0.1206	0.0

RUN SHEET (Continued)

FINANCIAL PARAMETERS:

DISCOUNT RATE (Fraction)	DISRTE	0.20	0.2
DOWNPAYMENT (Fraction)	DWNPMT	1.0	1.0
LOAN LIFE (Up To 40 Years)	LIFLON	0	12
SYSTEM LIFE (Up To 40 Years)	LIFSYS	12	12
INTEREST RATE (Fraction)	IRATE	0	0.2
INCOME TAX RATE (Fraction)	TXRATE	0.48	0.48
TAX CREDIT RATE (Fraction)	TAXCRD	0.10	0.20
INSURANCE RATE (Fraction)	INS	0.002[b]	0.005
INSURANCE ESCALATION RATE (Fraction)	INSRAT	0.071	0.0
PROPERTY TAX RATE (Fraction)	PCTAX	0.025	0.025
PROPERTY TAX ESCALATION RATE (Fraction)	PCRATE	0.071	0.0
DEPRECIATION LIFE (Up To 40 Years)	DEPYRS	5	5
DEPRECIATION MODE = 1 - SUM-OF-YEARS-DIGITS = 2 - STRAIGHT LINE = 3 - DOUBLE DECLINING BALANCE = 4 - 150% DB CHANGING TO SL = 5 - 175% DB CHANGING TO SYD = 6 - 200% DB CHANGING TO SYD	MODDEP	5	5

a. O&M costs from Table 1-11, include only maintenance, expendables, and burdened labor components.

b. From Table 1-11, as fraction of capital costs.

Model Outputs and Discussion of Results

The IRR for this system, which is over 28 percent, exceeds the hurdle rate for this investment. It can therefore be considered cost-effective under the economic assumptions made.

Some fuel substitution is brought about through implementation of this cogeneration option. Residual oil consumption at the plant is reduced while natural gas is now introduced to partially take its place and to simultaneously provide fuel for power generation. The results indicate that although the system burns oil and natural gas, it will result in a net saving of these fuels because cogeneration at the refinery will result in reduced oil and gas-fired generation at Louisiana Power and Light. The net energy savings resulting from cogeneration at the refinery are summarized in Table 2-29.

Table 2-29. Energy Savings (10^{12} Btu/year)

INDUSTRY ENERGY SAVINGS		UTILITY ENERGY SAVINGS	NET ENERGY SAVINGS
Residual oil:	+1.38	Oil and Natural Gas: +1.95	+1.26
Natural gas:	-2.07		

2.4.4 Example IV: Fine Chemicals Plant

The plant is located in the MAAC region of the National Electric Reliability Council. It is served by the Jersey Central Power and Light Co., which generates 59 percent of its power using coal and nuclear energy (Table 2-30). The remaining 41 percent is generated using a mix of oil, gas, and hydro. Jersey Central operates within the Pennsylvania - New Jersey - Maryland (PJM) interconnection, which is also dependent on a mix of fuels for power generation.

Table 2-30. Cogeneration System and Utility Characteristics

COGENERATION SYSTEM	
o Slow speed Diesel/generator, continuous rated output	23,275 kW
o Annual operation	8,400 hours
o Incremental Fuel Consumption (resid.)	$782,040 \times 10^6$ Btu/year
o Net Generation (8400 hr) (23,275 kW)	195.51×10^6 kWh/year
UTILITY - (Jersey Central Power & Light Co.)	
o System heat rate[1]	10,709 Btu/kW
o Transmission and Distribution Losses	7% (assumed)
o Fuels used for power generation[a] (in 1980)	
- coal	28%
- nuclear	31%
- oil	19%
- other (gas & hydro)	22%

[a]Based on Jersey Central Power & Light Co. 1980 Annual Report

The average pattern of energy use at this plant is as described in Section 1.7. The plant electrical load of 20,000 to 23,000 kW is currently met by power purchased from the utility. The thermal load is met by the plant's residual oil fired boilers which produce approximately 430,000 lb/hr. of steam at the desired pressures.

The cogeneration alternative considered for this plant features a slow-speed residual oil-fired diesel engine system (Figure 1-34). The hot gases from the diesel engine exhaust, containing about 15 percent oxygen by volume, are utilized as a source of combustion oxygen for a supplementary-fired waste heat boiler. Waste heat from the diesel is also recovered from the air cooler and engine water cooling circuits. The plant will utilize the entire thermal output of the cogeneration system and will also consume 23,000 of the 23,275 kW of electric power generated. The balance (about 275 kW) could will be exported to the utility grid. Table 2-30 presents the major characteristics of the proposed cogeneration system and that of the utility serving the plant.

Analysis Using Local Energy Prices

The local price for residual fuel oil, quoted as $\$4.88/10^6$ Btu, is the actual price paid for this fuel by the company in September 1981. Local electricity prices were 6.3¢/kWh (in September of 1981). It is assumed that the fuel oil and electricity prices escalate at identical rates of 10 percent each annually in this case, per assumptions used by the company.

The inputs to the ICOP model to perform the economic and energy savings analysis are presented in Table 2-31. This example differs from those discussed previously in that the projected startup of this system is in the 4th quarter of 1982, rather than 1985 since implementation of the system is currently underway.

For this illustrative example, only the regular investment tax credit has been taken. As the system is fired by residual oil, the 10 percent energy tax credit is denied. It is to be noted that of all the examples discussed thus far, only this system produces power in excess of plant demands. This excess power (about 275 kW) could be sold to the utility grid based on the "avoided cost"* to the utility of generating this power.

The IRR obtained for this system, as calculated by TRW using these fuel prices and retail electricity rates amounts to over 30 percent. It may therefore be considered an economically attractive investment. The high IRR in this case may be attributed to the high electricity prices and low fuel prices in the local region.

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*See Chapter 4 of this handbook for a detailed discussion on avoided costs.

TABLE 2-31 FINE CHEMICALS PLANT - MODEL RUN SHEET

RUN SHEET

RUN NO. H-1-2-LOCAL-1
23,275 kW DIESEL WITH
SUPPLEMENTARY-FIRED BOILER

PARAMETERS	VARIABLE NAME	VALUE	OR DEFAULT
TECHNICAL CHARACTERISTICS:			
INCREMENTAL FUEL CONSUMPTION (10^6 Btu/yr)	FUELCN	782,040	0.0
NET ELECTRICITY GENERATION (10^6 kWh/yr)	NETGEN	195.51	0.0
UTILITY HEAT RATE (INCLUDING T&D LOSSES) (Btu/kWh)	HTRATE	11,459	0.0
SYSTEM COSTS:			
CAPITAL INVESTMENT ($ in 1981)	CAPINV	21,520,000	0.0
CONSTRUCTION COST DISTRIBUTION -			
PERIODS OF CONSTRUCTION	NPER	5	0
PERIODS PER YEAR	IPER	4	0
CONSTRUCTION FRACTION PER PERIOD	FCONST	0.2	0.0
OPERATIONS & MAINTENANCE COST, INITIAL ($/yr in 1982)	OANDM	574,200[a]	0.0
O&M COST ESCALATION RATE (Fraction)	OMRATE	0.071	0.0
SALVAGE VALUE ($)	SALVAG	0	0.0
ENERGY COSTS:			
INCREMENTAL FUEL COST, INITIAL ($/yr in 1982)	FUEL	4,207,375	0.0
INCREMENTAL FUEL COST ESCALATION RATE (Fraction)	FRATE	0.10	0.0
ELECTRICITY COST, INITIAL ($/yr in 1982)*	ELECT	-13,881,210	0.0
ELECTRICITY COST ESCALATION RATE (Fraction)	ERATE	0.10	0.0

*Includes sales of 275 kW to utility grid.

FINANCIAL PARAMETERS:

DISCOUNT RATE (Fraction)	DISRTE	0.20	0.2
DOWNPAYMENT (Fraction)	DWNPMT	1.0	1.0
LOAN LIFE (Up To 40 Years)	LIFLON	0	12
SYSTEM LIFE (Up To 40 Years)	LIFSYS	12	12
INTEREST RATE (Fraction)	IRATE	0	0.2
INCOME TAX RATE (Fraction)	TXRATE	0.48	0.48
TAX CREDIT RATE (Fraction)	TAXCRD	0.10	0.20
INSURANCE RATE (Fraction)	INS	0.005[b]	0.005
INSURANCE ESCALATION RATE (Fraction)	INSRAT	0.071	0.0
PROPERTY TAX RATE (Fraction)	PCTAX	0.015	0.025
PROPERTY TAX ESCALATION RATE (Fraction)	PCRATE	0.071	0.0
DEPRECIATION LIFE (Up To 40 Years)	DEPYRS	5	5
DEPRECIATION MODE	MODDEP	4	5

= 1 - SUM-OF-YEARS-DIGITS
= 2 - STRAIGHT LINE
= 3 - DOUBLE DECLINING BALANCE
= 4 - 150% DB CHANGING TO SL
= 5 - 175% DB CHANGING TO SYD
= 6 - 200% DB CHANGING TO SYD

a. O&M costs from Table 1-13, include only maintenance and expendables, and burdened labor components.

b. From Table 1-13, as fraction of capital costs.

3.0 ENVIRONMENTAL CONSIDERATIONS

This chapter presents a summary of environmental considerations in implementing cogeneration systems. Included is a discussion of (1) Federal regulations applicable to cogeneration systems, (2) anticipated changes to regulations, and (3) new regulations for combustion devices that could be used in cogeneration applications. The major pollutants produced by conventional combustion systems are identified, and control options are described. Finally, a preliminary analysis of emissions changes in an industrial plant using a cogeneration system is performed to illustrate the potential environmental requirements to which a cogeneration user would be subject.

3.1 APPLICABLE REGULATIONS AND STANDARDS

3.1.1 Federal Environmental Protection Agency (EPA) Regulations

Several regulations currently applicable to fuel combustion devices would also be applicable to cogeneration, affecting the siting of sources as well as controlling emissions of specific pollutants. The most limiting regulations for fuel combustion systems are those dealing with air pollution caused by siting and operational requirements. Water quality and solid waste regulations also impact combustion systems, but to a lesser extent. The major environmental permits to be considered are listed in Table 3-1.

The regulations and standards described in this section are those that are currently applicable. It should be recognized that some of these regulations may change over the next few years due to the expiration of the Clean Air Act in August 1981 and the Administration's policy on energy development and environmental protection. The potential changes in the regulations will be discussed later in this section.

Air Pollution Control Regulations

New cogeneration facilities will be affected by regulations for (1) Prevention of Significant Deterioration (PSD), (2) nonattainment areas, and (3) New Source Performance Standards (NSPS). In some cases, modifications to existing industrial plants where cogeneration systems are planned will also be affected by these regulations. As compared with a steam

Table 3-1. Major Environmental Permit Requirements for Cogeneration Systems[a]

PERMIT	AGENCY JURISDICTION
Prevention of Significant Deterioration (PSD)	EPA
Compliance with New Source Performance Standards (NSPS)	EPA, Some states
Non-attainment area requirements	EPA
Permit to construct and operate air pollution emission source	All states, some counties
National Pollutant Discharge Elimination System (NPDES)	All states
Certification of waste disposal sites	Most states

[a] Other federal and state regulations may be applicable, depending upon size of cogeneration system, location, and amount of pollutants generated.

system alone, cogeneration systems usually require increased fuel consumption at the industrial plant, potentially resulting in higher onsite emissions, while overall net emissions (including the industrial and utility plants) may be lower than that of the steam system. Current regulations do not take into account this potential decrease in emissions; therefore, cogeneration systems are treated basically as conventional combustion systems for producing either heat or electrical energy.

Cogeneration systems would be subject to permit requirements imposed by PSD regulations in areas that are attaining National Ambient Air Quality Standards (NAAQS). Areas classified as nonattainment have different permit requirements as described later.

Under PSD regulations, most industrial firms building a new plant or installing a cogeneration system at an existing plant must submit a PSD permit application if the source will emit in excess of 100* tons/year (tpy) of a criteria pollutant** and if the cogeneration plant (considered in an existing plant or part of a new plant), as a modified source, emits pollutants greater than levels considered significant. In the latter case, the PSD permit applications must consider only those pollutants considered significant. This process is illustrated in Figure 3-1. These significant levels are listed in Table 3-2. In the permit application, the source owner or operator must provide an air quality modeling analysis to assess impacts on NAAQS and allowable increments (Table 3-3). In some cases, baseline air quality data must be provided by means of measurements taken over a period of one year if no data exist that meet EPA requirements. The need for baseline data usually occurs for sources located in rural areas, while in urban areas there is usually adequate historical data. The permit application is submitted to an EPA regional office which will review the application and issue the permit. A list of the ten regional offices is presented in Section 3.3.

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* Plants in one of 28 categories defined by EPA. If not in one of these categories the limitation increases to 250 tons/year.

**Criteria pollutant - pollutants for which ambient air quality standards have been established on the basis of health and welfare effects.

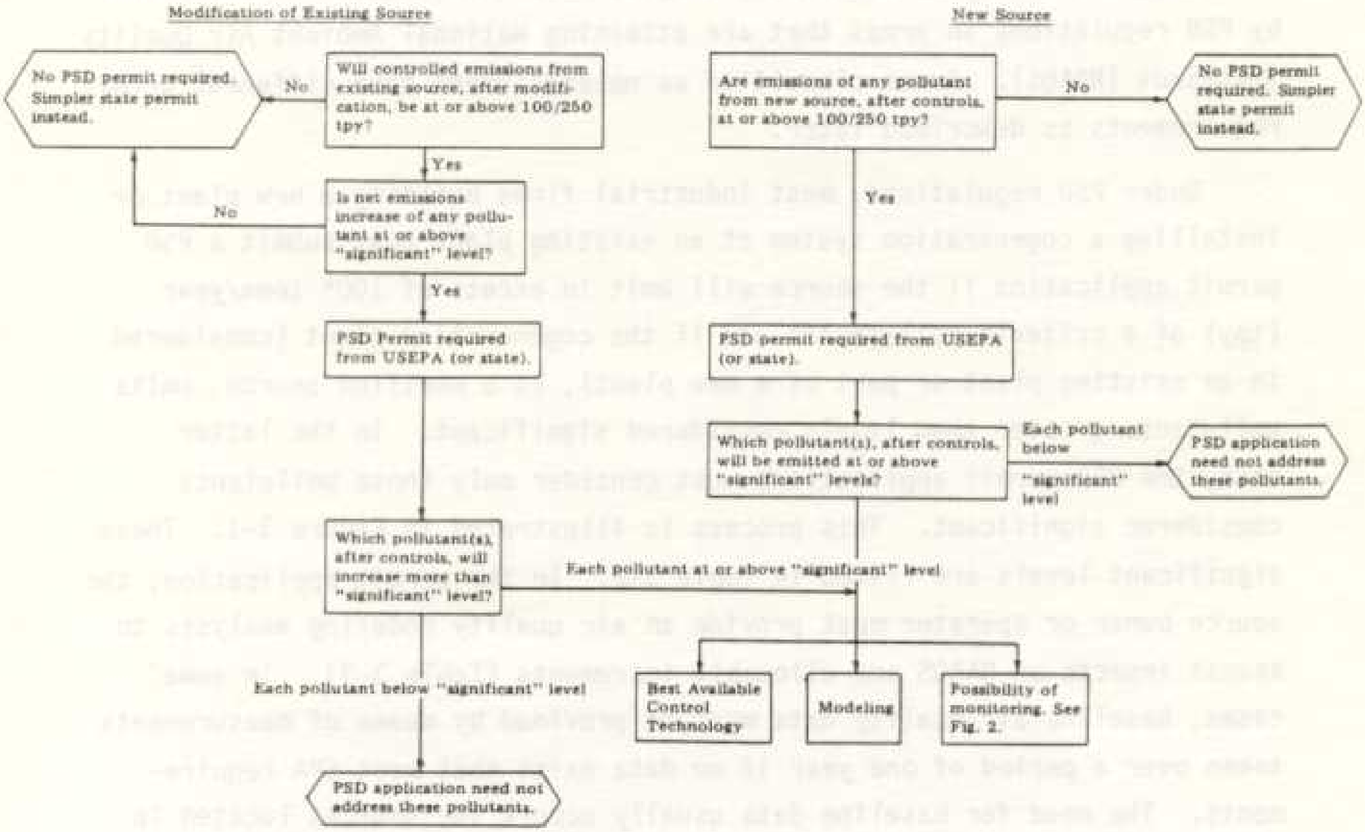

Figure 3-1. Preconstruction Review for New and Modified Sources

Table 3-2. Emission Levels Considered Significant Under PSD Regulations[a]

Pollutant	Emissions Rate (tons/year)
Carbon monoxide	100
Nitrogen oxides	40
Sulfur dioxide	40
Particulate matter	25
Ozone	40[b]
Lead	0.6
Asbestos	0.007
Beryllium	0.0004
Mercury	0.1
Vinyl chloride	1
Fluorides	3
Sulfuric acid mist	7
Hydrogen sulfide	10
Total reduced sulfur[c]	10
Reduced sulfur compounds[c]	10

[a] Notwithstanding the above values, any major source or modification locating within 10 km of a Class I area that causes an increase of at least 1 $\mu g/m^3$ in the ambient air concentration (over the Class I area) for a regulated pollutant (i.e., a pollutant for which an emission or air quality standard has been established) is regarded as emitting significant amounts of that pollutant.

[b] Volatile organic compounds.

[c] Including hydrogen sulfide.

Table 3-3. Allowable PSD Increments

Pollutant[a]	Maximum Allowable Increase (Micrograms per cubic meter)
Class I:	
Particulate matter:	
Annual geometric mean	5
24-hr maximum	10
Sulfur dioxide:	
Annual arithmetic mean	2
24-hr maximum	5
3-hr maximum	25
Class II:	
Particulate matter:	
Annual geometric mean	19
24-hr maximum	37
Sulfur dioxide:	
Annual arithmetic mean	20
24-hr maximum	91
3-hr maximum	512
Class III:	
Particulate matter:	
Annual geometric mean	37
24-hr maximum	75
Sulfur dioxide:	
Annual arithmetic mean	40
24-hr maximum	182
3-hr maximum	700

[a]Class I - National parks, wilderness areas, national memorial parks
Class II - All other areas except Class III - most areas in U.S. are Class II
Class III - Heavy industrial areas.

[b]For specified non-annual periods (e.g., 24-hr, 3-hr) the allowable increment may be exceeded during only one such period per year at any receptor site.

An additional major requirement for PSD is the application of Best Available Control Technology (BACT) for all pollutants subject to the PSD regulations. The BACT may take the form of a specific control technology in industrial processes or an emission limitation that the source may meet by any technology capable of achieving these limitations. Generally, BACT may be negotiated between the source and EPA, based on source-specific considerations which consider the energy, environmental, and economic aspects of control options. For cogeneration applications using conventional steam turbine systems, BACT will require electrostatic precipitation or fabric filters for particulates, and flue gas desulfurization or low-sulfur fuels for sulfur dioxide; for gas turbines, however, it will be achieved primarily by using low-sulfur and low-ash fuel.

Additional miscellaneous impact analyses are required for the permit applications. The source owner must analyze the impairment to visibility, soils, and vegetation that would occur as a result of construction or modification of a source. This analysis must include the effect of general commercial, residential, industrial, and other growth associated with the construction or modification. Also, an analysis is required of the air quality impact of the project for the area as a result of general commercial, residential, and industrial growth associated with the project. No standard permit forms exist for PSD; however, the regional office can provide guidance on preparing the application.

Those areas that have not achieved NAAQS for one or more pollutants have been classified as "nonattainment," and sources wishing to locate in these areas are not subject to PSD requirements. Major emission sources in these areas must, however:

- arrange for emission reduction from existing sources in the region that more than offset the total emissions of the new source or modification, and
- meet the Lowest Achievable Emission Rates (LAER) for the nonattainment pollutant. The LAER is the lowest emission level achieved in practice or required by any State Implementation Plan for attaining air quality standards.

All other sources in the State under the same ownership as the source or modification must be in compliance or under compliance schedules for all pertinent emissions. The attainment status of any area can be obtained from the state air pollution control agency or the EPA regional office.

The NSPS regulate emissions of specific pollutants for sources starting operation after the promulgation date of the standards. No standards exist specifically for cogeneration systems; however standards do exist for fossil fuel steam generators and electric utility steam generators greater than $250x10^6$ Btu/hour heat input and for stationary gas turbines of $10x10^6$ Btu/hour heat input and greater. The EPA has recently proposed rescinding the NO_x emission limit for industrial gas turbines greater than $100x10^6$ Btu/hour heat input. These standards would be applicable to cogeneration systems using either combustion device. Cogeneration facilities with greater than $250x10^6$ Btu/hour heat input and selling more than 25 MW of electricity or more than one-third of their potential electrical output capacity would be regulated by the NSPS for electric utility steam generators. Facilities selling less electricity would be regulated under the less stringent regulations for fossil fuel steam generators of greater than $250x10^6$ Btu/hour heat input. The NSPS for steam generators and gas turbines are shown in Tables 3-4 and 3-5 respectively.

The EPA is also considering NSPS's for several other source categories which can be used in cogeneration applications as follows: (1) industrial boilers, (2) non-fossil-fuel industrial boilers, and (3) stationary internal combustion engines. The standards for industrial boilers will regulate emissions of sulfur dioxide particulates, and nitrogen oxides to varying levels depending on the size of the boiler. The projected standards for coal-fired industrial boilers are shown in Table 3-6.

New Source Performance Standards are also being investigated for non-fossil-fuel fired boilers. These standards would apply to particulate emissions from boilers firing wood, municipal solid waste, refuse-derived fuels, and bagasse. For coal and wood mixtures, SO_2 standards would also apply. Development of these standards is at a very preliminary stage, and actual emission limits have not yet been considered.

Table 3-4. New Source Performance Standards (NSPS) for Steam Generating Units

Affected Facility	Pollutant	Emission Level
Fossil Fuel-Fired Steam Generators >73 MW Heat Input (>250 x 10^6 Btu/hr)		
Coal-fired boilers[a]	Particulate	0.10 lb/million Btu
	Opacity	20% (27% for 6 min/hr)
	SO_2	1.20 lb/million Btu
	NO_x	
	Anthracite, Bituminous, or Subbituminous Coal	0.70 lb/million Btu
	Lignite	0.60 lb/million Btu
	More than 25% coal refuse	Exempt
Oil or gas-fired boilers	Particulate	0.10 lb/million Btu
	Opacity	20% (27% for 6 min/hr)
	SO_2 -- oil	0.80 lb/million Btu
	NO_x -- oil	0.30 lb/million Btu
	NO_x -- gas	0.20 lb/million Btu
Electric Utility Steam-Generating Units >73MW Heat Input (>250 x 10^6 Btu/hr)		
Coal-fired boilers and coal-derived fuels	Particulate	0.03 lb/million Btu
	Opacity	20% (28% for 6 min/hr)
	SO_2	1.20 lb/million Btu and 90% reduction, except 70% reduction when emissions are less than 0.60 lb/million Btu
	NO_x	
	Anthracite, Bituminous, and Lignite	0.60 lb/million Btu
	Subbituminous Coal	0.50 lb/million Btu
	Coal-derived fuels and shale oil	0.50 lb/million Btu
	More than 25% coal refuse	Exempt
Oil or gas-fired boilers	Particulate	0.03 lb/million Btu
	Opacity	20% (27% for 6 min/hr)
	SO_2	0.80 lb/million Btu and 90% reduction or 0.20 lb/million Btu (no reduction requirement)
	NO_x -- oil	0.30 lb/million Btu
	NO_x -- gas	0.20 lb/million Btu

[a] Includes boilers firing coal/wood mixtures

Table 3-5. New Source Performance Standards for Stationary Gas Turbines[a]

Nitrogen Oxides Emissions

STD = 0.0150 (14.4/Y) + F

Where:

STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_x emission allowance for fuel-bound nitrogen as defined below.

Fuel-Bound Nitrogen (percent by weight)	F (NO_x - percent by volume)
$N \leq 0.015$	0
$0.015 < N \leq 0.25$	0.04(N)
$0.1 < N \leq 0.25$	0.004 + 0.0067 (N-0.1)
$N > 0.25$	0.005

Sulfur Dioxide Emissions

Emissions of sulfur dioxide are limited to 0.015 percent by volume at 15 percent oxygen and on a dry basis.

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[a] These standards are applicable to gas turbines with heat input at peak load equal to or greater than 10×10^6 Btu/hr and less than 100×10^6 Btu/hr, based on the lower heat value of the fuel. The NO_x standard for larger turbines has been proposed for recision.

Table 3-6. Projected Standards for Coal-Fired Industrial Boilers ($lb/10^6$ Btu Heat Input)

Boiler Size	NO_x*	SO_2	Particulates
$250x10^6$ Btu/hour or above	0.6-0.7	1.2 or 90% removal	0.05
$150\text{-}250x10^6$ Btu/hour	0.6-0.7	3.0 or 50% removal	0.1
$50\text{-}150x10^6$ Btu/hour	0.6-0.7	no standard	0.1
$0\text{-}50x10^6$ Btu/hour	no standard	no standard	no standard

*proposed standard would be 0.7 for low-sulfur coal, 0.6 for high sulfur

The NSPS for stationary internal combustion engines has been formulated; it is applicable to all diesel and dual-fuel engines that are greater than 560 cubic inch displacement per cylinder. The standards are applicable only to NO_x emissions and limit emissions to 600 parts per million, corrected to 15 percent oxygen on a dry basis. This NSPS is expected to be promulgated during calendar year 1982.

Potential Changes to Clean Air Act Amendments

The 1977 Clean Air Act amendments are expected to be revised in 1981 as the result of scheduled Congressional Reauthorization activities. Changes to the statute could significantly alter the regulatory programs affecting cogeneration as well as numerous other energy technologies. However, as considerable time is frequently required to implement new environmental statutes, the full impact of amendments may not be felt for several years following reauthorization. Prediction of the nature of the amendments which will be made or their impacts is virtually impossible. Given the stated goals of the Administration as well as preliminary indications from Congressional members, efforts will apparently be made to simplify and streamline the permitting process under the Clean Air Act and to reduce some of the more restrictive requirements.

Some of the changes being suggested that could affect cogeneration systems are as follows:

1. Elimination of the PSD increment system in Federal Class II and III areas, and replacement with BACT only.

2. Elimination of the SO_2 percentage removal requirement for utility steam generating units.

3. Relaxation or elimination of proposed regulations for industrial boilers

4. Increased state control over air quality programs and the State Implementation Plan, which would modify emission source compliance schedules, and state schedules for attaining air quality standards.

Water Quality

Federal water pollution regulations applicable to cogeneration are minimal. In addition to water quality standards, effluent guidelines and NSPS have been established for several industrial source categories, including steam electric power generating. These standards apply to facilities generating electricity for distribution and sale, with the exception of facilities with less than 25 MW rated net generating capacity or any units that are part of an electric utilities system with a total net generating capacity less than 150 MW. Standards of performance for new sources are presented in Table 3-7. No water quality standards exist or are proposed for other combustion systems that can be used in cogeneration applications.

Solid Waste

Solid and hazardous waste management is regulated under the Resource Conservation and Recovery Act (RCRA) which addresses pollution of the terrestrial environment by solid and hazardous wastes, including those generated by air- and water-pollution control devices. These regulations are not expected to have much impact on combustion systems used in cogeneration applications, as most of the wastes produced by these systems are exempt from the regulations. These wastes include fly ash, bottom ash, slag, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels. The management of these wastes will be controlled by state regulations. Solid or liquid waste that may

Table 3-7. Effluent Limitations for Steam Electric Power Generation

Effluent Characteristic[a,b]	Maximum for Any One Day (mg/liter)	Average of Daily Values Values for Thirty Consecutive Days Shall Not Exceed (mg/liter)
LOW VOLUME WASTE SOURCES		
Total Suspended Solids	100	30
Oil and Grease	20	15
BOTTOM ASH TRANSPORT WATER		
Total Suspended Solids	5	1.5
Oil and Grease	1	0.75
FLY ASH TRANSPORT WATER		
Total Suspended Solids	0	0
Oil and Grease	0	0
METAL CLEANING WASTES AND BOILER BLOWDOWN		
Total Suspended Solids	100	30
Oil and Grease	20	15
Copper, Total	1	1
Iron, Total	1	1
ONCE-THROUGH COOLING WATER		
Free Available Chlorine (Maximum Concentration)	0.5	0.2
COOLING TOWER BLOWDOWN		
Free Available Chlorine (Maximum Concentration)	0.5	0.2
Materials Added for Corrosion Inhibition Including Zinc, Chromium, Phosphorus, and Other	No Detectable Amount	No Detectable Amount

[a]pH of all discharges (except once-through cooling water) is to be within a range of 6.0-9.0

[b]Heat discharge may not exceed the lowest temperature of recirculated cooling water prior to the addition of make-up water.

meet the criteria of hazardous wastes are those containing corrosion inhibitors used to prevent boiler tube fouling in steam turbine systems.

3.1.2 State Regulations

In addition to the Federal regulations described previously, regulations at the State level would also be applicable to cogeneration facilities and may in some cases be more stringent than the Federal regulations. Regulations vary from state to state depending upon specific environmental problems within the state or region, types of industries in the state, and type of fuels available. Since all state regulations cannot be described in this document, the State of Louisiana will be used as an example. The preliminary environmental analysis in Section 3.3 will use a plant located in Louisiana as an example in showing air pollution emission changes due to cogeneration.

The Louisiana air pollution emission control regulations for fuel combustion sources are presented in Table 3-8. These regulations are applicable to systems used in cogeneration, and there is no distinction between the types of fuels used nor the type of system used (e.g., gas turbines and diesels) as exists under the Federal regulations. The opacity standards at the state level are the same as the Federal standards, while the Federal NSPS for particulates and sulfur dioxide are more stringent for utility plants.

There are no specific industrial wastewater effluent standards, although all industrial sources must submit a report to the Louisiana Stream Control Commission prior to the start of operation.

3.2 ENVIRONMENTAL EMISSIONS AND CONTROL TECHNOLOGIES

This section presents a description of the environmental pollutants produced by the three main combustion systems in use today which would be used in cogeneration applications in the near term. The combustion systems are steam turbines, gas turbines, and diesel engines. Emphasis is on air pollutants as these are the major environmental residuals and will have the greatest impact on siting new sources or modifying existing facilities.

Table 3-8. Louisiana Air Pollution Emission Regulations Applicable to Cogeneration

Emission Source Category	Emission Limit
1. New and existing fuel burning units not subject to NSPS producing steam for generation of electricity for sale	
a. Particulates	0.6 lb/10^6 Btu heat input. Opacity limited to 20%. Emission controls required for fugitive particulates.
b. Sulfur Dioxide	Gases limited to 2,000 ppm of SO_2 by volume.

3.2.1 Steam Turbine Systems

Fossil fuel steam generators used in producing electricity or process steam are major sources of air pollution and can also produce significant amounts of water pollutants and solid waste. Air pollutants produced during combustion in fossil fuel boilers include total suspended particulates, sulfur dioxide, and nitrogen oxides. The majority of each of these pollutants is due to firing of bituminous coal. Fuel oil firing is a factor in sulfur and nitrogen oxides emissions while particulate and nitrogen oxides have to be considered for wood-fired boilers. Emission control systems for steam generating units are described in the following sections.

Particulate Emissions Controls

Four types of emission control devices, all of which have been previously used for coal firing, are used for particulates. They are electrostatic precipitation, fabric filters, multitube cyclones, and wet scrubbers.

Particulate emissions are a function of the ash content of fuels, which can range from 5 to 15 percent in coals depending upon their geographic origin. Residual oil contains less than 1 percent ash while distillate oil and natural gas contain trace amounts.

Electrostatic precipitators (ESP) are characterized by high collection efficiency, in excess of 99 percent, and moderate operating costs compared with the other three systems. They are adaptable to small boilers; however, the greatest efficiency is obtained with larger systems such as utility boilers. Variations in fuel characteristics, such as sulfur, alkali, and particle size, can play an important role in determining ESP performance. These variations are more common in industrial boiler fuels than in utility boiler fuels. Industrial boiler operators usually purchase coal on the "spot" market rather than through long-term commitments, which are practiced by utilities. In addition, load levels are more constant and shutdowns are less frequent for utility boilers. Field tests of ESP performance have ranged from 97.0 to 99.8 percent removal for utility boilers with emission levels down to 0.01 $lb/10^6$ Btu heat input. For meeting an intermediate level of control of 0.1 $lb/10^6$ Btu heat input, which is an emission limit set by many states, efficiencies of 80 to 98.8 percent would be required for coal-fired boilers. Under the stringent requirement of 0.03 $lb/10^6$ Btu heat input, which is the NSPS for utility boilers, collection efficiencies of 94 to 99.7 percent would be needed. ESP is the least energy intensive of the four systems and is the most cost effective with high sulfur coals.

For oil-fired boilers, ESP efficiency can vary from 45 to 90 percent, but these units are not normally used for new installations. They are being used in oil-fired boilers that originally used coal. With no modifications, an ESP unit originally designed for coal and now used on an oil-fired boiler, may only provide an efficiency of approximately 50 percent.

Fabric filtration (bag houses) for industrial boilers accounts for approximately 10 percent of the market for particulate controls. Collection efficiencies of 96 to over 99 percent with emission rates of 0.01 to 0.046 $lb/10^6$ Btu have been achieved on coal-fired boilers. Major factors affecting boilers equipped with fabric filters are additional maintenance requirements, potential corrosion problems, and transient operations. Fabric filters are not normally used for oil-fired units because of potential damage to filters from the hydroscopic character of oil fly ash. At the stringent level of emission control, fabric filters are more cost effective than ESP when low-sulfur coals are used.

The use of wet scrubbers for coal-fired boilers has several advantages and disadvantages. The major advantages are (1) ability to remove both particulates and gases (2) ability to function in wet, corrosive, and explosive gas atmospheres; and (3) less space requirements than either ESP or fabric filters. Some of the major disadvantages are: energy penalties associated with their operation; poor efficiency for fine particulates; potential water and solid waste problems; and high-pressure loss at equivalent ESP or fabric filter collection efficiencies. A major factor affecting scrubber performance is the non-steady state operation of industrial boilers; however, high particulate-removal efficiency can be achieved once steady state is reached. Collection efficiencies of 98 percent are achievable, although the mass emission rate may exceed standards because of inability to remove fine particulates. Wet scrubbers are not usually used on oil-fired boilers, since oil particulates are usually less than 2 microns, which are not readily captured.

Mechanical collectors such as multitube cyclones have lower particulate removal efficiencies than the three devices previously described. Their performance is a function of aerosol particulate size, with particles over 10 microns most readily captured. Mechanical collectors are mostly used in conjunction with other control devices to improve efficiencies. By themselves, these systems have emission rates of 0.19 to 3.05 $lb/10^6$ Btu, which are higher than allowed by most state regulations.

Sulfur Dioxide Emissions Control

Sulfur dioxide (SO_2) emissions are a function of the sulfur content of fuel which can range from less than 0.5 percent for distillate oil to over 4 percent for high sulfur eastern coal. Several methods may be used to reduce SO_2 emissions from industrial boilers to comply with current emission limits at the state level. Potential control methods are (1) use of low sulfur fuel, (2) physical and chemical coal cleaning, (3) use of coal derived gases or liquids, (4) fluidized bed combustion, and (5) flue gas desulfurization (FGD). The most effective means of SO_2 control for cogeneration systems in the near term are low-sulfur fuels and FGD, and possibly coal cleaning. Many industrial and utility sources are using low-sulfur fuel to meet state emission regulations. Low sulfur eastern coals and western sub-bituminous coals typically contain less than 1 percent sulfur which is adequate to meet emission regulations for several states. The emphasis of this section will be on FGD systems, since they are currently in use at several utility and industrial plants and may also be required for many industrial applications when industrial boiler NSPS are promulgated.

Five FGD systems are in commercial use in the U.S. today, and another six are at the demonstration stage. The five commercial processes are Lime/Limestone, Double Alkali, Wellman-Lord, Magnesium Oxide, and Sodium Scrubbing. Each of these systems is capable of 90 percent and greater SO_2 removal efficiency. Another system, spray drying, which is in the demonstration stage, also has high SO_2 removal efficiency and reliability. These FGD processes (with the exception of magnesium oxide and Wellman-Lord) are throwaway processes producing non-marketable byproducts, while the latter two are regenerable systems, producing sulfur and sulfuric acid. A summary of the performance of six processes is presented in Table 3-9. Most of the applications of these systems in the U.S. have been for coal-fired boilers, although they are also adaptable to oil firing. Since the FGD systems have fairly comparable SO_2 removal efficiencies, other factors such as cost, energy requirements, and secondary environmental impacts will also need to be considered by a potential cogeneration user.

There is some cost variation between the throwaway and regenerable systems, with the simple throwaway processes such as sodium scrubbing and spray drying the least expensive, and regenerable systems the most expensive. Table 3-10 presents FGD capital costs estimates for six candidate FGD systems on a reference industrial size boiler.

Table 3-9. Summary of FGD Process Performance

Process	Comments
Lime/Limestone	Lime/limestone systems have demonstrated greater than 90 percent SO_2 removal. Reliability has been a problem in the past but is now improving.
Double Alkali	Very high removals (>90 percent) and reliabilities have been demonstrated by double alkali systems on industrial boilers in the U.S.
Wellman-Lord	The first application of the Wellman-Lord process to a coal-fired boiler in the U.S. has produced very good results. SO_2 removal rates greater than 90 percent are reported. Reliability was high during the testing period.
Magnesium Oxide	SO_2 removal efficiencies of greater than 90 percent have been demonstrated. Overall process reliability is difficult to evaluate since the longest continuous period of operation to date has been eight days.
Sodium Scrubbing	SO_2 removal levels of greater than 90 percent are reported. System reliability is generally excellent.
Spray Drying	Pilot unit test results have shown greater than 90 percent removal for low sulfur coal operations. Reliability should be very good although only pilot scale units have been operated to date.

