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MONTANA BIOMASS COGENERATION MANUAL:

A WORKSHOP HANDBOOK

Prepared for

MONTANA DEPARTMENT of NATURAL RESOURCES and CONSERVATION

MONTANA BIOMASS COGENERATION MANUAL: A WORKSHOP HANDBOOK

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I. INTRODUCTION

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A. BACKGROUND

According to the General Accounting Office, U.S. industry and electric utilities use nearly half the primary energy consumed, and the waste heat from power generation and process energy use amounts to over seven million barrels per day oil equivalent (1). Cogeneration can offer a method to reduce the amount of waste heat by simultaneously producing electricity and useful thermal energy from a common primary energy source. Because of its potential for efficient use of energy, cogeneration is receiving increasing attention in the U.S.

The concept of cogeneration is not new. Industrial generation of electricity has been practiced for a long time. In the early 1900's, most industrial plants generated their own electricity and approximately half of this was using cogeneration (2). On-site generation/cogeneration was more reliable and less expensive than utility generated power. However, in the 1920's and 1930's, the regulation of electric utilities, first by state agencies and then by the Federal government, resulted in elimination of unproductive competition, and consolidation and extension of utility service areas. Coupled with the availability of inexpensive fuels for power generation and technological advances in central station utility generation and transmission of electricity, industrial generation/cogeneration became economically less attractive. From the 1920's to the mid-1970's, there was a generally declining trend in the proportion of electricity cogenerated in industry (3). Other factors contributing to this declining trend included the following:

- Industry was hesitant to invest in generation because of the possibility of Federal and state regulation as a utility, and the related reporting requirements.

- Utilities offered very low prices for excess power sold by an industry to a utility.
- Utilities charged high prices for standby or supplemental power needed by the cogenerator.

As a result, industrial generation declined from 18% of total electric generation in 1941 to about 4% in 1977 (4).

In the last decade, the energy situation in the United States has undergone a significant transition. The nation has faced increasing prices and decreasing availability of conventional energy sources, energy supply disruptions, environmental constraints to the utilization of coal, and high capital costs for expanding the energy delivery system. Efficient utilization of our energy resources has become a very high priority and cogeneration has become economically attractive. At the same time, Federal legislation has attempted to remove some of the institutional barriers to cogeneration and small scale power production. Moreover, the problems faced by electric utilities have resulted in increased interest, on their part, in industrial cogeneration.

Industry facing rapidly escalating energy costs is searching for alternative methods to obtain its future energy requirements. Cogeneration offers the potential for increased efficiency of energy use, less uncertainty in energy costs and more reliable supply of energy. Moreover, the recent regulatory changes (discussed below) provide industry an opportunity to obtain significant economic benefits from cogeneration.

Many electric utilities are facing financial problems of unprecedented magnitude. New generating capacity committed in the 1968-1974 time frame, when demand forecasts were growing at an annual rate of 7-10 percent, has been mostly deferred or cancelled. Few large projects have been completed. The basic problems faced by the utilities include high costs of new capacity, high interest rates, escalating fuel costs, environmental/siting constraints, increased customer resistance to rate increases and regulatory lag.

These problems, coupled with slower load growth, have led to lower revenues than forecast, while the capital requirements for new capacity have continued to escalate rapidly. These utilities, looking ahead to the late 1980's, see their best prospects in completing plants now almost completed, and to some extent, discouraging increases in load growth with the expectation that a two percent annual growth rate will be manageable, allowing time for their economic situation to stabilize before having to undertake another new plant. As part of this basic approach it would be advantageous to flatten the system load curve and to reduce or eliminate use of expensive peaking generation requiring use of high cost fuels in relatively inefficient power plants. Cogeneration could contribute significantly in this approach. In addition, utilities may be able to raise capital through innovative financing schemes such as joint ventures or third party arrangements to build new capacity for cogeneration.

The significant changes in the economic and institutional aspects of power generation, which occurred in the 1970's and are expected to continue in the 1980's, have created a trend towards increased interest in and acceptance of industrial cogeneration by utilities. These changes have led utilities not only to consider industrial cogeneration in their planning for future capacity needs, but have also resulted in the growing recognition of cogeneration systems as a utility business opportunity. Cogeneration ventures, owned and operated by a utility, can be highly complementary to traditional utility operations and possibly offer a potential for higher profits than the traditional utility business. Utilities are therefore increasingly interested in examining opportunities for participation in industrial cogeneration projects (6).

B. BIOMASS AS AN ENERGY RESOURCE

Cogeneration systems can be fired with conventional as well as non-conventional fuels. Among the non-conventional fuels, biomass is an important energy source. The use of biomass as an energy resource is not a new idea either. In the mid-1800's wood supplied over 90% of our energy needs; and as late as 1940, 20% of the homes in the U.S. used wood for space heating.

In the wake of the first oil shock that started raising the costs of fossil fuels, biomass fuels once again became a focus of interest as an alternate source of energy. Biomass residues are a renewable energy resource which are primarily produced as wastes or by-products of industrial and agricultural production. Biomass residues typically possess limited economic value and may even carry a significant economic penalty for their disposal. Conversion technologies that can economically convert biomass residues to usable energy are currently commercially available.

The greatest potential for biomass residue utilization resides in the on-site or local use of residues that are accumulated at central locations. Examples are timber mill wastes, cotton gin trash, dairy and feedlot manures, and food processing wastes. Economic incentives for biomass residue utilization are increased when the residue carries an associated disposal cost. Examples are some food processing and lumber mill wastes, cotton gin trash, orchard prunings, and rice straw.

The utilization of biomass residues as an energy fuel need not be limited to those industries which produce the residues. Industries located near central collection points for biomass residues may contract with their owners for supply of these residues. Alternatively, an industry may be supplied with biomass fuels by a firm which may have recently formed to process and market biomass residues acquired from surrounding industries.

The utilization of biomass residues for fuel also need not be limited to new biomass conversion installations. Many plants have fossil fuel fired boilers that still have significant operating lives remaining. There are several options available for retrofit of these boilers to biomass residue use.

This manual will provide a broad description of cogeneration technologies and biomass fuels that can be used to fire the cogeneration systems. Brief case studies of five working biomass fueled cogeneration systems are presented in Appendix A. A resource list of manufacturers/suppliers of prime-movers and multi-fuel boilers for cogeneration systems is given in Appendix B.

II. COGENERATION TECHNOLOGIES

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A. INTRODUCTION

Cogeneration is defined as the sequential production of two forms of output energy from the same energy input. Typically, cogeneration systems produce electrical and thermal energy. The thermal energy may be in the form of steam, hot water or hot air. A system that produces mechanical energy, e.g., shaft power to drive process equipment, and at the same time produces thermal energy to meet process requirements, is also a cogeneration system. This discussion of cogeneration technologies will focus on systems capable of producing electricity and steam, because this is the primary form of cogeneration in use. Schematically, mechanical cogeneration systems are similar to electrical ones except that a compressor, pump or fan is substituted for the electrical generator. When electricity or shaft power is the first output, the system is called a Topping Cycle, and when the thermal output is produced first it is termed a Bottoming Cycle.

Several cogeneration technologies are being used by industry or are under development, because no single technology will meet the requirements of all cogeneration applications. For a specific application, the characteristics of the industrial process and the cogeneration system must be compatible for cogeneration to be technically and economically feasible. The following characteristics must be considered when selecting a cogeneration system:

- Applicable size range
- Total installed cost
- Fuels required
- Ratio of electric energy to thermal energy output, and ease of varying this ratio during operation

- Operation and maintenance requirements
- Part load performance
- Turn down (i.e., minimum output)
- Construction time.

Cogeneration technologies suitable for use with biomass-derived fuels that are presently in use include:

1. Steam Turbines
2. Combustion Turbines
3. Internal Combustion Engines
4. Combined-Cycle Systems
5. Bottoming Cycles

In addition, a great deal of research and development effort is being focused on developing more efficient and/or more economical systems. Two of these are the closed-cycle gas turbine and the fuel cell.

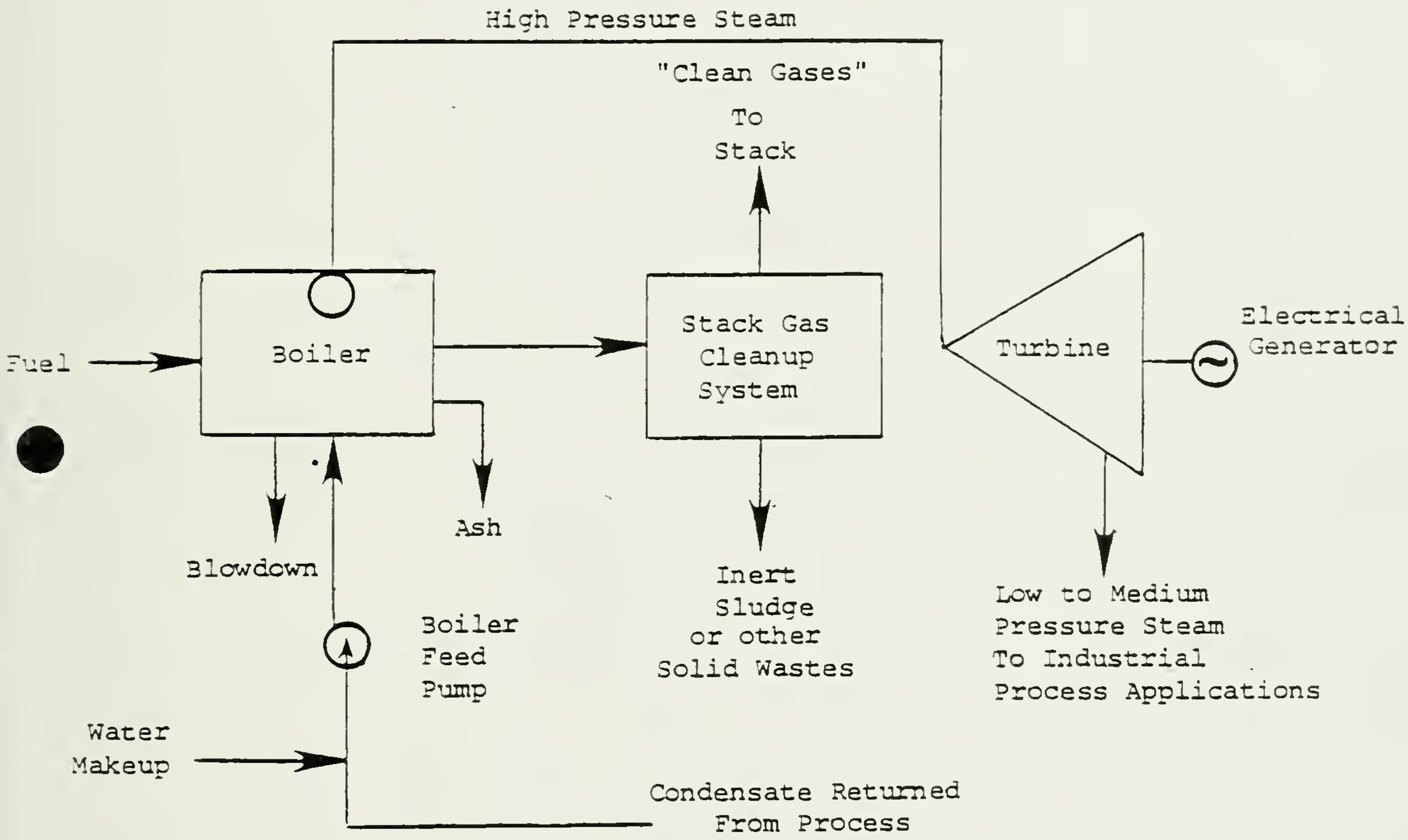
B. SYSTEM DESCRIPTIONS

1. Steam Turbine Systems

A schematic diagram of a conventional steam turbine (ST) cogeneration system (topping cycle) is shown in Figure II-1. This system utilizes a backpressure turbine. High pressure steam from the boiler is expanded in the turbine, which in turn drives an electrical generator to produce electricity. The low- to medium-pressure steam (i.e. steam at pressures less than 600 pounds per square inch) exiting the turbine exhaust is used to meet process thermal requirements. The condensate returning from the process is usually less than the steam delivered to it because of losses or consumption.

Figure II-1

COGENERATION SYSTEM WITH A BACKPRESSURE STEAM TURBINE



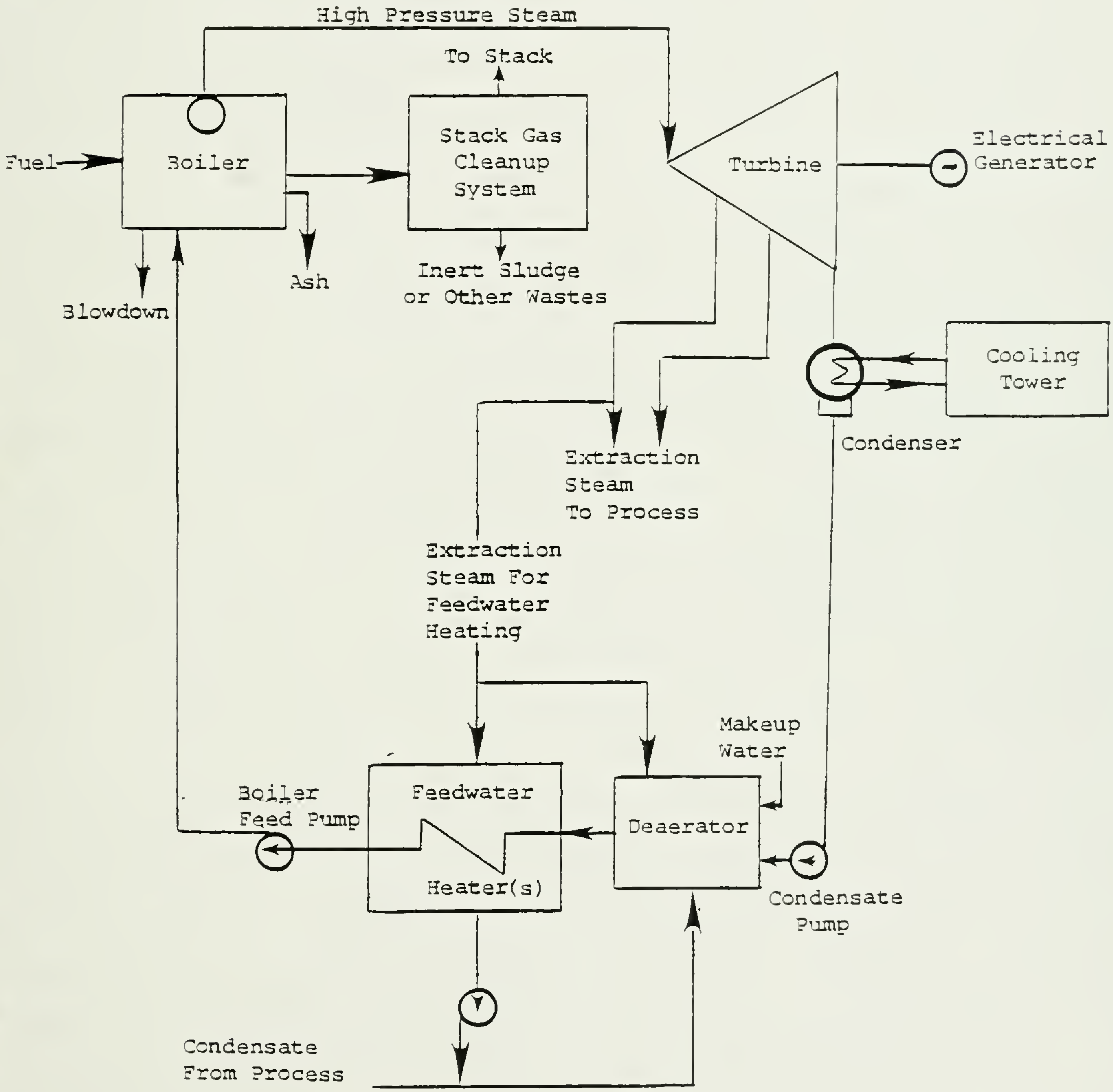
A schematic diagram of a cogeneration system using an extraction/condensing steam turbine is shown in Figure II-2. In this system, some of the steam exits the turbine at one or more intermediate points and supplies the process requirements while a large fraction of the steam is expanded in the turbine to a vacuum condition. A small amount of the extraction steam is used to meet auxiliary steam requirements and to heat the feedwater returning to the boiler. Although not shown in Figure II-1, a backpressure turbine system usually is designed to allow the extraction of all the steam at intermediate pressures. Feedwater heating is one of three system design enhancements used to increase overall system efficiency, but which also increase system cost. The other two (not shown in the figures) use either boiler blowdown or hot stack gases to pre-heat the incoming make-up water and/or returned condensate.

A backpressure steam turbine system is the least expensive steam turbine cogeneration system because it does not need a separate heat rejection system (i.e., cooling tower) or a condenser. It is more efficient than a condensing system because the thermal energy from the boiler is not lost in a cooling tower. A backpressure turbine is also less expensive than a condensing turbine. However, the quantity of electrical energy available is directly proportional to the steam requirements of the industrial process. This has two consequences: (a) the ratio of electrical output to thermal output is smaller, and (b) the electrical output of a backpressure system decreases proportionately with the decrease in process steam requirements.

A condensing steam turbine cogeneration system (such as that shown in Figure II-2), is more flexible than a backpressure system. If the process steam requirements decrease, the electrical output can remain constant or even increase by increasing the steam flow to the condenser, assuming the turbine and condenser have sufficient capacity. Alternatively, if electrical power requirements decrease, the rate at which steam is extracted from the turbine can be

Figure II-2

COGENERATION SYSTEM WITH AN EXTRACTION CONDENSING STEAM TURBINE



increased. In many applications, this added flexibility and the additional electrical output per unit steam flow to process may offset the increased cost of a condensing system.

Figures II-1 and II-2 show a biomass-fired (or coal-fired) boiler with a stack-gas cleanup system to remove particulates and other contaminants that typically occur when solid fuels are burned. Boilers fired by gaseous or liquid fuels derived from biomass (or by natural gas or fuel oil) usually do not require a scrubber, but the cost of equipment that generates "clean" fuel forms from "dirty" solid forms may be quite significant.

An alternative to a conventional boiler for use with wood, wood wastes, coal, and other solid fuels is the fluidized-bed boiler. An atmospheric fluidized bed (AFB) boiler eliminates the need for a complex flue gas treatment system. AFB boilers can also burn fuels that cannot be used in conventional boilers.

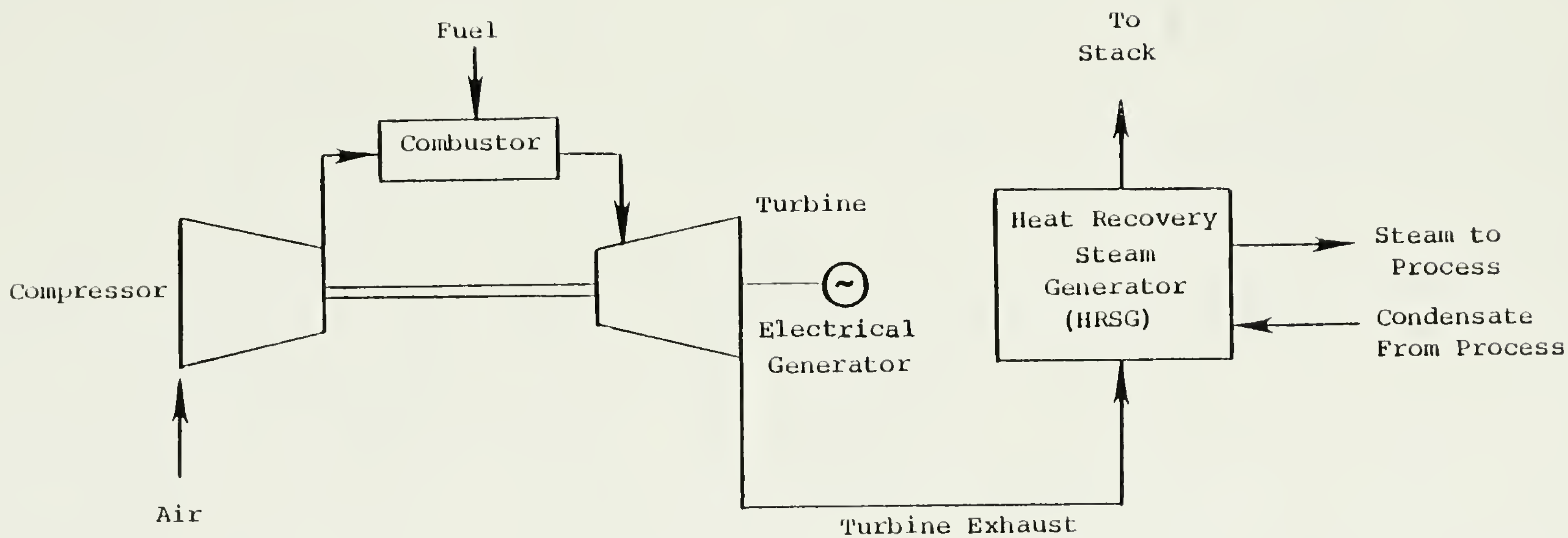
In a fluidized-bed combustion boiler, fuel is burned in a bed of inert particles suspended by air currents in the combustion zone. The bed is in constant motion, similar to a boiling liquid. This results in rapid heat transfer to the boiler tubes, located in the fluidized bed or the combustion chamber walls. The stack gases usually are cooled and passed through large fabric bags to remove particulate emissions.

2. Combustion Turbine Systems

A schematic diagram of a combustion turbine (CT) cogeneration system is shown in Figure II-3. A combustion turbine (sometimes called a gas turbine) consists of a compressor and a turbine connected by a common shaft, and a combustor. Ambient air is compressed, heated to a high temperature in the combustor, and the hot gases are then expanded in the turbine. The energy from the expanding gases is used

Figure II-3

COMBUSTION TURBINE COGENERATION SYSTEM



to drive both the compressor and generator, and the hot turbine exhaust gases are used to produce process steam in a heat exchanger. If a larger ratio of steam to electricity is needed, additional fuel is burned in the heat recovery steam generator.

Gas turbine cogeneration systems can supply steam at very high pressures, up to 1500 psia. Their principal disadvantage is that they burn only relatively expensive, "clean" gaseous or liquid fuels. However, since CT systems are modular, construction time is less than that required for steam turbine systems. At sizes less than several megawatts, CT systems are also more economical than steam turbine systems.

3. Internal Combustion Engines

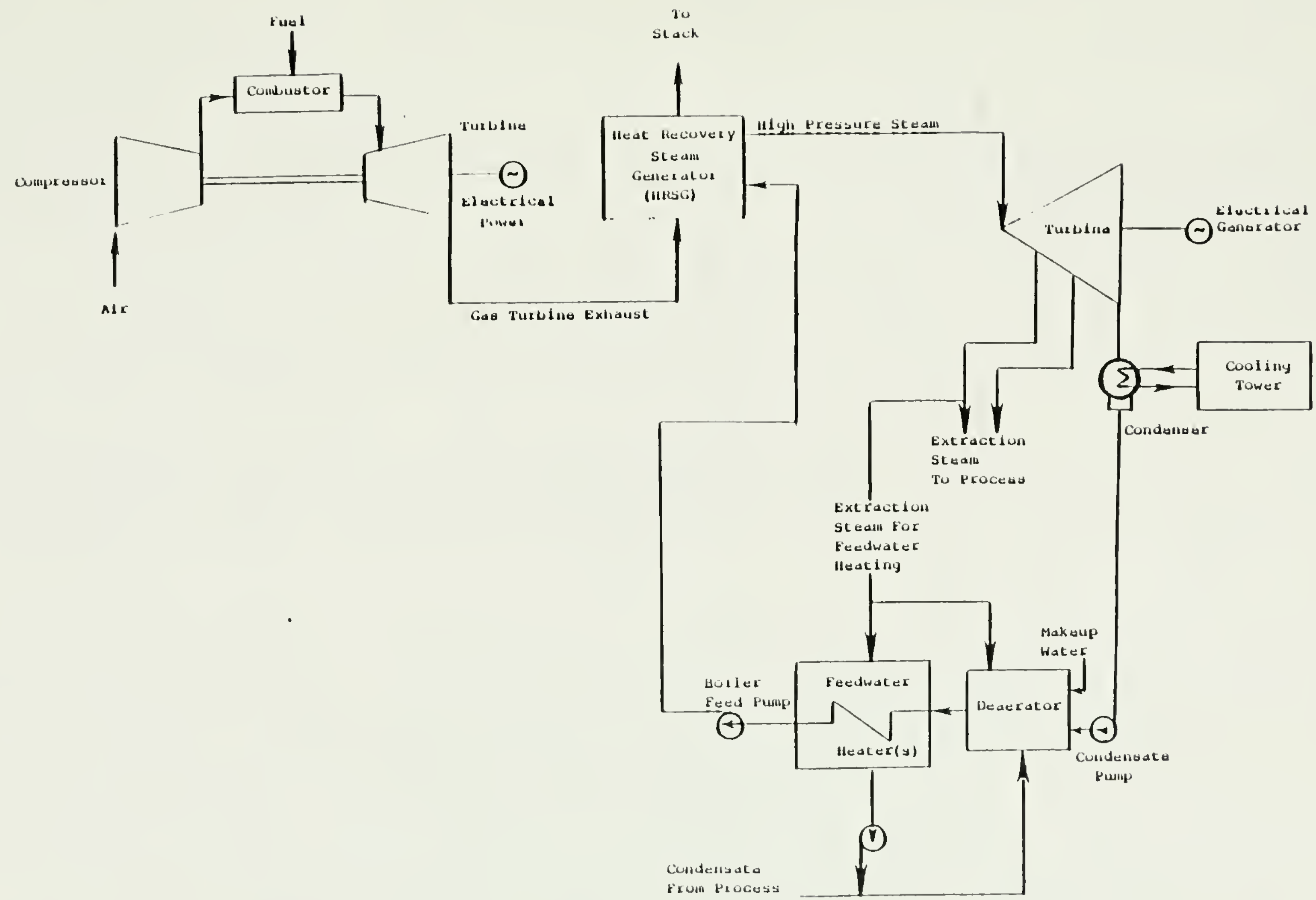
Internal combustion (IC) engines also require very "clean" liquid or gaseous fuels. By connecting a heat recovery steam generator to the exhaust, an engine can cogenerate steam and electric power. Hot water can be produced in the engine jacket and oil cooler. If steam is not required, heat recovered from the engine exhaust, in addition to the heat from the engine jacket and oil cooler, can be used to heat large quantities of water. The ratio of electricity to heat is larger than with a CT system. IC engines are available in a wide range of sizes and are particularly attractive for use in smaller cogeneration systems. Because engine-based systems are modular and factory built, construction time can be quite short.

4. Combined-Cycle Cogeneration Systems

As shown in Figure II-4, a combined-cycle (C-C) cogeneration system consists of a gas turbine and a bottoming steam turbine cycle. The gas turbine exhaust is used to generate steam for process heating and to generate electricity in a steam turbine. Process steam can also be extracted from the steam turbine.

Figure II-4

COMBINED-CYCLE COGENERATION SYSTEM



A C-C system is more complex and more expensive (per kW of electrical output) than either a CT or a ST cogeneration system, and they are generally used only in sizes greater than 50 MW. Since large quantities of biomass fuels usually are not available at one location, it is unlikely that C-C systems will be used with biomass fuels (these are the same fuels used with CT systems). The C-C system has a higher energy conversion efficiency at part load than either a CT or ST system, because a combined-cycle system is more flexible in adjusting to varying steam and electric loads.

5. Bottoming Cycle Systems

Bottoming cycle cogeneration is essentially the recovery of "waste" heat from a process to generate mechanical or electric power. The concept is shown in Figure II-5. In industrial applications, prime candidates for bottoming cycles would be processes that exhaust heat at high temperatures. In principle, any external-combustion heat engine may be used in this cycle (e.g., Rankine, Brayton and Stirling cycle engines). In practice, however, only the Rankine and Brayton cycles are usually considered, because Stirling engines have not been developed sufficiently.

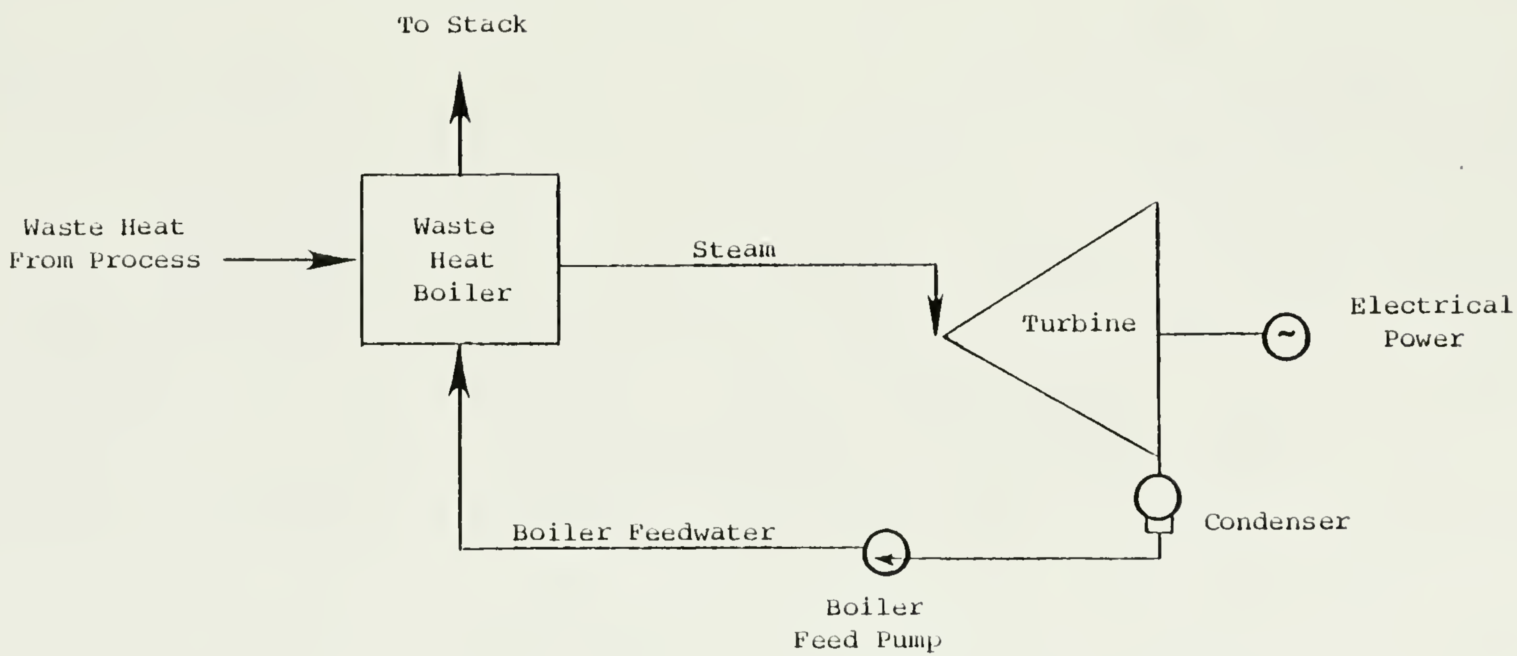
- Steam Rankine Cycle

In the steam Rankine bottoming cycle, high temperature waste heat from any process (e.g., metal refining and treatment, glass and cement manufacture) produces steam in waste heat boilers. The steam is used to drive a steam turbine, which in turn drives a generator to produce electricity. The expanded steam is condensed in a condenser and pumped back to the boiler, usually after being heated in a regenerator.

In addition to the advantages of ready availability, and well-established technology, the steam Rankine cycle is attractive for bottoming cycle applications because it has a good efficiency and moderate capital cost for most of the temperature and size ranges of

Figure II-5

STEAM RANKINE BOTTOMING CYCLE



interest. Steam turbine bottoming cycles are most suited to applications where the available waste heat has a temperature between 500°F and 1200°F. These advantages are counterbalanced by certain inherent difficulties due to the physical properties of water, the working fluid. Since water can become very corrosive when it contains certain kinds of impurities, strict control has to be maintained over its composition. Because of the thermodynamic properties of water, the system has to be operated at a pressure of several hundred pounds per square inch, which increases the cost of the piping, pumps, valves, etc. The steam should be superheated to avoid erosion of the turbine blades that results from impingement of water droplets.

Although the above mentioned problems, common to ST topping cycles and C-C plants, have well established solutions, they do lead to higher complexity, cost and maintenance demands. These factors become more significant at the lower power levels appropriate for bottoming cycles as a consequence of the quantity of waste heat available at 500°F or more.

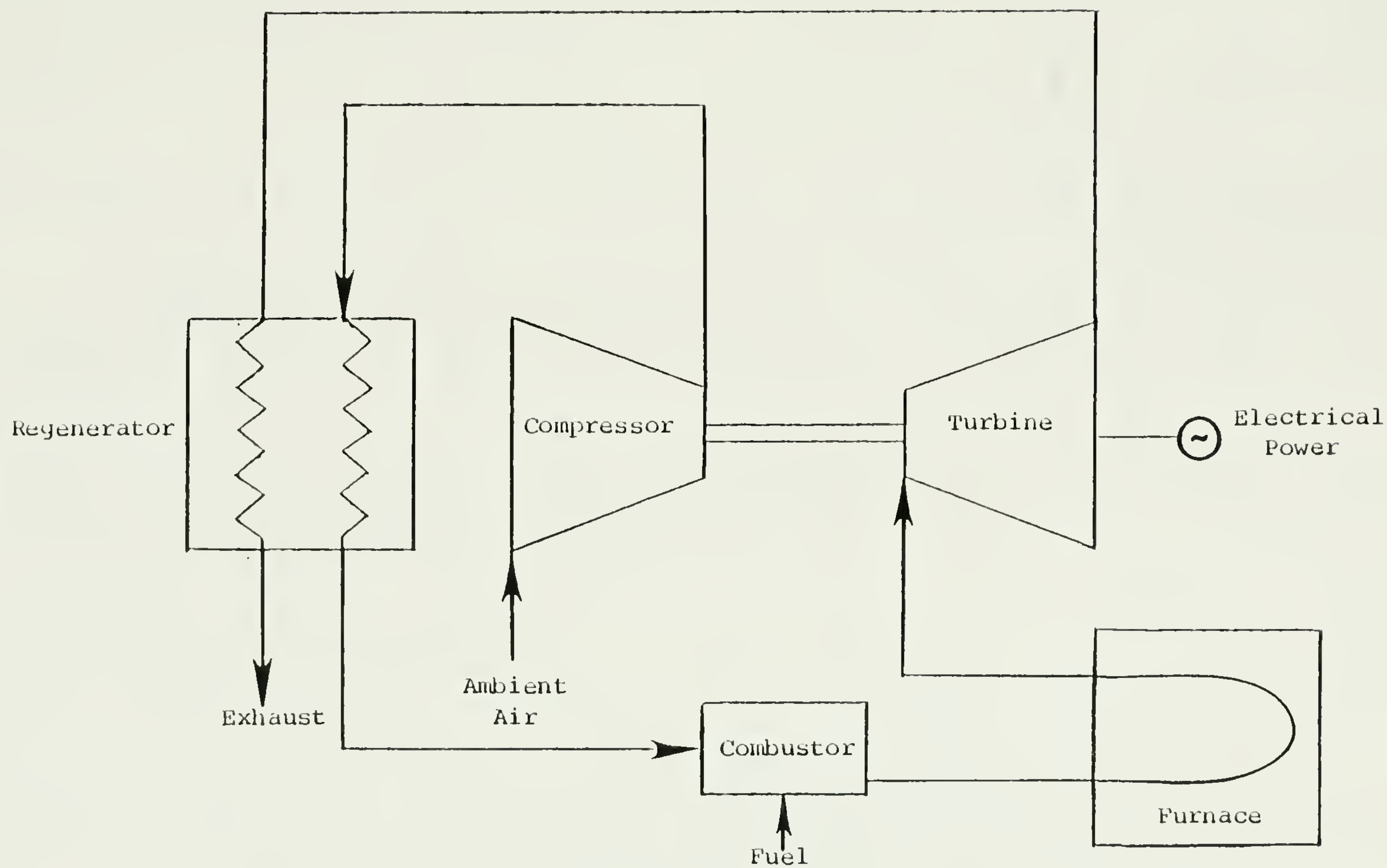
- <u>Organic Rankine Cycle</u>

The configuration of an organic Rankine bottoming cycle is essentially the same as a steam Rankine bottoming cycle. The basic difference between the two cycles is that an organic Rankine cycle uses an organic compound, such as toluene, as the working fluid, rather than water.

There are several reasons for preferring organic fluids rather than water in low to medium temperature applications (200°F to 850°F). Since organic fluids have a much lower saturation pressure in this temperature range, boiler tubes, piping, turbine cases, and feed pumps can be designed for lower pressures. Some organic fluids can be condensed at pressures above atmospheric pressure without a significant loss of efficiency, eliminating air in-leakage problems such as excess

Figure II-6

GAS TURBINE BOTTOMING CYCLE



with condensing steam turbines. Organic fluid vapor becomes superheated as it expands in the turbine, whereas steam begins to condense. Thus, superheating and re-superheating are unnecessary in organic Rankine systems. Organic fluids have a much higher molecular weight than water. As a result, organic vapors are denser than steam and, therefore, organic cycle turbines are smaller and simpler than steam turbines. At lower temperatures, the organic Rankine cycle has a definite cost advantage over a steam Rankine cycle. The disadvantage is that the equipment is less commonly used and may have to be specially designed, and there is not as much operating experience as with steam systems.

- Gas Turbine (Brayton) Cycle

Gas turbine bottoming cycles are suited to those rare applications where high temperature waste heat is available (1000°F to 1700°F). A schematic diagram of the cycle is shown in Figure II-6, in which a gas turbine bottoming cycle is applied to an indirectly heated furnace.*

Alternatively, a combustion turbine combustor could be replaced by a heat exchanger and the gas turbine working fluid heated by hot waste gases. Ambient air is compressed and then heated in the regenerator. (The use of a regenerator, which is a gas-to-gas heat exchanger, improves the system's efficiency.) The compressed air is then heated to high temperature in the combustor and is used to heat the furnace. The hot gases leaving the furnace are then expanded in a turbine to drive the compressor and an electric generator. In this application, hot furnace exhaust gases that might otherwise be wasted are used to generate electricity.

*A furnace in which the products of combustion from the burning fuel do not contact the item being heated, but instead heat the interior walls of the furnace cavity.

The main advantages of the gas turbine for bottoming cycle applications are: the technology is well developed, capital costs are moderate compared to steam systems, and maintenance requirements are relatively low. The primary limitation is the need for waste heat at very high temperatures.

6. New Technologies

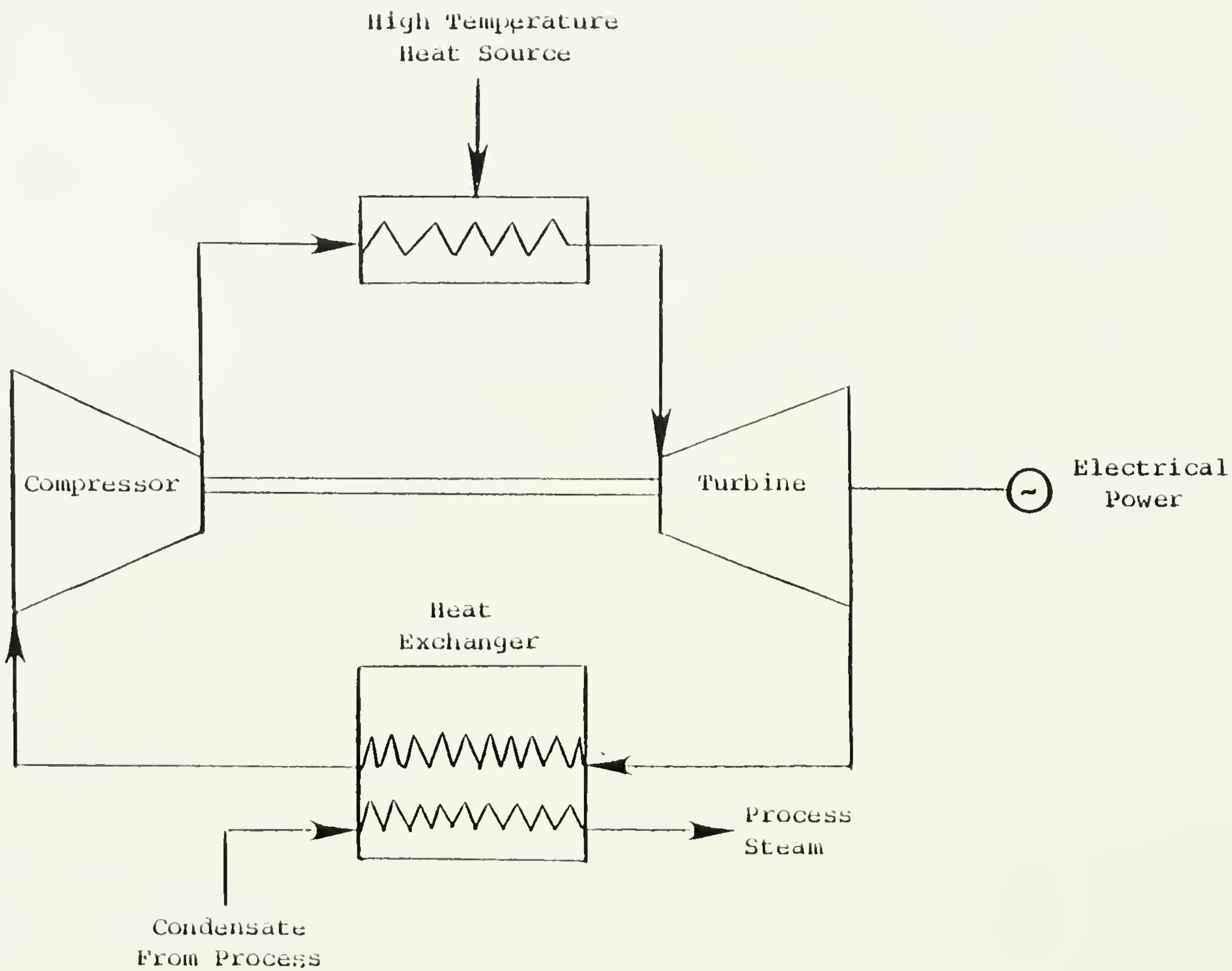
The closed-cycle gas turbine system offers a wide range of design possibilities, since it is neither limited to air as the working fluid nor to atmospheric pressure at the compressor inlet. In this system, an external heat source is used to heat the compressed working fluid in a heat exchanger. The hot gas is expanded in a turbine, then used to produce steam for process use, as shown in Figure II-7. Since the gas turbine exhaust is not contaminated by products of combustion, it can be returned to the compressor to complete the cycle. The cooling requirement after the heat-recovery boiler is very small, because the boiler removes most of the heat from the turbine exhaust gases.

The gas turbine shown in Figure II-3 uses an open cycle, so named because the compressor inlet and turbine exhaust are at ambient pressure and are not directly connected. In a closed-cycle system, the compressor inlet and turbine exhaust pressures are greater than ambient. As a result, it is possible to obtain a higher outlet pressure from the compressor than is possible in an open-cycle system. Because of the higher system pressures, the working fluid has a higher density, and the closed-cycle system is physically smaller. Also, it is possible to use a working fluid other than air.

The closed-cycle system is not yet commercially available. Two options for using closed-cycle gas turbines for cogeneration have been studied: one using an atmospheric fluidized bed as the heat source (1500°F turbine inlet temperature), and the other using an oil-fired furnace with a turbine inlet temperature of 2200°F.

Figure II-7

CLOSED CYCLE GAS TURBINE COGENERATION SYSTEM



One of the advantages of the closed cycle is that part-load efficiency can be nearly equal to full-load efficiency. However, because of the cost of the heat exchangers and interconnecting piping, a closed-cycle system is more expensive than an open-cycle one despite the fact that the turbine and compressor are physically smaller.

C. COGENERATION SYSTEM CHARACTERISTICS

1. Total Installed Costs

Applicable size range, performance characteristics, installed cost, operation and maintenance cost, and construction time vary significantly among cogeneration technologies. System characteristics are presented to facilitate a comparison of the different technologies for specific applications. This information is representative of the current state-of-the art, but it should be used with caution. Cogeneration systems are not "off-the-shelf" items they must be designed for each application. As a result, the cost and performance of a specific system may be significantly different from average values because, for example, the cost of essentially similar equipment may vary among manufacturers. Therefore, the information presented here represents expected values that are useful for the preliminary assessment of cogeneration feasibility, but are not a substitute for a detailed, site-specific engineering study.

Total installed cost as a function of peak rate of fuel usage (i.e., design firing rate) is shown in Figures II-8, II-9 and II-10 for several cogeneration technologies. Total installed costs are given in 1982 dollars. The system size ranges shown in these figures are based on the information available.

The total installed cost for a wood- or wood-waste-fired steam turbine system, as shown in Figure II-8, includes the cost of a flue-

Figure II-8

STEAM TURBINE COGENERATION SYSTEM INSTALLED COSTS

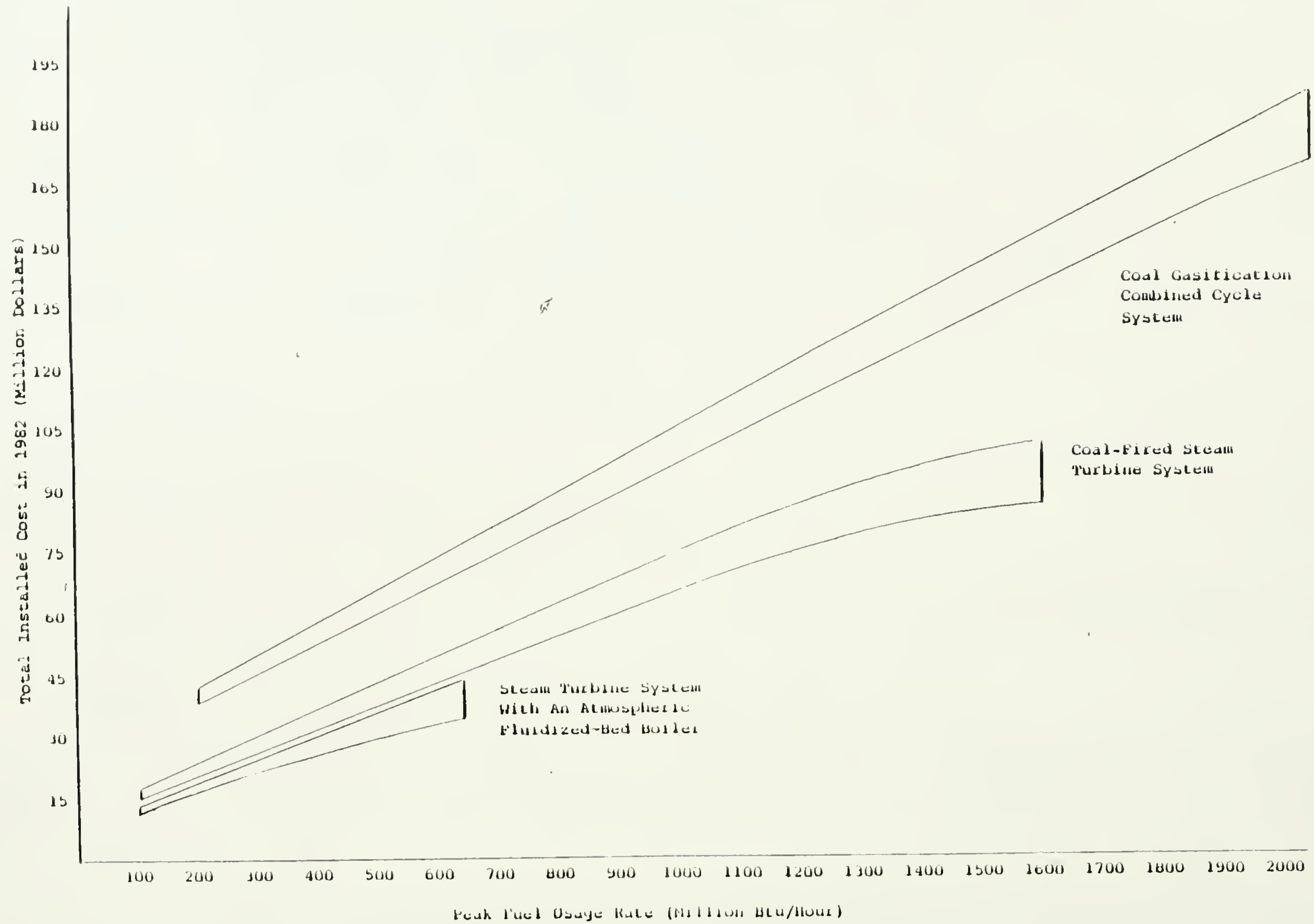


Figure II-9

COMBUSTION TURBINE AND COMBINED CYCLE COGENERATION SYSTEM INSTALLED COSTS

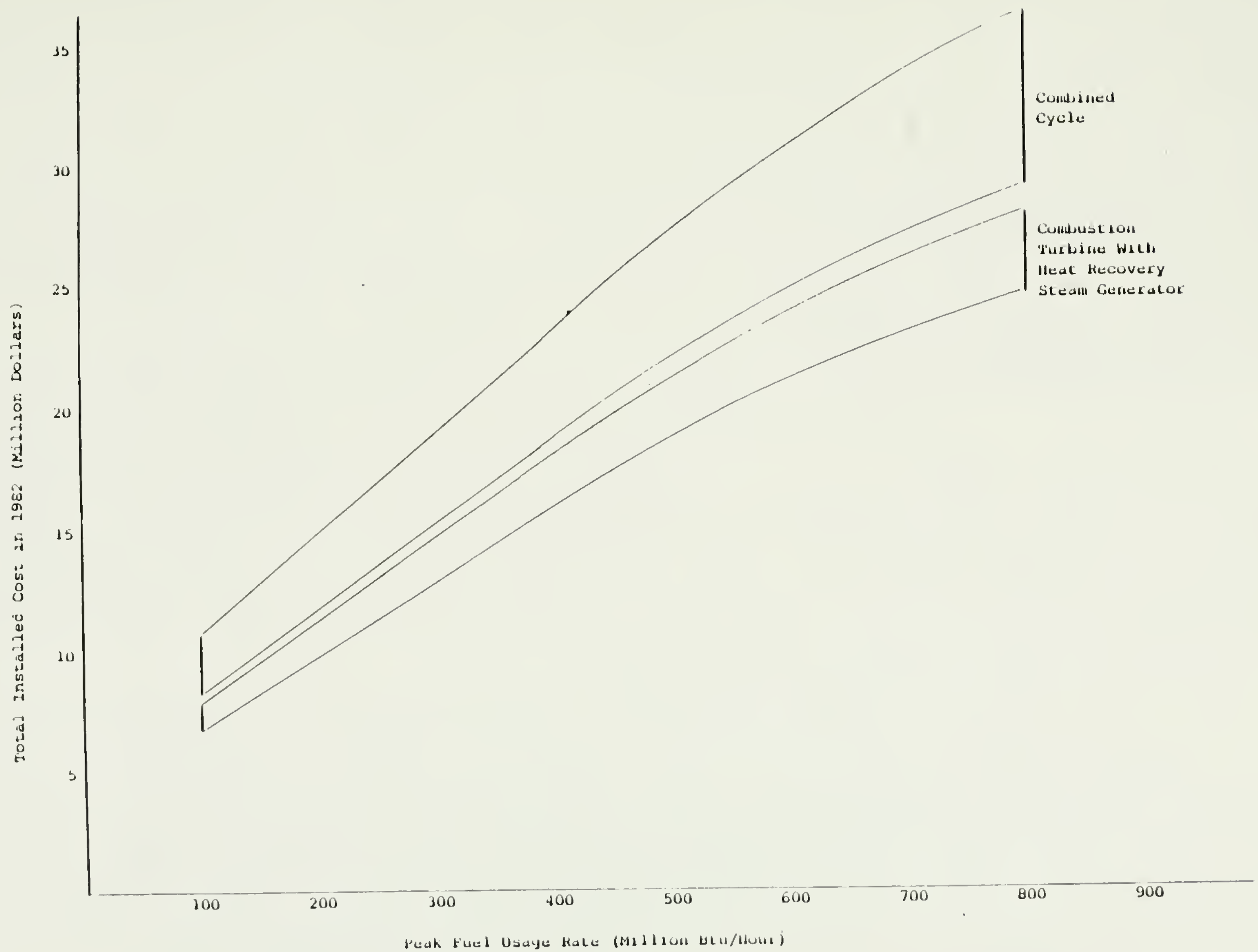


Figure II-8

STEAM TURBINE COGENERATION SYSTEM INSTALLED COSTS

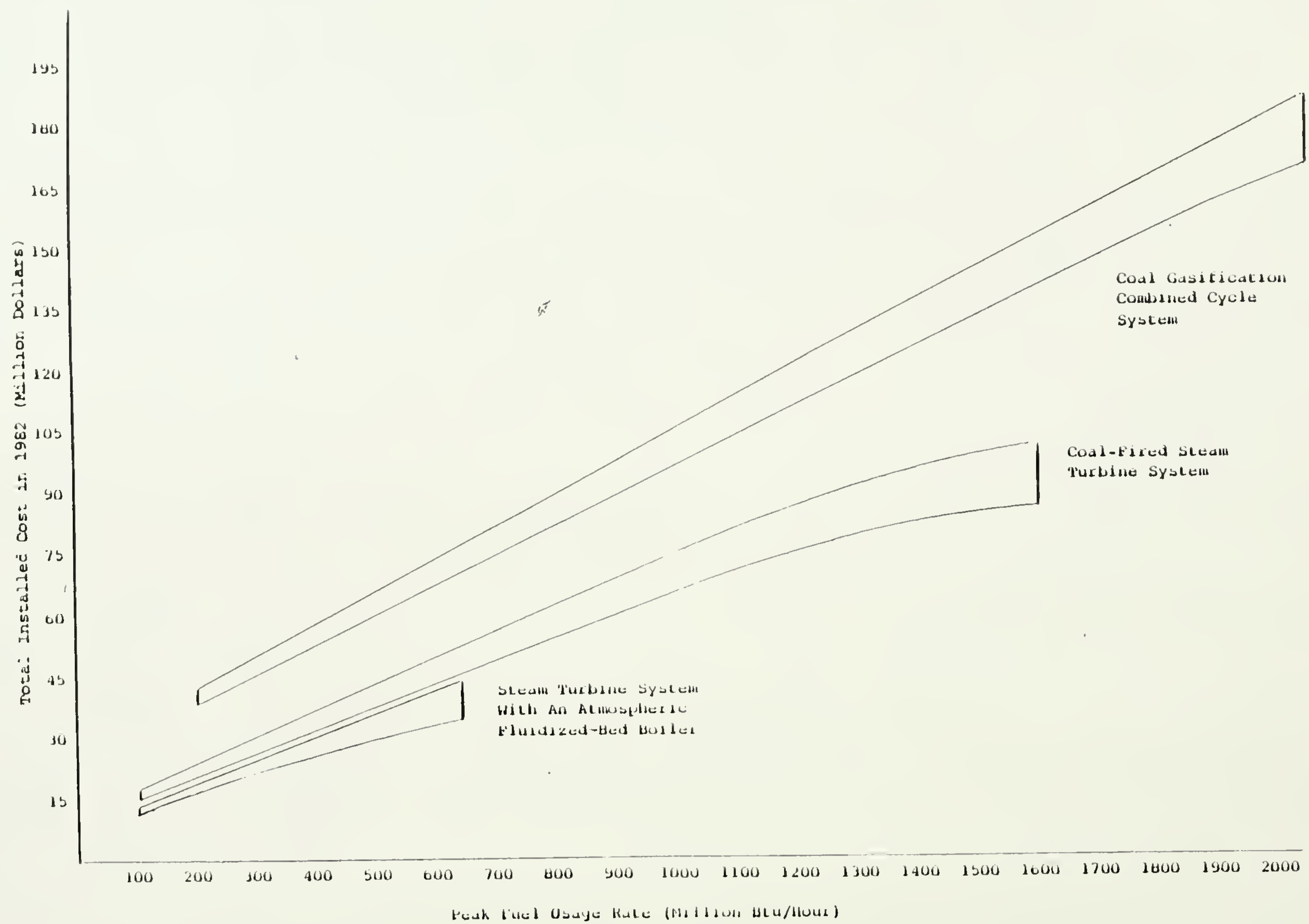


Figure II-9

COMBUSTION TURBINE AND COMBINED CYCLE COGENERATION SYSTEM INSTALLED COSTS

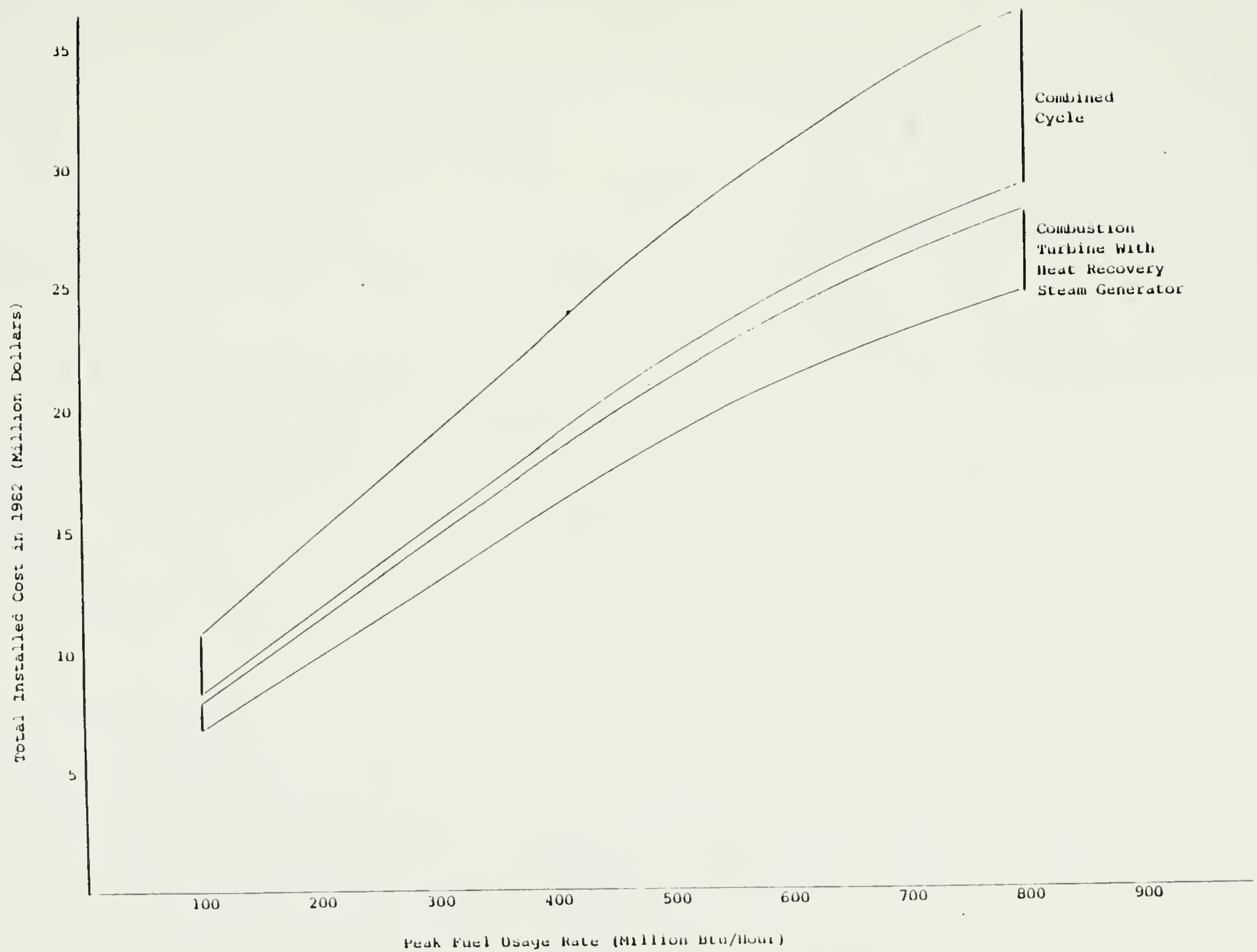
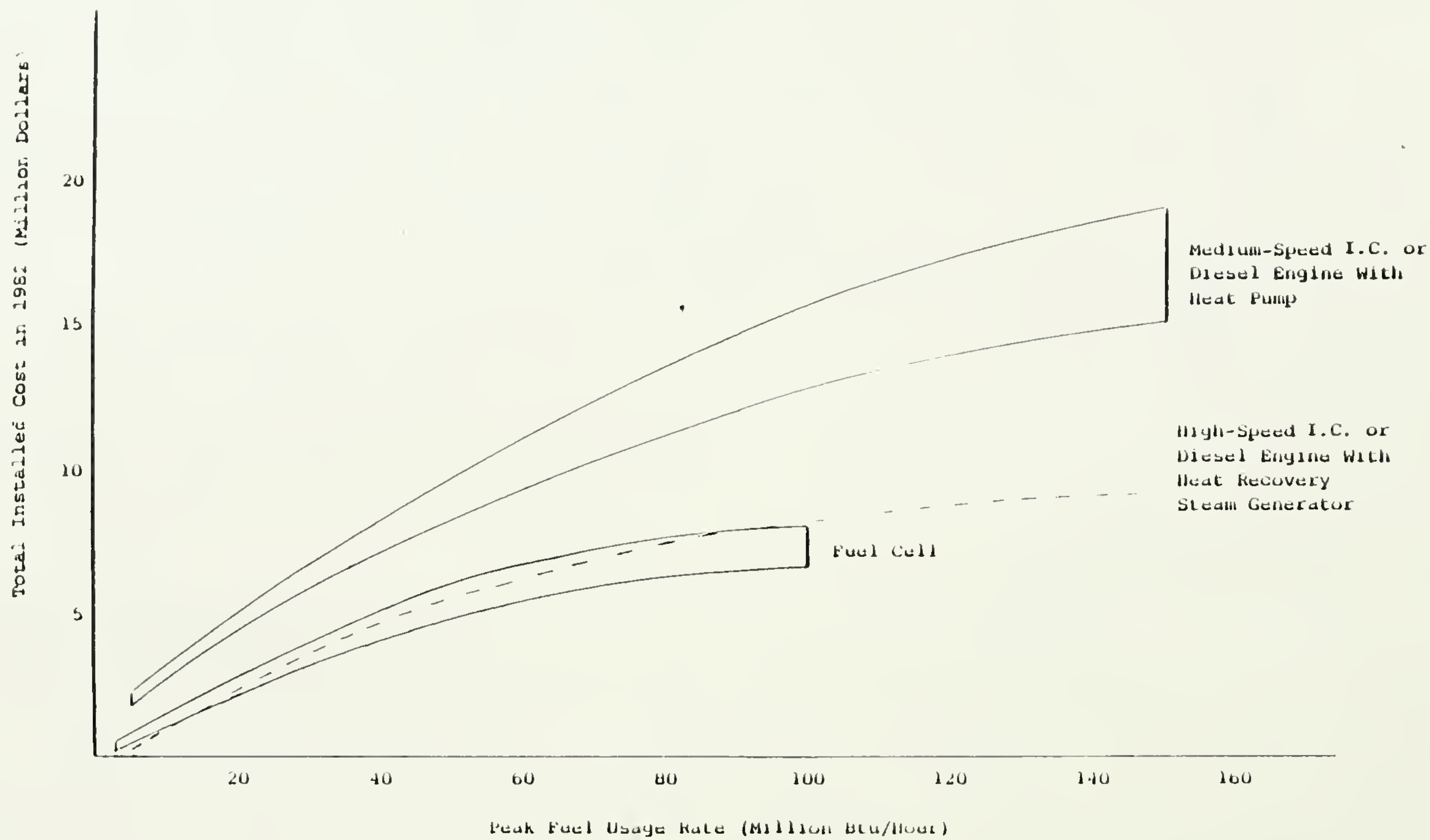


Figure II-10

INTERNAL COMBUSTION, DIESEL AND FUEL CELL COGENERATION SYSTEM INSTALLED COSTS



gas particulate removal system. If it is not required because a "clean" fuel is used, the total installed cost is reduced significantly (i.e., approximately 25%). The lower cost curve for each system represents the total installed cost of a backpressure turbine cogeneration system with no condensing capacity, while the upper curve represents the cost with an extraction turbine and full condensing capacity.

