TVA/OP/ECR-82/34

Tennessee
Valley
Authority

Biogas Electric Power Cogeneration

25 kW or Greater

TVA/OP/ECR--82/34

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Tennessee Valley Authority Solar Applications Branch

By Energy Research & Applications, Inc.

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25 KW OR GREATER

TENNESSEE VALLEY AUTHORITY

Solar Applications Branch

June 1, 1981

Prepared by Energy Research & Applications, Inc.

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CHAPTER 1

INTRODUCTION

Biogas cogeneration contributes to solving two present-day problems--environmental pollution and dwindling domestic sources of conventional energy. It is a rare technology which assists in both of these areas at the same time and offers attractive investment economics as well. Any operation which generates sufficient organic wastes and has power and heat requirements is a prime candidate for biogas cogeneration. Municipal wastewater treatment plants have been doing it for years and, recently, due to rising energy costs and increased pressure to reduce water pollution from livestock wastes, biogas cogeneration has become feasible at dairies, feedlots, and swine and poultry farms.

Biogas is a valuable fuel by-product of bacterial stabilization of organic wastes. Cogeneration is the simultaneous production of useful power (electrical or mechanical) and useable heat. A biogas cogeneration system basically consists of: 1) an <u>anaerobic digester</u> which produces gas, 2) a <u>prime mover</u> which burns the gas and makes power, and 3) <u>recovery devices</u> which capture engine waste heat. The purpose of this manual is to guide the interested owner-operator through the exercise of determining whether biogas cogeneration is worthwhile. This book is not intended to serve as a design, construction, or operating manual, though it covers these functions to give a general idea of what is involved in building and running a biogas cogeneration system. The manual contains theoretical and practical background on biogas cogeneration. The final chapter offers directions for collecting site data and a method for performing a preliminary economic analysis for a given operation.

CHAPTER 2

MEETING ENERGY NEEDS THROUGH BIOGAS COGENERATION

Cogeneration is an old practice whose time has come again. Production of more than one form of useful energy by a single process can be done with a wide variety of fuels including "medium-Btu" biogas produced in digestion of organic wastes. Cogeneration has been getting quite a lot of attention lately, as has biogas production at farms and wastewater treatment plants. This manual presents a marriage of these two concepts. Firms specializing in the design of biogas cogeneration systems are listed in Appendix 1.

Cogeneration occurs in "topping" and "bottoming" cycles as shown in Figure 1. The "topping" cogeneration concept is to burn fuel in an engine to produce shaft horsepower for any desired electromechanical workload, then recover engine waste heat to do further work. The most versatile application of the rotating shaft is to drive a generator for electricity production, but direct shaft drive of other machinery might be preferable in certain situations. "Bottoming" cogeneration involves producing heat directly from fuel, as in an industrial furnace, for example, then capturing very high temperature process exhaust to generate electricity, usually with a waste heat boiler and steam turbine. Biogas applications discussed in this manual are all topping cycles. Cogeneration is most attractive at sites with concurrent and continuous demands for electricity and heat.

Table 1 is a quick introduction to the numbers behind the concept of biogas cogeneration. The entries in the left-hand column indicate the size of facility which can generate about 25 kilowatts of electricity. This electricity and the recoverable engine waste heat can provide for process energy demands and digester heating at the five types of waste-producing operations covered in this manual: wastewater treatment plants, dairies, cattle feedlots, and swine and poultry farms. At all these sites, the demand for energy grows as operations expand, but generally waste materials which can be converted to gas and useful forms of energy are increasing at the same time. Numbers in Table 1 can be scaled up directly for larger operations. Combining biogas cogeneration with other practical forms of energy conservation will substantially reduce energy costs at wastewater treatment plants and farms.

A biogas cogeneration system is actually the middle step in what must be a 3-phase operation. First, wastes must be collected and loaded into a digester before they will produce biogas. Then, while the gas fires a cogeneration system, the digested wastes must be disposed of in a reasonable manner. Digested sewage sludge or farm manure can, however, have considerable economic value, so that solving the "disposal" problem may actually make the economics of

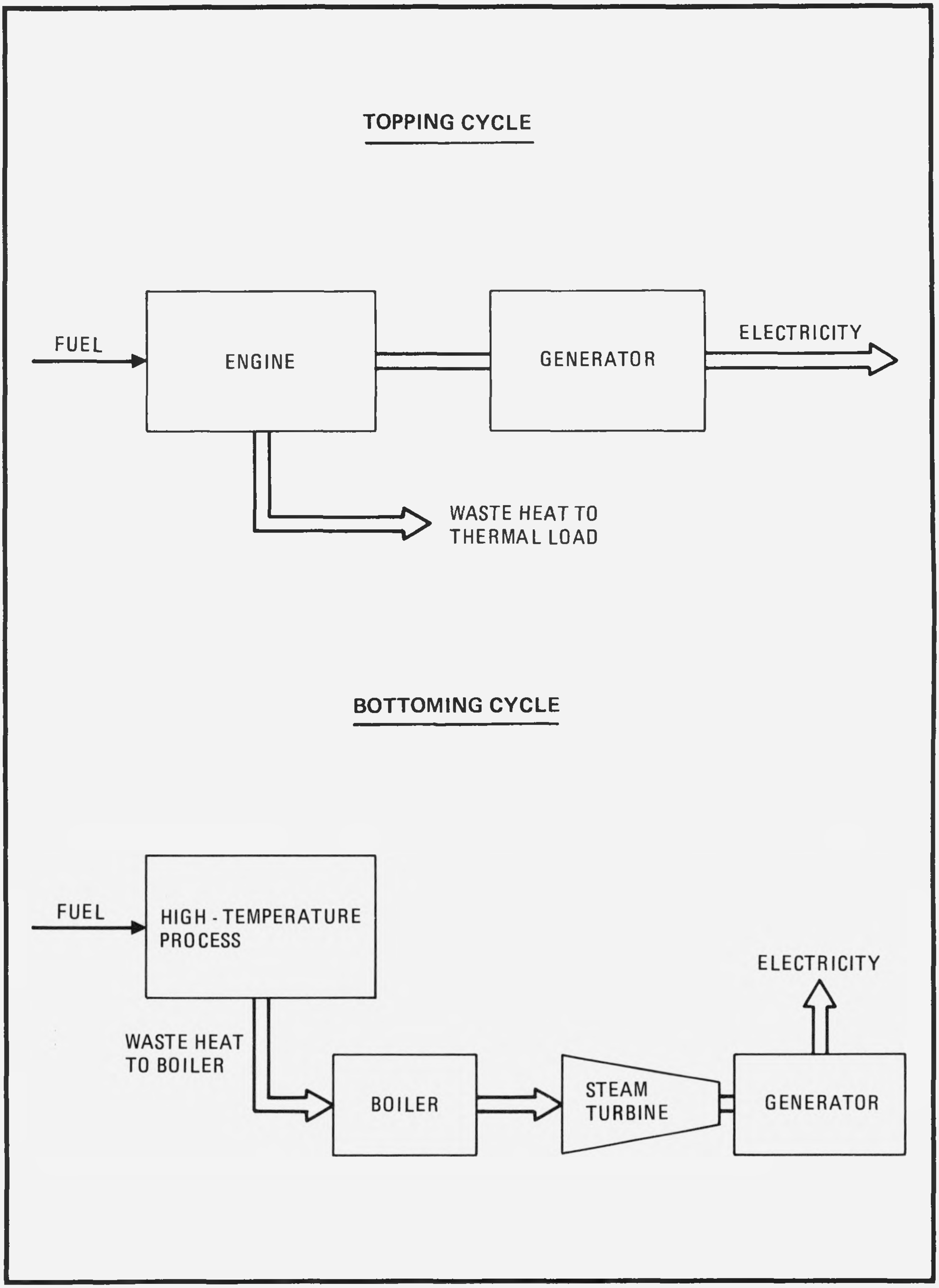

Figure 1. Topping and Bottoming Cogeneration Cycles

Table 1

Sample Biogas Cogeneration Energy Production Figures (Near 25KW Size)

Facility	Total fresh wt. (lb)	Wastes/Day vol. (ft^3)	Daily Gas Production (ft^3) a)	Available Heat b) (Btu/day)	Available Heat b) (Btu/hr)	KW from Engine-Generator c)	Recoverable Heat (Btu/hr) d)
240 Cow Dairy	24,000 @10% solids	385	13,500	8.1×10^6	337,500	25	168,800
360 Steer Feedlot	24,000 @10% solids	385	13,500	8.1×10^6	337,500	25	168,800
1500 Hogs	15,000 @17% solids	240	14,300	8.6×10^6	360,000	26	180,000
30,000 Layer Hens	10,000 @25% solids	160	14,000	8.4×10^6	350,000	26	175,000
1.25mgd e) Sewage Plant	48,000 @5% Solids	770	13,500	8.1×10^6	337,500	25	168,800

a) Calculated assuming 80% volatile solids and 7ft^3 of gas generated per pound of volatile solids destroyed: ft^3 gas = (lb fresh wt.)x(% solids)x(% volatile solids)x(7 ft^3/lb VS).
b) 600 Btu/ft^3 biogas.
c) 25% engine-generator efficiency (13,656 Btu/hr/KW).
d) 50% of total input heat.
e) Primary and conventional activated sludge treatment.

biogas cogeneration more attractive. Digesting wastes, generating electricity and heat, and putting digested solids to good use also contribute to reducing water pollution as well as meeting site energy needs.