Table 3.10. Preliminary FGD System Cost Estimates
(200×10^6 Btu/hr Sized Systems)

Process	Preliminary Capital Cost (10^6 \$)
Lime/Limestone	1.9
Double Alkali	2.0
Wellman-Lord	2.3
Magnesium Oxide	2.1
Sodium Scrubbing	1.8
Spray Drying	1.8

In addition to capital costs, the costs associated with operating the FGD systems must be considered. These costs may be considerable, because 3 to 8 percent of the net heat input of the boiler is consumed. A summary of the estimated energy requirements for candidate FGD systems are presented in Table 3-11, indicating that the throwaway processes are less energy intensive than regenerable processes. This is largely a result of energy required for regeneration of the SO_2 sorbent and producing byproducts such as sulfur or sulfuric acid.

Table 3-11. FGD System Energy Requirements
(200×10^6 Btu/hr system, 3.5 percent S coal, 90 percent SO_2 removal)

Process	Overall Energy Requirements (10^6 Btu/hr)	Ranking
Lime/Limestone	6.4	Medium
Double Alkali	5.6	Low-Medium
Wellman-Lord	16.8	High
Magnesium Oxide	10.7	Medium-High
Sodium Scrubbing	5.6	Low-Medium
Spray Drying	2.6	Low

Environmental impacts from using FGD systems must be considered since these systems produce both solid and liquid wastes in addition to the wastes that would be generated by steam turbine systems using other emission control techniques such as low-sulfur coal. Some of the FGD systems are capable of removing some particulates from flue gas. Table 3-12 lists the particulate removal capability and secondary pollutant generation of the candidate FGD systems.

Nitrogen Oxides Emissions Controls

Nitrogen oxides (NO_x) formed during combustion result from either thermal fixation of atmospheric nitrogen in the combustion air, or to the conversion of chemically bound nitrogen in the fuel. For natural gas and distillate oil firing, nearly all NO_x emissions result from thermal fixation, while with residual oil and coal, the contribution from fuel bound nitrogen can predominate. The rate of formation of both thermal and

TABLE 3-12. FGD SYSTEM ENVIRONMENTAL IMPACTS

Process	Multipollutant control Particulate removed	Secondary pollutants generated Air	Solid	Liquid
Lime/Limestone	Yes	None	Sludge	Possible leaching from waste solids
Double Alkali	Yes	None	Sludge	Possible leaching from solids
Wellman-Lord	No	None	Relatively small Na_2SO_4 purge	Possible Chloride purge
Magnesium Oxide	No	Possible particulate emissions from calcining	None	Small purge stream
Sodium Scrubbing	Yes	None	None	High total dissolved solids (TDS) wastewater stream
Spray Drying	Yes	None	Dry Sodium/ Calcium Salts	None

fuel NO_x is highly dependent on combustion conditions, and both are promoted by rapid mixing of the oxygen with the fuel. In addition, thermal NO_x is increased by long residence time at high temperatures. Because of NO_x dependence on combustion conditions, control techniques to date are emphasizing combustion process modifications. These modifications, which are applicable to coal-, oil-, or gas-fired boilers, include:

- Low excess air (LEA)
- Staged combustion air (SCA); overfire air or sidefire air
- Low NOx burners
- Flue gas recirculation
- Reduced air preheat
- Load reduction or reduced combustion intensity
- Ammonia injection

These techniques have varying effectiveness in reducing NO_x emissions, and also have operational, cost, and environmental impacts which are shown in Tables 3-13 through 3-15 for coal-, oil-, and gas-fired boilers, respectively.

Among these various control options, there are several which are candidate best systems for moderate, intermediate, or stringent levels of control, on the basis of control effectiveness, reliability, capital and operating costs, energy impacts, and environmental impacts. For pulverized coal-fired boilers, low excess air and overfire air can achieve an NO_x intermediate level of emissions of 0.6 lb/10^6 Btu heat input and are rated as the best techniques. For residual oil firing, low NO_x burners and staged combustion are effective for intermediate emission control, while ammonia injection is necessary for stringent emission limits. The best control systems for distillate oil-fired boilers include reduced air preheat, flue gas recirculation, low NO_x burners, and staged combustion. For natural gas, a combination of reduced air preheat with any of the other three techniques described for distillate oil-fired boilers is considered the best system.

3.2.2 Gas Turbine Systems

Gas turbines have limited environmental impact in that they produce some air pollutants, with minimal generation of water pollutants, solid waste, and noise. The air pollutants of concern are nitrogen oxides and sulfur dioxide. New Source Performance Standards (NSPS) for stationary gas

Table 3-13. Nitrogen Oxides Emissions Control Techniques for Pulverized Coal-Fired Boilers

Technique	Effectiveness[a] (% NO_x Reduction)	Operational Impact	Cost Impact[b]	Environmental Impact
Low Excess Air	5 - 25	Increased boiler effiency.	Increased efficiency offsets capital and operating costs.	Possible increased CO and organic emissions.
Overfire Air	5 - 30	Possible increased slagging or corrosion. Perhaps slight decrease in boiler efficiency.	Major modification. Marginal increase in cost for new units.	Possible increased particulate and organic emissions.
Reduced Combustion Intensity	5 - 25	None. Best implemented as increased furnace plan area in new designs.	Major modification. Marginal increase in cost for new units.	None.
Low NO_x Burners	45 - 60	None expected.	Potentially most cost-effective.	None expected.
NH_3 Injection	40 - 60	Possible implementation difficulties. Fouling problems with high sulfur fuels, load restrictions. Close operator attention required.	Several fold higher than conventional combustion modifications.	Possible emissions of NH_3 and byproducts.

[a]Effectiveness based on control applied singly

[b]Incremental cost impact noting capacity/cost of boiler to which control is applied.

Table 3-14. Nitrogen Oxides Emissions Control Techniques for Residual Oil-Fired Boilers

Technique	Effectiveness[a] (% NO_x Reduction)	Operational Impact	Cost Impact[b]	Environmental Impact
Low Excess Air	5 - 20	Increased boiler efficiency.	Increased efficiency partially offsets costs.	Possible increased CO and organic emissions.
Staged Combustion	20 - 40	Perhaps slight decrease in boiler efficiency.	Major modification, perhaps costly.	Possible increased particulate and organic emissions.
Low NO_x Burners	20 - 50	None expected.	Potentially most cost-effective.	None expected.
NH_3 Injection	40 - 70	Possible implementation difficulties. Fouling problems with high sulfur fuels, load restrictions. Close operator attention required.	Several fold higher than conventional combustion modification.	Possible emissions of NH_3 and byproducts.

[a]Effectiveness based on control applied singly.

[b]Incremental cost impact noting capacity/cost of boiler to which control is applied.

Table 3-15. Nitrogen Oxides Emission Control Techniques for Distillate Oil- and Gas-Fired Boilers

Technique	Effectiveness[a] (% NO_x Reduction)	Operational Impact	Cost Impact[b]	Environmental Impact
Low Excess Air	5 - 15 (oil) 5 - 10 (gas)	Increased boiler efficiency.	Increased efficiency should offset some of costs	Possible increased CO and organic emissions.
Staged Combustion	20 - 40 (oil) 25 - 45 (gas)	Perhaps slight decrease in boiler efficiency.	Major modification, probably costly.	Possible increased organic emissions.
Flue Gas Recirculation	40 - 70 (oil) 45 - 75 (gas)	Possible flame instability. Can be eliminated with proper engineering/testing.	Major modification, probably costly.	Possible increased organic emissions.
Reduced Air Preheat	20 - 55 (oil) 20 - 55 (gas)	Replacing air preheater with economizer in new designs.	None, other than engineering redesign of new units (if necessary).	None.
Low NO_x Burners	20 - 50	None expected.	Potentially most cost-effective.	None expected.

[a] Effectiveness based on control applied singly.

[b] Incremental cost impact noting capacity/cost of boiler to which control is applied.

turbines were promulgated by EPA in September 1979 to regulate emissions of these pollutants. The emissions of particulates, hydrocarbons, and carbon monoxide are less significant.

Several basic techniques exist for reducing the formation of thermal NO_x:

1. Reduce combustion pressure
2. Decrease peak flame temperatures in the combustor reaction zone
3. Reduce effective residence time of combustion gases at elevated temperature
4. Control the amounts of nitrogen and oxygen available for the production of NO_x.

Emissions control techniques for thermal NO_x formation include wet systems consisting of water or steam injection, or dry systems consisting primarily of combustion modifications. The wet control techniques provide a heat sink which absorbs some of the heat of reaction, reducing peak combustion temperatures and the rate of NO_x formation. Reductions in NO_x emissions in excess of 80 percent have been achieved. Little difference in control efficiency has been found between water and steam injection, and both are accepted by industry as valid techniques for reducing NO_x emissions. Wet control techniques also are not expected to affect turbine life, based on reported experience. A decrease of approximately 1 percent occurs in the overall efficiency of the turbine when water or steam injection is used.

Dry control techniques have demonstrated NO_x emissions reductions of over 90 percent in combustor rig tests, and exceeding 40 percent in applications to full turbine engines. Combustion designs utilizing dry control techniques to retard the formation of thermal NO_x involve design modifications to influence the following:

1. Reaction flame temperature
2. Residence time of gases at temperature
3. Amounts of oxygen available for conversion to NOx
4. Atomization and vaporization of the fuel
5. Mixing of fuel and air

The effects of wet and dry techniques on the reduction of NO_x emissions have been shown to be cumulative, as emissions reductions to a certain level may be achieved by dry techniques, with additional reductions achieved with wet techniques. Emissions of NO_x from any new gas turbine used in a cogeneration application will be limited to the standards described in Section 3.1.1.

Sulfur dioxide emissions are primarily a function of the efficiency of the gas turbine and the sulfur content of the fuel because virtually all fuel sulfur is converted to oxides. Gas turbines have historically fired low sulfur distillate fuels or natural gas. The use of low-sulfur distillate fuel is the only technique currently used to control SO_2 emissions. Flue gas scrubbing has not been applied, as desulfurization of the fuel is less costly. Natural gas, where available, will be the first choice of gas turbine operation.

Particulates are emitted from gas turbines at low levels, varying from 0.002 gr/scf to 0.10 gr/scf, for turbines operating at base loads of 12 and 44 MW, respectively. Emissions can be decreased by burning natural gas or low ash fuels, and by combustor modifications that provide more complete combustion of hydrocarbons and carbonaceous particulates. No particulate control devices applicable to stationary gas turbines are available. Visible emissions from turbines are caused by only a small portion of the total particulate emissions. Visible emissions from combustion sources are usually regulated at the state level, with regulations varying from 0-20 percent opacity. These emissions from gas turbines are generally less than 10 percent opacity and are comprised of extremely small and finely divided particulate matter, usually less than 1 micron in size. One method of reducing visible emissions is the use of fuels with high hydrogen content, or use of fuel additives such as soluble compounds of manganese, barium, lead, and iron. Other methods include combustor redesign to provide leaner fuel-to-air mixtures.

Hydrocarbon and carbon monoxide emissions from gas turbines are usually low because of high combustion efficiencies. Control requirements become important only at low loads. Decreased emissions can be achieved by

(1) combustor and fuel injection modifications which promote better fuel atomization, (2) improved fuel and air mixing, and (3) by control of fuel-to-air ratios and residence time at temperature.

Other than air pollutants, minimal environmental impacts are associated with gas turbines. Water pollutants are limited to dissolved solids from the water used for thermal NO_x emissions control. Solid wastes are produced only from the precipitation of solids from the water treatment systems used for NO_x control. These wastes may be landfilled if they are not regulated by RCRA requirements. The use of dry control systems will eliminate potential water and solid waste pollutants. The noise impact of gas turbine engines will need to be investigated to protect workplace environments in industrial plant applications, as the turbine can, unless muffled, constitute a sizeable source of noise emissions. No additional regulations are proposed or anticipated for gas turbines.

3.2.3 Stationary Diesel Engines

Stationary internal combustion engines are sources of several air pollutants, namely, nitrogen oxides, carbon monoxide, particulates, hydrocarbons, and sulfur dioxide. The NO_x emissions from the engines are of the most concern because of two factors: (1) NO_x is the primary pollutant emitted by stationary engines compared with total emissions for each pollutant; (2) the EPA has assigned a high priority to development of NO_x emission standards, which are expected to be promulgated during 1981.

Large-bore engines, which would be used in cogeneration systems, account for the majority of NO_x emissions from stationary internal combustion engines, but relatively small amounts of hydrocarbon (HC) and carbon monoxide (CO) emissions. In addition, 80 percent of the HC are comprised of methane, a nonreactive pollutant. Emissions of CO, although significant for carbureted or naturally aspirated gas engines, are much lower for diesel engines. Particulate emissions from diesel engines are believed to be very small, averaging approximately 33.5 lbs/1000 gallons of fuel consumed.

Sulfur oxides emissions from internal combustion engines are dependent upon the sulfur content of the fuel and the firing rate. The use of low-sulfur fuels is currently the only viable method of SO_2 control since exhaust gas scrubbing is economically infeasible. Due to lower operating and maintenance costs of burning low-sulfur fuel, industries are expected to continue this emission control approach; therefore, SO_2 emissions from these sources are expected to be minor. Other environmental impacts such as water pollution or solid waste are nonexistent from diesels using low-sulfur fuel. The engines may be a source of noise that will need to be controlled in industrial applications.

Four emission control techniques or combinations of these techniques have been demonstrated to be effective in reducing NO_x emissions from stationary large-bore internal combustion engines. These techniques are (1) retarded ignition or fuel injection, (2) modification of air-to-fuel ratios, (3) manifold air cooling, and (4) deration of power output. For diesel engines, the most effective NO_x emission control technique is fuel injection retard. Both retard and air-to-fuel ratio changes are effective in reducing NO_x emissions from dual fuel engines, those firing both a liquid and gaseous fuel. The specific emission control technique to be used is not specified in the proposed standard; only an exhaust gas NO_x concentration has been specified. Other than the proposed standards for NO_x emissions from stationary diesel engines, no additional standards or requirements for these sources are anticipated.

3.3 PRELIMINARY ENVIRONMENTAL ANALYSIS

3.3.1 Air Pollution Emissions Analysis

This section presents a preliminary environmental assessment for a cogeneration application to (1) illustrate the method of calculating emission changes that would occur from the operation of a cogeneration system, and (2) describe how the facility would be subject to current regulations. The analysis will emphasize air pollution emissions, as they are the major barriers to the installation of fuel combustion sources, although liquid and solid wastes are also important environmental considerations.

The illustrative example is the coal-fired cogeneration system for the large refinery located in Norco, Louisiana (Chapter 1). The cogeneration system is an 11.1 MW boiler/steam turbine system, which will burn coal at the rate of 5.584×10^{12} Btu/yr, replacing residual oil use of 4.944×10^{12} Btu/yr.

Emissions calculations for five air pollutants were made for the refinery on the basis of the reduced oil use and projected coal use. Because the type of coal to be used in the new boiler is not known, emissions estimates were made for both lignite and bituminous coal and are shown in Table 3-16. The increased emissions from coal firing are substantially offset by reduced oil use. The net change in emissions results in most pollutants exceeding 100 tons/year. Since the heat input of the boiler is in excess of 250 x 10^6 Btu/hr the boiler will be subject to the NSPS for steam generators. In addition, it is also subject to PSD requirements since the refinery is located in an attainment area and meets the criteria for emission levels for modified sources.

Table 3-16. Emissions Changes Due To Cogeneration, Large Refinery (Tons/Year)

	COAL		OIL	NET CHANGE	
	LIGNITE	BITUMINOUS		LIGNITE	BITUMINOUS
TSP	+279	+279	-165	+114	+114
SO_2	+3350	+3350	-1815	+1535	+1535
NO_x	+1675	+1954	-991	+684	+963
CO	+206	+121	-83	+123	+38
HC	+48	+36	-17	+45	+19

Table 3-17 indicates the methodology used to calculate the emissions changes for the cogeneration system.

3.3.2 Required Environmental Permits

Several environmental permits are required prior to the start of construction and operation of a facility. These permits are at the Federal, state and, in some cases, county levels. At the Federal level, the major permit needed for air pollution sources is for PSD, which is issued by the EPA regional offices as previously described. A list of all EPA regional offices and the states for which they are responsible is presented in Table 3-18.

Table 3-17. Air Pollution Emissions Calculations

General Assumptions

Fuel Use Changes, Coal: $+5,584 \times 10^{12}$ Btu/yr
Oil: $-4,944 \times 10^{12}$ Btu/yr

Emission Limits Based on NSPS (Table 3-3)

Particulates: 0.10 lb/10^6 Btu
Sulfur Dioxide: 1.2 lb/10^6 Btu
Nitrogen Oxides: 0.7 lb/10^6 Btu - Bituminous
0.6 lb/10^6 Btu - Lignite

Emission Factors Based on EPA AP-42[a]

Hydrocarbons: 0.3 lb/ton of coal burned
Carbon Monoxide: 1.0 lb/ton of coal burned

Calculations

Emissions From Lignite Use

Particulates:
5.584×10^{12} Btu/yr x 0.10 lb/10^6 Btu ÷ 2000 lb/ton = 279 tons/yr

Sulfur Dioxide:
5.584×10^{12} Btu/yr x 1.2 lb/10^6 Btu ÷ 2000 lb/ton = 3350 tons/yr

Nitrogen Oxides:
5.584×10^{12} Btu/yr x 0.6 lb/10^6 Btu ÷ 2000 lb/ton = 1675 tons/yr

Carbon Monoxide:
5.584×10^{12} Btu/yr ÷ 13.56 x 10^6 Btu/ton = 411,799 tons/yr of Lignite
411,799 tons/yr x 1.0 lb/ton ÷ 2000 = 206 tons/yr

Emissions from Bituminous Coal Use

Particulate and sulfur dioxide emissions are the same as for lignite since they are based on heat input.

Nitrogen Oxides:
5.584×10^{12} x 0.7 lb/10^6 Btu ÷ 2000 = 1954 tons/yr

Carbon monoxide
5.584×10^{12} Btu/yr ÷ 23.1 x 10^6 Btu/ton = 241,732 tons/yr on coal
241,732 tons/yr x 1.0 lb/ton ÷ 2000 = 121 tons/yr

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[a]Compilation of Air Pollution Emission Factors, AP-42, U.S. Environmental Protection Agency, February 1980

Table 3-17. Air Pollution Emissions Calculations (Continued)

Hydrocarbons
241,732 tons/yr x 0.3 lb/ton ÷ 2000 = 36 tons/yr

Emissions from Regional Oil Replaced - Emission Factors Used for Calculations

Fuel Use of 4.944×10^{12} Btu/yr ÷ 149,690 Btu/gal = 33,028,258 gals/yr

Particulates:
33,028,258 gal/yr x 10 lb/10^3 gals ÷ 2000 lb/ton = 165 tons/yr

Sulfur Dioxide:
33,028,258 gal/yr x 0.7% sulfur content x 157 lb/103 gals ÷ 2000 lb/ton = 1815 tons/yr

Nitrogen Oxides:
33,028,258 gal/yr x 60 lb/10^3 gals ÷ 2000 lb/ton = 991 tons/yr

Carbon Monoxide:
33,028,258 gal/yr x 5 lb/10^3 gals ÷ 2000 lb/ton = 83 tons/yr

Hydrocarbons
33,028,258 gal/yr x 1 lb/10^3 gals ÷ 2000 lb/ton = 17 tons/yr

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A permit to construct or modify a fuel burning unit at the refinery would also be required by the Louisiana Air Control Commission. The permit application must include the necessary information that will enable the commission to determine whether the source will be designed to operate in conformance with the provision of the state regulations and will not cause or contribute to the violation of the air quality standards.

A wastewater discharge permit is usually required in all states for industrial wastewater. In Louisiana, the permit is issued by the Stream Control Commission. The permit application must indicate the type of facility to be operated, quantities of wastewater, pollution control system used, and composition of the wastewaters. The State Department of Natural Resources is responsible for regulating solid wastes from industrial sources that may impact surface and groundwaters. A coal-fired boiler will generate fly ash and bottom ash that must be disposed of in approved landfills. Boiler wastes are usually exempt from hazardous waste regulations; however, the state may require an analysis of the wastes to assess whether surface or groundwaters may be contaminated, especially by heavy metals in the bottom ash.

Table 3-18. U.S. Environmental Protection Agency Regional Offices

EPA Regional Office, Air Programs Branch	States Included in Region
1 - John F. Kennedy Federal Building Room 2303 Boston, MA 02203 (617) 223-6883	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont
2 - Federal Office Building 26 Federal Plaza New York, NY 10007 (212) 264-2517	New Jersey, New York, Puerto Rico, Virgin Islands
3 - Curtis Building Sixth and Walnut Streets Philadelphia, PA 19106 (215) 597-8175	Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia
4 - 345 Courtland, NE, Atlanta, GA 30308 (404) 881-3043	Alabama, Florida, Georgia, Mississippi, Kentucky, North Carolina, South Carolina, Tennessee
5 - 230 South Dearborn Chicago, IL 60604 (312) 353-2205	Illinois, Minnesota, Michigan, Ohio, Indiana, Wisconsin
6 - First International Building 1201 Elm Street Dallas, TX 75270 (214) 767-2745	Arkansas, Louisiana, New Mexico, Oklahoma, Texas
7 - 324 E. Eleventh Street Kansas City, MO 64106 (816) 374-5971	Iowa, Kansas, Missouri, Nebraska
8 - 1860 Lincoln Street Denver, CO 80295 (303) 837-3471	Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming
9 - 215 Fremont Street San Francisco, CA 94105 (415) 556-4708	Arizona, California, Hawaii, Nevada, Guam, American Samoa
10 - 1200 Sixth Avenue Seattle, WA 98101 (206) 442-1230	Washington, Oregon, Idaho, Alaska

4.0 LEGAL AND REGULATORY CONSIDERATIONS

Recent Federal energy legislation significantly affects the implementation and economic viability of industrial cogeneration systems. Depending on the particular system and application, significant benefits may be extended to a cogenerator seeking to establish interconnected operation with an electric utility. Cogeneration efficiency standards may or may not apply, tax credits and other incentives may be provided or denied, and the system may or may not be subject to extensive Federal regulation concerning fuels use. It is extremely important that a potential cogenerator become familiar with this legislation and pertinent implementing rules so that maximum advantage can be taken of available benefits while regulatory problems in system implementation are minimized.

Table 4-1 summarizes current legal and regulatory provisions relating to cogeneration. The Powerplant and Industrial Fuel Use Act (FUA) regulations are likely to be streamlined to make the exemption process less costly, time-consuming, and burdensome to industry (also see Section 4.1.5). Possibly legislative action will be taken to repeal major provisions of FUA. While no such action directly affecting cogeneration has been taken thus far, the Omnibus Reconciliation Act of 1981 (Pub. L. 97-35) repeals provisions of FUA prohibiting natural gas use in existing powerplants.

In addition to the laws and regulations discussed herein that have specific cogeneration provisions, the Economic Recovery Tax Act (ERTA) of 1981 provides significant tax incentives for new business investment in general. The Accelerated Cost Recovery System (ACRS) of ERTA relating to cogeneration investment analysis has been incorporated in Section 2.3 of this handbook.

TABLE 4-1. SUMMARY OF COGENERATION LEGAL AND REGULATORY PROVISIONS

STATUTE	PERTINENT SECTIONS OF STATUTE	IMPLEMENTING AGENCY	IMPLEMENTING RULES	COGENERATION PROVISIONS
Public Utility Regulatory Policies Act of 1978 (PURPA) Pub.L. 95-617	201 210	FERC	18 CFR 292	Prohibits electric utility discrimination and provides rate benefits to qualifying cogeneration facilities; provides for exemption of such facilities from regulation as electric utilities.
Natural Gas Policy ACT OF 1978 (NGPA) Pub.L. 95-621	206(c) 206(d)	FERC	18 CFR 292 18 CFR 282	Provides FERC authority to exempt qualifying cogeneration facilities from incremental pricing of natural gas.
Energy Tax Act of 1978 (ETA) Pub.L. 95-918	301	IRS	26 USC 46, 48, 167; Income Tax Regulations	Provides 10 percent energy investment tax credit for investments in designated energy property; Denies regular 10 percent investment tax credit and accelerated depreciation to boilers fueled by oil or gas.
Crude Oil Windfall Profit Tax Act of 1980 (COWPTA) Pub.L. 96-223	221 222 223	IRS	26 USC 46, 48	Amends ETA to provide 10 percent energy tax credit for investments in cogeneration equipment not using oil or gas.
Powerplant and Industrial Fuel Use Act of 1978 (FUA) Pub.L. 95-620	212(c) 312(c)	ERA	10 CFR 503.37 10 CFR 504.35 10 CFR 505.27 10 CFR 506.35	Provides permanent exemptions from FUA prohibitions on oil and gas use for eligible cogeneration facilities.

4.1 DISCUSSION OF COGENERATION PROVISIONS OF CURRENT LEGISLATION AND STATUS OF IMPLEMENTING RULES

The following sections discuss in more detail the cogeneration provisions of PURPA, NGPA, ETA, COWPTA and FUA, and the pertinent implementing rules. Prospective cogenerators should refer to the Federal Register and consult with the appropriate Federal agency to obtain the latest information on implementing rules.

4.1.1 Public Utility Regulatory Policies Act of 1978 (PURPA)

PURPA contains a number of significant provisions designed to encourage industrial cogeneration by preventing electric utility discrimination and reducing utility-related State and Federal regulations.

Congress enacted sections 201 and 210 of PURPA as part of the National Energy Act of 1978. These provisions authorized the Federal Energy Regulatory Commission (FERC) to prescribe rules as the Commission determines necessary to encourage cogeneration.

Section 210 of PURPA authorized FERC to prescribe rules requiring electric utilities to purchase electric energy from cogeneration facilities which obtain qualifying status under Section 201 of PURPA. For such purchases, FERC was authorized to require electric utilities to pay rates that are just and reasonable to the rate payers of the utility, are in the public interest, and that do not discriminate against cogenerators. Section 210 also required electric utilities to provide retail electric service to qualifying cogeneration facilities at just, reasonable, and non-discriminatory rates. Finally, Section 210 authorized FERC to exempt all qualifying cogeneration facilities from State regulation regarding utility rates and financial organization, from Federal regulation under the Federal Power Act, and from the Public Utility Holding Company Act.

Section 201 of PURPA authorized FERC to prescribe rules establishing requirements for qualifying cogeneration facilities and develop procedures by which the qualified facilities can obtain the benefits set forth under Section 210.

Pursuant to the statutory mandates of PURPA, FERC issued a final rule implementing Section 210 on February 19, 1980 (Order No. 69) and a final rule implementing Section 201 on March 13, 1980 (Order No. 70). These rules are contained in 18 CFR 292.

Applicability of FERC Rules

The rules promulgated by FERC apply to all electric utilities, defined in Section 3(4) of PURPA as any person, State agency, or Federal agency which sells electric energy. Within this definition are investor-owned electric utilities and non-regulated utilities, including publicly owned systems, cooperatively owned systems, and Federal power-marketing agencies.

Exchanges of Power between Utilities and Cogenerators

In recognition that it could not prescribe a perfect pricing formula appropriate for each utility and qualifying cogenerator, FERC issued a set of pricing principles to be used by the State Regulatory Commissions (SRC) and non-regulated utilities in developing methodologies for specifying rates. The operative term used in these pricing principles is "avoided cost." Under the "avoided cost" principle, rates for power produced by the cogeneration facility are based on the costs avoided by the utility in not having to generate the power itself or purchase it from another source. This obviates the need for the cogenerator to keep detailed cost-of-service records.

In those instances where a utility can cut back on its need to construct new power plants or to buy, lease, or rent capacity from another utility, the avoided cost can also include the capital costs of the otherwise required unit or the demand charge included in the utility's firm power purchase contract.

FERC specifies that all interconnection requirements be reasonable. Utilities cannot, for example, force qualifying facilities to buy and install unnecessary safety equipment. As for what is "reasonable," the regulations leave it up to SRCs to decide. These commissions must also make sure that the costs of interconnection are attributable to the cogeneration system. FERC regulations stipulate that the utility cannot charge the qualifying facility any more for interconnection than the actual net expense of connecting the qualifying facility, less charges the utility would have had to incur to connect its own power plants to its system to provide the same amount of power. Finally, FERC regulations state that a qualifying facility cannot be assessed twice for the same connection. If, for example, a qualifying facility that had already been connected to an electric utility for the purpose of buying electricity decides to sell power to the utility, the qualifying facility can only be charged for additional expenses.

FERC's pricing rules state that if a qualifying cogenerator consents, the purchasing utility may transmit power to a second utility. If this occurs, the second utility is subject to the same purchase requirements as the "wheeling" utility, except that the second utility is only obligated to pay for the power it actually receives.

For power purchases from a cogeneration facility whose construction commenced on or after the date of enactment of PURPA (November 9, 1978), utilities must pay the full avoided cost. For existing facilities, utilities may pay a lower rate so long as the rate is sufficient to encourage cogeneration.

The FERC rules also permit a new cogenerator to require an electric utility to purchase, at the full avoided cost, all of the power produced by the new cogeneration capacity, while permitting the cogenerator to purchase all of the electric power it uses at non-discriminatory retail rates. The effect of this provision is to separate the activities of the facility as a generator and as a load, thereby enhancing the likelihood that new cogeneration capacity will be developed.

State Implementation

Under the statutory framework of Section 210, implementation of the rules issued by FERC is reserved for the SRCs and to non-regulated electric utilities. Within one year of the issuance of the FERC rules, each State regulatory commission and non-regulated electric utility must, after notice and opportunity for hearing, commence to implement the FERC rules pertaining to rates for purchases, rates for sales, interconnection costs, system emergencies, and standards for operating reliability. As of March 20, 1981, the date that appropriate rates and procedures were to have been established, some states and utilities had completed their hearings and had reported established purchase rates to FERC. Others were still conducting hearings on developing their implementation plans. For the most recent information on the status of PURPA implementation and established rates, the public utility commission (PUC) for each state should be contacted. Table 4-2 lists the PUC contact sources in each of the 50 states.

Exemption from Regulation

Qualifying cogeneration facilities are exempted from utility regulation under the Public Utility Holding Company Act, certain sections of the Federal Power Act, and certain types of state law. As a result of these exemptions, cogeneration facilities which sell electric power to utilities will not be subject to rate regulation by FERC under Sections 205 and 206 of the Federal Power Act. Their books will not be scrutinized by FERC and they will not be subject to many of the prohibitions and requirements imposed on electric utility companies by the Securities and Exchange Commission under the Holding Company Act.

The exemption from State law applies only insofar as State law would regulate sales to utilities. A cogenerator who sells power at retail may still be subjected to State utility regulation.

The exemptions provided are only from laws and regulations concerning rates and financial organization. Cogeneration facilities are still subject to state and Federal laws and regulations concerning siting and environmental requirements and tax treatment.

Criteria for Qualification as Cogeneration Facility

Section 201 of PURPA contains the criteria for designation as a qualifying cogeneration facility. It defines a cogeneration facility as a facility which produces electric energy and steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating, or cooling purposes. The definition of a cogeneration facility established by FERC requires that electric energy and forms of useful thermal energy be produced through the sequential use of energy. Within this definition, it is important to note that electric energy must be produced to qualify as a cogeneration facility.

Table 4-2. State's Cogeneration Rate-Setting Under PURPA[a]

STATE	STATUS (As of April 1981)	CONTACT
ALABAMA ERNEST MERCER DIRECTOR OF UTILITIES PUBLIC SERVICE COMMISSION P.O. BOX 991 MONTGOMERY, AL 36130	Final rates for production of 100 kw or less. Others pending. The PSC is developing rates for larger producers, but has deferred at request of Alabama Industrial Group because industrial users have not yet agreed to terms with utilities.	Call Wallace Tidmore, Alabama PSC (205) 832-3421
ALASKA GORDON ZERBETZ, CHAIRMAN PUBLIC UTILITIES COMMISSION MACKAY BLDG. 338 DENALI ST. ANCHORAGE, AK 99501	Not approved	Call Robert Barber, Alaska PUC (907) 276-6222
ARIZONA S. R. WHITFIELD, DIRECTOR CORPORATION COMMISSION UTILITIES DIVISION 1210 W. WASHINGTON ST. PHOENIX, AZ 85007	Pending Has not held hearings.	Call Jim Apperson, ACC (602) 255-4251
ARKANSAS VANCE JONES, DIRECTOR PUBLIC SERVICE COMMISSION, UTILITIES DIVISION 400 UNION STATION LITTLE ROCK, AR 72201	Pending Proposed order being considered.	Call Betty Wood, Arkansas PSC (501) 370-5480

[a]Used by permission from Energy User News, Vol 6., No. 16
Monday April 20, 1981, 7 E. 12th St., New York 10003

Table 4-2. State's Cogeneration Rate-Setting Under PURPA (Con't)

STATE	STATUS (As of April 1981)	CONTACT
CALIFORNIA B. R. BRAKOVICH, DIRECTOR POLICY AND PROGRAM DEVELOP. PUBLIC UTLITIES COMMISSION 350 MCALLISTER ST. SAN FRANCISCO, CA 94102	Temporary rates. In Dec. 1979 PUC ordered utilities to buy cogenerated power at avoided costs. These interim utility-set rates are subject to PUC rulemaking in May. Also, staff has recommended summer hearings on accuracy of utility-avoided cost figures.	Call John Quinley, California PUC (415) 557-2904
COLORADO EDYTHE S. MILLER, CHAIRMAN PUBLIC UTILITIES COMMISSION REGULATORY AGENCIES DEPT. STATE SERVICES BLDG., 5TH FLOOR DENVER, CO 80203	Pending	Call Mike Homyaki, Colorado PUC (303) 866-4300
CONNECTICUT JOHN T. DOWNEY, CHAIRMAN PUBLIC UTILITIES CONTROL AUTHORITY STATE OFFICE BLDG. 165 CAPITOL AVE. HARTFORD, CT 06115	Temporary rates. Department-set rates in effect until utility-proposed rates are approved.	Call Mark Jeske, Connecticut DPUC (203) 566-7882
DELAWARE JOSHUA W. MARTIN III, CHAIRMAN DIVISION OF PUBLIC UTITLITIES CONTROL 1560 S. DUPONT HWY. DOVER, DE 19901	Pending. Hearings May 20-21 on Delmarva Power Co. tariff. Hearing May 6 for Lincoln-Ellendale Electric Co.	Call Robert Kennedy, Delaware PSC (302) 736-4247
FLORIDA ROBERT MANN, CHAIRMAN PUBLIC SERVICE COMMISSION 101 EAST GAINES TALAHASSEE, FL 32301	Final rules. Commission encourages negotiated rates. In lieu of contract, rates are based on computer-monitored utility fuel costs.	Call Florida PSC (904) 488-8501

Table 4-2. State's Cogeneration Rate-Setting Under PURPA (Con't)

STATE	STATUS (As of April 1981)	CONTACT
GEORGIA PUBLIC SERVICE COMMISSION 244 WASHINGTON ST. ATLANTA, GA 30334	Proceedings suspended. Awaiting outcome of Supreme Court decision on constitutionality of PURPA.	Call Sam Weaver, Georgia PSC (404) 656-4541
HAWAII ALBERT Q. Y. TOM, CHAIRMAN PUBLIC UTILITIES COMMISSION 1164 BISHOP ST., SUITE 911 HONOLULU, HI 96813	Not approved	Call Leroy Yuen, Hawaii PUC (808) 548-3990
IDAHO MYRNA WALTERS, SECRETARY PUBLIC UTLITIES COMMISSION 427 W. WASHINGTON ST. BOISE, ID 83720	Pending. Rates filed by CP National, but they have not yet been approved.	Call Idaho PUC (702) 885-5134
ILLINOIS GARY HUNT COMMERCE COMMISSION PUBLIC UTILITY DIVISION 527 E. CAPITOL AVE. SPRINGFIELD, IL 62701	Final rules. Rules subject to approval of Illinois legislature's Joint Committee on Administrative Rules. Rates not yet filed.	Call Charles Teclaw, ICC (217) 785-0326
INDIANA LARRY J. WALLACE, CHAIRMAN PUBLIC SERVICE COMMISSION 901 STATE OFFICE BLDG. INDIANAPOLIS, IN 46204	Pending. Cogeneration rate formula developed by PSC sent to state attorney general's office for approval. Then must go to governor.	Call William D. Boyd, Indiana PSC (317) 232-2711
IOWA RAYMOND VAWTER COMMERCE COMMISSION PUBLIC UTILITY DIVISION STATE CAPITOL DES MOINES, IA 50319	Final rules. Commission has developed rate and avoided-cost formula.	Call Bob Latham, Iowa SCC (517) 373-6430

Table 4-2. State's Cogeneration Rate-Setting Under PURPA (Con't)

STATE	STATUS (As of April 1981)	CONTACT
KANSAS FRED B. ADAM, DIRECTOR UTILITIES DIVISION, CORPORATION COMMISSION STATE OFFICE BLDG., 4TH FLOOR TOPEKA, KS 66613	Pending. Staff is developing avoided-cost methodology. Hearing April 27-28.	Call Carol Lawson, KCC (913) 296-3326
KENTUCKY RICHARD S. TAYLOR UTILITY REGULATORY COMMISSION P.O. BOX 615 FRANKFORT, KY 40602	Pending. Commission now deciding rates on case-by-case basis. Hearings begin April 27. Rate schedule expected by July.	Call Richard Heman, Kentucky URC (502) 564-3940
LOUISIANA LOUIS S. QUINN, SECRETARY PUBLIC SERVICE DEPT. ONE AMERICAN PLACE, SUITE 1630 BATON ROUGE, LA 70825	Pending. Hearing held in Feb. No action expected soon.	Call Arnold Chauviere, Louisiana PSC (504) 342-4404
MAINE RALPH H. GELDER, CHAIRMAN PUBLIC UTILITIES COMMISSION 242 STATE ST. AUGUSTA, ME 04333	Pending. PUC asking utilities to file cogeneration rate requests. Hearings not yet scheduled.	Call Maine PUC (207) 289-3831
MARYLAND THOMAS J. HATEM, CHAIRMAN PUBLIC SERVICE COMMISSION 231 E. BALTIMORE ST. BALTIMORE, MD 21202	Pending. April 6 proposed order requires utilities to file tariffs for facilities producing 100 kw or less. Each tariff to be considered separately.	Call Paul Daniels, Maryland PSC (301) 659-6021