In Figure II-9, cost curves are shown for the combined-cycle and combustion turbine cogeneration systems. The lower curves for each system represent the total installed cost for a system designed for relatively large thermal energy production and relatively small electric power generation, while the upper curves are for systems designed to maximize electric power generation and have relatively small thermal energy production.

Figure II-10 includes cost curves for high-speed and medium-speed IC engines. Medium-speed engines have a higher installed cost than high-speed ones, but are more efficient.

The total installed cost of a specific cogeneration system may vary depending on the type of fuel burned due to fuel handling or processing requirements and equipment design. Total installed cost multipliers for different fuel types are shown in Table II-1. These multipliers can be applied to the cost curves in Figures II-8, II-9, and II-10 to assess the effect of fuel type on systems installed costs.

The total installed cost for steam and organic rankine bottoming cycles as a function of power generating capacity is shown in Figure II-11. These costs are given in 1980 dollars. Cost information for gas turbine bottoming cycles was not available. However, as a first approximation, the costs should be similar to that of a combustion turbine with a heat recovery steam generator as shown in Figure II-10.

Table II-1

TOTAL INSTALLED COST FACTORS

SYSTEM	FUEL TYPE*			
	COAL	NO. 2 OIL	RESIDUAL OIL	NATURAL GAS
Steam Turbine**	1.0	-	0.45	0.4
Fuel Cell	-	1.0	-	1.0
Combustion Turbine With Heat Recovery Steam Generator	-	1.0	1.03	0.9
Combined-Cycle	-	1.0	1.1	0.9
Diesel and I.C. Engine	-	1.0	1.05	1.05

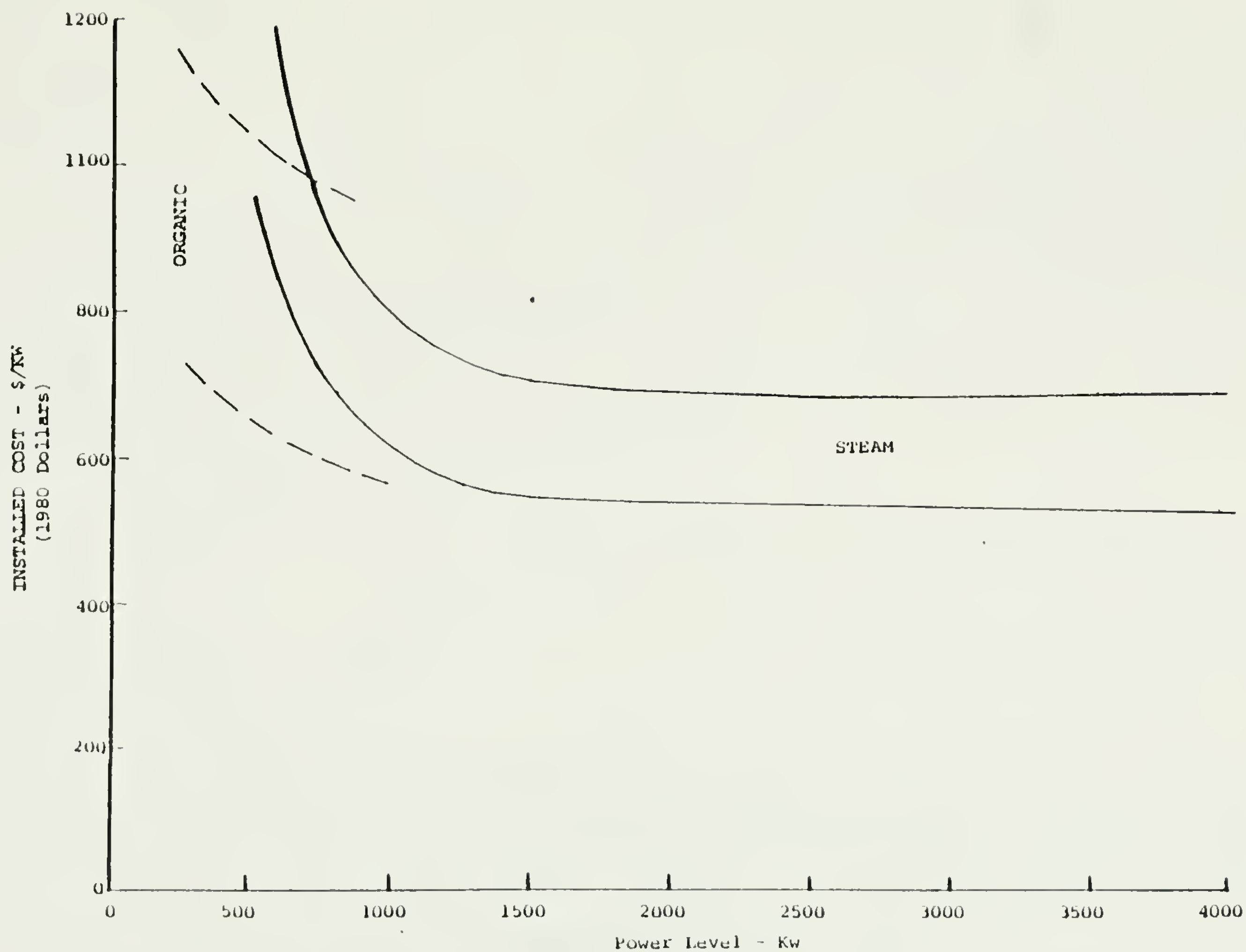
*A dash indicates either an incompatibility between fuel and system type or a lack of information.

**Applies to variants shown in Figure II-10, including coal-gasification/combined-cycle.

Figure II-11

INSTALLED COSTS FOR PACKAGED BOTTOMING CYCLE ORGANIC AND STEAM TURBO-GENERATOR SYSTEMS

(DATA FROM THERMO ELECTRON CORP., SUNDSTRAND CORP., AND KINETICS CORP.)



2. System Performance

Design (i.e., full load) performance factors for several cogeneration technologies are shown in Table II-2 for three industrial process steam pressures and two modes of system operation. It should be noted that for the two modes of operation, the system design may vary. For example, the steam turbine performance factors shown in Table II-2 for the operating mode that maximizes thermal energy production are for a system with a backpressure turbine, whereas the performance factors for maximum electrical power generation are for a system with an extraction steam turbine and a full capacity condenser. Although the performance factors for the two modes of operation shown in Table II-2 may apply to different system designs, the valves shown indicate the range of performance possible with each cogeneration technology.

Cogeneration systems are typically designed to maximize thermal energy production in industrial applications, because this results in a higher fuel utilization efficiency and a lower system installed cost. With the enactment of the Public Utilities Regulatory Policies Act (PURPA), electric utilities must purchase electricity from cogenerators. If the rate that a utility will pay for cogenerated power is sufficiently high, it may be economically feasible to install an "oversized" cogeneration system capable of maximizing electric power production. The revenue from the sale of electricity, in such a case, must compensate for the higher total installed cost and higher fuel and operating and maintenance costs.

The performance factors from Table II-2 and the cost curves from Figures II-8, II-9 and II-10 can be used to estimate the cost of a cogeneration system for specific applications. Except for an IC engine, the performance factors for a cogeneration system designed to maximize thermal energy production relate to the lower cost curves in Figures II-8, II-9 and II-10 for each system. Conversely, the performance factors for maximum electricity production relate to the upper cost curves for each system.

Table II-2

COGENERATION SYSTEM PERFORMANCE FACTORS

COGENERATION SYSTEM	PROCESS STEAM PRESSURE (PSIA)	OPERATING MODE: MAXIMUM THERMAL ENERGY PRODUCTION — THERMAL ENERGY TO FUEL RATIO (Million Btu/Million Btu)	OPERATING MODE: MAXIMUM THERMAL ENERGY PRODUCTION — ELECTRICAL POWER TO FUEL RATIO (Megawatt/Million Btu/Hr)	OPERATING MODE: MAXIMUM ELECTRICAL POWER PRODUCTION — THERMAL ENERGY TO FUEL RATIO (Million Btu/Million Btu)	OPERATING MODE: MAXIMUM ELECTRICAL POWER PRODUCTION — ELECTRICAL POWER TO FUEL RATIO (Megawatt/Million Btu/Hr)
Steam Turbine (865 psia, 825°F)	15	0.525	0.056	0	0.075
	150	0.603	0.032	0	0.079
	450	0.642	0.017	0	0.079
Steam Turbine (1465 psia, 950°F)	15	0.514	0.064	0	0.082
	150	0.572	0.042	0	0.082
	450	0.618	0.028	0	0.082
Steam Turbine With Atmospheric Fluidized-Bed Boiler	15	0.546	0.064	0	0.084
	150	0.626	0.042	0	0.084
	450	0.677	0.028	0	0.084
Coal Gasification Combined-Cycle	15	0.327	0.073	0	0.122
	150	0.626	0.042	0	0.084
	450	0.408	0.052	0	0.122
Fuel Cell	15	0.494	0.072	0.215	0.122
	50	0.503	0.072	0.262	0.122
	100	0.494	0.072	0.215	0.122
Combustion Turbine And Heat Recovery Steam Generator	30	0.491	0.061	0.399	0.113
	150	0.468	0.061	0.307	0.113
	450	0.461	0.061	0.287	0.113
Combined-Cycle	15	0.351	0.103	0	0.139
	150	0.424	0.088	0	0.139
	450	0.400	0.082	0	0.139
Diesel or I.C. Engine With Heat Pump	15	0.442	0.092	0.216	0.104
	150	0.478	0.068	0.148	0.104
	450	0.496	0.054	0.156	0.104
High Speed Diesel or I. C. Engine	15	0.214	0.102	0.214	0.102
	150	0.214	0.102	0.214	0.102
	615	0.19	0.102	0.19	0.102

To illustrate the use of Table II-2 and Figures II-8, II-9 and II-10, the cost of a combustion turbine with a heat recovery steam generator will be estimated for an industrial process requiring 100 million Btu per hour of steam at a pressure of 150 psia. It will be assumed that a system designed to maximize thermal energy production is required. The peak fuel usage rate is equal to the steam demand divided by the thermal energy to fuel ratio. The peak fuel usage rate is 214 million Btu per hour (i.e., 100 million Btu per hour steam demand divided by 0.468 from Table II-2). Referring to Figure II-9, the total installed cost for this system, obtained from the lower cost curve for a combustion turbine with a heat recovery steam generator, is $10.6 million. The electrical generating capacity of this system is equal to the peak rate of fuel usage times the electrical power to fuel ratio from Table II-2. Multiplying 214 by 0.061 results in a generating capacity of 13 megawatts.

The efficiency of bottoming cycle cogeneration systems as a function of peak cycle temperature is shown in Figure II-12. The peak cycle temperature will typically be 50°F to 200°F less than the temperature of the recoverable waste heat. If the temperature and quantity of waste heat available is known, the electrical power available from a bottoming cycle can be estimated using Figure II-12. System installed cost can then be determined from Figure II-11.

3. Operation and Maintenance Costs

Annual operation and maintenance costs will vary as a function of system type, fuel burned, annual hours of operation and system size. Estimated first year operation and maintenance costs, expressed as a percent of total installed cost, are shown in Table II-3.

D. INDUSTRIAL APPROACHES TO COGENERATION

At least three cogeneration approaches can be taken by industrial users. One approach is to design a system capable of meeting peakload

Figure II-12

BOTTOMING CYCLE EFFICIENCY AS A FUNCTION OF PEAK CYCLE TEMPERATURE

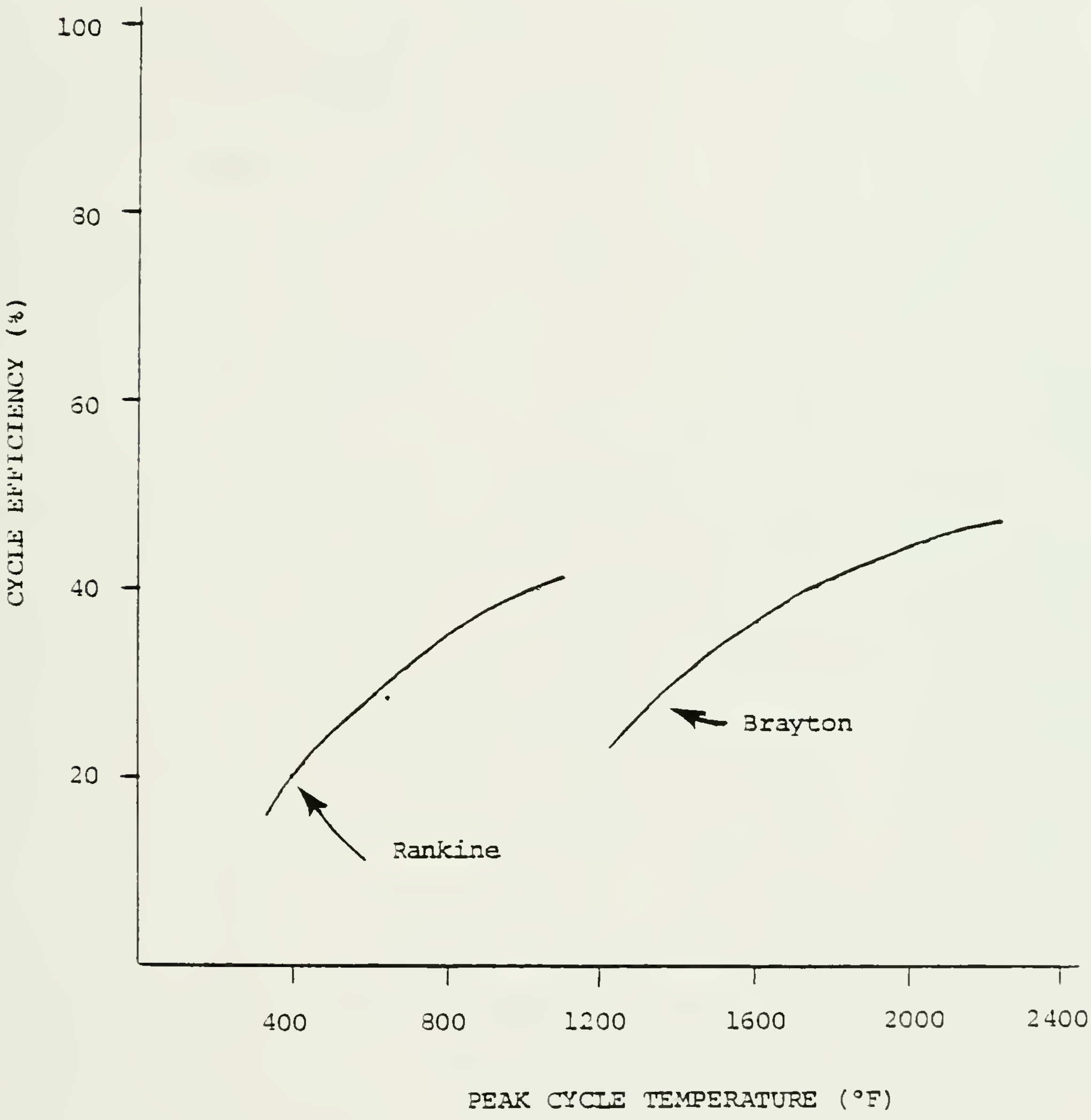


Table II-3

OPERATION AND MAINTENANCE COSTS FOR

FIRST YEAR OF SYSTEM OPERATION

COGENERATION TECHNOLOGY	OPERATION AND MAINTENANCE COST (PERCENT OF TOTAL INSTALLED COST)
Steam Turbine	6.0%
Steam Turbine With Atmospheric Fluidized-Bed Boiler	7.2%
Coal Gasification Combined-Cycle	3.9%
Fuel Cell	6.2%
Combustion Turbine With Heat Recovery Steam Generator	5.3%
Combined-Cycle	5.9%
Diesel or I.C. Engine With Heat Pump	6.2%
High Speed Diesel or I.C. Engine	6.2%
Bottoming Cycle	5.0%

requirements that is connected to the grid and sells excess electricity. The excess power is ether purchased by the utility system for resale to customers, or transmitted via the utility network to another user. The use of grid for selling excess electricity directly to another private user is known as "wheeling".

Under this industrial cogeneration approach, electricity can be produced with minimal requirements for standby equipment. a utility may be able to use the excess power it purchases from an industrial cogenerator to help meet its own baseload or peakload demands, which it might otherwise have to meet with less efficient equipment. this approach provides the greatest flexibility and offers the greatest potential cost and fuel savings of the three industrial options -- if the utility and the industrial cogenerator work together.

A second approach pursued by industrial facilities is to build a cogeneration system connected to the utility grid to allow for the purchase of supplemental electricity when needed. In a grid-connected system, equipment is sized to meet the user's normal baseload electrical requirements, and electricity is purchased from the grid to meet peakload requirements. Supplemental thermal energy and some redundancy in standby equipment may be required; initial capital costs will therefore be higher.

A third industrial approach is to design a system that operates independent of the utility grid. Although this approach eliminates the risk of potential utility power blackouts, it is effective only if sufficient equipment redundancy or overcapacity is built in to ensure reliability. Independent systems have traditionally been sized to meet peak electric requirments, with supplemental equipment included to meet thermal demand.

E. FUELS FOR COGENERATION SYSTEMS

Cogeneration systems can be fired with conventional as well as non-conventional renewable fuels. Conventional fuels such as oil, gas and coal are well known as are the technologies used to burn them, and will not be addressed in this manual. However, non-conventional sources of fuel such as biomass are not so well known, and will be discussed in the following chapters.

III. BIOMASS ENERGY RESOURCES

III. BIOMASS ENERGY RESOURCES

Although the term biomass is defined as living matter, in the energy context it is used to refer to wood, plants, and municipal, agricultural and animal wastes, which are mostly organic materials. Currently, two approaches exist to the utilization of biomass as an energy resource. One approach is the intensive cultivation of trees and other plants specifically for use as fuel. The other approach is the utilization of available waste materials, such as wood and agricultural residues and municipal waste, as the fuel source. This manual will address only the latter approach only because of the high capital costs and long payback periods associated with energy plantations.

This chapter will describe the various biomass energy resources that can be utilized with cogeneration systems, and discuss their collection and transportation.

A. WOOD AND WOOD WASTES

Woody biomass consists mainly of forest residues and forest products mill wastes. The forest residues consist of standing timber that has no commercial value at present, i.e., dead and diseased trees, non-marketable species, thinnings and culls. Mill wastes, which include bark from paper mills, trimmings and sawdust from sawmills, and other industrial and commercial wood waste materials. Table III-1 gives estimates of wood residue generation.

Collection and transportation costs contribute significantly to the total cost of woody biomass. Methods for the economical harvesting and collection of biomass from woods are rapidly being developed. Mechanical equipment is now available that reduces manual labor and increases productivity.

Table III-1

FACTORS FOR

ESTIMATING WOOD WASTE GENERATION

TYPE OF WASTE	QUANTITY
Mill wastes	.28 percent of lumber
Loggin Residue	
Hardwood	10-15 tons/acre
Softwood	5-15 tons/acre
Pre-Commercial Thinning	25 tons/acre
Land Clearing	50-150 tons/acre

Conventional approaches to in-woods processing include topping and de-limbing to produce shortwood (lengths of up to 8 or 10 feet) and longwood (tree-length logs with tops removed). These approaches require transport as roundwood with appropriate unloading, handling, and chipping at the power generation facility. Studies of the economics favor in-woods chipping and this approach has been incorporated into the design of some of the power generation facilities that are in operation now.

In-woods processing can now be accomplished by machines that take whole trees and reduce them rapidly to chips. Some forestry operations now utilize in-woods chippers along with mechanical fellers, feller-bunchers, skidders, or combinations of such equipment to provide a complete "chip-making" operation on wheels that can be relocated from place to place in the forest. The chips produced are then loaded into a truck or van for transport to the plant, where they can be handled more easily than logs and routed directly to a furnace for combustion.

Two basic approaches to the transport system are truck and rail. Trucks are invariably used for the trip out of the woods. Although a fuelwood procurement radius of 50 miles or less is generally advisable, railroads offer possibilities for low-cost transport, especially if distances are long enough to warrant an extra loading-unloading operation. Mechanical means of loading and unloading are essential to the transportation system and must be investigated for incorporation into the design of the system.

The estimated cost of collecting forest residues, including skidding, chipping, and loading, is provided in Table III-2. Collection costs for the Pacific North West (PNW) region are about three times those incurred in the South, because of the PNW's rough terrain. There are no collection costs associated with forest industry residues (e.g., bark, sawdust) because such materials are generated at central locations. Transportation methods and costs are the same as those given in Table III-2 for forest residues.

Table III-2

ESTIMATED COST OF COLLECTION, REDUCTION, AND TRANSPORTATION OF LOGGING RESIDUES IN THE PACIFIC NORTHWEST AND SOUTHEAST U.S.

	COST ($/DTE)*
Pacific Northwest (Douglas-Fir Region)	
Collection	36.70
Chipping	10.50
Transportation (50 miles)	9.30
Labor	5.00
Average delivered cost	61.50
Southeast (Loblolly Pine Plantation)	
Collection	9.40
Chipping	5.60
Transportation (20 miles)	5.50
Labor	2.60
Total delivered cost	23.10

*DTE = Dry Ton Equivalent

Source: Howllet and Gamache, Silvicultural Biomass Farms: Forest and Mill Residues as Potential Sources of Biomass. MTR-7347: Volume VI, Mitre/Metrek, McLean, Virginia

B. MUNICIPAL SOLID WASTES (MSW)

Energy recovery from municipal solid wastes generated by households and commercial enterprises presents a unique opportunity to address two problems simultaneously: energy production and waste disposal. Municipal solid wastes consist of a mixture of materials, some that have energy value and some that can be recycled. Table III-3 presents an average composition of municipal waste.

Approximately 75% of the dry waste material is combustible. Moisture content averages 38%, ranging from 20% to 60%. The combustible materials can be burned to generate steam that can be used either to produce electricity or to provide heating for industrial processes. The metals and glass present in MSW may be recycled. However, the separation of these materials from MSW has been found to be an expensive and risky undertaking. Expensive because of the additional equipment needed to separate each type of recoverable material and risky because of uncertain demand and fluctuating prices for the recovered products. Table III-4 shows estimates of per capita waste generation in the U.S. by size of municipality. The U.S. Environmental Protection Agency (EPA) estimates that an average American generates 3.3 pounds of solid wastes per day, though this value varies substantially. The amount of MSW available in a given area can be roughly estimated if the population is known. However, any feasibility study of energy from solid wastes should include a thorough assessment of waste generation. Specific information on the quantity and composition of the wastes generated by various Montana municipalities and communities can be obtained from the Solid Waste Bureau of the Montana Department of Health and Environmental Sciences.

In order to obtain a regular supply of this fuel, waste deliveries must be established by contract with waste collectors. A tipping fee may be charged for accepting MSW since the plant is relieving the collectors/municipality of the greater expense of MSW disposal. As an

Table III-3

COMPOSITION OF U.S. URBAN

REFUSE, 1975

MATERIAL	COMPOSITION (%)
Paper	29
Glass	10
Metal	9
Plastic	3
Rubber	3
Textiles	2
Wood	4
Food Wastes	18
Yard Wastes	20
Miscellaneous Organic	2
Total	100

Source: New England Energy Congress

Table III-4

PER CAPITA WASTE GENERATION IN

MUNICIPALITIES OF VARIOUS SIZES

SIZE OF MUNICIPALITY (Population)	PER CAPITA GENERATION LBS./DAY
Less than 1,000	2.2
1,000-5,000	2.5
5,000-10,000	3.5
Over 10,000	4.5

Source: Dearborn, R.K. et al. Resource Recovery, Advisory Committee Report to the Maine Board of Environmental Protection, Augusta, ME, 1974.

alternative to contracting with governmental agencies and dealing with the many non-combustibles in MSW, arrangements may be made with a local college, commercial or retail building complex, or school system (or with private disposal contractors that serve such institutions) to utilize its wastes. In addition to fewer bureaucratic problems, this alternative provides more energy per pound of waste, because waste from these sources is almost entirely combustible.

C. AGRICULTURAL WASTES

Agricultural waste residues are by products of food production and consist of crop residues, food processing residues, orchard prunings and hulls (see Table III-5 and Appendix D). Usually, crop residue is used to condition and fertilize soil, control erosion and feed livestock. Depending on the crop and soil conditions, this residue can be removed from the field and used as an energy feedstock without harming soil productivity.

The U.S. Department of Agriculture estimates that 35% of the residue from corn, soybean, and small grain production are available for removal under conventional tillage practices. To assess the crop residue resource available at a given site, the type of crop, method of cultivation, and soil conditions must be considered. Estimates of potentially recoverable crop residues must be made on a site-specific basis, preferably in consultation with an agronomist or county extension agent.

Field crop residues (e.g., corn, cotton, barley, wheat) may either be collected at the same time the primary crops are collected (total harvest) or at some subsequent time (post-harvest). Vegetable crop residues may be similarly collected, except in those cases where air drying makes them crumbly and uncollectible. In both the total and post-harvest options, collection may consist of chopping and

Table III-5

CONVERSION FACTORS FOR ESTIMATING RESIDUE GENERATION

	QUANTITY	AVAILABILITY
Vegetable Crop Residues (Dry Wt.)		
Artichokes	1.7 tons/acre	95%
Asparagus	2.2 tons/acre	98%
Cucumbers	1.7 tons/acre	95%
Melons & Squash	1.2 tons/acre	90%
Potatoes	1.2 tons/acre	90%
Tomatoes	1.3 tons/acre	98%
Field Crop Residues (14% moisture)		
Barley	1.4-1.5 tons/acre	85%
Beans	1.2-2.0 tons/acre	80%
Corn	4.0-4.5 tons/acre	90%
Cotton	1.5-2.0 tons/acre	60%
Oats	1.0-1.5 tons/acre	85%
Rice	3.0-3.7 tons/acre	90%
Safflower	1.0-1.5 tons/acre	90%
Sorghum	2.7-3.0 tons/acre	90%
Wheat	1.5-1.6 tons/acre	85%
Orchard Pruning (25-45% moisture)		
Almonds	1.3-2.0 tons/acre	98%
Apples	1.0-2.25 tons/acre	98%
Apricots	1.5-2.0 tons/acre	98%
Avocadoes	0.2-1.5 tons/acre	98%
Cherries	0.4-1.5 tons/acre	98%
Dates	1.0 ton/acre	98%
Figs	1.2-2.25 tons/acre	98%
Grapefruit	1.0-1.2 tons/acre	98%

Table III-5

CONVERSION FACTORS FOR ESTIMATING RESIDUE GENERATION

(Continued)

	QUANTITY	AVAILABILITY
Orchard Pruning (25-45% moisture)		
Grapes	2.0-2.5 tons/acre	98%
Lemons & Limes	0.9-1.0 tons/acre	98%
Olives	1.0-1.5 tons/acre	98%
Oranges	1.0-1.8 tons/acre	98%
Peaches	1.7-2.5 tons/acre	98%
Pears	2.25-2.4 tons/acre	98%
Plums	1.4-2.0 tons/acre	98%
Prunes	1.0-1.5 tons/acre	98%
Walnuts	0.9-1.5 tons/acre	98%

stacking or one of several baling methods (e.g., standard bales, round bales, or giant round bales). Although total harvest collection possesses the economic advantage of reduced collection labor requirements, post-harvest collection allows the residues to field dry and is preferred. Transportation of these residues may be accomplished by tractor and field wagon, van or truck, depending on the transportation distance.

The costs of crop residue collection are primarily determined by the volume of residue per acre, while transportation costs depend on the bulk density of the residues, the transportation distance, and fuel cost. The low bulk density (2 to 3 lb/ft^3) of crop residues requires that some sort of baling method be used in all but short distance hauls.

Orchard prunings are currently collected as standard practice and are usually piled at roadside and burned. Current collection equipment consists of a small tractor and loader, but for energy production, the use of a compactor or chipper for trunk loading would also be required. Collection costs depend on the densification and loading method used. Current disposal costs for the residues should be subtracted to obtain the true cost of using these residues for energy production. The bulk density of orchard prunings is sufficiently high for loads to be weight-limited rather than volume-limited.

Another agricultural residue that deserves mention is waste from the food processing industry. Food processing activities produce substantial quantities of waste products that can be gathered and used either as directly combustible fuel or as a feedstock for anaerobic digestion to produce methane.

Agricultural processing industry residues are already collected at their point of generation. No additional collection costs would be incurred by the utilization of these residues. Transportation costs for these residues vary widely, depending on their moisture content and bulk density.

D. ANIMAL WASTES

Animal wastes provide a good fuel source for the production of biogas through anaerobic digestion. This biomass fuel resource consists of manure from cattle, poultry, and swine. The value of animal wastes as potential energy feedstock is due to their availability in fairly large quantities that are continually being generated in centralized locations. They are also often the source of solid waste disposal and water pollution problems. Another important "spillover" benefit from the use of animal waste as a source of fuel is the salinity removal that results from conditioning the wastes in a digester.

The main requirement for a viable source of animal wastes is that the animals be reared in confined areas such as feedlots; otherwise collection is not feasible. Wastes recovered from dirt lots contain impurities that create both biological and physical problems in a digester. Processing animal waste for its energy content need not reduce its availability as a fertilizer. Animal waste contains 85 percent water and 15 percent solids. About 90 percent of the solids are volatile and, after treatment in a methane gas producing digester, the remaining effluent is an excellent fertilizer. In fact, its nitrogen is in a form more readily absorbed by plants than the nitrogen in the raw waste and it can easily be distributed by a liquid manure handling system. Table III-6 shows estimates of average animal waste production in the U.S. per day. A summary of animal waste characteristics is shown in Table III-7.

The type of manure disposal method employed depends on the type of farming operation (beef or dairy cattle). Disposal systems may be divided into two categories: solid disposal and liquid disposal systems. Of the two types, liquid disposal systems generally cost more.

Liquid disposal is common in dairy operations and/or in the colder and damper climatic regions of the U.S. In this system, fresh

Table III-6

ANIMAL WASTE PRODUCTION PER DAY

ANIMAL	POUNDS OF WASTE WET	DRY
Dairy Cow (per 1,000 lb. live weight)	85	10
Beef Cow (per 1,000 lb. live weight)	60	7
Swine (per 150 lb. live weight)	15	0.9
Horse (per 1,000 lb. live weight)	50	6
Sheep (per 100 lb. live weight)	4	0.46
Poultry (per 250 4-lb. layers)	25	3.75

Source: Pennsylvania State University, College of Agricultural Extension Service. "Soil Tests, Manure Application, and Legumes," Special Circular 242.

Table III-7

SUMMARY OF ANIMAL WASTE CHARACTERISTICS[a]

WASTE COMPONENT	DAIRY COW	BEEF FEEDER	SWINE FEEDER	SHEEP FEEDER	HORSE	POULTRY LAYER	POULTRY BROILER
Raw Manure[b]	82	60	65	40	45	53	71
Total Solids	10.4	6.9	6.0	10.0	9.4	13.4	17.1
Volatile Solids	8.6	5.9	4.8	8.5	7.5	9.4	12.0
Biochemical Oxygen Demand	1.7	1.6	2.0	0.9	--	3.5	--
Chemical Oxygen Demand	9.1	6.6	5.7	11.8	--	12.0	--
Nitrogen (total, as N)	0.41	0.34	0.45	0.45	0.27	0.72	1.16
Phosphorous (as P)	0.073	0.11	0.15	0.066	0.046	0.28	0.26
Potassium (as K)	0.27	0.24	0.30	0.32	0.17	0.31	0.36

[a]Pounds of component per day per 1,000 live pounds of animal.

[b]Feces and urine with no litter or bedding.

Source: U.S. DOE, A Technology Assessment of Solar Energy Systems, September, 1980.

liquid manure is pumped through a sewer system into a ditch, septic tank, pond, or lagoon, where bacterial decomposition takes place over a prolonged time period. The biochemcial process involved is aerobic or anaerobic, often by default depending on the dissolved oxygen concentration in the pond. The solids settle to the bottom and can eventually be pumped out. In some cases the liquid can then be used to directly irrigate cropland through the use of large sprinklers or sprayers.

IV. BIOMASS ENERGY RECOVERY TECHNOLOGIES

IV. BIOMASS ENERGY RECOVERY TECHNOLOGIES

A wide variety of methods exist to convert available biomass wastes and residues into energy. Conversion techniques range from relatively simple to quite complex. Basically, there are two types of biomass energy conversion processes.

- Thermochemical conversion
- Biological conversion.

The thermochemical conversion processes use heat (sometimes in the absence of air) to produce chemical reactions in biomass. Examples of such conversions include:

- Direct Combustion
- Gasification
- Pyrolysis.

The biological conversion processes are chemical reactions caused by treating biomass with enzymes, fungi, or micro-organisms. These conversion techniques include:

- Anaerobic digestion
- Fermentation.

This chapter will provide an overview of some of the important biomass energy conversion techniques that may be suitable for Montana.

A. DIRECT COMBUSTION

This is the simplest and best developed biomass conversion process. Forest and agricultural wastes and residues can be burned to produce steam, electricity, or heat. Wood and lumbermill wastes have been used successfully in boilers for process steam and electicity production for some time. It has been estimated that the forest products industry uses biomass to supply at least 1.1 quads, or about 45 percent, of its total energy needs per year. This industry has the potential to become virtually energy self-sufficient by using more of the biomass already available to it. Other industries, such as textiles and paper products, that require heat in the preparation and treatment process of goods can also use the direct combustion conversion process. Hot water, steam, and hot air are required for many manufacturing processes; and a large percentage of this energy could be supplied by direct combustion.

Multifuel boilers are available that can be fired with a number of fuels. Common multifuel boilers can use wood or coal with natural gas or oil as back up fuels. Although boilers are available that can be fired with coal and wood, the capital investment is usually quite large for these types of systems. In general, combustion technologies described in the following section can also burn coal. Fuel handling and pollution control systems for coal combustion would be different. Fluidized bed systems have the additional potential of using municipal solid waste. MSW is generally not fired in boilers designed for coal or wood because of its corrosive characteristics.

This section describes direct combustion technologies as applicable to wood wastes and to municipal solid wastes. Since these two types of fuels require slightly different technologies, they will be described separately.

1. Wood Combustion Technologies

Techniques for wood combustion are similar to those employed with coal, though there are a few important differences. Wood usually has a high moisture content, as high as 60-70 percent in wet climates.

This makes firing difficult and lowers boiler efficiency since a proporation of the wood's energy is lost in evaporating the water. Wood is a relatively clean fuel, with practically no sulfur and very little ash. The collection and handling of wood residues results in the addition of soil and rocks to the fuel in some cases, negating the low ash content of the wood. (See Tables IV-1 and IV-2).

Assuming that a user has arranged to have wood waste delivered to the plant at a competitive price (a ton of wood is approximately equivalent to 7000 cu. ft. of natural gas), there are a number of alternative modes of preparing the wood for burning. For ease of handling, the wood should be hogged (shredded) to 2" to 4" by a hammermill, knife hog or chipper. Since many wood furnaces have trouble sustaining combustion when the moisture content of wood exceeds about 57 percent, wet wood is usally dried. This can be done by hydraulic presses, which can reduce moisture to 50 to 55 percent but consume power and have high maintenance costs. A hot hog can be used (heated air is sent through the hogging machine, combining size reduction with drying) but this method has the same limitations as pressing. Rotary and Cascade dryers can use flue gas from the boiler to dry the wood, improving steam cycle efficiency slightly. In both systems the hog-fuel stream passes through the dryer where fines are separated, conveyed to the boiler, and burned in suspension. The rotary dryer (Figure IV-1) allows regulation of fuel moisture by employment of supplemental firing. The moisture content of wood fuel from a cascade dryer (Figure IV-2) is dependent upon the heat content of the flue gas. The optimum level of drying is to about 35 percent moisture content, since further drying requires additional energy while posing problems in the handling of a dry, possibly explosive fuel.

There are a number of techniques for burning wood wastes, depending on type and supply of wastes. (See Table IV-3).

Table IV-1

FUEL PROPERTIES OF BARK, WOOD AND COAL

	CHEMICAL COMPOSITION, % BY WT (DRY BASIS)										
	BARK				WOOD			COAL			
Fuel Characteristics	Pine	Oak	Spruce[1]	Redwood	Redwood	Pine	Fir/Pine[2]	Lig[3]	Sub[4]	Bit[5]	Bit[6]
Proximate Analysis											
Volatile Matter	72.9	76.0	69.6	72.6	82.5	79.4	75.1	44.1	39.7	35.4	16.0
Fixed Carbon	24.2	18.7	26.6	27.0	17.3	20.1	24.5	44.9	53.6	56.2	79.1
Ash	2.9	5.3	3.8	0.4	0.2	0.5	0.4	11.0	6.7	8.4	4.9
Ultimate Analysis											
Hydrogen	5.6	5.4	5.7	5.1	5.9	6.3	6.3	4.6	5.2	4.8	4.8
Carbon	53.4	49.7	51.8	51.9	53.5	51.8	50.7	64.1	67.3	74.6	85.4
Sulfur	0.1	0.1	0.1	0.1	0	0	0	0.8	2.7	1.8	0.8
Nitrogen	0.1	0.2	0.2	0.1	0.1	0.1	2.4	1.2	1.9	1.5	1.5
Oxygen	37.9	39.3	38.4	42.4	40.3	41.3	40.2	18.3	16.2	8.9	2.6
Ash	2.9	5.3	3.8	0.4	0.2	0.5	0.4	11.0	6.7	8.4	4.9
Heating Value											
Dry Basis, Btu/lb	9030	8370	8740	8350	9220	9130	8795	11,084	12,096	13,388	15,000

ources: Babcock & Wilcox Company, Combustion Engineering, Inc., Coen Company.

/Logs Stored in Saltwater 2/Sanderdust 3/Texas Lignite 4/Wyoming Subbituminous B 5/Illinois Bituminous (high volatile A)

/West Virginia Bituminous (low-volatile)

Source: "Power From Wood", Power, February 1980

Table IV-2

HOW FUEL MOISTURE CONTENT AFFECTS EFFICIENCY

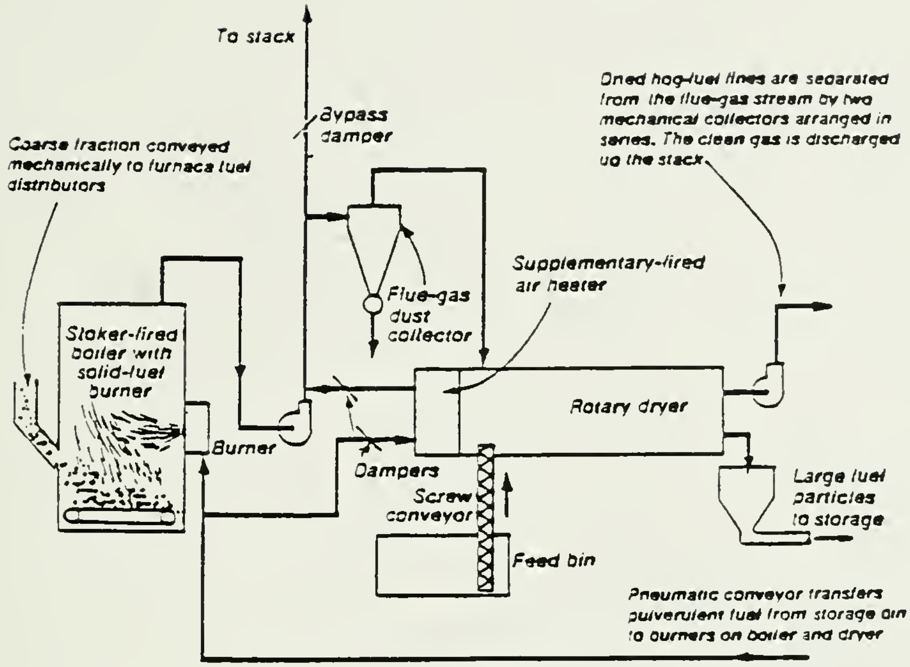
Moisture Content (as received, %)	Gross Heating Value (as-fired), Btu/lb[1]	Net Heating Value (heat available for steam production), Btu/lb[2]	Boiler Efficiency %[3]
15	7440	5767	77
30	6125	4505	73
40	5250	3682	70
50	4375	2860	65
60	3500	2038	58

Source: North Carolina State University, School of Forest Resources.
1/Assumes a higher heating value of 8750 Btu/lb for wood and bark.
2/Assumes a stack temperature of 500° F and excess air (%) equal to the percentage of moisture contained in the fuel.
3/Overall efficiency is found by subtracting other losses - such as radiation, blowdown, etc.

Source: "Power From Wood", Power, February 1980.

Figure IV-1

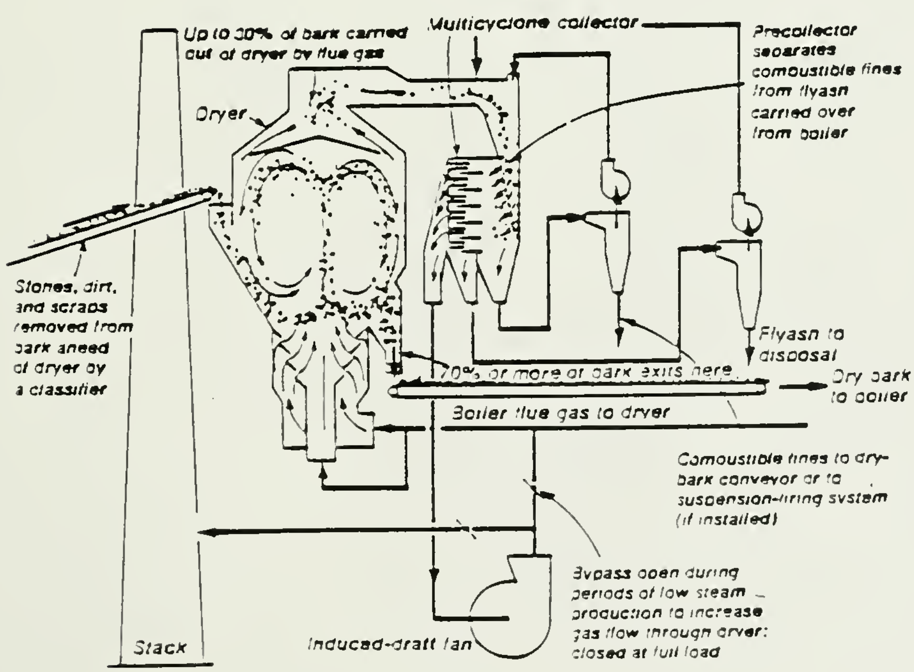
ROTARY DRUM DRYER



Source: "Power From Wood", POWER, February 1980

Figure IV-2

CASCADE DRYER



Source: "Power From Wood", POWER, February 1980.

Table IV-3

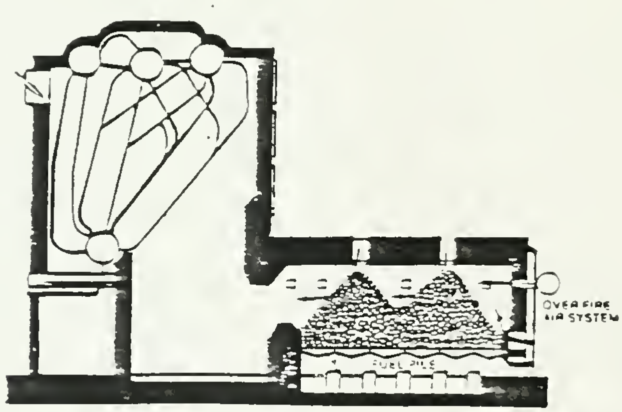
TYPES OF WOOD-FUELED COMBUSTION SYSTEMS

TYPE OF FURNACE	STEAM CAPACITY (LBS/HR)
Dutch Oven	Up to 50,000
Water Cooled Grates	Up to 150,000
Spreader Stokers:	
Traveling Grate	Up to 250,000
Vibragrate	Up to 150,000
Dumping Grate	Up to 80,000
Cyclone Burners:	
Water Cooled	200,000 and up
Refactory	Up to 50,000
Suspension Firing	200,000 and up

Source: "Boiler Hardware for Burning Woodwaste", Energy and the Wood Products Industry, Forest Products Industry, Forest Products Research Society, 1976

Figure IV-3

DUTCH OVEN



Source: "Improved Operation of Dutch Oven Boilers" Hardware for Energy Generation in the Forest Products Industry, 1979.

- **Pile Combustion**

  - Dutch Ovens

    Dutch ovens and similar furnaces are the oldest method of wood burning. The oven utilizes a refractory lined combustion chamber in which the wood, piled up to a foot, is dryed and gasified with the combustion of the volatile matter being completed in the second chamber (see Figure IV-3). Dutch Ovens are rarely installed today because of high maintenance costs, poor load following characteristics, and manual ash removal. Refractory-lined fuel cells are similar to Dutch Ovens except that the flue gas exits through the top of the combustion chamber rather than the back or side.

  - Cyclone Furnace

    In a cyclone furnace, woodwaste is fed from beneath a grate via a screw conveyor. Preheated air is fed through the gate while cold, high pressure air is fed tangentially at the top of the furnace. These units can burn woodwaste with up to 68 percent moisture without an auxiliary burner and with extremely clean combustion gas. Disadvantages are the same as the Dutch Ovens.

- **Semi-pile Combustion**

  - Inclined Water-Cooled Pinhole Grate

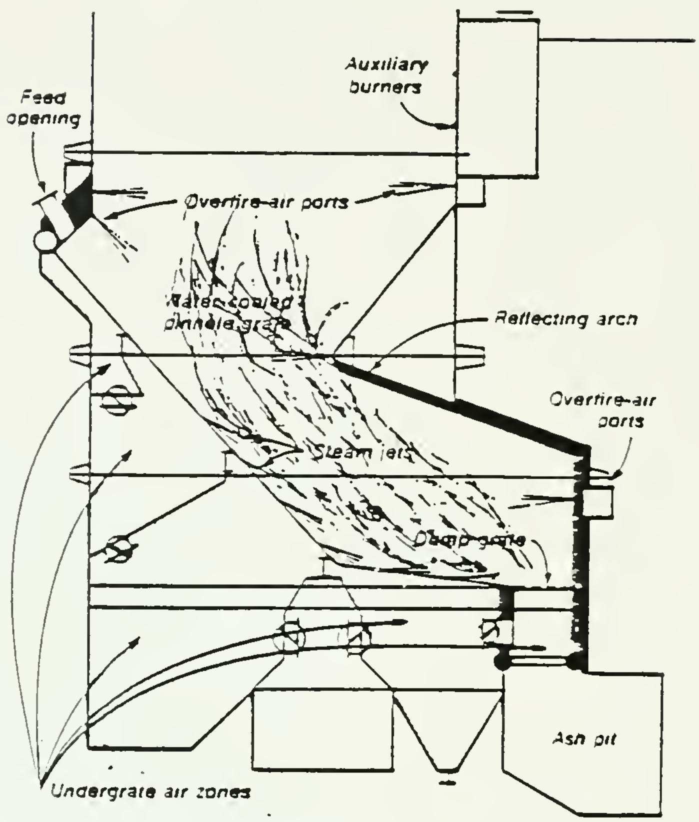
    In these boilers, hogged or unhogged woodwaste is fed onto an inclined grate (angle of approximately 55^{o}) where it slides toward the bottom with drying, vaporization and combustion occuring during this movement (see Figures IV-4 and IV-5). Air is fed from beneath the grate as well as above, and steam jets located on the grate blast ash down to the bottom of the furnace. The grate blocks are mounted on cooling water pipes, and within each block there are "pinholes", about 5/16" in diameter through which 75-80 percent of combustion air is fed.

- **Semi-suspension Firing**

  In semi-suspension firing, hogged wood is fed onto a grate by pneumatic distributors to form a thin, even bed. The type of grate chosen depends on the size of the boiler and the requirements of the industrial use.

Figure IV-4

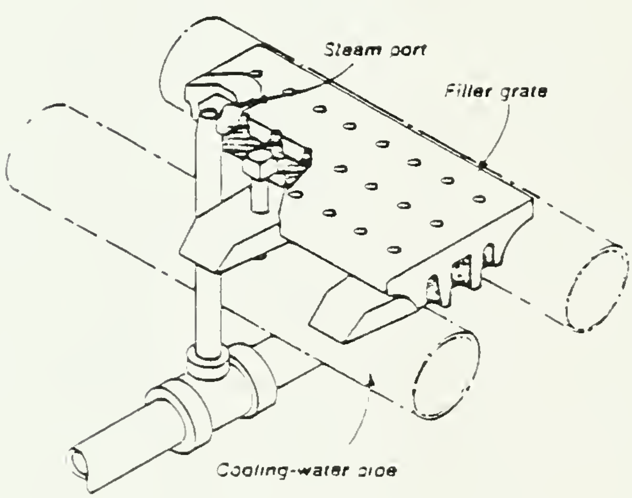
INCLINED WATER COOLED GRATE



Source: "Power From Wood", POWER, February 1980.

Figure IV-5

PINHOLE GRATE DESIGN



Source: "Power From Wood", POWER, February 1980.

- Flat Air-Cooled Grates

  Flat air-cooled grates are more economical than water cooled grates for boilers producing less than 70,000 pph steam. A wide range of designs is offered by various manufacturers.

- Water-cooled Grates

  Water-cooled grates have higher heat utilization rates than air-cooled grates and permit the use of a smaller furnace for a given steam demand. They can handle fuel with up to 55 percent moisture without auxiliary firing. Since a water cooled grate can be totally fired with auxiliaries if desired non-forest industries may desire this capability in case of a hog fuel supply interruption. Both designs require minimal maintenance, exhibiting high reliability.

- Traveling-grate Spreader Stokers

  Traveling-grate spreader stokers provide continuous ash discharge, accurate load control, and the ability to burn coal with wood. The traveling-grate spreader stoker is the popular choice for boilers rated 175,000 pph or greater with fuels containing 55 percent moisture or less. However, it is more expensive than the pinhole grate. It should be remembered that if the unit is designed for wood steaming capacity will be lower on coal where control of primary air is necessary to prevent slagging.

- Water-cooled Vibrating Grates

  Water-cooled vibrating grates are the most expensive design, but it can burn fuel with a higher moisture than a traveling grate with advantages similar to the traveling grate spreader stokers.

• Suspension Firing

  Suspension burning can only be done with clean, dry, finely divided woodwaste such as sanderdust. These systems burn clean enough to be installed on packaged boilers designed for oil or gas.

- Scroll Feed Burners

  Scroll feed burners inject dry wood fines in an annualar scroll discharge between two oppositely rotating combustion air streams. A standing pilot is recommended to ensure re-ignition if there is a disruption of the fuel flow.

- Suspension Burners

  Suspension burners fire small pieces of woodwaste containing less than 12 percent moisture by mixing the wood with air under pressure, and injecting the mixture through a nozzle into a refractory section of the burner where it is ignited.

- Cyclonic Burners

  Cyclonic burners are cylindrical furnaces in which dry wood particles are injected, swirled by combustion air and burned before reaching the end of the refractory chamber. They are usually used for direct drying due to relatively high cost. Experience with cyclonic furnaces is satisfactory when operated in a non-slagging mode; however, there have been problems with units attempting to remove ash as molten slag.

- **Regulatory Aspects**

The only environmental problem associated with burning wood is particulate emissions. In order to lower particulate emissions to a permissible level (.2 - .4 lbs/million Btu) it will probably be necessary to use a scrubber, bag filter or electrostatic precipitator. However, it is possible that some systems, burning clean woodwaste, may be able to meet emission requirements with only mechanical collectors. The ten percent investment tax credits for alternative energy property applies to wood burning furnaces. See cogeneration section.

2. Technologies for Municipal Solid Wastes (MSW)

The basic purpose of incinerating MSW is reduction of the amount of waste destined for ultimate disposal in a sanitary landfill. Other purposes include sterilization of the waste and reduction of its putrescible content. This is accomplished by converting the organic part of the waste, through combustion, to the end products of carbon dioxide, water, ash and heat. In recent years, interest has grown in recovering this heat in the form of steam and electricity.

The only commercialized technology for energy recovery from solid wastes is incineration with heat recovery. The type of incineration technique depends on the quantity of refuse to be burned. Waterwall incinerators are often used for refuse quantities greater than 150 tons per day. Boiler efficiences are approximately 70 percent of heat input and steam production can be used for electricity or process purposes. Electrostatic precipitators are sufficient to meet particulate emission standards, while the low sulfur content of most refuse guarantees compliance with sulfur dioxide emission requirements (see Figure IV-6 for a process flow diagram). Given a load of 1000 tons per day of typical MSW, the steam output would be 250,000 pph, equivalent to the burning of 360 tons of coal per day. The volume of residue would be 10% of the original refuse stream. A plant this size would require a large metropolitan area (at least 500,000 people) to supply the required solid waste, and a large industrial customer or a district heating system would be needed to purchase the steam. Capital charges for a waterwall incinerator range from $15,000-30,000/ton/day capacity while operating costs are around $10-15/ton (1977 dollars).

Incineration of smaller quantities of refuse with heat recovery usually is accomplished with some combination of modular combustion units. These units are commonly dual chamber, starved air incinerators. In the primary chamber the solid refuse is combusted under conditions of starved air resulting in incomplete combustion and production of combustible particulates and gases. These gases and particulates are fed into the secondary chamber where they are mixed with additional air and burned at high temperatures. The flue gases then pass through a heat recovery boiler to produce steam (see Figure IV-7). The units are about 55% efficient while reducing waste volume by 90 percent. Costs are similar to waterwall incinerators but exact figures are difficult to determine because the technology has been steadily evolving during the last few years.