Table 2 lists examples of collection and disposal systems at existing farm biogas installations. The simplicity of most methods of collection is notable as is the variety of uses for the digested manure. Wastewater treatment plants are fed by sewers which do the "collecting." Traditionally, the ultimate fate of sewage sludge has been incineration, landfilling, and lagooning, but digested sludge from municipal plants has utility as a soil conditioning product, especially after composting. The value of digested sludge products varies with the local (or on-farm) demand and the cost of the product it replaces. If a dairy farmer currently purchases sawdust for bedding material, a free digested manure substitute would be attractive. On the other hand, if the in-laws own a lumber yard and bring a truckload of sawdust every Sunday when they come to dinner, then digested sludge has little value as a bedding material for that site.

SAMPLE BIOGAS COGENERATION SYSTEMS

Figure 2 through 6 illustrate hypothetical biogas cogeneration systems at the five types of sites discussed in the manual. The examples are typical, but by no means restrictive, of operations at each site.

Wastewater Treatment Plants

Figure 2 depicts very simply the kind of system becoming more and more common throughout the country. A biogas cogeneration installation can assist in cutting wastewater energy costs which are rising not only because of inflation but also because new advanced treatment processes mandated by law are energy-intensive. A well-designed cogeneration system might provide 30-50% of a plant's total energy needs. If engine exhaust heat is recovered as well as the energy in engine cooling water, the cogeneration system should be able to heat the digester year-around. Biogas storage in a conventional spherical pressure vessel helps to even out supplies. Where space permits, cogenerated shaft power can directly displace electrical demand by driving plant blowers or pumps or other equipment. The example plant in Chapter 6 drives compressors with its biogas engines.

Dairies

Like most dairies, the farm pictured in Figure 3 is equipped to clean out manure from its barns. An existing water-flush system can easily be adapted to send manure slurry to a central holding basin for pumping into the digesters. Spent manure, as shown in Figure 3, has moisture squeezed out and thus becomes a suitable material for

Table 2

Manure Collection and
Disposal Systems in Livestock Operations

Type of Installation	Waste Collection Method	Ultimate Fate of Digested Manure
Feedlot (Imperial Valley, CA)	Collected by front loader from dirt floor, dumped into spreader, fed into mix tank then slurried, pumped into digester.	Dewatered in centrifuge then used as high-protein feed.
Feedlot (Bartow, FL)	Manure falls through slatted floors into 3' deep "basement," scraped into troughs and pumped into digester.	Stored in ponds on-site and used for land reclamation.
Feedlot (Guymon, OK)	Manure piled for storage, loaded into shredders, passed through shakers, emptied into mix/settling tanks, "defibered," and pumped into digester.	Dewatered. Liquid sprayed on fields, solids refed to cattle.
Swine Farm (Wyoming, MN)	Central sloping gutter in hog building feeds covered steel holding tank. Overflow into storage lagoon. Pumped to digester from tank.	Applied to land.
Dairy (Gettysburg, PA)	Manure on sloped, concrete floors washed into troughs on low end. Piped to settling tank and pumping basin where pumped to digester.	Pressed dry and used as bedding material.
Dairy (Bedford, VA)	Manure on dirt barn floors pushed into holding pit with small front loader. Slurry stirred; then pumped to digester.	Lagooned; then spread on fields.

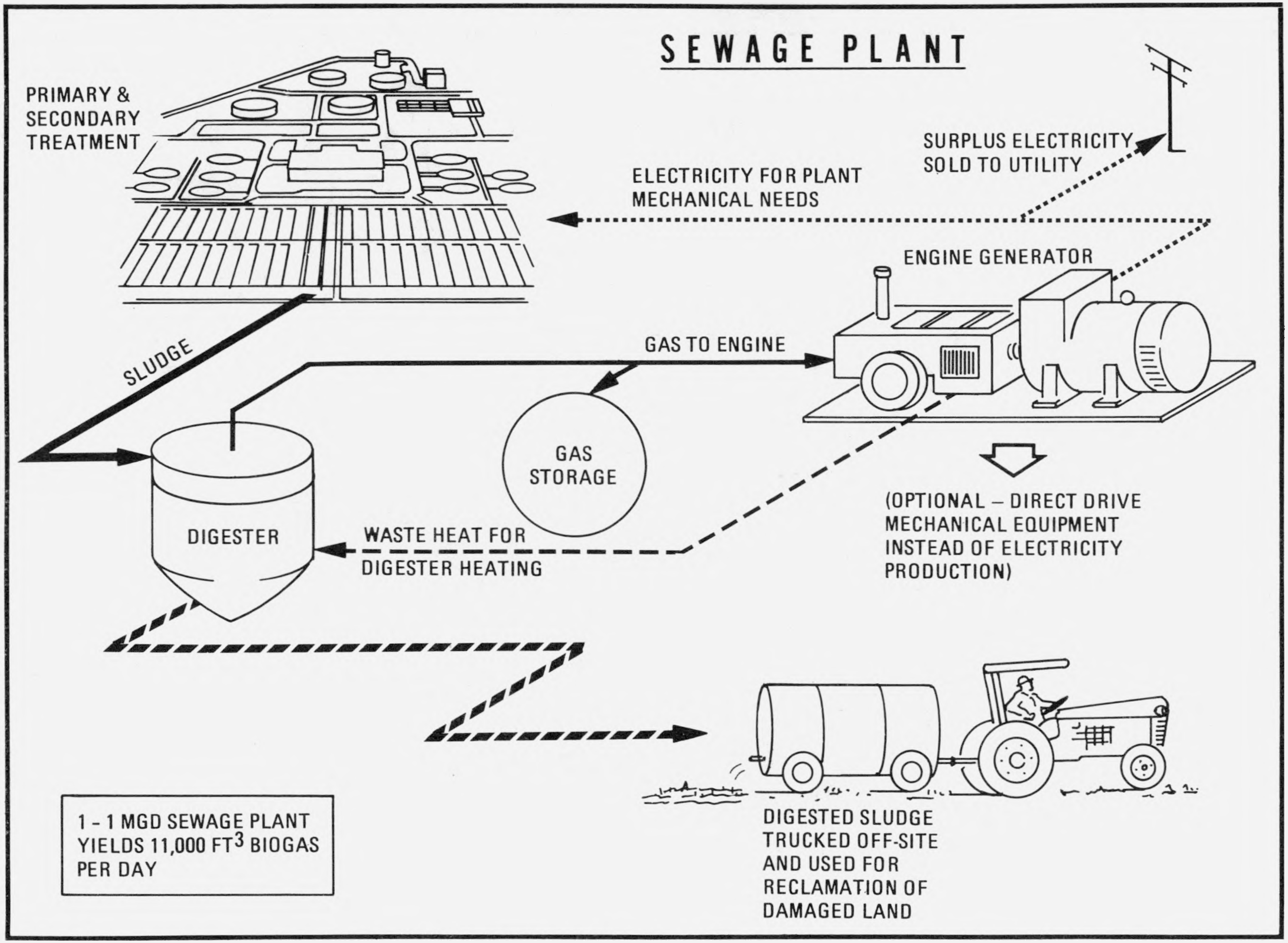

Figure 2. Sewage Plant Biogas Cogeneration System.