Table 4-2. State's Cogeneration Rate-Setting Under PURPA (Con't)

STATE	STATUS (As of April 1981)	CONTACT
MASSACHUSETTS DORIS R. POTE, CHAIRWOMAN PUBLIC UTILITIES DEPT. 100 CAMBRIDGE ST. BOSTON, MA 02202	Pending. All hearings held. DPU to adopt cogeneration rules by end of April.	Call Massachusetts DPU (617) 727-6900
MICHIGAN DANIEL J. DEMLOW, CHAIRMAN PUBLIC SERVICE COMMISSION P.O. BOX 30221 LANSING, MI 48909	Pending. PSC ordered utilities to remove cogeneration barriers, and sent out questionnaires on cogeneration rates. Hearings to be held.	Call Margaret Cooney, Michigan PSC (517) 373-8171
MINNESOTA ROBERT W. CARLSON PUBLIC UTILITIES COMMISSION 780 AMERICAN CENTER BLDG. 160 KELLOGG BLVD. ST. PAUL, MN 55101	Pending. Avoided-cost formula being debated by PUC and state legislature.	Call Stuart Mitchell, Minnesota PUC (612) 296-8662
MISSISSIPPI KEITH HOWLE PUBLIC SERVICE COMMISSION P.O. BOX 1332 JACKSON, MS 39205	Pending. Power companies asked to submit avoided-cost rate design for power producers under 100 MW. Larger projects likely to be decided case by case. Hearings expected in late April.	Call C. Keith Howle, Mississippi PSC (601) 353-7265
MISSOURI KEN RODEMAN PUBLIC SERVICE COMMISSION DEPT. P.O. BOX 360 JEFFERSON CITY, MO 65102	Final PSC order issued April 7, effective May 15.	Not applicable

Table 4-2. State's Cogeneration Rate-Setting Under PURPA (Con't)

STATE	STATUS (As of April 1981)	CONTACT
MONTANA DAN ELLIOT PUBLIC SERVICE REGULATION DEPT. PUBLIC UTILITY DIVISION 1227 11TH AVE. HELENA, MT 59601	Final rules. Rates to be approved in October.	Call Ted Otis, Montana PSRD (406) 449-2649
NEBRASKA DUANE GAY, CHAIRMAN PUBLIC SERVICE COMMISSION 301 CENTENIAL MALL SOUTH FIRST FLOOR LINCOLN, NE 68509	Public power districts deal directly with Department of Energy to set rates. Some public power districts have set rates for power producers under 100 kW and will set rates for larger producers on case-by-case basis.	Not available
NEVADA HEBER P. HARDY, CHAIRMAN PUBLIC SERVICE COMMISSION OF NEVADA 505 EAST KING ST. CARSON CITY, NV 89710	Final rules. Idaho Power and CP National have filed rates, but rates have not yet been approved. Sierra Pacific Power has not established a rate. Nevada Power has approved rate.	Call Nevada PSC (702) 885-5134
NEW HAMPSHIRE J. MICHAEL LOVE, CHAIRMAN PUBLIC UTILITIES COMMISSION 8 OLD SUNCOCK RD CONCORD, NH 03301	Final rates	Call Judy Elliott, New Hampshire PUC (603) 271-2437
NEW JERSEY PUBLIC UTILITIES DEPT 101 COMMERCE ST NEWARK, NJ 07102	Hearings concluded. Final rates expected by end of April. Jersey Power & Light already has tariff.	Call Steve Gable, New Jersey Public Utility Dept. (201) 648-2045

Table 4-2. State's Cogeneration Rate-Setting Under PURPA (Con't)

STATE	STATUS (As of April 1981)	CONTACT
NEW MEXICO RICHARD MONTOYA, CHAIRMAN PUBLIC SERVICE COMMISSION BATAAN MEMORIAL BLDG. SANTA FE, NM 87503	Pending. Task force formed to submit recommendations. Electric utilities to present recommendations by April 27, 1981.	Call New Mexico PSC (505) 827-2827
NEW YORK LESTER STUZIN PUBLIC SERVICE DEPT. PUBLIC SERVICE COMMISSION EMPIRE STATE PLAZA AGENCY BLDG. 3 ALBANY, NY 12223	Temporary rates. Utility-proposed rates can now be used in contracts, but are subject to change by PSC rate-setting.	Call Craig Indyke, New York PSC (518) 474-6515
NORTH CAROLINA DENNIS NIGHTINGALE COMMERCE DEPT. UTILITIES COMMISSION DOBBS BLDG. 430 N. SALISBURY ST. RALEIGH, NC 27611	Approved	Call North Carolina PUC (919) 733-2267
NORTH DAKOTA JANET SAUTER, SECRETARY PUBLIC SERVICE COMMISSION CAPITOL BLDG., 12TH AND 13TH FLOORS BISMARCK, ND 58505	Final rules. Cogeneration rules approved. Utilities in process of filing rate schedules.	Call Wally Owen, North Dakota PSC (701) 224-4078
OHIO WILLIAM S. NEWCOMB, JR., CHAIRMAN PUBLIC UTILITIES COMMISSION 375 SOUTH HIGH ST. COLUMBUS, OH 43215	Pending. Hearings held. Suggested tariffs due by May 4.	Call Ohio PUC (614) 466-7750

Table 4-2. State's Cogeneration Rate-Setting Under PURPA (Con't)

STATE	STATUS (As of April 1981)	CONTACT
OKLAHOMA HOWARD MOTLEY, DIRECTOR CORP. COMMISSION, PUBLIC UTILITY DIV. 329 JIM THORPE BLDG. OKLAHOMA CITY, OK 73105	Final order issued March 20 by Oklahoma Corporation Commission.	Not applicable
OREGON WILLIAM KRAMER PUBLIC UTILITY COMMISSION LABOR AND INDUSTRIES BLDG. SALEM, OR 97310	Pending. Proposed rules issued.	Call Leon Hagen, Oregon PUC (503) 378-6687
PENNSYLVANIA SUSAN M. SHANAMAN, CHAIRMAN PUBLIC UTILITY COMMISSION 104 N. OFFICE BLDG. HARRISBURG, PA 17120	Pending. Staff has proposed regulations that basically follow FERC draft. Hearings expected.	Call Rick Sandusky, Pennsylvania PUC (717) 783-1546
RHODE ISLAND EDWARD F. BURKE, CHAIRMAN PUBLIC UTILITIES COMMISSION 100 ORANGE ST. PROVIDENCE, RI 02903	Pending. Two major electric utilities were ordered to submit proposed cogeneration rates. No hearing dates set.	Call Laura Dowd, Rhode Island PUC (401) 277-3500
SOUTH CAROLINA CHARLES W. BALLENTINE PUBLIC SERVICE COMMISSION UTILITIES DIVISION P.O. DRAWER 11649 COLUMBIA, SC 29201	Final rules. Commission encourages negotiated rates and will review agreements at request of user or utility. In lieu of contract, rates are based on rate schedules set by utilities.	Call South Carolina PSC (803) 758-5362

Table 4-2. State's Cogeneration Rate-Setting Under PURPA (Con't)

STATE	STATUS (As of April 1981)	CONTACT
SOUTH DAKOTA COMMERCE AND CONSUMER AFFAIRS DEPT. PUBLIC UTILITIES COMMISSION CAPITOL BLDG., 1ST FLOOR PIERRE, SD 57501	Pending	Call Walter Washington, South Dakota PUC (605) 773-3201
TENNESSEE FRANK COCHRAN, CHAIRMAN PUBLIC SERVICE COMMISSION CORDELL HULL BLDG. NASHVILLE, TN 37219 OR TENNESSEE VALLEY AUTHORITY (TVA) NEW SPANGLE BLDG. KNOXVILLE, TN 37902	Final rates	Call Robert Hemphill, TVA (615) 755-2061
TEXAS GEORGE M. COWDEN, CHAIRMAN PUBLIC UTILITIES COMMISSION 7800 SHOAL CREEK BLVD. SUITE 400 NORTH AUSTIN, TX 78757	PUC staff preparing proposed order based primarily on report of industry-utility task force completed late 1980.	Call Tom Halicki, Texas PUC (512) 458-0270
UTAH BUSINESS REGULATION DIVISION OF PUBLIC UTILITIES 330 E. 4TH SOUTH ST. SALT LAKE CITY, UT 84111	Temporary rates. Interim utility-set rates have been approved but are subject to PSC rate-setting.	Call Douglas Kirk, Utah PSC (801) 533-6416
VERMONT PUBLIC SERVICE BOARD 7 SCHOOL ST. MONTPELIER, VT 05602	Pending. Expects to adopt rules within next two months.	Call Deborah DeGraff, Vermont PSB (802) 828-2880

Table 4-2. State's Cogeneration Rate-Setting Under PURPA (Con't)

STATE	STATUS (As of April 1981)	CONTACT
VIRGINIA DAVID R. LESHER STATE CORPORATION COMMISSION PUBLIC UTILITIES DIVISION BLANTON BLDG. RICHMOND, VA 23230	Final rates	Call Virginia SCC (804) 786-4932
WASHINGTON ARCHIE MARTIN, ADMINISTRATOR UTILITIES UTILITIES AND TRANSPORTATION COMMISSION HIGHWAYS-LICENSES BLDG. OLYMPIA, WA 98504	Final rules. Rates will be determined later for units 100 kw and less. Rates for larger systems will be negotiable.	Call David Rees, Washington UTC (206) 753-6420
WEST VIRGINIA DANDRIDGE MCDONALD, CHAIRMAN PUBLIC SERVICE COMMISSION E. STATE CAPITOL CHARLESTON, WV 25305	Pending. For facilities below 100 kW, proposed order likely this month and becomes final if PSC does not act in 15 days. For larger facilities, hearings expected on draft proposal.	Call Rick Hitt, West Virginia PSC (304) 348-2174
WISCONSIN STANLEY YORK, CHAIRMAN PUBLIC SERVICE COMMISSION 4802 SHEBOYGAN AVE. MADISON, WI 53702	Temporary rates. Six largest utilities have own rates. Hearings on PSC rates are continuing.	Call Terrence Nicolia, Wisconsin PSC (608) 266-5620
WYOMING FRANK L. RAUCHFUSS UTILITIES DEPT. PUBLIC SERVICE COMMISSION CAPITOL HILL BLDG. 320 W. 25TH ST. CHEYENNE, WY 82002	Final rates	Call Dave Walker, Wyoming PSC (405) 777-7427

Sequential use of energy is the key provision of this definition. Only those processes that use heat rejected from one process for another process can be considered cogeneration facilities. Eligible cogeneration includes both topping-cycle and bottoming-cycle cogeneration facilities. In 18 CFR 292.203, new diesel cogeneration systems were excluded as qualifying facilities pending further FERC action. However, on June 1, 1981 (Order 70-E), the Commission approved an amendment to the PURPA rule allowing diesel and dual-fuel systems to be qualifying facilities and thus be eligible for PURPA benefits.

A cogeneration facility is a qualifying facility if it can meet the operating and efficiency standards and the ownership criteria prescribed by FERC in 18 CFR 292, Subpart B. Figure 4-1 shows a logic diagram to determine if a facility can qualify as a cogenerator under PURPA.

Operating and Efficiency Standards

To obtain qualifying status, the cogeneration facility may have to meet operating and efficiency standards established by FERC. All topping-cycle cogenerators must meet FERC's operating standard. If oil or natural gas is used by new topping-cycle cogenerators, the efficiency standards pertain as well. No operating standards are prescribed for bottoming-cycle cogenerators. However, if oil or natural gas is used for supplementary firing, an efficiency standard is applied.

- Topping-Cycle Facilities

Operating Standard

The useful thermal energy output of the facility must, during any calendar year, be no less than 5 percent of the total energy output. This standard applies to all topping-cycle cogenerators regardless of the fuel used or date of installation.

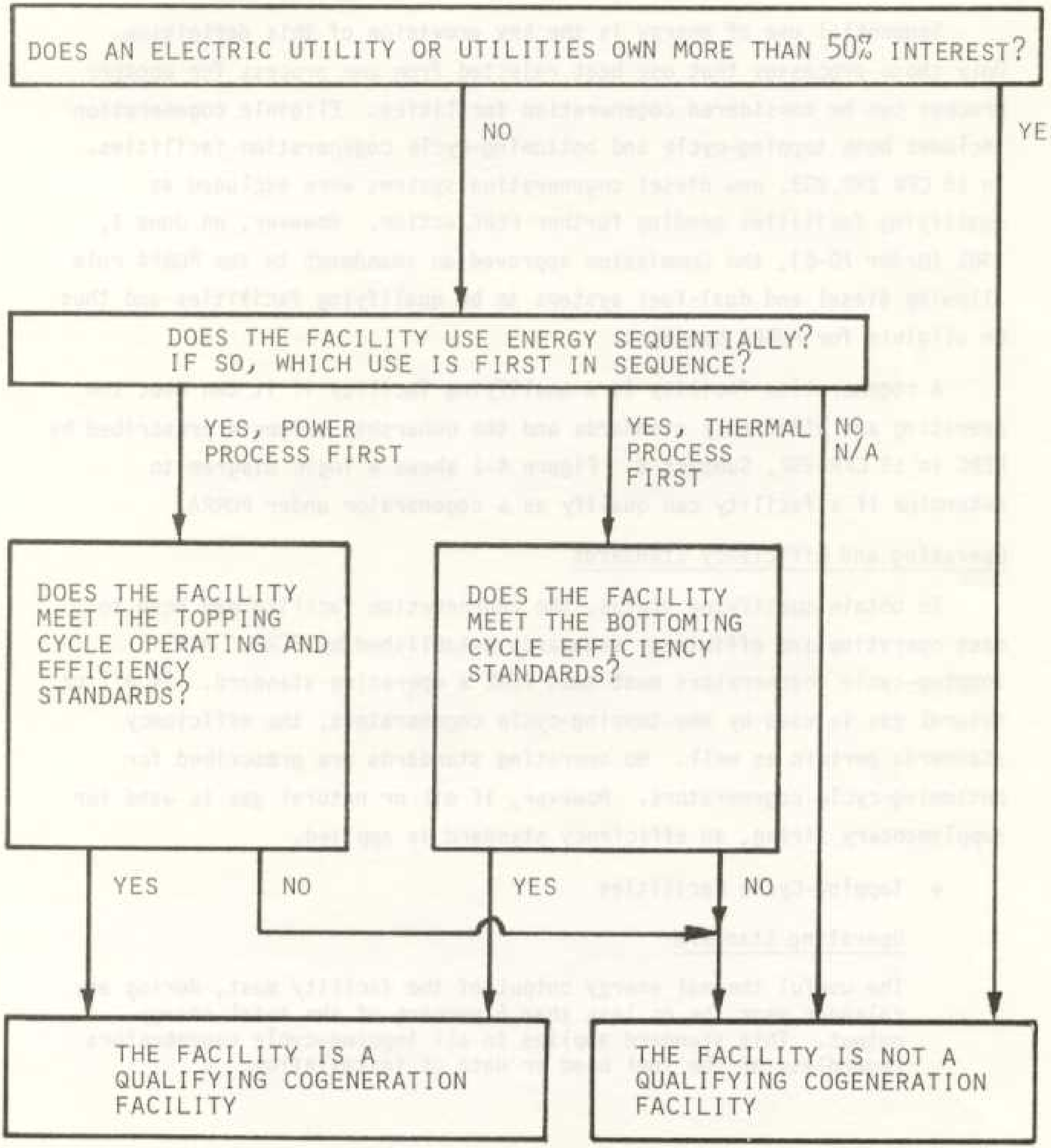

Figure 4-1. Logic Schematic for the Qualification of a Cogeneration Facility Under PURPA

Efficiency Standard

If any of the energy input is natural gas or oil and installation of the cogeneration facility began on or after March 13, 1980, the useful power output of the facility plus one-half the useful thermal output during any calendar year period must:

- be no less than 42.5 percent of the total energy input of natural gas or oil, or

- be no less than 45 percent of the total energy input of natural gas and oil if the useful thermal energy output is less than 15 percent of the total energy output of the facility.

- Bottoming-cycle Facilities

Operating Standard

None prescribed for bottoming cycle facilities.

Efficiency Standard

For any bottoming-cycle cogeneration facility for which any of the energy input as supplementary firing is natural gas or oil, and the installation of which began on or after March 13, 1980, the useful power output must, during any calendar year period, be no less than 45 percent of the energy input of the natural gas and oil used for supplementary firing.

Ownership Criteria

To qualify for the regulatory exemptions and the electric power sale and purchase benefits under PURPA, a cogeneration facility must be owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities). Electric utilities may participate in joint ventures that own qualifying facilities. However, electric utilities may together own no more than 50 percent of the equity of a qualifying facility (18 CFR 292.206).

Procedures for Obtaining Qualifying Status

A cogeneration facility that meets the operating and efficiency standards and ownership criteria listed above is a qualifying facility. Certification as such can be accomplished by either self-qualification or FERC certification; the cogenerator is free to choose which procedure to follow. FERC certification may offer advantages to the cogenerator in dealings with financial institutions and electric utilities.

- Self-certification. The owner or operator of a qualifying cogeneration facility must provide FERC the following information.
  - The name and address of the applicant and location of the facility
  - A brief description of the cogeneration facility
  - The primary energy source used or to be used by the facility
  - The power production capacity of the facility
- FERC Certification. In addition to the information supplied by a self-qualifier, the applicant for FERC certification must provide the following information:
  - The percentage of ownership held by any electric utility, by any public utility holding company, or by any person owned by either
  - A description of the cogeneration system, including whether the facility is a topping- or bottoming-cycle and sufficient information to determine that the operating and efficiency standards prescribed by FERC will be met
  - The date installation of the facility began or will begin
  - A notice for publication in the Federal Register. The general format for this notice is contained in FERC Order No. 70-A (45 FR 33603, May 20, 1980).

Within 90 days of filing an application, FERC will issue an order permitting or denying the application or setting the matter for hearing. Any order denying certification will identify the specific requirements not met. In the event no order is issued within 90 days of filing of the complete application, certification will be deemed to have been granted.

General Recommendations for Filing an Application for FERC Certification

There is no standard form to fill out. However, an application for Commission certification should follow the general format of Order No. 70-A.

The applicant should be specific as to what sort of facility is involved (topping- or bottoming-cycle cogeneration). An application which presents a lot of facts and asks the Commission to determine the appropriate type of facility may be delayed.

An application must include sufficient information to ensure that all applicable standards are met. All work should be clearly shown in the calculations required for determining compliance with operating and efficiency standards.

Although not required, it is helpful to provide to the Commission the telephone number of an individual familiar with the facility.

The address of FERC is:

Federal Energy Regulatory Commission
825 North Capitol St., N.E.
Washington, D.C. 20426

4.1.2 Natural Gas Policy Act of 1978 (NGPA)

Title II of the NGPA provides that incremental cost increases incurred by natural gas suppliers as a result of the phased deregulation of natural gas wellhead prices (under Title I)must be passed through to customers burning natural gas in non-exempt industrial boilers and other non-exempt industrial facilities defined by FERC. The NGPA also authorizes FERC to exempt cogeneration facilities from incremental pricing. Phase I of the incremental pricing rule is in place. This rule applies only to boiler fuel use of natural gas used in large industrial boiler fuel facilities. However, "boiler fuel use" means the use of any fuel for the generation of steam or electricity. Natural gas use in combustion turbines and reciprocating engines may thus be defined as boiler fuel use. Any benefits from exemption from incremental pricing would be reduced or eliminated, however,as gas is deregulated in 1985-87 under other provisions of the NGPA.

FERC rules concerning cogeneration exemptions from incremental pricing are contained in 18 CFR 292.205, 18 CFR 292 (Subpart E) and 18 CFR 282. All topping-cycle cogeneration facilities which produce electricity may qualify for an exemption if the facility meets both the operating and efficiency standards specified by FERC under Section 201 of PURPA. However, the March 13, 1980 installation date is not operative in determining compliance with efficiency standards for the incremental pricing exemptions.

For bottoming-cycle facilities, natural gas used for cogeneration is exempt to the extent that reject heat emerging from the useful thermal energy process is made available for power production. In other words, if half of the hot exhaust gases emerging from a high-temperature thermal process go into a heat exchanger for power production, then proportionately half of the natural gas input to the facility would be exempt. Since the incremental pricing rule applies at present only to industrial boilers, which are unlikely to be a heat source for a bottoming cycle, few if any bottoming-cycle facilities would be subject to incremental pricing in the first place.

Under these rules, all gas used for supplementary firing is not exempt from incremental pricing. Of course, such gas may be exempt under other provisions of the incremental pricing rules.

Cogeneration facilities that were in existence on November 1, 1979, and used natural gas as a fuel on or prior to that date may be exempted from incremental pricing under an Interim Rule that has been retained by the Commission. The Interim Rule, 18 CFR 292 (Subpart E), pertains only to incremental pricing. A facility qualifying under the Interim Rule does not gain the PURPA Section 210 benefits.

In brief, the Interim Rule consists of two alternative efficiency standards. A cogenerator can elect either standard, but all facilities must meet an efficiency test. The standards differ from the PURPA Section 201 efficiency standard in that:

- All fuels or energy inputs other than supplementary firing, are entered into the efficiency calculation
- Power outputs and thermal outputs are weighed equally (thermal energy is not divided by two)
- The ratio of energy outputs to inputs (deleting supplementary firing) must equal at least 0.55, or in the alternative, 0.70, after subtracting boiler efficiency considerations
- Gas used for supplementary firing may be exempted from incremental pricing under the Interim Rule.

Cogeneration facilities producing no electricity may qualify for an exemption from incremental pricing under Order No. 104, issued on October 23, 1980 (45 FR 71787, October 30, 1980). The exemption afforded such mechanical cogeneration facilities is similar to that under PURPA Section 201, except that useful power outputs do not include electricity.

Obtaining an Exemption from Incremental Pricing

The procedures by which the owner or operator of a cogeneration facility may obtain an exemption from incremental pricing of natural gas are contained in 18 CFR 282.204. In the event that an exemption affidavit is required to be filed with FERC, the natural gas supplier serving the cogeneration facility can provide the necessary forms. Exemption affidavit forms are also available from the Office of Public Information, Federal Energy Regulatory Commission, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

4.1.3 Energy Tax Act of 1978

Title III of the Energy Tax Act of 1978 (ETA) provides for changes in the business investment credit to encourage conservation of, or conversion from, oil and gas. The energy investment tax credit of 10 percent, for investments in designated energy property, is in addition to the regular 10 percent investment tax credit. The credits are used to offset the taxpayer's income tax liability.

To be eligible for the energy investment tax credit, property must be depreciable with a useful life of three years or more. The energy tax credit applies against all tax liability not offset by the regular credit. Excess investment credits from a taxable year may be carried to apply against tax liability over a 15-year carryover period under provisions of ERTA. The energy credits generally apply to costs incurred for the period of October 1, 1978 through December 31, 1982. There is no termination date for the regular investment credit.

To qualify for the energy investment credit, the property must be new (not used) and first placed in service after September 30, 1978. The energy credit (but not the regular investment tax credit) is available for structural components of buildings which otherwise qualify as energy property.

Availability of Energy Investment Tax Credits for Cogeneration

Cogeneration equipment and facility investments are not specifically addressed in the ETA. This was rectified in the Crude Oil Windfall Profit Tax Act of 1980 (see Section 4.1.4). However, the ETA provides energy investment tax credits for two classes of property, which include a number of the components, both equipment and structural, which may be used in cogeneration systems. These energy property classifications are alternative energy property and specially defined energy property.

Alternative energy property includes:

- Boilers which do not use oil or natural gas or products of oil or natural gas as a primary fuel
- Burners for combustors which do not use oil or natural gas or products of oil or natural gas as a primary fuel
- Pollution control equipment required by Federal, State, or local law to be installed in connection with the above items subsequent to October 1, 1978
- Equipment designed to modify existing equipment which uses oil or natural gas as a fuel so that such equipment will use a substance other than oil or natural gas or an oil mixture where oil will not constitute more than 75 percent of the fuel
- Equipment used for unloading, transfer, storage, reclaiming from storage, and preparation at the point of use of fuel other than oil or natural gas, or any product of oil or natural gas.

Alternative energy property excludes public utility property; see Section 4.1.4.

Specially defined energy property includes: recuperators, regenerators, heat wheels, heat exchangers, waste heat boilers, heat pipes, automatic energy control systems, turbulators, preheaters, combustible gas recovery systems, economizers, and any other property of a kind specified by the Secretary of the Treasury by regulations, the principal purpose of which is reducing the amount of energy consumed in any existing industrial or commercial process and which is installed in connection with an existing industrial or commercial facility.

Denial of Regular Investment Tax Credits and Accelerated Depreciation for Boilers Fueled by Oil and Gas

As noted above, boilers fueled by oil and gas are not included as alternative energy properties and are not eligible for the energy investment tax credit. In addition, under the ETA, such boilers are denied the regular investment tax credit unless the use of coal is precluded by air pollution regulations or unless use of such boilers will be an exempt use. Use of oil or gas in a facility which is an integral part of manufacturing, processing, or mining is not an exempt use unless in Hawaii or unless the facility is used for the production of electric power with a heat rate of less than 9,500 Btu/kWh and is capable of converting to synthetic fuels. Finally, boilers fueled by oil or gas are denied accelerated depreciation; such boilers must be depreciated using the straight line method.

4.1.4 Crude Oil Windfall Profit Tax Act (COWPTA) of 1980

The Crude Oil Windfall Profit Tax Act of 1980 (COWPTA) establishes new tax incentives for energy efficiency and extends or modifies certain provisions included in the Energy Tax Act of 1978. Cogeneration equipment is eligible for tax incentives under the COWPTA as described below.

Between January 1, 1980 and December 31, 1982, the COWPTA provides a 10 percent, nonrefundable energy credit for qualified investments in cogeneration equipment. Cogeneration equipment is defined as property which is an integral part of a system which uses the same fuel to produce electricity and qualified energy. Qualified energy is defined as steam, heat, or other forms of useful energy (other than electric energy), for industrial, commercial, or space-heating purposes (other than for production of electricity).

To qualify for the credit, the equipment must not use oil or natural gas or their by-products as fuel for any purpose other than startup, flame control, or backup. Further, during any taxable year, not more than 10 percent (determined on a Btu input basis) of the fuel can be oil or natural gas or their products.

The credit is allowed for equipment installed in connection with an existing industrial, agricultural, or commercial facility which produced electricity or qualified energy on January 1, 1980. For purposes of the credit, the term "industrial facilities" includes water purification and desalination facilities.

Qualifying equipment must be added to a system to either begin cogeneration activities or expand existing capacity. The credit will apply only to the extent that additional or replacement cogeneration equipment increases the capability of the system to produce electricity or qualified energy, whichever is the secondary product of the system. For example, if a facility is presently producing steam for process use as its primary energy product and electricity as its secondary energy product, a boiler that merely increases the facility's steam capacity would not qualify. However, the boiler may otherwise be eligible for an energy credit as an alternative energy property if it primarily uses an alternate fuel.

The determination of primary and secondary energy product within an energy using system will be made on the basis of the relative amounts of energy used by the two functions. In the case of an energy-using system where the primary energy product is steam, heat, or other useful energy (such as shaft power) for process or space heating purposes, qualifying cogeneration equipment includes a turbine and generator to produce electricity, and also any other equipment up to the electrical transmission stage. Where electricity is the primary product, qualifying equipment includes that equipment necessary to recover, distribute, but not to use, excess energy after the electrical generation function.

The 10 percent energy tax credit may be extended to December 31, 1990, provided the following criteria are met or apply to a cogeneration project with a normal construction period of two years or more:

- Before January 1, 1983 the taxpayer has completed all engineering studies in connection with the commencement of the construction of the project, and

- Before January 1, 1986 the taxpayer has entered into binding contracts for the acquisition, construction, reconstruction, or erection of equipment specially designed for the project and the aggregate cost to the taxpayer of that equipment is at least 50 percent of the reasonably estimated cost of all such equipment which is to be placed in service as a part of the project upon its completion.

To qualify for the 10 percent energy tax credit, cogeneration equipment must not be public utility property. Public utility property is that used predominantly in the trade or business of furnishing or selling of electric energy and steam through a local distribution system or transportation of steam by pipeline, if the rates are fixed by a public body such as a public utility commission. Sale of electricity by cogenerators to utilities at rates based on avoided costs pursuant to PURPA does not disqualify property for the 10 percent energy tax credit.

4.1.5 <u>Powerplant and Industrial Fuel Use Act of 1978 (FUA)</u>

The FUA, passed by Congress as part of the National Energy Act of 1978, was designed to increase the use of coal and other alternatives to oil and natural gas. The Act prohibits the use of oil and natural gas in certain new and existing major fuel burning installations (MFBIs) and powerplants unless ERA grants an exemption for such use. Sections 212(C) and 312(C) of the FUA specifically provide for exemptions for oil and natural gas use in eligible new and existing cogeneration systems.

Permanent exemptions for a cogeneration facility may be granted by ERA upon a finding "that the petitioner has demonstrated that economic and other benefits of cogeneration are unobtainable unless petroleum or natural gas, or both, are used in such facility... ."

Cogeneration facilities are classified as either electric powerplants or MFBIs to determine how the FUA applies. Facilities are defined as electric powerplants if they produce electric power and more than 50 percent of the electric power they generate annually is sold or exchanged for resale. Otherwise, cogeneration facilities are considered MFBIs.

The classification of a cogeneration facility as a power plant or an MFBI can radically alter the applicability and types of fuel use prohibitions. New powerplant cogenerators are subject to prohibitions on oil and gas use in boilers, gas turbines, and combined-cycle units. New

MFBI cogenerators are subject to prohibitions on oil and gas use in boilers only. Although ERA has authority to issue rules banning oil and gas use in new MFBI gas turbines, combined-cycle units, and internal combustion engines, such rules have not yet been proposed.

Existing MFBIs and powerplants are subject to no statutory prohibitions on oil or natural gas use, but ERA may prohibit such use if the facility can burn an alternative fuel. The one exception is a prohibition on oil use for existing powerplants that used coal in 1977. Such powerplants may not use oil in excess of the amounts used in 1977 unless a permit is granted by ERA. (See FUA Section 405)

Regulatory Background

ERA has published final rules [see 45 FR 38276 (June 6, 1980)] which (1) define MFBI, electric powerplant, and cogeneration facility; (2) describe the prohibitions applicable to new powerplants and MFBI's as well as the exemptions available; and (3) provide administrative procedures for applying for exemptions. ERA has also published final rules relating to the prohibitions against oil and gas use in existing facilities and exemptions available [see 45 FR 53682 (August 12, 1980)].

Interim rules relating to exemptions for cogeneration facilities were published in 44 FR 28950, 28994, 29014 (May 17, 1979) and 44 FR 43176, 43204, 43219 (July 23, 1979). However, in a Notice of Proposed Rulemaking (NOPR) in 45 FR 53368 (August 11, 1980), ERA proposed amending the interim cogeneration rule. The proposed amendment would establish a statewide energy limit on oil and gas use by cogenerators as a means of encouraging cogeneration in those regions of the country where there is potential for oil and gas savings while ensuring that new alternate fuel-fired capacity would not be deferred. The NOPR also proposed changing the definition of "electric generating unit" and "cogeneration facility." This change would prevent certain cogeneration systems from being classified as powerplants (rather than MFBIs). A new cogeneration facility which is a "powerplant" would be subject to FUA statutory prohibitions on oil and gas use in new boilers, gas turbines, and combined-cycle units as well as prohibitions on the construction of a powerplant without the capability of using an alternate fuel as its primary energy source. There is no corresponding statutory prohibition on construction applicable to new MFBIs and the statutory prohibition on oil and gas use by new MFBIs applies only to boilers. Consideration of testimony and public comments on the August 11, 1980,NOPR is proceeding under Docket No. ERA-R-80-24.

On March 25, 1981,the President's Task Force on Regulatory Relief announced a list of existing regulations which should be reassessed by Executive Branch Agencies, including the regulatory program under FUA. As a result, ERA issued a new NOPR in 46 FR 31216 (June 12, 1981). These proposed rules would extensively revise previous regulations implementing FUA to simplify the administrative procedures and exemption criteria applicable to owners or operators of new and existing powerplants and MFBIs which are subject to the prohibitions of the Act. For many of the exemptions, including those for cogeneration, ERA has proposed a streamlined procedure which would enable a petitioner to qualify for an exemption through a simple certification procedure. Consideration of these proposed changes is proceeding under Docket No. ERA-R-81-06.

Pending the issuance of a final rule, ERA will continue to function under the 1979 interim cogeneration rules. These interim rules are published in 10 CFR 503.37 (new powerplants), 504.35 (existing powerplants), 505.27 (new MFBIs), and 506.35 (existing MFBI's).

Applicability of the FUA and ERA Rules

To determine how the FUA and ERA's implementing rules affect a given cogeneration facility, the series of questions shown schematically in Figure 4-2 and listed below should be answered.

- Does the facility use oil or gas as a primary energy source? If no oil or gas is used or if only minimum amounts are used,* the facility is not affected by FUA.
- If the facility does use oil or gas as a primary energy source, does the facility have a design heat input rate of 100 million Btu/hr or more? Or is the facility functionally integrated with other facilities** in a system with a total heat input rate of 250 million Btu/hr or more? If the answer to both questions is no, the facility is not affected by FUA.

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*For unit ignition, start-ups, flame stabilization, control, unanticipated equipment outages, and emergencies resulting from electric power outages.

**Units that use less than 50 million Btu/hr are not counted in the total.

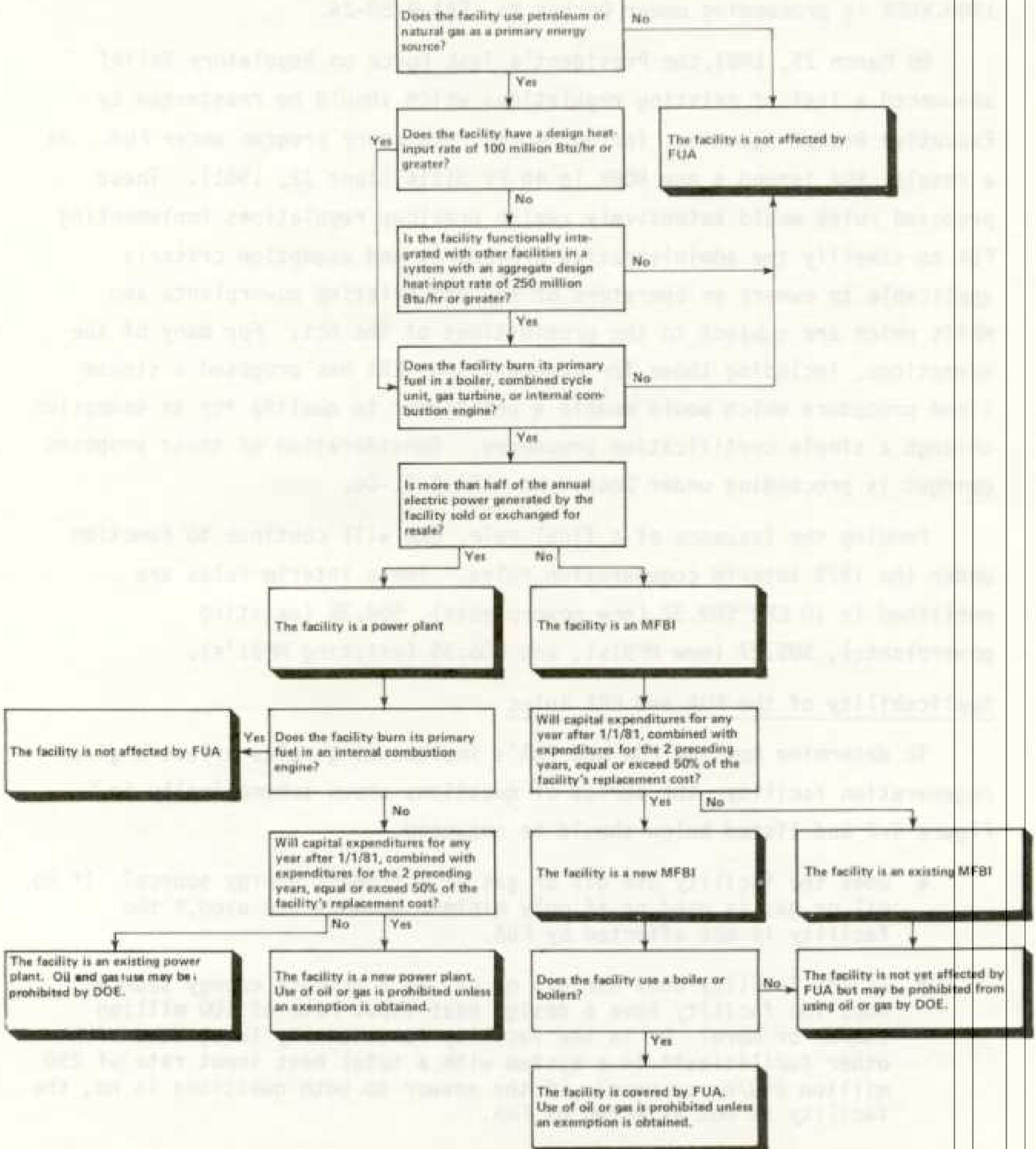


Figure 4-2. Applicability of Fuel Use Act

- If a facility's energy consumption exceeds these thresholds, how does the facility burn its primary fuel? FUA applies only to facilities with stationary boilers, combined cycle units, gas turbines, or internal combustion engines. If a facility uses none of these, FUA does not apply.

Facilities to which the FUA applies fall into the four classifications shown below.