Figure IV-6

WATERWALL PROCESS FLOW DIAGRAM

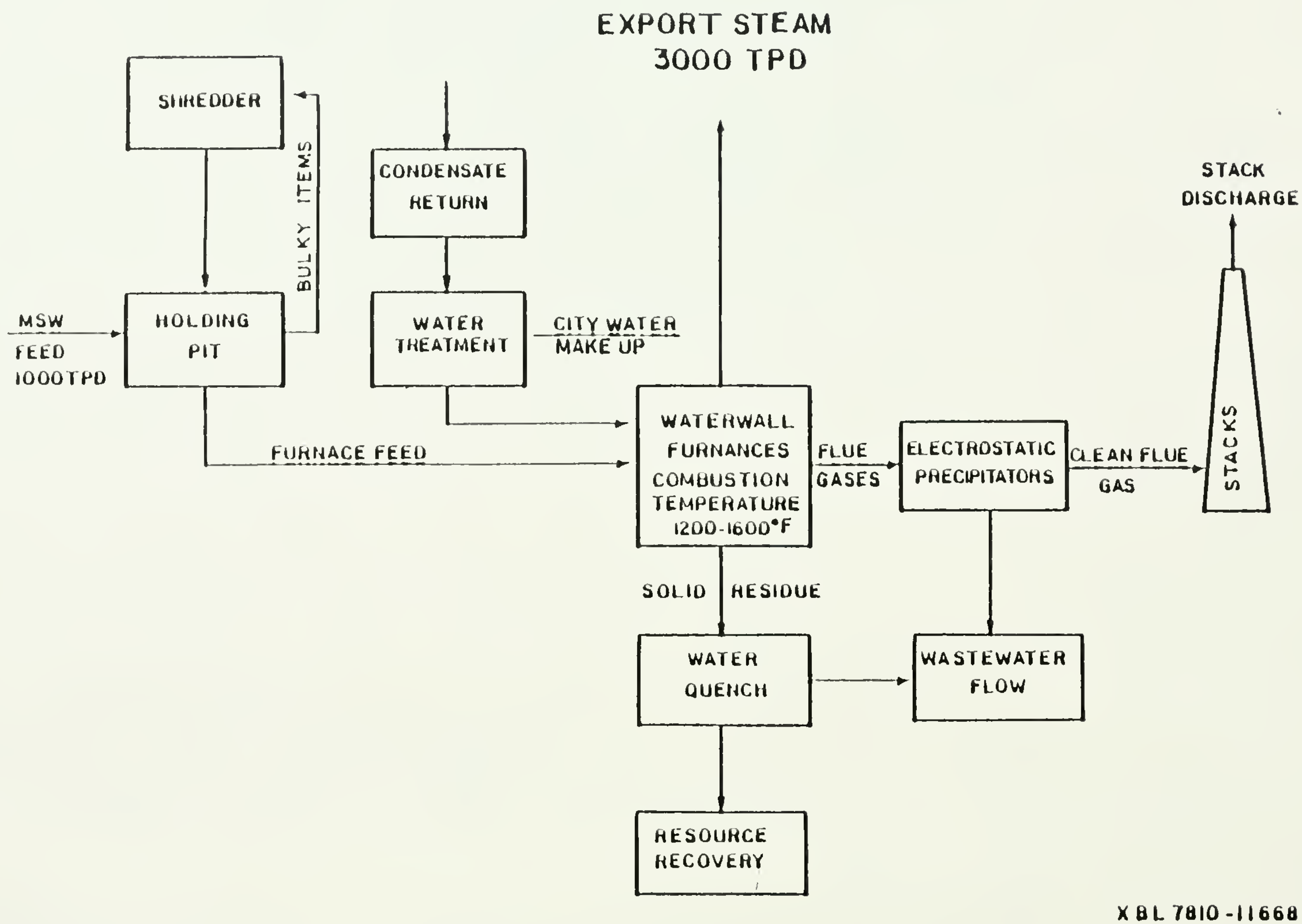
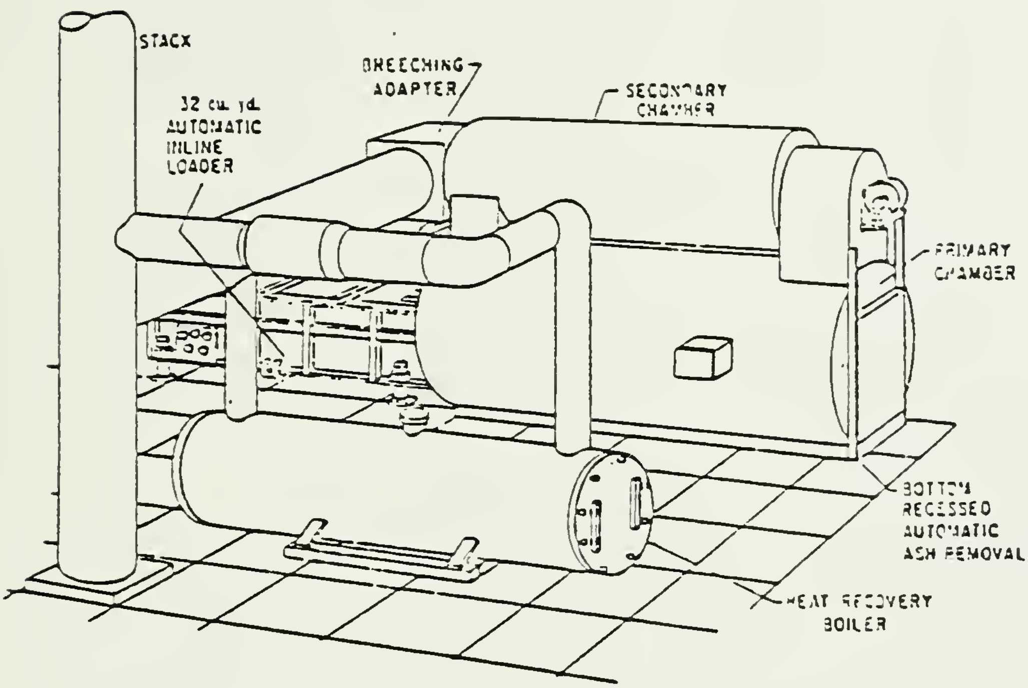


Figure IV-7

CROSS-SECTION THROUGH A TYPICAL TWO-CHAMBER "CONTROLLED" AIR INCINERATOR



The other technologies for energy recovery from waste have yet to demonstrate that they are capable of competitive performance relative to waste disposal alternatives. The most advanced of these technologies is the production of Refuse Derived Fuels (RDF). Solid wastes are shredded or milled for size reduction, followed by air classification to separate the light organic material from heavy organic material, glass and metals. The light fraction is called "fluff" RDF. It can be transformed into "densified" RDF by pelletizing or briquetting. Brittlizing chemicals can be added, followed by pulverization to produce "powdered" RDF. The heavy material can be further separated into various components such as glass cullet, aluminum, and ferrous scrap, which can be sold (see Figure IV-8). Materials separation can also be performed with other energy recovery systems; however the capital cost of separation equipment (air classifiers, magnetic separators, etc.) require a large quantity of waste and dependable customers located nearby in order to justify the investment.

There is a wet RDF process that is an adaptation of hydropulping technology. The refuse is fed into a hydropulper where it is chopped up in a water suspension. Large items are rejected and the remaining slurry fed into a liquid cyclone separator to remove additional heavy materials. The remaining material is partially dewatered, leaving RDF with a 20-50 percent water content which can be burned as supplement to coal, or alone in a fluidized bed combustor. The advantage of this technique is that it eliminates the fire hazard associated with dry RDF while allowing control of the moisture content in the fuel (Figure IV-9).

Pyrolysis techniques involve heating organic materials in an oxygen deficient environment to stimulate the physical and chemical decomposition of the solid waste. By controlling operating parameters such as temperature, pressure, type of catalysts, reaction time, etc., it is possible to control the composition of the pyrolysis products. Current pyrolysis technologies result in either a low Btu gas, medium Btu gas, or a liquid fuel.

Figure IV-8

DRY PROCESS RDF SYSTEM

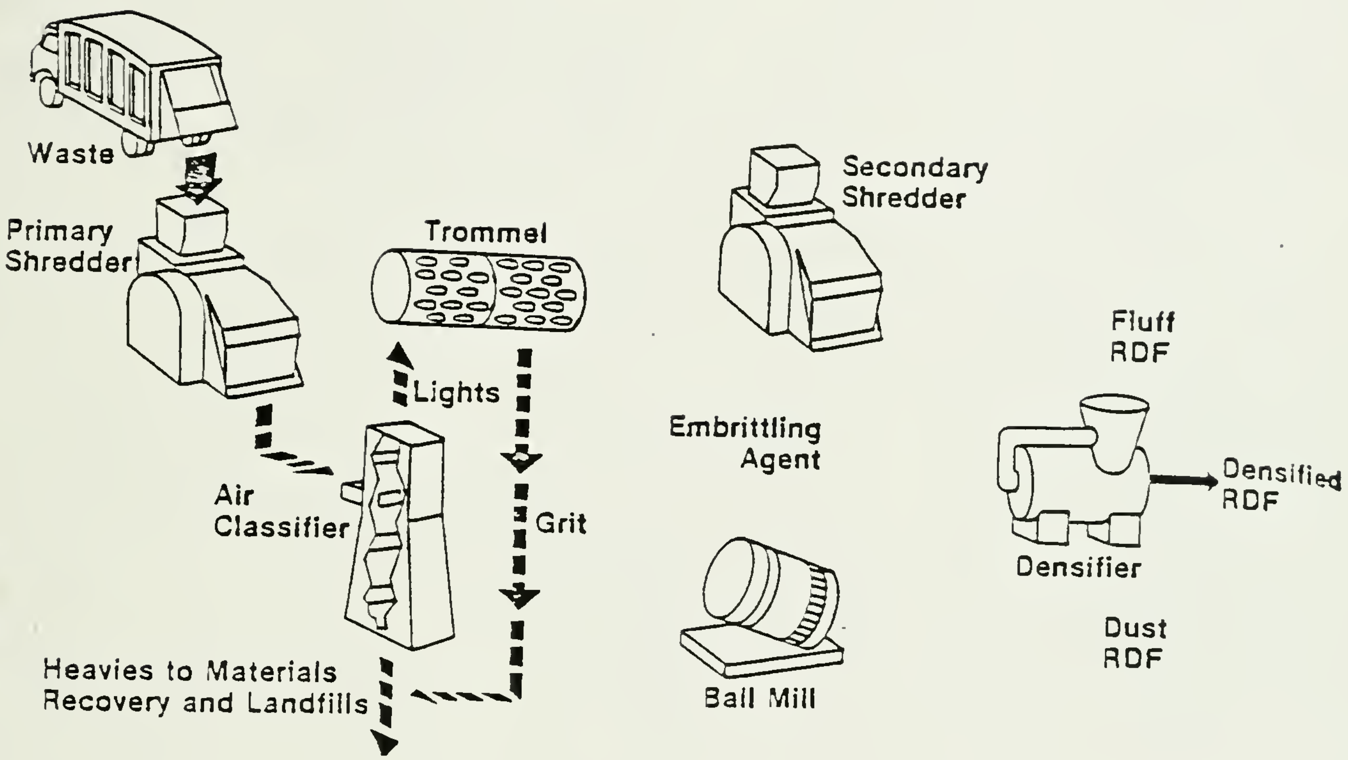
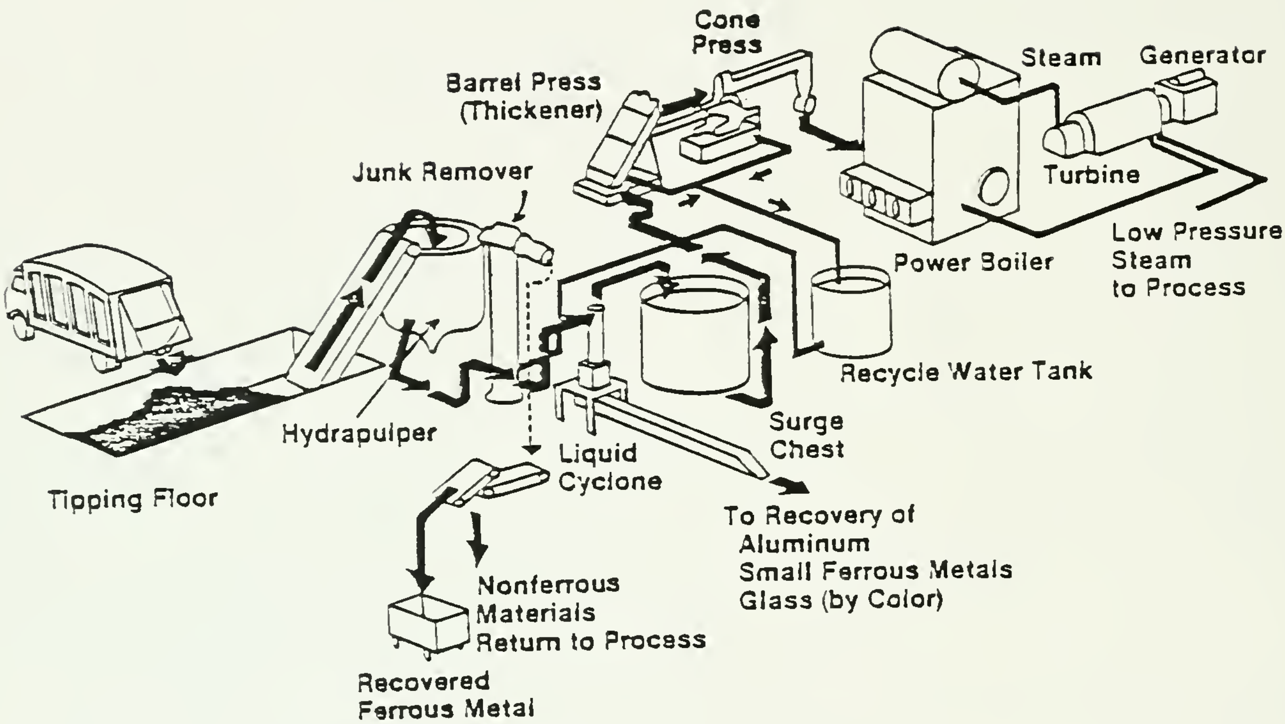


Figure IV-9

WET PROCESS RDF SYSTEM



Bioconversion methods use bacteria to convert organic wastes into compounds which can be further processed by fuels. Because of the possible toxicity of MSW and industrial waste, the optimum materials for bioconversion are sewage sludge, animal manure and crop residues. Two types of bacteria are used: acid formers that produce organic acids, and methane producers that create methane, carbon dioxide and small quantities of other gases.

Hydrolysis is a method used for the production of ethanol from solid waste. Acid hydrolysis, (a well-developed industrial method for producing ethanol for non-fuel purposes), and enzyme hydrolysis, (an experimental process), are the two methods under investigation. Hydrolysis works by converting cellulosic material, glucose, which is then fermented to dilute ethanol, followed by distillation to remove water.

Institutional and Regulatory Issues

Though energy recovery from solid waste is a desirable concept and, in many cases, financially attractive, there are various institutional constraints which need to be resolved when considering this sort of facility. If MSW is used, there arises the problem of deciding who should own and operate the facility, and how expenses and fees should be calculated and assessed. In rural areas, obtaining a sufficient supply of MSW may entail obtaining the agreement of various municipal and county officials in order to ensure a reliable supply of MSW. If the recovery facility is owned by a municipality, the energy purchaser will be expected to make a long-term agreement to purchase energy. If industrial waste is used in the facility, the industry will need to determine whether the energy recovery process meets the standards for hazardous and non-hazardous wastes under the Resource Conservation and Recovery Act of 1976 and the Clean Air Act Amendments of 1977. Disposal of residues is also influenced by RCRA. If hazardous waste is to be incinerated, the plant will have to be licensed as a hazardous waste disposal facility.

These two Acts, and other regulations, have helped to improve the economics of an energy resurce recovery facility. The limitations concerning landfills and the elimination of open dumps have increased the expense of conventional methods for the disposal of solid wastes. The Energy Tax Act of 1978 provides an additional 10 percent investment tax credit for energy recovery plants. The combination of increasing disposal costs and escalating energy prices will mean that a facility that was not economically feasible a few years ago may be so today.

B. GASIFICATION

This process releases bio-energy by heating wastes in limited amounts of air or oxygen. Wood wastes and wastes from food processing operations can be converted by this process. Gasification can produce synthetic natural gas (SNG), methanol, ammonia, hydrogen, carbon monoxide or synthetic gasoline. Saw mills and wood products manufacturing plants can use their wastes to generate gas for use in natural gas-fired boilers or turbines for electricity generation. With additional cleaning, the gas can be used for a reciprocating internal combustion engine as well.

The principal economic advantage of gasifiers is that they can be retrofitted to existing gas and oil fired boilers, thus saving some of the costs associated with switching to new, solid-fuel fired systems. In addition, gasification systems produce clear combustion products similar to the output of oil burners.

Gasification can be simply explained as a special case of direct combustion. In direct combustion, three processes continuously occur: (1) heating and drying of feedstock as it is brought from ambient to reaction temperature, (2) evolution of hydrocarbon gas for subsequent combustion, and (3) combustion of fixed carbon char. In gasifiers, processes (1) and (3) occur in a vessel under conditions of controlled temperature and oxygen starvation (pyrolysis). Most of the evolved gases in process (2) are not ignited. In addition, gases evolved from gasification of the char join the gases evolved in process (2) to form a low-energy gas. Various gasifier designs are briefly explained in the following pages.

1. Counter-Current Gasification

The simplest gasifier is the counter-current (updraft), fixed bed gasifier in which air or oxygen is introduced through grates in the bottom of the shaft furnace. High temperatures are generated when the air contacts the char, and as the combustion gases rise they encounter the descending biomass, which undergoes pyrolysis to produce char, tars, and gases. The rising combustion gases also contact the wet, incoming biomass and dry it. The gas produced will retain a heating value of 100-200 Btu/scf (standard cubic foot) for air-fed gasifiers, and 300-500 Btu/scf for oxygen-fed gasifiers.

A wide variety of chemicals, tars, and oils is produced during pyrolysis and, if allowed, will condense in cooler regions causing problems of tar formation. However, if the hot gas product is used in the "close-coupled" mode in which it is mixed immediately with air and burned completely, the tars will be burned off with the gas and will contribute to the energy value of the gas. Since all of the gas generated is combusted and the sensible heat of the gas stream is conserved in close-coupled gasifiers, these units can have very high efficiencies (85-90%). Alternatively, the product gas may be cooled and cleaned before product utilization occurs. This gas conditioning will increase costs and reduce the energy value of the gas.

2. Co-Current Gasification

Two basic types of co-current gasifiers exist: downdraft and cross-flow, of which the downdraft is the more important. Downdraft gasifiers are designed specifically to elminate the tars and oils from the gases. After passing through a drying zone, the biomass feedstock undergoes pyrolysis. The gases, tars, and char produced contact incoming air and are oxidized under high temperatures. The remaining chars and gases then pass through a cooler reduction zone where most of the tars are broken down into gases. These gases can then be used with minimal filtering to fuel spark and diesel engines, the principal use of downdraft gasifiers. Downdraft gasifiers are highly sensitive to moisture and cannot tolerate content greater than 30 percent.

3. Fludized Bed Gasification

Fluidized bed gasifiers offer the potential for a much greater through-put and gas production capacity. In this type of gasifier, the bed of biomass particles is pneumatically mixed with a hot granular material, such as sand. A very rapid pyrolysis occurs, resulting in a short residence time that permits a much greater volume of biomass to be gasified. The gases formed by the pyrolysis reaction exits the gasifier and enter a cyclone separator where the entrained char is removed. A potential advantage of the fluidized bed gasifer is its ability to produce charcoal as a solid energy product. Charcoal has a high heating value, making it an excellent means of storing energy in more dense concetrations then biomass This ability to store energy allows an industry to solve the problem of producing energy in excess of its actual plant needs.

The gases produced by the gasifiers can be burned in existing oil/gas installations. The gas is somewhat more difficult to burn than natural gas, and requires insulated piping to prevent condensation of pyrolysis oils and tars. A gas pilot flame or a flame holder is used to ensure combustion. The temperature of the low-Btu gas flame will be lower than that of natural gas or oil, so it is possible that some de-rating of the boiler will be necessry. Operating costs will be higher for the retrofit gasifier due to maintenance of a solids handling system, while fuel costs will, of course, be significantly lower.

Gasifiers require fuel with a moisture content of less than 30 percent, so drying of the biomass fuel before burning may be required. Two methods of drying are used: the rotary drum dryer, and the suspension dryer. When the gas is to be used as engine fuel, waste heat sources from the jacket coolant and exhaust gases can be used to predry the gasifier fuel. Alternatively, the drying system can make direct use of boiler flue gases as a heat source. Drying equipment is expensive to install and operate.

The fuel used by the gasifier will require processing through a device that reduces the size of the particles (known as "hogging"). A system involving a screen and hog (such as a hammerhill) is commonly used, reducing energy use and maintenance costs by screening out correctly sized fuel and hogging only the oversized fuel. Fixed bed gasifiers are most suitable for fuels of larger sizes (more than 1/4 inch), and fluidized beds can operate with a range of sizes. More information on fuel preparation is presented in Section III.

C. ANAEROBIC DIGESTION

This biological conversion process is the controlled decay of organic material in the absence of oxygen to produce methane. Manures, argicultural wastes, sewage, paper, sea weed and algae all can be converted to produce methane gas. This section will describe the digester systems currently available.

1. Digester Systems and Designs

Digester systems are of two basic types: batch process and continuous feed. The batch type digester is filled with a slurry of organic materials that is left to digest for a specified retention period, after which the digester is emptied and refilled. This system is advantageous where the materials are available only sporadically. Batch digesters require little daily attention. However, gas production is variable in batch systems, starting out at a very low rate and increasing to a peak and then declining again. This is undesirable if a continuous user of the biogas is available. The disadvantage of uneven gas production can be reduced by use of additional digesters filled at regular intervals. However, investment in numous batch digesters will usually be uneconomic on small farms.

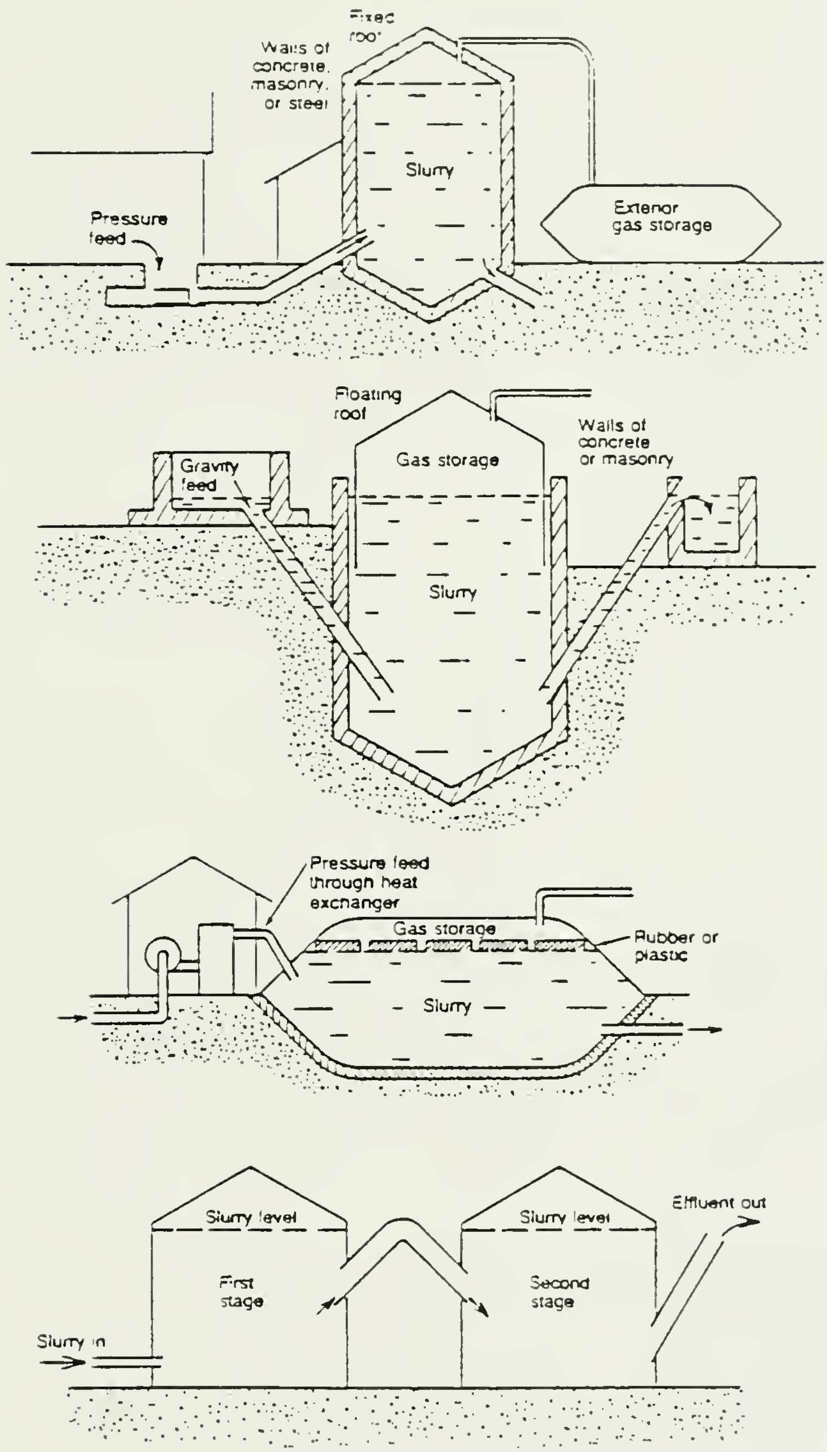
Continuous-feed digesters are better suited to the continuous supply of animal wastes on farms and feedlots. These digesters are loaded on a regular schedule, usually daily, with a fraction of their capacity, and an equal fraction is unloaded. The loading amount is generally the amount of manure slurry produced each day. The size of the digester is then determined by the desired retention time. Retention time in days (usually 10 to 20) multiplied by the daily loading volume will determine digester size.

2. Structures and Structural Components

A wide variety of structures have been used for digesters of animal wastes. Figure IV-10 shows some examples. The variations usually are effects of slurry feed systems and gas storage alternatives. A rigid structure with a fixed roof can be used if an exterior storage system is available for biogas (Figure IV-10). However, even with continuous use of biogas some gas storage capacity is required in order to account for minor variations in gas production rates. A floating roof design (not unlike many petroleum storage facilities) can incorporate the minimum storage capacity if biogas is to be used constantly and continuously. Flexible walled digesters (Figure IV-10) will also allow some gas storage, and are inexpensive. Use of gravity or pressurized feed systems will determine whether the digester is built below or above ground level. Pumped feed systems are more expensive and more complex (prone to mechanical failures); however, excavation costs for below-ground digesters may be high, depending on site layout and existing topography. One advantage of below-ground digesters, even with pumped feed, is the potential for reduced heat losses in cold climates.

Figure IV-10

TYPICAL DESIGNS OF AGRICULTURAL DIGESTERS



Source: Pennsylvania State University College of Agriculture, Bulletin 827, November 1979, "Agricultural Anaerobic Digesters, Design and Operation."

The two-stage digester design (Figure IV-10) was developed on the basis of two definite steps in the microbial process of the anaerobic digester: the acid forming and the methane forming stages. It has been suggested that this design should be more efficient, although there seems to be no operating data to support the suggestion. The two stage design may be two separate chambers or one chamber with a dividing wall.

3. Slurry Preparation

The most efficient digestion process will result if manure is fed into the digester as soon as possible after it leaves the animal. Delays in moving manure from animal housing to digester are to be avoided. The slurry preparation area should be kept warm in order to avoide equipment damage. Location within or next to the animal shelter is suggested in order to take advantage of the animal heat. This area is one of the most likely trouble spots, according to digester operators, so planning for reasonable access area to all equipment should be made.

A water supply will be needed, for addition of water to manure is essential in order to maintain a constant solids/slurry level acceptable to all equipment used. Mechanical manure collection systems should feed directly into a hopper that feeds the mechanical or gravity digester feed systems. This hopper, and water supply to slurry, help to ensure a mixed and fluid feed to the digester and also reduce the chance of air (which is toxic to methogenic microbes in the digester) being pumped into the digester. Dilution water may also be needed to prevent ammonia toxicity.

A temporary storage area should also be provided for manure, in case of equipment failure.

4. Storage of Digester Effluent

The required storage area for the digester effluent will depend upon the desired use for this effluent. If the residue is to be spread on fields daily, only a storage area for two or three days effluent would be needed, in case of equipment or weather problems. However, if the residue is to be spread at the best time for land application, then a larger storage area will be needed. In Iowa, the Water Quality Commission recommends that land spreading on snow covered or frozen ground be avoided; thus, storage for several months may be in order.

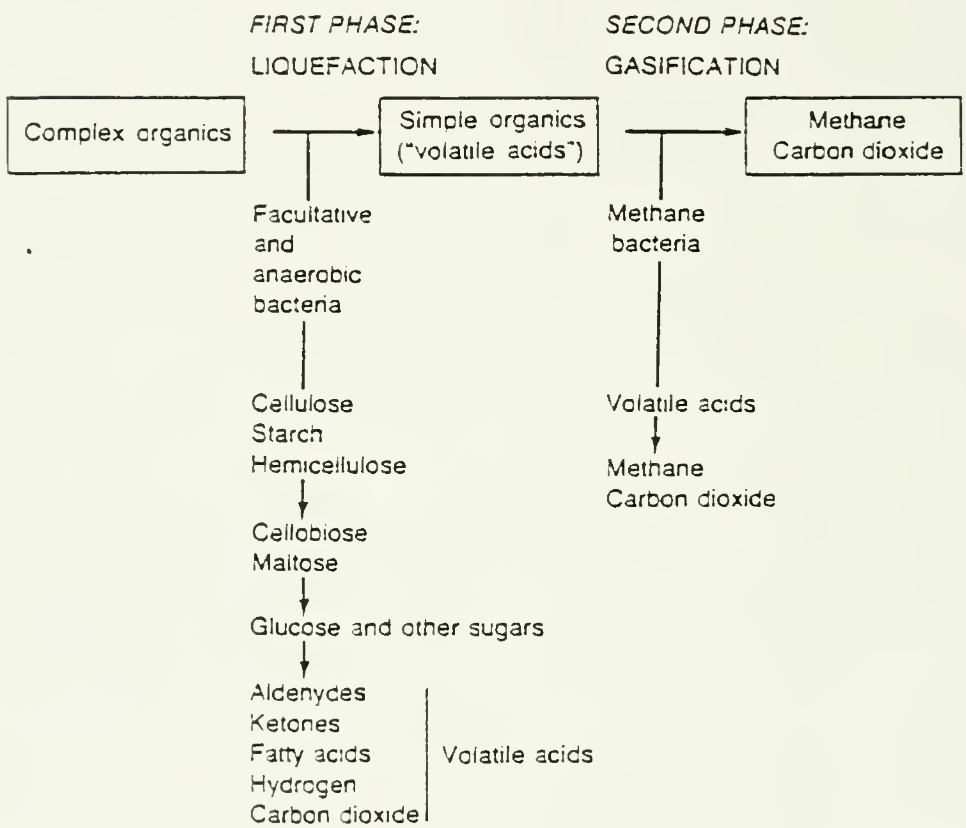
Separation of liquids and solids may be desirable so liquids could then be distributed as fertilizer by irrigation or other methods. More importantly, it may be possible to recycle some water back into the digesten slurry, reducing storage requirements and water usage. Solids storage requires no special facility. These could be spread on fields when desired (as a soil conditioner), used as bedding material, or refed to beef cattle.

5. Characteristics of Anaerobic Digestion

Many factors influence digester preformance. The process of anaerobic digestion is a complex chemical and microbiotic process well understood by scientists in its purist sense, when precise chemical and biological components are known. However, the actual digestion of animal wastes, mixed with bedding materials, uneaten feed, and other unknown contaminates defies precise description. A simple flow diagram, such as in Figure IV-11, shows the basic process. Two types of anaerobic bacteria, acid-forming and methane-forming bacteria, break down complex organic compounds into simple organics and then into methane, carbon dioxide, and other gases. Since this is a complex process acting upon a complex mixture of materials, the actual results of the process vary due to many factors.

Figure IV-11

SIMPLIFIED DESCRIPTION OF ANAEROBIC DIGESTION PROCESS



Source: Pennsylvania State University College Of Agriculture,
Bulletin 827, November 1979.

6. Slurry Composition

The animal from which the manure comes is a major influencing factor, as the animal's diet and digestive system determine manure composition. Beef cattle, dairy cows, swine, and poultry, the four major animal waste producers in Montana, are represented in Table IV-4. A discussion of some specific factors of manure composition and their influence on digester operations follows.

Manure, as used in this discussion, includes feces, urine, bedding material, wasted feed, anti-slip materials and grit tracked into the barn by animals and workers. The composition of manure will vary for different animals, as well as for each farm. Seasonal changes in farm operation and diet will also affect composition. Major components of manure are water, organic matter, and ash. The organic compounds include protein, starch, fat, cellulose and lignin. Dairy cow manure, for example, have been determed to contain as much as 30 percent cellulose and 20 percent lignin (weight of solids basis). The major element in manure is carbon; other chemicals include nitrogen, oxygen, hydrogen, and minerals.

The carbon-to-nitrogen ratio can significantly affect digester operation. Carbon and nitrogen are the principal elemental nutrients for anaerobic bacteria. The carbon component is converted into methane, and nitrogen is necessary as food for the bacteria and as a catalyst for the process. However, if the nitrogen content is too high, the process is retarded or stopped. The optimum carbon-nitrogen ratio is believed to be between 16 and 30. The availability of carbon and nitrogen in manures varies for different animal species, with age and diet of the animals, and with manure management.

The carbon content in dairy manure is slightly higher than that required for an efficient balance, and swine and poultry manures usually have excess nitrogen. Consequently, adding swine or poultry manure to the dairy manure will increase gas production and the efficiency of solids reduction. However, this is not practical unless the two livestock species are housed on the same farm, or a cooperative venture is established that includes both species. Conversely, digestion of swine or poultry manure becomes more effective when material that contains excess carbon (in relation to nitrogen), such as bedding or litter, is added.

Only a fraction of volatile solids in manure can be converted to gas by bacteria. Lignin is practically unaffected by bacteria in a digester, and cellulose is broken down only very slowly. Biological oxygen demand (BOD) value may be used as a measure of biodegradability of the slurry. A BOD to volatile solids (VS) ratio of about 1 indicates that most of the volatile solids can be converted. Dairy manure, for example has a low BOD/VS ratio, about 0.25, whereas swine and poultry manure show higher values. On the basis of volatile solids percentage (of total solids) and the BOD/VS values available for daily manure, as little as 20 percent of the total solids may be available for conversion in the digester.

Based upon some analyses for typical incoming solids, the expected production of biogas (at 60 percent methane) is estimated at 11 cubic feet of biogas per pound of converted volatile solids. Conversion rates are often given relating gas output to the amount of volatile solids fed to the digester (as in Table IV-4). These figures are less than 11 cubic feet per pound because (1) not all volatile solids are biodegradable and (2) not all biodegradable solids are converted in the time that they remain in the digester (retention time).

7. Landfill Biogas

The natural process of anaerobic digestion of municipal waste in landfills produces biogas -- a mixture of methane, carbon dioxide, nigtrogen and trace amounts of other gases. Once the landfill is covered with an impermeable surface, the biogas is recoved by drilling

Table IV-4

RETENTION TIME, LOADING RATE, SOLIDS CONCENTRATION, GAS PRODUCTION AND SIZE FOR FARM DIGESTERS

Manure source	Concentration of input slurry	Retention time	Daily VS a/ loading rate (per unit digester volume)		Daily biogas production: Per unit digester volume		Daily biogas production: Per animal		Digester volume per animal	
	(% TS) b/	(days)	(lb/ft^3)	(kg/m^3)	(ft^3/ft^3)	(m^3/m^3)	(ft^3)	(m^3)	(ft^3)	(m^3)
Dairy										
Design c/	13	14	0.5	8	1.9	1.9	53	1.5	28	0.8
Range d/	6-20	10-30	0.13-0.7	2-11	0.7-2.0	0.7-2.0				
Beef										
Design	10	18	0.3	4.8	2	2	38	1.1	19	0.53
Range	5-10	15-40	0.25-0.31	4-5					7-46	0.2-1.3
Swine										
Design	9	21	0.22	3.5	2	2	8	0.23	4	0.11
Range	2.5-11	10-30	0.08-0.31	1.2-5	0.1-2	0.1-2			1.4-14	0.04-0.4
Poultry										
Design	8	40	0.13	2	0.4	0.4	0.15	0.004	0.35	0.01
Range	7-14	20-50	0.11-0.21	1.8-3.4	0.01-0.9	0.01-0.9			0.2-0.4	0.006-0.012

a/ VS = volatile solids (total solids less ash content of 1-2 percent).
b/ TS = total solids.
c/ Value suggested for design of modern high-rate digesters.
d/ VAlues reported by various workers with farm-size digesters.

Source: Pennsylvania State University, Bulletin 827.

shallow wells (between 30 feet and 100 feet deep) into the landfill and using standard industrial compressors to create pressure differentials between the landfill and the collecting wells. After processing, the biogas can be used on site or transported to nearby industrial facilities. The heating value of the biogas at the wellhead is between 450 and 550 Btu per cubic foot. Some projects find it more economical to use carbon dioxide removal techniques to produce a high-Btu product which gas companies use to augment their supplies.

Recovering the gas from landfills can reduce some of the environmental hazards associated with landfills such as gas accumulation and explosion. Research directed towards improving the efficiency and environmental safety of the recovery technology is continuing in response to the positive results of the early operational sites.

8. Opportunities for Utilization of Biogas

Biogas has a composition of approximately 60 percent methane and 40 percent carbon dioxide and other gases. The compositions of biogas and natural gas are compared below. (Specific information on the Btu content of natural gas delivered in various Montana localities is presented in Appendix E.)

	Biogas	Natural Gas
Methane (%)	54-70	96.1-98.1
Carbon dioxide (%)	27-43	0.8
Hydrogen sulfide (%)	1-5	---
Carbon Monoxide (%)	0.1	---
Hydrogen (%)	1-10	---
Nitrogen (%)	1-5	1.1-3.2
Oxygen (%)	0.5-1	---
Others (%)	trace	---

Source: Vause, 1980.

The heating value of biogas ranges from 540 to 700 Btu per cubic foot; the exact value is determined by the methane content. Biogas can be upgraded to essentially pure methane by removing the carbon dioxide. Methane has a heating value of approximately 1,000 Btu per cubic foot.

Biogas can be utilized as an energy source as the mixture of methane and carbon dioxide as produced or converted into pure methane. Pure methane can be produced from biogas by scrubbing the carbon dioxide and other gases from the mixture. Though gas scrubbing is not particularly complex, the systems require substantial capital investment. Therefore, carbon dioxide removal should only be considered when methane can be sold for pipeline distribution or when substantial storage is necessary. Energy in the form of pure methane can be stored more compactly than in the form of biogas. Biogas has various potential household and farm uses; its use as a vehicle fuel is usually limited by the unfavorable economics of gas storage, i.e., low pressure storage requires very large container volumes while high pressure storage requires expensive compression equipment. Hydrogen sulfide and water can be removed to minimize corrosion and plugging effects, although not all impurities need to be removed for every use.

Biogas can be used directly in boilers and water heaters of many types with only minor modification of equipment. Burner equipment modifications include:

- Enlargement of burner nozzle orifices from the standard natural gas or LP designed orifices. The heating value of biogas is only 30 percent of LP gas and 60 percent of natural gas. LP gas burner orifices should be enlarged by about 70 percent.

- Air supply to the burner should be reduced. Air inlet ports on conventional boilers can be almost entirely closed.

- A separate fuel source, such as LP gas shoud be used for pilot fuel. This is primarily a precaution should the supply of biogas be interrupted.

In addition, one treatment measure -- the removal of water vapor -- should be provided for biogas before combustion in boilers and water heaters of any type. A system for cooling and heating the gas in combination with condensate traps will facilitate the delivery of biogas to valves and orifices without risk of condensation in these narrow channels. An example of such a moisture removal system is shown in Figure IV-12.

Biogas-fueled engines are common in municipal sewage treatment plants. Many experimental digesters have furnished gas for engines, tractors, trucks, or automobiles. However, a fuel tank that would store sufficient biogas to operate a mobile vehicle will be quite large, so use of biogas as a motor fuel will likely be confined to stationary engines.

Biogas has a high (100 to 110) octane rating and consequently can be used in high compression engines. However, the high octane rating also means that the fuel mixture must be ignited by a spark or by some other fuel. In spark-ignition engines, biogas alone can be used as fuel. In diesel engines, however, a small amount of regular diesel fuel must be injected in order to achieve ignition of the biogas. In this case, the engine may run on 20 percent diesel fuel and 80 percent biogas.

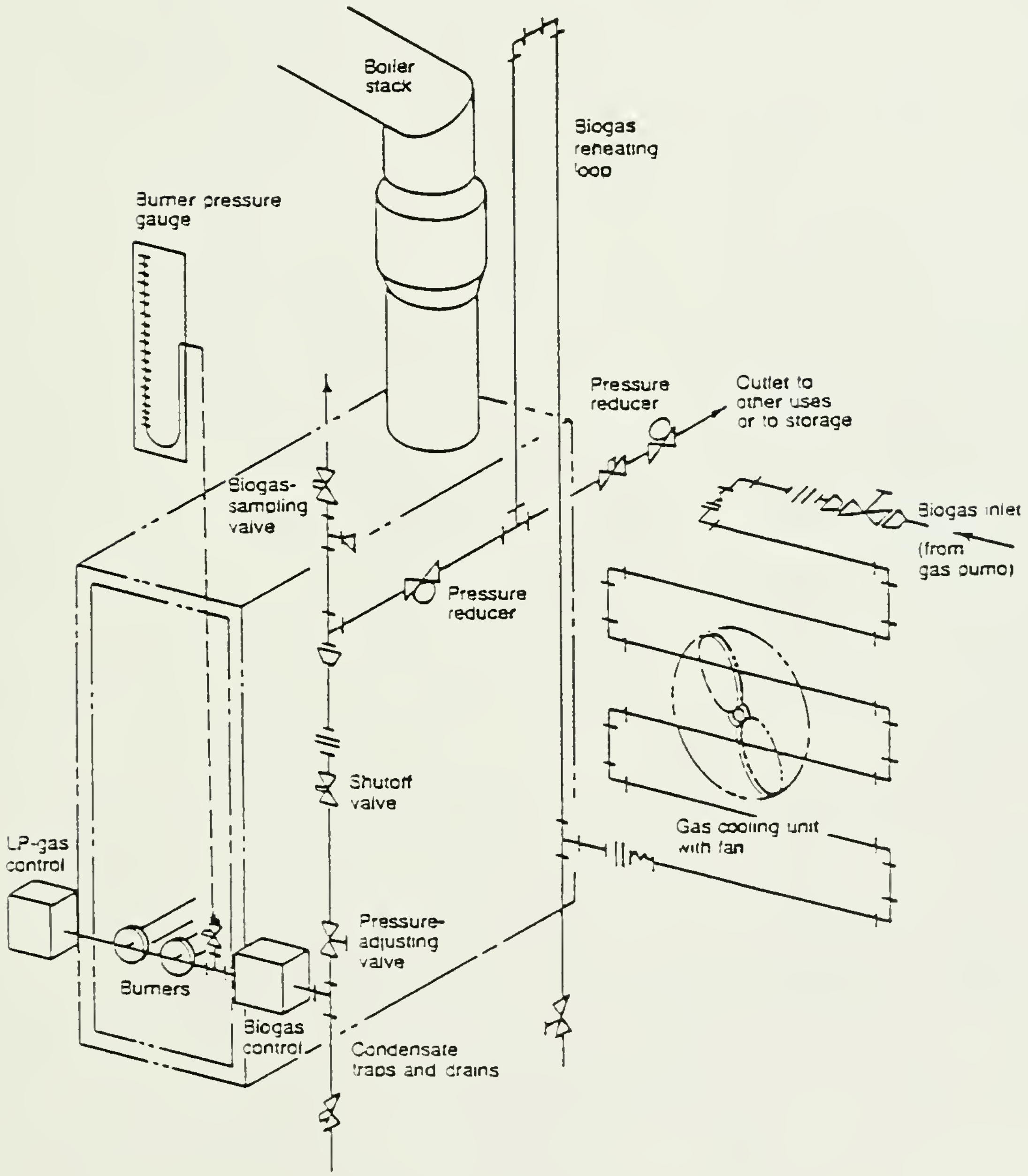
The heat value per unit volume of an appropriate biogas-air mixture is only 60 percnt of the heat value of a gasoline-air mixture, and only 75 percent of the heat value of the fuel mixture used in a diesel engine. Consequently, the maximum power output from an engine operated on biogas will be 20 to 40 percent less than that of the engine operating on liquid fuels.

Conversion of a compression-ignition (diesel) engine from liquid fuel to dual fuels, is more complicated than conversion of a spark-ignition engine; however, energy conversion should be more efficient with a diesel operation.

Figure IV-12

SYSTEM FOR MOISTURE REMOVAL FROM BIOGAS

BEFORE COMBUSTION



Source: Pennsylvania State University College of Agriculture, Bulletin 827.

Potential uses of biogas are direct burning for boiler fuel, space heating, cooking, crop drying, in stationary engines, and engine/generators for the production of electricity. The biogas produced by the cooperative may be used at an adjacent or nearby energy-consuming facility, such as a factory or a process plant.

V. COGENERATION: ECONOMIC AND FINANCIAL CONSIDERATIONS

V. COGENERATION: ECONOMIC AND FINANCIAL CONSIDERATIONS

COGENERATION - OLD GAME, NEW RULES

A number of significant changes have occurred in the last few years relative to the institutional and regulatory aspects of cogeneration and small scale power production.

The National Energy Act (NEA) of 1978 contains a number of important provisions which attempt to remove institutional barriers to cogeneration/self-generation. The most important provisions are in the Public Utility Regulatory Policies Act (PURPA), which provides the following for facilities that "qualify" by meeting certain operating and efficiency requirements (7).

- Utilities must purchase any and all power that the qualifying facility (QF) wants to sell.
- The rate offered by the utility for such power purchase should be based on the "avoided cost" of the utility.
- The rates charged by a utility to a QF for standby/backup power must be non-discriminatory.
- The QF is exempted from utility regulation under the Federal Power Act, the Public Utility Holding Company Act and state regulations related to rates and financial reporting.

To qualify, the facility must not be more than 50% owned by an electric utility. A self-generation (small power production) facility must be smaller than 80 MW and use biomass, waste or renewable resources to produce electricity.

In addition to PURPA, three other parts of the 1978 NEA also provide incentives for cogenerators. The Powerplant and Industrial Fuel Use Act (FUA) allows cogenerators to be exempted from prohibitions on the use of oil and natural gas. The Natural Gas Policy Act (NGPA) provides an exemption from incremental pricing of natural gas to cogenerators. The Energy Tax Act (ETA) provides a 10% investment tax credit for certain property which may be used with cogeneration systems. Also, additional incentives were provided in subsequent legislation passed by the 96th Congress (8).

Recent Federal Court rulings in Mississippi (which ruled PURPA unconstitutional) and in the D.C. Court of Appeals (which asked FERC to reconsider the 100% avoided cost rule and the requirement for utilities to interconnect with a QF) created some uncertainties in PURPA implementation. The Supreme Court recently overturned the Mississippi ruling, and has agreed to hear an appeal by FERC of the D.C. Court of Appeals ruling. However, a resolution of the latter case is not likely to occur until spring 1983.

TECHNICAL OPTIONS FOR COGENERATION

Cogeneration can be achieved by "topping" or "bottoming" cycles. Topping cycles involve the secondary utilization of thermal energy after the electricity generation process. (In some cases, the thermal energy would have been conventionally treated as "reject heat" and have no value.) In bottoming cycles, on the other hand, thermal energy is used in an industrial process first, and the energy which would normally be rejected is used to generate electricity.

A number of different options are available for topping cycles. These include:

- Extraction steam turbines
- Back-pressure steam turbines

- Gas turbines
- Gas turbines with waste heat boiler
- Combined cycles (steam turbine and gas turbine)
- Low-speed diesels
- Fuel cells
- Other new technologies.

Bottoming options include:

- Low-pressure Rankine cycle
- Stirling cycles
- Brayton cycles.

Most existing cogeneration systems use steam turbines (extraction or back-pressure), gas turbines or diesels. Steam turbines, of course, represent the most prevalent method for electric power generation. For cogeneration, steam is taken from the turbine at a pressure and temperature appropriate for the process energy needs (generally much higher than the energy conventionally rejected from a power plant). This is achieved by extracting the steam at an intermediate step in the turbine (extraction turbine) or by having the steam exhausted from the turbine at a high pressure (back-pressure turbine). The result is a decrease in the amount of electricity produced per unit of steam and an increase in the availability of thermal energy. Gas turbines are also conventionally used for power generation. The exhaust from a gas turbine can be used as hot air for process use or passed through a waste heat boiler to generate steam. For a given quality of steam requirements, gas turbines can produce more electricity than steam turbines. However, under present technology, gas turbines need natural gas or distillate oils as input fuels, while steam turbines (at least large installations) can use coal-fired boilers. Diesel engines have a higher conversion efficiency than gas turbines but also require petroleum-based fuels. Steam turbine systems are generally economically feasible only in large sizes (over 10 MW). Gas turbines can be used to intermediate or large sizes -- there are many in the 1-10 MW range. Diesels can be as small as 100 KW.

New technologies such as combined cycle cogeneration or fuel cells with heat recovery are likely to be attractive technical options because of the possibility of decoupling the electric and thermal outputs (changing the ratio of electric and thermal output). Other new technologies, including solar and geothermal, can also be used to generate electricity and thermal energy, and are currently being researched, but are not likely to achieve significant penetration in the 1980's.

Bottoming applications depend on the quality (temperature and pressure) of reject heat from an industrial process. Low-pressure steam turbines can be used with reject heat temperatures of 400°F to 1000°F. The electrical efficiency is, however, low. Organic Rankine cycles which use a process similar to steam turbines, but with organic fluids, can be used with reject heat streams as low as 150°F. With high temperature boiler and furnace exhausts (450°F), Stirling cycles can also be used. and with very high-temperature streams, Brayton cycles can be employed. The potential for bottoming cycle cogeneration appears to be limited in the 1980's.

Table V-1 shows some of the technical characteristics of cogeneration systems.

THE ECONOMICS OF COGENERATION

The changing economics of energy have made cogeneration an attractive option for industry. Currently available and emerging technological options can be used to provide industry's thermal needs and generate power for the utility grid. Also, as discussed above, Federal legislation has attempted to remove most of the institutional barriers

Table V-1

COGENERATION TOPPING CYCLE PERFORMANCE PARAMETERS

Cogeneration Systems	Electrical Capcity of a Single Unit (kW)	Heat Rate[2] (Btu/Kwh)	Electrical Efficiency (%)	Thermal Efficiency (%)	Total Efficiency (%)	Exhaust Temperature ^{o}F	Steam #/hr. Generation @ 125 psig
Small reciprocating Gas Engines	1-500	25,000 to 10,000	14-34	52	66-86	600-1200	0-200[1]
Large reciprocating Gas Engines	500-17,000	13,000 to 9,500	26-36	52	78-88	600-1200	200-10,000[1]
Diesel Engines	100-1,000	15,000 to 11,000	23-31	44	67-75	700-1500	100-400[1]
Industrial Gas Turbines	800-10,000	14,000 to 11,000	24-31	50	74-81	800-1000	3,000-30,000
Utility Size Gas Turbines	10,000-75,000	13,000 to 11,000	26-31	50	76-81	700	30,000-300,000
Steam Cycles	5,000-100,000	50,000 to 10,000	7-34	28	35-62	350-1000	10,000-100,000

1 Hot water @ $250^{o}F$ is available at 10 times the flow of the steam

2 Heat rate is the heating value input to the cycle per Kwh of electrical output. The electrical generation efficiency in percent of a prime mover can be determined from its heat rate by the following formula:

$$\text{Efficiency} = \frac{3413}{\text{Heat Rate}} \times 100$$

to industrial cogeneration. State implementation of the Federal rules, expected shortly, will allow industries to cogenerate without fear of utility-type regulation, and obtain a reasonable price for exports of electricity. The legislation also prevents high standby charges. However, a careful evaluation of cogeneration economics must be performed before investing significant capital. A number of analytical tools are available to perform such economic evaluation.

It is important to note that the economic evaluation of cogeneration must adequately consider utility perspectives and roles. Since the price paid by the utility for purchase of power from the industry is based on the avoided cost, which depends on the generation mix, fuel types and cost, and anticipated capacity expansion, the changing economics of the utility's generation are important to the cogenerator. The perspective of the utility must therefore be understood by the cogenerator, and included in his economic analysis.

The EPRI Project

In a current EPRI project to evaluate cogeneration alternatives, Synergic Resources Corporation is developing a computerized evaluation tool to assess the costs and benefits of cogeneration (9). The objectives of the EPRI project, called "Evaluation of Dual Energy Use Systems (DEUS) Applications" are to (10):

- Develop a methodology to assess cogeneration options, with explicit consideration of utility perspectives and impacts.
- Identify promising candidate applications for cogeneration.

- Identify and assess utility options for participation in industrial cogeneration.

- Identify research, development and demonstration needs and priorities.

The first step in this study was to conduct surveys and case studies of existing cogeneration facilities to identify the site-specific factors which influence successful implementation of cogeneration. A methodology for screening and evaluation of cogeneration applications is being developed and is described in a recent paper by Limaye (11). The methodology will be supported by a data base on the performance and cost characteristics of existing cogeneration facilities.

Methodology for Cogeneration Evaluation

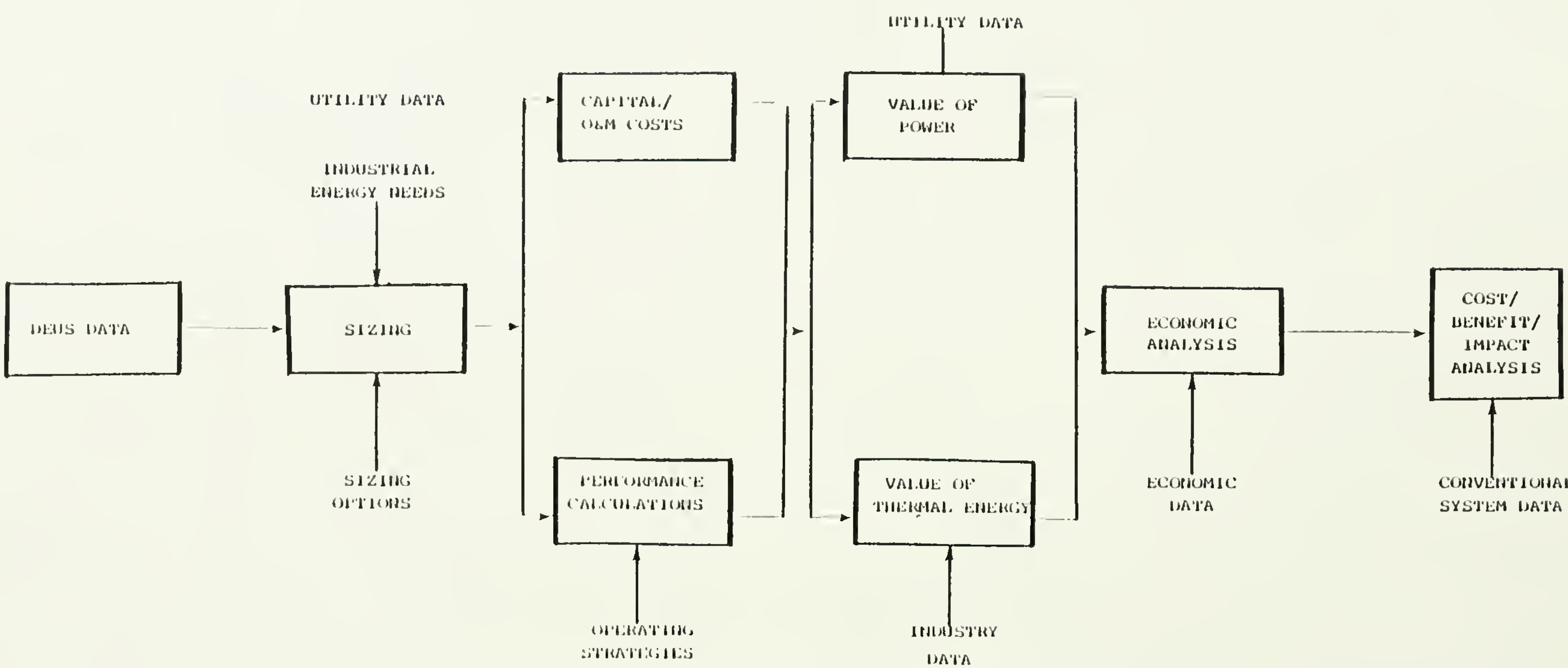
The methodology consists of two steps. In the first step, the aggregate benefits, costs and impacts of cogeneration are calculated, taking into account the total impacts on the utility, industry and society. This calculation is based on the value of electric and thermal energy used, the costs of producing these outputs, and the related social and environmental considerations. Institutional and regulatory considerations such as standby and buy-back rates (PURPA rates), tax credits, alternative arrangements for ownership and operation, etc., do not affect the overall benefits of cogeneration from the systems viewpoint, but do determine how the benefits, costs and impacts are shared by the various affected parties. Such institutional and regulatory factors are therefore considered in the second step under each type of arrangement for ownership or operation. These considerations influence the negotiated position of each party relative to the cogeneration venture.

An overview of the first step is shown in Figure V-1. Using information regarding the characteristics of cogeneration technologies, the energy needs for the application, and local utility data, the size of the cogeneration system is determined under alternative sizing options.