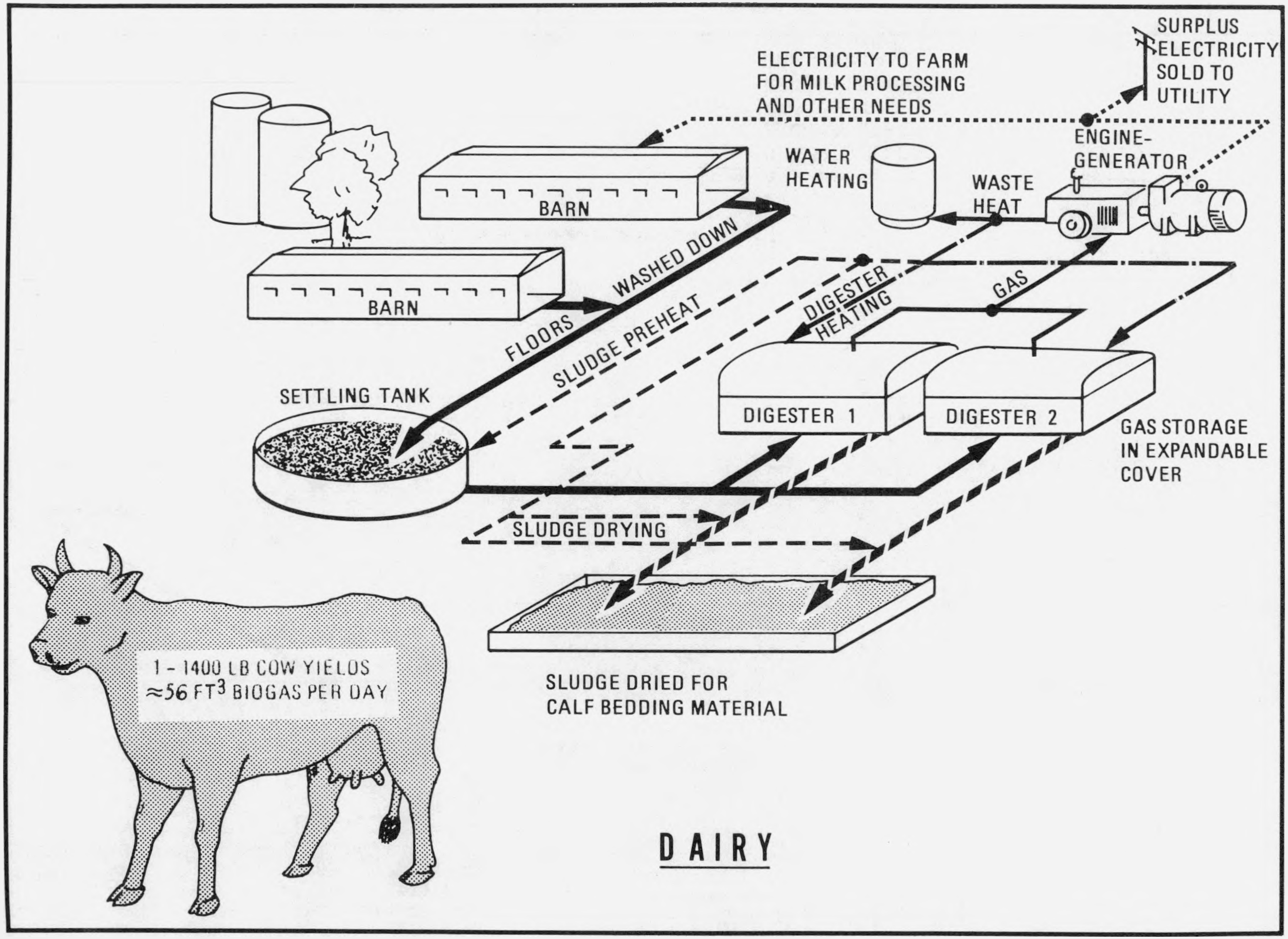

Figure 3. Dairy Biogas Cogeneration System.

bedding in stalls. The separated liquid has plant nutrient value and can be applied to fields. In Figure 3, two smaller digesters rather than a single large unit provide some operational flexibility during maintenance periods or in the event a digester malfunctions.

Cogenerated energy helps meet electricity and heat needs of milk processing. Refrigeration and heating of water for processing equipment washdown demand a considerable fraction of total farm energy. Biogas cogeneration at dairies, as illustrated in Figure 3, can supply almost all the electricity needs of the farm if the system is sized to make maximum use of available wastes. A digester cover such as the one depicted in Figure 3 might store a day's gas production, which allows generation of electricity when needed. Waste heat from a prime mover first supplies sludge heat, then serves other purposes on the farm, depending on the amount available.

Feedlots

As shown in Figure 4, cogeneration using biogas from digestion of feedlot wastes can provide some of the energy for mechanical equipment needed for feeding steers and processing feed plus keep the digester warm. When much of the mechanical equipment at a feedlot is directly driven by engines, more electricity generated on-site with biogas is available to sell. A spherical pressure vessel might be used to store large quantities of gas to generate electricity for resale during the local utility's daily peak hours. Manure might be collected from pens by front end loader, which is common practice at most feedlots. The digested manure is dewatered; then dried and refed to cattle. Several feedlots in the country are experimentally "refeeding": considerable food value is available in the residue due to the inefficiency of steer digestion.

Swine Farms

Space heating demands the most energy in hog operations. Newborn pigs in indoor pens must be kept comfortable to gain weight at sufficient rates. If a swine farm is equipped with electric heating, then cogenerated electricity could displace utility purchases for this purpose. Figure 5 shows engine waste heat not needed for sludge warming applied to space heating, and cogenerated electricity put to other uses on the farm. Conventional propane tanks might be used for biogas storage. Manure is collected underneath a slotted hog building floor and flushed into a settling tank. Digested sludge could be composted at the farm and used to fertilize swine food crops.

Poultry Farms

Figure 6 shows chicken manure being scraped from underneath holding buildings and pushed into a pit where wastes are slurried then pumped to the digester. A digester with a floating cover would be able to store some biogas. Poultry farms have plenty of demand for

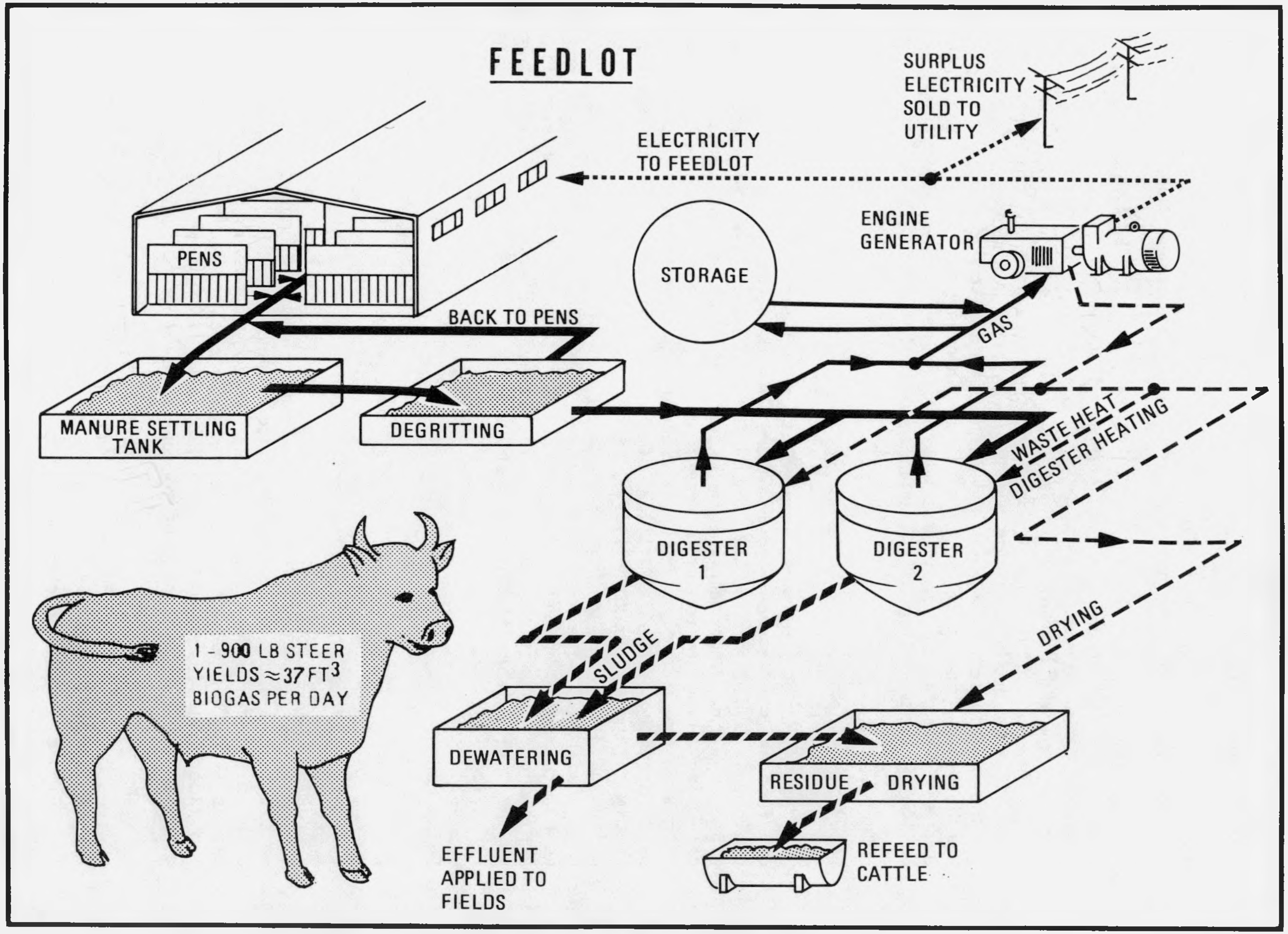

Figure 4. Feedlot Biogas Cogeneration System.