- New powerplant. Use of oil or gas as a primary fuel is prohibited, and the powerplant cannot be built without the capability of using coal or another alternative fuel.
- Existing powerplants. DOE may prohibit the use of oil or gas if the facility has the capability of burning coal or another alternative fuel.
- New MFBIs. If the facility uses a boiler, use of oil or gas is prohibited. DOE may also prohibit use of oil or gas in other types of facilities.
- Existing MFBIs. DOE may prohibit use of oil or gas if the facility has or could have the capability of burning an alternative fuel.

Cogeneration Exemptions

To qualify for an exemption under the 1979 interim rules, the electricity generated by a cogeneration facility must constitute more than 10 percent and less than 90 percent of the useful energy output of the facility. If this test is met, ERA may grant an exemption by reason of FUA, for cogeneration, if the oil or gas to be consumed by the cogeneration facility will be less than would otherwise be consumed by units which would not be expected to use an alternate fuel in the absence of the cogeneration facility. The essential test is whether the cogeneration facility would save oil or gas over and above the savings that FUA could reasonably be expected to achieve.

To facilitate analysis of exemption availability, ERA has categorized the units which would not be expected to use an alternate fuel by reason of FUA. First, there are units that are or would be too small to be covered by the regulations. Second, there are FUA-covered units that are existing noncoal capable units or exempt units, and are less than 40-years old in the case of field-erected units and less than 20-years old in the case of package units. Units that are older than these could reasonably be expected to be retired soon, and if they were replaced, the use of alternate fuels in the replacement unit would have to be considered. If a cogeneration exemption is granted, and units less than 20 or 40-years old were included in the calculation of the oil or gas that would have been consumed absent cogeneration, under the regulation, these would have to be retired or shut down. Third, there may be units that are not yet constructed that would be covered by FUA. To include oil and gas from these projected units in the "otherwise consumed" oil- or gas-savings calculation, the petitioner would have to demonstrate that each would be entitled to an exemption. In addition to these three categories, oil or gas savings may be attributed to displacing electricity from the grid. Savings of oil and gas due to displacement of utility electricity must be based on a 10-year forecast that includes construction and retirement of utility plants within those 10 years.

The cogeneration exemption in these regulations also contains a public interest provision. ERA may grant an exemption even if oil or gas savings could not be demonstrated in certain cases such as where the facility will employ a technical innovation or where the facility would result in retaining industry in urban areas.

ERA may also refuse to grant an exemption if it determines that such a grant would not be in the public interest or in accordance with the purposes of the Act, notwithstanding the fact that the evidence furnished to ERA in an exemption petition substantiates that the facility would otherwise be eligible to receive the exemption.

Exemption Petitions

A petition to ERA for a cogeneration exemption must contain at least the following evidence:

(1) An engineering description of the cogeneration system including proposed output and uses thereof, with sufficient detail to ensure that the facility qualifies as a cogeneration facility

(2) A detailed oil and natural gas savings calculation identifying the projected oil or natural gas consumption of the cogeneration facility and the oil or natural gas that would otherwise be used

(3) Identification of the FUA status of the proposed and displaced units with respect to coverage and designation as new, existing, or exempted age of units, and alternate fuel capability of units

(4) Identification of all persons and their roles in the proposed cogeneration facility

(5) Where a demonstration is required that the units would be entitled to an exemption, submission of all evidence required by the regulations with respect to the applicable exemptions, including the alternate site showings

(6) In the case of an exemption under public interest provisions, an explanation of the public interest factors the cogenerator believes should be considered by ERA.

In addition, the petition must include evidence demonstrating that use of a mixture of natural gas or petroleum and an alternate fuel is not economically or technically feasible, as required in 10 CFR 503.9. Finally, an environmental impact analysis as required by 10 CFR 503.15 must be included in the petition.

ERA processing of an exemption petition is illustrated in Figure 4-3.

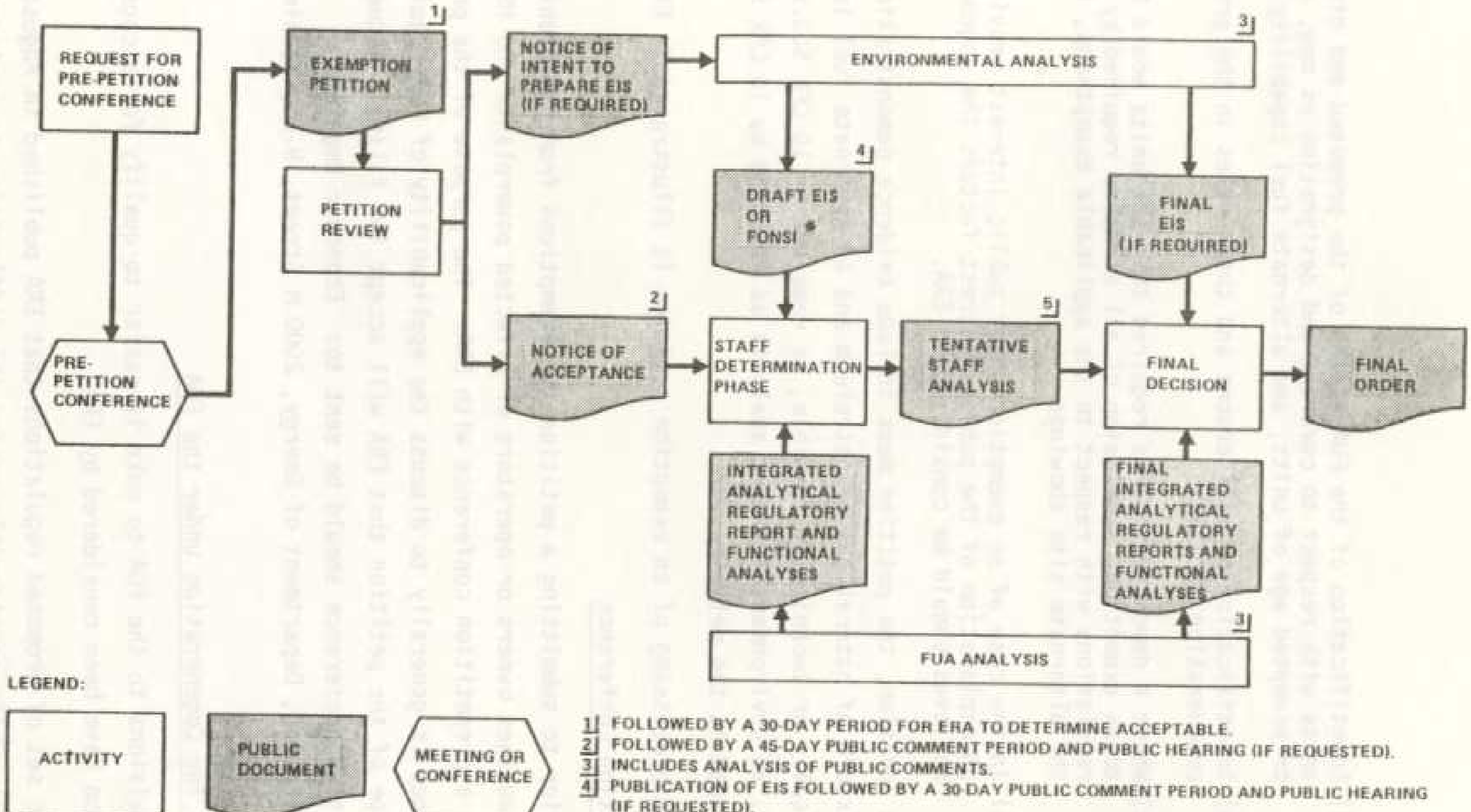
Prepetition Conference

Prior to submitting a petition for exemptions from FUA prohibitions, ERA encourages owners or operators of affected powerplants and MFBIs to request a prepetition conference with ERA. The purpose of the prepetition conference is generally to discuss the applicability of FUA regulations and the scope of the petition that ERA will accept for filing. Requests for a prepetition conference should be sent to: Economic Regulatory Administration, Department of Energy, 2000 M Street, N.W., Washington, D.C. 20461.

Outlook for Cogeneration under the FUA

Revisions to the FUA to make it easier to qualify for a cogeneration exemption have been considered by ERA.

The set of proposed regulations that ERA published in August 1980 and June 1981, while considerably easing the difficulties in qualifying for a



1/ FOLLOWED BY A 30-DAY PERIOD FOR ERA TO DETERMINE ACCEPTABLE.
2/ FOLLOWED BY A 45-DAY PUBLIC COMMENT PERIOD AND PUBLIC HEARING (IF REQUESTED).
3/ INCLUDES ANALYSIS OF PUBLIC COMMENTS.
4/ PUBLICATION OF EIS FOLLOWED BY A 30-DAY PUBLIC COMMENT PERIOD AND PUBLIC HEARING (IF REQUESTED).
5/ FOLLOWED BY A 14-DAY PUBLIC COMMENT PERIOD AND PUBLIC HEARING (IF REQUESTED).

*Finding of no significant impact

Figure 4-3. Exemption Petition Processing Flow cogeneration exemption, have not been finalized. Consequently, cogeneration exemptions must still be submitted and processed under the 1979 interim rules. Although filing fees are no longer required and the Fuels Decision Report does not have to be submitted with the application, the basic qualifying rules remain in effect. Modified rules that are similar or less stringent than the proposed rules are likely to be approved eventually.

Since the FUA only affects facilities using oil or natural gas, prospective cogenerators using alternate fuels should proceed with their plans. PURPA and the ETA as modified by the COWPTA provide considerable incentives to develop an expanded industrial cogeneration energy production base.

4.2 PRACTICAL EFFECTS ON COGENERATION

The practical effects of the above laws and regulations on cogeneration must be determined on a case-by-case basis. However, several general points should be noted by the prospective cogenerator.

- The regulations generally favor facilities burning coal or alternative fuels. Such facilities are not required to meet efficiency standards to qualify for PURPA benefits, and are eligible to receive the regular 10 percent investment tax credit plus the additional 10 percent energy investment credit. Such facilities also avoid the regulatory problems associated with FUA.

  On the other hand, oil- and gas-fired facilities must meet efficiency standards to qualify under PURPA, are generally ineligible for the energy investment credit, and in the case of boilers, are ineligible for the regular investment tax credit and accelerated depreciation. These facilities are subject to FUA regulations if using a boiler or if classified as a powerplant.

- FERC rules under PURPA can provide added benefits to a qualifying cogeneration facility that sells its entire power output to a utility at an avoided cost-based rate and purchases all of its power from the utility at normal retail rates. Under ERA rules implementing FUA, however, such a facility would be classified as a "powerplant" and would thus be subject to statutory prohibitions on oil and gas use in boilers, gas turbines, and combined cycles. If less than half of the electric power output of the facility was sold or exchanged for resale the facility would be classified as an MFBI, and statutory prohibitions on oil and gas use would apply only to boilers.

- A cogeneration facility under PURPA is defined as equipment used to produce electric energy and forms of useful thermal energy through the sequential use of energy. The definition of a cogeneration facility under FUA also requires the production of electric power and other forms of useful energy. Mechanical cogeneration facilities producing only shaft power are thus excluded. However, under the NGPA, FERC can exempt mechanical cogeneration facilities from incremental pricing.

- A cogeneration facility cannot qualify for PURPA benefits if electric utilities or their affiliates hold more than a 50 percent equity interest in the facility. Also, cogeneration and other types of energy property do not qualify for the energy tax credit if they are considered to be public utility property.

4.2.1 Textile Fiber Plant Example

The effect of the legal and regulatory provisions on the cogeneration options considered in Chapters 1 and 2 for Example I, the DuPont Textile Fiber Plant and Intermediate Plant in South Carolina, is explored in this section. The three options are (I-A), a natural gas-fired combustion turbine combined cycle system; (I-B), a natural gas-fired combustion turbine topping existing process heaters; and (I-C), a coal-fired steam turbine system. Legal and regulatory concerns are among the many factors to be considered in selecting a cogeneration configuration for a specific site. The impact of PURPA, NGPA, ETA, COWPTA, and FUA on the DuPont facility cogeneration options are each discussed below. The coal-fired option encounters the least problems and would be eligible for the energy investment tax credit.

PURPA

To qualify for benefits under PURPA, a cogeneration system must meet certain criteria to determine if the facility is a qualifying cogeneration facility. A utility or utilities cannot own more than a 50 percent interest, electrical energy must be produced, and operating and efficiency standards must be met. All three options meet the first two criteria.

The operating standard, which applies only to topping cycles, requires that the useful thermal energy output be at least 5 percent of the total energy output, during any calendar year. The systems run in a steady state, so the computations may be made based on the hourly output. For each system, the thermal output in Btu/hour is calculated for each steam flow delivered to the process and then summed to determine the total useful thermal output. The net electrical output is then converted to Btu/hour, and the thermal output is divided by the sum of the thermal and electrical outputs (data is taken from Chapter 1, Figures 1-25, 1-27, and 1-28):

I-A. Combined cycle (in 10^7 Btu/hour):

$$\frac{10.7}{10.7 + 7.7} = 58\% > 5\%$$

I-B. Combustion turbine (in 10^8 Btu/hour):

$$\frac{4.47}{4.47 + 1.43} = 76\% > 5\%$$

I-C. Steam turbine (in 10^8 Btu/hour):

$$\frac{5.55}{5.55 + 0.38} = 94\% > 5\%$$

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PURPA

To qualify for benefits under PURPA, a cogeneration system must meet certain criteria to determine if the facility is a qualifying cogeneration facility. A utility or utilities cannot own more than a 50 percent interest, electrical energy must be produced, and operating and efficiency standards must be met. All three options meet the first two criteria.

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I-A. Combined cycle (in 10^7 Btu/hour):

$$\frac{10.7}{10.7 + 7.7} = 58\% > 5\%$$

I-B. Combustion turbine (in 10^8 Btu/hour):

$$\frac{4.47}{4.47 + 1.43} = 76\% > 5\%$$

I-C. Steam turbine (in 10^8 Btu/hour):

$$\frac{5.55}{5.55 + 0.38} = 94\% > 5\%$$

steam turbine and generator should qualify under COWPTA, providing the system is engineered and installed within the time limitations of these acts.

With the combined cycle option, the unfired heat recovery boiler probably qualifies as specially defined energy property eligible for the 10 percent energy investment tax credit. For the combustion turbine option, the supplementary fired heat recovery boiler may not be eligible for the regular investment tax credit or accelerated depreciation. IRS rulings would be needed to confirm these interpretations of the acts.

FUA

The Powerplant and Industrial FUA applies only to the use of oil and natural gas, and so the coal-fired cogeneration option (Example I-C) is not subject to the act. The other two options are large enough to be covered by the Act and would be classified as new MFBIs. FUA prohibits burning natural gas in a boiler for new MFBIs. The combined cycle option (example I-A) is permitted, since it includes no fired boilers. The combustion turbine option (Example I-B) uses a supplementary fired boiler with natural gas as the supplemental fuel. This facility might be required to obtain an exemption. To qualify for an exemption, the electricity generated must constitute between 10 and 90 percent of the useful energy output of the facility. This facility would qualify (based on Figure 1-27):

$$\frac{1.43 \times 10^8 \text{ Btu/hr}}{(4.47 + 1.43) \times 10^8 \text{ Btu/hr}} = 24\%$$

For an exemption, the cogeneration facility must save oil or gas over and above the savings that FUA could reasonably be expected to achieve. Since this system probably displaces coal at the local utility while replacing residual oil at the plant, a net oil and gas savings is probably not achieved.

The granting of an exemption to FUA is somewhat complex. ERA encourages owners or operators to request a prepetition conference with ERA to discuss the applicability of FUA regulations and the scope of the petition. This would be advisable for the combustion turbine cogeneration option.

4.2.2 Fine Chemicals Plant Example

In contrast to the previous example, in which the legal and regulatory aspects of three cogeneration options were explored and contrasted, this example concentrates on one cogeneration option for the Fine Chemicals Plant in New Jersey: a slow-speed diesel engine with a supplementary-fired recovery boiler. The impact of PURPA, NGPA, ETA/ COWPTA, and FUA on this oil-fired system is discussed below.

PURPA

This proposed cogeneration system, which is Example IV from Chapters 1 and 2, produces some electrical power for export. Under PURPA, if the system qualifies as a cogeneration facility, the utility must purchase the power at a fair rate, and provide back-up power at a fair rate. To qualify, a utility or utilities cannot own more than a 50 percent interest in the facility. Because of a June 1, 1981 FERC ruling, the facility is not disqualified because it is a diesel system. This system is a topping cycle and must meet operating and efficiency standards to qualify for PURPA benefits.

The operating standard requires that the useful thermal output be at least 5 percent of the total thermal output. For this system, based on Chapter 1, Figure 1-34 data, (in 10^6 Btu/hour):

$$\frac{211.8}{211.8 + 79.4} = 73\% > 5\%$$

The efficiency standard requires that the useful power output plus one-half of the useful thermal output be no less than 42.5 percent of the energy input in oil or gas. This yields (in 10^6 Btu/hour, from Figure 1-34):

$$\frac{79.4 + 105.9}{336.5} = 55\% > 42.5\%$$

This facility would be a qualifying cogeneration facility entitled to the benefits under PURPA. Certification as such can be accomplished by self-certification or FERC certification.

NGPA

As NGPA only concerns natural gas-fired units, this oil-fired system is unaffected by the Act.

ETA/COWPTA

Since this cogeneration system is fueled by oil (including supplementary firing in the recovery boiler), it is not eligible for the 10 percent energy investment tax credit under either ETA or COWPTA. Under ETA, the supplementary-fired heat recovery boiler may be denied the regular investment tax credit and accelerated depreciation since it burns oil, subject to IRS rulings.

FUA

Under FUA, the diesel cogeneration facility would be classified as a new MFBI. Oil use presently is only prohibited for boilers. Since this system contains a boiler which does have oil firing, the supplementary firing may be prohibited by FUA unless an exemption is granted.

To qualify for an exemption under the 1979 interim rules, the electricity generated by a cogeneration facility must constitute between 10 and 90 percent of the useful energy output of the facility. This facility meets this criteria (in 10^6 Btu/hour, from Figure 1-34):

$$\frac{79.4}{211.8 + 79.4} = 27\%$$

The primary test for an exemption is whether the cogeneration facility would save oil or gas over and above the savings that FUA could reasonably be expected to achieve. FUA savings could result from fuel switching in boilers being replaced, new boilers, and savings at the electric utility. In this case, the fuels displaced at the utility are probably oil and gas, and so the overall system results in oil and gas savings. All existing boilers in the plant are burning residual oil and are less than 20 years old. Indeed, the company has applied for an exemption to FUA, using the local utility's ten-year projected estimate of marginal oil and gas use along with the heat rates and use patterns of the existing boilers to calculate the net oil and gas savings.

5.0 SYSTEM IMPLEMENTATION CASE STUDY

A case study is presented in this chapter and treated in considerable detail to illustrate how a potential industrial cogenerator may evaluate the technical, economic, environmental, and institutional factors involved in the selection and implementation of a cogeneration system. The case study in point is that of an integrated pulp and paper mill owned by the Scott Paper Company. The mill is located in Mobile, Alabama, and produces 800 tons/day of tissue paper and 600 tons/day of writing paper. The utility serving the mill is the Alabama Power Company, whose schedule of avoided costs for cogenerators supplying more than 100 kW has not yet been filed with the state utility commission. Hearings on that subject are expected to be held during the fall of 1981. For cogenerators supplying less than 100 kW, the utility is offering approved energy credits between 2.04 and 2.17¢/kWh. No capacity credits are being contemplated. In 1980, the utility was essentially 100 percent dependent on coal, nuclear, and hydro for power generation (Table 5-1).

Table 5-1. Alabama Power Company Fuel Use Profile (1980)

	Generation By Fuel Type[a] (%)
Coal	71.7
Nuclear	14.5
Hydro	13.7
Oil/Gas	0
TOTAL	100

Overall System Heat Rate 10,405 Btu/kWh[b]

[a] Alabama Power Co., Annual Report, 1980

[b] Electrical World, Directory of Utilities, 1980-81

Because of the low expected credits to cogenerators, the marginal increase in the total return on investment due to the addition of capacity for exporting power is likely to be small. The economically indicated mode of operation is therefore cogenerated power primarily for internal use.

Another important factor is the local availability and cost of fuels. Considerations of the relative costs of different fuels in a particular location, past experience with curtailments or shortages, or expectations of future cost and availability are frequently dominant elements of a company's strategic planning of its operations. Such planning may include capacity expansion, changes in process technology, or changes in product structure that could substantially affect energy demands at a given location. Environmental issues, including Federal and local regulations and the attainment status of the air quality control region in which the plant is located, also influence the choice and quality of fuels that can be used. Taken together, the above considerations could ultimately determine the type of fuel to be used and thereby establish the particular cogeneration technology. In the case of the Scott mill, no particular fuel restriction exists. However, the Company's policy is to become ultimately independent of petroleum and natural gas fuels and projects a future fuel mix of 85 percent wood and 15 percent coal. This strategic choice narrows the options to steam turbine cogeneration.

5.1 ESTABLISHING PLANT ENERGY USE PROFILES

Determination of the pattern of plant energy use is an important step in the process of identifying possible cogeneration options and analyzing their relative merits. Careful audits should be conducted of all the types and quantities of energy supplies and demands. Consumption of electricity and primary fuel is easily determined from monthly expenditures and the metering normally available in most plants. More difficult to determine are the steam and hot water flows to the different processes. Such flows are usually only measured at the source (boiler or water mains) and not at individual demand centers, although the header pressures are generally known.

Although it is easier to have a cogeneration system deliver its thermal energy to the main supply headers leaving the distribution system undisturbed, it is frequently possible to deliver the energy more efficiently in its direct form to the process with only minor modifications. For example, if steam is used to heat water for process use (as in the textile or food industries) or for space heating, reduction of the steam load and delivery of the hot water directly (e.g., from a diesel or spark-ignited engine) may be possible. For this reason, it is important to separately identify the end uses by energy form and conditions. All end uses should be identified taking care to avoid "doublecounting" where the streams are used more than once in a cascaded fashion--a common practice in pulp and paper mills, petroleum refineries, and chemical plants.

Waste heat sources should also be included in the audit, particularly sources at high temperatures that could be used for cogeneration by bottoming systems. Pictorial diagrams illustrate the overall energy flows and minimize the possibility of double counting. To complete the characterization of the plant, it is necessary to determine the seasonal and daily variations in energy use. This is more conveniently displayed in the form of graphs, wherein the daily fluctuations in energy demands can be given for typical working days and weekends. The graphs help to characterize the cogeneration system and its operation.

For the Scott paper mill, fuel consumption by type and end use are shown in Table 5-2. The predominant uses are in boilers whose capacities are listed in Table 5-3. Electrical loads by end use are given in Table 5-4. Four steam turbine generators with a combined capacity of 48 MW generate part of the power required, and the remainder is purchased from the utility. The integrated daily and seasonal variations in electrical and steam consumptions are given in the distribution curves of Figures 5-1 and 5-2. These curves show that electrical demand is fairly flat at about 60 MW for most of the year while the process steam demand varies somewhat around an average of 1.12×10^6 lbs/hr. The flatness of the curves indicates that the plant's steam and electrical demands are fairly constant during most of the year. This feature is desirable for several reasons, largely related to economic operation. First, a baseloaded cogeneration system generally obtains a more favorable avoided-cost rate and is viewed by the utility as a more reliable system than one whose power output

Table 5-2. Typical Fuel Input - Paper Mill Case Study

	10^6 Btu/hr	PERCENT OF TOTAL PLANT
Boilers		
Natural Gas	410	15.6
No. 6 Oil	640	24.3
TOTAL PURCHASED FUEL	1,050	39.9
Black Liquor	930	35.4
Wood Bark	200	7.6
TOTAL BY-PRODUCT FUEL	1,130	43.0
TOTAL BOILER FUEL	2,180	82.9
Paper Machine Hood Dryers		
No. 2 Oil & Natural Gas	110	4.2
Lime Kiln		
High S No. 6 Oil	140	5.3
Purchased Electricity*	200	7.6
TOTAL PLANT FUEL	2,630	100.0

*1 kWh = 10,000 Btu

Table 5-3. List of Power Boilers, Kilns, Paper Machines, Hoods, and Turbogenerators - Paper Mill Case Study

USER	FUEL	CAPACITY	STACK OUTLET TEMPERATURE
#1 Boiler	Resid. Oil 1/2%S, Nat. Gas	90,000#/hr	320°F
#2 Boiler	Resid. Oil 1/2%S, Nat. Gas	90,000#/hr	320°F
#3 Boiler	Resid. Oil 1/2%S, Nat. Gas	90,000#/hr	320°F
#4 Boiler	Resid. Oil 1/2%S, Wood Waste	160,000#/hr	350°F
#5 Boiler	Resid. Oil 1/2%S, Nat. Gas	200,000#/hr	350°F
#6 Boiler	Resid. Oil 1/2%S, Wood Waste	300,000#/hr	150°F (Scrubber)
#3 Recovery	Black Liquor, Resid. Oil	85,000#/hr	320°F
#4 Recovery	Black Liquor, Resid. Oil	130,000#/hr	320°F
#5 Recovery	Black Liquor, Resid. Oil	130,000#/hr	325°F
#6 Recovery	Black Liquor, Resid. Oil	204,000#/hr	350°F
#1 Kiln	Resid. Oil, Nat. Gas	65 T/D Lime	180°F (Scrubber)
#3 Kiln	Resid. Oil, Nat. Gas	65 T/D Lime	180°F (Scrubber)
#4 Kiln	Resid. Oil, Nat. Gas	130 T/D Lime	180°F (Scrubber)
Machine Hoods	Distillate #2, Nat. Gas	-	650°F

Steam Conditions: 575 psig, 740°F, Feedwater Temperature 355°F

Turbogenerators	1	7,500 kW
	2	7,500 kW
	3	13,500 kW
	4	19,500 kW
TOTAL		48,000 kW

Table 5-4. Electrical Loads - kW - Paper Mill Case Study

	MAXIMUM PERIOD	AVERAGE	MINIMUM PERIOD
Wood Preparation	1,860	1,750	1,642
Continuous Pulping	2,068	1,990	1,789
Batch Pulping	6,154	4,935	3,899
Bleaching	6,503	6,060	5,515
P & C [a]Stock Prep.	4,702	4,735	3,787
P & C [a]Machines	13,214	12,110	11,265
T/M [b]Stock Prep.	2,626	2,385	2,202
T/M [b]Machines	14,497	13,190	11,774
T/M [b]Finishing	1,905	1,760	1,548
Pulp Dryers	1,190	970	692
Evaporators	759	695	456
Recovery	2,406	2,295	2,157
Causticizing	1,085	855	962
Water	1,976	1,845	1,752
Power Boilers	1,761	1,560	1,385
Waste Treatment	1,205	765	333
Miscellaneous	1,384	1,340	1,258
TOTAL HOUR	61,305	58,880	56,017
DAY	1,471,320	1,413,120	1,334,410

[a]P&C = Printing and Converting

[b]T/M = Tissue and Towel

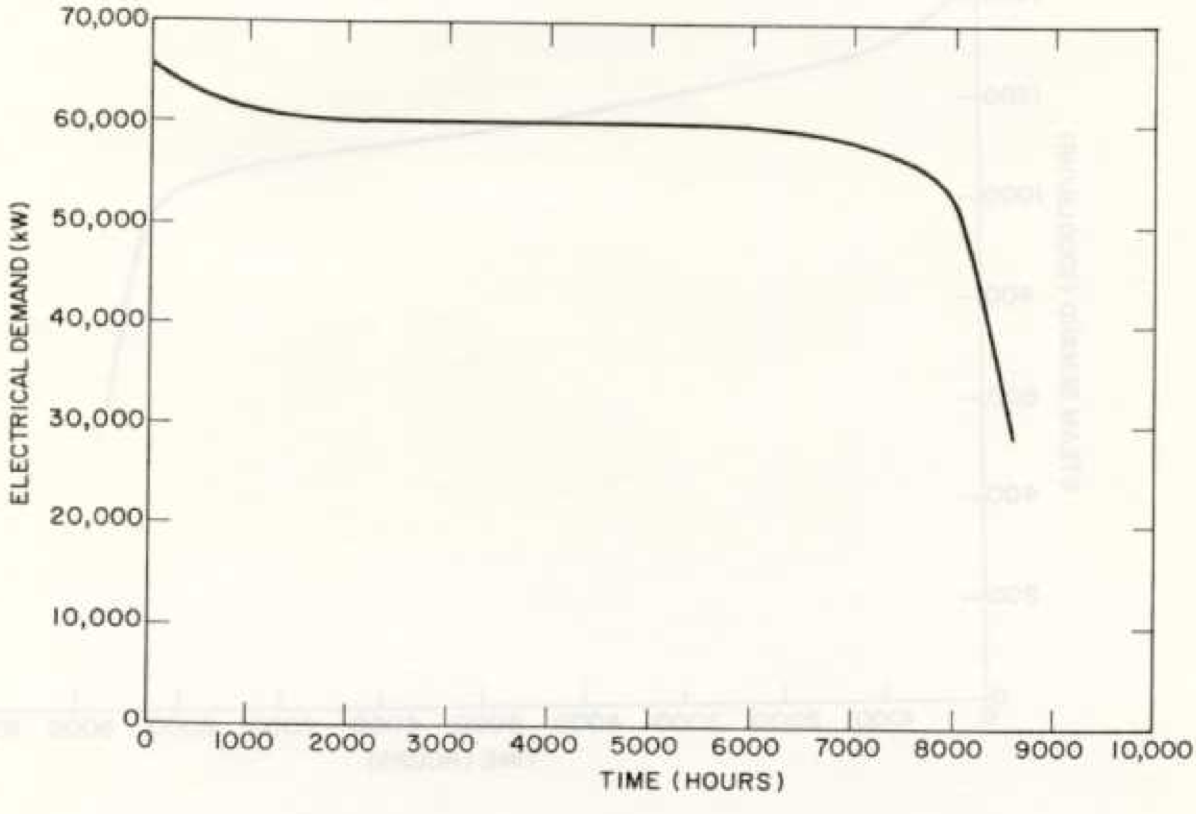

Figure 5-1. Electrical Demand Curve - Paper Mill Case Study

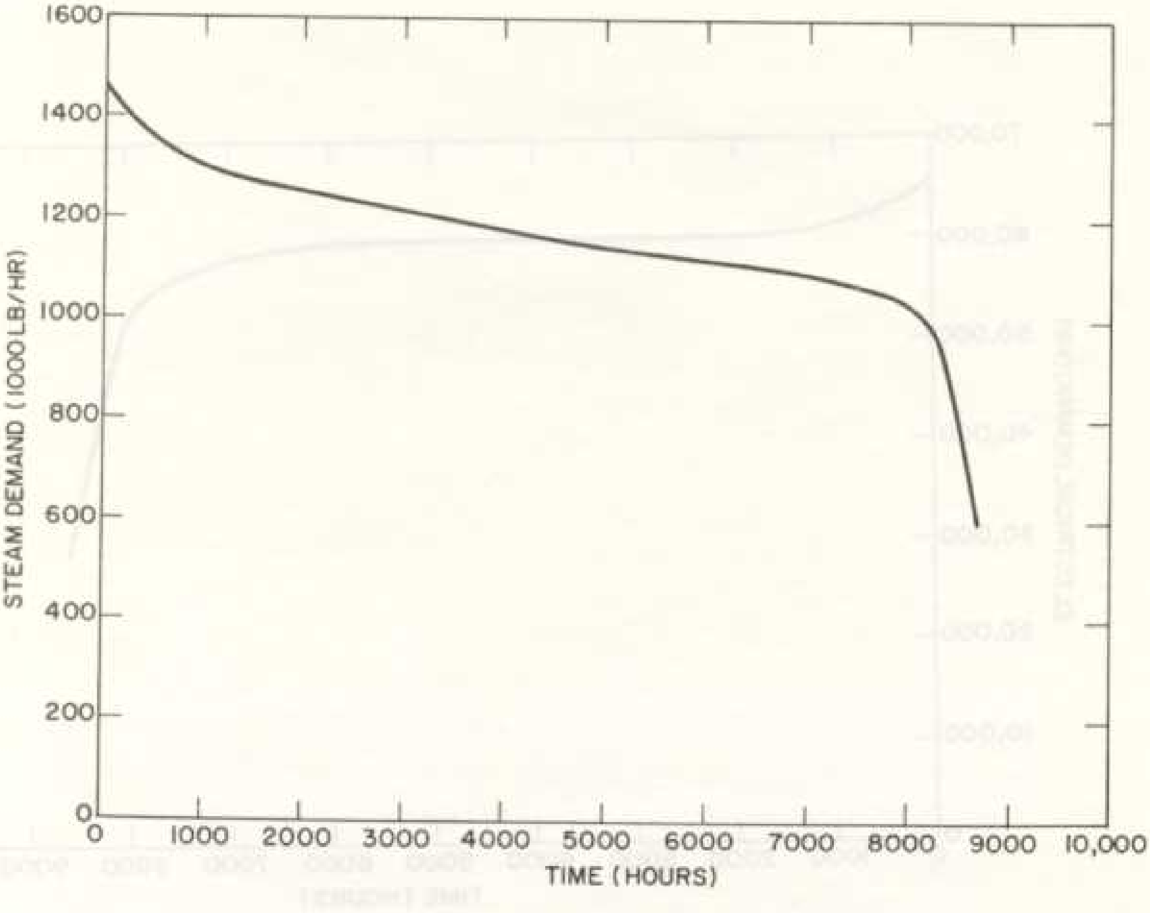

Figure 5-2. Steam Demand Curve - Paper Mill Case Study

fluctuates in an unpredictable manner. Second, if significant fluctuations occur in steam demand and a steam turbine cogeneration system is used, it becomes necessary to provide for condensation of a portion of the steam at times when it is not needed.

Depending on the frequency of these fluctuations and the amount of condensed steam relative to the extracted steam, the cogeneration system may not satisfy the FERC efficiency criterion and hence may not be eligible for power sale at the avoided cost if the boiler is fueled with oil or gas.* In addition, the incremental investment made in the larger size machine (yielding more power when steam is condensed) and in the condenser and associated cooling system will be used for only a fraction of the year, thereby yielding a poor return. A third consequence of fluctuating power and thermal outputs is loss of efficiency at part load operation.

The average pattern of energy use is obtained from the energy audit and the distribution curves. A pictorial representation of that pattern for the Scott mill (Figure 5-3) is useful in visualizing the overall pattern of energy production and use and allows the detection of sizeable flows of throttled steam that could be used to provide power. The schematic also provides a convenient means of visualizing the cogeneration system and its interactions with the plant distribution system.

5.2 COGENERATION CONCEPTUAL DESIGN

Scott's policy of becoming independent of oil and gas would lead the company to assess the advantages of switching to wood and coal separately from the merits of cogeneration. Thus, the following questions must be asked: (1) What is the economic return of switching to wood and coal? and (2) What additional gains can the company expect from cogeneration?

To answer the first question, it is necessary to determine the configuration of boilers required for operation; the capital costs of conversion; and the relative costs of fuel and operation and maintenance.

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*This is not applicable to the Scott case wherein the boilers will be fueled with wood and coal.

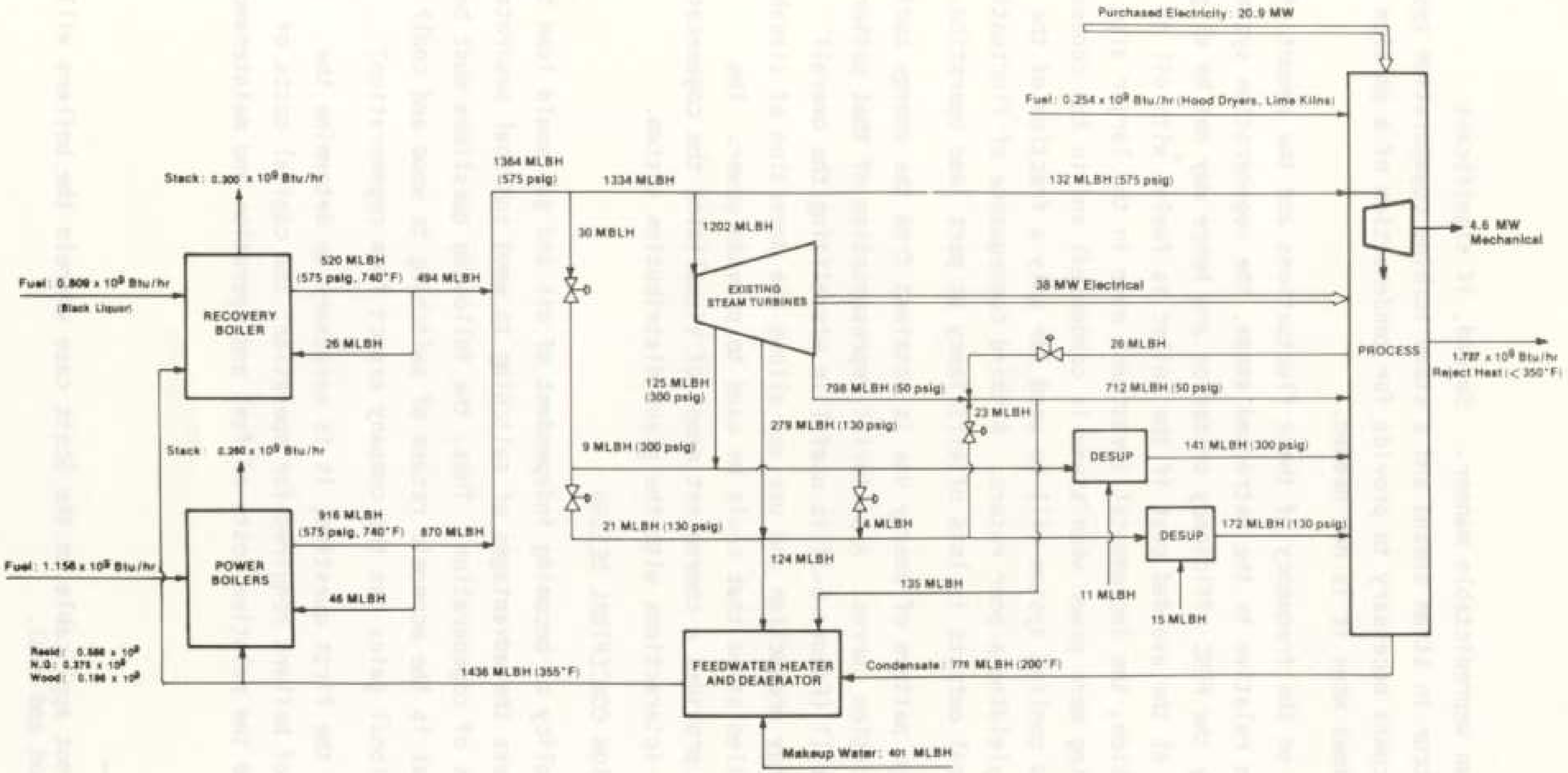

Figure 5-3. Average Energy Use of an Integrated Pulp and Paper Mill Case Study
(1 MLBH = 1,000 lb/hr)

The boiler configuration (in Figure 5-4) consists of converting boilers No. 4 and No. 6 to wood and coal and purchasing a new wood/coal boiler operating at the main header pressure of 575 psig. The capital costs associated with this transition and the relative costs of operation and maintenance are shown in Table 5-5.