Figure V-1

SUGGESTED APPROACH FOR EVALUATION OF DEUS OPTIONS

STEP 1 - IDENTIFICATION OF ATTRACTIVE OPTIONS



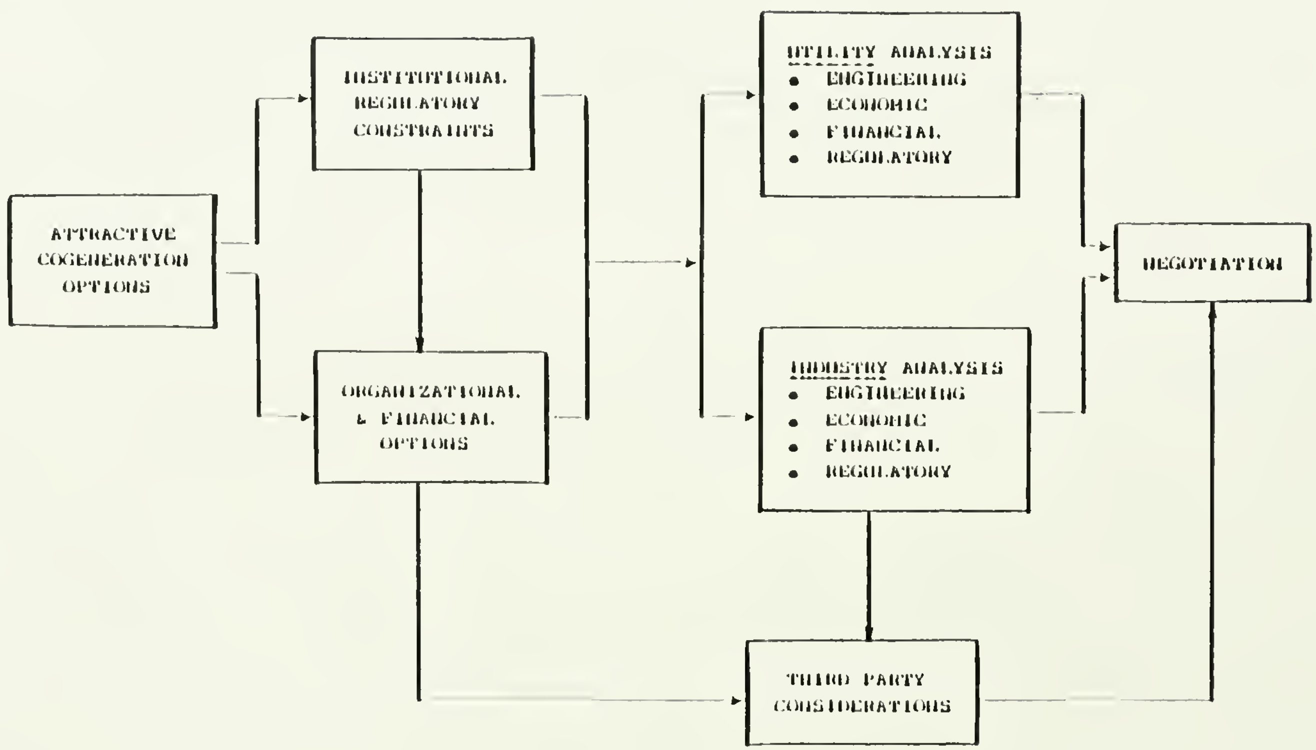
Calculations are then performed for the performance of the cogeneration system and its capital, operating and maintenance costs. The performance calculations provide information regarding the amount of thermal and electric energy generated by the cogeneration system under different operating strategies. The value of the power generated is then calculated based on data on the utility's generation mix and expansion plan. Similarly, the value of thermal energy generated is calculated based on the alternative costs of thermal energy generation for the industry. An economic analysis is then performed, taking into account the value of the thermal and electric outputs relative to the capital and O&M costs under each sizing and operating option. The economic data are then compared to the conventional energy generation systems to determine the aggregate costs, benefits and impacts of the cogeneration option. By performing these sets of calculations for different cogeneration technologies and different sizing and performance options, the most attractive options can be identified.

Figure V-2 shows an overview of the second step, the detailed analysis of the cogeneration options. For each option considered to be an attractive option, an analysis of the institutional and regulatory constraints is performed. Based on this analysis, the alternative organizational and financial options are identified. For each of these options, an analysis of the impacts on the utility and industry is then performed. Where appropriate, if third party considerations are important, the analysis includes the impact on such third parties. In this step, a detailed evaluation of the economic, financial and regulatory aspects is performed from the point of view of the utility and industry to provide information regarding the alternative methods of allocating the benefits of the cogeneration option. It is hoped that this analysis will provide all concerned parties with adequate information to enter into a meaningful negotiation process which will lead to the implementation of the most attractive cogeneration systems.

Figure V-2

SUGGESTED APPROACH

STEP 2 - DETAILED ANALYSIS OF OPTIONS



Value Of Thermal And Electric Energy

The value of thermal energy produced by a cogeneration system can be calculated as equal to the costs of alternative generation of such energy in a conventional plant, taking into account the customer's requirements for thermal energy supply reliability. In order to calculate this value, it is necessary to determine the fuel costs at the customer's site, and the costs of installing a boiler or other means of generating the required thermal energy. The operating hours of the plant, thermal load factors and other operating characteristics will have to be considered in determining these costs.

The value of the electric power generated by the cogeneration system consists of two parts: the energy value and the capacity value. The energy value of the power can be calculated, taking into account the following considerations:

- The amount and the type of fuel saved by the local electric utility because of the availability of cogenerated power
- The variation of the available power by time of day and the related fuel used by time of day for the utility
- The variation of fuel use and power generated by season, if any
- The future changes in the fuel mix and fuel prices, expected over the lifetime of the cogeneration facility
- Any savings in operating and maintenance costs for utility plants
- Possible reductions in transmission and distribution losses for the utility system.

The capacity value of the power generated also depends on a large number of considerations. These include the following:

- The availability of the power to the utility - In order to realize credits for capacity, the power generated by the cogeneration system must displace utility capacity over some period of time. If the cogenerated power is not available when the utility needs it, then the utility will have to back up the cogeneration system with additional capacity. In such situations, the capacity credit would be very small, or non-existent. On the other hand, if the cogenerated power is available at all times when the utility needs it, then there should be some capacity credit given to the cogeneration system.

- Reliability - While no power generation facility is likely to be 100% reliable, experience with cogeneration facilities shows that they can accomplish a high degree of reliability with a small amount of unscheduled maintenance. In general, the higher the reliability of the system, the greater should be its capacity value. Some utilities have argued that they would have to back up cogeneration facilities with enough standby capacity and that there would be no avoided capacity costs. However, if the reliability of the cogeneration system is adequately accounted for in the utility's calculations of loss of load probability and reserve margin, then an appropriate method can be determined for developing the proper capacity value.

- Long-term availability of power - In many cases, the capacity value of a cogeneration system will have to be calculated based on displaced utility capacity over some future planning horizon. This requires some guarantees of the long-term availability of power from the cogenerator. In general, a cogenerator which is prepared to guarantee long-term availability through a long-term contract is likely to have a greater value for its capacity than one where there is some uncertainty regarding the long-term availability of power.

- Supply diversity - Given a number of cogenerators on a utility system, the supply diversity of the probability of outages of one or more cogenerators should be calculated in determining the appropriate capacity credits. This can be accomplished by treating each cogenerator as another unit in the utility system available to meet the utility's loads. The characteristics of power output, forced outage rates and maintenance schedules for each cogenerator can be analyzed using the utility's evaluation methodologies. The greater the diversity of supply, the greater the capacity value of the cogenerator.

- Short-term versus long-term considerations - Many utilities with excess generation capacity have argued that they should not provide any capacity value to potential cogenerators. Their arguments are probably valid in the short-run. If utilities do not save any capacity costs by having cogenerated power available, then the short-term capacity credit should be zero. Short-term capacity credits are relevant only for utilities with low current reserve margins, or utilities with substantial purchased capacity. In the long-run, however, the situation is different. If a utility has excess capacity now, but is experiencing some load growth, it may have to add capacity in the future. The availability of the cogenerator will allow such capacity additions to be either deferred or cancelled, leading to some savings in investment costs. Such savings should be reflected in the development of the capacity value of the cogenerator.

- Other factors affecting generation capacity credits - Other factors which influence the capacity value of a cogenerator include the quality of the power generated, the degree of operating control that the utility has over a cogeneration system, the size of the cogenerator and the possible value of the cogenerator for spinning reserve.

- Transmission and distribution capacity credits - It is possible that a cogeneration system would reduce the need for transmission and distribution capacity additions. The calculation of avoided transmission and distribution capacity has to be site-specific and is extremely difficult. It requires the analysis of the reliability of supply at the customer level, which includes an assessment of the reliability of the T&D network. If the cogenerator is sufficiently large and is located near a load center, it is possible that it could lead to the deferral or elimination of some future T&D investments by the utility. In such cases, the cogenerator should be given an appropriate capacity credit.

Computer Evaluation of Dual Energy Use Systems (DEUS)

In order to perform the sizing and performance calculations, and to screen and evaluate the costs and benefits of cogeneration options relative to a conventional systems, an analytical model called DEUS - Computer Evaluation of Dual Energy Use Systems, has been developed. This model accomplishes step 1 of the evaluation methodology. An overview of this model is provided in Figure V-3. The model can evaluate up to twelve systems, (including a no-cogeneration base case) taking into account industrial requirements for heat and power, fuel types, utility rate schedules, (including industrial and PURPA rates), economic data, operational ground rules, and various ownership types.

In many industrial processes, the actual process thermal and power demands vary with time-of-day and/or seasonally. To be compatible with anticipated PURPA rate schedules, the program has the capability to represent 36 time periods per year. For example, the 36 time periods might be used to cover four seasons, three types of days per week, and three time periods per day (on-peak, near-peak, and off-peak). The program has the capability to evaluate DEUS configurations incorporating up to four fuel streams, with each fueling a given type energy conversion system (ECS).

COPE - Cogeneration Options Evaluation

A computer model called COPE - Cogeneration Options Evaluation, has been developed to calculate after tax cash flows to the utility, industry and, where appropriate, third parties (12). COPE can handle all practical ownership and financial arrangements and account for tax credits, depreciation and other relevant financial and economic parameters, taking into account the most recent legislation and regulations. COPE is designed to provide information to all potential participants in a cogeneration venture so as to identify mutually beneficial institutional arrangements (see Figure V-4).

The magnitude and distribution of after-tax costs and benefits of a cogeneration system are significantly influenced by its ownership structure (utility, industry, third party), operating mode (thermal dispatch versus utility economic dispatch) and the electricity sales arrangement (simultaneous buy-sell, buy-shortage/sell-excess). COPE is designed to evaluate alternative combinations of ownership, operating modes and sales arrangements.

Figure V-3

OVERALL STRUCTURE OF DEUS PROGRAM

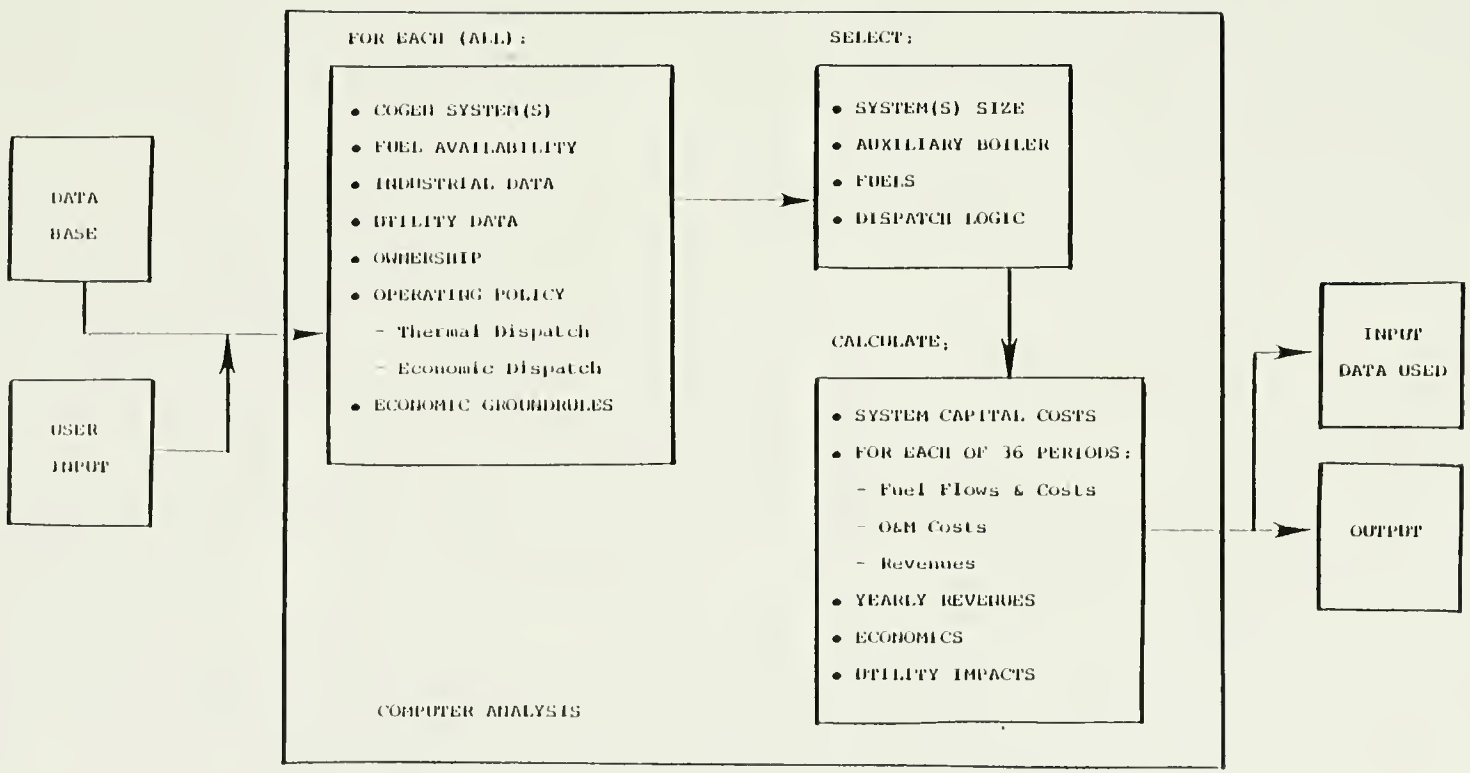
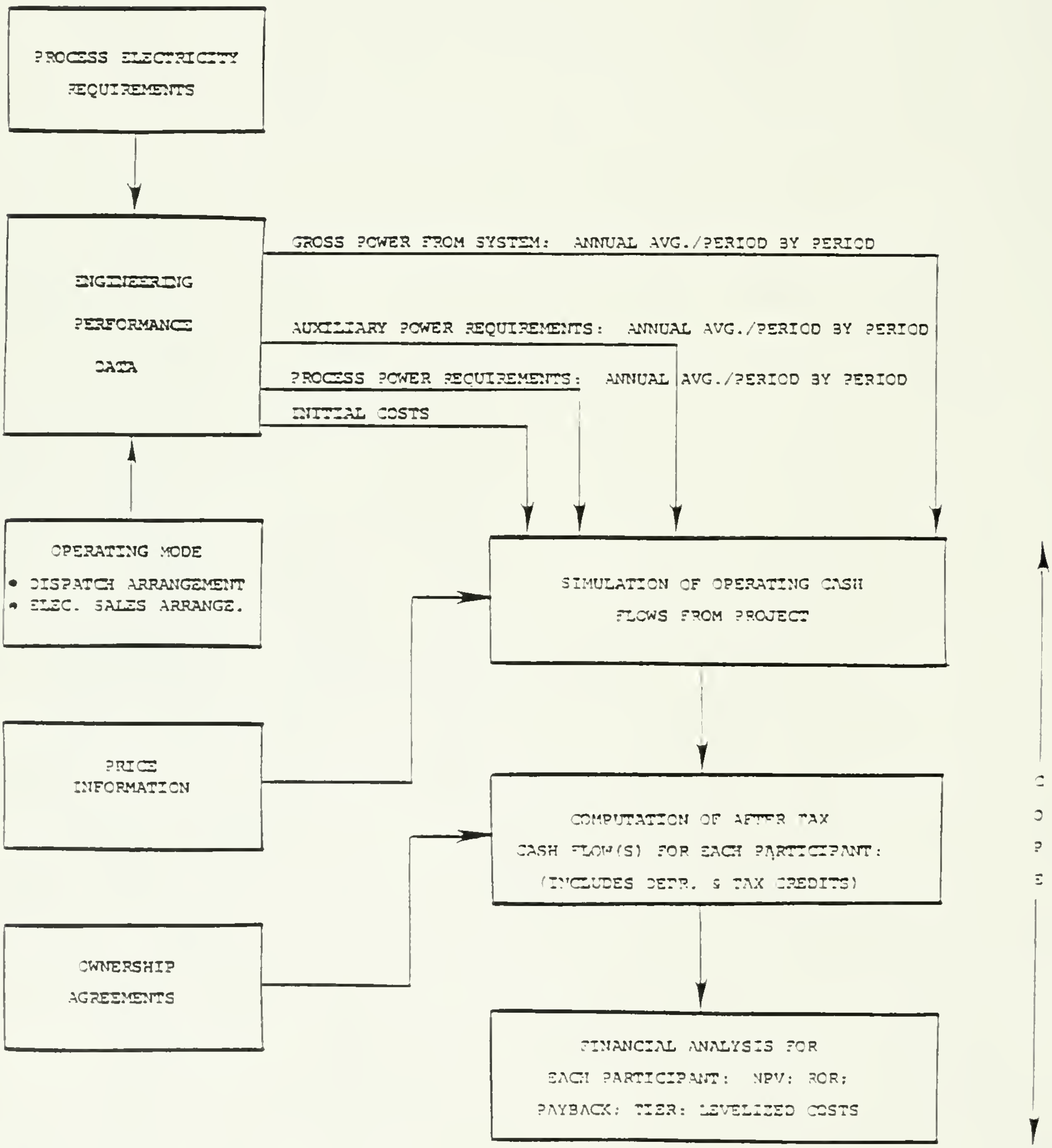


Figure V-4

OVERVIEW OF COPE COGENERATION OPTION EVALUATION



In the past, a common assumption was that a cogeneration system is owned entirely either by an industry or a utility. With the increased interest in cogeneration, a number of innovative arrangements are being considered. For example, joint ventures among industry, utility and third parties may offer benefits to all the participants. One arrangement to form a joint venture is to create a separate corporation for the sole purpose of owning and operating the cogeneration project. In this arrangement, the cogeneration project would be taxed as a corporation.

The partnership arrangement can also be used to form joint ventures. Partnerships do not pay a Federal tax on earnings comparable to the corporate earnings tax; however, each partner pays Federal tax on his share of earnings from the partnership. Also, partnerships enjoy considerable flexibility in the apportionment of tax and depreciation benefits as well as profits (or losses) among partners. It is possible, therefore, to design partnership arrangements so as to attract private (or "third party") investors by offering them substantial tax-related benefits. At the same time, third parties, having no site-specific thermal or electric requirements, are unlikely to insist on specific operating modes. Thus, partnerships between utilities, industries and "third parties" could often be mutually beneficial.

COPE is being designed to analyze any one of the following ownership arrangements. The utility can be either an investor-owned or a tax-exempt utility.

- 100% Ownership
  - 100% Utility Ownership
  - 100% Industry Ownership
  - 100% Third Party Ownership (or Separate Corporation).
- Joint Ventures
  - Partnership - Utility/Industry

- Partnership - Utility/Third Party

- Partnership - Industry/Third Party

- Partnership - Utility/Industry/Third Party.

- Leasing Arrangements

  - Lessor/Lessee - Third Party/Utility

  - Lessor/Lessee - Third Party/Industry.

Case studies of cogeneration ventures are currently being conducted and will be presented at a forthcoming workshop sponsored by EPRI.

Illustrative Results

Illustrative results of the application of these models for the economic evaluation of cogeneration in a pulp mill are shown in Figure 5. The results indicate that a 59 MW cogeneration system offers a 25% rate of return on incremental investment over a no-cogeneration case. A 100 MW cogeneration system offers a 15.6% rate of return. The revenues from electricity sales in the 100 MW case are comparable to income from pulp sales. Figure V-6 shows the rate of return vs. size for the pulp mill application.

FINANCING COGENERATION PROJECTS

The current regulatory environment and uncertainties with PURPA are leading towards cooperative efforts among cogenerators and utilities for financing and implementing cogeneration.

The reasons for considering such cooperative efforts are:

- Cogeneration is likely to be more capital intensive than a conventional energy system, and industry may have other uses for capital which are more attractive.

Figure V-5

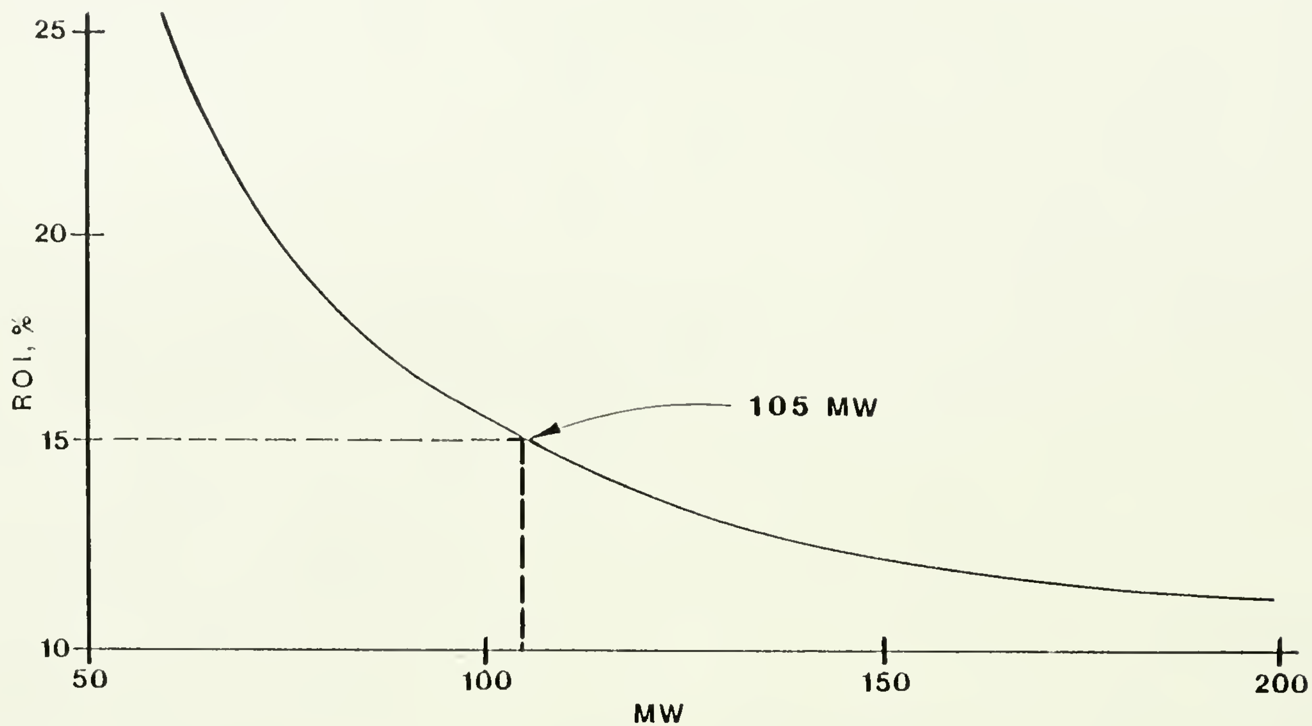
ILLUSTRATION OF COGENERATION ECONOMICS

PULP MILL EXAMPLE

	NO GENERATION	ASSUMED THERMAL MATCH	MAXIMUM COGENERATION
Gross MW Output	0	59.1	100
Total Installed Cost of Power Plant (Million $)	88	146	202
Cost chargeable to Power Plant Generation (Million $)	---	58	114
Annual Operating & Maintenance Costs (Million $)	2.98	6.09	7.01
Annual Fuel Costs (Million $)	7.29	17.48	33.10
Annual Cost of Purchased Electricity (Million $)	13.04	13.91	15.02
Annual Electric Revenues (Million $)	0	37.71	61.07
Projected Return on Investment (%)	0	25.4%	15.6%

Figure V-6

PROJECTED RETURN ON INVESTMENT VS MEGAWATT SIZE
1985 CONCEPTUAL DESIGN, 1000 TONS/DAY BLEACHED KRAFT PULP MILL WEST COAST, U.S.A.



VI. FEDERAL REGULATION OF COGENERATION

- The industry may not have the skilled staff needed to operate and maintain a power generation system.

- Industry may not consider power generation a natural extension of its primary business, even when such generation is economically attractive.

- Utilities are generally willing to accept a lower rate of return than industry.

- Industrial plant managers may be hesitant to face the problems related to the handling, storage and use of coal and the associated environmental requirements.

- Utilities can offer the necessary expertise in the construction, operation and maintenance of cogeneration systems.

Many utilities are currently actively seeking cooperative ventures with industry. Thus, industries interested in cogeneration may find the local utility a willing and cooperative partner.

Options For Industry/Utility Cooperation

A number of options exist for cooperative efforts among industry and utilities to implement cogeneration including:

- Sole utility ownership of the cogeneration plant with sale of thermal energy by the utility to industry

- Joint venture between industry and utility (with utility owning 50% or less to qualify the cogeneration facility for PURPA benefits).

- Third party ownership with contracts for thermal energy and electricity sales to industry and utility respectively.

- Partial ownership with the utility owning the power generation equipment and industry owning the remaining plant

- Sole industry ownership but operating control (dispatch) by utility.

Multi-Party Approaches For Financing

The main theoretical justification for a multi-party approach is to share the risk of a project. This reduces the total risk to any one participant, while commensurately reducing the possible returns. In addition, a joint venture arranagement should reduce the "moral risk" of a project where two or more participants must cooperate: if all participants have a stake in the operation, they will all have an incentive to do their part. This is particularly appropriate in the case of cogeneration, where cooperation between the industrial user(s) of the thermal energy and the utility purchaser of the electricity is essential. The advantages and disadvantages of joint ventures are presented in Figure V-7 and a typical structure is shown in Figure V-8.

Types of Joint Ventures

The term joint venture refers to financing a specific contractual relationship or undertaking among the two or more participants in a project. The legal relationship among the participants may take the form of a partnership, a jointly owned corporation, or an unincorporated association. The partnership structure offers great flexibility for joint venture arrangement between utilities and industrial cogenerators. The utility may, in fact, be able to contribute more than 50% of the equity to the partnership and/or receive more than 50% of the cash flow, and still qualify under PURPA as long as the assets are divided equally upon liquidation of the partnership.* A hypothetical partnership agreement could be structured as follows:

- Utility puts up 75% of equity and industry 25%

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*Opinion provided by FERC personnel based on informed review of hypothetical examples. These opinions do not carry assurance that an actual project structured along similar lines may not be treated differently.

Figure V-7

ADVANTAGES AND DISADVANTAGES OF JOINT VENTURE FINANCING OF A COGENERATION PROJECT

ADVANTAGES

- May be able to use tax incentives more effectively than individual ownership.
- Provides additional sources of capital.
- May be arranged without impact on the balance sheets of the participants.

DISADVANTAGES

- Control over timing and use of the facility may not be optimal for all participants.
- Risk of regulations changing and the property being treated as a regulated utility operation.
- May impare the credit of the participants.

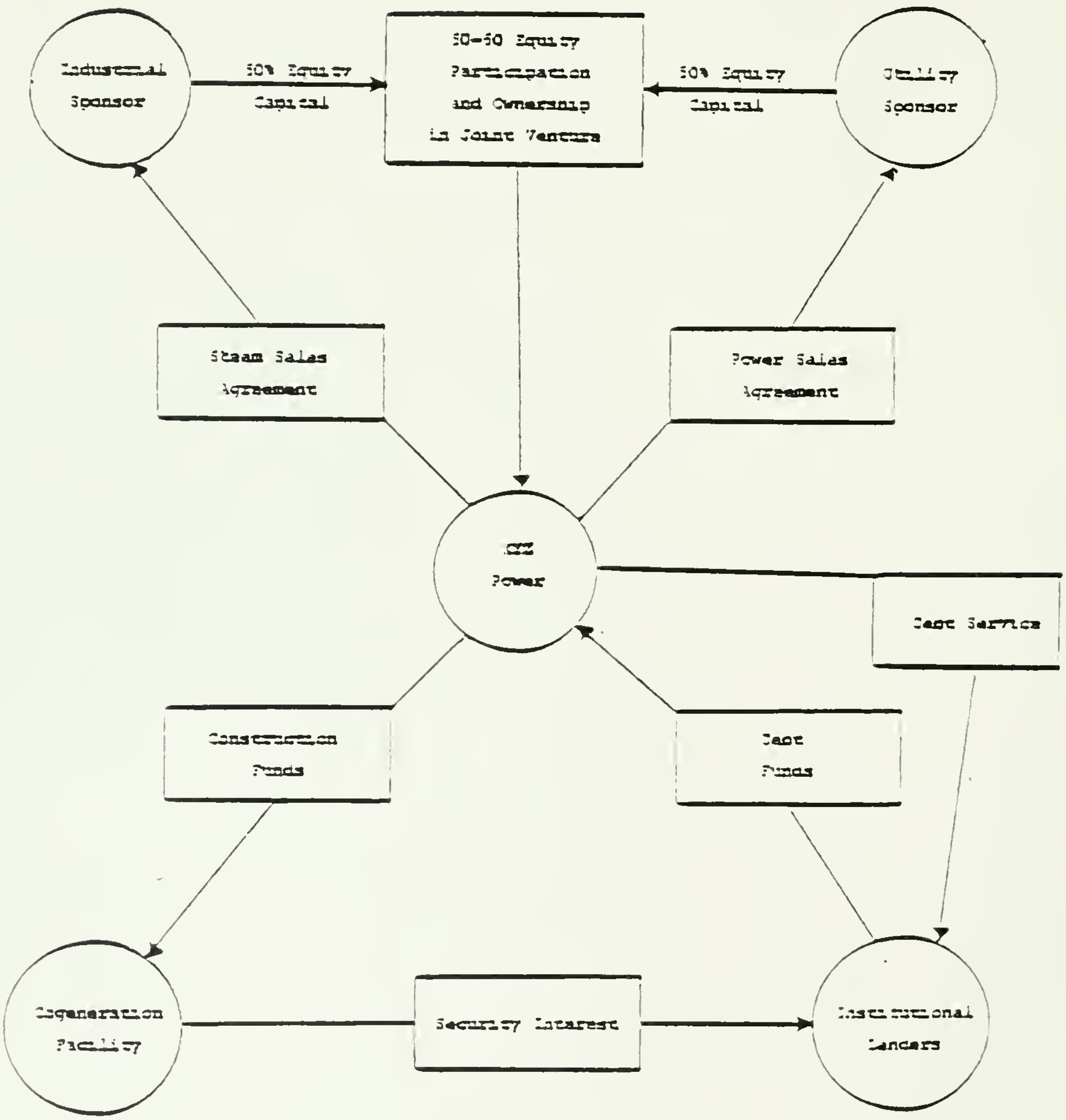
IMPLICATIONS FOR UTILITIES

Joint venture financing is the most likely method of financing cogeneration under the current PURPA ownership limits. Joint ventures can reduce the costs of capital and the capital requirements for participants when compared to the alternative of sole ownership. Joint ventures using partnerships allows great flexibility in structuring the financial arrangement between the participants.

Figure V-8

JOINT VENTURE FINANCING FOR COGENERATION FACILITIES

SCHEMATIC FLOW DIAGRAM



- Utility gets 75% of the profit and losses and cash flows until the difference in their initial equity contribution is paid back. Thereafter, profits/losses and cash flows are split equally

- If or when the partnership is terminated/liquidated, the utility and industry agree to split the value equally.

Cogeneration Financing Structures

Financing structure describes the arrangements used to secure capital, allocate risks and share benefits of the project that is being developed. The financing structures that are available for cogeneration projects are "undivided interest" and "project entity", as shown in Figure V-9.

Undivided Interest

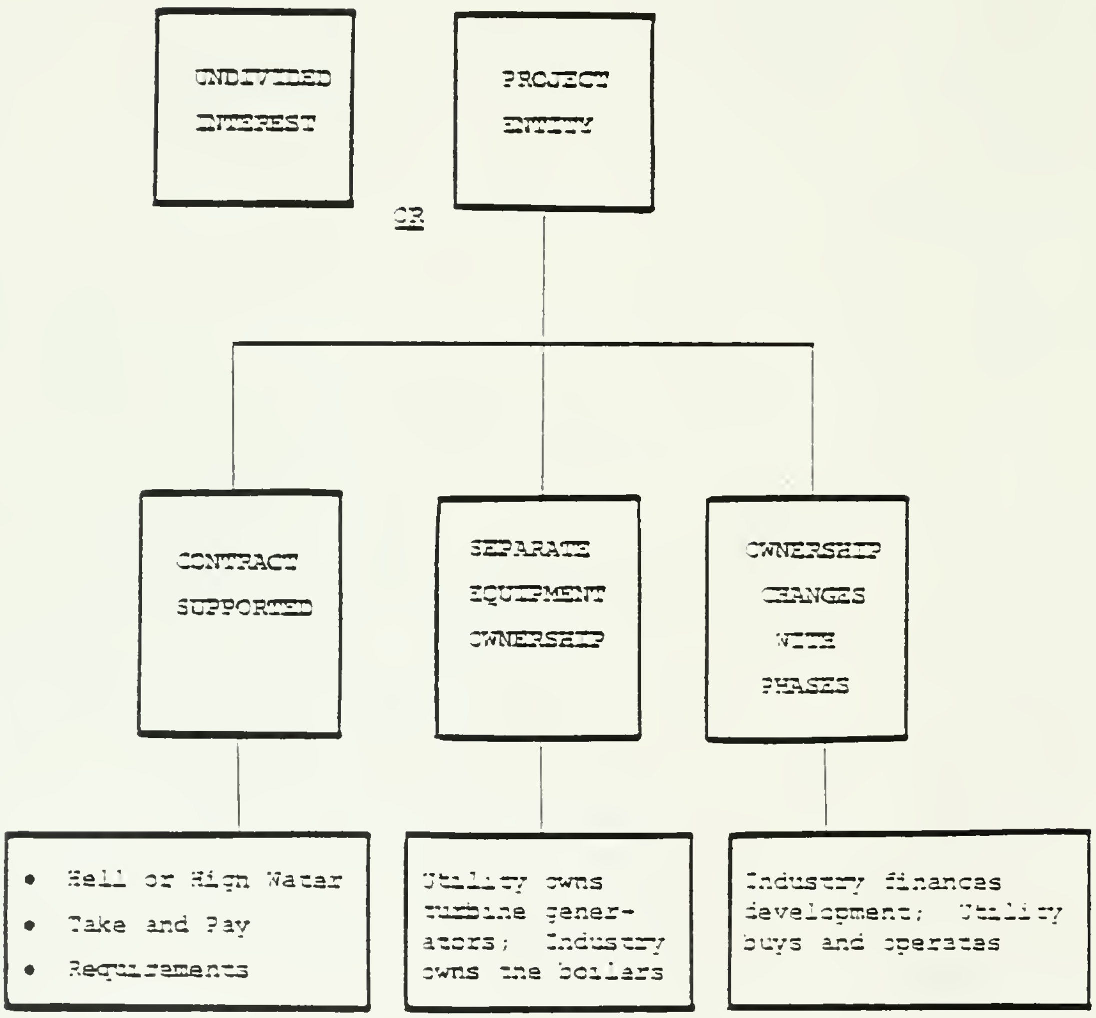
The undivided interest structure may be used by a sole owner or a joint venture. The owner(s) of an undivided interest in a project contributes capital in proportion with his ownership and receives profits in the same proportion. Any funds borrowed to capitalize the project would be shown on the participant's balance sheet as would the assets of the project. If a wholly owned subsidiary owns an undivided interest in the project's assets, the parent would have to consolidate the subsidiary's accounting with its own as if it owned the undivided interest itself.

Project Entity

Under the project entity approach, the cogeneration project would be established as a separate entity to own and operate the equipment. Project financing is the term used to describe the raising of capital to finance a project entity approach. The cogeneration project entity may be owned by a sole owner or by a joint venture.

Figure V-9

COGENERATION FINANCING STRUCTURES



Each participant contributes capital and receives project benefits based on agreement with other participants (not necessarily in proportion to his ownership interest). Capital is secured by the assets and future cash flows of the project. The debts of the project are not shown as debts on the participant's balance sheets. The project entity approach may affect the participant's cost of credit or ability to raise additional debt even though the project debt does not appear on the participant's balance sheet.

There are three basic variations on the project entity structure:

- Contract supported.
- Separate equipment ownership.
- Ownership changes with phases.

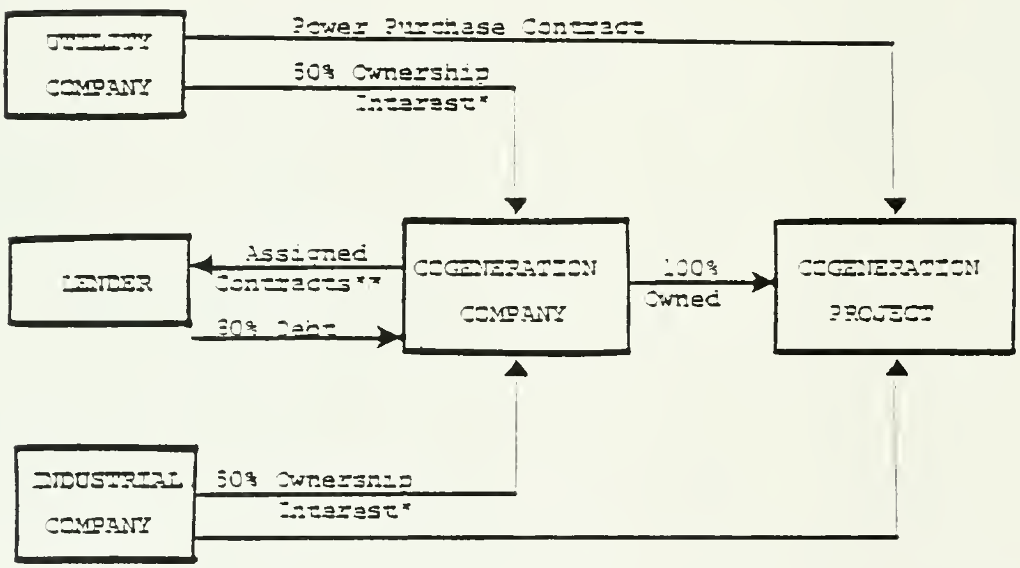
Contract-Supported Project Financing

Contract-supported project financing is the most common form of project financing and is really a form of credit support by the sponsors of a project. A cogeneration project is a much better risk from a lender's point of view if it has long-term contracts for the purchase of its outputs, namely, the steam and electricity. The sponsors can enter into such contracts and then assign them to the lenders. The contracts become a form of collateral, which reduces the risk, and therefore reduces the financing costs. Depending on how firm the contracts are, the owners may or may not have to show the obligations on their balance sheets.

A schematic flow chart which describes a simple contract-supported project financing for a cogeneration project is presented in Figure V-10.

Figure V-10

CONTRACT-SUPPORTED FINANCING OF A COGENERATION FACILITY



Different Methods for Different Equipment

Another possible means of combining various project entity structures is to divide the equipment to be employed in the project into separate component groups and to adopt a different ownership option for each group. A primary reason for using this approach would be to avoid the regulation of industrial participants in a state which recaptures the earnings from cogeneration and sale of electric energy. A financing structure may be employed in which the specific assets associated with steam production, principally boilers, burners and condensers, would be owned by the industrial companies through a project entity, while the turbine generators and related electrical equipment would be owned by the utility on a sole ownership basis.

Different Methods for Different Phases of the Project

A third means of integrating various structural approaches into the organization of a single project is to adopt different methods for the developmental and operational phases of the project. This approach can help the utility participant finance the construction of a facility and solve the problem which industrial participants have in financing utility-type assets with an industrial-type capital structure. The basis of this method is that the industrial firm(s) will bear the burden of construction financing, with the utility assuming responsibility for permanent financing following completion of construction.

Summary of Project Financing Structures

The most common project financing structure is contract supported. Other project financing structures include: separate equipment ownership and ownership that changes with project phases. The foregoing structures may properly be considered the basic building blocks of project financing. One of the keys to successful project financing, however, is the ability to arrange the structural components in such a manner as to meet the specific objectives and requirements of the participants. Each utility must evaluate the appropriate theoretical and practical considerations in order to select the most desirable financing arrangement.

The practical considerations involved in selecting a financing arrangement include: the ability of each participant to raise capital, the cost of the capital, alternative uses for the capital and the ability to maximize and utilize the tax benefits and other incentives available to the project. The utility and other potential participants must identify their financial capabilities and constraints to determine their proper roles in any cogeneration project. The structures identified above may be used to finance projects that could not be undertaken by any one participant or may produce better financial results by reducing capital costs through the best use of tax credits.

VI. FEDERAL REGULATION OF COGENERATION

INTRODUCTION

Prior to 1978, the Federal laws that governed the relationship between the electric utilities and industrial cogenerators were the Federal Power Act and the Public Utility Holding Company Act. These laws made the sale of electric power by an industrial firm subject to the same regulation as public utilities. Industrial firms that cogenerated electric power avoided regulations by using the electricity internally. Utilities were able to sell thermal energy cogenerated from power plant operations, but the rates of return from these operations were usually regulated by state law.

The relationship between cogeneration and utilities was changed in 1978 with the enactment of the National Energy Act. The National Energy Act included three major parts that defined cogeneration and identified regulatory incentives for cogeneration facilities that qualified under the definitions. The three Acts are the Public Utility Regulatory Policies Act, the Fuel Use Act and the Natural Gas Policy Act.

The National Energy Act was signed into law on November 9, 1978, and represented the Carter Administration's energy policy of conservation of oil and natural gas. The National Energy Act included restrictions on fuel use, tax incentives for energy project development and incentives for small power producers and cogenerators. These latter incentives were largely contained in the Public Utility Regulatory Policies Act of 1978.

PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

General Description

The Public Utility Regulatory Policies Act of 1978 (PURPA) authorized the Federal Energy Regulatory Commission (FERC) to remove regulatory and economic obstacles to cogeneration and electric power production by small facilities using certain renewable or novel fuels. Section 201 of PURPA authorized FERC to prescribe rules establishing requirements for qualifying cogeneration and small power production facilities, and procedures by which qualifying facilities could obtain the benefits provided under Section 210 of PURPA.

Section 210 of PURPA authorized FERC to prescribe rules requiring electric utilities to purchase electric energy from cogeneration and small power production facilities which obtain qualifying status. 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 and in the public interest, and that do not discriminate against cogenerators or small power producers. These rates were not to exceed the utility's avoided cost.

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(e) of PURPA exempted all qualifying cogeneration and certain qualifying small power production facilities from state regulation regarding utility rates and financial organization, and from most Federal regulations under the Federal Power Act and the Public Utility Holding Company Act. Licensing and permitting under Part 1 of the Federal Power Act and Sections 210, 211 and 212 of the Federal Power Act still apply to qualifying facilities.

The final rules implementing Sections 210 and 201 were issued by the FERC on February 19 and March 13, 1980 respectively.* The rules promulgated by the FERC apply not only to utilities that sell power for resale in interstate commerce but, more broadly, to all electric utilities. As a result, non-regulated electric utilities, including publicly owned systems, cooperatively owned systems, and the Tennessee Valley Authority, are subject to these requirements. Utilities in States or areas not subject to regulation by the FERC under Section 201 of the Federal Power Act are nevertheless subject to these requirements including utilities in Alaska, Hawaii and parts of Texas.

Specific Provisions of PURPA Implementation

Under the statutory framework of Section 210 of PURPA, implementation of the rules issued by the FERC is reserved to the state regulatory commissions and to the non-regulated electric utilites. Section 210(f) of PURPA requires that within one year of the issuance of the rules by the FERC, each State regulatory authority and non-regulated electric utility must implement the FERC rules. As of March 20, 1981, one year from the issuance of the FERC final rules, only 15 states had submitted their regulations implementing the FERC requirements.

Rates for Utility Purchase of Power

One of the key provisions of PURPA 210 deals with the rates for exchanges of power between utilities and cogeneration facilities. The FERC described avoided costs as the pricing principle that the states had to use in implementing PURPA. Rates to be paid to qualifying facilities

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*Section 210 - 45 Federal Register 12214 (February 25, 1980).
Section 201 - 45 Federal Register 17959 (March 20, 1980).

would not be based on the cost of service for the qualifying facility but rather on the avoided costs of the utility purchasing the power. Avoided costs were defined as all the expenditures that the utility would save by not generating or purchasing the equivalent amount of power produced by the qualifying facility. These expenditures would include fuel savings and other variable operating and maintenance expenses. Each state regulatory commission must establish the specific avoided costs for utilities under its jurisdiction. The majority of states had opened dockets and held hearings on PURPA rates by November 1981.

In some cases, when power is provided by a cogeneration facility on a reliable basis, the utility can cut back on its need to construct new power plants, or to buy or rent capacity from other utilities. In such cases, the avoided costs also include the capital costs of the avoided unit, or the demand charge included in the avoided firm power purchase contract, which the utility avoids by obtaining power from cogeneration or small power production facilities.

Wheeling

The FERC's rules provide that if the qualifying facility consents, the purchasing utility may transmit or wheel power to a second utility. If this occurs, the second utility is subject to this same requirement to purchase the power. The second utility is only obligated to pay the avoided cost of the power it actually receives. It does not have to pay the transmission charges.

For power purchases from new capacity (capacity for which the construction commenced on or after the date of the enactment of PURPA), utilities must pay full avoided costs. For existing facilities, utilities may pay a lower rate, so long as the rate is sufficient to encourage cogeneration.

Simultaneous Buy-Sell Provision

These rules permit a new cogenerator to require an electric utility to purchase, at the full avoided cost, all of their electric power produced, while purchasing from the utility all of the electric power they use at non-discriminatory retail rates. In many cases, these rates will be lower than the utility's avoided costs. The effect of this provision is to separate the activities of the facility as a generator and as a load. The economic benefits of this arbitrage accrue solely to the qualifying facility and are not shared by the utility's ratepayers.

Rates for Standby/Backup Power

The FERC's rules regarding sales of back-up power from utilities to qualifying cogeneration or small power production facilities are expressed in the form of a prohibition. A utility's rates cannot be based on the unsupported assumption that all qualifying facilities will require power at the same time and that this time will be the system peak. The rules require that traditional principles of load diversity be applied in a nondiscriminatory manner to rates for generating as well as non-generating customers.

Exemption from Utility Regulation

The FERC exercised its exemption authority to the full extent authorized by Section 210(e) of PURPA. It exempted all qualifying cogeneration facilities from utility regulation under the Public Utility Holding Company Act, the Federal Power Act, and state law. As a result of these exemptions, cogeneration facilities which sell electric power to utilities will not be subject to rate regulation by the Commission under Sections 205 and 206 of the Federal Power Act. Their books and records 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 cogeneration or small power producer which 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 applicable state and Federal laws concerning siting and environmental restrictions.

QUALIFICATION CRITERIA FOR COGENERATION AND SMALL POWER PRODUCTION FACILITIES

Definition of Cogeneration Facility

Section 201 of PURPA contains the criteria for qualification for these rate and exemption provisions. 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 in the FERC rules requires that electric energy and other forms of useful energy be produced through the sequential use of energy. The key provision of this definition is that requiring sequential use. Only those processes which use heat rejected from one process for another process are able to obtain the greater efficiencies associated with cogeneration. Eligible cogeneration systems include both topping-cycle facilities, in which energy is first used to produce useful power and the reject heat from power production is used to provide useful thermal energy, and bottoming-cycle facilities, in which energy is first applied to the useful thermal process and reject heat emerging from the process is used for electric power generation. Qualifying cogeneration facilities are not subject to restrictions regarding size or fuel type.

One type of topping-cycle cogeneration facility, the new diesel and dual fuel cogeneration facility, had been temporarily excluded from qualifying under the FERC rules, pending the completion of a final environmental impact statement (EIS). The FERC staff recently issued the EIS recommending that new diesel commercial cogeneration units be qualified under PURPA and the FERC has accepted this recommendation.* On August 17, FERC granted Consolidated Edison's petition to rehear Order Number 70-E, its Final Rule establishing qualifying status for cogenerators and small power producers. FERC granted the petition to allow itself more time to consider the issues raised by Con Ed. The company sought to eliminate an amendment in the Rule that removes the exclusion of new diesel and dual-fuel cogenerators from QF status.**

Definition of Small Power Production Facility

Small power production facilities are defined in federal regulations as those facilities, with a capacity of 80 megawatts or less, which use biomass, waste, or renewable resources to produce electric energy. Small power production facilities include solar, wind, and geothermal electric conversion systems; small hydroelectric projects; biomass burning facilities such as wood chip fired boilers; and municipal solid waste facilities.

Unlike cogeneration facilities, small power production facilities are subject to statutory restrictions regarding both size and fuel use. Qualifying small power production facilities may not have a rated capacity greater than 80 megawatts. In addition, only facilities of 30 megawatts and less are exempt from regulation under the Federal Power Act, the Public Utility Holding Company Act, and state regulation of rates and financial organization - except for biomass and geothermal small power production facilities, which in

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*Energy User News, June 1, 1981.

**Edison Electric Institute, Dispersed Energy Update.

addition to these exemptions are also exempt from regulations by the Securities and Exchange Commission under the Holding Company Act, even if they are between 30 and 80 megawatts. Figure 2-1 presents a summary of the qualifications for exemption.

Section 643 of the Energy Security Act of 1980 amends Section 210 of PURPA by, among other things, authorizing the FERC to exempt geothermal qualifying facilities of 80 megawatts or less from the above-cited state and Federal regulations. In addition, it permits the FERC to provide the rate and exemption benefits of Section 210 of PURPA to utility-owned geothermal power production facilities.

Fuel Use Restrictions

As stated previously, qualifying small power production facilities must use renewable resources, biomass or waste as their primary energy source. In the rulemaking proceedings, FERC received comments from representatives of the paper industry stating that the use of wood wastes as an energy source often requires the use of oil or gas for flame stabilization. FERC accordingly permitted these small power production facilities to use up to 25 percent of their annual fuel inputs to be oil or gas.

While qualifying small power production facilities may use only renewable resources, biomass, or waste as a primary energy input, qualifying cogeneration facilities may use any fuel, including gas or oil. However, when use of these fuels by new facilities is involved, the FERC restricted qualification to facilities which meet efficiency standards.

Operating Standard (Bona Fide Test)

FERC has recognized the problem of distinguishing cogeneration facilities that achieve meaningful energy conservation from those that are merely token facilities producing trivial amounts of useful heat. FERC in its final rules adopted a test specifying that at least five percent of a qualifying topping-cycle cogeneration facility's total energy output must be in the form of useful thermal energy output. This operating standard would prevent a powerplant from attaining qualifying status by bleeding off a trivial amount of steam for some heating use. The standard also serves to prevent small power production facilities which fail to qualify due to excessive fossil fuel use or large size from gaining the regulatory and economic incentives by installing some token use of thermal energy to qualify as cogenerators. Existing power plants that use part of their waste heat for heating water for fish raising would not qualify as cogeneration facilities. Other thermal energy uses that are an integral part of conventional generating facilities are not eligible for the benefits of Section 210 of PURPA.*

Efficiency Standards

The rules require that for any topping-cycle cogeneration facility, the installation of which began on or after March 13, 1980, in which any of the energy input is natural gas or oil, the useful power output plus one half of the useful thermal energy output of the facility must be no less than 42.5 percent of the energy input of natural gas and oil to the facility. However, if the useful thermal energy output of the facility is less than 15 percent of its total energy output, the standard requires 45 percent efficiency. Since the energy outputs of a facility are

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*FERC Docket Number QF81-13-000, Order Granting Application for Certification as a Qualifying Cogeneration Facility (Issued July 23, 1981).

compared only to the input of oil and gas, the standards become progressively easier to meet as a facility substitutes alternative fuels for oil and gas. The efficiency standards for PURPA qualifying cogeneration projects are presented in Figure 2-2.

Bottoming-cycle cogeneration comprises a special class of cogeneration facilities. Since heat which would otherwise be wasted is converted to electricity, efficiency standards would serve no fuel conservation purpose. Moreover, when bottoming-cycle cogeneration equipment is added to an existing plant, the efficiency of energy utilization within the plant is irrelevant to the effectiveness of the bottoming-cycle. Standards are retained only for facilities which use oil or gas for supplementary firing. In this application, the fuel is used only for electricity generation. The standard requires that for any new bottoming-cycle facility in which gas or oil is burned in a supplementary firing mode, the useful power output of the facility must be no less than 45 percent of the energy input of natural gas and oil used for supplementary firing. As this standard compares a facility's output to only the oil and gas used in supplementary firing, the standard becomes progressively easier to meet as more waste heat (and less oil and gas) is used for power production.

Ownership

Section 201 of PURPA provides that in order to qualify, a cogeneration or small power production 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 or small power production facilities). However, the Conference Report of the House and Senate managers of the PURPA legislation specifically stated that electric utilities may participate in joint ventures that own qualifying facilities. To implement this provision, the FERC adopted a rule providing that electric utilities may own no more than 50 percent of the equity of a qualifying facility. This rule has been modified to allow

100% electric utility ownership of qualifying geothermal facilities and to allow 100% ownership by companies which are declared not to be electric utilities under certain provisions of the Public Utility Holding Company Act.

FERC provided two procedures for obtaining qualifying status. Under the first, a cogenerator need not apply for qualification and can be "self certifying". A second procedure was established for FERC certification which involves filing ownership, location, capacity and fuel use data. FERC then examines the application and issues orders certifying the facility as qualified or denying certification. The FERC ruling is expected to take about 50-60 days.

Summary of PURPA

In summary, the key provisions of Section 210 of PURPA include:

- New qualifying facilities are to be paid 100% of the avoided costs for the power sold to the utility.
- The state regulatory commission and non-regulated utilities are to establish the rates or procedures to implement the rules.
- The power may be wheeled at the qualifying facility's expense to a second utility which must pay the avoided cost for the power delivered.
- The simultaneous purchase and sale of power between the utility and the qualifying facility is allowed.
- Interconnection must be made and stand-by power must be provided at non-discriminatory rates.
- All qualifying facilities are exempt from Federal and state regulation concerning rates and financial organization.

The key provisions of Section 201 of PURPA include definition of a qualifying <u>cogeneration</u> facility as:

* One which produces electricity and other form(s) of useful energy through the sequential use of energy.

* One which is not more than 50% owned by electric utilities.

* Unlimited in size and unrestricted as to fuel used.

* One which meets minimum operating efficiency standards and produces at least 5% useful thermal output.

Modifications to PURPA

The rules for a qualifying small power production facility were modified by Section 643 of the Energy Security Act to allow unlimited utility participation in geothermal projects and to raise the size limit from 30 to 80 megawatts. In this regard, FERC issued final rules implementing the legislation in Order Number 135, March 23, 1981 (46 FR 19229).

The final rule:

* extends "qualifying facility" status to geothermal energy projects.

* exempts geothermal facilities up to 80 MW from certain obligations under the Federal Power Act, state rate and financial regulation and the Public Utility Holding Company Act (PUHCA).

As a result of comments FERC received from several state utility commissions, it left for future determination the implications of extending the other exemption and rate privileges under Section 210 of PURPA to geothermal facilities more than 50% owned.

In another change in final rule making for cogeneration and small power production facilities, the FERC lifted the 50% ownership limit on cogeneration facilities for certain electric utilities including combined gas and electric utilities. The amendment (Docket Number RM 79-54) allows electric utilities that are declared not to be electric utilities under certain provisions of the PUHCA to own 100% equity in a qualifying facility. Thus, a combination gas and electric utility company which earns most of its revenues from its gas utility operations may be allowed to own all the equity in a qualifying facility.

Bills have recently been introduced in Congress to amend PURPA to increase electric utility ownership and expand the definition of cogeneration facilities. Representative Heftel (D-Hawaii) has introduced a bill (HR 2992) which would amend PURPA and the Federal Power Act to allow 100% electric utility ownership of qualifying cogeneration facilities. Representative Alexander (D-Arkansas) has introduced a similar bill (HR 2876). Senators Humphrey (R-New Hampshire) and Johnson (D-Louisiana) introduced a similar bill in the Senate (S-1885).

A constitutional challenge to PURPA Titles I, III and Section 210 has also been raised. Federal District Court Judge William H. Cox, ruling on a suit brought by the State of Mississippi, declared certain parts of PURPA to be unconstitutional. In granting Mississippi's motion for a summary judgement, Judge Cox found that the Act unduly displaces and usurps the right of a state to make its own policies on intrastate matters. FERC has appealed the ruling directly to the U.S. Supreme Court and the Department of Justice will prosecute the appeal. The case is expected to be heard by the Supreme Court in its October 1981 term with a decision expected in the spring of 1982. Pending the appeal, Judge Cox's ruling applies only to the southern district of Mississippi, although its holding may be followed in other jurisdictions. The National Association of Regulatory Utility Commissioners encouraged members to implement PURPA in their states.

In January 1981, American Electric Power Service Corporation, Consolidated Edison of New York and Colorado-Ute Electric Association petitioned the DC Circuit of the U.S. Court of Appeals to vacate four aspects of FERC rules implementing PURPA. Intervenors in the case are Elizabethtown Gas Company, American Paper Institute and the Brooklyn

Union Gas Company. The four issues under appeal are FERC's legal ability:

- to exclude "fuel use" considerations in defining cogenerators as qualifying facilities (QFs) eligible for PURPA benefits.
- to require utilities to pay QFs full avoided costs for power purchases, thereby transferring all the utility's cogeneration benefits to QFs.
- to allow "arbitrage" (the simultaneous buy-sell provision of PURPA 210).
- to sell exempt all QFs from FERC interconnection requirements (Federal Power Act, Sections 210 and 212).

FERC denied a May 1980 request to rehear these issues, leading to the court challenge. The petitioning companies feel these four issues are contrary to congressional intent and violate the PURPA statute.*

THE POWERPLANT AND INDUSTRIAL FUEL USE ACT OF 1978 (FUA)

Introduction

The purposes of the Powerplant and Industrial Fuel Use Act of 1978 include the reduction of the Nation's dependence on foreign oil and the encouragement of the use of coal and other alternate fuels in lieu of natural gas and petroleum. The Act directs the Secretary of Energy to issue regulations which prohibit or limit the use of petroleum and natural gas in certain new and existing powerplants and major fuel burning installations (MFBI). This authority includes coverage of cogeneration unless the Secretary grants an exemption for such use.

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*Edison Electric Institute, Dispersed Energy Update.

Sections 212(c) and 312(c) of the Act specifically provide for exemptions for petroleum and natural gas use in any new or existing cogeneration facility upon a finding by the Secretary that "economic and other benefits of cogeneration" are unattainable unless petroleum or gas is used in the facility. The Act contains various prohibitions and restrictions on the use of petroleum and natural gas.

Definition of Fuels Covered

The Act defines natural gas and petroleum and excludes certain categories. These definitions have been further refined by the Department of Energy and the Economic Regulatory Administration (ERA) in final rules issued June 6, 1980. Fuels which do not come under the Act's definition of petroleum or natural gas are not be subject to fuel use regulation.

Petroleum subject to FUA regulation is crude oil and products derived from crude oil, except for those products specifically exempted by rule or statute. Natural gas (except products which are specifically exempted) which is subject to regulation includes any fuel consisting in whole or in part of natural gas, and includes components of natural gas such as methane and ethane, liquid petroleum gas, synthetic gas from petroleum or natural gas liquids and any mixture of natural and synthetic gas.

To the extent a powerplant or MFBI uses gas which is either derived entirely from coal or other alternate fuels, or is high cost gas as defined under Section 107 of the NGPA or stripper well gas, the prohibitions of the FUA do not apply. The orientation of the Act seems to be towards allowing use of types of gas where the use of these types would not have normally occurred. A cautionary note is that these types of natural gas are likely to be higher priced gas than natural gas normally sold by gas utilities.

Definition of Cogeneration Facilities

ERA issued final rules on 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 exemptions available; and (3) provide administrative procedures for applying for exemptions. ERA also published on May 15, 1979 and July 23, 1979 interim rules relating to the prohibitions against oil and gas use in existing facilities and exemptions available, as well as rules relating to exemptions for cogeneration facilities.