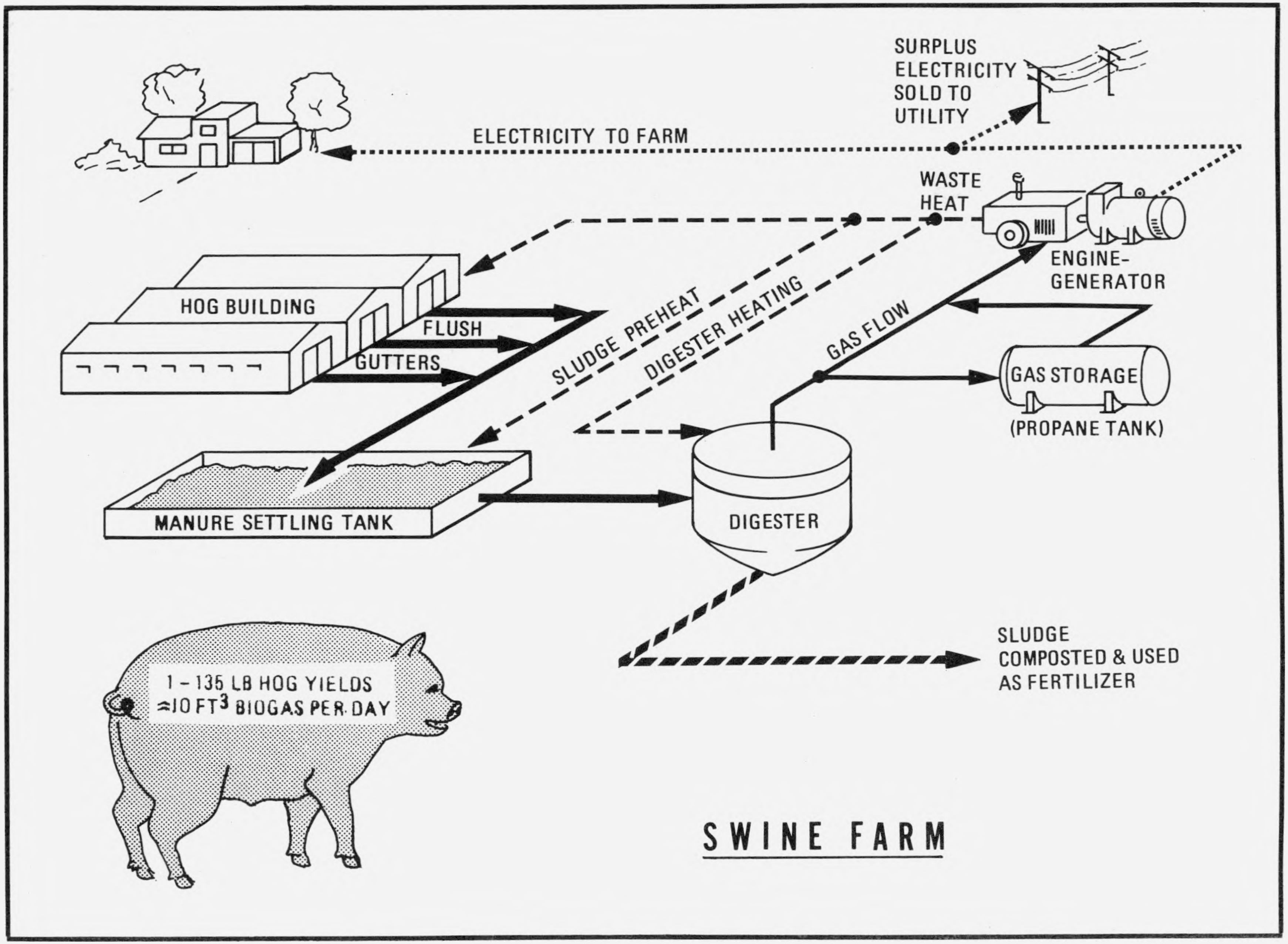

Figure 5. Swine Farm Biogas Cogeneration System.

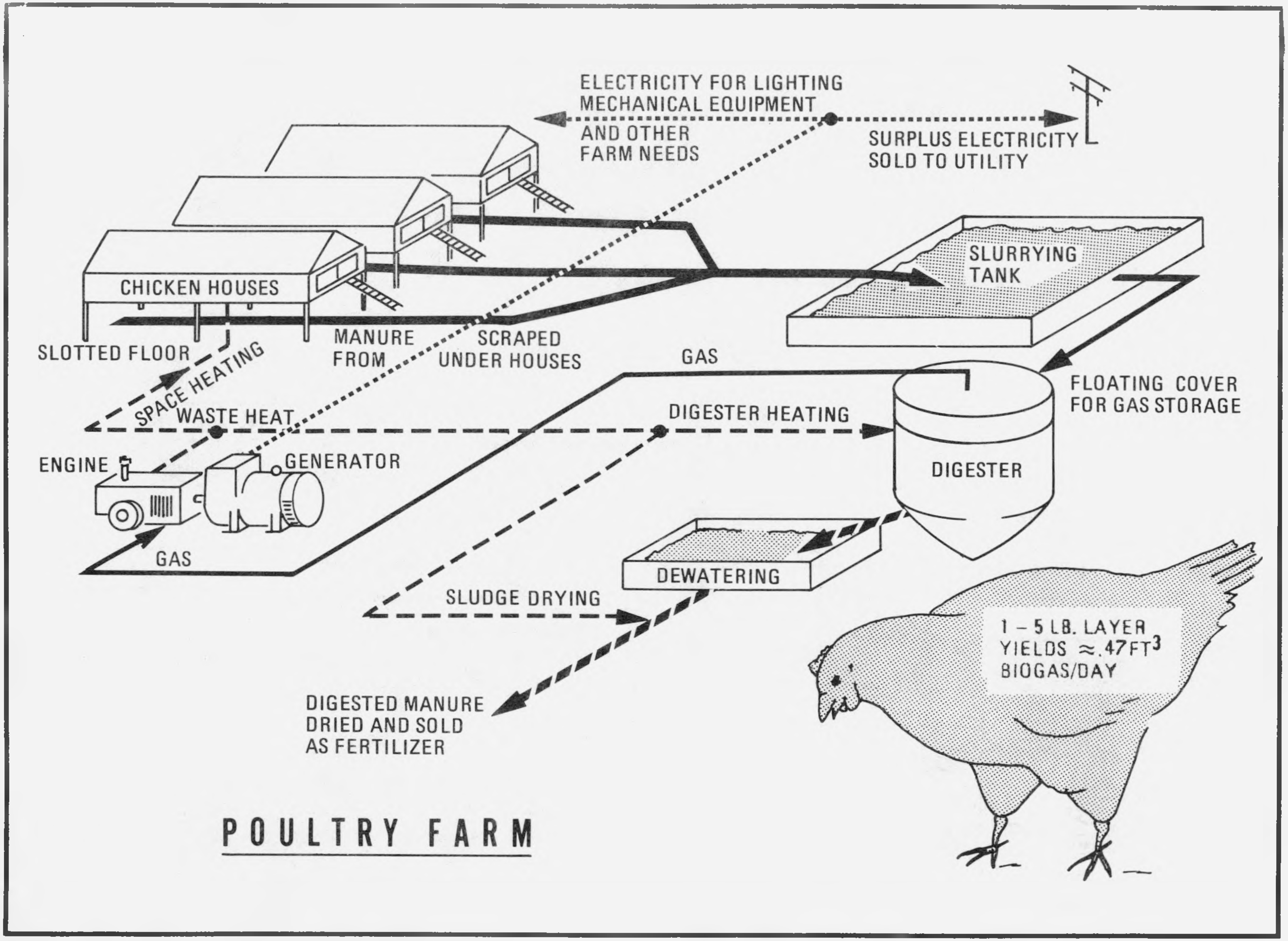

Figure 6. Poultry Farm Biogas Cogeneration System.

cogenerated energy because of their lighting, heating and ventilating requirements. On large egg ranches, egg collection conveyors and mechanical feeders can boost electrical demand noticeably. In Figure 6, the sample poultry operation uses engine waste heat first for digester warming and routes excess to coop heating. Digester residue, which can be up to 30% protein, has been successfully used as a fraction of the chicken feed, which further reduces costs of operation.

UTILITY RELATIONSHIPS

Figures 2 through 6 show biogas cogenerators hooked up to the local utility grid. Even when the cogeneration unit cannot meet the peak power needs of the site, it is likely that there will be times when surplus electricity is available to sell. The relationship required with the local electric utility to accomplish such a sale has two parts: technical and contractual. These requirements are obviously interrelated, since technical conditions must be satisfied before contracts can be signed.