To answer the second question, consideration of a specific cogeneration scheme is necessary. Figure 5-5 shows back-pressure steam turbines topping the distribution header with the lowest process steam pressure (50 psig) to obtain as much power as possible by steam expansion through the turbines.* The power could be further increased by increasing the turbine throttle pressure. This process, however, requires a higher pressure and more expensive boiler. The difference between boiler steam flows in the reference and cogeneration cases is necessary to fully utilize the newer turbines and maintain the plant heat balance. Turbo-generators No. 1 and No. 3 are retired. Table 5-5 gives the total capital cost of the cogeneration system. The difference between this cost and the cost of fuel switching is the incremental cost of the cogeneration system. Purchased energy variations from current operation are shown in Table 5-6.

5.3 ESTIMATING ECONOMIC AND ENERGY SAVINGS PERFORMANCE

The economic analysis for the Scott Paper case study considers two options as noted earlier. The first option is fuel switching alone. In this case, the economics of converting the existing system (Figure 5-3) to burn wood waste and coal are analyzed. The energy use pattern reflecting this option is shown in Figure 5-4. The new system meets all of the original process steam requirements of Scott Paper. However, no additional electric power is generated.

The technical and economic data relating to this system are presented in Tables 5-4 and 5-5 (under wood/coal reference case). The inputs to the ICOP model to perform the economic analysis are presented in Table 5-7. Regional energy price forecasts from Tables B-1, B-3, B-4, and B-5 (in Appendix B) are assumed for the prices paid for electricity, residual oil, natural gas, and coal, respectively. Wood waste prices were estimated at

*This option was studied in ICOP as one of the five alternatives and yielded the highest return on investment.

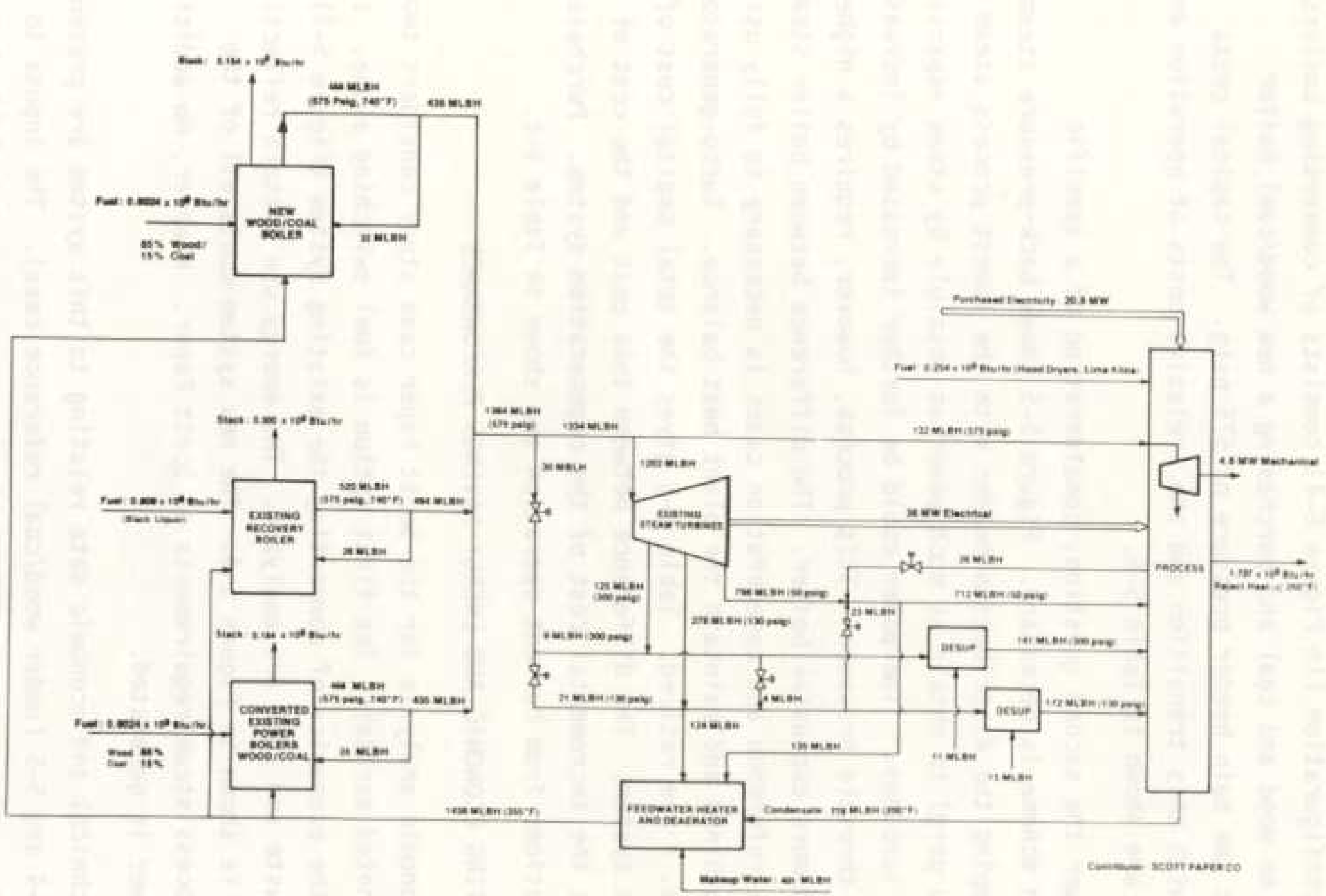

Figure 5-4. Energy Use Pattern with Wood/Coal Conversion - Paper Mill Case Study

Table 5-5. Cost Summary of Case Study Cogeneration System[a]

CAPITAL COSTS[b]

ITEM	Wood/Coal Reference Case Cost ($ millions)	Cogeneration System Total Cost ($ millions)	Cogeneration System Incremental Cost ($ millions)
Convert Boilers No. 4 and No. 6 to Wood/Coal	7.0	7.0	--
(2) New 250,000 lb/hr Wood/Coal Boilers	25.0[c]	37.5[d]	12.5
(2) New 15.0 MW Steam Turbine-Generators	--	6.0	6.0
Switchgear	--	0.2	0.2
Engineering	3.0	3.4	0.4
Site Preparation, Yard Work, Construction	3.0	3.5	0.5
Contingency	6.0	9.0	3.0
Total	44.0	66.6	22.6

ANNUAL OPERATING & MAINTENANCE EXPENSES[e]

Maintenance and Expendables	$ 700,000[f]	$1,100,000[f]	$400,000
Burdened labor (@ $30,000/person)	270,000[f]	360,000[f]	90,000
Insurance	90,000[f]	140,000[f]	50,000
	$1,060,000	$1,600,000	$440,000

[a] All costs are in 1981 dollars

[b] Estimated Construction Time: 4 years

[c] 575 psig, 740°F

[d] 1,250 psig, 850°F

[e] 8,000 Operating Hours/yr (estimated)

[f] Increase over Current Operations

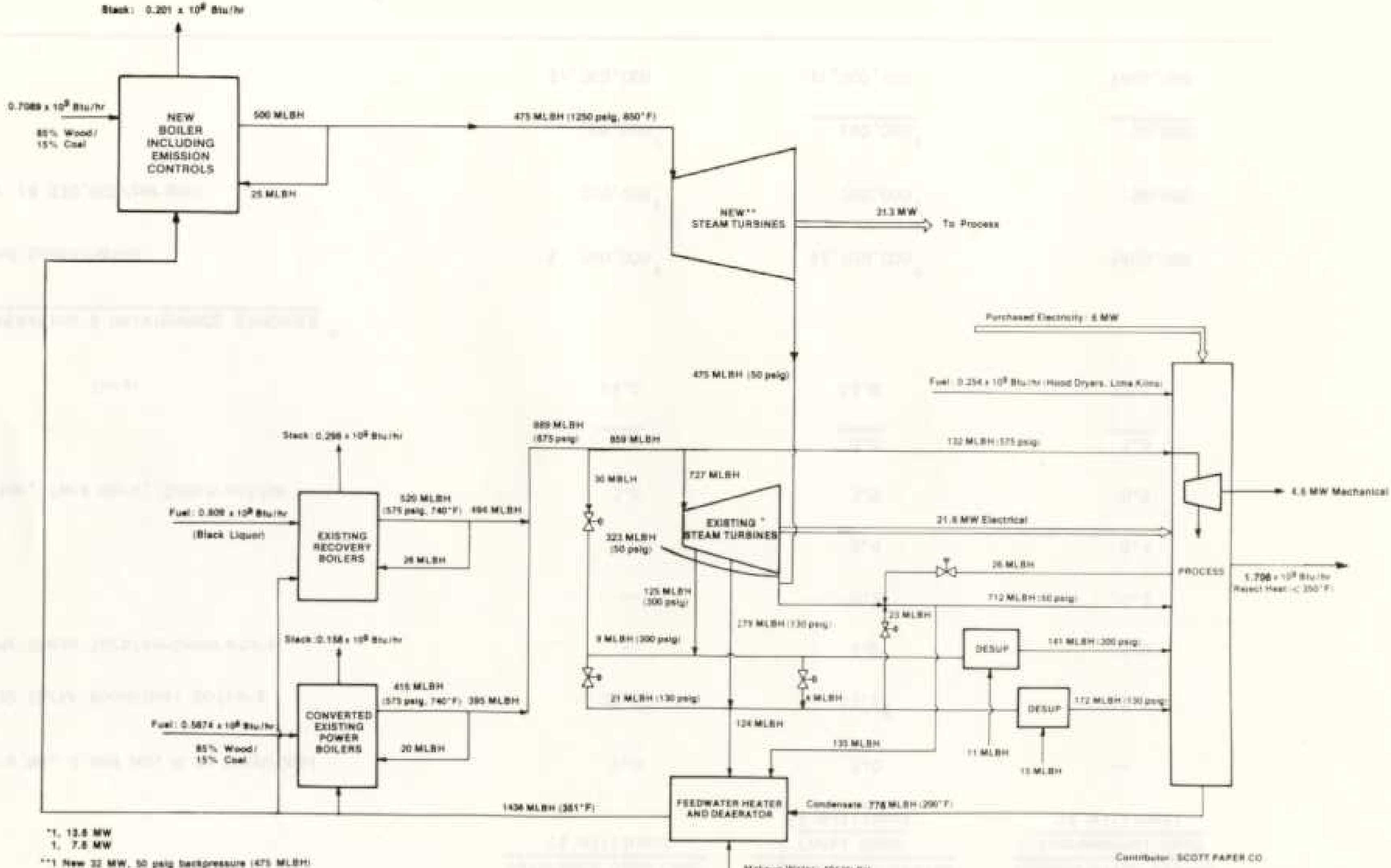

Figure 5-5. Energy Use Pattern with Wood/Coal Cogeneration - Paper Mill Case Study

Table 5-6. Purchased Fuels and Electricity - Paper Mill Case Study

ITEM	PURCHASED ENERGY					TOTAL COGENERATION CAPACITY (MW)
	NG	RESIDUAL	WOOD	COAL	ELECTRICITY	
	(10^{12} Btu/yr)				(10^6 kWh/yr)	
Current Operation	3.002	4.686	1.561	--	167.2	42.6
Wood/Coal Reference Case	--	--	8.193	1.446	167.2	42.6
Wood/Coal Cogeneration	--	--	8.679	1.532	48.0	57.5

TABLE 5-7. Scott Paper - Sample Model Run Sheet

RUN SHEET

RUN NO. SP-1-2A

CONVERT EXISTING BOILERS TO WOOD/COAL
AND INSTALL ADDITIONAL NEW WOOD/COAL BOILERS

PARAMETERS	VARIABLE NAME	VALUE	OR DEFAULT
TECHNICAL CHARACTERISTICS:			
INCREMENTAL FUEL CONSUMPTION, (10^6 Btu/yr)	FUELCN	390,000	0.0
NET ELECTRICITY GENERATION (10^6 kWh/yr)	NETGEN	0	0.0
UTILITY HEAT RATE (INCLUDING T&D LOSSES) (Btu/kWh)	HTRATE	0	0.0
SYSTEM COSTS:			
CAPITAL INVESTMENT ($ in 1985)	CAPINV	44,000,000	0.0
CONSTRUCTION COST DISTRIBUTION -			
PERIODS OF CONSTRUCTION	NPER	16	0
PERIODS PER YEAR	IPER	4	0
CONSTRUCTION FRACTION PER PERIOD	FCONST	0.0625	0.0
OPERATIONS & MAINTENANCE COST, INITIAL ($/yr in 1985)	OANDM	1,386,130	0.0
O&M COST ESCALATION RATE (Fraction)	OMRATE	0.071	0.0
SALVAGE VALUE ($)	SALVAG	0	0.0
ENERGY COSTS:			
INCREMENTAL FUEL COST, INITIAL ($/yr in 1985)	FUEL	-42,821,220	0.0
INCREMENTAL FUEL COST ESCALATION RATE (Fraction)	FRATE	0.1350	0.0
ELECTRICITY COST, INITIAL ($/yr in 1985)	ELECT	0	0.0
ELECTRICITY COST ESCALATION RATE (Fraction)	ERATE	0	0.0

TABLE 5-7. SCOTT PAPER - MODEL RUN SHEET (CONTINUED)

RUN SHEET (Continued)

FINANCIAL PARAMETERS:

DISCOUNT RATE (Fraction)	DISRTE	0.20	0.2
DOWNPAYMENT (Fraction)	DWNPMT	1.0	1.0
LOAN LIFE (Up To 40 Years)	LIFLON	0	12
SYSTEM LIFE (Up To 40 Years)	LIFSYS	12	12
INTEREST RATE (Fraction)	IRATE	0	0.2
INCOME TAX RATE (Fraction)	TXRATE	0.48	0.48
TAX CREDIT RATE (Fraction)	TAXCRD	0.20	0.20
INSURANCE RATE (Fraction)	INS	0.002	0.005
INSURANCE ESCALATION RATE (Fraction)	INSRAT	0.071	0.0
PROPERTY TAX RATE (Fraction)	PCTAX	0.025	0.025
PROPERTY TAX ESCALATION RATE (Fraction)	PCRATE	0.071	0.0
DEPRECIATION LIFE (Up To 40 Years)	DEPYRS	5	5
DEPRECIATION MODE	MODDEP	5	5

= 1 - SUM-OF-YEARS-DIGITS
= 2 - STRAIGHT LINE
= 3 - DOUBLE DECLINING BALANCE
= 4 - 150% DB/SL
= 5 - 175% DB/SYD
= 6 - 200% DB/SYD

$\$0.82/10^6$ Btu in 1985 based on the cost of alternative disposal and were assumed to escalate at the inflation rate. The IRR for this system is calculated as 38.4 percent, which exceeds Scott's hurdle rate (17 percent) by a significant margin.

The second option (Figure 5-5) is fuel switching plus 14,900 kW of new cogeneration. This option is analyzed in two ways: (1) by computing the IRR on the incremental capital investment and operating costs over and above the costs of fuel switching alone, and (2) by computing the IRR on a total cost basis as compared with the existing plant. Technical and economic data for the analysis are presented in Tables 5-5 and 5-6, and inputs to the ICOP model for the two analysis methods are shown in Tables 5-8 and 5-9, respectively.

Viewed on an incremental basis the cogeneration investment produces an IRR of 17.3 percent while the IRR for the same system on a total cost basis is 33.4 percent. Economic and energy savings results for the cases analyzed are summarized in Table 5-10.

The results show that the economic savings resulting from switching from oil and gas to wood and coal is the dominant factor in the investment options. The marginally acceptable IRR for the incremental cogeneration case occurs primarily because credit cannot be taken for conversion to lower cost fuel when the system is viewed on an incremental cost basis. The increased capital cost for larger higher pressure boilers and cogeneration equipment might thus be considered a marginal investment for this plant, which is located in a region where electricity prices are relatively low.

TABLE 5-8. Scott Paper Wood/Coal Cogeneration - Sample Model Run Sheet

RUN SHEET

RUN NO. SP-1-2B
31,300 kW WOOD/COAL STEAM TURBINE
TOPPING DISTRIBUTION HEADER
(Incremental Cost Basis)

PARAMETERS	VARIABLE NAME	VALUE	OR DEFAULT
TECHNICAL CHARACTERISTICS:			
INCREMENTAL FUEL CONSUMPTION, (10^6 Btu/yr)	FUELCN	572,000	0.0
NET ELECTRICITY GENERATION (10^6 kWh/yr)	NETGEN	119.2	0.0
UTILITY HEAT RATE (INCLUDING T&D LOSSES) (Btu/kWh)	HTRATE	11,133	0.0
SYSTEM COSTS:			
CAPITAL INVESTMENT ($ in 1985)	CAPINV	22,600,000	0.0
CONSTRUCTION COST DISTRIBUTION -			
PERIODS OF CONSTRUCTION	NPER	16	0
PERIODS PER YEAR	IPER	4	0
CONSTRUCTION FRACTION PER PERIOD	FCONST	0.0625	0.0
OPERATIONS & MAINTENANCE COST, INITIAL ($/yr in 1985)	OANDM	700,210	0.0
O&M COST ESCALATION RATE (Fraction)	OMRATE	0.071	0.0
SALVAGE VALUE ($)	SALVAG	0	0.0
ENERGY COSTS:			
INCREMENTAL FUEL COST, INITIAL ($/yr in 1985)	FUEL	696,940	0.0
INCREMENTAL FUEL COST ESCALATION RATE (Fraction)	FRATE	0.0859	0.0
ELECTRICITY COST, INITIAL ($/yr in 1985)	ELECT	-7,771,840	0.0
ELECTRICITY COST ESCALATION RATE (Fraction)	ERATE	0.0835	0.0

TABLE 5-8. SCOTT PAPER WOOD/COAL COGENERATION - MODEL RUN SHEET (CONTINUED)

RUN SHEET (Continued)

FINANCIAL PARAMETERS:

DISCOUNT RATE (Fraction)	DISRTE	0.20	0.2
DOWNPAYMENT (Fraction)	DWNPMT	1.0	1.0
LOAN LIFE (Up To 40 Years)	LIFLON	0	12
SYSTEM LIFE (Up To 40 Years)	LIFSYS	12	12
INTEREST RATE (Fraction)	IRATE	0	0.2
INCOME TAX RATE (Fraction)	TXRATE	0.48	0.48
TAX CREDIT RATE (Fraction)	TAXCRD	0.20	0.20
INSURANCE RATE (Fraction)	INS	0.002	0.005
INSURANCE ESCALATION RATE (Fraction)	INSRAT	0.071	0.0
PROPERTY TAX RATE (Fraction)	PCTAX	0.025	0.025
PROPERTY TAX ESCALATION RATE (Fraction)	PCRATE	0.071	0.0
DEPRECIATION LIFE (Up To 40 Years)	DEPYRS	5	5
DEPRECIATION MODE = 1 - SUM-OF-YEARS-DIGITS = 2 - STRAIGHT LINE = 3 - DOUBLE DECLINING BALANCE = 4 - 150% DB/SL = 5 - 175% DB/SYD = 6 - 200% DB/SYD	MODDEP	5	5

TABLE 5-9. Scott Paper Wood/Coal Cogeneration - Sample Model Run Sheet

RUN SHEET

RUN NO. SP-1-2C
31,300 kW WOOD/COAL STEAM TURBINE
TOPPING EXISTING DISTRIBUTION HEADER
(TOTAL COST BASIS)

PARAMETERS	VARIABLE NAME	VALUE	OR DEFAULT
TECHNICAL CHARACTERISTICS:			
INCREMENTAL FUEL CONSUMPTION, (10^6 Btu/yr)	FUELCN	962,000	0.0
NET ELECTRICITY GENERATION (10^6 kWh/yr)	NETGEN	119.2	0.0
UTILITY HEAT RATE (INCLUDING T&D LOSSES) (Btu/kWh)	HTRATE	11,133	0.0
SYSTEM COSTS:			
CAPITAL INVESTMENT ($ in 1985)	CAPINV	66,600,000	0.0
CONSTRUCTION COST DISTRIBUTION -			
PERIODS OF CONSTRUCTION	NPER	16	0
PERIODS PER YEAR	IPER	4	0
CONSTRUCTION FRACTION PER PERIOD	FCONST	0.0625	0.0
OPERATIONS & MAINTENANCE COST, INITIAL ($/yr in 1985)	OANDM	1,986,991	0.0
O&M COST ESCALATION RATE (Fraction)	OMRATE	0.071	0.0
SALVAGE VALUE ($)	SALVAG	0	0.0
ENERGY COSTS:			
INCREMENTAL FUEL COST, INITIAL ($/yr in 1985)	FUEL	-42,124,280	0.0
INCREMENTAL FUEL COST ESCALATION RATE (Fraction)	FRATE	0.1357	0.0
ELECTRICITY COST, INITIAL ($/yr in 1985)	ELECT	-7,771,840	0.0
ELECTRICITY COST ESCALATION RATE (Fraction)	ERATE	0.0835	0.0

TABLE 5-9. SCOTT PAPER WOOD/COAL COGENERATION - MODEL RUN SHEET (CONTINUED)

RUN SHEET (Continued)

FINANCIAL PARAMETERS:

DISCOUNT RATE (Fraction)	DISRTE	0.20	0.2
DOWNPAYMENT (Fraction)	DWNPMT	1.0	1.0
LOAN LIFE (Up To 40 Years)	LIFLON	0	12
SYSTEM LIFE (Up To 40 Years)	LIFSYS	12	12
INTEREST RATE (Fraction)	IRATE	0	0.2
INCOME TAX RATE (Fraction)	TXRATE	0.48	0.48
TAX CREDIT RATE (Fraction)	TAXCRD	0.20	0.20
INSURANCE RATE (Fraction)	INS	0.002	0.005
INSURANCE ESCALATION RATE (Fraction)	INSRAT	0.071	0.0
PROPERTY TAX RATE (Fraction)	PCTAX	0.025	0.025
PROPERTY TAX ESCALATION RATE (Fraction)	PCRATE	0.071	0.0
DEPRECIATION LIFE (Up To 40 Years)	DEPYRS	5	5
DEPRECIATION MODE	MODDEP	5	5

DEPRECIATION MODE
- = 1 - SUM-OF-YEARS-DIGITS
- = 2 - STRAIGHT LINE
- = 3 - DOUBLE DECLINING BALANCE
- = 4 - 150% DB/SL
- = 5 - 175% DB/SYD
- = 6 - 200% DB/SYD

Table 5-10. Economic Performance and Energy Savings

SYSTEM	IRR (%)	PLANT ENERGY SAVINGS (10^{12} Btu/yr)	UTILITY ENERGY SAVINGS (10^{12} Btu/yr)	NET ENERGY SAVINGS (10^{12} Btu/yr)
Coal/wood Reference	38.4	-0.39	0	-0.39
Cogeneration (incremental over fuel switching)	17.3	-0.57	+1.32	+0.75
Cogeneration (over existing operations)	33.4	-0.96	+1.32	+0.36

5.4 ENVIRONMENTAL ANALYSIS AND COMPLIANCE

A preliminary assessment of air pollution emissions from the paper mill can be made using methodology similar to that illustrated in Chapter 3. Results are as shown in Table 5-11. Considering fuel switching alone with no new cogeneration, particulate, carbon monoxide, and hydrocarbon emissions each increase while sulfur and nitrogen oxide emissions decrease.

The increase in particulates results from the large amount of non-combustible material in wood as compared with natural gas and oil. Carbon monoxide and hydrocarbon emission are higher with wood because of lower operating efficiencies, since the composition of the wood can vary significantly. The emission factors used are based on several varieties of wood and waste bark, and actual emission levels can best be determined by emissions testing. The decrease in sulfur and nitrogen oxides is due to the minimal amount of sulfur contained in wood and lower nitrogen content than in either oil or gas.

The paper plant is located in a non-attainment area for ozone, and part of Mobile County is classified as non-attainment for particulates. Emission increases of over 100 tons/year of criteria pollutants in non-attainment areas require emission offsets from other facilities. Although hydrocarbon emissions increase by over 300 tons/year, the majority of hydrocarbon emissions from fuel combustion sources are composed of methane

Table 5-11. Air Pollution Emission Changes
Due to Fuel Switch and Cogeneration Options
Emissions in Tons/Year[a]

	Existing Emissions	Fuel Switch	Fuel Switch with Cogeneration	Net Change Between Fuel Switch and Existing Operations	Net Change Between Cogeneration and Existing Operations	Net Change Between Cogeneration and Fuel Switch
TSP[b]	207	483	511	+276	+304	+28
SO_2	1300	1247	1321	- 53	+ 21	+74
NO_x	1344	1300	1378	- 44	+ 34	+78
CO	197	525	556	+328	+359	+41
HC	114	503	533	+389	+419	+30

[a]ASSUMPTIONS:

1. Existing emissions based on emission factors in Air Pollution Emission Factors, AP-42, through supplement 10, U.S. Environmental Protection Agency, February 1980.
2. Residual oil has sulfur content of 0.5%
3. New boiler used in fuel switch and cogeneration meets NSPS for steam cogenerators (Section 3.1)

[b]TSP = Total Suspended Particulates

which is a non-reactive pollutant in ozone formation. Therefore, an offset would not be required. For particulates, if the plant is located in the non-attainment portion of the county, an emission offset of greater than 276 tons/year would be needed from another particulate emission source in the region. If the plant is located in the attainment portion of the county, but could still adversely impact the non-attainment area, an offset would still be necessary. If the non-attainment provisions are not applicable, the plant would be subject to the PSD requirements for particulates, carbon monoxide, and hydrocarbons as each is emitted in excess of 100 tons/year.

The increased emissions from cogeneration over fuel switching alone are minimal since the cogeneration system increases fuel use by only 6 percent. There would be no additional permit requirements for the cogeneration system since the emission of all pollutants is less than 100 tons/year, and permits would have been covered under the non-attainment or PSD provisions as described above.

5.5 LEGAL AND REGULATORY FACTORS

The cogeneration system examined in this case study should receive favorable treatment under the laws and regulations currently in effect. Since the system burns wood and coal, it does not fall under FUA jurisdiction. The new boiler/steam turbine cogeneration system would be eligible for the regular 10 percent investment tax credit and accelerated depreciation which under the Energy Tax Act (ETA) would be denied for boilers fired by oil or gas. In addition the new cogeneration system, which expands existing cogeneration capacity, would be eligible for the additional 10 percent energy tax credit under provisions of the Crude Oil Windfall Profit Tax Act (COWPTA). The conversion of the existing power boilers from oil- and gas to wood- and coal-firing would also receive the additional 10 percent energy tax credit since the conversion equipment would fall within the definition of "alternate energy property" under the ETA.

Under the Public Utility Regulatory Policies Act (PURPA), the system would be classified as a topping-cycle facility, and since none of the energy input is gas or oil, only the Operating Standard must be met for certification as a qualifying facility. This standard, which requires that the useful thermal energy output of the facility be no less than 5 percent of the total energy output, is easily met by the system. Upon certification, the facility would be entitled to PURPA benefits including non-discriminatory treatment by Alabama Power Company and exemption from certain state and Federal regulations.

5.6 COGENERATION PRELIMINARY DESIGN

The decision of whether to proceed with a cogeneration project is largely based on the ROI determined from a preliminary analysis and design of the system. That ROI is usually within a few percentage points of that obtained from more detailed studies. Projects having ROIs that are marginal relative to a Company's requirements need not be shelved, as variants of the options may be considered that yield higher returns. In addition, it may be possible to considerably increase the ROI by utility participation in the project or by a third party ownership scheme. Hence, projects yielding marginal to high ROI's should generally be considered as candidates for further study.

The selection of a consulting engineering firm is a necessary first step if expertise within the company is not available. This may be done by direct contact and/or by competitive bidding on a Request for Proposal (RFP). Some utilities are willing to jointly finance such studies for potential cogenerators or actually perform the studies themselves. If an RFP is written, it should contain as much information on the plant's energy uses as possible. The work to be done should be clearly delineated in a Statement of Work (S.O.W.), which should include at least one site visit for familiarization with the plant's layout and its particular circumstances.

Site visits also permit closer estimates to be made of the costs of installation and retrofitting and thus help avoid unanticipated cost overruns. Preliminary discussions should be held with the serving utility to determine the avoided costs, and economic analyses should be made of several system options if possible to evaluate their relative merits. Energy savings should be estimated and an assessment made of the systems' compliance with environmental regulations and FUA restrictions. The S.O.W. should also require that a written report and presentation be made to the

Company's engineers and management. Depending on the size and complexity of the installation, the preliminary study can generally be completed in 2 to 12 weeks.

5.7 STEPS IN SYSTEM IMPLEMENTATION

If the results of the preliminary study are positive, the next step is to conduct a detailed study with preliminary engineering of the system including detailed system schematics and energy balances, site and system layouts, and preliminary specifications of all of the major components of the system. Cost estimates should be prepared based on vendor quotations as well as costs of detailed engineering, site preparation, installation and construction, and operation and maintenance. Construction time should be estimated and care should be exercised to include escalation costs during construction and all costs of grid interconnection. The system should be assessed for environmental compliance and satisfaction of the FERC operating standard and efficiency criterion. An economic analysis based on estimated costs should be performed and an assessment made of the effect on the ROI of different ownership and financing schemes.

In summary, the steps between the conceptualization of a cogeneration system and the final implementation of the project involve the consideration of technical, economic, and regulatory issues. These steps are summarized in Table 5-12 for convenient reference.

Table 5-12. Steps in System Implementation

PRELIMINARY EVALUATION

- Determine Avoided Costs Obtainable from Serving Utility
- Determine Plant Energy Demands
- Select Appropriate Cogeneration Technologies, Sizes, and Configurations
- Prepare Energy Balances and Determine Power Outputs, Fuel Consumptions, and Emissions
- Evaluate Energy Savings
- Assess Compliance with FERC, EPA, and FUA Regulations
- Estimate Capital and Operation and Maintenance Costs
- Evaluate ROIs

PRELIMINARY DESIGN AND ENGINEERING

Same as above with following additions:

- Prepare Detailed System Schematics, Energy Balances, and Site and System Layouts
- Prepare Preliminary Specifications of all Major Components
- Estimate Construction Time
- Obtain Vendor Quotations for Equipment
- Estimate Costs of Detailed Engineering, Site Preparation, Installation and Construction, and Operation and Maintenance
- Estimate Cost Escalation during Construction
- Evaluate Effects of Ownership and Financing on ROI

FINAL ENGINEERING DESIGN AND CONSTRUCTION

THE COGENERATION OPTION ADOPTED BY SCOTT

Subsequent to the ICOP study, Scott has embarked on an energy conservation program that has significantly changed its pattern of energy use. The cogeneration system currently being pursued involves substantial modifications in the equipment of the power plant and operation at a much higher (1420 psig) main header pressure. Power boiler No. 6, recovery boiler No. 6 and turbo-generator No. 3 will be retained. All other power boilers, recovery boilers, and turbo-generators will be retired. A new large coal/wood-fired boiler and a new large recovery boiler will be installed. A new single-extraction (310 psig)/back-pressure (55 psig) steam turbo-generator will produce 32.5 MW. An additional 29 MW will be generated by a new double-extraction (145 psig/55 psig) condensing (2 inches of mercury) steam turbine. Turbo-generator No. 3 will produce 5.8 MW giving a total of 67.3 MW and allowing the plant to become self-sufficient in power at a higher production level. The total system cost is estimated at about $250 million.