The Fuel Use Act defines a cogeneration facility as a facility which produces electric power, and any other form of useful energy (such as steam, gas, or heat) which is or will be used for industrial, commercial or space heating purposes. A cogeneration facility under the FUA may fall into the category of either a powerplant or an MFBI. The term powerplant excludes a cogeneration facility where less than half of its annual electric power generation is sold or exchanged for resale. It is very advantageous for a utility participating in cogeneration facility to be so excluded and only covered by the FUA as an MFBI. The Fuel Use Act cogeneration classifications are presented in Figure 2-3.

ERA has issued interim rules which incorporate these definitions and proposed final rules which provide that the electricity generated must constitute more than 10% and less than 90% of the useful energy output of the facility.

Additionally, for any facility, including a cogeneration facility, to be subject to the Fuel Use Act as either a powerplant or MFBI, the facility must be, by design, capable of a fuel heat input of at least 100 million Btu per hour, or be in an aggregation of one or more units located at the same site, which together are capable of a fuel heat input rate of at least 250 million Btu per hour.

Fuel Use Restrictions

If a facility falls into the category of a new powerplant rather than a new MFBI, it would be subject to statutory prohibitions in the Fuel Use Act on:

- The use of oil and natural gas in its boilers, gas turbines, or combined cycle units.
- Construction without the capability of using a fuel other than oil or natural gas as its primary energy source.

On the other hand, if a facility falls into the definition of a new MFBI, it would be subject to Fuel Use Act prohibition only with regard to the use of oil and natural gas in its boiler and not in any gas turbines or combined cycle equipment. And, unlike the situation with a new powerplant, there would be no statutory prohibition on construction as identified above, that the facility be constructed with the capability of using a fuel other than oil or natural gas as its primary energy source. Therefore, there are significant advantages to being classified as a new MFBI rather than a new powerplant.

For existing facilities, the Fuel Use Act prohibitions with regard to existing powerplants apply only to the use of natural gas and only to its use until 1991 in amounts greater than during the 1977 calendar year. After December 31, 1990, no natural gas would be permitted to be used in existing powerplants. There is no similar prohibition on the use of oil beyond December 31, 1990 in existing powerplants.

If a facility falls into the definition of an existing MFBI rather than an existing powerplant, the Fuel Use Act allows even greater latitude in the fuel choice. Existing MFBI's equal to or greater than 300 million Btu per hour are subject to case-by-case orders or categorical rules which may be issued by the Secretary imposing prohibitions on the use of petroleum or natural gas in such facilities. Existing

MFBI's under 300 million Btu per hour are subject to such a prohibition only on a case-by-case basis and the Secretary may not issue categorical rules imposing any such prohibition on such small facilities. Neither a case by case nor a categorical order may be issued unless the Secretary finds that the MFBI has or had the technical capability to use coal or another alternate fuel.

Therefore, in both the case of existing MFBI's and new MFBI's, the statutory prohibitions and authority of the Secretary of Energy to create administrative prohibitions on the use of oil and natural gas in these facilities are far less extensive than in the case of either new powerplants or existing powerplants. Especially in the case of existing MFBI's, the Secretary has the burden of going forward with the rulemaking on a case-by-case order, and must make the finding that the MFBI has or had the technical capability to use coal or another alternate fuel. And for the smallest class of existing MFBI's covered by the Act (namely those under 300 million Btu per hour), the Secretary may do this only on a case-by-case basis which is a significant burden, is expensive and may be the least effective way to proceed.

If a cogeneration facility is classified as a powerplant rather than an MFBI, it is more restricted in its fuel choices and subject to more statutory and administrative prohibitions under the Fuel Use Act. Therefore, it is important for a cogeneration facility which wishes to burn natural gas or petroleum to be classified as an MFBI rather than a powerplant.

<u>Summary of FUA</u>

In summary, the Fuel Use Act defines cogeneration differently from PURPA. Sections 212(c) and 312(c) of the FUA allow oil and gas for cogeneration if the benefits of cogeneration are unattainable without using oil or gas. Many classes of petroleum and natural gas are exempt from the FUA and if used would not be subject to regulation. A cogeneration facility as defined by the FUA could be classified as either a major fuel burning installation (MFBI) or as a powerplant. A cogeneration facility falling into the powerplant category but selling less than half of its annual electric generation would be covered as an MFBI. The fuel restrictions are different for new or existing facilities.

- A new powerplant would be prohibited from using oil and gas in its boilers, gas turbines or combined cycle units.
- A new MFBI would be prohibited from using oil and natural gas in boilers but could use these fuels in gas turbines or combined cycle equipment.
- In existing power plants, oil may be used while natural gas may be used only until 1991 and in no greater amount than the volume used in 1977.
- An existing MFBI burning greater than 300 million Btu per hour is subject to case-by-case orders or categorical rules. If under 300 million, the MFBI is subject only to to case-by-case orders.

The primary implication of the Fuel Use Act on electric utility participation in cogeneration is the availability of natural gas and oil to new MFBI gas turbine and combined cycle projects that would not be available to new power plants. Utilities, therefore, are encouraged to develop gas turbine or combined cycle projects with industrial partners where over half the electric output is used by the industry.

Proposed Regulations Revising The FUA

On August 11, 1980, ERA issued proposed regulations regarding exemptions for cogeneration facilities from the prohibitions of the Powerplant and Industrial Fuel Use Act of 1978.* The proposed

*Docket Number ERA-R-80-24 (10 CFR Parts 500, 503, 504, 505 and 506) (45 Fed. Reg. 53368, August 11, 1980).

regulations are an attempt to ease administrative burdens for cogeneration facilities seeking exemptions and virtually eliminate fuel use restrictions for industrial cogenerators that primarily produce thermal energy rather than electric energy. ERA has also proposed a blanket exemption for cogeneration facilities in states that use large amounts of oil and gas for electric generation up to the Statewide Energy Limit for the total capacity of those facilities. Comments were due on these proposals on December 15, 1980, but the comment period was extended.

On November 2, 1981, ERA indicated that it will publish final rules by the end of November that would relax the exemption requirements for the Fuel Use Act restrictions on oil and gas use in boilers.* This would provide relief for industrial and utility boiler owners although it would not become effective until 60 days after publication. Public comments raised additional issues so additional FUA reforms may be proposed later.

New bills have been introduced in the current session of Congress to modify the FUA. Representative Heftel (D-Hawaii) introduced a bill (HR 2922) to exempt qualifying facilities and mechanical cogeneration from FUA regulations. Representative Pauzin (D-Louisiana) introduced a bill (HR 2941) to repeal the Section 301 of the FUA. Representative Collins (R-Texas) introduced the Natural Gas Market Transition Act (HR 4885) which among other items would repeal all of the Fuel Use Act.

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*Docket ERA-R-81-06 (Federal Register, November 2, 1981).

NATURAL GAS POLICY ACT OF 1978 (NGPA)

Introduction

The major impact of the NGPA will be to create a national deregulated market for natural gas. This Act provides for incremental pricing where industrial users of gas are surcharged while other users are not. The Act provides an incentive for cogeneration in Section 206(c) which gives the FERC the discretion to exempt qualifying facilities from its incremental pricing program developed under Title II of the NGPA. Rules issued by the FERC implementing that legislation provided that natural gas used by qualifying cogeneration facilities shall be exempt from the incremental pricing provisions of the NGPA.* FERC believed it was appropriate to exempt existing facilities from efficiency standards for the purposes of PURPA. But FERC also believed it appropriate that all facilities, newand existing, be subjected to these efficiency standards before permitting facilities to take advantage of the exemption from incremental pricing. In other words, an existing qualifying facility will not get exemption from incremental pricing without meeting efficiency standards even though it would be exempt from regulation.

Efficiency Standards

At present two sets of efficiency standards have been promulgated by FERC. Under an interim rule issued November 9, 1979, cogeneration facilities in existence on November 1, 1980 (the effective date of the Commission's incremental pricing rules), that used natural gas as a fuel

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*18 CFR S 282.203(a).

on or prior to that date, could qualify under a simple efficiency standard. The efficiency standard is that the ratio of energy inputs to outputs (deleting supplementary firing) must equal at least 0.55, or alternatively 0.70 after subtracting boiler efficiency considerations. This interim efficiency rule results only in exemption from incremental pricing. Approximately 160 facilities filed affidavits for exemption as qualifying cogeneration facilities. When the final rules under Section 201 of PURPA were issued, the Commission allowed facilities which had gained exemptions under the interim rule to retain their exemptions. New facilities, constructed after November 1, 1979, and facilities converting to gas from some other fuel must meet the efficiency standards in the final PURPA rule.

Generally, if a topping-cycle cogeneration facility qualifies, all the natural gas used is exempt. With regard to bottoming-cycle cogeneration facilities, all of the natural gas use (excluding supplemental firing) is exempt from incremental pricing, if all of the reject heat is made available for power production. If only a fraction of the reject heat is used for power generation, that fraction of the total natural gas use is exempt. Gas used for supplementary firing is not exempted by this provision. Such gas, however, may be exempt from other provisions of incremental pricing regulations.

The FERC issued final regulations exempting mechanical cogeneration facilities from the incremental pricing provisions under Title II of NGPA.* Prior to taking effect, this rule must be submitted to Congress for review. This rule is intended to make available to mechanical cogeneration facilities the same exemption from incremental pricing that is provided to electric cogeneration facilities.

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*45 Federal Register 45098, (10 CFR Part 580).

Curtailment Priorities

On July 2, 1980, in Docket No. ERA-R-79-10-A, ERA issued a proposed rulemaking to revise the priority system of curtailments for interstate pipelines for natural gas. In the proposed rule, ERA specifically stated that cogeneration facilities would not be treated differently than any other user of natural gas under a curtailment plan. ERA apparently believes that a plan to manage the use of gas during curtailments is not the place to provide incentives for cogeneration. Comments were due on August 29, 1980.*

In July 2, 1981, ERA and FERC issued Natural Gas Curtailment Dockets** which adopt the end user gas curtailment system. Residential, commercial and process gas users get higher priorities, while boiler gas users get the lowest priorities. Issuance of the final rule is not expected until early 1982.

Summary of NGPA

The NGPA encourages industry participation in qualifying cogeneration projects by exempting those projects from incremental pricing rules. Qualifying cogeneration projects were not granted priority under interstate pipeline gas curtailment rules. Such priority would have substantially improved cogeneration attractiveness both to industry and to utilities.

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*45 Federal Register 71787, October 30, 1980.

**ERA Docket R-79-10-A and FERC RM-80-67.

ADDENDUM

Since the preparation of this report in Fall 1981, a number of significant events have occurred which could have implications for utility participation in DEUS. A summary is provided below:

D.C. Court of Appeals

On January 22, 1982, the Court of Appeals for the District of Columbia issued its opinion in the appeal of the American Electric Power Service Corporation and several other utilities challenging certain provisions of the Federal Energy Regulatory Commission's ("FERC's") Orders 69 and 70, which apply to rates and exemptions for cogeneration and small power production.

The appeal presented four issues:

- Whether the rates utilities pay for purchases from qualifying cogeneration and small power production facilities ("QFs") should be based on full avoided cost

- Whether FERC has authority to require, by rule, utilities to make all interconnections necessary to sell to or purchase from a QF

- Whether QFs could make simultaneous sales to utilities at avoided cost and purchases from utilities at system average cost

- Whether FERC is required to impose fuel use restrictions on qualifying cogeneration facilities.

The Court vacated FERC's rule requiring utilities to pay full avoided cost for electricity purchased from QFs. This decision was based on the conclusion that PURPA requires FERC to strike a balance among three criteria - the public interest, the interests of QFs and the interest of electric consumers - in determining a rate for power purchased from QFs. The Court stated that while PURPA identifies avoided cost as the upper limit for such rates, it does not mandate that the purchase rate be at the avoided cost level. The Court held that FERC had failed to explain adequately how the avoided cost formula is consistent with PURPA's mandate. As a result of the Court's action, FERC must promulgate a new rule to establish rates for purchases from QFs.

The Court also vacated FERC's rule requiring utilities to make all necessary interconnections with QFs. It held that Sections 210 and 212 of the Federal Power Act require FERC to provide utilities an opportunity for a hearing before issuing an interconnection order. FERC must consider the potential economic and operational impacts of the interconnection, including its impact on a utility's reliability and ability to render adequate service.

The Court upheld FERC's "simultaneous transactions" rule, which permits a QF to take advantage of utility rates below avoided cost by engaging in the fiction that the electricity it produces for its own use is simultaneously purchased by the utility and sold back to the cogenerator. It also upheld FERC's decision not to invoke fuel use limitations as part of the criteria for cogenerators to obtain qualifying status under Section 210 of PURPA.

The decision is being appealed by FERC to the Supreme Court. This decision did not address the question of the constitutionality of PURPA. That issue was argued before the Supreme Court in FERC v. Mississippi (see below).

FERC v. Mississippi

As indicated in this report, Judge Cox in the United States District Court of the Southern District of Mississippi ruled that certain portions of PURPA were unconstitutional. On March 13, 1981, the Solicitor General of the United States filed a notice of appeal of this decision with the Federal District Court of Mississippi on behalf of the Department of Energy and the Federal Energy Regulatory Commission.

Judge Cox issued a final judgement on February 27, 1982, on the case specifically identifying Title I, Section 210 and Title III, of PURPA as unconstitutional. These portions of PURPA deal with a mandatory consideration by state regulatory authorities and non-regulated utilities of rates for small power producers and cogenerators. Section 210 of PURPA specifically authorizes FERC to issue rules requiring utilities to buy electric power from qualifying cogenerators and small power producers at rates based on guidelines established by PURPA. The basic legal argument in the Mississippi case was that PURPA invaded an "integral state function" which was in violation of standards previously established by U.S. Supreme Court decision.

The case was appealed by FERC to the Supreme Court. On June 1, 1982 the Supreme Court overturned the Mississippi District Court decision. The Supreme Court held that the provisions of PURPA which were challenged in the FERC vs. Mississippi case

- were "within Congress' power under the Commerce clause".
- did not "trench on state sovereignty in violation of the Tenth Amendment".

Powerplant and Industrial Fuel Use Act

The U.S. Department of Energy has adopted a number of rules dealing with fuel use by private industry. In addition, a number of other rules are in the process of formulation. The main thrust of these rules will be to broaden the definition of "cogeneration facility", so as to enable more facilities to apply for an exemption to the Powerplant and Industrial Fuel Use Act. The rules will also have the impact of minimizing unnecessary regulatory intervention in fuel use decision-making by private industry in general.

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2. Fred J. Sissine, "Energy Conservation: Prospects for Cogeneration Technology," Issue Brief No. IB81006, Library of Congress, Washington, D.C., February 1982.

3. Frederick H. Pickel, Cogeneration in the U.S.: An Economic and Technical Analysis, M.I.T. Energy Laboratory Report, MIT-EL-78-039, Boston, Massachusetts 1978.

4. Synergic Resources Corporation, Cogeneration Data Base, Draft Report submitted to Electric Power Research Institute, September 1981.

5. Synergic Resources Corporation, Industrial Cogeneration Case Studies, EPRI EM-1531, Electric Power Research Institute, September 1980.

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7. Governor's Energy Council, Pennsylvania Renewable Energy Resource Assessment, June 1982.

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9. California Energy Commission. Biomass Handbook for the Biomass Conversion Demonstration Program. November 1980.

10. Development Planning and Research Associates, Inc. Energy Resource Potential From Animal Wastes in Iowa. Prepared for the Energy Policy Council. May 1982.

11. Howeett and Gamache, Silvicultural Biomass Forms: Forest and Drill Residues as Potential Source of Biomass. Georgia Pacific Corporation. Portland Oregon; MTR-7347; Volume VI, Ditre/Detrek, McLean, VA, 1977.

12. Office of Technology Assessment, Energy From Biological Processes, Washington, D.C., July 1980.

13. Solar Energy Research Institute, Biomass Energy Conversion Workshop for Industrial Executives, April 9-10, 1979. Golden, Colorado.

14. U.S. DOE, Cogeneration: Technical Concepts, Trends, Prospects. (DOE-FFU-1703) September 1978.

15. U.S. DOE, A Technology Assessment of Solar Energy System: Environmental Residuals and Capital Costs of Energy Recovery From Municipal Sludge and Feedlot Measure. (DOE/EU-0107) September 1980.

Chapter II

1. Synergic Resources Corporation, Assessment of Potential Industrial Cogeneration In Pennsylvania, Preliminary report submitted to Pennsylvania Governor's Energy Council, June 1982.

Chapter III and IV

1. Governor's Energy Council, Pennsylvania Renewable Energy Resource Assessment, June, 1982.

2. Argonne National Laboratory, Solid Waste Utilization - Incineration with Heat Recovery. (ANL/CES/TE78-3), April, 1978.

3. California Energy Commission, Biomass Handbook for the Biomass Conversion Demonstration Program. November, 1980.

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5. Howlett and Gamache, Silvicultural Biomass Forms: Forest and Mill Residues as Potential Sources of Biomass. Georgia Pacific Corporation, Portland Oregon; MTR-7347: Volume VI, Mitre/Metrek, McLean, Virginia, 1977.

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9. U.S. DOE, A Technology Assessment of Solar Energy System: Environmental Residuals and Capital Costs of Energy Recovery from Municipal Sludge and Feedlot Manure. (DOE/EU-D107) September, 1980.

Chapter V

1. U.S. General Accounting Office, Industrial Cogeneration - What it is, How it works, Its potential, EMD-80-7, April 29, 1980.

2. Fred J. Sissine, "Energy Conservation: Prospects for Cogeneration Technology," Issue Brief No. IB81006, Library of Congress, Washington, D.C., February 1982.

3. Frederick H. Pickel, Cogeneration in the U.S.: An Economic and Technical Analysis, M.I.T. Energy Laboratory Report, MIT-EL-78-039, Boston, Massachusetts 1978.

4. Synergic Resources Corporation, Cogeneration Data Base, Draft report submitted to Electric Power Research Institute, September 1981.

5. Synergic Resources Corporation, Industrial Cogeneration Case Studies, EPRI EM-1531, Electric Power Research Institute, September 1980.

6. Thomas C. Hough and Dilip R. Limaye, Utility Participation in DEUS Projects: Regulatory and Financial Aspects, Draft Final Report, submitted to Electric Power Research Institute, April 1981.

7. For further details, see Final Rules Implementing Sections 201 and 210 of PURPA, 45 Federal Register, 12214 and 17949.

8. The legislation providing additional incentives to cogeneration includes the Crude Oil Windfall Profits Tax Act, the Energy Security Act and the Housing and Community Development Act of 1980.

9. Synergic Resources Corporation, Evaluation of Dual Energy Use Systems: Volume I, Executive Summary, Draft Report, March 1981.

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11. Dilip R. Limaye, Methodology for Evaluation of Cogeneration Projects, paper presented at the National Fuel Cell Seminar, Norfolk, Virginia, June 1981.

12. B. Venkateswara, Technical Documentation of COPE-Cogeneration Options Evaluation, unpublished draft report, Synergic Resources Corporation, Bala Cynwyd, PA, April 1982.

APPENDIX A

CASE STUDIES

CHAMPION PACKAGING

MISSOULA, MONTANA

Champion Packaging is a division of Champion International, a major paper and packaging company. Champion has been operating a biomass cogeneration system in its paper mill facilities since the 1960's. The firm currently generates an average of 7.5 MW with some peak capacity being held in emergency power reserve. the system is fueled primarily by boilers burning hog fuel and black liquor waste from the pulping process. System energy is supplemented to some extent by natural gas. Present generation capacity supplies 10 to 15 percent of the firm's total requirements for electricity.

Champion Packaging has recently quadrupled the hog fuel capacity of its system by adding a 350,000 lb/hr boiler. This expansion has substantially reduced the company's natural gas requirements.

Champion Packaging is collecting and utilizing hog fuel obtained from sources loacated up to 200 miles away. Much of this fuel is being obtained from other Champion facilities.

WEYERHAEUSER
SPRINGFIELD, OREGON

Biomass cogeneration operation at Weyerhaeuser's Springfield facilities presently consists of two generation systems totaling over 62 MW in nameplate capacity. The larger system (51.2 MW) is the product of a relationship between Weyerhaeuser and the local electric utility, Eugene Water and Electric Board (EWEB), and has been operating for over five years. EWEB installed and operates the turbine-generator on leased land within the mill site, while Weyerhaeuser is responsible for generating steam. The steam fed to the turbine is produced from two black liquor recovery boilers and one fossil fuel boiler at 875 psig. The steam is then returned to Weyerhaeuser through the turbine extraction valve at 165 psig and turbine exhaust at 65 psig to meet process steam requirements within the pulp and paper operations. The second system is completely owned by Weyerhaeuser and is fueled by wood waste. Depending on the market price for power, the electricity is wheeled through EWEB and sold to the Bonneville Power Administration or to other industrial firms.

The Weyerhaeuser/EWEB system exemplifies the possibility of the cooperative company/utility ownership and operating arrangement described in an earlier section. The division of ownership and responsibility for the various components of the system has been made on the basis of which party had the better business and operational knowledge. The production of steam is the sole responsibility of Weyerhaeuser. EWEB owns and is responsible for the turbine generator and the electric output for use within the EWEB system. Other aspects of the relationship include:

- No joint ownership arrangements or undivided interests of any facilities have been made due to legal and operational considerations.

- A single engineering firm completed the design for the entire project, thereby reducing interface problems.

- The price paid by the utility for steam is based on the kilowatt hours produced and indexed to the market price of petroleum.

- Weyerhaeuser controls the rate of steam production, and thus exerts indirect control over the rate of electrical production.

The concept has been well received in the community and public attitudes toward each entity have improved measurably. Governmental agencies, both local and state, have offered considerable support to the program. The project is seen as one measure in the larger effort to deal with energy shortages in the Northwest and as providing some guarantee of continuing jobs in the area.

Facility availability has been in excess of 92 percent. A portion of this overall system dependability can be attributed to the use of multiple boilers instead of a single large unit. An overall fuel conversion efficiency of 81 percent has been acheived by the system.

DIAMOND WALNUT GROWERS, INC.
STOCKTON, CALIFORNIA

This Diamond Walnut Growers plant in Stockton, California, is one of the world's larger walnut-processing facilities in the world. It produces about one hundred tons of waste walnut shells daily. In 1976, when Pacific Gas and Electric informed Diamond Walnut Growers about possible natural gas shortages, the company began investigating the possibility of using walnut shells as a fuel. Development of a cogeneration facility was approved in 1979, and it became operative in October 1980.

The cogeneration system is based on a steam topping cycle. Ground shells are used to fire a 15,000-lbs/hr boiler which drives a 4.5-MW steam turbine. About 25 percent of the steam is extracted from the turbine at low pressure for process use and for heating the facility, including offices. The remaining steam is condensed to maximize electricity production, which results in a net heat rate of 14,600 Btu/kWh and an overall cogeneration efficiency of 31.5 percent.

The system is integrated with the utility grid. The company sells all generated power to Pacific Gas and Electric and buys all electricity required to run the process plant operations. This leads to a net sale of about 18,000 MWh per year. According to company estimates it costs about 2.9¢/kWh to cogeneration electricity, excluding capital cost considerations.

In 1981, this biomass cogeneration system met 100% of the electricity demand of the plant and 90% of the thermal demand. Net electricity sales to the local utility exceeded $1 million. Annual system availability was 90%.

PUBLISHERS PAPER

OREGON CITY, OREGON

Publishers Paper has established cogeneration units at a number of its Oregon locations. In 1963, the company removed a hog fuel boiler at one of its facilities and converted to petroleum. Because of rapidly increasing fuel prices, Publishers had switched back to hog fuel by 1974. A 5 MW unit was established in 1977 and in 1978, a 10 MW turbine was added. Although much of the wood fuel is generated internally, some is obtained from outside sources on a contract basis.

The biomass cogeneration facilities have had consistenly good technical performance. Publishers has expanded its system a number of times and has recently installed a $14 million, 20 MW, 300,000 lb/hr system at one of its sites.

One of the important advances in waste utilization energy systems is the Portland Metro Service District resource recovery facility. Plans call for a utilization rate of 700,000 tons of refuse each year. Publishers has contracted for the entire thermal production of the facility. The steam will be used in plant process and in the generation of electricity to be used internally by Publishers. The plant is expected to be operating in 1984.

MANITOBA FORESTRY RESOURCES

THE PAS, MANITOBA, CANADA

The Company has a production capacity of 130,000 tons of unbleached Kraft Paper and 57 million board feet of kiln dried lumber annually. It commenced production in 1970.

Both the paper and the lumber processes involve extensive use of energy in the form of steam and electricity. Steam generating facilities include one Combustion Engineering recovery boiler rated at 210,000 lbs/hr and two Foster Wheeler Power boilers, each with a capacity of 275,000 lbs/hr. The latter were designed to produce 60% of total steam from Bunker "C" oil and the balance from hogged fuel.

Electricity is generated in-house by two turbo-generators rated at 11 MW (extraction-condensing unit) and 13 MW (backpressure unit). These meet about 45% of the plant's electrical load requirements with the remainder supplied from Manitoba Hydro.

By 1976, it became apparent that a respite from the continuing escalation of oil prices was not likely and that the supply itself might eventually be in jeopardy. Management prudently embarked upon a program to reduce total energy consumption per unit of production and also to replace bunker oil with more hogged fuel.

A major program was implemented in 1978 with the ultimate goal of replacing 6 million imperial gallons of bunker "C" a year with 50,000 tons of hogged fuel. This involved modification of existing equipment and considerable investment in additional material handling. Some of this is hauled 70 miles from lumber mills.

In addition an ingenious melding of the old and new systems was undertaken. This greatly increased flexibility of opportunities to exploit the most economical and oil conserving options by plant operators.

Fossil fuel usage per ton of paper dropped 50% between 1976 and 1979. This represents a decrease of 53 imperial gallons per ton of paper or about 6 million gallons of Bunker "C" a year.

APPENDIX B

COGENERATION SYSTEMS SUPPLIES, CONSULTANTS, AND INFORMATION CONTACTS

COGENERATION SYSTEMS SUPPLIERS

This list of suppliers of cogeneration systems consists of those known to the Montana Department of Natural Resources and Conservation at this time. It should not be construed as complete and all additions, deletions, or corrections should be brought to the attention of Montana DNRC.

The list of suppliers was compiled from two primary sources:

- The Cogeneration Equipment Compendium - published by the California Energy Commission

- Major Suppliers of Cogeneration Systems - published in the July 12, 1982 issue of Energy User News.

Permission was received to print the portion of this list compiled from Energy User News.

Further information about these two primary sources including any updates may be obtained from:

- Manager, Cogeneration Program
  California Energy Commission
  1111 Howe Avenue
  Sacramento, CA 95825
  (916) 924-2496

- Energy User News
  7 E. 12th St.
  New York, N.Y. 10003
  (212) 741-4485

MAJOR SUPPLIERS

Air Products & Chemicals, Inc.
Allentown, PA 18105

Air Research Div. of Garret Corp.
9851 Sapulveda Blvd.
Los Angeles, CA 90045

Alpha Systmes
1301 El Segunda Blvd.
El Segunda, CA 90245

Alturdyne
8050 Armour St.
San Diego, CA 92111

American M.A.N. Corporation
1114 Avenue of the Americas
New York, N.Y. 10036

Brown Boveri-Turbo Machinery
711 Anderson Avenue North
St. Cloud, Minn 56301

Caterpillar Corp.
Mossville Building A
100 N.E. Adams
Peoria, IL

Cogeneration Development Corp.
Empire State Building, Rm. 1134
New York, N.Y. 10001

Cogenic Energy Systems
645 5th Ave.
New York, N.Y. 10022

Combustion Engineering Inc.
100 Prospect Hill Road
Windsor, Conn 06095

Cummins Engine Co.
1000 Fifth St.
Columbus, Ind 47201

Cooper Energy Services
N. Sandusky St.
Mount Vernon, Ohio 43050

Coppus Engineering Corp.
P.O. Box 457
Worcester, Mass 01613

In-Novo Engineering and Development Co.
210-09 67th Ave.
Bayside, N.Y. 11364

Curtis Wright Corp.
1 Passaic St.
Wood Ridge, N.J. 07075

Dravo Corp.
One Oliver Plaza
Pittsburgh, PA 15222

Electro-Thermal Systems Inc.
629 Forest Ave.
Staten Island, N.Y. 10301

Fairbanks Morse Engine
Div. of Colt Industries
701 Laton Ave.
Beloit, Wis 53511

Fluor Power Services Inc.
200 W. Monroe St.
Chicago, Ill 60606

Foster Wheeler Energy Corp.
11 S. Orange Ave.
Livingston, N.J. 07039

Gas Energy Inc.
Div. of Brooklyn Union Gas
195 Montague St.
Brooklyn, N.Y. 11201

General Motors Corp.
Detroit Diesel Allison Div.
13400 West Outer Drive
Detroit, Mich 48228

General Electric Co.
Medium Steam Turbine Dept.
1100 Western Ave.
Lynn, Mass 01910

Hispano-Suiza Inc.
10633 Shadow Wood Drive
Houston, TX 77043

Ingersoll-Rand
Industrial Rotary Marketing
9525 Katy Freeway, Suite 333
Houston, TX 77024

Louis Allis
Div. of Litton Industrial Products Inc.
427 E. Stewart St.
Milwaukee, Wis 53207

Martin Cogeneration Systems
P.O. Box 1698
Topeka, Kan 66601

Mechanical Technology Inc.
968 Albany Shaker Road
Latham, N.Y. 12110

National Urban Energy Corp
59-55 47th Ave.
Queens, N.Y. 11377

North American Turbine
11500 Charles St.
P.O. Box 40510
Houston, TX 77040

Norwalk-Turbo
7 Northway Lane
Latham, N.Y. 12110

O'Brien Machinery
Dowington, PA 19335

Onan Division of McGraw Edison
Generator Sets And Controls-3
1400 73rd Ave. NE
Minneapolis, Minn 55432

Perrenial Energy Systems
Paradise Hill Dr.
Union Springs, N.Y. 13160

Rolls-Royce, Inc.
375 Park Ave.
New York, N.Y. 10022

Skinner Engine Co.
Division of Banner Industries
Erie, PA 16512

Solar Energy Systems Inc.
Columbus Road
Burlington, N.J. 08016

Solar Turbines International
2200 Pacific Highway
P.O. Box 80966
San Diego, CA 92138

Sundstrand Energy Systems
4747 Harrison Ave.
Rockford, ILL 61101

Terry Corp.
Subsidiary of Ingersoll Rand
Lamberton Road
Windsor, Conn 06095

Thermo Electron Corp.
Energy Systems Div.
123 Second Ave.
Waltham, Mass 02154

The Trane Company
Process Division
3600 Pammel Creek Road
LaCrosse, Wis 54601

Transamerica Delaval
Engine and Compressor Division
5500 85th Ave.
P.O. Box 2161
Oakland, CA 94621

Turbodyne, Worthington Group
McGraw Edison Co.
Wellsville, N.Y. 14895

Turbonetics Energy, Inc.
968 Albany-Shaker Road
Latham, N.Y. 12110

Ultrasystems, Inc.
2400 Michelson Dr.
Irvine, CA 92715

United Technologies
Power Systems Division
10 Farm Springs Road
Farmington, CT 06032

Waukesha Engine Div.
Dresser Industries
1000 W. St. Paul
Waukesha, Wis 53187

Western Engine Co.
500 S. Lombard Road
Addison, Ill 60101

Westinghouse Electric Corp.
Gateway Center
Pittsburgh, PA 15222

Whiting Corp.
Ormat Div.
15700 Lathrop Ave.
Harvey, Ill 60426

ENERGY CONSULTANTS

ENERGY CONSULTANTS

The Energy Consultants' Directory was developed to assist you in locating organizations within the region which provide cogeneration energy consulting services. This directory should not be considered complete but consists of organizations known to Montana Department of Natural Resources and Conservation at this time. Additions, deletions, or corrections should be brought to the attention of Montana DNRC.

Most of the organizations were identified from the "5th Annual Directory of Energy Consultants" published by Energy User News and are reprinted with their permission. Additional information about the Energy User News' Directory can be obtained from:

Energy User News
7 E. 12th St.
New York, N.Y. 10003
(212) 741-4485

ENERGY CONSULTANTS

Eliot Allen & Associates Inc.
5006 Commercial St. SE
Salem, OR 97306
(503) 371-4561
Eliot Allen

EMC Engineers, Inc.
Box 36009
2750 S. Wadsworth, #201
Denver, CO 80236
(303) 988-2951
Virgil E. Carrier

Energard Corp.
P.O. Box 4241
Bellevue, WA 98009
(206) 455-5723
James R. Scace

Energy & Resource Consultants
P.O. Drawer 0
Boulder, CO 80306
(303) 449-5515
Dr. Michael D. Yokell

Forster-Morrell Engineering
1617 N. Circle Dr.
Colorado Spring, CO 80909
(303) 574-2127
Bruce E. Morrell

Matney - Frantz Engineering
849 W. Main St.
Bozeman, MT 59715
(406) 586-3748
Claud E. Matney, P.E.

Planergy Inc.
901 W. Martin Luther King Blvd.
Austin, TX 78701
(512) 477-8012
Wayner N. Brown

- 520 S.W. 6th Ave. #1112
  Portland, OR 97204
  (503) 226-3457

Stone & Webster Management Cons
(Stone & Webster Inc.)
90 Broad St.
New York, N.Y. 1004
(212) 269-4224
Thomas C. Luhmann

- P.O. Box 5406
  Denver, CO 80217
  (303) 770-7700

Synergic Resources Corporation
Three Bala Plaza, 5th Floor
Bala Cynwyd, PA 19004
(215) 667-2160
Dilip R. Limaye

- 4th & Pike Building, Suite 820
  Seattle, WA 98101
  (206) 624-8508

ARCHITECTS/ARCHITECTURAL ENGINEERING SERVICES

Arix Engineers Architects Planners
2021 Clubhouse Dr.
Greeley, CO 80632
(303) 330-2749
Patrick C. Dwyer

- 760 Horizon Dr.
  Grand Junction, CO 81501
  (303) 243-7569

- 609 E. Madison, Suite #1
  Riverton, WY 82501
  (307) 856-6505

- Suite 100
  1815 S. State St.
  Orem, UT 84057
  (801) 225-8491

The Benham Group
1200 NW 63rd
P.O. Box 20400
Oklahoma City, OK 73156
(405) 848-6631
Bill Allison

- 3101 S. Maryland Parkway
  Suite 201
  Las Vegas, NV 89109
  (702) 369-5800

Burns and Roe Industrial Service Corp.
650 Winters Ave.
Paramus, N.J. 07652
(201) 265-2000
John A. Rocco

- 601 Williams Blvd
  Richland, WA 99352
  (509) 943-8200

Leo A. Daly
8600 Indian Hills Dr.
Omaha, NE 68114
(402)391-8111
James M. Ingram

- 200 Cedar St.
  Seattle, WA 98121
  (206) 682-1571

Ellerbe Associates Inc.
(Ellerbe Inc.)
One Appletree Sq.
Bloomington, MN 55420
(612) 853-2328
William Marshall

- 3025 One Union Sq. 30th Floor
  Seattle, WA 98101
  (206) 625-0666

John Graham and Co.
1110 3rd Ave.
Seattle, WA 98101
(206) 447-5620
Harold Broomell

CONSULTING ENGINEERS

R.W. Beck & Associates
Tower Building
7th Ave. at Olive Way
Seattle, WA 98101
(206) 622-5000
Herbert C. Westfall

Bouillon Christofferson & Schairer
505 Washington Building
Seattle, WA 98101
(206) 682-3910
Robert J. Smith

Brown and Caldwell
1501 N. Broadway
Walnut Creek, CA 94596
(415) 937-9010
George Chouinard

- Suite A-109
  10200 E. Girard Ave.
  Denver, CO 80231
  (303) 750-3983

- 100 W. Harrison St.
  Seattle, WA 98119
  (206)281-4000

CH2M Hill
1600 S.W. Western Blvd.
Corvallis, OR 97339
(503) 752-4271
Lamont Matthews

- 1500 114th Ave. S.E.
  Bellevue, WA 98004
  (206) 453-5000

- P.O. Box 22508
  Denver, CO 80222
  (303) 771-0900

Dames & Moore
445 S. Figueroa
Los Angeles, CA 90071
(213) 683-1560
Gary E. Melickian

- 1626 Cole Blvd.
  Golden, CO 80401
  (303) 232-6262

- 250 E. Broadway
  Salt Lake City, UT 84111
  (801) 521-9255

- 115 N.E. 100th
  Seattle, WA 98115
  (206) 523-0560

Ekono, Inc.
(Ekono Oy)
410 Bellevue Way S.E.
Bellevue, WA 98004
(206) 455-5969
William O. Aho

Energy Systems Management Inc.
12191 Ralston Rd.
Suite 100
Arvada, CO 80004
(303) 425-0958
James L. Ponder

Thomas J. Gerard & Associates Inc.
N. 1322 Post
Spokane, WA 99201
(509) 328-2771
Thomas Gerard

Gibbs & Hill, Inc.
11 Penn Place
393 Seventh Ave.
New York, N.Y. 10001
(212) 760-4000
George H. Ehrhardt

- 1250 14th St.
  Denver, CO 80202
  (303) 893-4907

Gilbert/Commonwealth
(Gilbert Associates, Inc.)
P.O. Box 1498
Reading, PA 19603
(215) 775-2600
Carl W. Horst

- 5650 DRC Parkway
  Suite 100
  Englewood, CO 80111
  (303) 741-2600

- 11400 S.E. 6th St.
  Bellevue, WA 98004
  (206) 454-0065

Kei Kruchek Engineers Inc.
3312 S.W. Kelly Ave.
Portland, OR 97201
(503) 292-6472
William McNeal

A.M. Kinney, Inc.
2900 Vernon Pl.
Cincinnati, OH 45219
(513) 281-2900
N.T. Neff

- 333 W. Hampden Ave.
  Denver, CO 80110
  (303) 761-3522

McFall Konkel & Kimball C.E. Inc.
2160 S. Clermont St.
Denver, CO 80222
(303) 753-1260

The RMH Group, Inc.
405 Urban St.
Denver, CO 80228
(303) 988-7720
Jack McKee

J.E. Sirrine Co.
P.O. Box 5456
Greenville, S.C. 29606
(803) 298-6000
J.E. Roberson

- P.O. Box 23296
  Tigard, OR 97723
  (503) 639-1451

Swanson Rink & Associates
1640 Boulder St.
Denver, CO 80211
(303) 433-6721
Jerry W. Kiel, P.E.

Trans Energy Systems
Suite 101
14711 N.E. 29th Place
Bellevue, WA 98007
(206) 881-8500
Douglas D. Huxtable

Van Gulik & Associates Inc.
543 Third St.
Lake Oswego, OR 97034
(503) 635-3734
Joe Van Gulik

Wood/Harbinger, Inc.
12707 120th Ave. N.E.
Kirkland, WA 98033
(206) 821-4242
Stephen V. Wood, P.E.

MONTANA ELECTRIC UTILITIES

MONTANA ELECTRIC UTILITIES

INVESTOR OWNED SYSTEMS

Montana Dakota Utilities Co.
Main Office:
400 N. Fourth St.
Bismarck, N.D. 58501
(701) 222-7900

Montana Light & Power Co.
Troy, MT 59935
(406) 295-4540

- Controlled by St. Regis Paper Co
  Libby MT

Montana Power Co.
40 E. Broadway
Butte, MT 59701
(406)723-5421

Pacific Power & Light Co.
Main Office:
920 S.W. 6th Ave.
Portland, OR 97204
(505) 243-1122

- Montana Office:
  448 Main
  Kalispell, MT 59901
  (406) 775-7461

RURAL ELECTRIC COOPERATIVE SYSTEMS

Beartooth Electric Cooperative, Inc.
P.O. Box 1119
Red Lodge, MT 59068
(406) 446-2310

Big Flat Electric Cooperative Inc.
P.O. Box H
Malta, MT 59538
(406) 654-2040

Big Horn County Electric Cooperative Inc.
P.O. Box AE
Lodge Grass, MT 59050
(406) 639-2341

Central Montana Electric G&T Cooperative
705 Lincoln Lane
Billings, MT 59101
(406) 248-7936

Fergus Electric Cooperative Inc.
313 W. Janeaux St.
Box 58
Lewistown, MT 59457
(406) 538-3465

Flathead Electric Cooperative, Inc.
510 LaSalle Rd.
Kalispell, Mt 59901
(406) 755-5483

Glacier Electric Cooperative, Inc.
P.O. Box 358
410 East Main
Cut Bank, MT 59427
(406) 873-5566

Goldenwest Electric Co-Op Inc.
Box 245
Wibaux, MT 59353
(406)795-2423

Hill County Electric Cooperative, Inc.
Highway 2 West
P.O. Box 430
Havre, MT 59501
(406) 265-7807

Lincoln Electric Cooperative Inc.
P.O. Box 628
Eureka, MT 59917
(406) 296-2511

Lower Yellowstone Electric Association
310 Second Avenue, N.E.
Sidney, MT 59270
(406) 482-1602

Marias River Electric Cooperative Inc.
910 Roosevelt Highway
Shelby, MT 59474
(406) 434-5575

McCone Electric Co-Op, Inc.
P.O. Box 368
Circle, MT 59215
(406) 485-3430

Mid-Yellowstone Electric Cooperative Inc
P.O. Box 386
Hysham, MT 59038
(406) 342-5521

Missoula Electric Cooperative, Inc.
1950 Sherwood St.
Missoula, MT 59801
(406) 549-6115

Northern Electric Cooperative, Inc.
Box 287
Opheim, MT 59250
(406) 762-3352

Park Electric Cooperative, Inc.
Box 908
Livingston, MT 59047
(406) 222-3100

Ravalli County Electric Co-Op Inc.
P.O. Box 109
Corvallis, MT 59828
(406) 961-3211

Sheridan Electric Cooperative Inc.
P.O. Box 227
Medicine Lake, MT 59247
(406)789-2231

Southeast Electric Cooperative, Inc.
P.O. Box 368
Ekalaka, MT 59324
(406) 775-8762

Sun River Electric Cooperative, Inc.
Box 217
Fairfield, MT 59436
(406) 467-2526

Tongue River Electric Cooperative, Inc.
Box 138
Ashland, MT 59003
(406) 784-2341

Upper Missouri G & T Electric Co-Op, Inc.
Box 1069
Sidney, MT 59270
(406) 482-4100

Valley Electric Cooperative, Inc.
P.O. Box 392
Glasgow, MT 59230
(406) 367-5315

Vigilante Electric Cooperative Inc.
225 E. Bannack St
P.O. Box 71
Dillon, MT 59725
(406) 683-2327

Yellowstone Valley Electric Co-Op, Inc.
Huntley, MT 59037
(406) 348-3411

FEDERAL SYSTEMS

U.S. Bureau of Indian Affairs
Department of the Interior
(Flathead Irrigation Project - Power Div.)
Polson, MT 59860
(406) 883-5361

Water & Power Resources Service
Department of the Interior
Regional Office
P.O. Box 2553
Billings, MT 59103

STATE AND FEDERAL AGENCIES

AND

INFORMATION CONTACTS

STATE AND FEDERAL CONTACTS

ENERGY

Montana Energy Division
Department of Natural Resources and Conservation
Helena, MT 59620
(406) 449-3940

Montana Public Service Commission
Helena, MT 59620
(406) 449-3008

Montana Facility Siting Bureau
Department of Natural Resources and Conservation
Helena, MT 59620
(406) 449-4600

U.S. Department of Energy
Region VIII
Lakewood, CO 80226
(303) 234-2420

U.S. Department of Energy
Bonneville Power Administration
Portland, OR 97208
(503) 234-3361

- Biomass, Municipal Waste
  (503) 234-5052

- Cogeneration
  (503) 234-4037

Federal Energy Regulatory Commission
555 Battery St.
Room 415
San Francisco, CA 94111
(415) 764-7150

ENVIRONMENTAL

Montana Air Quality Bureau
Department of Health & Environmental Science
Helena, MT 59620
(406) 449-3454

Montana Water Quality Bureau
Department of Health & Environmental Science
Helena, MT 59620
(406) 449-2406

Montana Water Resource Department
Helena, MT 59620
(406) 449-2872

Montana Solid Waste Management Bureau
Department of Health & Environmental Sciences
Helena, MT 59620
(406) 449-2821

United States Environmental Protection Agency
Drawer 10096
Helena, MT 59626
(406) 449-5414

WOOD

Montana Department of State Lands
Misoula, MT 59801
(406) 728-4300

- Regional Administrator
  Helena, MT
  (406) 449-2074

U.S. Forest Service
Federal District Forester
Missoula, MT 59801
(406) 329-3604

BOILER PERMITS

Montana Bureau of Safety & Health
Helena, MT 59620
(406) 449-3402

INFORMATION

University of Montana
Missoula, MT 59812

- Resource Information
  (406) 243-5113

- Biomass/Waste Fuels
  Department of Chemistry
  (406) 243-4022

Montana State University
Bozeman, MT 59715

- Biogas
  Department of Microbiology
  (406) 994-2903
  Department of Chemistry
  (406) 994-4801

- Geothermal
  Department of Earth Sciences
  (406) 994-3331

Montana Crop & Lifestock Reporting Service
Helena, MT 59604
Crop Residue Resource Information
(406) 449-5303

Geo-Heat Utilization Center
Oregon Institute of Technology
Klamath Falls, OR 97601
(503) 882-6321

TAX INCENTIVES

Montana Department of Revenue
Helena, MT 59620
(406) 449-2837

BUILDING CODES

Montana Department of Administration
Helena, MT 59620
(406) 449-3933

APPENDIX C

<u>MONTANA FACILITIES SITING ACT AND CURRENT</u>

<u>BUY BACK RATES AS ESTABLISHED BY THE</u>

<u>MONTANA PUBLIC SERVICE COMMISSION</u>

TITLE 75
ENVIRONMENTAL PROTECTION

CHAPTER 20
MAJOR FACILITY SITING

Part 1

Policy and General Provisions

75-20-101. Short title. This chapter shall be known and may be cited as the "Montana Major Facility Siting Act".

History: En. Sec. 1, Ch. 327, L. 1973; amd. Sec. 1, Ch. 494, L. 1975; R.C.M. 1947, 70-801.

75-20-102. Policy and legislative findings. (1) It is the constitutionally declared policy of this state to maintain and improve a clean and healthful environment for present and future generations, to protect the environmental life-support system from degradation and prevent unreasonable depletion and degradation of natural resources, and to provide for administration and enforcement to attain these objectives.

(2) The legislature finds that the construction of additional power or energy conversion facilities may be necessary to meet the increasing need for electricity, energy, and other products and that these facilities have an effect on the environment, an impact on population concentration, and an effect on the welfare of the citizens of this state. Therefore, it is necessary to ensure that the location, construction, and operation of power and energy conversion facilities will produce minimal adverse effects on the environment and upon the citizens of this state by providing that a power or energy conversion facility may not be constructed or operated within this state without a certificate of environmental compatibility and public need acquired pursuant to this chapter.

History: En. Sec. 2, Ch. 327, L. 1973; amd. Sec. 2, Ch. 494, L. 1975; R.C.M. 1947, 70-802.

75-20-103. Chapter supersedes other laws or rules. This chapter supersedes other laws or regulations except as provided in 75-20-401. If any provision of this chapter is in conflict with any other law of this state or any rule promulgated thereunder, this chapter shall govern and control and the other law or rule shall be deemed superseded for the purpose of this chapter. Amendments to this chapter shall have the same effect.

History: En. Sec. 23, Ch. 327, L. 1973; amd. Sec. 23, Ch. 494, L. 1975; R.C.M. 1947, 70-823; amd. Sec. 1, Ch. 676, L. 1979.

75-20-104. Definitions. In this chapter, unless the context requires otherwise, the following definitions apply:

(1) "Addition thereto" means the installation of new machinery and equipment which would significantly change the conditions under which the facility is operated. 1981 Chan

(2) "Application" means an application for a certificate submitted in accordance with this chapter and the rules adopted hereunder.

(3) "Associated facilities" includes but is not limited to transportation links of any kind, aqueducts, diversion dams, transmission substations, storage ponds, reservoirs, and any other device or equipment associated with the production or delivery of the energy form or product produced by a facility, except that the term does not include a facility.

(4) "Board" means the board of natural resources and conservation provided for in 2-15-3302.

(5) "Board of health" means the board of health and environmental sciences provided for in 2-15-2104.

(6) "Certificate" means the certificate of environmental compatibility and public need issued by the board under this chapter that is required for the construction or operation of a facility.

(7) "Commence to construct" means:

(a) any clearing of land, excavation, construction, or other action that would affect the environment of the site or route of a facility but does not mean changes needed for temporary use of sites or routes for nonutility purposes or uses in securing geological data, including necessary borings to ascertain foundation conditions;

(b) the fracturing of underground formations by any means if such activity is related to the possible future development of a gasification facility or a facility employing geothermal resources but does not include the gathering of geological data by boring of test holes or other underground exploration, investigation, or experimentation;

(c) the commencement of eminent domain proceedings under Title 70, chapter 30, for land or rights-of-way upon or over which a facility may be constructed;

(d) the relocation or upgrading of an existing facility defined by (b) or (c) of subsection (10), including upgrading to a design capacity covered by subsection (10)(b), except that the term does not include normal maintenance or repair of an existing facility.

(8) "Department" means the department of natural resources and conservation provided for in Title 2, chapter 15, part 33.

(9) "Department of health" means the department of health and environmental sciences provided for in Title 2, chapter 15, part 21.

(10) "Facility" means:

(a) except for crude oil and natural gas refineries, and facilities and associated facilities designed for or capable of producing, gathering, processing, transmitting, transporting, or distributing crude oil or natural gas, and those facilities subject to The Montana Strip and

Underground Mine Reclamation Act, each plant, unit, or other facility and associated facilities designed for or capable of:

(i) generating 50 megawatts of electricity or more or any addition thereto (except pollution control facilities approved by the department of health and environmental sciences added to an existing plant) having an estimated cost in excess of $10 million;

(ii) producing 25 million cubic feet or more of gas derived from coal per day or any addition thereto having an estimated cost in excess of $10 million;

(iii) producing 25,000 barrels of liquid hydrocarbon products per day or more or any addition thereto having an estimated cost in excess of $10 million;

(iv) enriching uranium minerals or any addition thereto having an estimated cost in excess of $10 million; or

(v) utilizing or converting 500,000 tons of coal per year or more or any addition thereto having an estimated cost in excess of $10 million;

(b) each electric transmission line and associated facilities of a design capacity of more than 69 kilovolts, except that the term does not include an electric transmission line and associated facilities of a design capacity of 230 kilovolts or less and 10 miles or less in length;

(c) each pipeline and associated facilities designed for or capable of transporting gas (except for natural gas), water, or liquid hydrocarbon products from or to a facility located within or without this state of the size indicated in subsection (10)(a) of this section;

(d) any use of geothermal resources, including the use of underground space in existence or to be created, for the creation, use, or conversion of energy, designed for or capable of producing geothermally derived power equivalent to 25 million Btu per hour or more or any addition thereto having an estimated cost in excess of $750,000;

(e) any underground in situ gasification of coal.

(11) "Person" means any individual, group, firm, partnership, corporation, cooperative, association, government subdivision, government agency, local government, or other organization or entity.

(12) "Transmission substation" means any structure, device, or equipment assemblage, commonly located and designed for voltage regulation, circuit protection, or switching necessary for the construction or operation of a proposed transmission line.

(13) "Utility" means any person engaged in any aspect of the production, storage, sale, delivery, or furnishing of heat, electricity, gas, hydrocarbon products, or energy in any form for ultimate public use.

History: En. Sec. 3, Ch. 327, L. 1973; amd. Sec. 1, Ch. 231, L. 1974; amd. Sec. 1, Ch. 268, L. 1974; amd. Sec. 3, Ch. 494, L. 1975; R.C.M. 1947, 70-803; amd. Sec. 1, Ch. 133, L. 1979; amd. Sec. 1, Ch. 527, L. 1979; amd. Sec. 2, Ch. 676, L. 1979; amd. Sec. 1, Ch. 539, L. 1981.

Compiler's Comments

1981 Amendment: Substituted "would significantly change the conditions under which the facility is operated" for "would significantly change the conditions under which the certificate was issued" at the end of (1); added facilities subject to The Montana Strip and Underground Mine Reclamation Act within the exception to the definition of facility in (10)(a); increased $250,000 to $10 million throughout (10)(a); deleted "refining" after "utilizing" in (10)(a)(v); and increased $250,000 to $750,000 at the end of (10)(d).

1981 Effective Date: Section 9, Ch. 539, L. 1981, provided: "This act is effective on passage and approval." Approved April 29, 1981.

1979 Effective Date: Section 2, Ch. 527, L. 1979, provided: "This act is effective on passage and approval." Approved April 10, 1979.

75-20-105. Adoption of rules. The board may adopt rules implementing the provisions of this chapter, including but not limited to:

(1) rules governing the form and content of applications;

(2) rules further defining the terms used in this chapter;

(3) rules governing the form and content of long-range plans;

(4) any other rules the board considers necessary to accomplish the purposes and objectives of this chapter.

History: En. Sec. 20, Ch. 327, L. 1973; amd. Sec. 4, Ch. 268, L. 1974; amd. Sec. 20, Ch. 494, L. 1975; R.C.M. 1947, 70-820(1).

75-20-106. Contracts for information. (1) The department may contract with a potential applicant under this chapter in advance of the filing of a formal application for the development of information or provision of services required hereunder.

(2) Payments made to the department under such a contract shall be credited against the fee payable hereunder.

History: En. Sec. 6, Ch. 327, L. 1973; amd. Sec. 1, Ch. 115, L. 1974; amd. Sec. 2, Ch. 268, L. 1974; amd. Sec. 1, Ch. 270, L. 1975; amd. Sec. 6, Ch. 494, L. 1975; amd. Sec. 1, Ch. 179, L. 1977; R.C.M. 1947, 70-806(2)(c).

75-20-107 through 75-20-110 reserved.

75-20-111. Grants, gifts, and funds. The department may receive grants, gifts, and other funds from any public or private source to assist in its activities under this chapter.

History: En. Sec. 22, Ch. 327, L. 1973; amd. Sec. 22, Ch. 494, L. 1975; R.C.M. 1947, 70-822.

75-20-112. Moneys to earmarked revenue fund. All fees, taxes, fines, and penalties collected under this chapter shall be deposited in the earmarked revenue fund for use by the department in carrying out its functions and responsibilities under this chapter.

History: En. 70-824 by Sec. 3, Ch. 270, L. 1975; R.C.M. 1947, 70-824.

Part 2

Certification Proceedings

75-20-201. Certificate required -- operation in conformance -- approval by popular vote of certificate for nuclear facility. (1) A person may not commence to construct a facility in the state without first applying for and obtaining a certificate of environmental compatibility and public need issued with respect to the facility by the board.

(2) A facility with respect to which a certificate is issued may not thereafter be constructed, operated, or maintained except in conformity with the certificate and any terms, conditions, and modifications contained therein.

(3) A certificate may only be issued pursuant to this chapter.

(4) If the board decides to issue a certificate for a nuclear facility, it shall report such recommendation to the applicant and may not issue the certificate until such recommendation is approved by a majority of the voters in a statewide election called by initiative or referendum according to the laws of this state.

History: En. Sec. 4, Ch. 327, L. 1973; amd. Sec. 4, Ch. 494, L. 1975; R.C.M. 1947, 70-804(1); amd. Sec. 3, I.M. 80, app. Nov. 7, 1978.

75-20-202. Exemptions. (1) This chapter does not apply to any aspect of a facility over which an agency of the federal government has exclusive jurisdiction, but applies to any unpreempted aspect of a facility over which an agency of the federal government has partial jurisdiction.

(2) A certificate is not required under this chapter for a facility under diligent onsite physical construction or in operation on January 1, 1973.

(3) The board may adopt reasonable rules establishing exemptions from this chapter for the relocation, reconstruction, or upgrading of a facility that:

(a) would otherwise be covered by this chapter; and

(b) (i) is unlikely to have a significant environmental impact by reason of length, size, location, available space or right-of-way, or construction methods; or

(ii) utilizes coal, wood, biomass, grain, wind, or sun as a fuel source and the technology of which will result in greater efficiency, promote energy conservation, and promote greater system reliability than the existing facility.

History: En. Sec. 4, Ch. 327, L. 1973; amd. Sec. 4, Ch. 494, L. 1975; R.C.M. 1947, 70-804(3) thru (5); amd. Sec. 3, I.M. 80, app. Nov. 7, 1978; amd. Sec. 2, Ch. 539, L. 1981.

Compiler's Comments

1981 Amendment: Added subsection (3)(b)(ii).

Effective Date: Section 9, Ch. 539, L. 1981, provided: "This act is effective on passage and approval." Approved April 29, 1981.

75-20-203. Certificate transferable. A certificate may be transferred, subject to the approval of the board, to a person who agrees to comply with the terms, conditions, and modifications contained therein.

History: En. Sec. 4, Ch. 327, L. 1973; amd. Sec. 4, Ch. 494, L. 1975; R.C.M. 1947, 70-804(2); amd. Sec. 3, I.M. 80, app. Nov. 7, 1978; amd. Sec. 3, Ch. 676, L. 1979.

75-20-204 through 75-20-210 reserved.

75-20-211. Application -- filing and contents -- proof of service and notice. (1) (a) An applicant shall file with the department and department of health a joint application for a certificate under this chapter and for the permits required under the laws administered by the department of health and the board of health in such form as the board requires under applicable rules, containing the following information:

(i) a description of the location and of the facility to be built thereon;

(ii) a summary of any studies which have been made of the environmental impact of the facility;

(iii) a statement explaining the need for the facility;

(iv) a description of reasonable alternate locations for the proposed facility, a general description of the comparative merits and detriments of each location submitted, and a statement of the reasons why the primary proposed location is best suited for the facility;

(v) baseline data for the primary and reasonable alternate locations; (1979)

(vi) at the applicant's option, an environmental study plan to satisfy the requirements of this chapter; and

(vii) such other information as the applicant considers relevant or as the board and board of health by order or rule or the department and department of health by order or rule may require.

(b) A copy or copies of the studies referred to in subsection (1)(a)(ii) above shall be filed with the department, if ordered, and shall be available for public inspection.

(2) An application may consist of an application for

two or more facilities in combination which are physically and directly attached to each other and are operationally a single operating entity.

(3) An application shall be accompanied by proof of service of a copy of the application on the chief executive officer of each unit of local government, county commissioner, city or county planning boards, and federal agencies charged with the duty of protecting the environment or of planning land use in the area in which any portion of the proposed facility may be located, both as primarily and as alternatively proposed and on the following state government agencies:

(a) environmental quality council;
(b) department of public service regulation;
(c) department of fish, wildlife, and parks;
(d) department of state lands;
(e) department of commerce;
(f) department of highways;
(g) department of revenue.

(4) The copy of the application shall be accompanied by a notice specifying the date on or about which the application is to be filed.

(5) An application shall also be accompanied by proof that public notice thereof was given to persons residing in the area or alternative areas in which any portion of the proposed facility may be located, by publication of a summary of the application in those newspapers that will substantially inform those persons of the application.