On the technical side, there are specific equipment requirements for physically hooking up to the grid. While it may seem that the only necessity is an electric meter which can run backwards, protective devices to prevent the cogenerator from feeding into the grid when it is down and vice versa are also needed. In the region served by the Tennessee Valley Authority, it is the TVA which sets physical hookup requirements (described in Chapter 5) since it owns and operates the grid. Local electric distributors, however, are the ones with whom contracts for purchase will be made. Rates for buying cogenerated power are set by TVA, from whom the local distributors purchase the power they retail to the consumer.

CHAPTER 3

THE NATURE OF BIOGAS

Biogas is a by-product of anaerobic digestion, the decomposition of organic wastes by bacteria in an oxygen-free environment. The process does not completely stabilize municipal and farm wastes, but it can break down much of the degradable material which is a nuisance or health hazard. Other stabilization methods do not offer the advantage of producing both fuel and a material which can be used as an animal feed, soil conditioner, or livestock bedding.

ANAEROBIC DIGESTION

The production of biogas through anaerobic digestion of wastes is not a perfect process controlled by a strict recipe because wastes of variable character yield gas of variable character in environments of variable character. The high energy component of biogas is methane (CH_4). Natural gas is almost 100% methane, while biogas might vary between 35 and 70%, depending on the feedstock, digester design, and location. This section provides background about anaerobic digestion which is a prerequisite to learning the art of maximizing methane production.

Digestion is basically a three-phase biochemical sequence. The anaerobic bacteria which produce methane will not begin to multiply until all the oxygen present in the sludge is consumed by aerobic bacteria either before or after loading it into the digester. Anaerobic digestion can be partitioned into: 1) hydrolysis and acid formation and, 2) methane formation, with different bacteria accomplishing the last two steps. In a balanced digester, the anaerobic phases occur simultaneously and at the same rate.

In the first anaerobic (oxygen-free) step, bacteria break down complex sludge particles into simpler organic substances which they can metabolize. Simple organic acids formed during this stage serve as substrate for the second group of bacteria, the methane-producers. These bacteria cannot utilize more complex sources of nutrition, and are thus dependent on the acid formers for their food. In simple terms, successful digestion depends on achieving and maintaining a balance between those bacteria which produce organic acids and those which produce methane from the organic acids.

Three major factors contributing to digester balance for maximum methane production are pH, temperature, and composition of wastes. Each factor is discussed below.

1) Acid or Alkaline Condition (pH).

Acid-forming bacteria can tolerate acidic (low pH) conditions while the methane producers cannot. Keeping both types of microbes present in balanced numbers requires a near neutral (pH 6.8-7.2) or slightly alkaline pH. An observable drop in digester pH (in other words: increase in acidity) indicates a digester is in serious trouble.

2) Temperature.

Within the 40-105°F survival limits for mesophilic methane-forming bacteria, gas production is optimized between 86°F and 98°F. Above this range, a group of thermophilic methane-formers functions well between 120 and 140°F. Either set of microbes can do the digesting job, but digesters should be maintained to favor one or the other. Operators have found thermophilic bacteria more finicky about digester conditions than mesophilic bacteria, but higher temperature digestion offers the prospect of shorter term sludge processing in smaller digesters. Short-term drops in digester temperature from optimum reduce gas production rates but usually do not harm the essential bacteria.

3) Composition of Wastes.

Bacterial populations of digesters need carbon, nitrogen, and other nutrients to grow, multiply and thereby produce gas. A shortage of any basic nutrient can inhibit microbial activity. Different digesters have displayed different C:N (carbon:nitrogen) optimum ratios, but most typical feedstocks are of suitable composition.

The amount and spatial distribution of volatile solids (materials which can be decomposed by the bacteria) in the sludge also affects gas production. This volatile fraction is generally reduced by: 1) water and, 2) the presence of inert solids such as soil, clay, calcium carbonate and salts. Not all the stubborn solids are inorganic. Lignin, a structural organic material in wood, is particularly difficult to break down. Skimming, thickening, continuous loading, and mixing enhance digestion by increasing the fraction and uniform distribution of volatile solids.

Substances toxic to bacteria are sometimes present in sludge. Materials such as heavy metals, antibiotics, phenols, pesticides, detergents, sulfur compounds, and disinfectants are common inhibitors of anaerobic digestion. The source of the wastes is often a good predictor of the toxic constituents. Some of these substances can be diluted to non-toxic concentrations, some can be precipitated out of the sludge, and still others must be removed from wastes before they enter digestors.

The pH, temperature, and composition of wastes are primarily responsible for the success or failure of anaerobic digestion. Chapter 4 introduces the art of manipulating these conditions in a digester for maximum gas production.

CHARACTERISTICS OF BIOGAS

The major ingredients of biogas are always methane (CH_4) and carbon dioxide (CO_2), but the proportions of these gases and other minor constituents vary with the composition of the wastes and the particular digester. The heating value of biogas is directly proportional to its methane content. Methane has a fuel value of about 1000 Btu per cubic foot (ft^3), so biogas containing 35-70% methane measures about 350 to 700 Btu per ft^3. A properly working digester should produce biogas with 550-700 Btu/ft^3 heating value.

Table 3 lists the gases which commonly make up biogas and typical proportions of constituents recorded by digester operators. The methane value generally observed in the U.S. is about 60%, and many sources agree that this figure represents a reasonable estimate for planning purposes. While the non-methane components of biogas do little to affect the overall heating value, hydrogen sulfide (H_2S) should be removed because of its corrosiveness. H_2S, CO, O_2, and CH_4 (methane) also can be hazardous in sufficient concentrations, the former two gases because of toxic physiological effects and the latter two because of explosion risk when they are mixed.

In general, it is carbon dioxide which reduces the heating value of biogas. The minimum CO_2 fraction of about 30% occurs as a respiratory product of microorganisms essential for anaerobic digestion. Among controllable factors contributing to increased CO_2, and less methane are:

1) <u>Introduction or diffusion of O_2 into the digester</u>.

The presence of oxygen allows aerobic decomposers, which "exhale" CO_2, to grow in the digester. Removal of O_2 in sludge prior to digester loading and a well-sealed digester minimize this production of CO_2.

2) <u>Digester pH imbalance</u>.

A great deal of CO_2 is generated when digester conditions have shifted significantly to favor either the acid-formers or methane producers at the expense of the other group. Excessively high loading rates are a common cause of digester <u>low</u> pH problems. Maintaining the digester in a state where neither group of bacteria dominates alleviates this problem of unnecessary CO_2 production.

ECONOMIC VALUE OF BIOGAS

Despite the fact that biogas has only about two-thirds as much heating value as natural gas, and may contain one or more contaminants as well, there are several factors that enhance the economic value of biogas as a fuel.

First and foremost is the fact that once the digester is installed, the gas is free, or nearly so. In a wastewater treatment plant, where some method of sludge stabilization must be used in any case, the capital and operating costs of the digester can be wholly

Table 3

Composition of Biogas

	Gas	Percent
CH_4	Methane	55-70%
CO_2	Carbon Dioxide	30-45%
N_2	Nitrogen	Trace*
H_2	Hydrogen	0.1-2%
CO	Carbon Monoxide	0.1%
O_2	Oxygen	Trace*
H_2S	Hydrogen Sulfide	Trace-0.3%
H_2O	Water Vapor	

*The presence of significant quantities of these gases indicates air leaks into the digester.

NOTE: H_2S becomes toxic at concentrations in air of around 0.04%. CO is a threat at 0.05%.

charged to sludge processing, with only engine-related costs attributable to biogas utilization. For animal-based biogas plants, the entire digestion facility cost will probably be assigned to biogas production, since anaerobic digestion of manures would not be practiced for any other reason. There are no on-going payments to any foreign or domestic suppliers for the gas itself though, making biogas an energy source resistant to cost increases.

A second quality that often makes biogas cogeneration economically attractive is that generally this energy source "fits" on-site energy use in a number of ways:

1) The quantities of power and heat produced will often be of the same order of magnitude as required at the site.

2) The installation can usually be made reasonably compact, with gas production near areas of energy use. This feature will be especially significant at remote sites with high fuel delivery costs.

3) The technology used in biogas cogeneration is largely within the experience of a seasoned farm owner or sewage plant operator.

4) Allowing for short-term lags, the timing of gas production will coincide with fluctuations in energy demand. For instance, if sludge availability drops off (perhaps as a result of selling some livestock), both sludge pumping and sludge heating requirements will decline immediately, followed a short time later by reduced gas production and hence less energy availability.