APPENDIX A

CONVERSION FACTORS, BASIC EQUIVALENTS, ENERGY CONTENT OF FUELS, ENERGY EQUIVALENTS

Table A-1. English - Metric (SI)[a] Conversion Factors

To Convert From	To	Multiply By
Atmosphere (Atm)	Pascal (P) (or 1 Newton/metre^2)	101,325[b]
Barrel (bbl)	Metre^3 (m^3)	0.158987
British Thermal Unit (Btu)	Joule (J)	1,055.06
	Kilocalorie (kCal)	0.251996
Btu/bbl	Joule/Metre^3	6,636.10
Btu/ft^3	Joule/Metre^3	37,258.9
Btu/Kilowatt-Hour (kWh)	Joule/Joule	0.000293
Btu/short ton (2,000 lbs)	Joule/Tonne	1163[b]
Foot (ft)	Metre (m)	0.3048[b]
Gallon (231 m^3)	Metre^3 (m^3)	0.00378541
	Litre (L)	3.78541
(U.S.) Horsepower	Metric Horsepower	1.01387
	Kilowatt (kW)	0.745700
Inch (in)	Centimeter (cm)	2.54[b]
Kilowatt (kW)	Metric Horsepower	1.35962
Kilowatt-Hour (kWh)	Joule (J)	3,600,000[b]
Pound Force (lb_f)	Newton (N)	4.44822
Pound Mass (lb_m)	Kilogram (kg)	0.45359237[b]
Pound per Square Inch (psi)	Pascal (P)	6,894.76
Short ton (2,000 lbs)	Tonne	0.907185

[a] "Systeme International"
[b] Exact Value

Table A-2. Basic Equivalent

MEASURE	EQUIVALENT: BRITISH/U.S.	EQUIVALENT: S.I.
WEIGHT		
1 short ton	2000 lbs	907 kg
1 metric ton	1.102 short tons	1000 kg
1 long ton	1.120 short tons	1016 kg
CRUDE OIL (AVERAGE GRAVITY)		
1 bbl	42 U.S. gal	$0.159\ m^3$ 159 litres
1 bbl	0.136 metric tons	136 kg
1 metric ton	7.33 bbl	$1.165\ m^3$
1 short ton	6.65 bbl	$1.057\ m^3$
URANIUM		
1 short ton (U_3O_8)	0.769 metric tons uranium	769 kg
1 short ton (UF_6)	0.613 metric tons uranium	613 kg
1 metric ton (UF_6)	0.676 metric tons uranium	676 kg
OTHER		
1 therm	1×10^5 Btu	105.5×10^6 J

Table A-3. Aggregate Heat Content Of Fuels

FUEL	EQUIVALENT BRITISH/U.S.	EQUIVALENT S.I.
PETROLEUM		
Crude Oil	5.820×10^6 Btu/bbl	38.62×10^9 J/m^3
Gasoline	5.253×10^6 Btu/bbl	34.86×10^9 J/m^3
Jet Fuel	5.600×10^6 Btu/bbl	37.16×10^9 J/m^3
Distillate Fuel Oil	5.825×10^6 Btu/bbl	38.66×10^9 J/m^3
Residual Oil	6.287×10^6 Btu/bbl	41.72×10^9 J/m^3
NATURAL GAS		
Natural Gas Liquids	4.011×10^6 Btu/bbl	26.62×10^9 J/m^3
Natural Gas	1.032×10^6 Btu/1000 ft^3	38.45×10^6 J/m^3
COAL		
Steam Coal:		
Average Consumption	22.5×10^6 Btu/short ton	26.2×10^9 J/Tonne
Production by Rank		
Bituminous	23.80×10^6 Btu/short ton	27.68×10^9 J/Tonne
Midbituminous	21.80×10^6 Btu/short ton	25.35×10^9 J/Tonne
Subbituminous	18.33×10^6 Btu/short ton	21.32×10^9 J/Tonne
Lignite	13.00×10^6 Btu/short ton	15.12×10^9 J/Tonne
Metallurgical Coal	27.00×10^6 Btu/short ton	31.40×10^9 J/Tonne
ELECTRICITY CONSUMPTION	3,412 Btu/kWh	3.6×10^6 J/kWh

Table A-4. Electricity Conversion Heat Rates For Existing Plants In Base Mode

FUEL	HEAT RATE BRITISH/U.S.	S.I.
COAL		
Bituminous	8,900-12,300 Btu/kWh	$9.40\text{-}12.96 \times 10^6$ J/kWh
Subbituminous & Lignite	10,400-13,980 Btu/kWh	$10.98\text{-}14.76 \times 10^6$ J/kWh
GAS	9,800-12,200 Btu/kWh	$10.33\text{-}12.85 \times 10^6$ J/kWh
OIL	9,700-14,000 Btu/kWh	$10.22\text{-}14.76 \times 10^6$ J/kWh
NUCLEAR STEAM-ELECTRIC	10,000 Btu/kwh	10.59×10^6 J/kWh
HYDROELECTRIC	10,389 Btu/kWh	10.94×10^6 J/kWh

APPENDIX B

FUEL AND ELECTRICITY PRICE FORECASTS:
BEST, LOW, AND HIGH PRICE SCENARIOS

Table B-1. Best Case
Average Annual Industrial Electricity Prices by Region
(cents per kWh)

	1978	1979	1980	1981	1982	1983	1984	1985
NENG	3.549	4.065	4.860	6.011	6.494	6.845	7.477	8.271
MATL	3.181	3.490	4.330	5.253	5.949	6.363	7.063	7.593
SATL	2.744	2.910	3.549	4.431	4.942	5.594	6.179	6.722
ENC	2.760	2.993	3.586	4.214	4.918	5.532	6.003	6.624
WNC	2.768	2.969	3.574	4.199	5.110	5.696	6.427	7.017
ESC1	2.280	2.631	3.318	3.849	4.620	5.168	5.662	6.225
ESC2	2.496	2.913	3.615	4.146	4.916	5.465	5.959	6.522
WSC1	2.322	2.423	3.002	3.675	4.384	5.105	5.962	6.943
WSC2	2.220	2.570	3.048	3.722	4.431	5.152	6.009	6.989
MTN1	3.163	3.928	4.874	5.705	6.334	7.042	7.700	8.298
MTN2	1.515	1.752	2.074	2.766	3.305	3.645	4.153	4.741
MTN3	2.764	3.096	3.788	4.619	5.249	5.957	6.614	7.213
PAC	2.143	2.254	2.907	3.739	4.368	5.076	5.733	6.332
US	2.593	2.850	3.482	4.220	4.890	5.487	6.107	6.753

	1986	1987	1988	1989	1990	1991	1992
NENG	9.217	10.128	11.039	12.770	14.475	14.931	16.600
MATL	8.268	8.946	10.200	11.017	12.147	13.569	14.562
SATL	7.670	8.608	9.655	10.537	11.596	12.936	14.055
ENC	7.670	8.490	9.085	9.883	10.530	11.477	12.235
WNC	8.441	9.389	10.166	10.942	11.593	12.450	13.107
ESC1	7.297	8.222	9.160	10.256	10.978	12.180	12.824
ESC2	7.593	8.519	9.457	10.553	11.275	12.477	13.121
WSC1	8.398	9.690	11.251	12.570	13.869	15.939	17.204
WSC2	8.445	9.736	11.297	12.617	13.916	15.985	17.250
MTN1	9.256	10.184	11.175	11.975	12.827	13.837	14.854
MTN2	5.453	6.151	6.989	8.102	8.909	9.702	10.073
MTN3	8.171	9.099	10.090	10.890	11.742	12.751	13.769
PAC	7.290	8.218	9.209	10.009	10.861	11.870	12.888
US	7.803	8.731	9.744	10.713	11.652	12.911	13.860

	1993	1994	1995
NENG	17.315	19.187	19.914
MATL	15.745	16.982	18.268
SATL	15.181	16.364	17.754
ENC	12.851	13.483	14.703
WNC	13.772	14.472	15.223
ESC1	13.163	13.623	14.238
ESC2	13.460	13.920	14.535
WSC1	18.615	20.127	21.788
WSC2	18.661	20.173	21.834
MTN1	15.468	16.532	18.011
MTN2	10.570	11.017	12.466
MTN3	14.383	15.447	16.925
PAC	13.502	14.566	16.045
US	14.712	15.704	16.964

Table B-2. Best Case
Average Annual Industrial Distillate Fuel Prices by Region
(dollars per million Btu)

	1978	1979	1980	1981	1982	1983	1984	1985
NENG	2.775	4.172	5.970	7.729	8.462	9.252	10.245	11.444
MATL	2.765	4.156	5.947	7.699	8.429	9.216	10.206	11.400
SATL	2.698	4.055	5.803	7.513	8.225	8.992	9.958	11.124
ENC	2.719	4.087	5.849	7.572	8.290	9.064	10.037	11.212
WNC	2.628	3.950	5.653	7.318	8.012	8.760	9.701	10.836
ESC1	2.727	4.099	5.866	7.595	8.315	9.091	10.067	11.245
ESC2	2.668	4.011	5.739	7.430	8.135	8.894	9.849	11.002
WSC1	2.336	3.511	5.024	6.504	7.121	7.786	8.622	9.631
WSC2	2.336	3.511	5.024	6.504	7.121	7.786	8.622	9.631
MTN1	2.464	3.704	5.301	6.863	7.513	8.215	9.097	10.162
MTN2	2.472	3.716	5.318	6.885	7.538	8.242	9.127	10.195
MTN3	2.464	3.704	5.301	6.863	7.513	8.215	9.097	10.162
PAC	2.692	4.047	5.791	7.498	8.208	8.975	9.939	11.102
US	2.682	4.031	5.768	7.468	8.176	8.939	9.899	11.057

	1986	1987	1988	1989	1990	1991	1992
NENG	12.776	14.319	16.069	18.004	20.148	22.517	25.038
MATL	12.726	14.263	16.007	17.935	20.070	22.430	24.942
SATL	12.418	13.917	15.619	17.500	19.584	21.886	24.337
ENC	12.516	14.028	15.743	17.639	19.739	22.060	24.530
WNC	12.097	13.558	15.216	17.047	19.078	21.321	23.708
ESC1	12.553	14.069	15.790	17.691	19.798	22.126	24.603
ESC2	12.282	13.765	15.448	17.308	19.370	21.647	24.071
WSC1	10.751	12.050	13.523	15.151	16.956	18.949	21.071
WSC2	10.751	12.050	13.523	15.151	16.956	18.949	21.071
MTN1	11.344	12.714	14.268	15.986	17.890	19.994	22.232
MTN2	11.381	12.755	14.315	16.038	17.948	20.059	22.305
MTN3	11.344	12.714	14.268	15.986	17.890	19.994	22.232
PAC	12.393	13.890	15.588	17.465	19.545	21.843	24.288
US	12.344	13.834	15.526	17.395	19.467	21.756	24.192

	1993	1994	1995
NENG	27.714	30.621	33.699
MATL	27.607	30.502	33.568
SATL	26.938	29.763	32.754
ENC	27.152	29.999	33.015
WNC	26.241	28.994	31.908
ESC1	27.232	30.088	33.112
ESC2	26.643	29.437	32.396
WSC1	23.323	25.769	28.359
WSC2	23.323	25.769	28.359
MTN1	24.608	27.189	29.922
MTN2	24.688	27.278	30.019
MTN3	24.608	27.189	29.922
PAC	26.884	29.704	32.689
US	26.777	29.585	32.559

Table B-3. Best Case
Average Annual Industrial Residual Fuel Prices by Region
(dollars per million Btu)

	1978	1979	1980	1981	1982	1983	1984	1985
NENG	2.097	3.071	4.293	5.505	6.070	6.755	7.533	8.472
MATL	2.176	3.186	4.454	5.713	6.299	7.010	7.817	8.792
SATL	2.014	2.949	4.122	5.287	5.830	6.487	7.234	8.136
ENC	2.058	3.014	4.214	5.404	5.959	6.631	7.394	8.316
WNC	1.951	2.857	3.994	5.122	5.648	6.285	7.008	7.882
ESC1	2.006	2.937	4.106	5.266	5.806	6.461	7.205	8.103
ESC2	1.856	2.717	3.799	4.872	5.372	5.978	6.666	7.497
WSC1	1.819	2.664	3.724	4.776	5.266	5.860	6.535	7.349
WSC2	1.819	2.664	3.724	4.776	5.266	5.860	6.535	7.349
MTN1	1.858	2.720	3.803	4.877	5.378	5.984	6.673	7.505
MTN2	1.933	2.830	3.956	5.074	5.595	6.226	6.943	7.808
MTN3	1.858	2.720	3.803	4.877	5.378	5.984	6.673	7.505
PAC	1.774	2.598	3.632	4.659	5.137	5.716	6.374	7.169
US	2.028	2.970	4.151	5.324	5.871	6.533	7.285	8.193

	1986	1987	1988	1989	1990	1991	1992
NENG	9.619	10.743	12.016	13.416	14.963	16.674	18.489
MATL	9.981	11.148	12.469	13.922	15.527	17.303	19.187
SATL	9.237	10.317	11.539	12.884	14.369	16.013	17.756
ENC	9.442	10.546	11.795	13.170	14.688	16.368	18.149
WNC	8.949	9.995	11.179	12.482	13.921	15.513	17.202
ESC1	9.200	10.276	11.493	12.832	14.311	15.949	17.685
ESC2	8.512	9.507	10.633	11.872	13.241	14.755	16.361
WSC1	8.344	9.320	10.424	11.639	12.980	14.465	16.039
WSC2	8.344	9.320	10.424	11.639	12.980	14.465	16.039
MTN1	8.521	9.517	10.644	11.885	13.255	14.772	16.379
MTN2	8.865	9.902	11.074	12.365	13.790	15.368	17.041
MTN3	8.521	9.517	10.644	11.885	13.255	14.772	16.379
PAC	8.140	9.091	10.168	11.353	12.662	14.110	15.646
US	9.302	10.390	11.621	12.975	14.471	16.126	17.881

	1993	1994	1995
NENG	20.407	22.484	24.674
MATL	21.177	23.332	25.605
SATL	19.598	21.592	23.696
ENC	20.032	22.071	24.221
WNC	18.986	20.918	22.956
ESC1	19.519	21.505	23.600
ESC2	18.059	19.896	21.835
WSC1	17.703	19.505	21.405
WSC2	17.703	19.505	21.405
MTN1	18.078	19.918	21.858
MTN2	18.809	20.723	22.741
MTN3	18.078	19.918	21.858
PAC	17.269	19.027	20.880
US	19.736	21.745	23.863

Table B-4. Best Case
Average Annual Industrial Natural Gas Prices by Region
(dollars per million Btu)

	1978	1979	1980	1981	1982	1983	1984	1985
NENG	2.843	3.201	3.995	4.751	5.325	6.134	7.108	8.237
MATL	2.352	2.686	3.179	3.786	4.275	5.033	6.029	7.116
SATL	1.805	2.213	2.689	3.232	3.671	4.400	5.341	6.370
ENC	1.985	2.363	2.912	3.566	4.044	4.765	5.581	6.556
WNC	1.490	1.861	2.341	2.919	3.319	4.082	4.819	5.894
ESC1	1.667	2.068	2.550	3.118	3.546	4.207	5.009	5.932
ESC2	1.655	2.135	2.589	3.154	3.583	4.332	5.117	6.039
WSC1	1.483	1.691	2.375	2.872	3.382	4.422	5.238	6.318
WSC2	1.991	2.190	2.661	3.119	3.620	4.590	5.391	6.482
MTN1	1.613	2.022	2.710	3.322	3.778	4.569	5.355	6.364
MTN2	1.471	1.920	2.588	3.262	3.708	4.371	5.085	5.937
MTN3	1.523	2.192	2.829	3.260	3.705	4.342	5.111	5.983
PAC	2.196	2.501	3.277	4.183	4.739	5.509	6.306	7.325
US	1.910	2.425	2.888	3.356	3.843	4.677	5.499	6.542

	1986	1987	1988	1989	1990	1991	1992
NENG	9.945	11.165	13.422	15.432	16.822	18.747	20.704
MATL	8.743	9.971	12.371	14.350	15.899	17.796	19.724
SATL	7.914	9.076	11.403	13.471	14.944	16.759	18.601
ENC	8.060	9.109	11.386	13.272	14.834	16.640	18.470
WNC	7.403	8.398	10.568	12.452	14.117	15.894	17.690
ESC1	7.490	8.537	10.856	12.825	14.898	16.700	18.514
ESC2	7.641	8.688	11.001	12.953	14.686	16.524	18.384
WSC1	8.138	9.073	10.299	11.581	12.960	14.503	16.133
WSC2	8.327	9.294	10.660	12.046	13.494	15.102	16.789
MTN1	8.044	9.048	10.793	12.426	13.983	15.687	17.445
MTN2	7.403	8.410	10.735	12.478	14.102	15.797	17.666
MTN3	7.461	8.496	10.675	12.591	14.177	16.649	18.392
PAC	8.875	10.035	11.885	13.571	14.643	16.375	18.168
US	8.184	9.247	11.193	12.936	14.419	16.179	17.948

	1993	1994	1995
NENG	22.736	24.908	27.181
MATL	21.721	23.858	26.098
SATL	20.510	22.550	24.684
ENC	20.366	22.392	24.513
WNC	19.545	21.528	23.633
ESC1	20.380	22.364	24.425
ESC2	20.307	22.364	24.520
WSC1	17.860	19.731	21.702
WSC2	18.571	20.498	22.526
MTN1	19.286	21.266	23.347
MTN2	19.419	21.361	23.249
MTN3	20.181	22.071	24.018
PAC	20.047	22.071	24.199
US	19.802	21.783	23.882

Table B-5. Best Case
Average Annual Industrial Coal Prices by Region
(dollars per million Btu)

	1978	1979	1980	1981	1982	1983	1984	1985
NENG	1.758	1.822	2.066	2.290	2.541	2.819	3.102	3.461
MATL	1.433	1.484	1.625	1.839	2.085	2.365	2.665	3.004
SATL	1.567	1.682	1.821	2.052	2.321	2.614	2.937	3.321
ENC	1.448	1.590	1.742	1.956	2.194	2.437	2.700	3.019
WNC	1.092	1.199	1.331	1.526	1.751	1.998	2.271	2.597
ESC1	1.368	1.488	1.690	1.909	2.157	2.417	2.708	3.071
ESC2	1.599	1.802	1.947	2.184	2.449	2.749	3.076	3.473
WSC1	1.268	1.370	1.465	1.679	1.926	2.199	2.502	2.866
WSC2	0.831	1.176	1.493	1.732	2.012	2.326	2.685	3.128
MTN1	0.502	0.569	0.664	0.819	1.006	1.222	1.477	1.791
MTN2	0.637	0.819	0.903	1.052	1.230	1.430	1.654	1.923
MTN3	0.693	1.024	1.187	1.372	1.590	1.835	2.108	2.434
PAC	0.919	0.997	1.234	1.464	1.737	2.055	2.410	2.838
US	1.330	1.460	1.608	1.838	2.080	2.346	2.638	2.993

	1986	1987	1988	1989	1990	1991	1992	1993
NENG	3.896	4.372	4.871	5.392	5.953	6.542	7.137	7.748
MATL	3.404	3.833	4.299	4.818	5.379	5.953	6.561	7.210
SATL	3.782	4.278	4.805	5.364	5.969	6.606	7.256	7.935
ENC	3.411	3.832	4.255	4.690	5.165	5.697	6.268	6.874
WNC	2.979	3.394	3.833	4.304	4.818	5.352	5.897	6.458
ESC1	3.477	3.926	4.367	4.866	5.413	5.900	6.331	6.764
ESC2	3.939	4.432	4.951	5.503	6.098	6.724	7.308	7.790
WSC1	3.321	3.817	4.339	4.902	5.518	6.163	6.817	7.490
WSC2	3.647	4.211	4.814	5.462	6.174	6.914	7.665	8.446
MTN1	2.228	2.613	3.019	3.454	3.957	4.456	5.209	5.750
MTN2	2.245	2.591	2.949	3.325	3.733	4.156	4.588	5.032
MTN3	2.880	3.366	3.867	4.391	4.915	5.509	6.110	6.717
PAC	3.358	3.920	4.513	5.158	5.858	6.589	7.337	8.122
US	3.420	3.883	4.365	4.883	5.443	6.039	6.650	7.281

	1994	1995
NENG	8.364	9.039
MATL	7.890	8.589
SATL	8.651	9.408
ENC	7.512	8.162
WNC	7.046	7.669
ESC1	7.280	7.894
ESC2	8.205	8.703
WSC1	8.196	8.959
WSC2	9.267	10.140
MTN1	6.339	6.935
MTN2	5.495	5.986
MTN3	7.377	8.058
PAC	8.939	9.811
US	7.947	8.656

Table B-6. Low Case
Average Annual Industrial Electricity Prices by Region
(cents per kWh)

	1978	1979	1980	1981	1982	1983	1984	1985
NENG	3.549	4.065	4.860	5.778	6.108	6.217	6.537	7.124
MATL	3.181	3.490	4.330	5.158	5.769	6.035	6.559	7.030
SATL	2.744	2.910	3.549	4.356	4.796	5.335	5.835	6.273
ENC	2.760	2.993	3.586	4.184	4.850	5.367	5.706	6.290
WNC	2.768	2.969	3.574	4.189	5.167	5.492	5.726	6.199
ESC1	2.280	2.631	3.318	3.837	4.507	5.104	6.217	6.655
ESC2	2.496	2.913	3.615	4.133	4.804	5.401	6.514	6.951
WSC1	2.322	2.423	3.002	3.655	4.297	4.916	5.711	6.437
WSC2	2.220	2.570	3.048	3.702	4.343	4.962	5.758	6.484
MTN1	3.163	3.928	4.874	5.613	6.080	6.750	7.439	7.876
MTN2	1.515	1.752	2.074	2.759	3.309	3.510	3.844	4.351
MTN3	2.764	3.096	3.788	4.528	4.995	5.665	6.354	6.790
PAC	2.143	2.254	2.907	3.647	4.114	4.784	5.473	5.910
US	2.593	2.850	3.482	4.165	4.772	5.290	5.838	6.370

	1986	1987	1988	1989	1990	1991	1992
NENG	7.986	8.737	9.490	10.939	12.418	13.765	14.897
MATL	7.639	8.216	9.315	10.041	11.060	12.701	13.898
SATL	7.103	7.902	8.844	9.599	10.432	11.569	12.547
ENC	7.247	7.970	8.509	9.244	9.832	10.660	10.576
WNC	7.667	8.487	9.032	9.544	9.837	10.297	10.417
ESC1	7.283	8.192	9.194	10.342	11.172	12.476	13.648
ESC2	7.580	8.489	9.490	10.639	11.468	12.773	13.945
WSC1	7.389	8.402	9.804	10.986	12.271	13.783	15.147
WSC2	7.435	8.448	9.851	11.032	12.318	13.829	15.194
MTN1	8.531	9.346	10.233	10.963	11.727	12.602	13.479
MTN2	5.088	5.717	6.414	7.338	8.067	8.673	8.994
MTN3	7.445	8.261	9.147	9.878	10.642	11.517	12.394
PAC	6.565	7.380	8.266	8.997	9.761	10.636	11.513
US	7.214	8.008	8.900	9.744	10.559	11.603	12.237

	1993	1994	1995
NENG	16.915	16.822	18.208
MATL	15.348	15.933	17.091
SATL	13.500	14.504	15.618
ENC	11.572	12.996	14.389
WNC	12.195	13.372	15.142
ESC1	14.032	14.744	14.799
ESC2	14.329	15.041	15.096
WSC1	16.263	17.800	18.242
WSC2	16.309	17.847	18.288
MTN1	13.896	14.552	15.307
MTN2	9.281	10.514	10.990
MTN3	12.811	13.466	14.222
PAC	11.930	12.586	13.341
US	13.249	14.269	15.361

Table B-7. Low Case
Average Annual Industrial Distillate Fuel Prices by Region
(dollars per million Btu)

	1978	1979	1980	1981	1982	1983	1984	1985
NENG	2.775	4.172	5.970	7.245	7.587	8.052	8.614	9.266
MATL	2.765	4.156	5.947	7.217	7.557	8.021	8.580	9.230
SATL	2.698	4.055	5.803	7.042	7.374	7.826	8.372	9.006
ENC	2.719	4.087	5.849	7.098	7.433	7.888	8.439	9.078
WNC	2.628	3.950	5.653	6.860	7.183	7.624	8.156	8.773
ESC1	2.727	4.099	5.866	7.119	7.455	7.912	8.464	9.104
ESC2	2.668	4.011	5.739	6.965	7.293	7.741	8.281	8.907
WSC1	2.336	3.511	5.024	6.097	6.384	6.776	7.249	7.797
WSC2	2.336	3.511	5.024	6.097	6.384	6.776	7.249	7.797
MTN1	2.464	3.704	5.301	6.433	6.736	7.149	7.648	8.227
MTN2	2.472	3.716	5.318	6.454	6.758	7.173	7.673	8.254
MTN3	2.464	3.704	5.301	6.433	6.736	7.149	7.648	8.227
PAC	2.692	4.047	5.791	7.028	7.359	7.811	8.356	8.988
US	2.682	4.031	5.768	7.000	7.330	7.780	8.322	8.952

	1986	1987	1988	1989	1990	1991	1992
NENG	10.168	11.318	12.664	14.115	15.733	17.471	19.300
MATL	10.129	11.275	12.616	14.061	15.672	17.404	19.225
SATL	9.884	11.001	12.310	13.720	15.292	16.982	18.759
ENC	9.962	11.089	12.408	13.829	15.413	17.117	18.908
WNC	9.628	10.717	11.991	13.365	14.897	16.543	18.274
ESC1	9.992	11.122	12.444	13.870	15.459	17.167	18.964
ESC2	9.775	10.881	12.175	13.570	15.125	16.796	18.554
WSC1	8.557	9.525	10.658	11.879	13.240	14.703	16.242
WSC2	8.557	9.525	10.658	11.879	13.240	14.703	16.242
MTN1	9.029	10.050	11.245	12.533	13.969	15.513	17.137
MTN2	9.058	10.083	11.282	12.574	14.015	15.564	17.193
MTN3	9.029	10.050	11.245	12.533	13.969	15.513	17.137
PAC	9.864	10.979	12.285	13.693	15.261	16.948	18.722
US	9.825	10.936	12.236	13.638	15.201	16.881	18.647

	1993	1994	1995
NENG	21.241	23.361	25.545
MATL	21.159	23.270	25.446
SATL	20.646	22.706	24.829
ENC	20.810	22.887	25.026
WNC	20.112	22.119	24.187
ESC1	20.872	22.954	25.100
ESC2	20.420	22.458	24.557
WSC1	17.875	19.659	21.497
WSC2	17.875	19.659	21.497
MTN1	18.861	20.742	22.682
MTN2	18.922	20.810	22.756
MTN3	18.861	20.742	22.682
PAC	20.605	22.661	24.779
US	20.523	22.571	24.681

Table B-8. Low Case
Average Annual Industrial Residual Fuel Prices by Region
(dollars per million Btu)

	1978	1979	1980	1981	1982	1983	1984	1985
NENG	2.097	3.071	4.293	5.161	5.443	5.879	6.333	6.859
MATL	2.176	3.186	4.454	5.355	5.648	6.101	6.572	7.118
SATL	2.014	2.949	4.122	4.956	5.227	5.646	6.082	6.587
ENC	2.058	3.014	4.214	5.066	5.343	5.771	6.216	6.733
WNC	1.951	2.857	3.994	4.801	5.064	5.470	5.892	6.381
ESC1	2.006	2.937	4.106	4.936	5.206	5.623	6.057	6.560
ESC2	1.856	2.717	3.799	4.567	4.816	5.202	5.604	6.070
WSC1	1.819	2.664	3.724	4.477	4.721	5.100	5.494	5.950
WSC2	1.819	2.664	3.724	4.477	4.721	5.100	5.494	5.950
MTN1	1.858	2.720	3.803	4.572	4.821	5.208	5.610	6.076
MTN2	1.933	2.830	3.956	4.756	5.016	5.418	5.837	6.322
MTN3	1.858	2.720	3.803	4.572	4.821	5.208	5.610	6.076
PAC	1.774	2.598	3.632	4.367	4.606	4.975	5.359	5.804
US	2.028	2.970	4.151	4.991	5.264	5.686	6.125	6.633

	1986	1987	1988	1989	1990	1991	1992	1993
NENG	7.656	8.492	9.470	10.518	11.683	12.938	14.252	15.641
MATL	7.944	8.813	9.827	10.915	12.124	13.426	14.789	16.231
SATL	7.352	8.156	9.094	10.101	11.220	12.425	13.687	15.021
ENC	7.515	8.336	9.296	10.325	11.469	12.700	13.990	15.354
WNC	7.123	7.901	8.810	9.786	10.870	12.037	13.259	14.552
ESC1	7.323	8.123	9.058	10.061	11.175	12.375	13.631	14.960
ESC2	6.775	7.515	8.380	9.308	10.339	11.449	12.612	13.841
WSC1	6.641	7.367	8.215	9.125	10.135	11.224	12.363	13.569
WSC2	6.641	7.367	8.215	9.125	10.135	11.224	12.363	13.569
MTN1	6.782	7.523	8.389	9.318	10.350	11.461	12.625	13.856
MTN2	7.056	7.827	8.728	9.694	10.768	11.924	13.135	14.416
MTN3	6.782	7.523	8.389	9.318	10.350	11.461	12.625	13.856
PAC	6.478	7.186	8.013	8.901	9.887	10.948	12.060	13.236
US	7.404	8.213	9.158	10.172	11.299	12.513	13.783	15.127

	1994	1995
NENG	17.153	18.704
MATL	17.800	19.409
SATL	16.473	17.962
ENC	16.838	18.360
WNC	15.959	17.401
ESC1	16.407	17.890
ESC2	15.179	16.551
WSC1	14.880	16.226
WSC2	14.880	16.226
MTN1	15.196	16.569
MTN2	15.809	17.239
MTN3	15.196	16.569
PAC	14.515	15.828
US	16.589	18.089

Table B-9. Low Case
Average Annual Industrial Natural Gas Price by Region
(dollars per million Btu)

	1978	1979	1980	1981	1982	1983	1984	1985
NENG	2.843	3.201	3.995	4.677	5.138	5.774	6.523	7.278
MATL	2.352	2.686	3.179	3.727	4.124	4.741	5.512	6.274
SATL	1.805	2.213	2.689	3.165	3.544	4.146	4.888	5.566
ENC	1.985	2.363	2.912	3.494	3.870	4.438	5.061	5.694
WNC	1.490	1.861	2.341	2.853	3.199	3.830	4.399	5.126
ESC1	1.667	2.068	2.550	3.091	3.434	3.971	4.602	5.207
ESC2	1.655	2.135	2.589	3.122	3.475	4.098	4.717	5.324
WSC1	1.483	1.691	2.375	2.854	3.315	4.125	4.697	5.377
WSC2	1.991	2.190	2.661	3.104	3.549	4.284	4.875	5.571
MTN1	1.613	2.022	2.710	3.263	3.641	4.261	4.848	5.493
MTN2	1.471	1.920	2.588	3.191	3.541	4.043	4.570	5.104
MTN3	1.523	2.192	2.829	3.184	3.544	4.054	4.626	5.195
PAC	2.196	2.501	3.277	4.069	4.484	5.043	5.614	6.281
US	1.910	2.425	2.888	3.305	3.715	4.363	4.984	5.663

	1986	1987	1988	1989	1990	1991	1992
NENG	8.412	9.250	10.942	12.458	13.425	14.852	16.290
MATL	7.376	8.204	10.002	11.482	12.592	13.992	15.403
SATL	6.564	7.346	9.103	10.651	11.700	13.029	14.365
ENC	6.663	7.355	9.071	10.469	11.597	12.918	14.243
WNC	6.083	6.718	8.328	9.717	10.943	12.237	13.530
ESC1	6.214	6.896	8.629	10.087	11.641	12.957	14.267
ESC2	6.347	7.022	8.754	10.200	11.482	12.828	14.178
WSC1	6.455	6.984	7.908	8.848	9.869	10.983	12.145
WSC2	6.673	7.230	8.252	9.259	10.331	11.495	12.701
MTN1	6.531	7.152	8.450	9.655	10.804	12.044	13.309
MTN2	6.029	6.680	8.423	9.705	10.882	12.109	13.460
MTN3	6.139	6.821	8.447	9.865	11.009	12.871	14.121
PAC	7.295	8.082	9.462	10.720	11.406	12.672	13.969
US	6.701	7.386	8.840	10.124	11.193	12.480	13.745

	1993	1994	1995
NENG	17.780	19.375	20.998
MATL	16.860	18.425	20.019
SATL	15.745	17.227	18.733
ENC	15.612	17.083	18.578
WNC	14.864	16.297	17.776
ESC1	15.610	17.045	18.492
ESC2	15.569	17.065	18.589
WSC1	13.374	14.718	16.091
WSC2	13.974	15.360	16.777
MTN1	14.631	16.062	17.523
MTN2	14.707	16.105	17.409
MTN3	15.399	16.758	18.110
PAC	15.326	16.795	18.295
US	15.078	16.500	17.976

Table B-10. Low Case
Average Annual Industrial Coal Prices by Region
(dollars per million Btu)

	1978	1979	1980	1981	1982	1983	1984	1985
NENG	1.756	1.819	2.064	2.276	2.493	2.735	2.973	3.258
MATL	1.431	1.482	1.623	1.829	2.047	2.298	2.560	2.836
SATL	1.565	1.680	1.818	2.040	2.278	2.539	2.820	3.134
ENC	1.446	1.588	1.740	1.945	2.153	2.366	2.589	2.844
WNC	1.091	1.198	1.330	1.518	1.719	1.942	2.183	2.456
ESC1	1.367	1.486	1.688	1.897	2.117	2.347	2.600	2.899
ESC2	1.597	1.800	1.945	2.171	2.404	2.670	2.952	3.277
WSC1	1.267	1.368	1.464	1.669	1.891	2.138	2.405	2.711
WSC2	0.830	1.175	1.492	1.722	1.977	2.263	2.584	2.965
MTN1	0.501	0.568	0.664	0.815	0.989	1.192	1.427	1.707
MTN2	0.636	0.818	0.902	1.046	1.208	1.392	1.593	1.823
MTN3	0.692	1.023	1.185	1.364	1.561	1.784	2.028	2.305
PAC	0.917	0.995	1.233	1.455	1.707	2.001	2.324	2.696
US	1.328	1.458	1.606	1.824	2.042	2.276	2.525	2.819

	1986	1987	1988	1989	1990	1991	1992	1993
NENG	3.596	3.967	4.362	4.776	5.222	5.687	6.160	6.646
MATL	3.152	3.492	3.868	4.293	4.754	5.219	5.721	6.259
SATL	3.503	3.899	4.326	4.782	5.275	5.791	6.323	6.880
ENC	3.151	3.482	3.813	4.155	4.530	4.954	5.420	5.916
WNC	2.766	3.103	3.463	3.854	4.280	4.718	5.169	5.633
ESC1	3.218	3.576	3.924	4.328	4.774	5.150	5.474	5.796
ESC2	3.645	4.034	4.449	4.893	5.373	5.874	6.334	6.691
WSC1	3.086	3.495	3.931	4.402	4.920	5.456	6.005	6.569
WSC2	3.398	3.868	4.375	4.924	5.528	6.149	6.785	7.445
MTN1	2.096	2.426	2.776	3.152	3.591	4.018	4.702	5.168
MTN2	2.092	2.381	2.680	2.995	3.337	3.688	4.049	4.420
MTN3	2.684	3.096	3.521	3.966	4.404	4.904	5.413	5.924
PAC	3.139	3.615	4.121	4.674	5.274	5.897	6.537	7.210
US	3.165	3.535	3.924	4.341	4.793	5.251	5.741	6.250

	1994	1995
NENG	7.120	7.637
MATL	6.815	7.372
SATL	7.457	8.057
ENC	6.431	6.941
WNC	6.111	6.610
ESC1	6.188	6.664
ESC2	6.964	7.306
WSC1	7.150	7.771
WSC2	8.129	8.844
MTN1	5.672	6.169
MTN2	4.800	5.197
MTN3	6.475	7.032
PAC	7.899	8.624
US	6.797	7.369

Table B-11. High Case
Average Annual Industrial Electricity Prices by Region
(cents per kWh)

	1978	1979	1980	1981	1982	1983	1984	1985
NENG	3.549	4.065	4.860	6.012	6.862	7.657	8.904	10.453
MATL	3.181	3.490	4.330	5.258	6.243	6.913	8.115	9.168
SATL	2.744	2.910	3.549	4.435	5.174	6.058	7.074	8.089
ENC	2.760	2.993	3.586	4.221	5.092	5.864	6.753	7.766
WNC	2.768	2.969	3.574	4.203	5.428	6.259	7.467	8.651
ESC1	2.280	2.631	3.318	3.856	4.798	5.511	6.348	7.303
ESC2	2.496	2.913	3.615	4.153	5.095	5.808	6.645	7.600
WSC1	2.322	2.423	3.002	3.686	6.186	7.316	8.993	10.806
WSC2	2.220	2.570	3.048	3.733	6.232	7.362	9.040	10.853
MTN1	3.163	3.928	4.874	5.707	6.830	7.794	8.982	10.121
MTN2	1.515	1.752	2.074	2.770	3.530	4.068	4.966	6.043
MTN3	2.764	3.096	3.788	4.622	5.745	6.708	7.897	9.036
PAC	2.143	2.254	2.907	3.741	4.864	5.828	7.016	8.155
US	2.593	2.850	3.482	4.226	5.386	6.220	7.329	8.478

	1986	1987	1988	1989	1990	1991	1992
NENG	12.243	14.055	15.916	19.122	22.085	22.807	25.845
MATL	10.300	11.511	13.686	15.169	17.126	19.643	21.401
SATL	9.528	11.071	12.764	14.244	16.010	18.276	20.408
ENC	9.620	11.292	12.440	14.056	15.366	17.214	18.445
WNC	11.176	13.085	14.768	16.451	17.955	19.901	21.291
ESC1	9.006	10.603	12.222	14.049	15.397	17.554	18.873
ESC2	9.303	10.900	12.519	14.345	15.694	17.851	19.170
WSC1	13.370	16.087	19.527	22.608	25.748	29.544	31.228
WSC2	13.417	16.134	19.574	22.655	25.794	29.591	31.274
MTN1	11.617	13.241	15.010	16.407	17.948	19.922	21.862
MTN2	7.434	8.889	10.648	12.894	14.419	16.346	16.894
MTN3	10.532	12.155	13.925	15.322	16.863	18.837	20.776
PAC	9.651	11.274	13.044	14.441	15.982	17.956	19.896
US	10.215	11.935	13.807	15.642	17.460	19.768	21.495

	1993	1994	1995
NENG	27.331	29.245	32.870
MATL	23.011	26.214	29.416
SATL	22.800	25.157	28.005
ENC	19.762	20.934	22.455
WNC	22.978	24.667	26.534
ESC1	19.714	20.821	22.227
ESC2	20.011	21.118	22.523
WSC1	33.241	35.994	40.126
WSC2	33.287	36.041	40.173
MTN1	23.300	25.138	28.058
MTN2	18.262	19.053	20.542
MTN3	22.214	24.053	26.972
PAC	21.334	23.172	26.091
US	23.106	25.096	27.637

Table B-12. High Case
Average Annual Industrial Distillate Fuel Prices
(dollars per million Btu)

	1978	1979	1980	1981	1982	1983	1984	1985
NENG	2.775	4.172	5.970	7.730	9.150	10.732	12.730	15.220
MATL	2.765	4.156	5.947	7.700	9.115	10.690	12.681	15.161
SATL	2.698	4.055	5.803	7.513	8.894	10.431	12.373	14.794
ENC	2.719	4.087	5.849	7.573	8.965	10.514	12.471	14.911
WNC	2.628	3.950	5.653	7.319	8.664	10.161	12.053	14.411
ESC1	2.727	4.099	5.866	7.596	8.991	10.545	12.508	14.956
ESC2	2.668	4.011	5.739	7.431	8.797	10.317	12.238	14.632
WSC1	2.336	3.511	5.024	6.505	7.700	9.031	10.713	12.809
WSC2	2.336	3.511	5.024	6.505	7.700	9.031	10.713	12.809
MTN1	2.464	3.704	5.301	6.864	8.125	9.529	11.303	13.514
MTN2	2.472	3.716	5.318	6.886	8.151	9.560	11.340	13.559
MTN3	2.464	3.704	5.301	6.864	8.125	9.529	11.303	13.514
PAC	2.692	4.047	5.791	7.498	8.876	10.410	12.348	14.764
US	2.682	4.031	5.768	7.469	8.841	10.369	12.299	14.706

	1986	1987	1988	1989	1990	1991	1992
NENG	18.138	21.665	25.757	30.433	35.776	41.927	48.822
MATL	18.068	21.581	25.657	30.316	35.638	41.765	48.633
SATL	17.630	21.058	25.035	29.581	34.774	40.752	47.454
ENC	17.770	21.225	25.234	29.816	35.050	41.076	47.831
WNC	17.174	20.514	24.388	28.816	33.875	39.699	46.228
ESC1	17.822	21.288	25.309	29.904	35.154	41.198	47.973
ESC2	17.437	20.828	24.761	29.257	34.394	40.306	46.935
WSC1	15.264	18.232	21.676	25.611	30.107	35.283	41.086
WSC2	15.264	18.232	21.676	25.611	30.107	35.283	41.086
MTN1	16.105	19.237	22.870	27.022	31.767	37.228	43.350
MTN2	16.158	19.300	22.945	27.111	31.870	37.349	43.492
MTN3	16.105	19.237	22.870	27.022	31.767	37.228	43.350
PAC	17.595	21.016	24.985	29.522	34.705	40.671	47.360
US	17.525	20.932	24.886	29.404	34.566	40.509	47.171

	1993	1994	1995
NENG	56.598	65.554	75.947
MATL	56.379	65.301	75.653
SATL	55.012	63.718	73.819
ENC	55.449	64.224	74.406
WNC	53.590	62.071	71.911
ESC1	55.613	64.414	74.626
ESC2	54.410	63.021	73.012
WSC1	47.629	55.167	63.913
WSC2	47.629	55.167	63.913
MTN1	50.254	58.207	67.435
MTN2	50.418	58.397	67.655
MTN3	50.254	58.207	67.435
PAC	54.902	63.591	73.672
US	54.684	63.338	73.378

Table B-13. High Case
Average Annual Industrial Residual Fuel Prices by Region
(dollars per million Btu)

	1978	1979	1980	1981	1982	1983	1984	1985
NENG	2.097	3.071	4.293	5.506	6.564	7.836	9.359	11.267
MATL	2.176	3.186	4.454	5.713	6.812	8.131	9.712	11.692
SATL	2.014	2.949	4.122	5.287	6.304	7.525	8.988	10.820
ENC	2.058	3.014	4.214	5.405	6.444	7.692	9.187	11.060
WNC	1.951	2.857	3.994	5.122	6.107	7.290	8.707	10.483
ESC1	2.006	2.937	4.106	5.266	6.279	7.495	8.952	10.777
ESC2	1.856	2.717	3.799	4.872	5.809	6.934	8.282	9.970
WSC1	1.819	2.664	3.724	4.776	5.695	6.797	8.119	9.774
WSC2	1.819	2.664	3.724	4.776	5.695	6.797	8.119	9.774
MTN1	1.858	2.720	3.803	4.877	5.815	6.941	8.291	9.981
MTN2	1.933	2.830	3.956	5.074	6.050	7.222	8.626	10.384
MTN3	1.858	2.720	3.803	4.877	5.815	6.941	8.291	9.981
PAC	1.774	2.598	3.632	4.659	5.555	6.631	7.920	9.535
US	2.028	2.970	4.151	5.325	6.348	7.578	9.051	10.897