History: En. Sec. 6, Ch. 327, L. 1973; amd. Sec. 1, Ch. 115, L. 1974; amd. Sec. 2, Ch. 268, L. 1974; amd. Sec. 1, Ch. 270, L. 1975; amd. Sec. 6, Ch. 494, L. 1975; amd. Sec. 1, Ch. 179, L. 1977; R.C.M. 1947, 70-806(part); amd. Sec. 1, Ch. 553, L. 1979; amd. Sec. 4, Ch. 676, L. 1979; amd. Sec. 6, Ch. 274, L. 1981; amd. Sec. 3, Ch. 539, L. 1981.

Compiler's Comments

1981 Amendments: Chapter 274 substituted "department of commerce" for "department of community affairs" in (3)(e).

Chapter 539 substituted "for the permits required under the laws administered by the department of health and the board of health" for "for the permits required by state air and water quality laws" in (1)(a); and substituted "as the board and board of health by order or rule or the department and department of health by order or rule may require" for "as the board and board of health by rule or the department and department of health by order require" at the end of (1)(a)(vii).

Effective Date: Section 9, Ch. 539, L. 1981, provided: "This act is effective on passage and approval." Approved April 29, 1981.

Transfer of Function: Section 6, Ch. 274, L. 1981, provided in part: "(1) The department of community affairs is abolished.

(2) The following functions of the department of

community affairs are transferred to the department of commerce: . . .

(e) relating to recommendations concerning major facility siting and contained in 75-20-211, 75-20-216, and 75-20-501; . . ."

Waiver of Baseline Data Requirement if Existing Contract: Section 26, Ch. 676, L. 1979, provided: "The department may in its discretion waive the requirement that baseline data for the primary and reasonable alternate locations be submitted with an application under 75-20-211(1)(a)(v) in those cases in which the applicant has, prior to July 1, 1979, entered into a contract with the department to compile baseline information."

Composite Section: This section was amended by Ch. 553 and Ch. 676, L. 1979, and a composite section was prepared by the Code Commissioner, 1979. Subsection (3) regarding persons and agencies to be served with a copy of an application was amended by both of the above chapters. Ch. 676 deleted "chief executive officer of each" but the Code Commissioner reinserted this phrase to incorporate the change by Ch. 553 from "municipality" to "unit of local government".

75-20-212. Cure for failure of service. Inadvertent failure of service on or notice to any of the municipalities, government agencies, or persons identified in 75-20-211(3) and (5) may be cured pursuant to orders of the department designed to afford them adequate notice to enable their effective participation in the proceeding.

History: En. Sec. 6, Ch. 327, L. 1973; amd. Sec. 1, Ch. 115, L. 1974; amd. Sec. 2, Ch. 268, L. 1974; amd. Sec. 1, Ch. 270, L. 1975; amd. Sec. 6, Ch. 494, L. 1975; amd. Sec. 1, Ch. 179, L. 1977; R.C.M. 1947, 70-806(part).

75-20-213. Supplemental material -- amendments. (1) An application for an amendment of an application or a certificate shall be in such form and contain such information as the board by rule or the department by order prescribes. Notice of such an application shall be given as set forth in (3), (4), and (5) of 75-20-211.

(2) An application may be amended by an applicant any time prior to the department's recommendation. If the proposed amendment is such that it prevents the department, the department of health, or the agencies listed in 75-20-216(5) from carrying out their duties and responsibilities under this chapter, the department may require such additional filing fees as the department determines necessary, or the department may require a new application and filing fee.

(3) The applicant shall submit supplemental material in a timely manner as requested by the department or as offered by the applicant to explain, support, or provide the detail with respect to an item described in the original application, without filing an application for an amendment. The department's determination as to whether information is

supplemental or whether an application for amendment is required shall be conclusive.

History: En. Sec. 6, Ch. 327, L. 1973; amd. Sec. 1, Ch. 115, L. 1974; amd. Sec. 2, Ch. 268, L. 1974; amd. Sec. 1, Ch. 270, L. 1975; amd. Sec. 6, Ch. 494, L. 1975; amd. Sec. 1, Ch. 179, L. 1977; R.C.M. 1947, 70-806(6); amd. Sec. 5, Ch. 676, L. 1979.

75-20-214. Notice of intent to file. A potential applicant for a certificate may file a notice of intent to file an application for a certificate for a facility defined in 75-20-104(10) at least 12 months prior to the actual filing of an application. The notice of intent shall specify the type and size of facility to be applied for, its preferred location, a description of reasonable alternative locations, and such information as the board by rule or department by order requires. An applicant complying with this section is entitled to a 5% reduction of the filing fee required under 75-20-215.

History: En. Sec. 6, Ch. 327, L. 1973; amd. Sec. 1, Ch. 115, L. 1974; amd. Sec. 2, Ch. 268, L. 1974; amd. Sec. 1, Ch. 270, L. 1975; amd. Sec. 6, Ch. 494, L. 1975; amd. Sec. 1, Ch. 179, L. 1977; R.C.M. 1947, 70-806(7); amd. Sec. 6, Ch. 676, L. 1979.

75-20-215. Filing fee -- accountability -- refund -- use. (1) (a) A filing fee shall be deposited in the earmarked revenue fund for the use of the department in administering this chapter. The applicant shall pay to the department a filing fee as provided in this section based upon the department's estimated costs of processing the application under this chapter, but which shall not exceed the following scale based upon the estimated cost of the facility:

(i) 2% of any estimated cost up to $1 million; plus

(ii) 1% of any estimated cost over $1 million and up to $20 million; plus

(iii) 0.5% of any estimated cost over $20 million and up to $100 million; plus

(iv) 0.25% of any amount of estimated cost over $100 million and up to $300 million; plus

(v) .125% of any amount of estimated cost over $300 million.

(b) The department may allow in its discretion a credit against the fee payable under this section for the development of information or providing of services required hereunder or required for preparation of an environmental impact statement under the Montana or national environmental policy acts. The applicant may submit the information to the department together with an accounting of the expenses incurred in preparing the information. The department shall evaluate the applicability, validity, and usefulness of the data and determine the amount which may be credited against the filing fee payable under this section. Upon 30 days' notice to the applicant, this credit may at any time be reduced if the department determines that it is necessary to carry out its responsibilities under this chapter.

(2) (a) The department may contract with an applicant for the development of information, provision of services and payment of fees required under this chapter. The contract may continue an agreement entered into pursuant to 75-20-106. Payments made to the department under such a contract shall be credited against the fee payable hereunder. Notwithstanding the provisions of this section, the revenue derived from the filing fee must be sufficient to enable the department, the department of health, the board, the board of health, and the agencies listed in 75-20-216(5) to carry out their responsibilities under this chapter. The department may amend a contract to require additional payments for necessary expenses up to the limits set forth in subsection (1)(a) above upon 30 days' notice to the applicant. The department and applicant may enter into a contract which exceeds the scale provided in subsection (1)(a).

(b) If a contract is not entered into, the applicant shall pay the filing fee in installments in accordance with a schedule of installments developed by the department, provided that no one installment may exceed 20% of the total filing fee provided for in subsection (1).

(3) The estimated cost of upgrading an existing transmission substation may not be included in the estimated cost of a proposed facility for the purpose of calculating a filing fee.

(4) If an application consists of a combination of two or more facilities, the filing fee shall be based on the total estimated cost of the combined facilities.

(5) The applicant is entitled to an accounting of moneys expended and to a refund with interest at the rate of 6% a year of that portion of the filing fee not expended by the department in carrying out its responsibilities under this chapter. A refund shall be made after all administrative and judicial remedies have been exhausted by all parties to the certification proceedings.

(6) The revenues derived from filing fees shall be used by the department in compiling the information required for rendering a decision on a certificate and for carrying out its and the board's other responsibilities under this chapter.

History: En. Sec. 6, Ch. 327, L. 1973; amd. Sec. 1, Ch. 115, L. 1974; amd. Sec. 2, Ch. 268, L. 1974; amd. Sec. 1, Ch. 270, L. 1975; amd. Sec. 6, Ch. 494, L. 1975; amd. Sec. 1, Ch. 179, L. 1977; R.C.M. 1947, 70-806(2)(a), (2)(b); amd. Sec. 7, Ch. 676, L. 1979.

75-20-216. Study, evaluation, and report on proposed facility -- assistance by other agencies. (1) After receipt of an application, the department and department of health shall within 90 days notify the applicant in writing that:

(a) the application is in compliance and is accepted as complete; or

(b) the application is not in compliance and list the deficiencies therein; and upon correction of these deficiencies and resubmission by the applicant, the department and department of health shall within 30 days notify the applicant in writing that the application is in compliance and is accepted as complete.

(2) Upon receipt of an application complying with 75-20-211 through 75-20-215, and this section, the department shall commence an intensive study and evaluation of the proposed facility and its effects, considering all applicable criteria listed in 75-20-301 and 75-20-503 and the department of health shall commence a study to enable it or the board of health to issue a decision, opinion, order, certification, or permit as provided in subsection (3). The department and department of health shall use, to the extent they consider applicable, valid and useful existing studies and reports submitted by the applicant or compiled by a state or federal agency.

(3) The department of health shall within 1 year following the date of acceptance of an application and the board of health or department of health, if applicable, within an additional 6 months issue any decision, opinion, order, certification, or permit required under the laws administered by the department of health or the board of health and this chapter. The department of health and the board of health shall determine compliance with all standards, permit requirements, and implementation plans under their jurisdiction for the primary and reasonable alternate locations in their decision, opinion, order, certification, or permit. The decision, opinion, order, certification, or permit, with or without conditions, is conclusive on all matters that the department of health and board of health administer, and any of the criteria specified in subsections (2) through (7) of 75-20-503 that are a part of the determinations made under the laws administered by the department of health and the board of health. Although the decision, opinion, order, certification, or permit issued under this subsection is conclusive, the board retains authority to make the determination required under 75-20-301(2)(c). The decision, opinion, order, certification, or permit of the department of health or the board of health satisfies the review requirements by those agencies and shall be acceptable in lieu of an environmental impact statement under the Montana Environmental Policy Act. A copy of the decision, opinion, order, certification, or permit shall be served upon the department and the board and shall be utilized as part of their final site selection process. Prior to the issuance of a preliminary decision by the department of health and pursuant to rules adopted by the board of health, the department of health shall provide an opportunity for public review and comment.

(4) Within 22 months following acceptance of an application for a facility as defined in (a) and (d) of 75-20-104(10) and for a facility as defined in (b) and (c)

of 75-20-104(10) which is more than 30 miles in length and within 1 year for a facility as defined in (b) and (c) of 75-20-104(10) which is 30 miles or less in length, the department shall make a report to the board which shall contain the department's studies, evaluations, recommendations, other pertinent documents resulting from its study and evaluation, and an environmental impact statement or analysis prepared pursuant to the Montana Environmental Policy Act, if any. If the application is for a combination of two or more facilities, the department shall make its report to the board within the greater of the lengths of time provided for in this subsection for either of the facilities.

(5) The departments of highways; commerce; fish, wildlife, and parks; state lands; revenue; and public service regulation shall report to the department information relating to the impact of the proposed site on each department's area of expertise. The report may include opinions as to the advisability of granting, denying, or modifying the certificate. The department shall allocate funds obtained from filing fees to the departments making reports to reimburse them for the costs of compiling information and issuing the required report.

History: En. Sec. 7, Ch. 327, L. 1973; amd. Sec. 3, Ch. 268, L. 1974; amd. Sec. 39, Ch. 213, L. 1975; amd. Sec. 7, Ch. 494, L. 1975; R.C.M. 1945, 70-807(1), (2); amd. Sec. 2, Ch. 218, L. 1979; amd. Sec. 8, Ch. 676, L. 1979; amd. Sec. 6, Ch. 274, L. 1981; amd. Sec. 4, Ch. 539, L. 1981.

Compiler's Comments

1981 Amendments: Chapter 274 substituted "department of commerce" for "department of community affairs" in (5).

Chapter 539 inserted "or department of health" after "the board of health" in the middle of the first sentence of (3); substituted "permit required under the laws administered by the department of health or board of health and this chapter" for "permit required by state or federal air and water quality laws and this chapter" at the end of the first sentence of (3); substituted "the board of health shall determine compliance with all standards, permit requirements, and implementation plans under their jurisdiction" for "the board of health shall determine compliance with air and water quality standards and implementation plans" in the second sentence of (3); deleted "of air and water quality impacts under the federal and state air and water quality statutes" after "The decision, opinion, order, certification, or permit, with or without conditions, is conclusive on all matters" in the third sentence of (3); substituted "specified in subsections (2) through (7) of 75-20-503" for "specified in 75-20-503(3) and (4)" in the third sentence of (3); substituted "the determinations made under the laws administered by the department of health and the board of health" for "the determinations made under federal and state air and water quality statutes" at the end of the third sentence of (3);

and deleted "A decision by the department of health or board of health is subject to appellate review pursuant to the air and water quality statutes administered by the department of health and board of health" at the end of (3).

Transfer of Function: Section 6, Ch. 274, L. 1981, provided in part: "(1) The department of community affairs is abolished.

(2) The following functions of the department of community affairs are transferred to the department of commerce: . . .

(e) relating to recommendations concerning major facility siting and contained in 75-20-211, 75-20-216, and 75-20-501; . . ."

Effective Date: Section 9, Ch. 539, L. 1981, provided: "This act is effective on passage and approval." Approved April 29, 1981.

75-20-217. Voiding an application. An application may be voided by the department for:

(1) any material and knowingly false statement in the application or in accompanying statements or studies required of the applicant;

(2) failure to file an application in substantially the form and content required by this chapter and the rules adopted thereunder; or

(3) failure to deposit the filing fee as provided in 75-20-215.

History: En. Sec. 18, Ch. 327, L. 1973; amd. Sec. 18, Ch. 494, L. 1975; R.C.M. 1947, 70-818(2); amd. Sec. 9, Ch. 676, L. 1979.

75-20-218. Hearing date -- location -- department to act as staff -- hearings to be held jointly. (1) Upon receipt of the department's report submitted under 75-20-216, the board shall set a date for a hearing to begin not more than 120 days after the receipt. Except for those hearings involving applications submitted for facilities as defined in (b) and (c) of 75-20-104(10), certification hearings shall be conducted by the board in the county seat of Lewis and Clark County or the county in which the facility or the greater portion thereof is to be located.

(2) Except as provided in 75-20-221(2), the department shall act as the staff for the board throughout the decisionmaking process and the board may request the department to present testimony or cross-examine witnesses as the board considers necessary and appropriate.

(3) At the request of the applicant, the department of health and the board of health shall hold any required permit hearings required under laws administered by those agencies in conjunction with the board certification hearing. In such a conjunctive hearing the time periods established for reviewing an application and for issuing a decision on certification of a proposed facility under this chapter supersede the time periods specified in other laws administered by the department of health and the board of

health.

History: En. Sec. 7, Ch. 327, L. 1973; amd. Sec. 3, Ch. 268, L. 1974; amd. Sec. 39, Ch. 213, L. 1975; amd. Sec. 7, Ch. 494, L. 1975; R.C.M. 1947, 70-807(4); amd. Sec. 10, Ch. 676, L. 1979; amd. Sec. 5, Ch. 539, L. 1981.

Compiler's Comments

1981 Amendment: Substituted "department of health and the board of health" for "duly authorized state air and water quality agencies" near the beginning and at the end of (3).

Effective Date: Section 9, Ch. 539, L. 1981, provided: "This act is effective on passage and approval." Approved April 29, 1981.

75-20-219. Amendments to a certificate. (1) Within 30 days after notice of an amendment to a certificate is given as set forth in 75-20-213(1), including notice to all active parties to the original proceeding, the department shall determine whether the proposed change in the facility would result in any material increase in any environmental impact of the facility or a substantial change in the location of all or a portion of the facility other than as provided in the alternates set forth in the original application. If the department determines that the proposed change would result in any material increase in any environmental impact of the facility or a substantial change in the location of all or a portion of the facility, the board shall hold a hearing in the same manner as a hearing is held on an application for a certificate. After hearing, the board shall grant, deny, or modify the amendment with such conditions as it deems appropriate.

(2) In those cases where the department determines that the proposed change in the facility would not result in any material increase in any environmental impact or would not be a substantial change in the location of all or a portion of the facility, the board shall automatically grant the amendment either as applied for or upon such terms or conditions as the board considers appropriate unless the department's determination is appealed to the board within 15 days after notice of the department's determination is given.

(3) If the department or the board under subsection (4) determines that a hearing is required because the proposed change would result in any material increase in any environmental impact of the facility or a substantial change in the location of all or a portion of the facility, the applicant has the burden of showing by clear and convincing evidence that the amendment should be granted.

(4) If the department determines that the proposed change in the facility would not result in any material increase in any environmental impact or would not be a substantial change in the location of all or a portion of the facility, and a hearing is required because the department's determination is appealed to the board as

provided in subsection (2), the appellant has the burden of showing by clear and convincing evidence that the proposed change in the facility would result in any material increase in any environmental impact of the facility or a substantial change in the location of all or a portion of the facility other than as provided in the alternates set forth in the original application.

(5) If an amendment is required to a certificate which would affect, amend, alter or modify a decision, opinion, order, certification, or permit issued by the department of health or board of health, such amendment must be processed under the applicable statutes administered by the department of health or board of health.

History: En. Sec. 7, Ch. 327, L. 1973; amd. Sec. 3, Ch. 268, L. 1974; amd. Sec. 39, Ch. 213, L. 1975; amd. Sec. 7, Ch. 494, L. 1975; R.C.M. 1947, 70-807(3); amd. Sec. 11, Ch. 676, L. 1979; amd. Sec. 1, Ch. 372, L. 1981.

Compiler's Comments

1981 Amendment: Substituted subsection (3) for "If a hearing is required, the applicant has the burden of showing by clear and convincing evidence that the amendment should be granted"; and inserted subsection (4).

75-20-220. Hearing examiner -- restrictions -- duties. (1) If the board appoints a hearing examiner to conduct any certification proceedings under this chapter, the hearing examiner may not be a member of the board, an employee of the department, or a member or employee of the department of health or board of health. A hearing examiner, if any, shall be appointed by the board within 20 days after the department's report has been filed with the board. If a hearing is held before the board of health or the department of health, the board and the board of health or the department of health shall mutually agree on the appointment of a hearing examiner to preside at both hearings.

(2) A prehearing conference shall be held following notice within 60 days after the department's report has been filed with the board.

(3) The prehearing conference shall be organized and supervised by the hearing examiner.

(4) The prehearing conference shall be directed toward a determination of the issues presented by the application, the department's report, and an identification of the witnesses and documentary exhibits to be presented by the active parties who intend to participate in the hearing.

(5) The hearing examiner shall require the active parties to submit, in writing, and serve upon the other active parties, all direct testimony which they propose and any studies, investigations, reports, or other exhibits that any active party wishes the board to consider. These written exhibits and any documents that the board itself wishes to use or rely on shall be submitted and served in like manner, at least 20 days prior to the date set for the hearing. For good cause shown, the hearing examiner may

allow the introduction of new evidence at any time.

(6) The hearing examiner shall allow discovery which shall be completed before the commencement of the hearing, upon good cause shown and under such other conditions as the hearing examiner shall prescribe.

(7) Public witnesses and other interested public parties may appear and present oral testimony at the hearing or submit written testimony to the hearing examiner at the time of their appearance. These witnesses are subject to cross-examination.

(8) The hearing examiner shall issue a prehearing order specifying the issues of fact and of law, identifying the witnesses of the active parties, naming the public witnesses and other interested parties who have submitted written testimony in lieu of appearance, outlining the order in which the hearing shall proceed, setting forth those section 75-20-301 criteria as to which no issue of fact or law has been raised which are to be conclusively presumed and are not subject to further proof except for good cause shown, and any other special rules to expedite the hearing which the hearing examiner shall adopt with the approval of the board.

(9) At the conclusion of the hearing, the hearing examiner shall declare the hearing closed and shall, within 60 days of that date, prepare and submit to the board and in the case of a conjunctive hearing, within 90 days to the board and the board of health or department of health proposed findings of fact, conclusions of law, and a recommended decision.

(10) The hearing examiner appointed to conduct a certification proceeding under this chapter shall insure that the time of the proceeding, from the date the department's report is filed with the board until the recommended report and order of the examiner is filed with the board, does not exceed 9 calendar months unless extended by the board for good cause.

(11) The board or hearing examiner may waive all or a portion of the procedures set forth in subsections (2) through (8) of this section to expedite the hearing for a facility when the department has recommended approval of a facility and no objections have been filed.

History: En. Sec. 9, Ch. 327, L. 1973; amd. Sec. 9, Ch. 494, L. 1975; R.C.M. 1947, 70-809(3); amd. Sec. 12, Ch. 676, L. 1979; amd. Sec. 6, Ch. 539, L. 1981.

Compiler's Comments

1981 Amendment: Inserted "or the department of health" after "board of health" throughout the last sentence of (1) and near the end of (9).

Effective Date: Section 9, Ch. 539, L. 1981, provided: "This act is effective on passage and approval." Approved April 29, 1981.

75-20-221. Parties to certification proceeding -- waiver -- statement of intent to participate. (1) The parties to a certification proceeding or to a proceeding involving the issuance of a decision, opinion, order, certification, or permit by the board of health under this chapter may include as active parties:

(a) the applicant;

(b) each political entity, unit of local government, and government agency, including the department of health, entitled to receive service of a copy of the application under 75-20-211(3);

(c) any person entitled to receive service of a copy of the application under 75-20-211(5);

(d) any nonprofit organization formed in whole or in part to promote conservation or natural beauty; to protect the environment, personal health, or other biological values; to preserve historical sites; to promote consumer interests; to represent commercial and industrial groups; or to promote the orderly development of the areas in which the facility is to be located;

(e) any other interested person who establishes an interest in the proceeding.

(2) The department shall be an active party in any certification proceeding in which the department recommends denial of all or a portion of a facility.

(3) The parties to a certification proceeding may also include, as public parties, any Montana citizen and any party referred to in (b), (c), (d), or (e) of subsection (1).

(4) Any party waives the right to be a party if the party does not participate in the hearing before the board or the board of health.

(5) Each unit of local government entitled to receive service of a copy of the application under 75-20-211(3) shall file with the board a statement showing whether the unit of local government intends to participate in the certification proceeding. If the unit of local government does not intend to particpate, it shall list in this statement its reasons for failing to do so. This statement of intent shall be published before the proceeding begins in a newspaper of general circulation within the jurisdiction of the applicable unit of local government.

History: En. Sec. 8, Ch. 327, L. 1973; amd. Sec. 8, Ch. 494, L. 1975; R.C.M. 1947, 70-808; amd. Sec. 2, Ch. 553, L. 1979; amd. Sec. 13, Ch. 676, L. 1979.

<u>75-20-222. Record of hearing -- procedure -- rules of evidence -- burden of proof.</u> (1) Any studies, investigations, reports, or other documentary evidence, including those prepared by the department, which any party wishes the board to consider or which the board itself expects to utilize or rely upon shall be made a part of the record.

(2) A record shall be made of the hearing and of all testimony taken.

(3) In a certification proceeding held under this chapter, the applicant has the burden of showing by clear

and convincing evidence that the application should be granted and that the criteria of 75-20-301 are met.

(4) All proceedings under this chapter are governed by the procedures set forth in this chapter, the procedural rules adopted by the board, and the Montana Rules of Evidence unless one or more rules of evidence are waived by the hearing examiner upon a showing of good cause by one or more of the parties to the hearing. No other rules of procedure or evidence shall apply except that the contested case procedures of the Montana Administrative Procedure Act shall apply if not in conflict with the procedures set forth in this chapter or the procedural rules adopted by the board.

History: En. Sec. 9, Ch. 327, L. 1973; amd. Sec. 9, Ch. 494, L. 1975; R.C.M. 1947, 70-809(1), (2); amd. Sec. 14, Ch. 676, L. 1979.

Part 3

Decisions

75-20-301. Decision of board -- findings necessary for certification. (1) Within 60 days after submission of the recommended decision by the hearing examiner, the board shall make complete findings, issue an opinion, and render a decision upon the record, either granting or denying the application as filed or granting it upon such terms, conditions, or modifications of the construction, operation, or maintenance of the facility as the board considers appropriate.

(2) The board may not grant a certificate either as proposed by the applicant or as modified by the board unless it shall find and determine:

(a) the basis of the need for the facility;

(b) the nature of the probable environmental impact;

(c) that the facility represents the minimum adverse environmental impact, considering the state of available technology and the nature and economics of the various alternatives;

(d) each of the criteria listed in 75-20-503;

(e) in the case of an electric, gas, or liquid transmission line or aqueduct:

(i) what part, if any, of the line or aqueduct shall be located underground;

(ii) that the facility is consistent with regional plans for expansion of the appropriate grid of the utility systems serving the state and interconnected utility systems; and

(iii) that the facility will serve the interests of utility system economy and reliability;

(f) that the location of the facility as proposed conforms to applicable state and local laws and regulations issued thereunder, except that the board may refuse to apply any local law or regulation if it finds that, as applied to the proposed facility, the law or regulation is unreasonably restrictive in view of the existing technology, of factors of cost or economics, or of the needs of consumers, whether located inside or outside of the directly affected government subdivisions;

(g) that the facility will serve the public interest, convenience, and necessity;

(h) that the department of health or board of health have issued a decision, opinion, order, certification, or permit as required by 75-20-216(3); and

(i) that the use of public lands for location of the facility was evaluated and public lands were selected whenever their use is as economically practicable as the use of private lands and compatible with the environmental criteria listed in 75-20-503.

(3) In determining that the facility will serve the public interest, convenience, and necessity under subsection (2)(g) of this section, the board shall consider:

(a) the items listed in subsections (2)(a) and (2)(b) of this section;

(b) the benefits to the applicant and the state resulting from the proposed facility;

(c) the effects of the economic activity resulting from the proposed facility;

(d) the effects of the proposed facility on the public health, welfare, and safety;

(e) any other factors that it considers relevant.

(4) Considerations of need, public need, or public convenience and necessity and demonstration thereof by the applicant shall apply only to utility facilities.

History: En. Sec. 10, Ch. 327, L. 1973; amd. Sec. 10, Ch. 494, L. 1975; R.C.M. 1947, 70-810(1), (3), (4); amd. Sec. 1, Ch. 69, L. 1979; amd. Sec. 15, Ch. 676, L. 1979.

<u>75-20-302. Conditions imposed.</u> If the board determines that the location of all or a part of the proposed facility should be modified, it may condition its certificate upon such modification, provided that the persons residing in the area affected by the modification have been given reasonable notice of the modification.

History: En. Sec. 10, Ch. 327, L. 1973; amd. Sec. 10, Ch. 494, L. 1975; R.C.M. 1947, 70-810(2); amd. Sec. 16, Ch. 676, L. 1979.

<u>75-20-303. Opinion issued with decision -- contents.</u> (1) In rendering a decision on an application for a certificate, the board shall issue an opinion stating its reasons for the action taken.

(2) If the board has found that any regional or local law or regulation which would be otherwise applicable is unreasonably restrictive pursuant to 75-20-301(2)(f), it shall state in its opinion the reasons therefor.

(3) Any certificate issued by the board shall include the following:

(a) an environmental evaluation statement related to the facility being certified. The statement shall include but not be limited to analysis of the following information:

(i) the environmental impact of the proposed facility;

(ii) any adverse environmental effects which cannot be avoided by issuance of the certificate;

(iii) problems and objections raised by other federal and state agencies and interested groups;

(iv) alternatives to the proposed facility;

(v) a plan for monitoring environmental effects of the proposed facility; and

(vi) a time limit as provided in subsection (4), during which construction of the facility must be completed;

(b) a statement signed by the applicant showing agreement to comply with the requirements of this chapter and the conditions of the certificate.

(4) The board shall issue as part of the certificate the following time limits during which construction of a facility must be completed:

(a) For a facility as defined in (b) or (c) of 75-20-104(7) that is more than 30 miles in length, the time limit is 10 years.

(b) For a facility as defined in (b) or (c) of 75-20-104(7) that is 30 miles or less in length, the time limit is 5 years.

(c) The time limit shall be extended for periods of 2 years each upon a showing by the applicant to the board that a good faith effort is being undertaken to complete construction. Under this subsection, a good faith effort to complete construction includes the process of acquiring any necessary state or federal permit or certificate for the facility and the process of judicial review of any such permit or certificate.

(5) The provisions of subsection (4) apply to any facility for which a certificate has not been issued or for which construction is yet to be commenced.

History: En. Sec. 11, Ch. 327, L. 1973; amd. Sec. 11, Ch. 494, L. 1975; R.C.M. 1947, 70-811(1), (2); amd. Sec. 1, Ch. 120, L. 1979.

Compiler's Comments

Effective date. Sec. 2, Ch. 120, L. 1979, provided: "This act is effective on passage and approval." Approved March 19, 1979."

75-20-304. Waiver of provisions of certification proceedings. (1) The board may waive compliance with any of the provisions of 75-20-216 through 75-20-222, 75-20-501, and this part if the applicant makes a clear and convincing showing to the board at a public hearing that an immediate, urgent need for a facility exists and that the applicant did not have knowledge that the need for the facility existed sufficiently in advance to fully comply with the provisions of 75-20-216 through 75-20-222, 75-20-501, and this part.

(2) The board may waive compliance with any of the provisions of this chapter upon receipt of notice by a

utility or person subject to this chapter that a facility or associated facility has been damaged or destroyed as a result of fire, flood, or other natural disaster or as the result of insurrection, war, or other civil disorder and there exists an immediate need for construction of a new facility or associated facility or the relocation of a previously existing facility or associated facility in order to promote the public welfare.

(3) The board shall waive compliance with the requirements of subsections (2)(c), (3)(b), and (3)(c) of 75-20-301 and 75-20-501(5) and the requirements of subsections (1)(a)(iv) and (v) of 75-20-211, 75-20-216(3), and 75-20-303(3)(a)(iv) relating to consideration of alternative sites if the applicant makes a clear and convincing showing to the board at a public hearing that:

(a) a proposed facility will be constructed in a county where a single employer within the county has permanently curtailed or ceased operations causing a loss of 250 or more permanent jobs within 2 years at the employer's operations within the preceding 10-year period;

(b) the county and municipal governing bodies in whose jurisdiction the facility is proposed to be located support by resolution such a waiver;

(c) the proposed facility will be constructed within a 15-mile radius of the operations that have ceased or been curtailed; and

(d) the proposed facility will have a beneficial effect on the economy of the county in which the facility is proposed to be located.

(4) The waiver provided for in subsection (3) applies only to permanent job losses by a single employer. The waiver provided for in subsection (3) does not apply to jobs of a temporary or seasonal nature, including but not limited to construction jobs or job losses during labor disputes.

(5) The waiver provided for in subsection (3) does not apply to consideration of alternatives or minimum adverse environmental impact for a facility defined in subsections (10)(b), (c), (d), or (e) of 75-20-104, for an associated facility defined in subsection (3) of 75-20-104, or for any portion of or process in a facility defined in subsection (10)(a) of 75-20-104 to the extent that the process or portion of the facility is not subject to a permit issued by the department of health or board of health.

(6) The applicant shall pay all expenses required to process and conduct a hearing on a waiver request under subsection (3). However, any payments made under this subsection shall be credited toward the fee paid under 75-20-215 to the extent the data or evidence presented at the hearing or the decision of the board under subsection (3) can be used in making a certification decision under this chapter.

(7) The board may grant only one waiver under subsections (3) and (4) for each permanent loss of jobs as defined in subsection (3)(a).

History: En. Sec. 11, Ch. 327, L. 1973; amd. Sec. 11, Ch. 494, L. 1975; R.C.M. 1947, 70-811(3), (4); amd. Sec. 17, Ch. 676, L. 1979; amd. Sec. 7, Ch. 539, L. 1981.

Compiler's Comments

1981 Amendment: Added subsections (3) through (7).

Effective Date: Section 9, Ch. 539, L. 1981, provided: "This act is effective on passage and approval." Approved April 29, 1981.

Part 4

Postcertification and Legal Responsibilities

75-20-401. Additional requirements by other governmental agencies not permitted after issuance of certificate -- exceptions. (1) Notwithstanding any other law, no state or regional agency or municipality or other local government may require any approval, consent, permit, certificate, or other condition for the construction, operation, or maintenance of a facility authorized by a certificate issued pursuant to this chapter, except that the state air and water quality agency or agencies shall retain authority which they have or may be granted to determine compliance of the proposed facility with state and federal standards and implementation plans for air and water quality and to enforce those standards.

(2) This chapter does not prevent the application of state laws for the protection of employees engaged in the construction, operation, or maintenance of a facility.

History: En. Sec. 17, Ch. 327, L. 1973; amd. Sec. 17, Ch. 494, L. 1975; R.C.M. 1947, 70-817; amd. Sec. 18, Ch. 676, L. 1979.

75-20-402. Monitoring. The board, the department, the department of health, and the board of health shall monitor the operations of all certificated facilities for assuring continuing compliance with this chapter and certificates issued hereunder and for discovering and preventing noncompliance with this chapter and the certificates. The applicant shall pay all expenses related to the monitoring plan established in subsection (3)(a)(v) of 75-20-303 to the extent federal funds available for the facility, as determined by the department of health, have not been provided for such purposes.

History: En. Sec. 20, Ch. 327, L. 1973; amd. Sec. 4, Ch. 268, L. 1974; amd. Sec. 20, Ch. 494, L. 1975; R.C.M. 1947, 70-820(2); amd. Sec. 19, Ch. 676, L. 1979.

75-20-403. Revocation or suspension of certificate. A certificate may be revoked or suspended by the board:

(1) for any material false statement in the application or in accompanying statements or studies required of the applicant if a true statement would have warranted the board's refusal to grant a certificate;

(2) for failure to maintain safety standards or to comply with the terms or conditions of the certificate; or

(3) for violation of any provision of this chapter, the rules issued thereunder, or orders of the board or department.

History: En. Sec. 18, Ch. 327, L. 1973; amd. Sec. 18, Ch. 494, L. 1975; R.C.M. 1947, 70-818(1).

75-20-404. Enforcement of chapter by residents. (1) A resident of this state with knowledge that a requirement of this chapter or a rule adopted under it is not being enforced by a public officer or employee whose duty it is to enforce the requirement or rule may bring the failure to enforce to the attention of the public officer or employee by a written statement under oath that shall state the specific facts of the failure to enforce the requirement or rule. Knowingly making false statements or charges in the affidavit subjects the affiant to penalties prescribed under the law of perjury.

(2) If the public officer or employee neglects or refuses for an unreasonable time after receipt of the statement to enforce the requirement or rule, the resident may bring an action of mandamus in the district court of the first judicial district of this state, in and for the county of Lewis and Clark. If the court finds that a requirement of this chapter or a rule adopted under it is not being enforced, the court may order the public officer or employee whose duty it is to enforce the requirement or rule to perform his duties. If he fails to do so, the public officer or employee shall be held in contempt of court and is subject to the penalties provided by law.

History: En. Sec. 19, Ch. 327, L. 1973; amd. Sec. 19, Ch. 494, L. 1975; R.C.M. 1947, 70-819(1), (2).

75-20-405. Action to recover damages to water supply. An owner of an interest in real property who obtains all or part of his supply of water for domestic, agricultural, industrial, or other legitimate use from a surface or underground source may sue a person to recover damages for contamination, diminution, or interruption of the water supply proximately resulting from the operation of a facility. The remedies enumerated in this section do not exclude the use of any other remedy which may be available under the laws of the state.

History: En. Sec. 19, Ch. 327, L. 1973; amd. Sec. 19, Ch. 494, L. 1975; R.C.M. 1947, 70-819(3).

75-20-406. Judicial review of board, board of health, and department of health decisions. (1) Any active party as defined in 75-20-221 aggrieved by the final decision of the board on an application for a certificate may obtain judicial review of that decision by the filing of a petition in a state district court of competent jurisdiction.

(2) The judicial review procedure shall be the same as that for contested cases under the Montana Administrative Procedure Act.

(3) When the board of health or department of health conducts hearings pursuant to 75-20-216(3) and 75-20-218 and the applicant is granted a permit or certification, with or without conditions, pursuant to the laws administered by the department of health and the board of health and this chapter, the decision may only be appealed in conjunction with the final decision of the board as provided in subsections (1) and (2). If a permit or certification is denied by the department of health or the board of health, the applicant may:

(a) appeal the denial under the appellate review procedures provided in the laws administered by the department of health and the board of health; or

(b) reserve the right to appeal the denial by the department of health or the board of health until after the board has issued a final decision.

(4) Nothing in this section may be construed to prohibit the board from holding a hearing as herein provided on all matters that are not the subject of a pending appeal by the applicant under subsection (3)(a).

History: En. Sec. 12, Ch. 327, L. 1973; amd. Sec. 12, Ch. 494, L. 1975; R.C.M. 1947, 70-812; amd. Sec. 20, Ch. 676, L. 1979; amd. Sec. 8, Ch. 539, L. 1981.

Compiler's Comments

1981 Amendment: Added subsections (3) and (4).

Effective Date: Section 9, Ch. 539, L. 1981, provided: "This act is effective on passage and approval." Approved April 29, 1981.

75-20-407. Jurisdiction of courts restricted. Except as expressly set forth in 75-20-401, 75-20-406, and 75-20-408, no court of this state has jurisdiction to hear or determine any issue, case, or controversy concerning any matter which was or could have been determined in a proceeding before the board under this chapter or to stop or delay the construction, operation, or maintenance of a facility, except to enforce compliance with this chapter or the provisions of a certificate issued hereunder pursuant to 75-20-404 and 75-20-405 or 75-20-408.

History: En. Sec. 13, Ch. 327, L. 1973; amd. Sec. 13, Ch. 494, L. 1975; R.C.M. 1947, 70-813.

75-20-408. Penalties for violation of chapter -- civil action by attorney general. (1) (a) Whoever commences to construct or operate a facility without first obtaining a certificate required under 75-20-201 or a waiver thereof under 75-20-304(2) or having first obtained a certificate, constructs, operates, or maintains a facility other than in compliance with the certificate or violates any other provision of this chapter or any rule or order adopted thereunder or knowingly submits false information in any report, 10-year plan, or application required by this chapter or rule or order adopted thereunder or causes any of the aforementioned acts to occur is liable for a civil penalty of not more than $10,000 for each violation.

(b) Each day of a continuing violation constitutes a separate offense.

(c) The penalty is recoverable in a civil suit brought by the attorney general on behalf of the state in the district court of the first judicial district of Montana.

(2) Whoever knowingly and willfully violates subsection (1) shall be fined not more than $10,000 for each violation or imprisoned for not more than 1 year, or both. Each day of a continuing violation constitutes a separate offense.

(3) In addition to any penalty provided in subsections (1) or (2), whenever the department determines that a person is violating or is about to violate any of the provisions of this section, it may refer the matter to the attorney general who may bring a civil action on behalf of the state in the district court of the first judicial district of Montana for injunctive or other appropriate relief against the violation and to enforce this chapter or a certificate issued hereunder. Upon a proper showing, a permanent or preliminary injunction or temporary restraining order shall be granted without bond.

(4) The department shall also enforce this chapter and bring legal actions to accomplish the enforcement through its own legal counsel.

(5) All fines and penalties collected shall be deposited in the earmarked revenue fund for the use of the department in administering this chapter.

History: En. Sec. 21, Ch. 327, L. 1973; amd. Sec. 2, Ch. 270 L. 1975; amd. Sec. 21, Ch. 494, L. 1975; R.C.M. 1947, 70-821; amd. Sec. 16, Ch. 68, L. 1979; amd. Sec. 21, Ch. 676, L. 1979.

75-20-409. Optional annual installments for location of facility on landowner's property. A landowner upon whose land a facility is proposed to be located shall have the option of receiving any negotiated settlement for use of his land, if and when the land is used for a facility, by easement, right-of-way, or other legal conveyance in either a lump sum or in not more than five consecutive annual installments.

History: En. Sec. 1, Ch. 71, L. 1979.

75-20-410. Order not stayed by appeal -- stay or suspension by court -- limitations. Notwithstanding any contrary provision in the law, the pendency of an appeal from a board order does not automatically stay or suspend the operation of the order. During the pendency of the appeal, the court may upon motion by one of the parties stay or suspend, in whole or in part, the operation of the board's orders on terms the court considers just. The court's action must be in accordance with the practice of courts exercising equity jurisdiction, subject to the following limitations:

(1) No stay may be granted without notice to the parties and an opportunity to be heard by the court.

(2) No board order may be stayed or suspended without finding that irreparable damage would otherwise result to the party seeking the stay or suspension, and any other stay or suspension of a board order must specify the nature of the damage.

History: En. Sec. 24, Ch. 676, L. 1979.

Compiler's Comments

Codification. Sec. 27, Ch. 676, L. 1979, provided: "It is the intent of the legislature that sections 24 and 25 become an integral part of Title 75, chapter 20, MCA, and that the provisions of that chapter apply to sections 24 and 25." Sections 24 and 25 are codified as 75-20-410 and 75-20-411.

75-20-411. Surety bond -- other security. If an order of the board is stayed or suspended, the court may require a bond with good and sufficient surety conditioned that the party petitioning for review answer for all damages caused by the delay in enforcing the order of the board; except that the cost of the bond is not chargeable to the applicant as part of the fee. If the party petitioning for review prevails upon final resolution of an appeal, he does not forfeit bond nor is he responsible for damages caused by delay.

History: En. Sec. 25, Ch. 676, L. 1979.

Compiler's Comments

Codification. Sec. 27, Ch. 676, L. 1979, provided: "It is the intent of the legislature that sections 24 and 25 become an integral part of Title 75, chapter 20, MCA, and that the provisions of that chapter apply to sections 24 and 25." Sections 24 and 25 are codified as 75-20-410 and 75-20-411.

Part 5

Long-Range Plans

75-20-501. Annual long-range plan submitted -- contents -- available to public. (1) Each utility and each person contemplating the construction of a facility within this state in the ensuing 10 years shall furnish annually to the department for its review a long-range plan for the construction and operation of facilities.

(2) The plan shall be submitted by April 1 of each year and must include the following:

(a) the general location, size, and type of all facilities to be owned and operated by the utility or person whose construction is projected to commence during the ensuing 10 years, as well as those facilities to be removed from service during the planning period;

(b) in the case of utility facilities, a description of efforts by the utility or person to coordinate the plan with other utilities or persons so as to provide a coordinated regional plan for meeting the energy needs of the region;

(c) a description of the efforts to involve environmental protection and land use planning agencies in the planning process, as well as other efforts to identify and minimize environmental problems at the earliest possible stage in the planning process;

(d) projections of the demand for the service rendered by the utility or person and explanation of the basis for those projections and a description of the manner and extent to which the proposed facilities will meet the projected demand; and

(e) additional information that the board by rule or the department on its own initiative or upon the advice of interested state agencies might request in order to carry out the purposes of this chapter.

(3) The plan shall be furnished to the governing body of each county in which any facility included in the plan under (2)(a) of this section is proposed to be located and made available to the public by the department. The utility or person shall give public notice throughout the state of its plan by filing the plan with the environmental quality council, the department of health and environmental sciences, the department of highways, the department of public service regulation, the department of state lands, the department of fish, wildlife, and parks, and the department of commerce. Citizen environmental protection and resource planning groups and other interested persons may obtain a plan by written request and payment therefor to the department.

(4) A rural electric cooperative may furnish the department with a copy of the long-range plan and 2-year work plan required to be completed under federal rural electrification requirements in lieu of the long-range plan required in subsection (1).

(5) No person may file an application for a facility unless the facility had been adequately identified in a long-range plan at least 2 years prior to acceptance of an application by the department.

History: En. Sec. 14, Ch. 327, L. 1973; amd. Sec. 40, Ch. 213, L. 1975; amd. Sec. 14, Ch. 494, L. 1975; R.C.M. 1947, 70-814; amd. Sec. 17, Ch. 68, L. 1979; amd. Sec. 3, Ch. 553, L. 1979; amd. Sec. 22, Ch. 676, L. 1979; amd. Sec. 6, Ch. 274, L. 1981.

Compiler's Comments

1981 Amendment: Substituted "department of commerce" for "department of community affairs" in (3).

Transfer of Function: Section 6, Ch. 274, L. 1981, provided in part: "(1) The department of community affairs is abolished.

(2) The following functions of the department of community affairs are transferred to the department of commerce: . . .

(e) relating to recommendations concerning major facility siting and contained in 75-20-211, 75-20-216, and 75-20-501; . . ."

75-20-502. Study of included facilities. If a utility or person lists and identifies a proposed facility in its plan, submitted pursuant to 75-20-501, as one on which construction is proposed to be commenced within the 5-year period following submission of the plan, the department shall commence examination and evaluation of the proposed site to determine whether construction of the proposed facility would unduly impair the environmental values in 75-20-503. This study may be continued until such time as a person files an application for a certificate under 75-20-211. Information gathered under this section may be used to support findings and recommendations required for issuance of a certificate.

History: En. Sec. 15, Ch. 327, L. 1973; amd. Sec. 15, Ch. 494, L. 1975; R.C.M. 1947, 70-815.

75-20-503. Environmental factors evaluated. In evaluating long-range plans, conducting 5-year site reviews, and evaluating applications for certificates, the board and department shall give consideration to the following list of environmental factors, where applicable, and may by rule add to the categories of this section:

(1) energy needs:

(a) growth in demand and projections of need;

(b) availability and desirability of alternative sources of energy;

(c) availability and desirability of alternative sources of energy in lieu of the proposed facility;

(d) promotional activities of the utility which may have given rise to the need for this facility;

(e) socially beneficial uses of the output of this facility, including its uses to protect or enhance environmental quality;

(f) conservation activities which could reduce the need for more energy;

(g) research activities of the utility of new technology available to it which might minimize environmental impact;

(2) land use impacts:

(a) area of land required and ultimate use;

(b) consistency with areawide state and regional land use plans;

(c) consistency with existing and projected nearby land use;

(d) alternative uses of the site;

(e) impact on population already in the area, population attracted by construction or operation of the facility itself;

(f) impact of availability of energy from this facility on growth patterns and population dispersal;

(g) geologic suitability of the site or route;

(h) seismologic characteristics;

(i) construction practices;

(j) extent of erosion, scouring, wasting of land, both at site and as a result of fossil fuel demands of the facility;

(k) corridor design and construction precautions for transmission lines or aqueducts;

(l) scenic impacts;

(m) effects on natural systems, wildlife, plant life;

(n) impacts on important historic architectural, archeological, and cultural areas and features;

(o) extent of recreation opportunities and related compatible uses;

(p) public recreation plan for the project;

(q) public facilities and accommodation;

(r) opportunities for joint use with energy-intensive industries or other activities to utilize the waste heat from facilities;

(s) opportunities for using public lands for location of facilities whenever as economically practicable as the use of private lands and compatible with the requirements of this section;

(3) water resources impacts:

(a) hydrologic studies of adequacy of water supply and impact of facility on streamflow, lakes, and reservoirs;

(b) hydrologic studies of impact of facilities on groundwater;

(c) cooling system evaluation, including consideration of alternatives;

(d) inventory of effluents, including physical, chemical, biological, and radiological characteristics;

(e) hydrologic studies of effects of effluents on receiving waters, including mixing characteristics of receiving waters, changed evaporation due to temperature differentials, and effect of discharge on bottom sediments;

(f) relationship to water quality standards;

(g) effects of changes in quantity and quality on water use by others, including both withdrawal and in situ uses;

(h) relationship to projected uses;

(i) relationship to water rights;

(j) effects on plant and animal life, including algae, macroinvertebrates, and fish population;

(k) effects on unique or otherwise significant ecosystems, e.g., wetlands;

(l) monitoring programs;

(4) air quality impacts:

(a) meteorology--wind direction and velocity, ambient temperature ranges, precipitation values, inversion occurrence, other effects on dispersion;

(b) topography--factors affecting dispersion;
(c) standards in effect and projected for emissions;
(d) design capability to meet standards;
(e) emissions and controls:
(i) stack design;
(ii) particulates;
(iii) sulfur oxides;
(iv) oxides of nitrogen; and
(v) heavy metals, trace elements, radioactive materials, and other toxic substances;
(f) relationship to present and projected air quality of the area;
(g) monitoring program;
(5) solid wastes impacts:
(a) solid waste inventory;
(b) disposal program;
(c) relationship of disposal practices to environmental quality criteria;
(d) capacity of disposal sites to accept projected waste loadings;
(6) radiation impacts:
(a) land use controls over development and population;
(b) wastes and associated disposal program for solid, liquid, radioactive, and gaseous wastes;
(c) analyses and studies of the adequacy of engineering safeguards and operating procedures;
(d) monitoring--adequacy of devices and sampling techniques;
(7) noise impacts:
(a) construction period levels;
(b) operational levels;
(c) relationship of present and projected noise levels to existing and potential stricter noise standards;
(d) monitoring--adequacy of devices and methods.

History: En. Sec. 16, Ch. 327, L. 1973; amd. Sec. 16, Ch. 494, L. 1975; R.C.M. 1947, 70-816; amd. Sec. 2, Ch. 69, L. 1979; amd. Sec. 23, Ch. 676, L. 1979.

Parts 6 through 9 reserved

Part 10

Geothermal Exploration

__75-20-1001. Geothermal exploration -- notification of department.__ The board shall adopt rules requiring every person who proposes to gather geological data by boring of test holes or other underground exploration, investigation, or experimentation related to the possible future development of a facility employing geothermal resources to comply with the following requirements:
(1) notify the department of the proposed action;
(2) submit to the department a description of the area involved;
(3) submit to the department a statement of the

proposed activities to be conducted and the methods to be utilized;

(4) submit to the department geological data reports at such times as may be required by the rules; and

(5) submit such other information as the board may require in the rules.

History: En. Sec. 20, Ch. 327, L. 1973; amd. Sec. 4, Ch. 268, L. 1974; amd. Sec. 20, Ch. 494, L. 1975; R.C.M. 1947, 70-820(3).

Part 11

Energy Conversion Facility
(Repealed. Sec. 28, Ch. 676, L. 1979)

Part Compiler's Comments

Histories of Repealed Sections:

75-20-1101 through 75-20-1105. En. 70-825 through 70-829 by Sec. 1 through 5, Ch. 517, L. 1975; R.C.M. 1947, 70-825 through 70-829.

Part 12

Nuclear Energy Conversion

75-20-1201. Purpose -- findings as to nuclear safety -- reservation of nuclear facility approval powers to the people. (1) The people of Montana find that substantial public concern exists regarding nuclear reactors and other major nuclear facilities, including the following unresolved issues:

(a) the generation of waste from nuclear facilities, which remains a severe radiological hazard for many thousands of years and to which no means of containment assuring the protection of future generations exists;

(b) the spending of scarce capital to pay the rapidly increasing costs of nuclear facilities, preventing the use of that capital to finance renewable energy sources which hold more promise for supplying useful energy, providing jobs, and holding down energy costs;

(c) the liability of nuclear facilities to sudden catastrophic accidents which can affect large areas of the state, thousands of people, and countless future generations;

(d) the refusal of utilities, industry, and government to assume normal financial responsibility for compensating victims of such nuclear accidents;

(e) the impact of nuclear facilities on the proliferation of nuclear bombs and terrorism;

(f) the increasing pattern of abandonment of used nuclear facilities by their owners, resulting in radiological dangers to present and future societies as well as higher public costs for perpetual management; and

(g) the detrimental effect of the large uranium import program necessary to the expansion of nuclear power on

American energy independence, defense policy, and economic well being.

(2) Therefore, the people of Montana reserve to themselves the exclusive right to determine whether major nuclear facilities are built and operated in this state.

History: En. Sec. 1, I.M. 80, app. Nov. 7, 1978.

Compiler's Comments

Severability. Section 7 of Initiative 80 was a severability clause.

Effective date. Initiative 80 was approved at the general election held November 7, 1978, and was effective July 1, 1979.

75-20-1202. Definitions. As used in this part and 75-20-201 through 75-20-203, the following definitions apply:

(1) (a) "Nuclear facility" means each plant, unit, or other facility designed for, or capable of,

(i) generating 50 megawatts of electricity or more by means of nuclear fission,

(ii) converting, enriching, fabricating, or reprocessing uranium minerals or nuclear fuels, or

(iii) storing or disposing of radioactive wastes or materials from a nuclear facility;

(b) "nuclear facility" does not include any small-scale facility used solely for educational, research, or medical purposes not connected with the commercial generation of energy.

(2) "Facility," as defined in 75-20-104(7) is further defined to include any nuclear facility as defined in subsection (1)(a) of this section.

History: En. Sec. 2, I.M. 80, app. Nov. 7, 1978.

75-20-1203. Additional requirements for issuance of a certificate for the siting of a nuclear facility. (1) The board may not issue a certificate to construct a nuclear facility unless it finds that:

(a) no legal limits exist regarding the rights of a person or group of persons to bring suit for and recover full and just compensation from the designers, manufacturers, distributors, owners, and/or operators of a nuclear facility for damages resulting from the existence or operation of the facility; and further, that no legal limits exist regarding the total compensation which may be required from the designers, manufacturers, distributors, owners, and/or operators of a nuclear facility for damages resulting from the existence or operation of such facility;

(b) the effectiveness of all safety systems, including but not limited to the emergency core cooling systems, of such nuclear facility has been demonstrated, to the satisfaction of the board, by the comprehensive laboratory testing of substantially similar physical systems in actual operation;

(c) the radioactive materials from such nuclear facilities can be contained with no reasonable chance, as determined by the board, of intentional or unintentional escape or diversion of such materials into the natural environment in such manner as to cause substantial or long-term harm or hazard to present or future generations due to imperfect storage technologies, earthquakes or other acts of God, theft, sabotage, acts of war or other social instabilities, or whatever other causes the board may deem to be reasonably possible, at any time during which such materials remain a radiological hazard; and

(d) the owner of such nuclear facility has posted with the board a bond totalling not less than 30% of the total capital cost of the facility, as estimated by the board, to pay for the decommissioning of the facility and the decontamination of any area contaminated with radioactive materials due to the existence or operation of the facility in the event the owner fails to pay the full costs of such decommissioning and decontamination. Excess bond, if any, shall be refunded to the owner upon demonstration, to the satisfaction of the board, that the site and environs of the facility pose no radiological danger to present or future generations and that whatever other conditions the board may deem reasonable have been met.

(2) Nothing in this section shall be construed as relieving the owner of a nuclear facility from full financial responsibility for the decommissioning of such facility and decontamination of any area contaminated with radioactive materials as a result of the existence or operation of such facility at any time during which such materials remain a radiological hazard.

History: En. Sec. 4, I.M. 80, app. Nov. 7, 1978.

75-20-1204. Annual review of evacuation and emergency medical aid plans. (1) The governor shall annually publish, publicize, and release to the news media and to the appropriate officials of affected communities, in a manner designed to inform residents of the affected communities, the entire evacuation plan specified in the licensing of each certified nuclear facility within this state. Copies of such plan shall be made available to the public upon request at no more than the cost of reproduction.

(2) The governor shall establish procedures for annual review by state and local officials of established evacuation and emergency medical aid plans with regard for, but not limited to, such factors as the adequacy of such plans, changes in traffic patterns, population densities, the locations of schools, hospitals, and industrial developments, and other factors as requested by locally elected representatives.

History: En. Sec. 5, I.M. 80, app. Nov. 7, 1978.

75-20-1205. Emergency approval authority invalid for __nuclear facilities.__ Notwithstanding the provisions of subsections (2) and (3) of 75-20-304, the board may not waive compliance with any of the provisions of this part or 75-20-201 through 75-20-203 relating to certification of a nuclear facility.

History: En. Sec. 6, I.M. 80, app. Nov. 7, 1978.

Form 403-B

Public Service Commission of Montana

The Montana Power Company

(Name of Company)

Sheet No. STPP-82 Supp. #

Cancelling Sheet No. STPP-82

Schedule STPP-82 Supp. #1

Short-Term Power Purchase Service

AVAILABILITY: To any Seller who operates facilities for the purpose of generating short-term electric energy in parallel with the Company's system. This schedule is applicable to Cogeneration and Small Power Production (COG/SPP) facilities that are Qualifying Facilities under the Rules of the MPSC.

DEFINITIONS: "Seller," for purposes of this schedule, is any individual, partnership, corporation, association, government agency, political subdivision, municipality, or other entity that:

1. Operates a qualifying COG/SPP facility;

2. Has signed the standard written contract with the Company stipulating the terms and conditions of the interconnection and sale of electricity to the Company;

3. Has agreed in the standard contract to provide electricity to the Company on a short-term basis as defined in the contract.

"Company" means The Montana Power Company.

"MPSC" means The Montana Public Service Commission.

"Contract Year" means twelve months beginning on July 1.

RATE: $0.0234/kWh

SPECIAL TERMS AND CONDITIONS:

1. Change of Rate: This schedule will be reviewed annually for each Contract Year and revised upon MPSC approval.

2. Net Billing Option: If the Seller opts for Short-Term Net Billing in the standard contract and the Seller's consumption kWh exceeds the production kWh, the Seller will be billed for only the consumption kWh in excess of production kWh according to the Company's applicable Retail Sales Rate Schedule. If the Seller's consumption kWh is less than the production kWh, the Seller will receive payment for only the production kWh in excess of consumption kWh according to the energy rate in this schedule. A Seller under this Option will receive no separate payment for capacity, and all metered consumption kW (if applicable) will be billed to

Issued July 30, 1982 (Date) By [illegible] (Signature of Officer of Utility)

Approved August 3, 1982 (Date)
Docket No. 81.2.15
Order No. 4865b & 4865c
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Effective For electric service rendered on and after (Date) August 3, 1982

PUBLIC SERVICE COMMISSION OF MONTANA.

[illegible signature]

Secretary.

*Space below these lines for use of Commission only.

Form 403-B

Public Service Commission of Montana

The Montana Power Company
Name of Company)

Sheet No. STPP-82 Supp. #1
Cancelling Sheet No. STPP-82

Schedule STPP-82 Supp. #1

Short-Term Power Purchase Service

the Seller according to the Company's applicable Retail Sales Rate Schedule. If the Seller is demand-metered for consumption, the Seller will be required to install a kW/kWh meter to separately measure production.

3. All service provided by the Company under this and all other schedules is governed by the rules and regulations approved by the MPSC.

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Issued July 30, 1982 (Date) By (Signature of Officer of Utility)

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PUBLIC SERVICE COMMISSION OF MONTANA.

Secretary.

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Public Service Commission of Montana

The Montana Power Company — Sheet No. LTPP-82 Supp. #

Cancelling Sheet No. LTPP-82

(Name of Company)

Schedule LTPP-82 Supp. #1

Long-Term Power Purchase Service

AVAILABILITY: To any Seller who operates facilities for the purpose of generating long-term electric energy in parallel with the Company's system. This schedule is applicable to Cogeneration and Small Power Production (COG/SPP) facilities that are Qualifying Facilities under the Rules of the MPSC.

DEFINITIONS: "Seller," for purposes of this schedule, is any individual, partnership, corporation, association, government agency, political subdivision, municipality, or other entity that:

1. Operates a qualifying COG/SPP facility;

2. Has signed the standard written contract with the Company stipulating the terms and conditions of the interconnection and sale of electricity to the Company;

3. Has agreed in the standard contract to provide electricity to the Company on a long-term basis as defined in the contract.