A third factor which enhances the economics of biogas cogeneration is the tax picture. In addition to the standard investment tax credit and depreciation and interest writeoffs, biogas cogeneration systems may qualify for either an energy tax credit (if owned by a business) or alternative energy credit (if owned by an individual). Public entities, such as municipal wastewater treatment plants, do not benefit from these tax incentives.

Finally, within the reliability limits of the equipment and the diligence of the maintenance person, biogas production is under the sole control of the owner-operator. Fuel scarcity arising from national or international events is not a problem.

CHAPTER 4

DIGESTERS

This chapter discusses basic features of anaerobic digesters. The purpose is to introduce readers to a technology that may be unfamiliar and demonstrate that, though digesters are not without complexities, they are no more intimidating to understand, select, and maintain than any other farm equipment. There is much current experimentation and debate over how to optimize digestion. Therefore, the equipment available to accomplish anaerobic digestion ranges widely in size, design and operation. Certain functions are generally needed, in any case, to transform the raw feedstock (sewage sludge or manure) into a digested product.

The basic functions are:

1) Feeding material to the digester.

Pumping a slurry from another container into the digestion chamber, either continuously or intermittently, is universally needed. Sewage plants generally do not have the option to store wastes for very long so sludge is piped continuously. Farms might pump wastes into the digester once a day. Intake position may vary with the digester's design, but most often raw influent is introduced at the bottom of the digestion chamber.

2) Heating raw material and maintaining temperature.

The influent sludge or manure may be heated to digestion temperatures before or after entering the digester. Heat can be applied by pumping the slurry through a heat exchanger, pumping hot water through or around the digester, or by injecting steam directly into the digesting mass or gas space. Once the necessary temperature has been reached, additional heating can be minimized by insulating the digester. Digesters maintained for thermophilic bacteria must be kept at higher temperatures than those for mesophilic bacteria.

3) Holding material during digestion process.

The digestion vessel must be sufficiently large to accommodate the raw material during its active digestion period (15 days for high-rate digestion; up to 50 days for slow digestion systems). A too-small digester will result in incomplete digestion due to a too short residence time, and more acute operating problems.

4) Keeping oxygen out of digester.

Since the anaerobic digestion process will fail in the presence of oxygen, the digester must be of air-tight construction. Air exclusion is also an important safety consideration, since oxygen and methane can be an explosive combination.

5) Mixing digester contents.

Although mixing may not be necessary in slow digestion of sewage sludge or manure it is important in high-rate digestion to thoroughly mix the heterogeneous mass. Mixing may be done by mechanical stirring, by injection and bubbling of gas, by pumping of the liquid or, less actively, by thermally induced convection currents.

6) Accumulating and releasing biogas.

The digester vessel must be capable of storing a small, but variable amount of biogas above its fluid contents. Such flexibility can be achieved by either a floating cover or an inflatable cover for gas collection. Outlet valves and piping must be provided at the top of the digester chamber. A relief valve and foam arrestors must also be provided.

7) Discharging digested material.

Removal of processed sludge/manure after digestion may be accomplished in the same ways as the feedstock is admitted to the digester, and on a continuous or batch basis. An overflow device is required for fluid level control. In addition, means must be provided to completely empty the digester for infrequent cleaning and maintenance.

8) Sampling material in the digester.

It is desirable to have some access to the digester for sludge sampling purposes to monitor the progress of decomposition or diagnose ailments.

SUCCESSFUL DIGESTER DESIGNS

Several types of digesters perform all of the above functions satisfactorily, but most are variations of the two principal designs described here. Firms listed in Appendix 2 are experienced in the design of these types of digesters. One widely operated anaerobic digester is the complete-mix high-rate tank commonly used in municipal wastewater plants.

A complete-mix high-rate digester is, by definition, a design which incorporates stirring or agitation of the contents to achieve good mixing and which also has a means of heating to ensure that digestion takes place at a stable optimum temperature. These digesters were first developed for the wastewater disposal field, but there are now many alternative types available, and it is generally recognized that, for maximum efficiency coupled with short retention periods, the high-rate concept is probably essential. A typical high-rate digester with mixing by gas circulation and sludge heating by external heat exchanger is illustrated in Figure 7. These digesters are essentially round concrete tanks with dome roofs of concrete or steel.

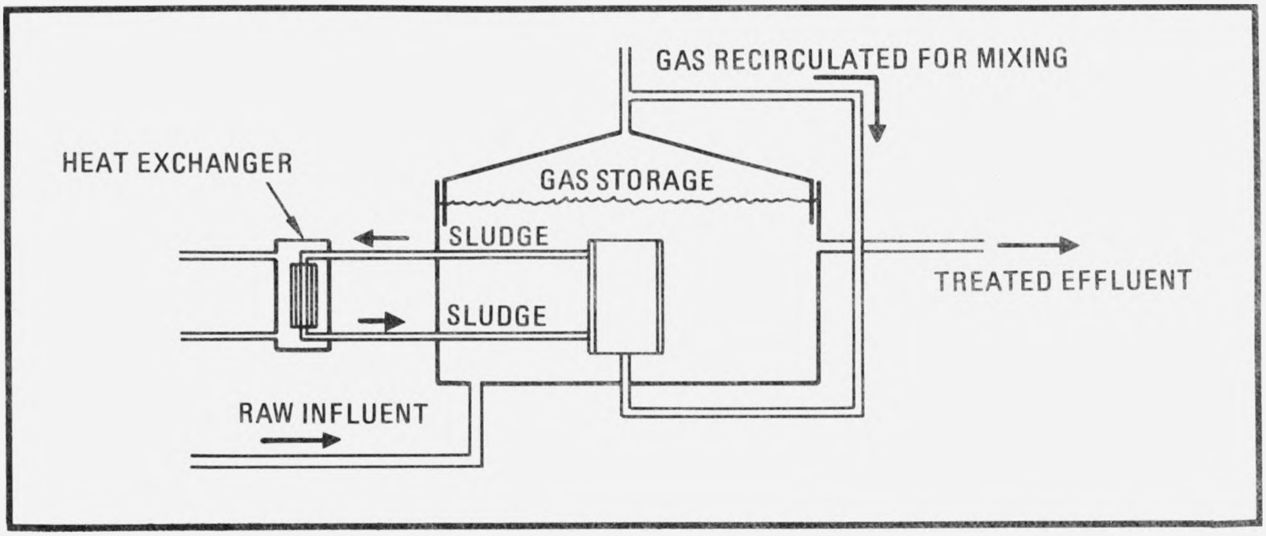

Figure 7. Traditional Complete-Mix Digester.

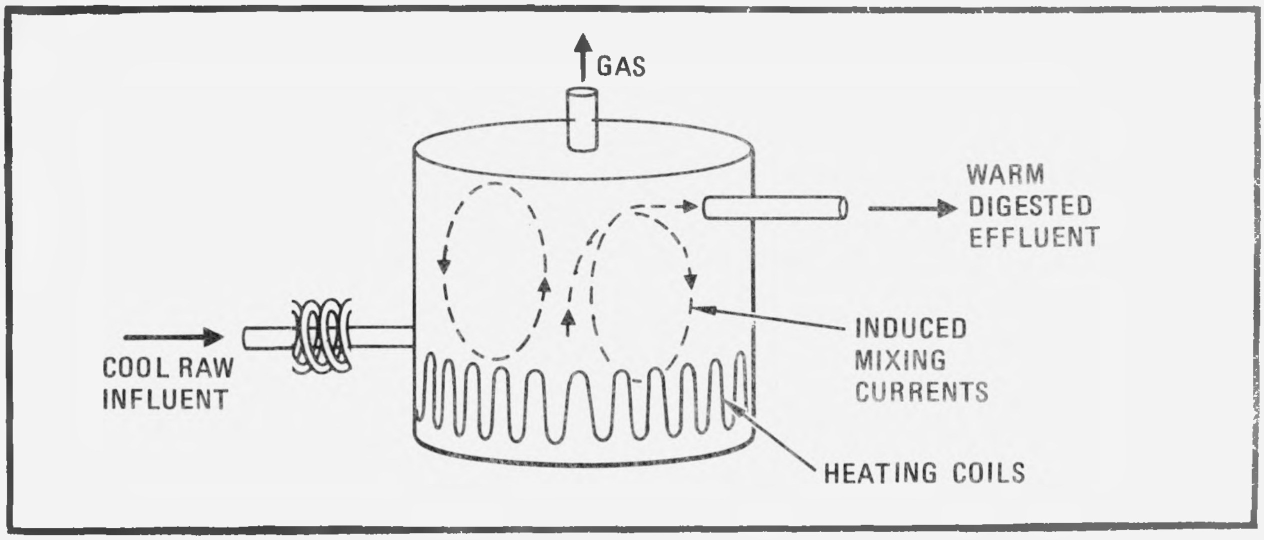

Figure 8. Simple Complete-Mix Digester.