	1986	1987	1988	1989	1990	1991	1992
NENG	13.656	16.255	19.259	22.678	26.568	31.048	36.052
MATL	14.171	16.868	19.986	23.533	27.570	32.219	37.412
SATL	13.114	15.611	18.496	21.779	25.515	29.817	34.622
ENC	13.405	15.957	18.905	22.261	26.080	30.477	35.389
WNC	12.705	15.123	17.918	21.099	24.718	28.886	33.541
ESC1	13.062	15.548	18.421	21.691	25.412	29.697	34.483
ESC2	12.084	14.384	17.043	20.068	23.511	27.475	31.903
WSC1	11.846	14.102	16.707	19.673	23.048	26.934	31.275
WSC2	11.846	14.102	16.707	19.673	23.048	26.934	31.275
MTN1	12.097	14.400	17.061	20.090	23.536	27.505	31.938
MTN2	12.586	14.982	17.751	20.901	24.487	28.616	33.228
MTN3	12.097	14.400	17.061	20.090	23.536	27.505	31.938
PAC	11.556	13.756	16.298	19.191	22.483	26.274	30.508
US	13.207	15.721	18.626	21.932	25.695	30.027	34.866

	1993	1994	1995
NENG	41.676	48.135	55.609
MATL	43.247	49.950	57.706
SATL	40.023	46.226	53.404
ENC	40.910	47.250	54.587
WNC	38.774	44.783	51.736
ESC1	39.862	46.040	53.189
ESC2	36.879	42.595	49.209
WSC1	36.154	41.757	48.241
WSC2	36.154	41.757	48.241
MTN1	36.920	42.642	49.263
MTN2	38.411	44.364	51.252
MTN3	36.920	42.642	49.263
PAC	35.267	40.733	47.058
US	40.305	46.552	53.780

Table B-14. High Case
Average Annual Industrial Natural Gas Prices by Region
(dollars per million Btu)

	1978	1979	1980	1981	1982	1983	1984	1985
NENG	2.843	3.201	3.995	4.771	6.935	7.698	9.458	11.453
MATL	2.352	2.686	3.179	3.809	5.953	6.545	8.332	10.258
SATL	1.805	2.213	2.689	3.227	5.296	5.839	7.537	9.345
ENC	1.985	2.363	2.912	3.585	5.632	6.214	7.790	9.558
WNC	1.490	1.861	2.341	2.918	4.811	5.475	6.942	8.797
ESC1	1.667	2.068	2.550	3.154	5.190	5.609	7.161	8.844
ESC2	1.655	2.135	2.589	3.182	5.306	5.862	7.402	9.083
WSC1	1.483	1.691	2.375	2.884	6.182	7.021	8.514	10.230
WSC2	1.991	2.190	2.661	3.135	6.322	7.130	8.635	10.370
MTN1	1.613	2.022	2.710	3.341	5.917	6.563	8.051	9.741
MTN2	1.471	1.920	2.588	3.276	5.272	5.812	7.235	8.820
MTN3	1.523	2.192	2.829	3.265	5.159	5.625	7.129	8.776
PAC	2.196	2.501	3.277	4.187	6.237	7.085	8.625	10.475
US	1.910	2.425	2.888	3.369	5.854	6.518	8.066	9.818

	1986	1987	1988	1989	1990	1991	1992
NENG	13.997	16.336	20.775	25.145	28.915	33.768	39.039
MATL	12.637	14.874	19.444	23.726	27.681	32.470	37.673
SATL	11.580	13.707	18.220	22.608	26.442	31.094	36.152
ENC	11.775	13.758	18.215	22.348	26.304	30.942	35.978
WNC	10.915	12.741	17.161	21.272	25.349	29.930	34.899
ESC1	11.043	12.952	17.511	21.732	26.414	31.054	36.074
ESC2	11.285	13.186	17.697	21.900	26.077	30.754	35.830
WSC1	12.381	14.057	17.009	20.243	23.855	28.054	32.739
WSC2	12.552	14.291	17.471	20.864	24.593	28.895	33.673
MTN1	11.914	13.733	17.522	21.282	25.190	29.653	34.557
MTN2	10.911	12.788	17.461	21.384	25.426	29.895	35.010
MTN3	10.931	12.852	17.295	21.441	25.411	31.074	35.996
PAC	12.842	15.135	18.983	22.847	26.073	30.587	35.553
US	12.021	13.975	18.002	21.915	25.731	30.261	35.216

	1993	1994	1995
NENG	44.868	51.491	59.099
MATL	43.428	49.976	57.511
SATL	41.749	48.123	55.460
ENC	41.554	47.903	55.214
WNC	40.399	46.665	53.938
ESC1	41.609	47.893	55.105
ESC2	41.444	47.841	55.210
WSC1	38.009	44.072	51.095
WSC2	39.033	45.188	52.309
MTN1	40.023	46.279	53.502
MTN2	40.355	46.574	53.461
MTN3	41.415	47.548	54.558
PAC	41.092	47.429	54.745
US	40.714	46.998	54.242

Table B-15. High Case
Average Annual Industrial Coal Prices by Region
(dollars per million Btu)

	1978	1979	1980	1981	1982	1983	1984	1985
NENG	1.756	1.819	2.064	2.297	2.594	2.976	3.431	4.019
MATL	1.431	1.482	1.623	1.844	2.128	2.493	2.936	3.469
SATL	1.565	1.680	1.818	2.058	2.368	2.756	3.237	3.836
ENC	1.446	1.588	1.740	1.962	2.240	2.572	2.983	3.501
WNC	1.091	1.198	1.330	1.531	1.786	2.105	2.498	2.989
ESC1	1.367	1.486	1.688	1.914	2.201	2.549	2.987	3.548
ESC2	1.597	1.800	1.945	2.190	2.500	2.900	3.393	4.016
WSC1	1.267	1.368	1.464	1.684	1.964	2.317	2.752	3.298
WSC2	0.830	1.175	1.492	1.737	2.052	2.448	2.946	3.583
MTN1	0.501	0.568	0.664	0.821	1.024	1.281	1.608	2.027
MTN2	0.636	0.818	0.902	1.054	1.254	1.504	1.814	2.202
MTN3	0.692	1.023	1.185	1.376	1.621	1.931	2.314	2.793
PAC	0.917	0.995	1.233	1.467	1.771	2.159	2.637	3.237
US	1.328	1.458	1.606	1.843	2.128	2.480	2.915	3.466

	1986	1987	1988	1989	1990	1991	1992	1993
NENG	4.749	5.581	6.468	7.431	8.494	9.643	10.869	12.183
MATL	4.121	4.857	5.658	6.558	7.556	8.619	9.781	11.049
SATL	4.576	5.412	6.312	7.296	8.386	9.566	10.830	12.197
ENC	4.149	4.880	5.642	6.462	7.373	8.392	9.511	10.730
WNC	3.587	4.266	4.996	5.801	6.697	7.659	8.690	9.795
ESC1	4.212	4.974	5.758	6.647	7.639	8.623	9.614	10.667
ESC2	4.775	5.623	6.530	7.525	8.623	9.812	11.031	12.221
WSC1	3.991	4.779	5.627	6.562	7.606	8.733	9.935	11.224
WSC2	4.359	5.241	6.196	7.251	8.431	9.699	11.052	12.511
MTN1	2.606	3.174	3.787	4.462	5.242	6.058	7.173	8.133
MTN2	2.682	3.223	3.798	4.423	5.117	5.863	6.661	7.515
MTN3	3.440	4.176	4.957	5.804	6.700	7.714	8.793	9.937
PAC	3.988	4.838	5.752	6.769	7.899	9.118	10.423	11.837
US	4.147	4.919	5.741	6.641	7.635	8.712	9.882	11.131

	1994	1995
NENG	13.582	15.162
MATL	12.424	13.931
SATL	13.681	15.330
ENC	12.053	13.498
WNC	10.993	12.325
ESC1	11.870	13.278
ESC2	13.420	14.818
WSC1	12.620	14.188
WSC2	14.093	15.855
MTN1	9.194	10.345
MTN2	8.441	9.468
MTN3	11.201	12.588
PAC	13.363	15.065
US	12.495	13.997

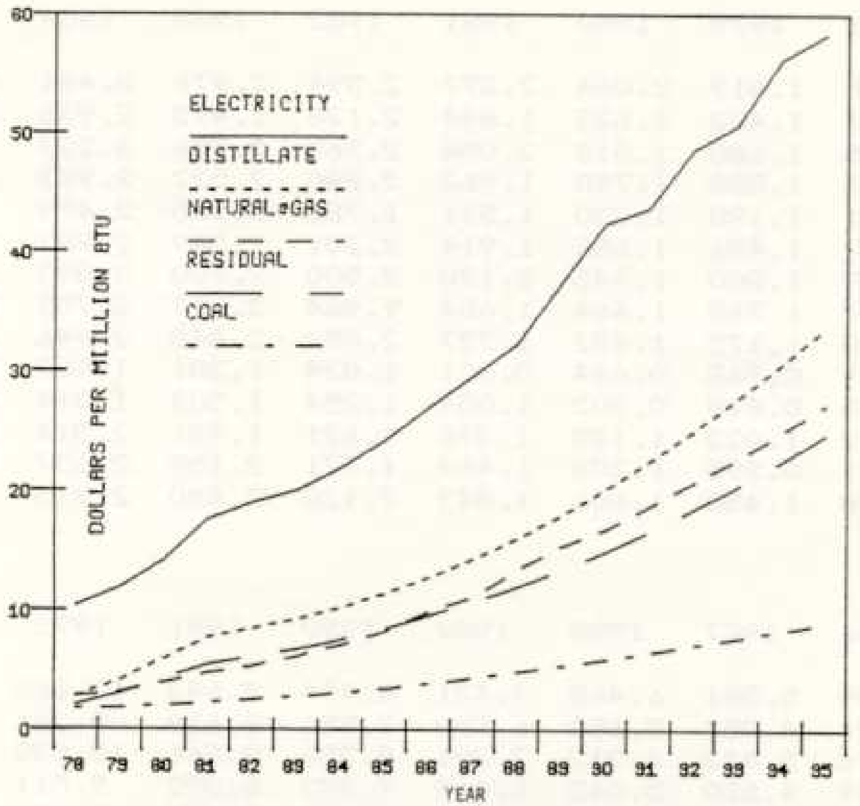

Figure B-1. New England Regional Fuels and Electricity Prices-Best Cast

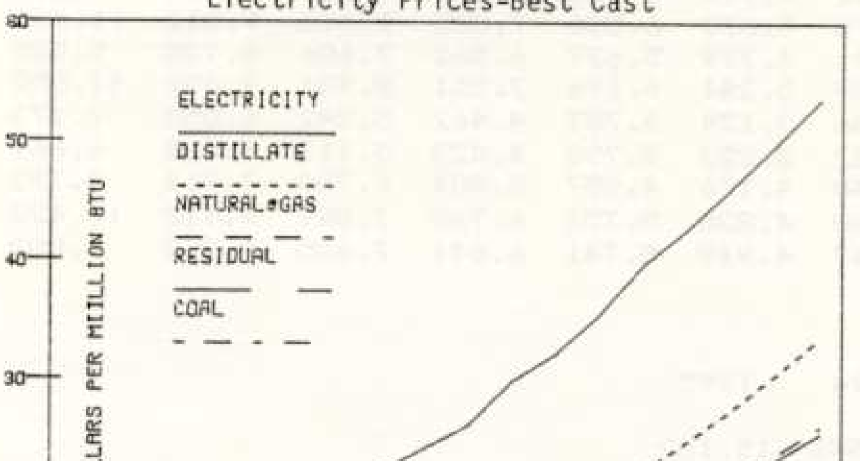

Figure B-2. Middle Atlantic Regional Fuels and Electricity Prices-Best Case

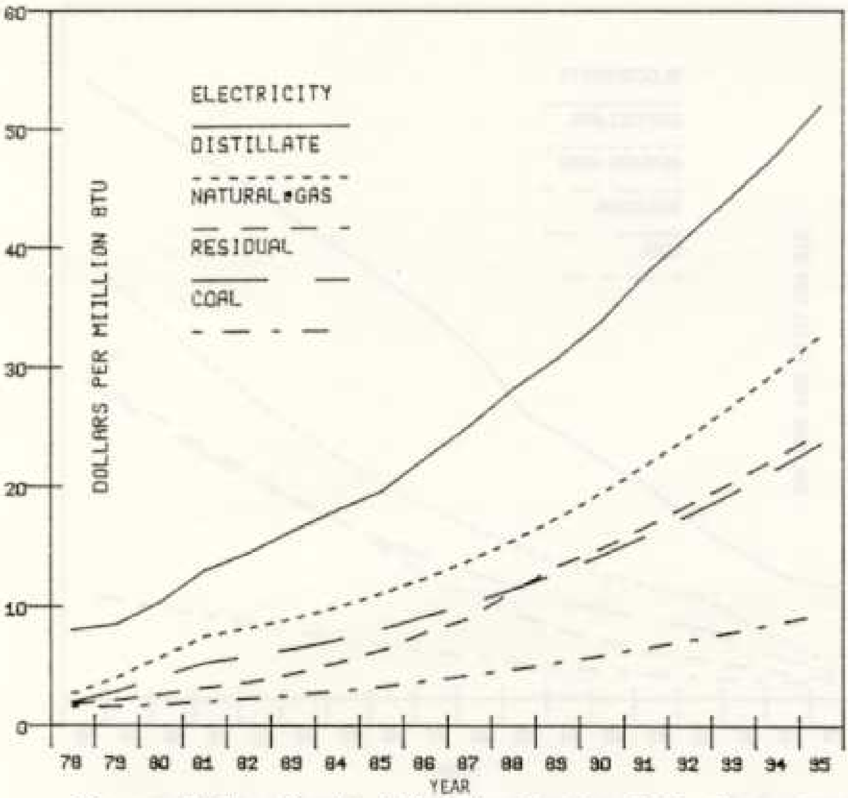

Figure B-3. South Atlantic Regional Fuels and Electricity Prices-Best Case

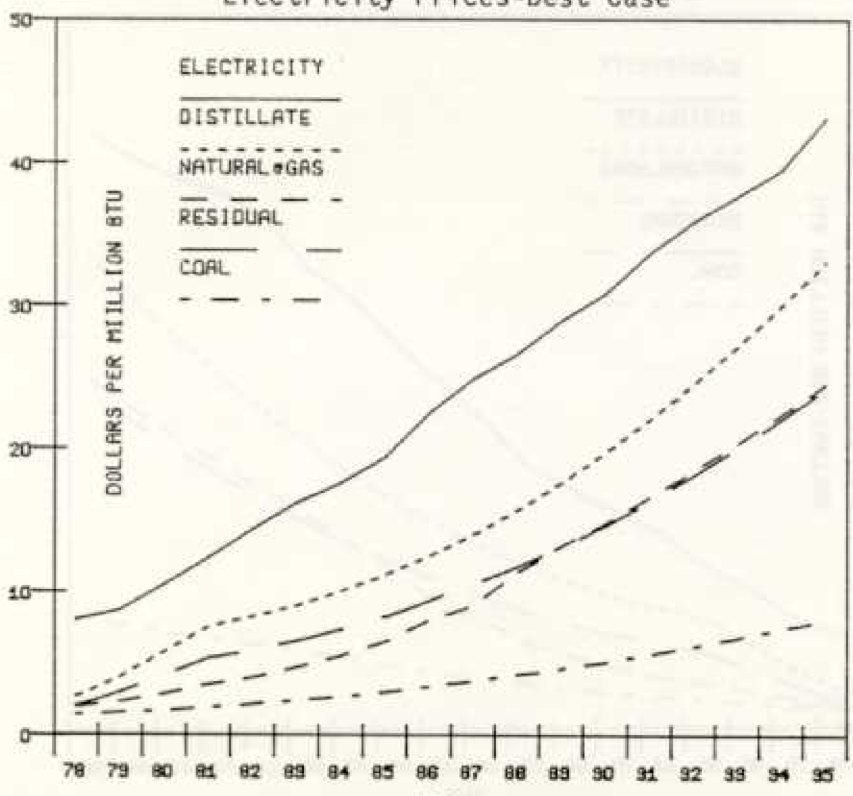

Figure B-4. East North Central Regional Fuels and Electricity Prices-Best Case

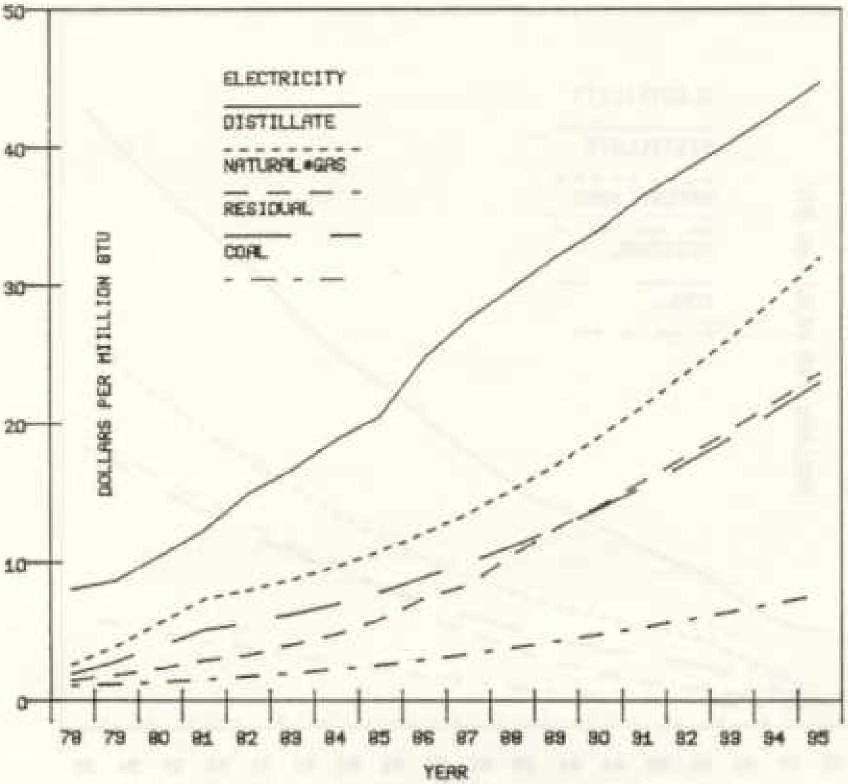

Figure B-5. West North Central Regional Fuels and Electricity Prices-Best Case

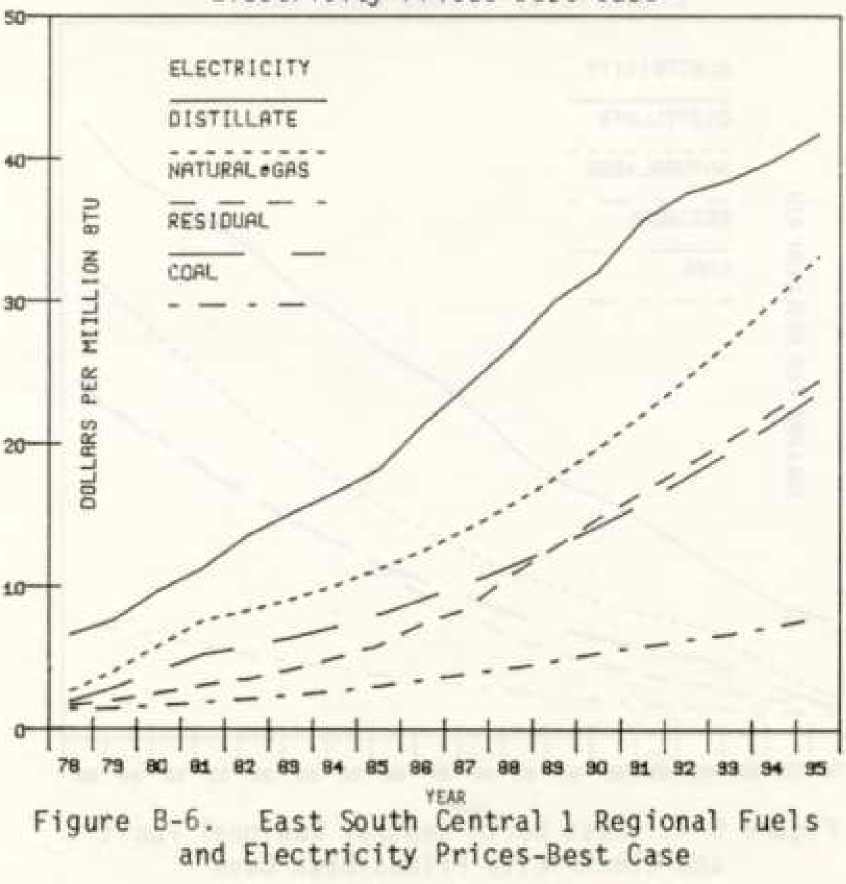

Figure B-6. East South Central 1 Regional Fuels and Electricity Prices-Best Case

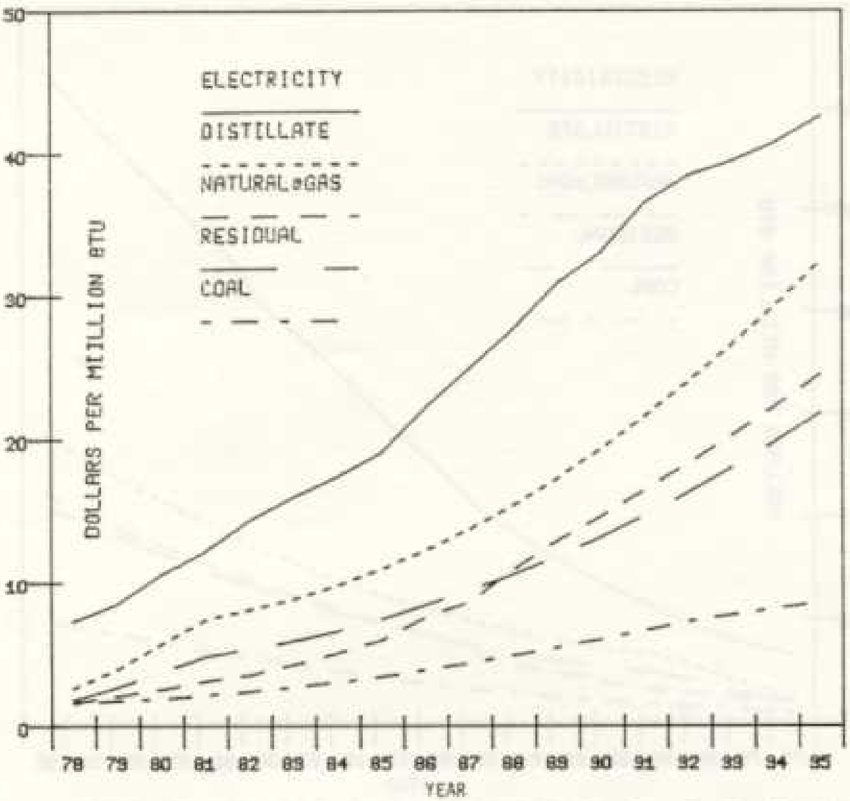

Figure B-7. East South Central 2 Regional Fuels and Electricity Prices-Best Case

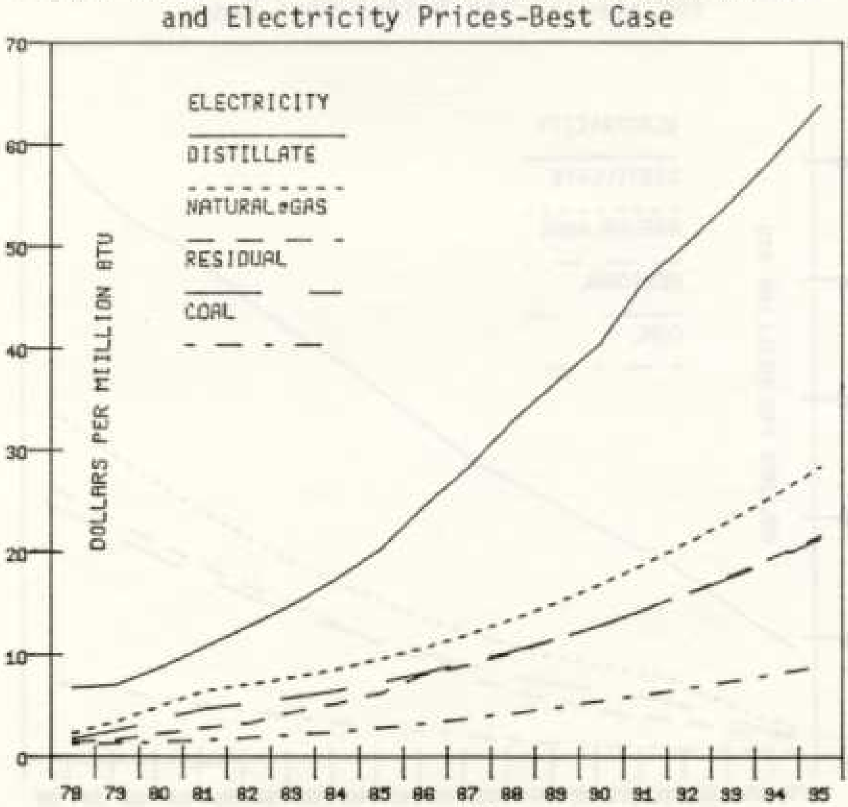

Figure B-8. West South Central 1 Regional Fuels and Electricity Prices-Best Case

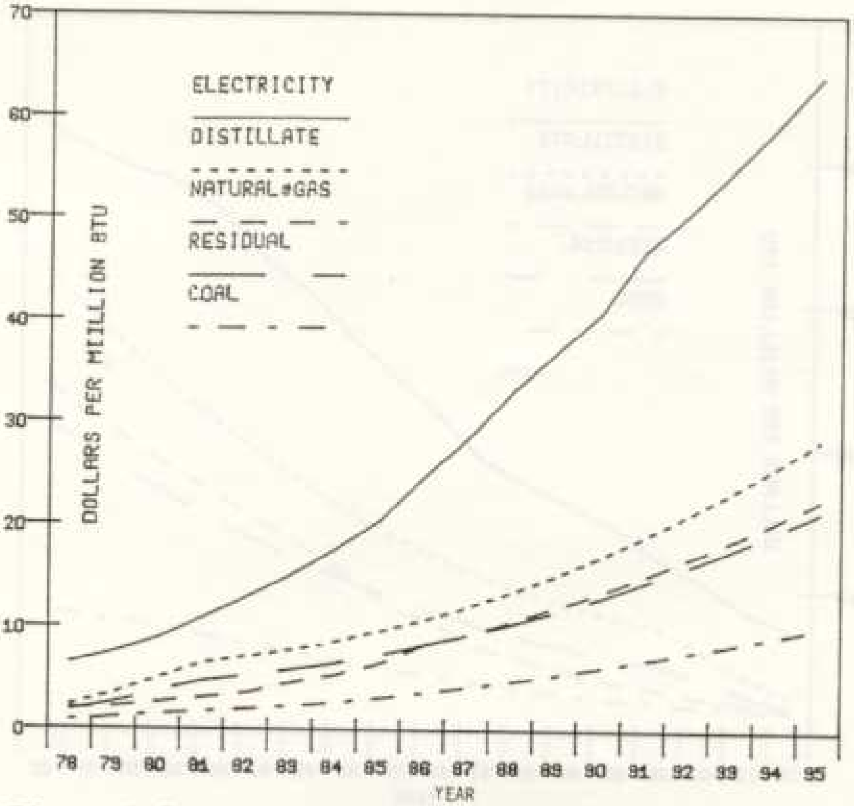

Figure B-9. West South Central 2 Regional Fuels and Electricity Prices-Best Case

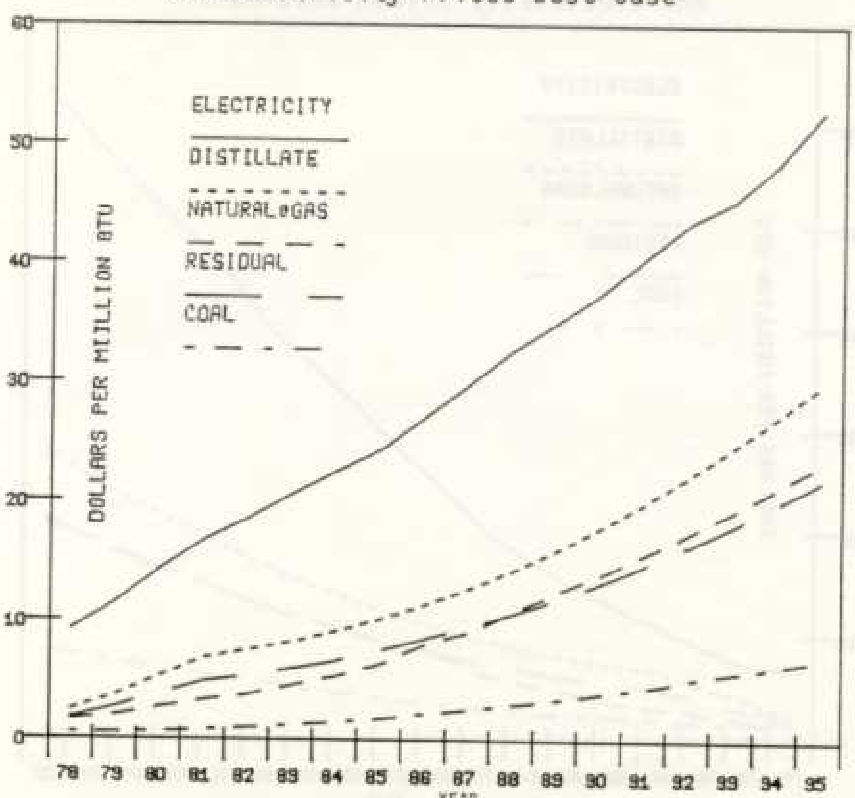

Figure B-10. Mountain 1 Regional Fuels and Electricity Prices-Best Case

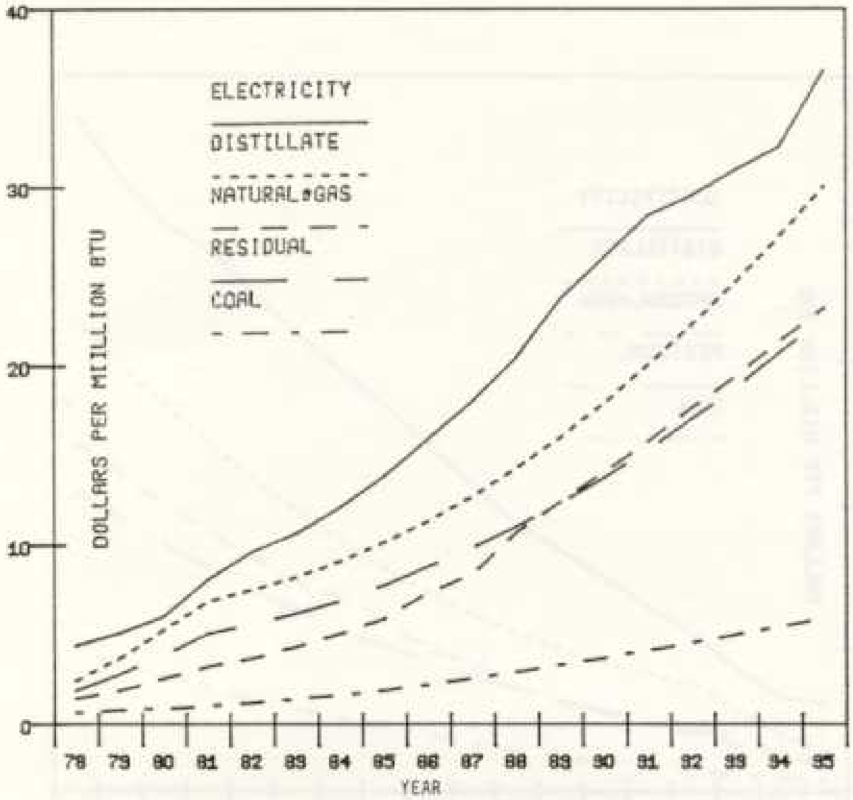

Figure B-11. Mountain 2 Regional Fuels and Electricity Prices-Best Case

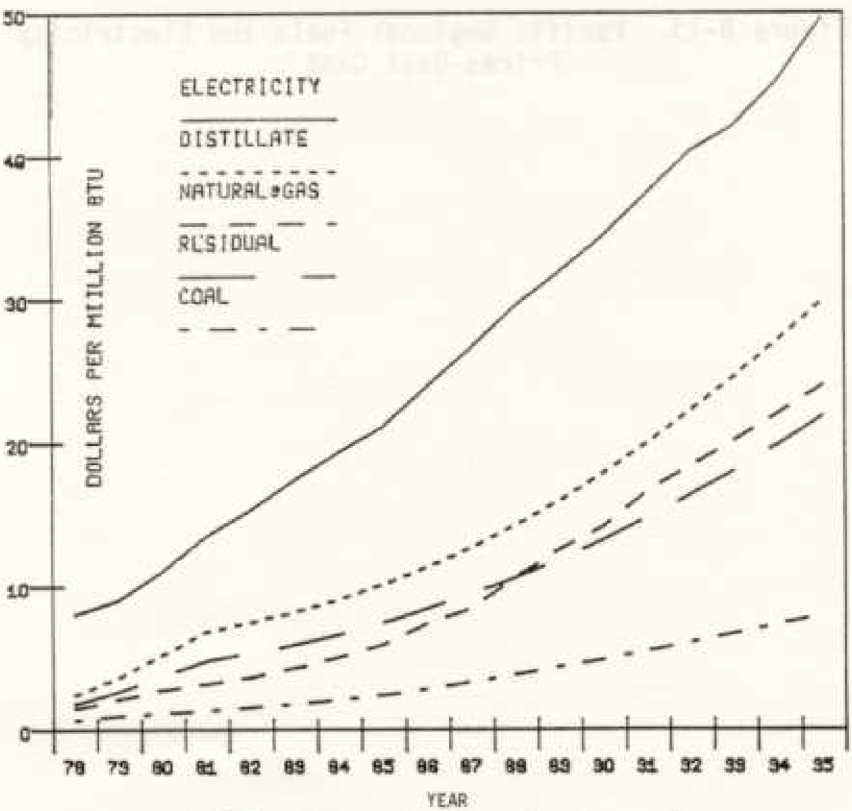

Figure B-12. Mountain 3 Regional Fuels and Electricity Prices-Best Case

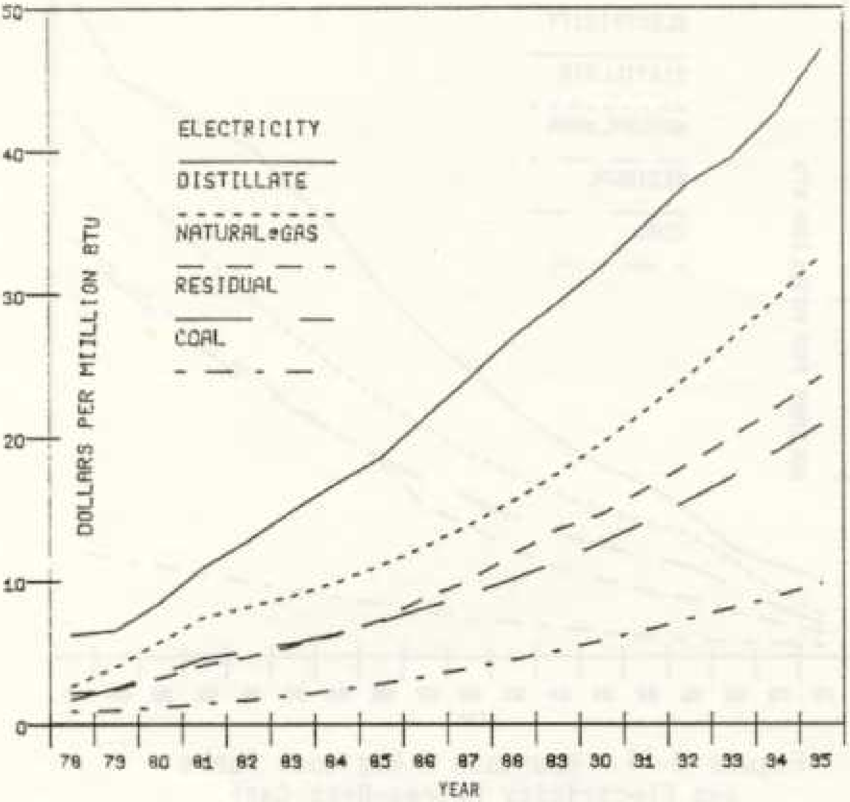

Figure B-13. Pacific Regional Fuels and Electricity Prices-Best Case

APPENDIX C

REGIONAL ELECTRIC UTILITY
FUEL USE TABLES
FOR DETERMINATION
OF SCARCE FUEL DISPLACEMENT

REGIONAL ELECTRIC UTILITY FUEL USE TABLES FOR
DETERMINATION OF SCARCE FUEL DISPLACEMENT*

Purpose

This Appendix provides hour-by-hour estimates of regional incremental oil and gas use by the electric utility industry for the forecast year of 1989 for each of the eleven electric supply regions. The intended use of this information is to estimate the change in utility oil and gas consumption resulting from any change in electrical production or electrical demand. Such changes can arise from a variety of circumstances including on-site generation, conservation initiatives, load management, and changes in energy usage patterns.