"Company" means The Montana Power Company.

"MPSC" means The Montana Public Service Commission.

"Contract Year" means twelve months beginning on July 1.

RATE: Energy: $0.0533/kWh

Capacity: The Seller will be compensated monthly for capacity according to the following formula:

$$\$/\text{Annual Contract kW/month} = \frac{\$6.74 \times ACCF}{.85}$$

where: ACCF = Annual Contract Capacity Factor

Annual Capacity Payment Adjustment: At the end of each Contract Year, a reconciliation of the accumulated monthly capacity payments made to the Seller for the Contract Year and actual capacity value to the Company for the Contract Year will be made utilizing the following formula:

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Approved August 3, 1982 (Date)
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Order # 4865b & 4865c
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Effective for electric service rendered on and after (Date) August 3, 1982

PUBLIC SERVICE COMMISSION OF MONTANA.

[signature] Secretary.

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Schedule LTPP-82 Supp. #1

Long-Term Power Purchase Service

$$\$/AAKW = \frac{(80.92 \times ACCF)}{(\quad .85 \quad)} \times \frac{(AACF)}{(ACCF)} \times \frac{(AAKW)}{(ACKW)}$$

Refund to Company = (Dollars Paid to Seller) - (\$/AAKW) (AAKW)

Where AAKW = Annual Actual kW (for Contract Year)
ACCF = Annual Contract Capacity Factor
AACF = Annual Actual Capacity Factor (for Contract Year)
ACKW = Annual Contract kW
If AAKW is greater than ACKW then AAKW = ACKW

SPECIAL TERMS AND CONDITIONS:

1. Change of Rate: This schedule will be reviewed annually for each Contract Year and revised upon MPSC approval.

2. Net Billing Option: (A) If the Seller opts for Long-Term Net Billing in the standard contract and the Seller's consumption kWh exceeds the production kWh, the Seller will be billed for only the consumption kWh in excess of production kWh according to the Company's applicable Retail Sales Rate Schedule. If the Seller's consumption kWh is less than the production kWh, the Seller will receive payment for only the production kWh in excess of consumption kWh according to the energy rate in this schedule.

(B) To meet the conditions of this Option and to receive a separate capacity payment, the Seller's consumption must be measured and billed on a demand basis and a separate kW/kWh meter to measure production is required. Under this Option, the Seller will be billed at the Company's applicable Retail Sales Rate Schedule for only the consumption kW in excess of the production kW. If the Seller's production kW exceeds the consumption kW, the Seller will be compensated for only the production kW in excess of the consumption kW according to the Production Capacity Payment Procedure detailed in this Schedule. The calculation of monthly capacity payments for the expected excess production kW will utilize the expected annual net production capacity factor. The Annual Capacity Payment Adjustment is to be applied to the actual excess production kW for the Contract Year. The procedure will utilize the annual contracted and annual gross production kW and gross capacity factor information for payment reconciliation.

Issued July 30, 1982 (Date) By [signature] (Signature of Officer of Utility)

Approved August 3, 1982 (Date)
Docket # 81.1.1
Order 4865b & 4865c
(Space for Stamp or Seal of Commission)

Effective for electric service rendered on and after August 3, 1982 (Date)

PUBLIC SERVICE COMMISSION OF MONTANA
[signature]
Secretary.

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Form 73-B

Public Service Commission of Montana

The Montana Power Company
(Name of Company)

Sheet No. LTPP-82 Supp.
Cancelling Sheet No. LTPP-82

Schedule LTPP-82 Supp. #1

Long-Term Power Purchase Service

3. All service provided by the Company under this and all other schedules is governed by the rules and regulations approved by the MPSC.

330378

Issued July 30, 1982 (Date) By [signature] (Signature of Officer of Utility)

Approved August 3, 1982 (Date)
Docket # 81.2.15
Order No. 4865b & 4865c
(Space for Stamp or Seal of Commission)

Effective for electric service rendered on and after (Date) August 3, 1982

PUBLIC SERVICE COMMISSION OF MONTANA.
[signature]
Secretary.

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STATE OF MONTANA
ELECTRIC RATE SCHEDULE

MONTANA-DAKOTA UTILITIES CO.
400 NORTH FOURTH STREET
BISMARCK, NORTH DAKOTA 58501

MPSC		Volume	1
	1st Revised	Sheet No.	25
Cancelling	Original	Sheet No.	25

SHORT TERM POWER PURCHASE - RATE STPP-92

AVAILABILITY:

To any qualifying cogeneration and small power production (COG/SPP) operating facilities for the purpose of generating short-term electric energy in parallel with the company's system. This schedule is applicable to cogeneration [illegible] qualifying facilities [illegible] the [illegible] the Montana Public Service Commission.

RATE:

Energy: 2.16¢/Kwh

TERMS AND CONDITIONS:

1. Change of Rates: This schedule will be reviewed annually for each Contract Year and revised upon the Commission's approval.

2. The rates and terms and conditions set forth herein are subject to the provisions of the "Net Billing Option," and "Interconnection Cost Amortization Option" set forth in Rates 94 and 95, respectively.

3. The company shall install appropriate metering facilities to record all flows of energy necessary to bill and pay in accordance with the charges and payments contained in this rate schedule.

4. The customer shall, with prior written consent of the company, furnish, install and wire the necessary service entrance equipment, meter sockets, meter enclosure cabinets, or meter connection cabinets that may be required by the company to properly meter usage and sales to the company.

5. The term of the contract hereunder shall be at least twelve months but less than four years.

6. A standard written contract with the company has been signed stipulating the terms and conditions of the interconnection and sale of the electricity to the company.

7. All services provided by the company under this and all other schedules are governed by the rules and regulations approved by the Montana Public Service Commission.

Issued July 7, 1982 (Date)

By C. Wayne Fox
Assistant Vice President

(SPACE BELOW THESE LINES FOR USE OF COMMISSION ONLY.)

Approved July 16, 1982 (Date)

Effective for electric service rendered on and after July 16, 1982 (Date)

Docket No. 81.2.15; Order No. 4865b

(Space for Stamp or Seal of Commission)

PUBLIC SERVICE COMMISSION OF MONTANA

Madeline L. Cottrill

MONTANA-DAKOTA UTILITIES CO.
400 NORTH FOURTH STREET
BISMARCK, NORTH DAKOTA 58501

LONG TERM POWER PURCHASE - RATE LTPP-93

AVAILABILITY:

To any qualifying cogeneration and small power production (COG/SPP) facilities for the purpose of generating long-term electric energy in parallel with the company's system. This schedule is applicable to cogeneration and small power production facilities that are Qualifying Facilities under the Rules of the Montana Public Service Commission.

RATE:

Energy: 5.23¢/Kwh

Capacity: The Seller will be compensated monthly for Capacity according to the following formula:

$$\text{\$/Annual Contract Kw/month} = \frac{\$5.33 \times \text{ACCF}}{.85}$$

where: ACCF = Annual Contract Capacity Factor

Annual Capacity Payment Adjustment: At the end of each Contract Year, a reconciliation of the accumulated monthly Capacity payments made to the Seller for the Contract Year and actual Capacity value to the company for the Contract Year will be made utilizing the following formula:

$$\text{\$/AAKW} = \frac{(\$63.96 \times \text{ACCF}) \times (\text{AACF}) \times (\text{AAKW})}{(\quad .85 \quad) \times (\text{ACCF}) \times (\text{ACKW})}$$

Refund to Company = (Dollars Paid to Seller) - (\$/AAKW) (AAKW)

where: AAKW = Annual Actual Kw (for Contract Year)
ACCF = Annual Contract Capacity Factor
AACF = Annual Actual Capacity Factor (for Contract Year)
ACKW = Annual Contract Kw
If AAKW is greater than ACKW then AAKW = ACKW

Issued July 7, 1982 (Date) By C. Wayne Fox Assistant Vice President

(SPACE BELOW THESE LINES FOR USE OF COMMISSION ONLY.)

Approved July 16, 1982 (Date)
Docket No. 81.2.15; Order No. 4865b

Effective ~~for electric service rendered~~ (Date) on and after July 16, 1982

PUBLIC SERVICE COMMISSION OF MONTANA

Madeline L. Cottrill (Secretary)

(Space for Stamp or Seal of Commission)

MONTANA-DAKOTA UTILITIES CO.
400 NORTH FOURTH STREET
BISMARCK, NORTH DAKOTA 58501

MPSC Volume 1
1st Revised Sheet No. 26.1
Cancelling Original Sheet No. 26.1

TERMS AND CONDITIONS:

1. Change of Rates: This schedule will be reviewed annually for each Contract Year and revised upon the Commission's approval.

2. The rates and terms and conditions set forth herein are subject to the provisions of the "Net Billing Option," and "Interconnection Cost Amortization Option" set forth in Rates 94 and 95, respectively.

3. The company shall install appropriate metering facilities to record all flows of energy necessary to bill and pay in accordance with the charges and payments contained in this rate schedule.

4. The customer shall, with prior written consent of the company, furnish, install and wire the necessary service entrance equipment, meter sockets, meter enclosure cabinets, or meter connection cabinets that may be required by the company to properly meter usage and sales to the company.

5. The term of the contract hereunder shall be four years or more.

6. A standard written contract with the company has been signed stipulating the terms and conditions of the interconnection and sale of the electricity to the company.

7. All services provided by the company under this and all other schedules are governed by the rules and regulations approved by the Montana Public Service Commission.

Issued July 7, 1982 (Date) By C. Verne [signature] Assistant Vice President

(SPACE BELOW THESE LINES FOR USE OF COMMISSION ONLY.)

Approved July 16, 1982 (Date)
Docket No. 81.2.15; Order No. 4865b

Effective ~~for electric service rendered~~ on and after July 16, 1982 (Date)

PUBLIC SERVICE COMMISSION OF MONTANA

Madeline L. Cottrill [signature]

(Space for Stamp or Seal of Commission)

PACIFIC POWER & LIGHT COMPANY

SCHEDULE NO. 87
PURCHASES FROM COGENERATORS AND SMALL POWER PRODUCERS

AVAILABLE:
For qualifying facilities located in the territory served by Company in Montana.

APPLICABLE:
To all non-utility owners or operators of qualifying facilities (Sellers) who are willing and able to enter into a written contract.

DEFINITIONS:
Qualifying Facility means either a cogeneration facility or small power production facility not greater than 50 megawatts capacity as defined hereunder:

(a) Cogeneration Facility means a facility which produces electric energy together with steam or other forms of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes through the sequential use of energy.

(b) Small Power Production Facility means a facility which produces electric energy using as a primary energy source biomass, waste, renewable resources, or any combination thereof.

CONDITIONS OF SERVICE:
All purchases shall be accomplished according to the terms and conditions of a written contract.

RATES FOR SALES:
All sales by Company to Sellers shall be in accordance with standard rate schedules filed by Company with the Commission.

RATES FOR PURCHASES:
The rates for purchases by Company hereunder shall be either 1) the Short-Term Rate or 2) the Long-Term Rate, at the option of the Seller exercised at the time of execution of a written contract at:

1) Short-Term Rate

a) All energy purchased is to be priced, at the option of the Seller, exercised at the time of execution of a written contract at i) the Average Rate or ii) the Time Differentiated Rate.

(Continued)

PACIFIC POWER & LIGHT COMPANY

SCHEDULE NO. 87
PURCHASES FROM COGENERATORS AND SMALL POWER PRODUCERS

RATES FOR PURCHASES: (Continued)

i) Average Rate

2.28¢ per kwh

ii) Time Differentiated Rate

On-Peak: 6 a.m. to 10 p.m. Monday through Friday
2.76¢ per kwh for all kwh purchased during the On-Peak period.

Off-Peak: All other times.
1.84¢ per kwh for all kwh sold during the Off-Peak period.

b) Term of Contract: Not less than one (1) year.

2) Long-Term Rate

a) Availability: Available to all Sellers willing to sign a written contract with a term of not less than four years.

b) All energy and contracted capacity is to be priced, at the option of the Seller, exercised at the time of execution of the contract, at i) the Average Rate or ii) the Time Differentiated Rate.

i) Average Rate

A) Energy Payment

4.99¢ per kwh

B) Capacity Payment

($7.21 per kw per month) x (dcf) for all contracted kw, where (dcf) represents the Demonstrated Capacity Factor pursuant to the terms and conditions of a written contract.

PUBLIC SERVICE COMMISSION
APPROVED
JUN 2 ? 1982
Madeline L. Cottrill
SECRETARY
OF MONTANA

(Continued)

PACIFIC POWER & LIGHT COMPANY

SCHEDULE NO. 87
PURCHASES FROM COGENERATORS AND SMALL POWER PRODUCERS

RATES FOR PURCHASES: (Continued)

ii) Time Differentiated Rate

A) Energy Payment

On-Peak: 6 a.m. to 10 p.m. Monday through Friday.
6.05¢ per kwh for all kwh sold during On-Peak periods.

Off-Peak: All other times.
4.03¢ per kwh for all kwh sold during Off-Peak periods.

B) Capacity Payment

All times
($7.21 per kw per month) x (dcf) for all contracted kw, where (dcf) represents the Demonstrated Capacity Factor pursuant to the terms and conditions of a written contract.

RULES AND REGULATIONS:

Service hereunder is subject to the General Rules and Regulations contained in the Company's regularly filed and published tariff and to those prescribed by regulatory authorities.

PUBLIC SERVICE COMMISSION
APPROVED
JUN 17 1982
Madeline L. Cottrill
SECRETARY
OF MONTANA

Issued 6/29/82 Fredric D. Reed Effective on and after

ved: January 4, Issued by PACIFIC POWER & LIGHT COMPANY Effective for electric
March 16, 1982 Fredric D. Reed, Vice President and Treasurer service rendered on an
No. 81.2.15 Public Service Building, Portland, Oregon after July 7, 1982
No. 4865 &4865a

Service Date: JAN 4 1982

DEPARTMENT OF PUBLIC SERVICE REGULATION

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MONTANA

* * * * *

In the Matter of Avoided Cost Based Rates for Public Utility Purchases from Qualifying Cogenerators and Small Power Producers.)	UTILITY DIVISION DOCKET NO. 81.2.15 ORDER NO. 4865

* * * * *

INDEX

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

In the Matter of Avoided Cost Based Rates for Public Utility Purchases from Qualifying Cogenerators and Small Power Producers.	)	UTILITY DIVISION DOCKET NO. 81.2.15 ORDER NO. 4865

* * * * *

APPEARANCES

Appearing on behalf of Montana-Dakota Utilities Co.:

John L. Alke, Hughes, Bennett, Kellner and Sullivan, 406 Fuller Avenue, Helena, Montana 59601.

Appearing on behalf of Pacific Power & Light Co.:

C. Eugene Phillips, Murphy, Robinson, Heckathorn & Phillips, P.O. Box 759, 1 Main Building, Kalispell, Montana 59901.

Thomas H. Nelson, Stoel, Rives, Boley, Fraser & Wyse, 900 South West Fifth Avenue, Portland, Oregon 97207.

Appearing on behalf of Montana Power Company:

Dennis R. Lopach, Scribner, Huss & Hjort, P.O. Box 514, Helena, Montana 59624.

Michael E. Zimmerman, Legal Department of the Montana Power Company, 40 East Broadway, Butte, Montana 59701.

Appearing on behalf of Montana Consumer Counsel:

John C. Allen, Penwell Building, Helena, Montana 59620.

Appearing on behalf of PSC Advocacy Staff:

Eileen E. Shore, Chief Counsel, Public Service Commission, 1227 11th Avenue, Helena, Montana 59620.

Robert Olson, Energy Law Institute, 2 White Street, Concord, New Hampshire 03301.

Appearing on behalf of PSC Advisory Staff:

Brenda Nordlund, Staff Attorney, Public Service Commission, 1227 11th Avenue, Helena, Montana 59620.

BEFORE THE MONTANA PUBLIC SERVICE COMMISSION:

GORDON E. BOLLINGER, Chairman
JOHN B. DRISCOLL, Commissioner
HOWARD L. ELLIS, Commissioner
CLYDE JARVIS, Commissioner
THOMAS J. SCHNEIDER, Commissioner

FINDINGS OF FACT

BACKGROUND

1. Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) required the Federal Energy Regulatory Commission (FERC), as well as state regulatory authorities, to prescribe rules to encourage cogeneration and small power production (COG/SPP) including rules requiring electric utilities to purchase electric power from cogeneration and small power production facilities. Among other things, the rules were to insure that rates for purchases of electric energy from qualifying facilities (QF) "be just and reasonable to the electric consumers of the electric utility and in the public interest" and that the rates would not exceed the "incremental cost to the electric utility of alternative electric energy."

2. On May 4, 1981 the Commission adopted final rules governing purchases and sales between public utilities and qualifying small power production facilities. The Commission rules are

modeled after FERC regulations implementing Section 201 and 210 of PURPA. The rulemaking procedure featured a public comment period commencing with the issuance of draft rules on September 2, 1980 and extending through October 23, 1980. The draft rules, with proper notice, went to public hearing on October 23, 1980 in Helena, Montana. Testimony and/or comments were received from the Montana Power Company (MPC), Pacific Power and Light (PP&L), Montana-Dakota Utilities (MDU), the City of Livingston, the Department of Natural Resources and Conservation (DNRC), and several individuals. A second, revised draft of the rules was issued on March 16, 1981 with public comment extending through April 27, 1981. Comments were received from MPC, PP&L, the Alternative Energy Resource Organization, the Energy Law Institute, and several individuals. The rulemaking proceeding ended with adoption of final rules on May 4, 1981.

3. The Commission's rules (ARM 38.5.1901 through 38.5.1908), pursuant to FERC regulations, provide the general obligations of the COG/SPP and the regulated electric utilities. The rules, however, left to a contested case proceeding the development of tariffs providing specific rates, terms, and conditions for service.

4. The Commission initiated this proceeding on February 24, 1981 when it requested that MDU, PP&L, and MPC file testimony regarding avoided cost methodologies, avoided cost-based rates, and tariffs and standard contracts for purchases of electricity from COG/SPP.

5. When the Montana Consumer Counsel declined to present a case in this docket, the Commission created the Commission Advocacy Staff for the purpose of providing testimony concerning the instant issues independent of each utility's case. Ms. Eileen Shore, Chief Counsel, was assigned to head the Advocacy Staff, and Drs. Thomas M. Power and John Fox were hired to provide expert testimony. Additionally, Mr. Robert Olson assisted Ms. Shore in the presentation and preparation of Advocacy Staff's case.

6. Pursuant to the procedural order dated April 13, 1981, Rural Energy Development Foundation (REDF) and Alpha Engineers, Incorporated were granted intervention status. REDF participated to a limited extent throughout the proceeding; Alpha Engineers, Inc. withdrew their intervention status immediately before the hearing.

7. Public hearings were held on September 29 and 30, 1981 in the district courtroom of the Federal Building in Helena, Montana. Parties were given an opportunity to cross-examine one another and other interested persons, including engineer James Barber of JUB Engineering, Inc. of Boise, Idaho and economist Dr. Lawrence Nordell of the Montana Department of Natural Resources and Conservation, presented statements to the Commission.

8. For explicatory purposes, and commensurate with the Commission's rules, the major issues have been divided into two categories: standard tariff rates and tariff and standard contract terms and conditions. Analysis of each issue will include

a brief summary of the parties' testimony and pertinent Commission rule when necessary, followed by the Commission's determinations on a general basis. Any utility-specific matters will be resolved at the end of each section.

STANDARD TARIFF RATES

Policy

9. ARM 38.5.1903(2) reads, in part, that "...each utility shall purchase any energy and capacity made available by a qualifying facility: (a) At a standard rate for such purchases which is based on avoided costs to the utility as determined by the Commission; or (b) If the qualifying facility agrees, at a rate which is a negotiated term of the contract between the utility and the facility..." ARM 38.5.1901(2)(j) defines standard rates as "those rates calculated by a means approved by the Commission which ...are based on avoided costs to the utility, are computed annually and made available to the public, are reviewed by the Commission, and are applicable to all contracts with qualifying facilities which do not choose to negotiate a different rate...". Thus, the Commission's intent, in respect to tariff rates, is to establish regulated rates to which all qualifying facilities (QFs) are entitled in exchange for the sale of power to the utilities. The tariff is only an option--an alternative to negotiation.

10. Prior to a discussion of the relative merits of each proposal and the resulting findings, the Commission wishes to set forth several critical policy findings.

11. The Commission recognizes that any deviation from full or complete avoided costs, either on the high side or low side, results in an adverse affect on ratepayers. Thus the primary objective in developing rate calculation methods is to allow rates which most accurately reflect full avoided costs. "Full avoided costs" is interpreted here to represent 1) exhaustiveness in cost components and, when appropriate, 2) long-run incremental costs.

12. A second goal in the Commission's deliberation is moderation, or gradualism. The Commission has found several substantial unknowns and thus has attempted to find some middle ground balancing the unknowns between the low side and high side of the true avoided costs. The Commission intends to encourage the progressive refinement of the methods and will entertain constructive criticism and evidence at each annual filing of proposed tariffs. If conclusive evidence is submitted suggesting the methods developed herein need refinement, then the Commission will revise the methods with grandfathering provisions as deemed necessary.

13. Both MDU and PP&L argued that the methods they proposed represent methods suited to their unique systems, are accepted by other state Commissions, and that any deviation from those methods would cause the incurrance of needless additional administrative costs. Although the Commission has neither gone out of its way to develop uniformity nor to maintain the PP&L and MDU proposals, it finds that it is the utilities, not the Commission,

who are best equipped to deal with the increased costs of differing methods. The Commission is establishing only an option available to all QFs and the companies are free to negotiate rates utilizing their proposals. Furthermore, the Commission has found portions of their proposals unacceptable for purposes of a standard tariff and has found that the utilities are similar in that they are all experiencing load growth with similar generation expansion plans.

Energy

14. In structuring energy payments all three utilities make some type of distinction between firm and nonfirm QF. Nonfirm energy rates, in all three cases, reflect short run incremental running costs via some form of production modeling, e.g. system lambda. The utilities diverge however in structuring firm energy rates. MPC uses the same production modeling effort but provides a 5 mill bonus for firm performance. MDU goes to the running cost of a baseload plant with the fixed costs added to reflect capacity. PP&L further distinguishes long-term firm from short-term firm. Short-term firm is, on an interim basis, treated as nonfirm while long-term firm is paid energy depending on specific resource(s) avoidable and ability to follow load.

15. The Advocacy Staff proposes a calculation of avoided energy costs which does not distinguish between nonfirm and firm energy and which does not utilize production modeling, or short

run marginal costs, but focuses on the energy function of base load plants.

16. The key to evaluating the alternative calculations of avoided energy costs lies in the purported relationship between short run incremental energy costs (e.g. system lambda) and the incremental energy costs of bringing on line a coal-fired base-load steam plant.

17. The Commission has been presented testimony in this proceeding as in several other proceedings, suggesting that the concept of fuel savings and optimal system planning necessarily, or at least theoretically, equate a rolling average system lambda with the energy-related cost of baseload expansion. In the case of MPC, Dr. Power (Exh. M, p.20-22) provides calculations which suggest that the theorem is correct -- at least for the period July, 1981 to June, 1982.

18. The Commission, however, is not convinced that the system-lambda-equal-energy-related-baseload-generation-costs theorem is correct when applied to systems characterized by load growth, hydro resources, and limited thermal peaking and/or cycling capacity. The Commission feels that a system with peak shaving hydro storage capability or a system with a relatively high load factor, in both cases resulting in little or no thermal peaking or cycling capability, lambda will be dominated by the running costs of baseload plants. An example exemplifies this situation. MPC's forecast of system lambda (Exh. B, Exh. TAL-2 p.1) projects a 56 percent real <u>decrease</u> in the load weighted

average system lambda between 1980 and 1990 (4.5 percent annual average). Despite the projected decrease in system lambda, or marginal energy costs, over the same time period the company projects (The Montana Power Company, 1981-2000 Projection of Loads and Resources February, 1981 and the Montana Power Company Forecast of Electricity and Natural Gas Prices 1981-1990, March, 1981), real total or average costs to escalate 81.6 percent (6.1 percent annual average). The latter figure represents annual real increases (over and above inflated operating expenses) of 18.78 percent in 1984, 15.02 percent in 1985, and 15.07 percent in 1990; reflecting Colstrip #3, Colstrip #4, and Resource 89, respectively. Evident is some substantial divergence between system lambda and long-run incremental energy costs. The long-range plans of all three utilities include no less than nine baseload plants prior to 1990.

19. In the short run, for example, one contract year or one test year, system lambda (or its equivalent short run production modeling) does represent the time differentiated costs the utilities will avoid by purchasing QF production. However, it is not system lambda, but coal-fired steam plants that the utilities have recently brought (Coyote #1, Jim Bridger) or will soon be bringing (Colstrip #3) to the Commission in search of additional revenues. It is these plants, not system lambda, that has and will result in substantial (perhaps drastic) increases in the utilities' costs and consumers' rates. Thus the Commission finds

that energy rates must reflect both system lambda in the short run and the baseload alternative in the long-run.

20. The avoided energy cost discussion to this point has addressed only avoided generation costs. The record in this proceeding has not provided the Commission a sound basis for establishing avoided energy-related line loss and transmission costs. Whereas the existence of a net avoidance of transmission costs, although logical, is not clearly established, the record indicates (e.g. Jordan Exh. O, p. 4, Barber Tr. p. 49) that some unknown amount of line losses will be avoided. Marginal line losses are substantial. MPC witness Bruce Ambrose calculates (Exh. 13, Sch. 1) a secondary energy loss factor of 30.5 percent and 26.1 percent for the winter and summer periods, respectively. Electric rate case proceedings for MDU and PP&L have indicated marginal line losses of similar magnitude. The Commission finds unacceptable the utilities and Advocacy Staff's proposed rates which simply ignore line losses. The proper approach is to establish some nominal energy loss factor subject to refinement with utility-specific analysis. For purposes of the initial tariffs, the Commission finds appropriate an energy loss factor of 8.3 percent. This factor represents the approximate load weighted average of transmission level energy losses calculated by Mr. Ambrose for the MPC system.

Capacity

21. The Commission has been presented four distinct proposals for structuring capacity payments. The three utilities' proposals are similar in that they reflect the possible deferral or avoidance of a specific avoidable generating plant. In the case of PP&L, 22 percent of the Wyodak #2 baseload plant (1986 recently deferred to 1988) is used to calculate avoided capacity. MDU also uses baseload expansion plans (1985) but proposes the entire fixed costs as potential capacity payments. MPC uses a 1985 gas-fired combustion turbine which was in their 1980 long-range plan but has since been deleted from the Company's expansion plans.

22. The capacity payments to QFs in each case are a function of the beginning year of the contract (1982-1988), length of the contract (5-35 years), industry construction inflation indices (generally, 6 percent to 10 percent), discount rates for discounting future cost avoidance (4 percent to 6 percent), and a qualifying performance criteria (capacity factor of 65 percent - 75 percent). The utilities' proposals do not recognize partial or aggregate capacity payments to QFs who do not meet the performance criteria and grant full payment to those above the criteria level with a full length contract beginning the year the avoidable plant is scheduled to come on line. All three utilities' offer some level of prepayments for capacity provided prior to the 1985-1988 period, but it is not clear whether these discounted prepayments in any way reflect expected avoidance of

system planning (engineering studies, siting, etc.) efforts. Payments for capacity contracts of less than full duration are discounted to reflect the inflated costs of building the plant beyond the deferral period (or length of contract).

23. The Advocacy Staff's proposal differs primarily in how the payments are calculated and to whom the payments are made, and not necessarily in the calculation of avoided capacity. The Advocacy Staff's proposal utilizes a combustion turbine to estimate the exclusively capacity-related value of baseload expansion. Whereas the utilities discount pre-on line capacity (1982-1985 or 1988), the Advocacy Staff's proposal features full prepayment of capacity. The Advocacy Staff, rather than levelizing the discounted sum of inflated costs over the life of the contract, annualize capital costs in terms of constant contract year dollars. A third area of major difference lies in the concept of partial capacity payments. The Advocacy Staff, as opposed to a make-or-break performance criteria, proposes partial capacity payments based on the QF's expected reliability relative to that expected of a combustion turbine.

24. The Commission in reviewing the capacity rate proposals of each utility found unnecessary complexity a predominant characteristic. For purposes of a standard tariff, updated at least annually, the Commission finds persuasive the Advocacy Staff's proposal to simply annualize the cost of a combustion turbine in constant contract year dollars. The Commission also finds merit in the concept of partial capacity credits and the recognition of

aggregate QF capacity. The Commission is less sure in respect to the merits of full prepayment. However, in light of the fact that 1) the magnitude of a full capacity payment is only in the area of four to seven mills, 2) the utilities do incur system planning costs (engineering studies, siting, etc.) prior to the on line dates, and primarily 3) the fact that several "full avoided cost" components (e.g. remote siting transmission, line losses, etc.) are not fully accounted for, leads the Commission to believe that full prepayment will not error on the high side of truly avoidable costs. The Advocacy Staff's capacity proposal accepted by the Commission is essentially that practiced by the utilities in recovering capacity-related revenues.

Rates

25. Commensurate with these findings, the Commission directs the utilities to develop a tariff providing rate schedules for two classes of QFs -- short-term and long-term. One class is to be comprised of QFs unwilling or unable to commit themselves to a performance contract of at least four years. The second class is to consist of all QFs who are willing and able to sign a contract of at least four years duration. It should be pointed out that there is no explicit distinction here between firm and nonfirm -- the pricing provisions of each schedule will dictate an implicit distinction. The short-term/long-term distinction is made in anticipation that the system planners, in the initial start up period only, will require four year con-

tracts with appropriate penalty provisions for incorporating QF loads into projections of system resources for purposes of designing system expansion plans.

Short-Term Rates

26. The short-term QF's energy rate schedule shall reflect short run incremental energy costs as determined from the utilities' production modeling efforts. The rate shall reflect a one contract year projection of annual load weighted average system lambda (or equivalent measure of short run incremental energy costs) and shall include the appropriate calculations of variable O&M, revenue requirement associated with working capital, and the nominal energy loss factor.

27. The Commission, initially, leaves to the utilities the option of establishing a short-term time differentiated rate schedule reflecting the companies' short run cost variation. The utilities are encouraged to structure time differentiated rates featuring seasonal, monthly, and/or daily rating periods. The relatively higher general level of sophistication on the part of QFs presents a challenge to structure rates most accurately reflecting costs. The companies' proposals will be scrutinized and adjustments made on an as needed basis. It should be pointed out that only MPC's proposal does not feature optional time differentiation, even with evidence of substantial seasonal cost variation.

28. In addition to the energy rate, the short-term option -- both annual average or time differentiated -- shall include a nominal aggregate capacity credit. For purposes of the initial tariffs and until convincing evidence is provided to suggest otherwise, the aggregate capacity payment shall be calculated by assuming a 42.5 percent availability level relative to an assumed 85 percent combustion turbine availability. That is, short-term QFs will receive one-half of a full capacity payment added to the energy payment using the assumed 85 percent load factor for converting the annualized capital costs into a Kwh payment.

29. The Commission again leaves to the utilities the option of time differentiation with respect to the nominal aggregate capacity payment. The utilities, should they desire to develop time differentiation in the initial tariffs, or the 1982 tariffs, must use hourly loss of load data for structuring the differentiation. That is, while the annual average aggregate capacity payment is spread over all hours, the time differentiated option would spread the same aggregate capacity payment over those hours, as indicated by loss of load probability, where the utility is most likely to be capacity short.

Long-Term Rates

30. The second class of QFs are those who are willing and able to commit themselves to a contract of at least four years with appropriate penalty provisions for failure to deliver con-

tracted capacity. These long-term QFs shall be paid an energy rate reflecting the energy-related generation costs associated with baseload expansion and a capacity payment reflecting the remaining capacity-related baseload expansion costs.

31. The utilities are directed to develop a long-term rate featuring an energy component based on the cost (current contract year constant dollars) of the projected running costs of the next baseload plant. Added to the running costs are the fixed costs associated with bringing on line a base load plant less the capital costs associated with bringing on line a combustion turbine. In addition to the energy payment, a separate annualized capacity payment based on the costs of a combustion turbine paid in proportion (above, as well as below) to a 85 percent availability factor is to be developed. The capacity payment can be structured on a monthly or annual basis.

32. As with the short-term option, the Commission encourages the utilities to structure a time differentiated suboption featuring time differentiated energy and capacity rates based on system lambda and hourly loss of load probability, respectively. The time differentiated energy rate shall feature the same baseload plant costs, but allocated to rating periods commensurate with system lambda. The separate time differentiated capacity payment, however, provides an opportunistic alternative to the nontime differentiated partial capacity payment. Rather than partial capacity payments reflecting the QF's probability of providing capacity as needed, the time differentiation can allow

for full capacity payments in exchange for QFs capacity provided in the hours most likely to correspond with capacity shortage. Depending on the level of differentiation, hours with less probability of capacity shortage should feature something less than full capacity. The Commission has left the time differentiation, at least initially, an option to the utilities. The utilities are encouraged to develop time differentiation (seasonal, monthly, and/or daily) in its offerings of long-term capacity payments.

33. The long-term costs shall be calculated and rates structured such that long-term energy and full capacity rates fully account for the annualized costs of owning and operating baseload plants. In the case of MPC, those costs shall reflect the costs of Colstrip #3 and #4, averaged. This overcomes the problem of relating common facilities to individual plants. MDU shall use Antelope Valley #2 and PP&L, Wyodak #2. The calculation of costs is to be exhaustive including coal, fuel inventory, taxes, insurance, administrative and general, O&M, as well as the nominal line loss factor of 8.3 percent. The costs of the combustion turbine used as a proxy to determine the portion of baseload expansion related solely to the capacity function, must be equally exhaustive and based on reasonable combustion turbine alternatives to QF's capacity and must reflect costs consistent with actual costing experience or industry estimates. All costs are to be stated in constant contract year dollars, to be updated each June 1, for the contract year beginning July 1st, to reflect

1) refined resource plans, 2) more accurate and/or complete cost information, and 3) inflation, according to standard industry practice.

34. Capital costs are to be annualized by applying the companies' overall incremental cost of capital including tax effect -- not embedded cost of capital -- and shall be updated annually to reflect the contract year capital market. Finally, for purposes of converting baseload capital costs into energy rates, each utility shall use an assumed baseload capacity factor of 70 percent. The 70 percent reflects the Commission's attempt at some middle ground, but is certainly an item open to future refinement and utility specific experience if it exceeds average industry or regional performance.

Procedure

35. Appendix A provides a summary of the rate schedules to be developed in compliance with this Order and Appendix B provides specific direction in costing to be followed in arriving at costs pursuant to this Order.

36. In submitting initial tariffs in compliance with this Order, and proposed revised tariffs each June 1st thereafter, each utility is directed to provide 1) the proposed tariffs, 2) the calculated avoided costs used in arriving at the tariffed rate schedules, and 3) detailed working papers. The tariffs are to include, in addition to the rate schedules, the terms and conditions for service and the standard contract, in compliance

with this Order. The avoided costs must include, at least, five year projections (beginning with the contract year) of: 1) the average annual system lambda (or equivalent short run production modeling), 2) time differentiated system lambda and/or loss of load probability supporting the time differentiation, 3) baseload running cost and capital cost calculations detailed by component, 4) detailed combustion turbine calculations, and 5) the estimate of overall marginal cost of capital. These five year projections must be presented in both constant contract year dollars and in nominal terms. These avoided cost data satisfy and supplement the requirements of ARM 38.5.1905(1). The working papers must provide the source and derivation of the costs, including incremental cost of capital, and provide the transformation of costs into rates. In the case of the baseload costs, the working papers must include the most recent version of the actual engineering cost study, revealing projections of costs by component by time of incurrance from the time of initial planning to on line production. If available, the actual engineering cost studies supporting the estimated combustion turbine avoided costs must also be provided.

37. As all parties become experienced in QFs production, the Commission encourages further pursuit of a progressively refined treatment of structuring QFs rates. Several obvious items requiring refinement are the 42.5 percent availability assumption in calculating aggregate capacity payments, the 70 percent baseload and 85 percent combustion turbine production

factors, the 8.3 percent line loss factor, and appropriate inflation factors. The utilities are directed to investigate avoided line losses, avoided transmission costs, and avoided reserve requirements. The Commission intends to expand the role of these factors in the calculation of the 1982 standard rates. The utilities are directed to provide evidence in their June 1, 1982 filing detailing appropriate transmission, line loss, and reserve requirement values to be included in the calculation of each rate schedule.

38. The tariff providing rates as found appropriate by the Commission precludes the use of "opportunity cost," "performance incentive," "levelized," "time of delivery," "retail rates," fixed capacity/variable energy," etc. payment schemes for purposes of a tariff, only. The Commission has merely established a payment option available to all QFs. The utilities and the QFs are encouraged to negotiate at will in a business-like atmosphere. For example, if PP&L finds that its tariffed short-term energy rate is too low and that it can offer its "opportunity cost" rate with no effect on ratepayers, then the Commission in no way intends to restrict that offering. The Commission, in its rules, did not require wheeling under the assumption that the utilities would, in good faith, utilize opportunity cost concepts in providing QFs access to lucrative regional markets with no effect on ratepayers. If the Commission finds its "good faith" assumption in respect to opportunity cost and wheeling, as well as other options provided herein, was in error, then it will

readdress these provisions. Likewise, the offering of levelized or front loading contracts as required by ARM 38.5.1903(2)(b), fixed capacity/variable energy contracts, and performance incentives is in no way restricted by this Order. The innovative contracts resulting from negotiation should be the prime mover in the purchase of QF's energy.

39. Lastly, the Commission wishes to remind the utilities that ARM 38.5.1903(8) requires each utility to "upon initial contact with a potential qualifying facility, provide the potential qualifying facility with one (1) copy of: a) these rules, b) the Commission's approved standard provisions tariff, and c) the Commission's standard complaint procedure." ARM 38.5.1908 requires each utility to provide the Commission with one copy of the utility's initial written response to the potential qualifying facility. In addition to these provisions of information, the Commission contemplates a utility sponsored working conference to be held in each utilities service area for purposes of providing information to potential QFs.

TARIFF AND STANDARD CONTRACT TERMS AND CONDITIONS

40. ARM 38.5.1902(5) reads, in part, that "All purchases... shall be accomplished according to the terms of a written contract between the parties or in accordance with the standard tariff provisions as approved by the Commission. The contract shall specify:

(a) The nature of the purchase and sales;
(b) The applicable rate schedule or negotiated rates for the purchases and sales;
(c) The amount and manner of payment of interconnection costs;
(d) The means for measurement of the energy or capacity purchased or sold by the utility;
(e) The method of payment by the utility for purchases, and the method of payment by the facility for utility sales;
(f) Any installation and performance incentives to be provided by the utility to the qualifying facility;
(g) The services to be provided or discontinued by either party during system emergencies;
(h) The term of the contract;
(i) Applicable operating safety and reliability standards with which the qualifying facility must comply;
(j) Appropriate insurance indemnity and liability provisions."

Commensurate with the rules, the Commission's intent here is to resolve contested issues with respect to the specific terms and conditions for service under the standard tariff.

41. The utilities propose that all QFs be required to execute a written contract prior to interconnection. Accordingly utility-sponsored testimony contains tariff and standard contract proposals in varying degrees of length and complexity.

42. To promote understanding of party responsibilities and to minimize uncertainty as to allocation of risks, for the present, the Commission finds that all QFs should be required to sign a standard contract, containing the terms and conditions of service, for a minimum term of one year. The standard contract is to be a component of the QF's tariff -- approved, regulated, and maintained by the Commission. The standard contract should concisely set forth the options available to QFs regarding short and long-term purchase rates and terms and billing and payment

alternatives, and the QF's choice should be clearly specified therein. To the extent practicable, definitions, technical specifications, and computations and/or formulas for payment determinations should be confined to appendices to the standard contract. Terms and conditions made redundant by Commission rules should be excluded from the QF tariff and standard contract.

BILLING ALTERNATIVES

43. Contrary to Commission rules, (ARM 38.5.1903(5)(c) and 38.5.1905(6)), each of the utilities confined their standard billing proposals to simultaneous sale and purchase arrangements. Their exclusion of any net billing option was premised on two contentions: (1) that the reliability of meters, not specifically designed to run backward and forward, was suspect; and (2) that valuable information concerning the production characteristics of QFs, individually and in the aggregate, could not be captured by a single meter.

44. Dr. Power maintained that the net billing option should be available to small QFs as such an option would minimize transaction and metering costs. On cross-examination, Dr. Power agreed that there was value to gathering information on the actual generating characteristics of small QFs but he questioned the cost-effectiveness of mandating dual meters for every QF when a sampling technique might provide the same information at a lower cost.

45. The fact the utilities are united in opposition to net billing, in combination with some of Dr. Power's statements regarding the concept, indicate to the Commission that there is a general lack of understanding, concerning the net billing option per the Commission's rules.

46. Dr. Power stated that in his opinion only very small QFs would opt for net billing, and that their motivation would be to avoid additional metering charges. In addition, he testified that the concept of net billing presumes that a utility's avoided costs and its retail rates are roughly approximate. Dr. Power then concluded that "[a]nybody who was in the range displacing all of their consumption certainly would be better off opting for some other arrangement than net billing." (Tr. B-115).

47. The Commission would clarify that net billing was premised on two assumptions: first, that the state of the art of metering is such that a single meter, whether currently in place in Montana or not, can accurately record net consumption or production within a given billing period, thus avoiding the cost of the second meter; and second, that up until the point a QF becomes a net producer, the QF is logically entitled to be billed for his/her net consumption at the retail rate.

48. Once during a billing period, a QF becomes a net producer, the costs the utility avoids in purchasing the QF's energy are accurately reflected in avoided cost, not retail, rates. The Commission wishes to dispel any notion that a QF who opts for net billing would receive any rate other than the

utility's avoided cost rate for its net production. This finding confirms what is explicitly stated in ARM 38.5.1905(6).

49. PP&L's proposed tariff implicitly recognizes the attractiveness of net billing wherein they give large QFs the option of offsetting their local load and then delivering any excess energy to the company at avoided cost rates. Likewise, PP&L's revised contract appears to endorse, to the exclusion of any simultaneous sale and purchase arrangements, a modified net billing approach via their definition of "Net Metered Output." In both instances, however, the amount subject to net billing is determined not by one but two meters.

50. The Commission finds merit in collecting QF production data, but it believes that there are means to accomplish such without abrogating the Commission rule that gives a QF the option of operating in parallel on a net billing basis. The utilities were given two hearing and public comment opportunities in the Fall of 1980 and the Spring of 1981. The Commission finds that the issue was resolved in those proceedings as reflected in ARM 38.1905(6). Should the utilities find a second meter necessary, then the utility shall provide the second meter (as PP&L has proposed) and make QF payments, upon request, under the net billing option. The Commission would note that by placing the cost of the second meter on the utilities, to the extent that meters currently in use cannot reliably track net consumption or production, the utilities will have incentive to stay abreast of

development regarding single meters that were specifically designed to operate on a net basis.

51. PP&L's definition of 'Net Metered Output' should be amended because it necessarily forecloses QF selection of a simultaneous sale and purchase arrangement.

52. These findings should serve to explicitly clear the air with respect to standard billing options. In summary, the QF has the option, upon request, of 1) simultaneous purchase and sale whereby all QF production is measured via a second meter, at the expense of the QF, and is purchased at the appropriate tariff schedule; and 2) operating in parallel with a single meter measuring net consumption or production. Net consumption is billed at the appropriate retail tariff schedule and net production is purchased at the appropriate QF's tariff schedule. If the utility deems a second meter necessary for either billing integrity or data collection then it remains the utilities' prerogative to install a second meter at no cost to the QF.

53. In a related matter the Commission finds MPC's and PP&L's billing procedures, as set forth in Appendix A and Articles IV and V of their respective contracts, to be unnecessarily convoluted. Mr. Jordan's suggested alternative should suffice to adequately meet the needs of QFs and utility alike, without excessive rigmarole: within 15 to 20 days after the billing period had ended, the utility should make payment to the QF. A statement showing the amount of energy delivered to the

utility's system during the billing period and the computation of the payment amount should be included with each payment.

54. The Commission finds MDU's 600 KWH per month ceiling on energy purchases from QFs of 100 KW or less to be inconsistent with Commission rules and MDU's policy to purchase all energy available from QFs. That restriction should be deleted from MDU's tariffs.

Interconnection Payments

55. ARM 38.5.1904(2)(c) provides that, if the utility installs interconnection facilities for the QF, the QF must reimburse the utility but "[the] reimbursement may be accomplished by means of amortization over a reasonable period of time within the term of the contract." ARM 38.5.1902 (5)(c) specifies that "the amount and manner of payment of interconnection costs" be set forth in the contract.

56. The Commission would reiterate that the issue of payment of interconnection costs was settled in the rules. MDU and PP&L are directed to amend their standard contracts to provide some method using reasonable financing charges for QFs to amortize such costs. The Commission is aware that instances may arise where a QF has as ready access to financing as do the utilities, however, absent guidelines as to how to distinguish which QFs need help financing interconnection costs, the amortization rule will be available to all QFs.

57. The Commission also determines that, once intertie has been accomplished between the utility and QF, the utility, not the QF, should be financially responsible for any alterations or modifications that are necessitated by a change in the utility's system voltage.

Insurance

58. The utilities proposed that the QFs be required to maintain liability and, if a capacity supplier, property damage or destruction insurance. Suggested floors for liability limits ranged from $500,000 to $1,000,000 per single occurrence, and property insurance provisions required that the utility be named insured as well as receive any proceeds, pending QF replacement of destroyed or damaged facilities. In addition, liability insurance proposals from MPC and PP&L give the utility unilateral power to require the QF to purchase additional coverage.

59. The Commission is reluctant to mandate comprehensive liability insurance coverage that would include explosion, collapse and underground hazards and contractual liability, without more information as to the cost of such insurance and a better justification as to why such insurance is essential to purchasing electricity from a QF. For the time being, the Commission will require only general liability insurance provisions in standard contracts. The Commission will permit the utilities to increase liability limits, whenever they see fit,

only if such requests are made in good faith and upon reasonable justification.

60. The Commission finds the record to be insufficient to justify distinguishing liability insurance limits on the basis of QF size, therefore, the Commission leaves to the initiative of insurance companies to differentiate premiums that reflect adequate liability coverage given a particular QF's size and operating characteristics.

61. The Commission finds the utilities' proposals for property insurance to be particularly lopsided. The combination of named insured treatment, and receipt and retention of proceeds in anticipation of proof of replacement expenditure, could necessitate duplication of policies by the QF. The Commission understands the utilities desire to have access to a source of funds should the QF be destroyed and performance be discontinued, however, there is not necessarily any direct relationship between the cost of replacing a QF and the damages the utility will face as a result of the disruption. Absent a better explanation for the need for such requirements, the Commission finds the standard contracts need only contain a provision requiring capacity suppliers to obtain and maintain adequate property insurance; named insured and proceeds requirements should be deleted.

62. In light of the Commission's decision to allow all QFs, irrespective of size, to contract to provide capacity, the utilities may want to amend their proposals to distinguish between smaller and larger QFs. Such proposals should be

accompanied by sufficient justification, based on system planning needs, for distinguishing property insurance treatment on the basis of QF size.

63. Following Advocacy Staff suggestion, the utilities are directed to investigate the possibilities of obtaining group insurance for smaller QFs.

Force Majeure

64. Both MPC and PP&L proposed force majeure clauses in their standard contract which specifically exlcuded nonavailability of fuel or lack of motive force to operate QF's facility. PP&L exempted small hydro projects from this exclusion on the rationale that, like PP&L, such projects are susceptible to dry water years that are beyond the control of the operator.

The Commission finds that it is unreasonable to give small hydro development deferential treatment when other types of small power production or cogeneration might suffer from similar circumstances. The utilities are directed to include nonavailability of fuel or motive force in their force majeure clauses. Lack of foreseeability or reasonable control will still be the major determinants as to whether performance will be excused. This provision should not be interpreted to give QFs carte blanche to enter into contractual obligations without reasonable engineering, meterological, or hydrological studies or economic forecasts.

Capacity Adjustments

65. The utilities argued that if during any contract year a QF fails to deliver sufficient capacity some adjustment to its total annual capacity payment should be made. The Commission agrees. Failure to meet contractual capacity commitments should not be casually disregarded.

66. MPC proposes that if a QF fails to meet its capacity commitment during any 12 hour contract capacity review the QF should lose its right to receive any capacity payments for that entire year; this "all or nothing" approach clearly is inconsistent with the proposition that a QF should be paid for any capacity it actually delivers to a utility. MDU's proposal has the same "all or nothing" effect even though its impact is less drastic -- MDU would only require forfeiture of the QF's right to capacity payments for the month in which the deficiency occurred.

66. Because PP&L's proposal accommodates the notion of paying QFs for the capacity they actually deliver, yet it recognizes that some reasonable adjustment should be made for failure to fulfill contractual obligations, the Commission finds that if a QF fails to deliver capacity according to its commitment it would be appropriate for the utilities to adjust either their annual or monthly capacity payment by a factor of delivered capacity to contracted capacity. The QF will still be paid for each kilowatt it delivers, but the reduced per unit payment will force the QF to realize a loss beyond that which results from the

loss of anticipated revenue associated with its decreased capacity production.

67. Additionally the Commission recommends that MPC and MDU incorporate PP&L's idea of using an estimate of capacity capabilities for the initial contract year and then adjusting the second and remaining years according to the QF's demonstrated capacity. MPC and MDU are directed to incorporate this finding into their standard contract.

Payment Options

68. A considerable amount of testimony was provided to the Commission pro and con variations in innovative payment schemes. Dr. Power urged that the utilities provide a variety of payment options to any QF contracting to supply energy and capacity over a four to five year contract term. He specifically addressed payments which were based upon (1) levelized annual payments for energy and capacity as derived from projected avoided costs, (2) a fixed capacity component, increased annually by the general inflation rate, and a variable energy component, based on either the preceding or succeeding years' actual or projected avoided energy costs, and (3) variable capacity and energy payments, based on the current contract year's avoided costs.

69. Mr. Barber too stressed the need for flexibility in payment options, particularly noting the desirability of front loaded contracts. In order to further facilitate QF financing, he also suggested that the utilities be required to sign a con-

tract with a QF for a firm amount, projected over the term of the contract, a number of years before the QF would actually deliver any energy; then when the QF comes on-line, he suggested that payments commence at the higher of the contracted rate (a projection) or the-then prevailing avoided cost rate (valuation at time-of-delivery). The Commission finds this proposal to be particularly noteworthy because it would not only give the QF greater flexiblity in financing but it would give system planners considerable lead time to integrate QF production into their resource planning efforts.

70. Of the three utilities, only PP&L presented any alternative method of payment. Their proposal consisted of payments that have been levelized over the term of the contract, based on prices as projected at the time the contract was executed. PP&L's levelized payment option was available only to QFs willing to provide capacity for a period of years. At hearing PP&L withdrew its levelized payment option and justified its action in light of a recent decision by the Oregon Public Utilities Commissioner that required all QFs opting for a levelized payment plan to provide a performance bond. In its rebuttal brief, however, PP&L requested that its initial levelized payment proposal and supporting testimony be reinstated because, on October 29, 1981, the Oregon Public Utilities Commissioner modified his position on performance bonds. Rather than requiring bonds for all QFs opting for levelized payments, the Oregon Commissioner may

require, upon utility petition and with good cause shown, QF performance bonds in particular instances.

71. With respect to the offering of levelized and/or front loaded contracts, the Commission merely wishes to remind the parties that this particular issue was, after considerable debate, resolved in rulemaking. ARM 38.5.1903(2)(b) explicitly requires the utilities to offer long-term levelized or front-loading contracts: "...the utility shall offer long-term contracts with qualifying facilities which permit a rate higher than avoided costs in the early years of the contract and a lower rate in the latter years."

72. When the Commission adopted this rule it recognized that front-loaded, or levelized, contracts, would initially aid the QF by covering debt service and ultimately benefit the utility and/or ratepayers by providing power below avoided costs during the second half of the contract. Neither the Commission rule, nor its policy, has changed in the interim.

73. The Commission reinstates and accepts PP&L's levelized payment proposal, with the admonition that Commission rules must not be disregarded merely because another state's regulatory body has taken a different approach to the same issue. MPC and MDU should expand their payment options to comply with Commission rules; their payment options need not mirror PP&L's proposal. As long as the payment option incorporated into the tariff and standard contract embodies the purposes of ARM 38.5.1903(2), MPC

and MDU will have discharged their obligation under the rule. The Commission wishes to emphasize, however, that all QFs signing long-term contracts, per Commission rule, are entitled to levelized or front-loaded contracts.

74. Because of the risk associated with nonperformance of front-loaded or levelized contracts PP&L has indicated in its rebuttal brief, that as a matter of corporate policy, all QF contracts of four megawatts or more which contain a levelized payment provision will be submitted to the Commission and that, should PP&L perceive that there is sufficient risk of nonperformance by the QF, PP&L will submit such a contract to the Commission for advance review.

75. The Commission rules do not contemplate advance review and Commission approval of questionable contracts. Although the Commission concedes that PP&L's suggestions may be practical and well conceived, they necessarily place the Commission in a position to set aside a rule when there are no rules or guidelines for doing so. In declining to act as arbitrator regarding prospects of QF nonperformance [dubious QF contracts containing a levelization of payments provision], the Commission assures the utilities that, should a QF default on a front-loaded or levelized contract and subsequently the QF is discovered to be judgment proof, any losses the utility incurred as a result of complying with this rule will be given appropriate treatment in ratemaking proceedings.

Liquidated Damages

76. The Commission finds that each utility should include a liquidated damages provision in their standard contract. The formulae for calculating the appropriate damages should account for two contingencies: (1) early termination or default on a front-loaded or "levelization of payments" long-term contract and (2) premature termination or default on a nonlevelized long-term contract. The particulars of how to compute these damages will be addressed below; first the Commission wishes to discuss the policy rationale for requiring such a provision.

77. The Commission requires this provision to encourage QFs to accurately assess energy and capacity production capabilities when it commits, and the utility integrates, its production into utility system resource planning under a long-term power contract. As well, the Commission recognizes that it may be very difficult to ascertain the losses either party has experienced as a result of termination or default, however, if a reasonable estimate of those losses can be agreed upon at the time the contract is executed, an additional element of uncertainty can be eliminated from the contract.

78. Although none of the utilities proposed a liquidated damages provision that specifically addressed default or termination of a levelized contract, because MPC's standard contract provided for per unit capacity payments that varied with the term of the contract, that liquidated damages clause can be used for a frame of reference in this instance. Overcollection

of payments during the actual term of the contract vis a vis the original term and the impact of unexpired term on system planning were handled separately under MPC's proposal. Differences in the amount of losses estimated due to overcollection were supposedly justified by the nature of the termination. System planning losses were recognized only in the eventuality that minimum notice requirements were not met.

79. Dr. Power suggested that the Commission adopt a repayment (liquidated damages) provision similar to that ordered by the Idaho Public Utilities Commission. There, rather than constructing what could be perceived as serious disincentives to QF development, the Idaho PUC forgave small QFs (less than 1 MW in size) all but a nominal proportion of the damages that could flow from early termination or default and only required larger QFs to repay one-half of what was lost.

80. The Commission rejects the notion that policy considerations warrant encouragement of cogeneration and small power production at any cost: QF accountability for early termination or default-related losses should not be a function of QF size, or implicitly, the magnitude of the possible loss to the utility and/or ratepayers. As of the date of notice of termination or termination, the QF should return the entire difference between the total payments received under the front-loaded contract and the total payments that would have been received had payments been based upon the QF's actual term of performance and avoided capacity and energy rates as projected at the time the contract

was executed. The Commission finds this repayment formula not only logical but eminently fair to QFs, utility and ratepayer alike.

81. Because the Commission determined above that, for system planning purposes, a minimum term of four years is required to actually avoid or defer capacity expansion, it follows that the utility will incur minimal, if any, damages should a QF, upon four or more years advance notice, terminate a long-term contract. However, if a utility relies on the continuation of QF capacity in its system planning and a QF prematurely terminates its minimum four year contract or gives less than 48 months notice of its termination, the utility will incur system planning related losses, and the QF should reimburse the utility for the value of the system planning latitude the utility has necessarily forfeited. An amount equal to the average monthly capacity payment times the difference between the lesser of 48 months or the unexpired term of the contract (in months) and the number of months notice given regarding the termination should roughly approximate these losses. The approach the Commission has adopted is a modification of similar proposals from MPC and MDU.

Governmental Regulation and Termination

82. Burdensome governmental regulation was proffered by the utilities as a suitable justification for almost immediate termination of a QF contract. Irrespective of the fact that they

could not envision a utility invoking this provision, the utilities suggested that inclusion of such a provision was primarily to the benefit of the QF.

83. The Commission is not persuaded. The fact that there is no mutuality involved making such a determination suggests that such a clause begs contention and promotes uncertainty as to party responsibilities. The utilities are requested to delete such provisions from their contracts.

CONCLUSIONS OF LAW

1. Montana-Dakota Utilities Company, Montana Power Company and Pacific Light & Power Company are public utilities within the meaning of Montana law, Sections 69-3-101, 69-3-601(3), MCA.

2. The Commission properly exercises jurisdiction over the rates and terms and conditions for the purchase of electricity by public utilities from qualified cogenerators and small power producers. Sections 69-3-102, 69-3-103 and 69-3-603, MCA.

3. The rates the Commission has directed the utilities to file are just and reasonable to Montana ratepayers as they reflect each utility's avoided energy and capacity costs.

4. The objective of encouraging cogeneration and small power production is promoted by the rates and terms and conditions established by this order.

ORDER

1. MDU, MPC and PP&L shall develop rates which are consistent with the Findings of Fact entered by the Commission in this order. These rates shall be developed as summarized below.

a) avoided energy rates shall be based on (1) for short-term contracts (one year), a one year projection of each utility's short run incremental running costs, and (2) for long-term contracts (four or more years), the annualized costs (per directions set forth in Appendix B) of owning and operating a baseload plant, converted to ¢/KWH by using an assumed capacity factor of 70 percent.

b) avoided capacity rates shall be based on the annualized capital costs of a combustion turbine; payments can be structured on either an annual or monthly basis. A factor relating a QF's capacity factor to a 85 percent availability factor of a combustion turbine shall be used to determine the capacity payment which a QF is entitled; for short-term energy, an aggregate capacity payment, equal to one-half of the avoided capacity rate, shall be added to the short-term energy rate.

c) detailed working papers shall be submitted in support of aforementioned rate calculations.

2. MDU, MPC and PP&L shall revise their proposed standard contracts in a manner that is consistent with the Findings of Fact herein.

3. Proposed tariffs, including avoided energy and capacity rates and standard contract, shall be filed with this Commission

within forty-five (45) days from the date of this order is issued.

Done and Dated this 4th day of January, 1982.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION.