When the material being digested is fairly homogeneous (as may be the case in farm settings), vigorous mixing may not be required for thorough digestion. By locating the intake and outlet ports strategically, and applying heat at the bottom of the digester, sufficient thermal currents may be induced to effectively mix the digester's contents. A flow schematic of an effectively mixed but not agitated digester appears in Figure 8. An actual operating unit appears in Figure 9. This digester is basically a steel tank covered with urethane foam insulation on the outside and epoxy on the inside. Even though the apparatus in Figure 8 is much simpler than that in Figure 7, the essential digestion reaction taking place inside is the same.

The second arrangement which has been used successfully to digest uniform sludges in farm settings is plug-flow or canal digester. Although not a pure plug-flow in the hydraulic sense (totally without longitudinal mixing), manure is fed into a long trough at one end and removed from the other, undergoing very little mixing in between. A schematic of a digestion trough appears in Figure 10. This type of digester might typically be built as a long, concrete-lined excavated trough with an impermeable "balloon" cover, (See Figure 15, Chapter 6). Under the cover, a layer of material such as styrofoam can serve to insulate the sludge and inhibit the formation of scum on its surface. Other construction possibilities include horizontal metal tanks or plastic-lined canals. In the canal-type digester, the sludge must be warmed before entering the chamber in order to prevent thermal stratification with the cold sludge flowing undigested along the bottom of the tank.

A decision between these two leading digester types should be based on several factors, which are summarized in Table 4. There is divided opinion as to which of these two digester types is better able to withstand operating upsets from overloading, excess acidity, and toxic exposure. It is highly desirable to operate any digester carefully to avoid such stresses.

A trait which both types of gas-recovering anaerobic digesters share is explosiveness, which is especially acute during periodic cleaning of the tank. Methane gas may remain in the digester even after extended airing of the tank, posing a real risk of spontaneous or spark-induced explosions. Every precaution should be taken to ensure that the tank is totally evacuated of gas before cleaning. The tank should always be treated as a fire hazard, and workers should avoid smoking and open flames when they are close to the tank.

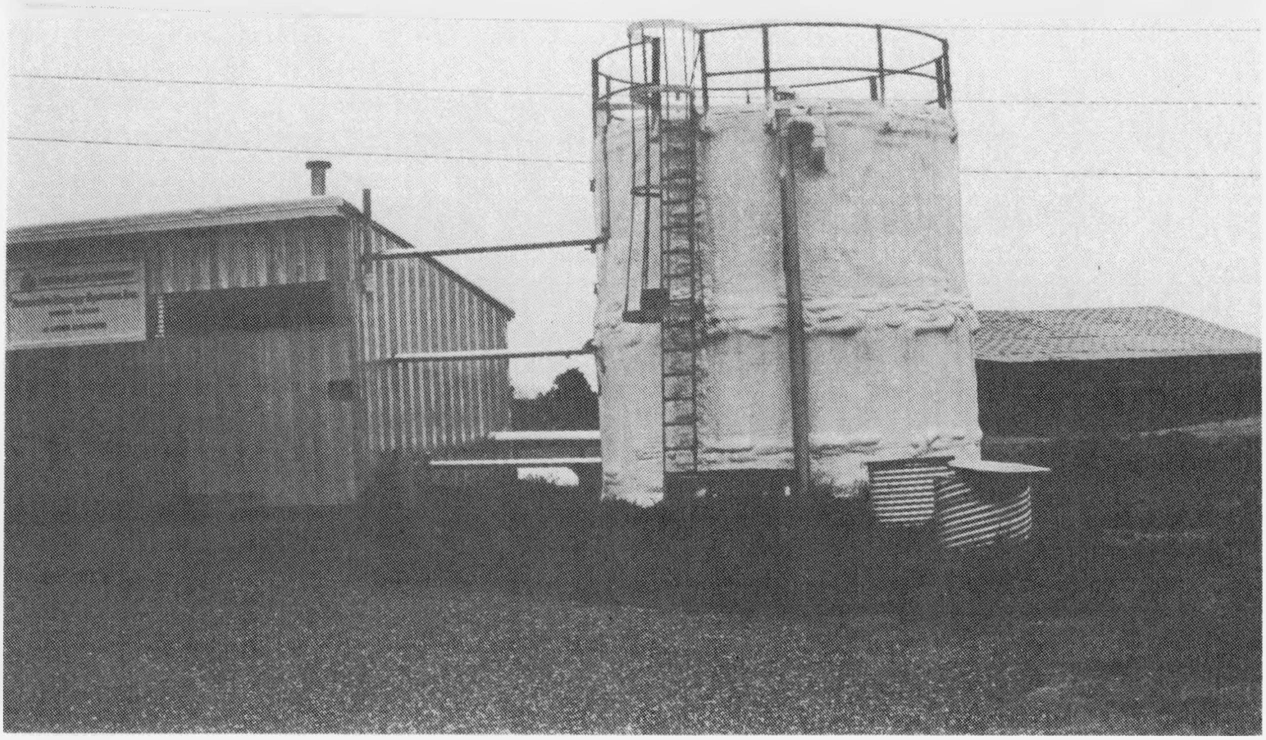

Figure 9. 21,000 Gallon Simple Complete-Mix Digester in Bedford, Virginia. Bumps showing through the bottom half of the tank are pipes carrying warm water to heat the digester. Adjacent building houses cogeneration equipment.

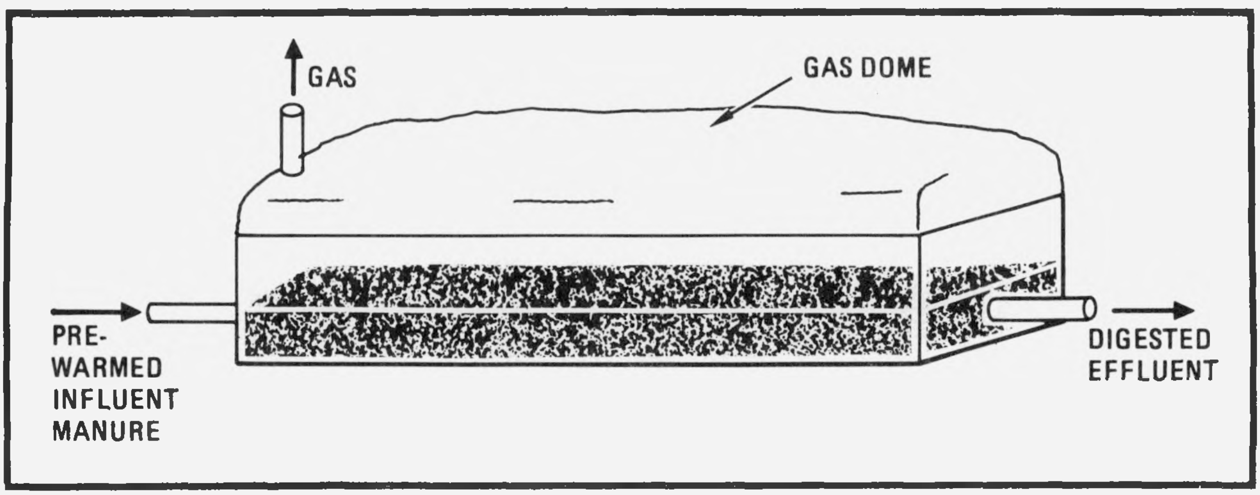

Figure 10. Plug-Flow Digester.

Table 4

Comparison of Complete-Mix and Plug-Flow Digesters

	Advantages	Disadvantages
Complete-Mix Digester	Little land required.	High capital cost.
	Maximum gas production.	Energy required for mixing.
	Short retention time (15-20 days).	Difficult to clean.
	Slow solids buildup (5 yr cleanout interval).	
Canal Plug-Flow Digester	Lower capital cost.	Large land requirements.
	No mixing required.	Less gas production.
	Cleanable with bulldozer or other means.	Long retention time.
		Rapid solids buildup (2 yr cleanout interval).

DIGESTER HEATING REQUIREMENTS AND METHODS

As mentioned in Chapter 3, temperature is a key controller of methane production in anaerobic digestion. Digester heating needs will be an important design parameter of a biogas cogeneration system. Digester heat requirements can be broken into two components:

1) Heat required to raise the temperature of the incoming raw sludge flow to digester operating temperature.

2) Heat required to maintain the digester operating temperature (make up for heat losses).

The temperature of the incoming sludge is rarely at the operating temperature of the digester and, therefore, heat must be added before digestion can proceed. Calculations of heat demand can be found in Chapter 7. Necessary heat is a function of incoming sludge temperature, sludge volume, and digestion temperature.