Results

The estimates of incremental oil and gas use for the eleven regions are presented in Tables C-1 through C-11. Each table lists a numerical value for each hour of several representative days of the year. These representative days include a weekday and a weekend day (or holiday) for each of the three seasons (spring and fall are considered as one intermediate season). These sample days represent the following number of days during the entire year:

	Weekdays	Weekend/Holidays
Spring/Fall	127	56
Summer	63	29
Winter	62	28

A numerical value of "0" is used to designate those hours for which the entire regional load could be met without using either oil- or gas-fired units. In every other instance, the numerical value that is listed is the average heat rate (in Btu's per kWh) of the last oil (or gas) unit dispatched to meet the load.

*Draft Chapter for "Electric Power Supply and Demand for the Contiguous United States, 1980-1989." U.S. Department of Energy, Economic Regulatory Administration. Division of Power Supply and Reliability. DOE/RG-0036 (Rev. 1). Revised and reprinted July 1980.

Because these units are dispatched in order of ascending heat rate, the listed value is approximately equal to the incremental heat rate of the entire utility system for that hour. For example, Table C-2 indicates that in Texas the incremental oil or gas heat rate for the hour between 10 and 11:00 a.m. on a winter weekday is 9,700 Btu/kWh.

The average annual incremental oil and gas use is also listed at the bottom of each fuel use table. These averages can be used to calculate the annual oil or gas savings associated with a measure that causes a constant, permanent change in electricity demand.

Basis of Estimates

A utility normally "dispatches" its available powerplants in increasing order of operating costs to minimize the cost of meeting demand for electric power at any particular moment. The response to a small change in load would be to vary the output of the plant (among those currently operating) that has the highest operating cost.* Because fuel is the dominant component of operating costs, the plant that provides the marginal, incremental unit of power, would use the most expensive fuel (of those currently operating) and would be the least efficient plant currently operating with that fuel. Thus plants using oil and gas would only be used to satisfy demand if all available plants using other fuels were already operating at full capacity.

The projections in this Appendix are based on a model of this process developed by Mathtech, Inc., and described in detail in Reference 10 (Appendix E). It is designed to model the hour-by-hour "economic dispatch" of all powerplants in a specific region (which generally is larger than a single utility service area). The analysis reported here was based on

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*Certain units on a system may sometimes have to operate even if their running costs exceed the running costs of units not operating at full capacity due to technical constraints such as area protection, reserve to cover forced outages, maintenance scheduling, etc. This was not included in the analysis. If included, it would occasionally have resulted in lower estimates of incremental oil or gas use.

eleven regions--the nine electric reliability councils, with two of those reliability councils (SERC and WSCC) split into two regions each.* This regional aggregation is believed to reflect the ability of utilities in 1989 to interchange power sufficiently well to exploit the major opportunities to avoid oil or gas use at times when unused capacity based on cheaper fuels is available.

The key inputs to the analyses are powerplant inventory projections, availability of these plants, load growth during the 1980's and hour-by-hour load profiles. The demand side of this model was constructed by assembling load profile data from 299 utilities (primarily those reporting under Form 12E-2) representing 98 percent of 1979 U.S. production. The actual loads of 1978 were projected to 1989, based on the projections in Reference 11 (see Table C-12).

The supply side of the model was constructed from the actual 1979 Inventory of Powerplants.+ The 1989 projections were obtained using the growth rates given in Reference 12 (see Table C-13). Plants were dispatched based upon relative heat rates. Powerplant availabilities for each type of plant were assumed to be the average for that type that was achieved in the period 1968-1977, as reported in Reference 13.

No distinction was made between oil and gas in the analysis, because most such plants are dual-fuel capable and can be expected to use whichever of these fuels is available at the lowest cost.

The many other assumptions required to complete this model (e.g., interregional transfers, reserve margins, system security, and spinning reserves) are discussed in Reference 10.

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*The split was necessary because of the great difference in utility fuel mix between Florida and the rest of SERC, and between the eastern and western portions of WSCC.

+Generating Utilities Reference File - November 1979. Energy Information Administration, Department of Energy.

Table C-1. Projected Oil or Gas Burned in 1989 By Utilities In East Central Area (ECAR) (Btu Per Incremental Kilowatt-Hour)

HOUR	SPRING OR FALL WEEKDAY	SPRING OR FALL WEEKEND/ HOLIDAY	SUMMER WEEKDAY	SUMMER WEEKEND/ HOLIDAY	WINTER WEEKDAY	WINTER WEEKEND/ HOLIDAY
MN-1	0.	0.	0.	0.	0.	0.
1-2	0.	0.	0.	0.	0.	0.
2-3	0.	0.	0.	0.	0.	0.
3-4	0.	0.	0.	0.	0.	0.
4-5	0.	0.	0.	0.	0.	0.
5-6	0.	0.	0.	0.	0.	0.
6-7	0.	0.	0.	0.	0.	0.
7-8	0.	0.	0.	0.	0.	0.
8-9	0.	0.	0.	0.	0.	0.
9-10	0.	0.	0.	0.	0.	0.
10-11	0.	0.	0.	0.	0.	0.
11-NOON	0.	0.	0.	0.	0.	0.
NOON-1	0.	0.	0.	0.	0.	0.
1-2	0.	0.	0.	0.	0.	0.
2-3	0.	0.	0.	0.	0.	0.
3-4	0.	0.	0.	0.	0.	0.
4-5	0.	0.	0.	0.	0.	0.
5-6	0.	0.	0.	0.	0.	0.
6-7	0.	0.	0.	0.	0.	0.
7-8	0.	0.	0.	0.	0.	0.
8-9	0.	0.	0.	0.	0.	0.
9-10	0.	0.	0.	0.	0.	0.
10-11	0.	0.	0.	0.	0.	0.
11-MN	0.	0.	0.	0.	0.	0.

AVERAGE ANNUAL INCREMENTAL OIL/GAS DISPLACEMENT= 0. BTU/KWH

Table C-2. Projected Oil or Gas Burned in 1989 By Utilities In Texas (ERCOT) (Btu Per Incremental Kilowatt-Hour)

HOUR	SPRING OR FALL WEEKDAY	SPRING OR FALL WEEKEND/ HOLIDAY	SUMMER WEEKDAY	SUMMER WEEKEND/ HOLIDAY	WINTER WEEKDAY	WINTER WEEKEND/ HOLIDAY
MN-1	9500.	9500.	10000.	9900.	0.	0.
1-2	9300.	9300.	9900.	9900.	0.	0.
2-3	9300.	0.	9900.	9700.	0.	0.
3-4	0.	0.	9900.	9700.	0.	0.
4-5	9300.	0.	9900.	9700.	0.	0.
5-6	9500.	0.	9900.	9700.	0.	0.
6-7	9600.	0.	10100.	9700.	9500.	0.
7-8	9900.	9500.	10200.	9900.	9700.	0.
8-9	9900.	9600.	10500.	10100.	9700.	9300.
9-10	10000.	9700.	10900.	10200.	9700.	9500.
10-11	10000.	9700.	11300.	10400.	9700.	9500.
11-NOON	10000.	9700.	11600.	10600.	9700.	9500.
NOON-1	10000.	9800.	12000.	11100.	10000.	9700.
1-2	10100.	9800.	12300.	11200.	10000.	9700.
2-3	10100.	9800.	12600.	11300.	10000.	9700.
3-4	10100.	9800.	12600.	11400.	10000.	9700.
4-5	10100.	9900.	12400.	11400.	10000.	9700.
5-6	10000.	9900.	12200.	11300.	10000.	9900.
6-7	10000.	9900.	11600.	11100.	10100.	9900.
7-8	10100.	10000.	11500.	10900.	10000.	9900.
8-9	10100.	10000.	11300.	10800.	10000.	9700.
9-10	9900.	9900.	10600.	10300.	9900.	9700.
10-11	9700.	9700.	10200.	10100.	9700.	9600.
11-MN	9600.	9500.	10100.	10000.	9600.	9500.

AVERAGE ANNUAL INCREMENTAL OIL/GAS DISPLACEMENT= 8900. BTU/KWH

Table C-3. Projected Oil or Gas Burned in 1989 By Utilities In Mid-Atlantic Area (MAAC)
(Btu Per Incremental Kilowatt-Hour)

HOUR	SPRING OR FALL		SUMMER		WINTER	
	WEEKDAY	WEEKEND/ HOLIDAY	WEEKDAY	WEEKEND/ HOLIDAY	WEEKDAY	WEEKEND/ HOLIDAY
MN-1	0.	0.	0.	0.	0.	0.
1-2	0.	0.	0.	0.	0.	0.
2-3	0.	0.	0.	0.	0.	0.
3-4	0.	0.	0.	0.	0.	0.
4-5	0.	0.	0.	0.	0.	0.
5-6	0.	0.	0.	0.	0.	0.
6-7	0.	0.	0.	0.	0.	0.
7-8	0.	0.	10100.	0.	11100.	0.
8-9	10100.	0.	12600.	0.	13000.	0.
9-10	10100.	0.	14000.	0.	13200.	0.
10-11	10200.	0.	14300.	0.	13700.	0.
11-NOON	10200.	0.	14100.	0.	13200.	0.
NOON-1	10100.	0.	14300.	0.	13900.	0.
1-2	10100.	0.	14400.	0.	13800.	0.
2-3	10100.	0.	14400.	0.	13100.	0.
3-4	10000.	0.	14400.	0.	12800.	0.
4-5	10000.	0.	14100.	0.	13900.	0.
5-6	9700.	0.	14100.	0.	14100.	9500.
6-7	10200.	0.	13100.	0.	14100.	9500.
7-8	10100.	0.	13200.	0.	13900.	9500.
8-9	10200.	0.	12600.	0.	13900.	9500.
9-10	9700.	0.	10200.	0.	12600.	0.
10-11	0.	0.	9400.	0.	10200.	0.
11-MN	0.	0.	0.	0.	9400.	0.

AVERAGE ANNUAL INCREMENTAL OIL/GAS DISPLACEMENT= 5200. BTU/KWH

Table C-4. Projected Oil or Gas Burned in 1989 by Utilities in Mid-West Area (MAIN)
(Btu Per Incremental Kilowatt-Hour)

HOUR	SPRING OR FALL		SUMMER		WINTER	
	WEEKDAY	WEEKEND/ HOLIDAY	WEEKDAY	WEEKEND/ HOLIDAY	WEEKDAY	WEEKEND/ HOLIDAY
MN-1	0.	0.	0.	0.	0.	0.
1-2	0.	0.	0.	0.	0.	0.
2-3	0.	0.	0.	0.	0.	0.
3-4	0.	0.	0.	0.	0.	0.
4-5	0.	0.	0.	0.	0.	0.
5-6	0.	0.	0.	0.	0.	0.
6-7	0.	0.	0.	0.	0.	0.
7-8	0.	0.	0.	0.	0.	0.
8-9	0.	0.	0.	0.	0.	0.
9-10	0.	0.	0.	0.	0.	0.
10-11	0.	0.	0.	0.	0.	0.
11-NOON	0.	0.	0.	0.	0.	0.
NOON-1	0.	0.	0.	0.	0.	0.
1-2	0.	0.	0.	0.	0.	0.
2-3	0.	0.	0.	0.	0.	0.
3-4	0.	0.	0.	0.	0.	0.
4-5	0.	0.	0.	0.	0.	0.
5-6	0.	0.	0.	0.	0.	0.
6-7	0.	0.	0.	0.	0.	0.
7-8	0.	0.	0.	0.	0.	0.
8-9	0.	0.	0.	0.	0.	0.
9-10	0.	0.	0.	0.	0.	0.
10-11	0.	0.	0.	0.	0.	0.
11-MN	0.	0.	0.	0.	0.	0.

AVERAGE ANNUAL INCREMENTAL OIL/GAS DISPLACEMENT= 0. BTU/KWH

Table C-5. Projected Oil or Gas Burned in 1989 by Utilities in North Central Region (MARCA)
(Btu Per Incremental Kilowatt-Hour)

HOUR	SPRING OR FALL		SUMMER		WINTER	
	WEEKDAY	WEEKEND/ HOLIDAY	WEEKDAY	WEEKEND/ HOLIDAY	WEEKDAY	WEEKEND/ HOLIDAY
MN-1	0.	0.	0.	0.	0.	0.
1-2	0.	0.	0.	0.	0.	0.
2-3	0.	0.	0.	0.	0.	0.
3-4	0.	0.	0.	0.	0.	0.
4-5	0.	0.	0.	0.	0.	0.
5-6	0.	0.	0.	0.	0.	0.
6-7	0.	0.	0.	0.	0.	0.
7-8	0.	0.	0.	0.	0.	0.
8-9	0.	0.	0.	0.	0.	0.
9-10	0.	0.	0.	0.	0.	0.
10-11	0.	0.	0.	0.	0.	0.
11-NOON	0.	0.	0.	0.	0.	0.
NOON-1	0.	0.	0.	0.	0.	0.
1-2	0.	0.	0.	0.	0.	0.
2-3	0.	0.	0.	0.	0.	0.
3-4	0.	0.	0.	0.	0.	0.
4-5	0.	0.	0.	0.	0.	0.
5-6	0.	0.	0.	0.	0.	0.
6-7	0.	0.	0.	0.	0.	0.
7-8	0.	0.	0.	0.	0.	0.
8-9	0.	0.	0.	0.	0.	0.
9-10	0.	0.	0.	0.	0.	0.
10-11	0.	0.	0.	0.	0.	0.
11-MN	0.	0.	0.	0.	0.	0.

AVERAGE ANNUAL INCREMENTAL OIL/GAS DISPLACEMENT= 0. BTU/KWH

Table C-6. Projected Oil or Gas Burned in 1989 by Utilities in Northeast (NPCC)
(Btu Per Incremental Kilowatt-Hour)

HOUR	SPRING OR FALL		SUMMER		WINTER	
	WEEKDAY	WEEKEND/ HOLIDAY	WEEKDAY	WEEKEND/ HOLIDAY	WEEKDAY	WEEKEND/ HOLIDAY
MN-1	0.	0.	0.	0.	9400.	0.
1-2	0.	0.	0.	0.	0.	0.
2-3	0.	0.	0.	0.	0.	0.
3-4	0.	0.	0.	0.	0.	0.
4-5	0.	0.	0.	0.	0.	0.
5-6	0.	0.	0.	0.	0.	0.
6-7	0.	0.	9700.	0.	9800.	0.
7-8	10000.	0.	10200.	0.	10800.	0.
8-9	10600.	0.	11000.	0.	12700.	9500.
9-10	10300.	9400.	12000.	0.	13700.	9800.
10-11	10300.	0.	10800.	0.	12300.	9900.
11-NOON	10300.	0.	10800.	0.	12100.	9900.
NOON-1	10100.	9400.	10800.	0.	13000.	9900.
1-2	10600.	0.	10800.	9400.	13100.	9800.
2-3	10600.	0.	10800.	0.	12900.	9800.
3-4	10500.	0.	10800.	9400.	13000.	9800.
4-5	10600.	0.	11200.	0.	13000.	9800.
5-6	10800.	9400.	10600.	9400.	14200.	10100.
6-7	10200.	0.	10300.	0.	13200.	10100.
7-8	10300.	9500.	10500.	0.	12200.	10000.
8-9	10600.	9400.	10200.	0.	12700.	9900.
9-10	10100.	0.	9900.	9400.	11200.	9800.
10-11	9800.	9400.	9500.	0.	10300.	9800.
11-MN	9400.	0.	0.	0.	9800.	9700.

AVERAGE ANNUAL INCREMENTAL OIL/GAS DISPLACEMENT= 6400. BTU/KWH

Table C-7. Projected Oil or Gas Burned in 1989 by Utilities in Southeast (Excluding Florida) (Btu Per Incremental Kilowatt-Hour)

HOUR	SPRING OR FALL WEEKDAY	SPRING OR FALL WEEKEND/HOLIDAY	SUMMER WEEKDAY	SUMMER WEEKEND/HOLIDAY	WINTER WEEKDAY	WINTER WEEKEND/HOLIDAY
MN-1	0.	0.	0.	0.	0.	0.
1-2	0.	0.	0.	0.	0.	0.
2-3	0.	0.	0.	0.	0.	0.
3-4	0.	0.	0.	0.	0.	0.
4-5	0.	0.	0.	0.	0.	0.
5-6	0.	0.	0.	0.	0.	0.
6-7	0.	0.	0.	0.	0.	0.
7-8	0.	0.	0.	0.	0.	0.
8-9	0.	0.	0.	0.	0.	0.
9-10	0.	0.	0.	0.	0.	0.
10-11	0.	0.	0.	0.	0.	0.
11-NOON	0.	0.	9500.	0.	0.	0.
NOON-1	0.	0.	9500.	0.	0.	0.
1-2	0.	0.	9700.	0.	0.	0.
2-3	0.	0.	10600.	0.	0.	0.
3-4	0.	0.	12100.	0.	0.	0.
4-5	0.	0.	12100.	0.	0.	0.
5-6	0.	0.	9500.	0.	0.	0.
6-7	0.	0.	9500.	0.	0.	0.
7-8	0.	0.	0.	0.	0.	0.
8-9	0.	0.	0.	0.	0.	0.
9-10	0.	0.	0.	0.	0.	0.
10-11	0.	0.	0.	0.	0.	0.
11-MN	0.	0.	0.	0.	0.	0.

AVERAGE ANNUAL INCREMENTAL OIL/GAS DISPLACEMENT= 600. BTU/KWH

Table C-8. Projected Oil or Gas Burned in 1989 by Utilities in Florida (Btu Per Incremental Kilowatt-Hour)

HOUR	SPRING OR FALL WEEKDAY	SPRING OR FALL WEEKEND/HOLIDAY	SUMMER WEEKDAY	SUMMER WEEKEND/HOLIDAY	WINTER WEEKDAY	WINTER WEEKEND/HOLIDAY
MN-1	0.	0.	0.	0.	0.	0.
1-2	0.	0.	0.	0.	0.	0.
2-3	0.	0.	0.	0.	0.	0.
3-4	0.	0.	0.	0.	0.	0.
4-5	0.	0.	0.	0.	0.	0.
5-6	0.	0.	0.	0.	0.	0.
6-7	0.	0.	9500.	0.	9900.	0.
7-8	9400.	0.	10200.	9500.	10600.	9700.
8-9	9700.	0.	10500.	9900.	10700.	10300.
9-10	10200.	9500.	10900.	10500.	10700.	10500.
10-11	10200.	9500.	11300.	10600.	10500.	10300.
11-NOON	10200.	9700.	11500.	10700.	10500.	10200.
NOON-1	10200.	9700.	11900.	10700.	10300.	9900.
1-2	10200.	9700.	11600.	10700.	10200.	9700.
2-3	10200.	9900.	11600.	10700.	10200.	9700.
3-4	10200.	9900.	11600.	10800.	10200.	9700.
4-5	10300.	10200.	11500.	11000.	10300.	9700.
5-6	10300.	10300.	11300.	10800.	10700.	10500.
6-7	10500.	10300.	10900.	10700.	11200.	10700.
7-8	10500.	10500.	10800.	10700.	11000.	10600.
8-9	10500.	10200.	10600.	10600.	10700.	10500.
9-10	9900.	9700.	10300.	10300.	10500.	10300.
10-11	9400.	9400.	9700.	9700.	10200.	9700.
11-MN	0.	0.	9400.	9400.	9500.	9500.

AVERAGE ANNUAL INCREMENTAL OIL/GAS DISPLACEMENT= 7100. BTU/KWH

Table C-9. Projected Oil or Gas Burned in 1989 by Utilities in South Central Region (SWPP) (Btu Per Incremental Kilowatt-Hour)

HOUR	SPRING OR FALL WEEKDAY	SPRING OR FALL WEEKEND/ HOLIDAY	SUMMER WEEKDAY	SUMMER WEEKEND/ HOLIDAY	WINTER WEEKDAY	WINTER WEEKEND/ HOLIDAY
MN-1	0.	0.	9500.	0.	0.	0.
1-2	0.	0.	0.	0.	0.	0.
2-3	0.	0.	0.	0.	0.	0.
3-4	0.	0.	0.	0.	0.	0.
4-5	0.	0.	0.	0.	0.	0.
5-6	0.	0.	0.	0.	0.	0.
6-7	0.	0.	9600.	0.	0.	0.
7-8	0.	0.	9800.	9500.	9600.	0.
8-9	9500.	0.	10100.	9700.	9600.	0.
9-10	9600.	0.	10300.	9900.	9600.	0.
10-11	9600.	0.	10600.	10100.	9600.	0.
11-NOON	9600.	0.	11100.	10200.	9600.	0.
NOON-1	9500.	0.	11200.	10300.	9500.	0.
1-2	9500.	0.	11400.	10400.	9500.	0.
2-3	9600.	0.	11500.	10400.	0.	0.
3-4	9500.	0.	11600.	10400.	0.	0.
4-5	9500.	0.	11400.	10500.	9500.	0.
5-6	9500.	0.	11200.	10400.	9600.	0.
6-7	9500.	0.	11000.	10300.	9600.	0.
7-8	9600.	0.	10600.	10200.	9600.	0.
8-9	9600.	0.	10400.	10200.	9600.	0.
9-10	0.	0.	10000.	9900.	9500.	0.
10-11	0.	0.	9700.	9700.	0.	0.
11-MN	0.	0.	9600.	9600.	0.	0.

AVERAGE ANNUAL INCREMENTAL OIL/GAS DISPLACEMENT= 4700. BTU/KWH

Table C-10. Projected Oil or Gas Burned in 1989 by Utilities in Mountain Region (WSCC-East) (Btu Per Incremental Kilowatt-Hour)

HOUR	SPRING OR FALL WEEKDAY	SPRING OR FALL WEEKEND/ HOLIDAY	SUMMER WEEKDAY	SUMMER WEEKEND/ HOLIDAY	WINTER WEEKDAY	WINTER WEEKEND/ HOLIDAY
MN-1	0.	0.	0.	0.	0.	0.
1-2	0.	0.	0.	0.	0.	0.
2-3	0.	0.	0.	0.	0.	0.
3-4	0.	0.	0.	0.	0.	0.
4-5	0.	0.	0.	0.	0.	0.
5-6	0.	0.	0.	0.	0.	0.
6-7	0.	0.	0.	0.	0.	0.
7-8	0.	0.	0.	0.	9500.	0.
8-9	0.	0.	0.	0.	11000.	0.
9-10	0.	0.	0.	0.	9500.	0.
10-11	0.	0.	11000.	0.	9500.	0.
11-NOON	0.	0.	11300.	0.	9500.	0.
NOON-1	0.	0.	12100.	0.	0.	0.
1-2	0.	0.	12400.	0.	0.	0.
2-3	0.	0.	12400.	0.	0.	0.
3-4	0.	0.	12100.	0.	0.	0.
4-5	0.	0.	11600.	0.	0.	0.
5-6	0.	0.	9500.	0.	12700.	0.
6-7	0.	0.	0.	0.	13200.	0.
7-8	0.	0.	0.	0.	12100.	0.
8-9	0.	0.	0.	0.	9500.	0.
9-10	0.	0.	0.	0.	0.	0.
10-11	0.	0.	0.	0.	0.	0.
11-MN	0.	0.	0.	0.	0.	0.

AVERAGE ANNUAL INCREMENTAL OIL/GAS DISPLACEMENT= 1300. BTU/KWH

Table C-11. Projected Oil or Gas Burned in 1989 by Utilities in Pacific Region (WSCC-West) (Btu Per Incremental Kilowatt-Hour)

HOUR	SPRING OR FALL		SUMMER		WINTER	
	WEEKDAY	WEEKEND/ HOLIDAY	WEEKDAY	WEEKEND/ HOLIDAY	WEEKDAY	WEEKEND/ HOLIDAY
MN-1	0.	0.	0.	0.	0.	0.
1-2	0.	0.	0.	0.	0.	0.
2-3	0.	0.	0.	0.	0.	0.
3-4	0.	0.	0.	0.	0.	0.
4-5	0.	0.	0.	0.	0.	0.
5-6	0.	0.	0.	0.	0.	0.
6-7	9500.	0.	10400.	0.	10900.	0.
7-8	10800.	0.	11100.	0.	12200.	9800.
8-9	11000.	9500.	11900.	9800.	12300.	10500.
9-10	11100.	9500.	12500.	10100.	12200.	10900.
10-11	11000.	9500.	12800.	10500.	12400.	10700.
11-NOON	10900.	9500.	12800.	10400.	12000.	10800.
NOON-1	10900.	0.	13200.	10500.	11900.	10500.
1-2	11000.	0.	13500.	10500.	11900.	10400.
2-3	10900.	0.	13400.	10500.	11700.	10100.
3-4	10700.	0.	12900.	10500.	11700.	10100.
4-5	10500.	0.	12500.	10500.	12300.	10900.
5-6	10800.	0.	12100.	10400.	14700.	11600.
6-7	11000.	9800.	11900.	10400.	13500.	11200.
7-8	11100.	10000.	11900.	10500.	12600.	11000.
8-9	11000.	9800.	11200.	10100.	12200.	10700.
9-10	10400.	0.	10500.	9500.	11300.	10400.
10-11	9500.	0.	9500.	0.	10700.	9800.
11-MN	0.	0.	0.	0.	9700.	0.

AVERAGE ANNUAL INCREMENTAL OIL/GAS DISPLACEMENT= 7100. BTU/KWH

Table C-12. Load Projections

Region	1978[a] Actual Energy For Load (Billion kWh)	1989[b] Projected Energy For Load (Billion kWh)	Percent Annual Load Growth Rate (1978-1989)
East Central (ECAR)	363.3	550.0	3.84
Texas (ERCOT)	147.3	250.0	4.93
Mid Atlantic (MAAC)	165.4	236.9	3.30
Mid West (MAIN)	160.7	237.2	3.60
North Central (MARCA)	94.3	154.6	4.60
Northeast (NPCC)	197.6	249.0	2.12
Southeast (SERC less Florida)	359.7	571.4	4.28
Florida (less panhandle)	85.1	135.6	4.33
South Central (SWPP)	199.9	335.9	4.83
Mountain (WSCC-East)	108.4	197.5	5.61
Pacific (WSCC-West)	298.8	465.9	4.12

Sources: [a]Reference 14
[b]Reference 11

Table C-13. Capacity Projections

Region	1978[a] Actual Capacity (1,000 MW)	1989[b] Projected Capacity (1,000 MW)	Percent Annual Growth Rate (1978-1979)
East Central (ECAR)	85.6	123.9	3.42
Texas (ERCOT)	39.0	59.9	3.91
Mid Atlantic (MAAC)	44.4	55.8	2.10
Mid West (MAIN)	40.3	58.8	3.49
North Central (MARCA)	21.7	34.8	4.39
Northeast (NPCC)	50.7	62.4	1.91
Southeast (SERC less Florida)	85.0	132.8	4.14
Florida (less panhandle)	21.7	32.0	3.59
South Central (SWPP)	48.0	79.1	4.65
Mountain (WSCC-East)	25.1	43.5	5.13
Pacific (WSCC-West)	69.3	105.8	3.92

Sources: [a]Reference 14
[b]Reference 12

APPENDIX D

GLOSSARY

APPENDIX D

GLOSSARY

The following is a list of terms and acronyms frequently used in discussions of cogeneration. The selection of terms was based primarily on those used in this handbook, although other frequently used terms are also included.

AEP - American Electric Power Company

APCD - Air Pollution Control District

APCO - Appalachian Power Company

AQCR - Air Quality Control Region

AQMA - Air Quality Maintenance Area

ARB - Air Resources Board

BACT - Best Available Control Technology (see Section 3.1, Environmental Regulations and Standards)

Base Load - The minimum load of electric power which is generated or supplied continuously over a period of time.

Bottoming cycle - Waste heat from an industrial process utilized for the generation of electricity.

Bottoming cycle, organic - The utilization of low-temperature waste heat from an industrial process for the generation of electricity in a system using an organic working fluid.

Bottoming cycle, steam - The utilization of waste heat from an industrial process for the generation of electricity using a steam turbine.

Brayton cycle - A reversible thermodynamic cycle that describes the heat-to-work conversion process in a gas turbine power plant.

By-product power - Power that is generated in conjunction with an industrial process that optimizes or matches the generation of electricity to the steam and/or heat requirements.

Capacity - The load for which a generating unit, generating station, or other electrical apparatus is rated, either by user or by manufacturer.

Capacity factor - The ratio of the average load on a machine or piece of equipment for the period of time considered to the capacity rating of the machine or equipment.

Capital cost - Cost of construction of new plant (additions, improvements, and replacements) and expenditures for the purchase or acquisition of existing facilities.

Central power generation, steam - Electricity generated by a utility at a large power generating plant, the primary purpose of which is the generation of electricity.

CFR - Code of Federal Regulations, published by the Office of the Federal Register, available from U.S. Government Printing Office. References to CFR cited by volume and part; e.g., 10 CFR 500.2 is volume 10 the Regulations, beginning with part 500.2.

Cogeneration - also, dual-purpose power plant - The generation of process steam, process heat,or space conditioning combined with the generation of electrical power, which leads to an efficiency of fuel utilization greater than that resulting from the independent generation of equivalent units of process steam, process heat, space conditioning, and electrical power.

Combined cycle - Waste heat from a gas turbine topping cycle is used for the generation of electricity in a steam turbine/generator system.

Condensing power - Power generated through a final steam turbine stage where the steam is exhausted into a condenser and cooled to a liquid to be recycled back into a boiler.

COWPTA - Crude Oil Windfall Profits Tax Act of 1980, (Section 4.1.4).

DB - declining balance, depreciation method

DCF - discounted cash flow

DDB - double declining balance, depreciation method

Demand Charges - part of utility service charged on the basis of the possible demand as distinguished from actual energy consumed

DOE - Department of Energy

DRI - Data Resources, Inc., 29 Hartwell Avenue, Lexington, Massachusetts, 02173.

ECAR - East Central Area Reliability Coordination Agreement, one of nine National Electric Reliability Council Regions.

EPA - Environmental Protection Agency

ERA - Economic Regulatory Administration

ERCOT - Electric Reliability Council of Texas, one of nine National Electric Reliability Council Regions.

ERDA - Energy Research and Development Administration, predecessor to present Department of Energy

ERTA - Economic Recovery Tax Act of 1981

ESP - Electrostatic precipitator

ETA - Energy Tax Act of 1978 (see Section 4.1.3).

FERC - Federal Energy Regulatory Commission

FGD - Flue gas desulfurization

Field assembled boiler - A high-pressure boiler which usually has a large capacity and is usually too large to be shop assembled and transported.

FR - Federal Register; references to the Federal Register cited by volume, page number, and date, e.g.,44 FR 28950 (6 June 1980), etc.

FUA - Powerplant and Industrial Fuel Use Act of 1978.

Fully Fired Recovery Boiler - A recovery boiler in which the oxygen content of the flue gases is the same as that obtained from a boiler operating with ambient air.

GNP - Gross National Product

Grid - A utility's power generation, transmission and distribution system, including transmission lines, transformer stations, etc.

Heat rate - A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting kilowatt-hour generation.

Heat recuperators - Equipment used to recycle heat back into the process improving the thermal efficiency of the overall process.

High-grade waste heat - Waste heat in the high-temperature range of 1000°F or above which can be used for power generation in a steam turbine.

ICOP - Industrial Cogeneration Optimization Program, Department of Energy

IOP Model - Name of discounted cash flow/internal rate of return computer model illustrated in this handbook, Section 2.3.

Interruptible power - Power made available under agreements which permit curtailment or cessation of delivery by the supplier. Advance notice is usually given from 1 to 1-1/2 hours prior to the interruption.

Investment tax credit - A specified percentage of the dollar amount of new investment in each of certain categories of assets that a firm can deduct as a credit against its income tax.

IRR - Internal Rate of Return - the discount rate that equates the present value of expected future receipts to the cost of the investment outlay.

LAER - Lowest Achievable Emission Rates

LEA - low excess air (see Section 3.1, Environmental Regulations and Standards)

Load - The amount of electric power delivered or required at any specified point or points on a system. Load originates primarily at the customers' power-consuming equipment.

Load factor - The ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load occurring in that period.

Low grade waste heat - Waste heat in the temperature range of less than 1000°F.

MAAC - Mid Atlantic Area Council, one of nine National Electric Reliability Council Regions.

MAIN - Mid-America Interpool Network, one of nine National Electric Reliability Council Regions.

MARCA - Mid-Continent Area Reliability Coordination Agreement, one of nine National Electric Reliability Council Regions.

Megawatt (MWe) - One million watts of electric power.

MFBI - Major fuel-burning installation

NAAQS - National Ambient Air Quality Standards

NEA - National Energy Act of 1978

NERC - National Electric Reliability Council, consisting of nine regions: ECAR, ERCOT, MAAC, MAIN, MARCA, NPCC, SERC, SPP, and WSCC.

NGPA - Natural Gas Policy Act of 1978 (see Section 4.1.2).

NOPR - Notice of Proposed Rulemaking

NPCC - Northeast Power Coordination Council, one of nine National Electric Reliability Council Regions.

NPV - Net percent value - a capital budgeting method that accounts for the time value of money through discounted cash flow analysis. The method determines the present value of the expected net revenue from an investment minus the cost outlay, discounted at the cost of capital.

NSPS - New Source Performance Standards (see Section 3.1, Environmental Regulations and Standards).

O&M - operations and maintenance

ORA - Omnibus Reconciliation Act of 1981

Package boilers - A low-pressure boiler, usually small enough to be shop assembled. It generally burns gas or liquid fuels.

Parallel generation - Industrial power generation facilities whose AC frequencies are exactly equal to and are synchronized with the utility service grid.

Payback period - The number of years required for a firm to recover the original investment from net returns before depreciation but after taxes.

Peak load - The maximum load demand occurring during a specified period of time.

Peak load management - An attempt to reduce the system peak load by leveling the load curve.

Power factor - The ratio of real power to apparent power for any given load and time. Generally, it is expressed as a ratio.

Preheaters - Equipment used to pre-heat the intake air prior to entering a combustion process, thus creating a higher thermal efficiency for the overall process.

Prime Mover - The component of a powerplant that transforms pressure or thermal energy to useful mechanical energy.

Process heat - Heat used for an industrial process in a plant and not for housekeeping chores such as space heating.

Process steam load - Number of pounds of steam per hour required for a specified industrial process.

PSD - Prevention of Significant Deterioration (see Section 3.1 - Environmental Regulations and Standards).

PURPA - Public Utility Regulatory Policies Act of 1978 (see Section 4.1.1).

PV - present value - The real value of a cash flow adjusted for the interest that could be earned or must be paid between the time of actual flow and the specified "present" time.

Qualified Energy - steam, heat, or other forms of useful energy other than electric energy, for use in industrial, commercial, or space heating purposes other than in the production of electricity.

Rankine cycle - A reversible thermodynamic cycle that describes the heat-to-work conversion process in a steam power plant.

Rate base - The value of assets, established by a regulatory authority, which a utility is permitted to earn a specified rate of return. Generally, this represents the amount of property used and useful in public service.

RCRA - Resource Conservation and Recovery Act

ROI - return on investment

SCA - Staged combustion air, see Section 3.1

SCF - Standard cubic feet of gas at a temperature of 60°F and a pressure of 30 inches of mercury.

SERC - Southeast Electric Reliability Council, one of nine National Electric Reliability Council regions.

Sinking fund - Cash or other assets, and the interest or other income earned thereon, set apart for the retirement of a debt, the redemption of a stock, or the protection of an investment in depreciable property.

SL - straight-line depreciation.

Spinning Reserve - Generating capacity that is on-line and ready to take load, but in excess of the current load on the system.

SPP - Southwest Power Pool, one of nine National Electric Reliability Council regions.

SRC - State Regulatory Commission

Standby service - also Standby power or Standby reserve - Service that is not normally used but that is available through a permanent connection in lieu of, or as a supplement to, the usual source of supply.

Sunk costs - Costs that have already been committed and thus are irrelevant to future investment decisions.

Supplementary Fired Recovery Boiler - A recovery boiler in which the average gas temperature after fuel combustion is 1800°F or less. The oxygen content of the flue gases of a supplementary fired boiler is higher than that obtained from a boiler operating with ambient air.

Surplus electricity - Energy generated that is beyond the immediate needs of the producing system. This energy is frequently obtained from spinning reserve and sold on an interruptible basis.

SYD - Sum-of-years'-digits, depreciation method

T&D - Transmission and distribution

TDS - Total dissolved solids

Topping cycle - also, engine topping - Energy is first used to generate electricity then used in an industrial process.

Topping cycle, back-pressure steam turbine - Steam is generated in a boiler then sent through a turbine generator, producing electricity. The steam is discharged from the last stage of the turbine at pressures needed for industrial process use.

Topping cycle, extraction steam turbine - This system operates in a similar manner to the back-pressure steam turbine, except that steam is extracted at different pressures from intermediate stages of the turbine and used in industrial processes, while the steam exhausting from the final stage is condensed and returned to the boiler for reuse.

Topping cycle, gas turbine/waste heat boilers - Compressed air and a gaseous fuel or light petroleum product are fired in a gas turbine. The hot combustion gases pass through a turbine-generator, producing electricity. The hot exhaust gases from the turbine are passed over waterfilled tubes in a waste-heat boiler, producing steam at pressures needed for industrial process use.

Total energy system - On-site generation of electricity with beneficial use of waste heat.

Turbine - An enclosed rotary type of prime mover in which heat energy in steam or gas is converted into mechanical energy by the force of a high velocity flow of steam or gases directed against successive rows of radial blades fastened to a central shaft.

TVA - Tennessee Valley Authority

Utility cogeneration - Utilization of waste heat from a central power generating plant to produce either thermal energy to sell for space or process heat.

VACAR - Virginia-Carolinas Reliability Group, a utility power pool

Waste heat - Unused thermal energy that is exhausted to the environment from an electric generation system or an industrial process.

Wheeling - The use of the transmission facilities of one system to transmit power of and for another system.

Wheeling charges - Price of wheeling power.

Working capital - The amount of cash or other liquid assets that a company must have on hand to meet the current costs of operations until such a time as it is reimbursed by its customers.

WSCC - Western Systems Coordination Council, one of nine National Electric Reliability Council Regions.

APPENDIX - E

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SELECTED REFERENCES

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