G. E. Bollinger
GORDON E. BOLLINGER, Chairman

John B. Driscoll
JOHN B. DRISCOLL, Commissioner

Howard L. Ellis
HOWARD L. ELLIS, Commissioner

Clyde Jarvis
CLYDE JARVIS, Commissioner

Thomas J. Schneider
THOMAS J. SCHNEIDER, Commissioner

ATTEST:

Madeline L. Cottrill
Secretary

(SEAL)
By: Inez Bastar Acting Secretary

NOTE: You may be entitled to judicial review of the final decision in this matter. If no Motion for Reconsideration is filed, judicial review may be obtained by filing a petition for review within thirty (30) days from the service of this order. If a Motion for Reconsideration is filed, a Commission order is final for purpose of appeal upon the entry of a ruling on that motion, or upon the passage of ten (10) days following the filing of that motion. cf. the Montana Administrative Procedure Act, esp. Sec. 2-4-702, MCA; and Commission Rules of Practice and Procedure, esp. 38.2.4806, ARM.

APPENDIX A

SUMMARY OF STANDARD TARIFF RATE SCHEDULES

At the option of the QF, energy and capacity is to be purchased at either 1) the Short-Term Schedule or 2) the Long-Term Schedule.

1) The Short-Term Schedule

- Availability: available to all QFs willing and able to sign the standard contract.

- Rates: all energy and capacity purchased is to be priced, at the option of the QF, at a) the Annual Average Rate or b) the Time Differentiated Rate.

  a) Annual Average Rate

  - X ¢/KWH for all KWH purchased, where X equals the annual average projection of short run incremental energy costs plus the aggregate capacity payment.

  b) Time Differentiated Rate (initially, at the option of the utility)

  - X_t ¢/KWH for all KWH purchased during time period t, where X equals the projection of short run incremental energy costs during each time period t plus the aggregate capacity payment allocated to each time period t based on hourly loss of load probability.

2) The Long-Term Schedule

- Availability: available to all QFs willing and able to sign the standard contract and a performance contract of duration not less than four years.

- Rates: all energy and contracted capacity is to be priced, at the option of the QF, at a) the Annual Average Rate or b) the Time Differentiated Rate.

  a) Annual Average Rate

i) Energy Payment

- X ¢/KWH for all KWH purchased, where X equals the annualized unit cost of owning and operating a baseload plant, less the annualized unit cost of owning a combustion turbine.

ii) Capacity Payment

- Y $/KW(cf) for all contracted KW, where Y equals the annualized unit cost of a combustion turbine (from 2ai, above) and CF represents the negotiated expected or demonstrated QF plant capacity factor.

b) Time Differentiated Rate (initially, at the option of the utility)

i) Energy Payment

- X_t ¢/KWH for all KWH purchased during each time period t where X represents the annualized unit cost of owning and operating a baseload plant less the annualized unit cost of a combustion turbine, differentiated by time period t to reflect short run incremental energy cost variation.

ii) Capacity Payment

- Y_t $/KW for all contracted KW delivered during each time period t, where Y equals the annualized unit cost of combustion turbine (from 2bi, above) differentiated by time period t to reflect the relative probability of capacity shortage in time period t.

APPENDIX B

SUMMARY OF SPECIFIC DIRECTION IN COSTING

- All values are to be inflated/discounted to reflect constant contract year dollars.
- Inflation is to reflect industry specific, regionalized real cost indices.
- Discounting is to reflect standard (e.g. DRI) projections of national general inflation.
- Variables and formulae are defined and an example provided, below.

Definition of Variables

λ = system lambda[1] (¢/KWH)
a = baseload capital cost[2] ($/KW)
b = combustion turbine capital cost[3] ($/KW)
c = baseload annual carrying charge[4] (%)
d = combustion turbine carrying charge[4] (%)
e = baseload fixed O&M[5] ($/KW)
f = combustion turbine fixed O&M[5] ($/KW)
g = line loss factor [6] (%)
h = coal cost[7] ($/ton)
i = coal fuel content[7] (BTU/lb)
j = baseload plant heat rate[8] (BTU/KWH)
k = baseload variable O&M[5] (¢/KWH)
cf = QF capacity factor[9] (KWH/KW)

1 Short run incremental energy cost via production modeling of economic dispatch. To include variable O&M and revenue requirement associated with working capital and fuel inventory.

2 Actual baseload capital cost estimates to be supported by actual engineering cost study. The capital cost estimates are to be exhaustive and detailed by component. Rather than list the components, the Commission refers you to Appendix A

of EPRI's "Coal-Fired Power Plant Capital Cost Estimates" (Bechtel Power Corporation, May, 1981, report #EPRI PE-1865). Cost estimates will be reviewed with necessary adjustment made as deemed appropriate.

3 Actual combustion turbine capital cost estimate supported by actual engineering cost study, if available, or consistent with industry estimates. Treatment must be equally exhaustive and detailed by component.

4 Annual carrying charges supported by calculations of incremental cost of capital; 35 year book life assigned to baseload plants, 25 for combustion turbines.

5 Appendix A of the EPRI report cited above provides the minimum components to be considered. Includes working capital and variable costs associated with SO_2 removal.

6 Initially, equal to 8.3% applied to all energy. Eventually, shall reflect utility specific actual analysis and, in the case of time differentiation, allocated to rating periods commensurate with analysis results.

7 Coal cost and fuel content are to reflect actual contract year purchase contracts. Coal cost is to include a separate component reflecting transportation costs.

8 Plant heat rate is to reflect actual plant heat rate at expected operating load.

9 QF capacity factor is to represent expected performance, initially, and demonstrated performance after first contract year.

Rate Schedule Formulae

short-term energy =

$$\lambda g + \frac{(bd + f).425}{(8760)(.85).85}$$

long-term energy =

$$\left(\frac{(ac + e) - (bd + f)}{(8760).70}\right)g + \frac{hj}{i} + k$$

long-term capacity =

$$\frac{(bd + f)cf}{.85}$$

Example Rate Calculation[10]

λ = 2.50 ¢/KWH	g = 8.3%
a = 1200 $/KW	h = 10.0 $/ton
b = 300 $/KW	i = 9,000 BTU/lb
c = 16%	j = 11,000 BTU/KWH
d = 17%	k = .3 ¢/KWH
e = 20 $/KW	cf = .65 KWH/KW
f = 10 $/KW	

$$\therefore \quad \underline{\text{short-term energy}} = .0250\,(1.083) + \frac{(300(.17) + 10).425}{8760(.85)(.85)}$$

$$= .0271 + .0041$$
$$= .0312 \text{ \$/KWH}$$

$$\underline{\text{long-term energy}} =$$

$$\left(\frac{(1200(.16) + 20) - (300(.17) + 10)}{8760(.70)}\right) 1.083 + \frac{(10(11,000))}{(2000(9000))} + .003$$

$$= .0266 + .0091$$
$$= .0357 \text{ \$/KWH}$$

$$\underline{\text{long-term capacity}} = \frac{(300(.17) + 10)(.65)}{(.85)}$$

$$= 46.65 \text{ \$/KW-YR}$$

10 These values are generally representative of those submitted by intervening parties in this proceeding. Although they are provided for illustrative purposes, they also serve as indicators of what the Commission has found to be reasonable.

Service Date: June 25, 1982

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

IN THE MATTER of Avoided Cost Based Rates for Public Utility Purchases from Qualifying Cogenerators and Small Power Producers.)	UTILITY DIVISION DOCKET NO. 81.2.15 ORDER NO. 4865b

* * * * *

FINDINGS OF FACT

BACKGROUND

1. Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) required the Federal Energy Regulatory Commission (FERC), as well as state regulatory authorities, to prescribe rules to encourage cogeneration and small power production (COG/SPP) including rules requiring electric utilities to purchase electric power from cogeneration and small power production facilities. Among other things, the rules were to insure that rates for purchases of electric energy from qualifying facilities (QF) "be just and reasonable to the electric consumers of the electric utility and in the public interest" and that the rates would not exceed the "incremental cost to the electric utility of alternative electric energy."

2. On May 4, 1981 the Commission adopted final rules governing purchases and sales between public utilities and

qualifying small power production facilities. The Commission rules are modeled after FERC regulations implementing Section 201 and 210 of PURPA. The rulemaking procedure featured a public comment period commencing with the issuance of draft rules on September 2, 1980 and extending through October 23, 1980. A second revised draft of the rules was issued on March 16, 1981 with public comment extending through April 27, 1981. The rulemaking proceeding ended with adoption of final rules on May 4, 1981.

3. The Commission's rules (ARM 38.5.1901 through 38.5.1908), pursuant to FERC regulations, provide the general obligations of the COG/SPP and the regulated electric utilities.

4. The Commission initiated Docket No. 81.2.15 on February 24, 1981 when it requested that MDU, PP&L, and MPC file testimony regarding avoided cost methodologies, avoided cost-based rates, and tariffs and standard contracts for purchases of electricity from COG/SPP. On January 4, 1982, the Commission issued Order No. 4865 setting forth the Commission's initial findings in this Docket.

5. On January 22, 1982, MDU, MPC and PP&L each filed Petitions for Reconsideration and/or Clarification and, on February [illegible] 1982, the Commission issued Order No. 4865a which add[illegible] the Petitions

6. By March 5, 1982 the utilities had submitted their original compliance tariffs. On March 12, 1982 the Commission had a working session where it (1) approved on an interim basis MPC's and MDU's tariffs (2) directed PP&L to resubmit new tariffs based on Colstrip 3 and 4 and (3) requested each utility to provide rebuttal to the Commission's concerns within 45 days.

7. The Commission has two objectives to achieve in this order regarding the avoided cost tariffs submitted by the three electric utilities.

8. First, the Commission seeks to approve, after correcting for apparent conceptual problems (detailed below) the utilities have with the avoided cost methodology, the interim tariffs for MDU and MPC and to address existing problems with PP&L's proposed tariffs; the resulting final tariffs will be updated June 1, 1983 for the contract year July 1, 1983 - June 30, 1984 (Order No. 4865, Finding of Fact No. 33).

9. Second, the Commission indicates negotiated payment options (e.g., fixed minimum payments and levelized) which it finds acceptable.

FINAL AVOIDED COST TARIFFS

10. This section reviews each Company's initial tariff filings, inherent problems the Commission perceives with these tariff filings, the Commission's corrective measures, and the final avoided cost tariffs.

> MDU did not submit any cost stream information with regards to the Antelope Valley project. Montana Power had a cost stream extending almost fourteen years for their Colstrip units #3 and #4, and were directed to take a time series calculation into account in order to equate that cost stream into present day dollars. MDU is not faced with that situation with regards to Antelope Valley since our letter of intent with Basin Electric states that we will not put forth any capital until 1984 should we choose to execute our option then. As a result, MDU will have one large capital expenditure in 1984, with another expenditure coming in 1985. Since the 1985 expenditure will undoubtedly be significantly less than the 1984 expenditure, MDU chose not to make a cost stream calculation but rather lumped all expenditures into one and then brought that value back to 1982 dollars.

15. While the Company's 1985 expenditure, relative to its 1984 expenditure, is small, the Commission finds no grounds for deviating from the direction of Orders 4865 and 4865a. In Schedule A, the Commission provides a corrected baseload capital cost calculation and resulting long-term energy rate.

Montana Power Company.

16. MPC's calculation of annual capital costs for the baseload electric generating plant suffers from the same analytic problems as MDU's. However, unlike MDU, MPC not only chose to not follow the direction of Order's 4865 and 4865a but further argues that the Commission's direction (Findings of Fact No. 33, Order No. 4865, and Finding of Fact No. 37, Order No. 4865a) is theoretically flawed.

17. In its March 17, 1982 correspondence to MPC, the Commission stated the following:

> The primary problem involves the Company's calculation of the capital cost associated with Colstrip Units #3 and 4. The cost stream (Cost Calculations, Table VI, Page 7 of 7) begins with a $489,000 expenditure in 1973, and culminates with $166,000 budgeted for 1987. Order No. 4865 (page 1 of Appendix B) contemplates converting this cost stream to 1982 dollars via real cost and inflation indices. The Company, however, has chosen not to follow this procedure and instead sums the actual cost stream with an AFUDC component. My discussions with Jim Cullier indicate that the Company's position is that the Company's treatment of the cost stream results in a calculation which reflects the ratepayers cost of Colstrip Units #3 and 4. While there is merit in the argument, the proferred fact is simply false.

18. In its "rebuttal comments" the Company (Mr. Jack Haffey, April 26, 1982) had the following remarks:

> The Company disagrees with that interpretation of the Order. No where in Appendix B or anywhere else in the Order is there any mention whatsoever of "cost streams." What is requested in Appendix B are the "actual baseload capital cost estimates." Those estimates or "values" have indeed been placed in 1982 dollars in the Company's calculation of capital costs.
>
> The Staff's letter of March 17, 1982 is the first indication in Docket 81.2.15 that the appropriate manner of calculating avoided costs is to inflate or deflate a stream of capital expenditures.

Mr. Haffey's letter goes on to add:

> The Staff's assertion that Order No. 4865 "contemplated" the conversion of the "cost stream" to 1982 dollars finds no support in the Order. In fact, such a procedure would not be consistent with the Order since a fictitious number bearing no resemblance to avoided costs would be the result. What this approach would yield is the cost of Colstrip #3 and 4 if it were built entirely in 1982. Such a calculation was not suggested by any of the witnesses in Docket No. 81.2.15 nor in Order No. 4865. Furthermore, by using the word "contemplated," it appears as though the Staff is admitting that the Order did not explicitly state what was required of the utilities. [Footnote deleted].

19. As stated in Finding of Fact No. 18, the Company claims to have converted its 1973 through 1987 baseload capital cost expenditures, including AFUDC, to 1982 dollars. The Company's analytic treatment involved simply summing all expenditures -- 1973 through 1987 -- in <u>nominal</u> or current year's dollars and then discounting this sum back from 1984 to 1982 dollars by multiplying the sum by a factor of 0.8629 (this factor equals the inverse of the product of 1.079 and 1.074 from page 7 of 7 of the Company's compliance work papers dated February 25, 1982).

20. It is the Commission's finding that this methodology is logically unsound, indicating <u>only</u> the cost of Colstrip #3 and 4 to Montana ratepayers on an accounting basis. This cost does not accurately reflect the time value of money which stems from two factors 1) price inflation -- a rise in the general price level -- and 2) the real earning potential of investments; this latter

definition representing economic cost. The following example rectifies for the Company the meaning of "avoided costs."

21. In Order No. 69, issued in February of 1980, the Federal Energy Regulatory Commission defined "avoided costs" as:

> "Avoided costs" means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source. (§292.101(b)6).

That is, avoided costs are to be based on the costs a utility would avoid incurring as a result of a QF's supplying energy and/or capacity.

22. For example, if the Company's forecasts indicate a one kw deficit in capacity in year 1990, the question could be posed as to what exactly the cost would be to the Company of obtaining an incremental kw of capacity. A literal interpretation of the Company's logic (Finding of Fact Nos. 18 and 19) would lead one to believe it would be capital costs that in part occured in year 1973 and in 1973 dollars. Clearly the Company recognizes that prices for materials, capital, labor, etc., have not remained constant since year 1973. That is, costs in 1973 dollars are not best estimates of what it would cost the Company today to install an incremental kw of capacity; a best estimate is reflected by use of constant contract year dollars.

23. Regarding the treatment of costs incurred overtime, the advocacy staff's expert witness Dr. Tom Power made the following statements:

> ... I certainly do not recommend -- and that is crystal clear in my testimomy -- that we take estimates in 1989 dollars and add them to estimates in 1986 dollars and add those to estimates in 1981 dollars. I know of nobody who would make that suggestion. (Tr. p. B-101)

24. The Commission finds the Company's baseload capital cost calculation of $1245.0 to underestimate a constant contract year estimate by $353.0. The Commission derived a constant contract year estimate of $1598.0/kw, described below, using the Company's cash flow with AFUDC and PP&L's escalation/de-escalation factors.

Pacific Power and Light

25. In its March 29, 1982 correspondence with PP&L, the Commission requested the following:

> In my discussions with Jerry Rust he indicated a preliminary Colstrip 3 and 4 cost of $1596/kw resulting in a modified long-term energy rate of 5.18¢/kwh. This calculation appears to properly follow the intent of Order No. 4865 (page 1 of Appendix B) in its treatment of the historical cost stream. It is requested that the Company provide, as soon as possible, two copies of signed tariff pages reflecting this calculation.

26. Evident from the Company's May 14, 1982 response is th Company's decision to deviate from its own finding regarding a

$1596/kw capital cost estimate for Colstrip #3 and 4; rather than use this estimate the Company simply adopted certain parameters including the $1245/kw estimate, from MPC. In a later finding in this Order, the Company is directed to adopt certain previously submitted values for parameters used in deriving short and long-term energy and capacity payments.

Resulting Tariffs.

27. In MDU's work papers complying with Order No. 4865, the Company did not separately discount 1984 and 1985 baseload capital cost expenditures. The Company has since corrected this problem and is reflected in the baseload $/kw estimate and the long-term energy rates in Schedule A.

28. MPC is to resubmit final avoided cost tariffs as computed by this Commission and summarized in Schedule A. These tariffs differ from the Company's in the value of the long-term energy rates, which reflects the Commission's baseload capital cost of $1598/kw. Schedule B details the assumptions used to arrive at $1598/kw for a baseload plant. As indicated below (Schedule A) this value of $1598/kw approximates PP&L's correctly computed baseload capital cost estimate of $1596/kw.

29. PP&L is to resubmit final avoided cost tariffs as summarized in Schedule A. The parameters and resulting tariffs

SCHEDULE A

Input Parameters and Resulting Avoided Cost Energy and Capacity Tariffs.

Variable/Utility		MDU	MPC	PP&L
	¢/Kwh	1.6	1.66	1.65
a	$/kw	1480	1598	1596
b	$/kw	318	367	347
c	%	19.047	20.04	18.31
d	%	19.69	21.87	19.76
e	$/kw	5.79	12.34	12.59
f	$/kw	1.4	0.66	5.0
g	%	8.3	8.3	8.3
h	$/ton	13.5	10.03	10.03
i	BTU/LB	6600	8500	8500
j	BTU/Kwh	11280	10819	10819
k	¢/Kwh	0.128	0.26	0.27
STE[1]	$/Kwh	0.0216	0.0234	0.0228
LTE[1]	$/Kwh	0.0523	0.0534	0.0518
LTC[2]	$/kw/yr	63.96	80.88	73.54

1 Short Term Energy (STE) and Long Term Energy (LTE).

2 Long Term Capacity (LTC).

SCHEDULE B

Calculation of Variable "a" For MPC

	Cash Flow[1] W/AFUDC	Escalation De-Escalation[2] Factor	December[3] 1981 $
1973	509	2.439	1,242
1974	1,214	2.267	2,752
1975	1,354	1.806	2,445
1976	2,287	1.642	3,488
1977	13,431	1.525	20,482
1978	8,915	1.424	12,694
1979	8,003	1.291	10,332
1980	46,365	1.17	54,247
1981	108,879	1.07	116,501
1982	164,304	1.0	164,304
1983	140,427	0.9174	128,828
1984	74,859	0.8495	63,593
1985	35,094	0.7865	27,601
1986	213	0.7351	157
1987	166	0.687	114
			610,000 X (1.1)[4]
			= $671,000 (December 1982 Dollars)

671,000 ÷ 420 MW = 1,598/kw.

---

1 Cash Flow with AFUDC was obtained from MPC's Order No. 4865 compliance work papers. Table IV Page 7 of 7 dated February 25, 1982.

2 Escalation and De-escalation factors are from PP&L's <u>1982 Montana Electric Long Run Incremental Cost Study</u>, Docket No. 82.4.28, (Workbook No. 8)

3 December 31, 1981 dollars.

4 The factor 1.1 indicates 10% inflation from the beginning of 1982 to year ending. (Workbook No. 8, Docket No. 82.4.28).

in this Schedule reflect PP&L's cost information for Colstrip #3 and 4 in constant contract year dollars.

30. All utilities are to resubmit their respective final avoided cost tariff pages within five days. These tariffs will become effective upon approval.

PAYMENT OPTIONS

31. With regard to payment options, Order No. 4865 allows a QF the option to adopt 1) either of the short-term or long-term standard tariffs, or 2) negotiate with their respective utility an alternate avoided cost energy and capacity rate. From recent communication with both utilities and prospective QF's, it is evident to this Commission that much concern has emerged over some sort of tariffed alternate payment option. From the QF's perspective, the concern is for more concrete information on future energy/capacity payments in order to acquire loans from financial institutions.

32. Some payment options that QF's and utilities are free to arrange via negotiation were summarized by Dr. Thomas Power:

Payment Arrangements

Q. What options for payment arrangements should be provided to QFs?

A. I would recommend that three options be provided by each of the utilities.

i. Rates based upon levelized annual payments for both energy and capacity based upon projected avoided costs. The levelized annual payments would have the same present value as the estimated avoided investment cost and operation costs over the life of the contract. All payments would be fixed in real terms for the life of the contract. An annual adjustment for the overall inflation rate in the economy would be made to protect the purchasing power of these payments.

ii. Rates which had a fixed and variable component for the life of the contract. The capacity payment would be fixed in real terms but the energy payment would be based upon the marginal energy costs actually experienced in the previous year or projected for the coming year. The capacity payment would be increased each year by the general rate of inflation to protect its value.

iii. Rates which were based entirely on current marginal energy and capacity costs. They would vary from year to year. (Exh. M, Page 47).

The first two of Dr. Power's proposed payment options (i and ii) are examples that QF's and utilities are free to negotiate and which the Commission finds acceptable. Dr. Power's third proposal is currently a standard tariff option.

33. To the above proposals which address the market failure problems QF's face in obtaining financing, the Commission offers the following elaborations.

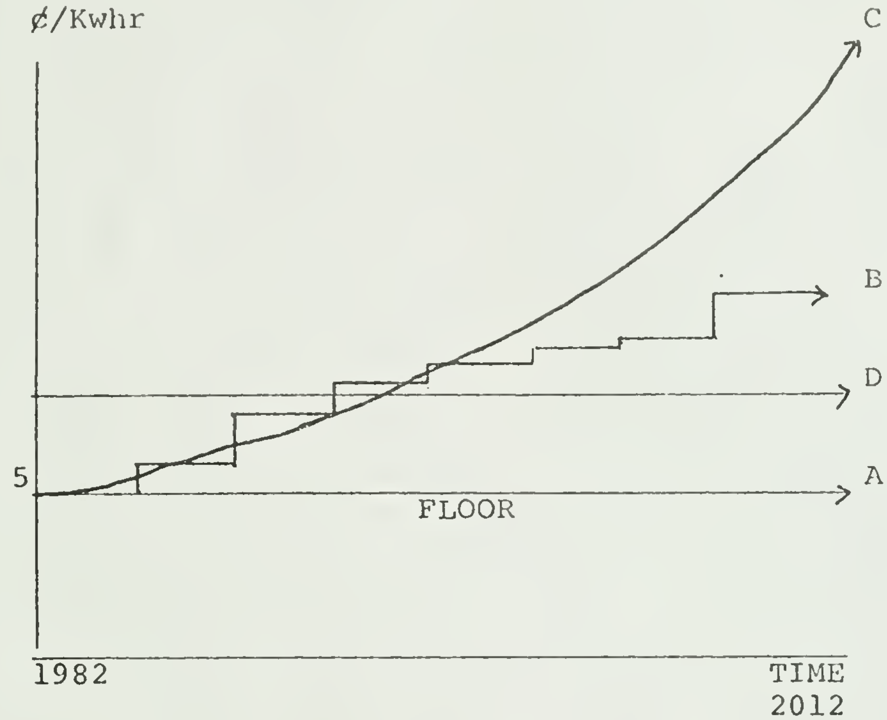
34. First, QF's may negotiate a fixed minimum rate with a utility. This proposal has two variants: (1) A fixed minimum

rate may be established that equals the initial year's standard tariff for long-term energy. Under no circumstances would the rate ever fall below the initial fixed minimum. (2) A fixed minimum rate may be negotiated that is annually adjusted for the previous years rise (fall) in the general price level, as indicated by the Consumer Price Index (CPI). As the U.S. Department of Labor's indices are initial estimates, the final or "revised" index may be used later, when published, to refine the initial estimate. As with (1) above, a latter year's avoided cost tariff may never fall below the initial floor.

35. A QF may also negotiate a levelized or front-loaded, contract with a utility. Such a contract would make use of standard capital recovery methods in levelizing capital costs. In fact this is just one procedure a utility may use to derive a fixed minimum rate. In turn, an annual inflation adjustment may be used with a levelized tariff as suggested by Dr. Power:

> I'm proposing that one estimate long-run incremental costs in current 1981 dollar terms and base the avoided cost rates on that, and I also suggest an option similar to what Pacific and Montana Power have both proposed, a levelizing arrangement that would load more the payments at the front end or something that I think has some attractive features, setting that avoided cost rate on a levelized basis in real purchasing power terms and then increasing it at whatever the actual experienced rate of inflation was each year. (Tr. p. B-139).

SCHEDULE C



36. Schedule C provides a graphical summary of payment options discussed above. In summary, the Commission has indicated five payment options which it finds acceptable:

1) The standard rate, where, over the life of the contract, the QF is paid the standard rate which varys from year to year [assuming no real inflation in the cost components used to compute standard rates, Curve B would represent this option].

2) A fixed minimum, where, over the life of the contract, the QF is paid the greater of the initial year's standard rate [Curve A] and the actual standard rate.

3) A fixed payment, where, over the life of the contract, the QF is paid the initial year standard rate plus the previous year's inflation [Curve B].

4) A fixed payment, where, over the life of the contract, the QF is paid the initial year standard rate plus a negotiated level of projected inflation [Curve C].

5) A levelized payment, where, the present value of the projected inflation [Curve C minus Curve A] is levelized over the life of the contract and added to the initial year standard rate [Curve A] resulting in Curve D.

37. Lastly, the Commission wishes to point out that the process of establishing final tariffs complying with the methodology set forth in this proceeding has been frustrating. The Commission finds the working session efforts initiated by all three utilities commendable. Further it finds that MDU has been relatively cooperative in addressing the compliance concerns of the Commission.

38. It is with PP&L's letter of May 14, 1982 and MPC's letter of April 26, 1982, that this Commission finds a possible lack of good faith. The Idaho Public Utilities Commission has taken the same problem into consideration when setting rates of return and approving issuances of security used to finance the construction of conventional thermal units.

39. The Montana Commission holds that utility failure to actively pursue QF contributions to their resource base, via negotiated terms of contract -- as discussed in Finding Nos. 33 through 36 -- to constitute failure to provide cost effective service. To the extent the evidence in future proceedings does not demonstrate that the utilities have in fact vigorously pursued such contracts, the Commission will use such evidence in considering whether utilities are providing adequate service at just and reasonable rates. Initially, it is the "conservation adder" recently granted in the equity returns of both MPC (Order No. 4775b, Finding No. 45) and PP&L (Order No. 4881a, Finding No. 33) which is at stake.

40. The Companies are reminded of their obligation to provide information to the Commission regarding their initial written response to each prospective QF [ARM 38.5.1908(1)]. In addition to reporting each <u>contact</u> made, the Commission directs the Companies to submit one copy of the completed contractural agreement with each QF. The Commission welcomes additional information that will aid the Commission in analyzing the individual efforts of each utility in encouraging QF contributions to a utility's resource base.

CONCLUSIONS OF LAW

1. Montana-Dakota Utilities Company, Montana Power Company and Pacific Power & Light Company are public utilities within the meaning of Montana law, Sections 69-3-101 and 69-3-601(3), MCA.

2. The Commission properly exercises jurisdiction over the rates and terms and conditions for the purchase of electricity by public utilities from qualified cogenerators and small power producers. Sections 69-3-102, 69-3-103 and 69-3-603, MCA. Section 210, Pub. L. 97-617, 92 Stat. 3119 (1978).

3. The rates the Commission has directed the utilities to file are just and reasonable to Montana ratepayers as they reflect each utility's avoided energy and capacity costs.

4. The objective of encouraging cogeneration and small power production is promoted by the rates and terms and conditions established by this order.

ORDER

Each utility is to submit their respective tariffs as listed in Schedule A within 5 days; these tariffs will become effective upon approval.

DONE IN OPEN SESSION this 21st day of June, 1982, by a vote of 3 - 0.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION.

JOHN B. DRISCOLL, Commissioner

HOWARD L. ELLIS, Commissioner

THOMAS J. SCHNEIDER, Commissioner

ATTEST:

Madeline L. Cottrill
Commission Secretary

(SEAL)

NOTE: You may be entitled to judicial review of the final decision in this matter. If no Motion for Reconsideration is filed, judicial review may be obtained by filing a petition for review within thirty (30) days from the service of this order. If a Motion for Reconsideration is filed, a Commission order is final for purpose of appeal upon the entry of a ruling on that motion, or upon the passage of ten (10) days following the filing of that motion. cf. the Montana Administrative Procedure Act, esp. Sec. 2-4-702, MCA; and Commission Rules of Practice and Procedure, esp. 38.2.4806 ARM.

APPENDIX D

MONTANA GRAIN CROP RESIDUES

MONTANA GRAIN CROP RESIDUES

CROP	UNIT WEIGHT (lb/bu)	STRAW/GRAIN WEIGHT RATIO	STRAW WEIGHT (lb/bu of grain)	AVAILABILITY
Winter Wheat	60	1.3	78	95%
Spring Wheat	48	1.3	71.2	95%
Barley	58	1.1	52.8	95%
Oats	34	1.6	54.4	95%

APPENDIX E

BTU CONTENT OF NATURAL GAS

IN MONTANA

****
* NATURAL GAS CONVERSION FACTORS FOR MONTANA SITES. BTU/MCF *
****

*SITE	*CONV BTU/MCF	*PRESS PSIA		*SITE	*CONV BTU/MCF	*PRESS PSIA
ABSOROKEE.......	908238	12.70	>>**<<	HINGHAM.........	941903	13.18
ALHAMBRA........	900523	12.59	>>**<<	HUNGRY HORSE....	939799	13.15
AMSTERDAM.......	892809	12.48	>>**<<	INVERNESS.......	932785	13.05
ANACONDA........	870366	12.16	>>**<<	JEFFERSON CITY..	890705	12.45
AUGUSTA.........	906836	12.68	>>**<<	JOPLIN..........	932785	13.05
BELGRADE........	893510	12.49	>>**<<	JUDITH GAP......	889302	12.43
BIG SANDY.......	953124	13.34	>>**<<	KALISPELL.......	944708	13.22
BIG TIMBER......	904030	12.64	>>**<<	KREMLIN.........	948916	13.28
BILLINGS........	925070	12.94	>>**<<	LEWISTOWN.......	911745	12.75
BOULDER.........	878081	12.27	>>**<<	LIVINGSTON......	884393	12.36
BOZEMAN.........	885795	12.38	>>**<<	LOGAN...........	904732	12.65
BROWNING........	893510	12.49	>>**<<	LOMA............	958034	13.41
BUTTE...........	857040	11.97	>>**<<	MANHATTAN.......	900523	12.59
CHESTER.........	938396	13.13	>>**<<	MARTIN CITY.....	939799	13.15
CHINOOK.........	963644	13.49	>>**<<	MAXVILLE........	880886	12.31
CHOTEAU.........	915252	12.80	>>**<<	MILES CITY......	956631	13.39
CLANCY..........	901926	12.61	>>**<<	MILLTOWN........	933487	13.06
CLINTON.........	927876	12.98	>>**<<	MISSOULA........	929980	13.01
COLUMBIA FALLS..	942604	13.19	>>**<<	MOUNT ELLIS.....	878081	12.27
COLUMBUS........	922966	12.91	>>**<<	NISSLER.........	864755	12.08
CONRAD..........	925772	12.95	>>**<<	OPPORTUNITY.....	876678	12.25
CORAM...........	937695	13.12	>>**<<	PHILIPSBURG.....	866859	12.11
CORVALLIS.......	926473	12.96	>>**<<	PINE GROVE......	933487	13.06
CUT BANK........	913148	12.77	>>**<<	RAMSAY..........	865456	12.09
DEER LODGE......	890705	12.45	>>**<<	RED LODGE.......	860547	12.02
DILLON..........	873171	12.20	>>**<<	ROBERTS.........	889302	12.43
DRUMMOND........	911044	12.74	>>**<<	ROCKER..........	864054	12.07
EAST GLACIER....	882990	12.34	>>**<<	RUDYARD.........	939097	13.14
EAST HELENA.....	913148	12.77	>>**<<	SHAWMUT.........	913849	12.78
ELLISTON........	875275	12.23	>>**<<	SHERIDAN........	874574	12.22
FAIRFIELD.......	909641	12.72	>>**<<	SIMMS...........	924369	12.93
FORT BELKNAP....	964346	13.50	>>**<<	SILVER BOW......	865456	12.09
FORT BENTON.....	955930	13.38	>>**<<	SILVER STAR.....	892107	12.47
FORT SHAW.......	925772	12.95	>>**<<	STEVENSVILLE....	930681	13.02
GALEN...........	884393	12.36	>>**<<	SUN RIVER.......	929279	13.00
GARRISON........	898419	12.56	>>**<<	THREE FORKS.....	906836	12.68
GILDFORD........	948916	13.28	>>**<<	TWIN BRIDGES....	888601	12.42
GLASGOW.........	967852	13.55	>>**<<	VALIER..........	915953	12.81
GREAT FALLS.....	922265	12.90	>>**<<	VAUGHN..........	930681	13.02
GREYCLIFF.......	911044	12.74	>>**<<	VICTOR..........	930681	13.02
HALL............	902628	12.62	>>**<<	WARM SPRINGS....	881587	12.32
HAMILTON........	923668	12.92	>>**<<	WEST GLACIER....	935591	13.09
HARLEM..........	965047	13.51	>>**<<	WHITEFISH.......	941903	13.18
HARLOWTON.......	903329	12.63	>>**<<	WHITEHALL.......	897017	12.54
HAVRE...........	960839	13.45	>>**<<	WOLF CREEK......	922265	12.90
HELENA..........	912446	12.76	>>**<<			

*SOURCE: MEMORANDUM FROM MONTANA POWER, JANUARY, 1981:
HEAT CONTENT OF GAS GIVEN BY THE FORMULA:
HV, BTU/MCF=1045*(PRESS+.25)*1000/14.9

APPENDIX F

WORKSHOP PRESENTATIONS

WOOD FOR FIBER PRODUCTS AND FUEL
A DIMINISHING SUPPLY?

By:

Charles E. Keegan
and
Mary L. Lenihan

The wood products industry is the backbone of western Montana's economy. It provides jobs for thousands of Montanans. It is the only sizable basic industry in some counties west of the Divide. And despite the industry's depressed condition during the recent recession, it will continue to provide a very large part of western Montana's economic base.

Over the past few years, both the industry and the general public have increased their use of wood fiber. This increased use has greatly increased the demand for dead and waste timber.

Until very recently the forest products industry's needs have been supplied almost entirely by harvesting sawtimber, timber suitable for high value products such as lumber and plywood. Residue from their manufacture (mill residue) was used for wood fiber products and fuel. In the immediate future the industry will use increasingly substantial volumes of lower quality dead and waste timber -- usually referred to as forest residue -- for wood fiber products such as pulp and paper, and for industrial fuel.

At the same time, the general public is using more dead and waste timber as a source of fuelwood. Energy costs have escalated rapidly in recent years. Many people are returning to wood for home heating, a fuel source that had been more or less abandoned by the early 1960s.

These shifts are leading to a potential conflict among users of dead and waste timber from Montana's forests. Ten years ago there was virtually no competition between home fuelwood and industrial users. Now Montana residents and industrial firms that rely on wood for heat, steam generation, and the manufacture of wood fiber products may find their supply dwindling and prices increasing.

The Bureau of Business and Economic Research at the University of Montana recently assessed both the industrial and home firewood user demand for wood fiber in Montana. Measured against the available supply of dead and waste wood, it is clear that there may be a shortage that could affect both types of users.

Industrial Demand for Wood Fiber

The wood products industry in western Montana changed considerably over the past ten years. New fiberboard and particleboard plants were built, and a pulp and paper mill greatly expanded its production capacity. In addition, increasing energy costs forced most major primary wood products manufacturers to shift to wood fiber as a fuel source. All these developments greatly increased industrial demand for wood fiber.

Until now, the preferred and virtually the only source of wood fiber for these users has been residue from lumber and plywood production. This manufacturing or mill residue will continue to provide the major source for industrial wood fiber users, both for fiber products and fuel. However, very recent increases have caused the projected demand for mill residue to exceed the anticipated supply substantially.

This mill residue shortfall, if it is to be satisfied, will have to come from increased harvesting of forest residue. Conflict may occur as both industrial and home users attempt to harvest the most readily accessible components.

To assess the potential shortage, we have projected industrial demand for wood fiber and considered the probable demand for home use. First we examined the estimated wood fiber demand for uses other than plywood and lumber production. Then we looked at the portion that will have to come from forest residue.[1]

We used three major sources. One is an industry-wide census sponsored jointly by the Bureau of Business and Economic Research and the Forest Service. That survey asked each forest products manufacturer to note its annual use of wood fiber residue from sawmills and plywood plants. Another source is the cooperative research work in forest residue utilization conducted jointly by the Bureau and the Forest Service.[2] Discussions with industry and Forest Service personnel comprise the third source.

These projections cover the years 1983 through 1990. All wood fiber volumes have been translated into cords. A cord is a stack of logs 4 feet by 4 feet by 8 feet, which is equivalent to approximately 2,150 pounds of wood fiber (oven dry weight).

Using these sources, we estimate that the annual industrial wood fiber needs for the manufacture of pulp, paper, particleboard, fiberboard, and industrial fuel in Montana will be just under 2.4 million cords for the remainder of the 1980s. Based on projected lumber and plywood production levels, approximately 2.1 million cords will be available in the form of mill residue.[3] This means that 300 thousand cords will have to be supplied by other sources.

Home Fuelwood Demand

Projecting demand for home fuelwood is more difficult because of the very large numbers of small users. The U.S. Department of Energy estimated that in 1981 Montanans used 380 thousand cords of home fuelwood. These estimates are similar to some the Bureau made earlier, based on user surveys and data from the 1980 Census of Population. We feel they are reasonably good estimates.[4]

Among those people we contacted there were mixed opinions concerning future home fuelwood use. We feel such use is peaking now due to the increasing competition for wood fiber. We will use the 1981 figure of 380 thousand cords as the annual demand for the years 1983 through 1990. Adding this to the 300 thousand cords for industrial use that will not be supplied by mill residue, we have a total annual demand for 680 thousand cords of dead and waste timber.

To provide some perspective, let us compare this projected demand to Montana's commercial sawtimber harvest for the ten-year period 1972-1981. The harvest in Montana for that period was just under 1.1 billion board feet per year, or approximately 2.9 million cords. To meet the projected industrial and home fuelwood demand for dead and waste timber it will be necessary to harvest an additional volume equal to 20 to 25 percent of the last ten years' annual sawtimber harvest. This is a considerable volume.

Supply

Is there wood available to meet this need? The demand for all or some of the 680 thousand cords will be supplied by forest residue. This includes any wood fiber material in commercial forests that is not of high enough quality to be sawtimber. It also includes small trees that will not be of sawtimber quality when mature.

Forest residue can be broken down into the following components, based on availability and removal costs:

- Logging residue--dead wood or low quality green wood left over after logging operations

- Small, live trees in overstocked stands
- Untreated slash from previous logging operations
- Dead or other "cull" (low value) material on sites not scheduled for logging or stand improvement.

If one looks at the total estimated volume of this dead and waste timber in Montana, the potential supply is enormous and greatly exceeds the demand for nonsawtimber wood fiber. But when we begin to examine such factors as accessibility and cost, a seemingly infinite supply becomes much more limited. In fact, given conventional harvesting methods, there may not be enough wood fiber available to meet the demand in fairly large areas of the state.

Dead and waste timber material from current logging sites--logging residue--is the first choice of industrial users and one of the top choices of home firewood users. Let's examine the supply available from that component and see if this supply is sufficient to meet statewide demand.

The Bureau of Business and Economic Research has made some rather detailed estimates of the volume of logging residue that might be available annually, at various costs, through conventional sawtimber harvesting techniques. Based on projected harvest levels, we estimated that nearly 840 thousand cords of logging residue, sound enough and large enough to be handled by conventional techniques, should be available annually in Montana.[5]

Some of this would be too expensive to recover, but it appears that the statewide supply might be sufficient to meet statewide demand. There is one catch: unfortunately, the demand is not distributed geographically in the same fashion as supply.

Industrial demand for nonsawtimber wood fiber is centered in west central Montana. In fact, we estimate that approximately half the expected demand for forest residue in the state is in Missoula County and its surrounding area (Figure 1). We estimate this demand to be 340 thousand cords annually, compared with the total statewide annual demand of 680 thousand cords. Of the 340 thousand cords, approximately two-thirds will be needed by industrial users, with one-third by home fuelwood users.[6]

Missoula area users, both industrial and home, will require a larger share of the total wood fiber supply than users in most other timber-producing parts of the state. As a result, there is greater potential for conflict between users in western Montana. To satisfy their demand, Missoula area users will be forced to incur higher removal and delivery costs since they'll have to use those components of the forest residue resource that are more difficult to obtain.

Our estimates indicate that approximately 170 thousand cords of logging residue will be available annually, at a reasonable price, within a 100-mile haul distance of the major processors in Missoula County. In this case, we used $65 per cord as a cutoff price, a relatively high price considering the uses.

Expanding the haul distance might raise the total available to almost 240 thousand cords. This is barely what industrial users expect to need, assuming they could get it all (which is unlikely). This leaves a shortfall of 100 to 120 thousand cords. Evidently, then, in west central Montana the future demand for nonsawtimber wood fiber for industrial and home fuelwood use may exceed the readily accessible supply by a large amount.

In some other parts of the state the situation is similar, though on a smaller scale. For example, a number of forests located east of the Continental Divide have estimated firewood cuts well in excess of the commercial timber harvest. This may cause supply problems in the near future.

One way to solve this shortfall problem is to begin utilizing components of forest residue other than those currently available in the course of conventional logging operations. This would entail using harvesting techniques that, while not new to the forest industry, have not been commonly used in the northern Rocky Mountain area.

In Montana, the tendency lately has been to use more small stems from overstocked or improperly stocked stands. Champion International is already utilizing relatively large volumes of small timber from thinning and stand conversion operations to meet industrial fuelwood needs at its pulp and paper mill.

Implications for Users and Land Managers

If it is not economically feasible to harvest small stems and other previously unutilized components of forest residue for fiber products and fuelwood, there may be some problems. The supply/demand relationship will mean conflicting demand for a limited supply of wood fiber.

Home fuelwood users. First of all, what might happen on the home fuelwood side? No matter what is done to develop new harvesting technology, we expect that there will be a great deal more commercialization of home fuelwood harvesting.

Most of the firewood currently used is gathered with free use permits. Were landowners and managers operating strictly to maximize dollar returns, they would attempt to recoup as much of their lands fuelwood value as they could. And we think this will happen, to a degree. However, the general feeling is that public relations and political factors will slow the rate of fuelwood commercialization on both public and industrial private lands. Free use or low-cost permit use, such as the recently announced $10 fee in certain sections of Northern Region National Forests, will probably continue for some time.

Physical constraints may also lead to increased commercialization of home fuelwood. The supply of timber physically available to the home firewooder with only a chainsaw and pickup will become greatly reduced in some areas. As the firewooder finds that wood is becoming more difficult to gather, he will become more willing to pay for it. Whatever the reason, more and more commercialization is coming and home fuelwood is going to become more expensive, especially in heavy use areas.

Industrial users. We expect that within the industry wood fiber costs will increase both for use as fiber and fuel. This will happen because more expensive components of roundwood, such as small steams, will have to be utilized and because increased competition for mill residue will cause prices to increase. A benefit, though, is that sawmills will receive more revenue for their wood fiber residue.

The present structure and normal operating levels of Montana's forest products industry will probably be maintained if successful techniques are developed to harvest additional wood fiber economically. If little or only limited success is achieved, we foresee various competition for nonsawtimber roundwood.

This competition could lead to a shortage of raw materials and resuting reduced operating levels in the pulp, paper, fiberboard, and particleboard sectors. In addition, the sawmills and houselog sectors of the industry might suffer as the pulp and paper industry and home fuelwood users compete for the lower quality sawtimber supply.

It is possible that we could see plant closures if new wood supplies are not developed. There are fiber product plants in the state with relatively low value use for wood fiber. These plants probably cannot afford to use any roundwood at all and may not be able to compete as mill residue prices increase. It's possible, then, that one or more of these plants could close as their current wood fiber contracts expire.

An additional ramification of the supply/demand relationship concerns energy use. If the price of dead and waste timber increases, industrial users may find other fuels becoming more competitive, despite recent price increases.

Land managers. Both public and private land managers should benefit from the upcoming demand for nonsawtimber roundwood. In Montana we have never had a consistent pulpwood market, let alone a home or industrial fuelwood market. Pulpwood has been harvested only in recession years. Commercial fuelwood harvesting has been low volume and sporadic. Now, in much of the state's timber-producing region, we will have a substantial and consistent market for dead timber and small stems. This should allow many stand treatments that were not economically feasible in the past.

Despite some of these rather negative concerns, we are optimistic about the potential for more fully utilizing our forest residue resource. The wood fiber is there. The land management agencies, the forest products industry, and universities in this region have all given the problem high priority. We do want to point out, though, that in many parts of Montana increased utilization of forest residue is no longer just a matter of a wood fiber resource that is unutilized. Rather it is a matter of an increasing demand of wood fiber that will require new harvesting techniques to satisfy.

FOOTNOTES

[1]Industrial demand is based on projected plant capacity. Price was not considered in this analysis.

[2]Both of these projects were completed under the sponsorship of the Forest Service Intermountain Forest and Range Experiment Station in Ogden, Utah. The cooperative research work on forest residue utilization was handled through the Intermountain Station's Forestry Sciences Lab in Missoula. The cooperative research on mill residue was handled through the Forest Survey Unit of the Intermountain Station.

[3]The demand and supply figures are based on estimates presented in Charles E. Keegan III and Randle V. White, "Forest and Mill Residue in Montana and the Potential for Major Manufacturing Plants," Montana Business Quarterly 17 (Winter 1979): 10-18. These estimates have been updated based on a 1981 census of the industry and discussions with industry personnel.

[4]U.S. Department of Energy, "Estimates of Wood Consumption from 1949 to 1981," (Washington, D.C.), August 1980. Throughout this report, home fuelwood demand is an estimate of expected consumption.

[5]Charles E. Keegan III, The Cost and Availability of Forest Residue in the Northern Rocky Mountains (Missoula, Montana: University of Montana, Bureau of Business and Economic Research, 1981).

[6]The localized industrial demand was estimated from the Bureau's Montana Forest Industries Data Collection System (unpublished data, 1982). Localized home fuelwood demand is based on 1980 U.S. Census of Population data and user survey data obtained from the Montana Power Company.

COST OF COLLECTING AND TRANSPORTING WOOD RESIDUES

By John A. Combes

A. Introduction: Wood residue consists of that portion of the woody biomass which will not be manufactured into a primary forest product such as lumber, plywood, poles, piling, or similar products. This does not mean that residues are not used in the marketplace. Paper products are a prime example of a product manufactured from residues. Firewood, roundwood for wafer and flakeboard manufacture, planer shavings for animal bedding, and barkdust for flower gardens are other examples of uses for wood residues.

Wood residues are broken down into three categories:

1. Residues (mill residues) from the manufacture of primary products.

2. Logging residues consisting primarily of tops, limbs and unmerchantable logs or pieces from trees harvested for primary forest products.

3. Forest residues consisting of pole size timber which need to be removed to improve the growth of residual crop trees. In addition, both live and dead unmerchantable trees, and downed material are included.

The discussion in this paper will deal with the collecting and transportation costs of logging and forest residues. The major obstacle to the use of logging and forest residues for energy purposes is its availability and cost of gathering and transportation.

B. Availability: Logging and forest residues as a potential resource for use in the generation of steam and electrical energy from the forests of Montana is first discussed:

1. Logging residues: An average of 1,150 million board feet of timber is harvested annually of which half is logged from National Forest lands. The total volume of logging residue generated from the harvest of timber is nearly 700,000 cunits of material annually.

   One cunit equals 100 cubic feet of solid wood. For the species of Montana, 1 cunit equals approximately 2,400 pounds of wood on a bone dry basis or 1.2 bone dry tones (bdt).

   The availability of logging residues is dependent upon several factors including the demand for primary forest products which dictates how much timber is harvested and residues generated annually. Other factors include the accessibility of residues to the log landing or road. Gathering residues with ground lead or skyline cable machines on steep terrain results in the logging residue becoming more economically inaccessible than when it is found on favorable terrain where skidders and log fowarders can readily operate. Other factors which affect the availability of logging residues are whether the tops and branches, while still attached to the merchantable log, are skidded to the log landing such as commonly done when harvesting is done with mechanical faller-bunchers and grapple skidders. Another important factor is the distance the logging area is from the area of potential use of the residues.

There is a tendency for residues in the form of roundwood to find its way into the pulp and paper market when the demand for lumber and plywood products is depressed. For example, during the years 1980 - 1982, many cull logs were harvested, hauled and chipped for pulp manufacture. However, the demand for such material in 1983 is nearly nonexistent since the market for primary wood products has markedly improved, resulting in a greater production of mill residues for use in the pulp and paper industry.

This brings us to the point of competition for wood residues. The demand for firewood, small timber and logs for tree stakes, posts, rails, corral poles, hog fuel for pulp mills, and pulpwood places residues from both logging and forest thinning operations on a competitive basis.

In conclusion from an economical standpoint, for use as a commercial fuel, there would be approximately 230,000 oven dry tons of logging residue generated in Montana annually of which 200,000 tons comes from Western Montana.

2. Forest residues: Forest residues are the most expensive and therefore, the least economically available residue for bio-energy or other uses. The major cost of making logging residues available is borne by the value generated by the primary product. However, the costs of making forest residues available is usually borne by the end product value of the residue itself. Sometimes under thinning contracts, part

of the cost in delivering the residue is offset by the funds received for performance of the contract from the contracting agency or company.

The total forest residue available for bio-energy or other products from the commercial forest land of the National Forests in Montana is estimated as follows:

	Million Cubic Feet
Pole timber	1,940
Cull trees	420
Sound dead trees	2,450
Down trees	5,500
Total	10,310

This, on the average, equals a little over 12.5 cunits of forest residues per acre. In areas of insect killed timber and thickets of suppressed lodgepole pine, as an example, the forest residues would be above the average per acre, whereas the residues would most likely be least in stands of sawtimber.

The most significant factor concerning the availability of forest residues is access. Forest residues must be located relatively near, probably no further than 500 feet, to existing roads in order to be economically available. At the present time, only about 45 percent of the commercial forest lands in the National Forests of Montana are accessible. Of the areas that are accessed, most likely less than half of the forest land is economically available for collecting forest residues. Therefore, of the 10,310 million cubic feet of forest residues available on commercial forest lands, approximately 2,500 million cubic feet would be economically available, providing suitable markets exist.

The question arises whether removing logging or forest residues removes the nutrients from the forest floor. The majority of the forest nutrients reside in the needles, twigs, and the smaller portions of the limbs. In general, the residues having commercial applications would be material with a small end diameter of 3 inches and larger.

Another question arising is whether a user of wood residues could contract for logging or forest residues on a long term basis. The answer to this question is generally <u>no</u>. The Forest Service, and most other public land owners do not sell forest products using long term contracts. The prime reasons for this are twofold. First, the competitive nature for forest products preclude the tying up the resource for only one user. Second, the ever changing economic, resource and environmental standards result in contractual stipulations being outdated in relatively short periods of time.

C. Cost of Collecting and Transporting: The major cost factors affecting the removal of residues is the falling and bunching, skidding or yarding and transportation.

1. Falling and bunching: This process would be associated with the gathering of forest residues if such residues have not been readied through a timber stand improvement contract. Mechanical faller-bunchers are the most efficient means for felling and bunching forest residues although the use of power saws with bunching done with winches is also quite efficient. The latter method is adaptable for handling small trees on steep terrain.

2. Skidding and yarding: The cost of skidding or yarding varies in accordance with many factors. Skidding refers to the gathering of woody material and transporting it to the landing or concentration area using rubber tired or tracked skidders. Yarding refers to the gathering of the material using cable systems. The latter is usually done on slopes over 35 percent and swampy terrain.

   Skidding techniques used in harvesting timber for primary forest products varies significantly. In the lodgepole pine and second growth forests, the use of faller-bunchers in conjunction with grapple skidding or forewarders results in most of the logging residues being taken to the landing attached to the sawtimber or trees to be manufactured into primary forest products. Conventional skidding techniques using chokers usually results in most of the residue being left in the woods. New techniques in prebunching trees using small radio controlled winches can materially reduce the cost of gathering or bunching trees for later transportation to the landing by use of grapple skidders on the more gentle terrain or cable yarders on steeper terrain.

Cable yarding, consisting of using ground lead yarders or skyline machines usually results in most residues being left in the woods. Many times, particularly on public lands, the logging contractor may be required to skid or yard the larger pieces of residue to the landing for the reduction of heavy fuels on the forest floor. This substantially reduces the cost of acquiring logging residue from the residue user's standpoint.

In summary, the most economical way to gather forest residues would be by using small faller-bunchers or prebuncher winches in conjunction with grapple skidders and forewarders. On steeper terrain, the use of prebuncher winches to bunch material into skyline corridors would be the most cost effective way.

3. Handling and chipping: The transportation of residues from the landing or concentration yard would be most efficiently done by chipping and blowing the residues into chip vans. The handling part of the operation primarily consists of feeding the residues into the mobile chipper. Large material consisting of dead and cull logs would normally be hauled on log trucks and processed through "in plant" chipping plants.

4. Transportation: Wood residues are bulky and from the fuel standpoint have low BTU values per unit of weight as compared to other conventional fuels. In addition, the residues normally average 50 percent moisture content. Therefore, a great deal of water is needlessly transported. The transportation cost per BTU for logging or forest residues varies with the moisture content, amount of compaction in the van, density of

the wood (varies by species), and inorganic contaminants mixed in with the residue. This would be in addition to the variation of cost due to haul distances and types and grades of roads on which the residues are hauled. A constraint to hauling residues from many points in the forest relates to the ability of chip vans to negotiate the forest roads. Many of the access roads to landings and potential sites for concentrating forest residues are not designed to handle commercial chip vans.

As a rule of thumb, 75 miles should be considered as the maximum haul for logging and forest residues. Economically, the average haul should be no more than 40-50 miles.

Costs can vary quite dramatically as demonstrated from the above discussion. To give some idea of the cost of delivering wood residues to a point of use for energy purposes, the following scenario is developed using costs on a 1981 dollar basis:

Dollars per Oven Dry Ton

	Forest Residues		Logging Residues	
	Skidding	Yarding	Skidding	Yarding
Felling and Bunching	$32.00	$35.00	-	-
Skidding or yarding	17.00	28.00	$10.00 1/	$16.00 1/
Handling and chipping	20.00	20.00	16.00 2/	16.00 2/
Transportation (50 miles)	13.00	13.00	15.00	15.00
	$82.00	$92.00	$41.00	$47.00

1/ Assumes that a certain amount of the material to be skidded or yarded to the landing is attached to saw logs or peeler logs.

2/ Assumes larger pieces of cull or dead material is hauled intact to the delivery point for chipping with an "in plant" chipper.

The cost per BTU can readily be figured using 8,500 BTU's per oven dry pound or 17 million BTU's per oven dry ton. If costs are developed on a green weight basis, the energy derived is approximately 6,400 BTU's per pound.

The Wood Residue Utilization Act of 1980 (Public Law 96-554) was enacted to help offset the cost of delivering logging residues to a point of use for energy purposes. This is accomplished by giving the purchaser of National Forest timber a credit against stumpage payments for gathering and transporting the residues. The credits to the purchaser cannot exceed the value received for the residues plus the value of the slash reduction benefits to the Forest Service. Unfortunately, no monies have been appropriated through fiscal year 1983 to implement the provisions of this act.

D. Conclusion: The cost of collecting and transporting logging residues is dependent upon its availability, characteristics of the area from which it is harvested, and the characteristics of the residues itself. The cost of delivering residues is higher than the delivery of conventional fuels in Montana and most other western States. Mill residues, although not discussed in this paper, are the least costly to deliver although they may be the least available of the residues because of competing uses and market fluctuation of the primary products. If mill residues are available, a mix of mill residues with logging and forest residues can significantly lower the delivery cost of the fuel. The major advantage of wood residues for energy purposes over conventional fuels is that it is renewable.

APPENDIX G

BIBLIOGRAPHY OF COGENERATION LITERATURE

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AGENDA

BIOMASS COGENERATION WORKSHOP

Holiday Inn

Missoula, Montana

May 17-18, 1983

May 17, 1983

8:00 - 9:00 **Registration**

9:00 - 9:15 **Welcome and Introduction**
Howard Haines, Montana Department of Natural Resources and Conservation

9:15 - 9:45 **Cogeneration: Old Game, New Rules**
Dilip Limaye, President, Synergic Resources Corporation

9:45 - 10:15 **Cogeneration: A National Perspective**
Tyson Greer, Chairperson, Northwest Chapter, International Cogeneration Society

10:15 - 10:30 Coffee Break

10:30 - 11:00 **Cogeneration in Montana: Status and Prospects**
Dilip Limaye, Synergic Resources Corporation

11:00 - 12:00 **A Technical Overview of Cogeneration**
Shahzad Qasim, Senior Analyst, Technology Division, Synergic Resources Corporation

- -

12:00 - 1:30 LUNCH

Speaker: Gerald Mueller, Member, Northwest Power Planning Council
Role of Cogeneration in the Regional Power Plan

- -

1:30 - 2:00 **Cogeneration: Economic and Financial Issues**
Dilip Limaye, Synergic Resources Corporation

2:00 - 2:30 **Utility Perspectives**
Peter Antonioli, Director, Conservation and Renewable Resources, Montana Power Company

2:30 - 3:00 **Industry Perspectives**
Emmett Lisle, St. Regis Paper

3:00 - 3:15 Coffee Break

3:15 - 3:45 **Regulatory Perspectives**
John Driscoll, Commissioner, Montana Public Service Commission

3:45 - 5:00 **Panel Discussion/Q&A Session**
(Dilip R. Limaye, MPC, St. Regis, MPSC)

AGENDA

BIOMASS COGENERATION WORKSHOP

Holiday Inn

Missoula, Montana

May 17-18, 1983

May 18, 1983

8:00 - 8:20 **BPA Biomass Cogeneration Program**
Douglas Seely, Bonneville Power Administration

8:20 - 8:45 **Wood Resources in Montana**
Chuck Keegan, Bureau of Business and Economic Research, University of Montana

8:45 - 9:30 **Collection and Transportation Costs**
John Combes, U.S. Forest Service

9:30 - 10:00 **Biomass Cogeneration Case Study**
Stanley Richardson, Flodin Lumber Company

10:00 - 10:15 Coffee Break

10:15 - 11:00 **Discussion of Energy Conversion Systems**
Shahzad Qasim, Synergic Resources Corporation

11:00 - 11:30 **Feasibility Analysis: Step by Step Approach**
Shahzad Qasim, Synergic Resources Corporation

11:30 - 12:00 **Panel Discussion/Q&A Session**

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