Since digester temperature must be maintained around 95°F for mesophilic bacteria and little can be done to control the incoming sludge temperature, the volume of influent becomes the crucial factor in reducing the sludge heat requirements. Reduction in sludge volume by increasing solids concentration directly reduces the amount of heat required to raise the incoming sludge to the digester operating temperature. The simplest method of increasing the solids is to let the wastes settle prior to digester loading, as was depicted in Figures 3, 4, and 5. Sludge is removed from the bottom of the settling tank for loading into the digester and excess water is drained from the top.

Indirectly, a reduction in sludge volume reduces radiant heat loss which occurs through the digester vessel, since the digester's surface area can be reduced. There is an upper limit to solids concentration of about 8-10%, however, in order to maintain a pumpable sludge. Six percent solids concentration should be the minimum concentration sent to the digester if recovered engine heat is to satisfy the total demand. See Chapter 7.

Heat losses occur through the digester's walls, floor and cover and are a function of digestion temperature, ambient temperature, surface area and insulating value of the container's sides. Again, since the temperature is less susceptible to change or control, the minimization of heat needs can only be accomplished by reducing surface area and providing some insulation for the vessel. Heat loss calculations appear in Chapter 7.

The foregoing discussion applies to either mesophilic (86-98°F) or thermophilic (120-140°F) digester operation, but clearly the higher thermophilic temperatures will demand more heat input both to attain digestion conditions and to overcome heat losses. In addition to heating requirements which favor the use of mesophilic digestion, other factors argue against the thermophilic condition. Although the higher temperatures yield slightly more gas in a shorter time, which reduces necessary digester size, the number of successful thermophilic digesters in operation is small compared to mesophilic. Thermophilic bacteria are more sensitive to change in digester conditions, thus thermophilic digesters demand more frequent attention and precise control. For these reasons, mesophilic digestion is recommended for cogeneration with biogas and its selection will be assumed through the remainder of this book.

Techniques for applying heat to the digesting sludge mass include the following:

1) Steam injection is convenient when high pressure steam is available nearby. Otherwise the expense and safety requirements for steam use make it infeasible for digester heating. The steam is piped into the bottom of the digester and diffused, both heating and mixing the sludge. In a complete mix digester, the steam may be injected into the gas space overlying the sludge to contact the agitated fluid at its surface. Although heat transfer is less efficient with this arrangement, high steam pressures are not required.

2) Circulating sludge through an outside heat exchanger is a widely used technique for warming anaerobically digested sludge. (See Figure 6.) This method is only suitable for very low solids content wastes, and its big disadvantage is that the heat exchangers quickly become fouled and regular maintenance is essential. The external heat exchanger has to be relatively small, and in order to transfer the quantity of heat needed, the surface temperatures are relatively high. This results in a fast build-up of crusted sludge and other material which effectively reduces the rate of heat transfer. If this method is to be used, careful attention must be paid to the design of the heat exchangers that are to be used, and provision for regular maintenance must be made.

3) Heating coils inside the digester circulate warm water in tubes usually situated on the walls of the digester (or around the draft tube if one is used in the mixing method chosen). With wall-mounted heating coils, the surface area is large, and the surface temperature can be much lower, thus reducing the fouling of the heat transfer surface. The disadvantage of this system is that when defouling of the heating coils is eventually required, the digester has to be emptied. Heating coils mounted on the outside of a metal tank digester can be effective if covered with sufficient insulation. (See Figures 7 and 8.)

The use of hot water for sludge heating, whether in an external heat exchanger or heating coils, lends itself readily to the engine heat recovery techniques described in Chapter 5.

DIGESTER OPERATION

While this book is not intended to be an operation manual, it is only fair to introduce some digester operating intricacies to anyone considering biogas cogeneration. An effective anaerobic digester is not a device which will run automatically without attention, but neither does it require full-time attendance. In general, wastes should be loaded frequently--not less than daily for most installations--in order to avoid losing solids volatility to oxidation and aerobic bacteria. Wastes fed to the digester should be measured, or at least approximated, by a count of contributing animals, pump timing, or direct weighing. Similarly, gas production should be continuously metered and recorded daily, as any fall off of gas production will usually be the first signal of digester upset. (See Table 5.)

The material to be fed to the digester should be inspected before entering the process. Slugs of unusual constituents, such as grain or fertilizer, for example, are to be avoided (whether or not they are suitable food for the anaerobes). A good rule of thumb is not to feed more than 10% by weight of any out-of-the-ordinary material to the tank. Obviously, toxic substances such as chlorinated hydrocarbons, pesticides, strong acids and bases, and heavy metals should never enter the digester--after all, it is a living process. In addition, straw and other floatable material should be avoided because they tend to form an undesirable scum layer on the surface of digesting fluid. Excess water will also slow digestion by diluting the active sludge mass, and will waste energy by increasing heating requirements.

The digester itself should be checked several times a week for acidity. Simple color-indicator test papers are available for this purpose. Also, the color and odor of the digesting or digested sludge should be monitored every day. Sludge color should be black--a grey color indicates acid build-up and insufficient digestion. The odor of a healthy digester is described as dry and pungent; that of a "sour" digester as nauseating, acidic and fatty. An experienced nose will detect the change immediately. Table 5 presents a few common digester ailments and corrective measures. The vast majority of digester failures are due to excess acidity, caused by overloading.

A small, bench-scale digester is very helpful in testing sludge, evaluating methane production, and identifying toxic materials. Such a device needn't be costly or elaborate to provide valuable operating information. The digester design firms listed in Appendix 2 generally have laboratory facilities which aid in solving more perplexing digester problems.

Aside from on-going operation and maintenance, a few comments should be made about start-up and shut-down of the digester. In order to begin digestion in a period of weeks rather than over the course of many months, a starter "seed" of previously digested sludge should be fed into the digester and then raw sludge added to it

Table 5

Common Digester Ailments

Problem	Symptom	Recommended Response
Shock overload (too many volatile solids)	1) Increased gas (CO_2) production (abrupt and significant) followed by a decrease. 2) pH reduction. 3) Excessive foam generation.	1) Reduce feeding. 2) Add soda ash (quantity based on bench test of fresh samples).
Toxic failure - mild	1) Decline in total gas production and methane fraction. 2) pH reduction. 3) Excessive foam generation.	1) Stop feeding. 2) Neutralize acidity with soda ash. 3) Reinnoculate with digested sludge.
Toxic failure - severe (critical poison and high dosage)	1) Cessation of gas production.	1) Empty digester and start over with new innoculum.
Loading rate too high	1) Excessive scum. 2) Diminished gas production. 3) pH reduction.	1) Reduce loading rate.

NOTE: Many digester aids on the market are merely freeze-dried healthy sludge and can be obtained fresh for free at most municipal wastewater plants.

gradually. "Seed" is usually available at the local sewage plant or from a neighboring digester owner. The more "seed" used for start-up, the better. Initial loading rates should be kept down to 0.02-0.03 lb volatile solids/day per ft^3 of digester volume (see Chapter 7) until gas production is well under way. After gas production begins, feeding rate can be increased gradually until the design loading rate is achieved.

As to digester shut-down, it will be necessary to empty any digester for accumulated solids removal every few years, depending on system design and degree to which indigestible solids have been introduced into the digester feed. At such a time, it is highly desirable to have more than one digester, so that gas production (albeit reduced) can continue and a fresh starter will be readily available for restarting the cleaned-out digester. Whereas complete mix digestion tanks will require considerable labor to clean, with shovels, buckets and high-pressure hoses; a well-designed canal-type digester can be rid of its solid build-up with a front end loader or similar farm equipment.

Every digester is unique by virtue of its location, design, and feedstock. The key to successful operation is not following an instructional manual, because it is likely one doesn't exist. Rather, passing along some conventional sewage plant wisdom, the operator must work with the principles underlying his or her system design to develop operating procedures which yield desired results. The patient digester operator with the ability and courage to experiment will achieve the long-term rewards of stable operation and reliable biogas production.

CHAPTER 5

PUTTING BIOGAS TO WORK

This chapter covers two important aspects of biogas-fueled cogeneration:

1) the basic technology and how it works, and

2) factors that have to be considered to identify and select the proper components of a system matched to a particular site and its needs.

In order to convert the energy potential of digester gas into useful work and heat, several tasks must be accomplished:

- Collect gas as it is produced in the digester;
- Transport gas to an engine, cleaning and compressing it before combustion, if necessary;
- Combust gas in the selected engine;
- Clean up engine emissions if required;
- Generate electricity with engine shaft power and transmit it to an electrical load;
- Recover engine waste heat and utilize it.

Each of these tasks requires a piece of equipment or the selection of a method to accomplish it. The following sections discuss the requirements for each part of a working biogas cogeneration system.

BIOGAS COLLECTION SYSTEMS

The biogas formed during anaerobic digestion will naturally collect in the top of the tank. Most commonly used digesters allow some space for gas storage within the digester. Since both gas production and gas consumption rates fluctuate, it is necessary for a good design to provide some flexibility in the gas space volume by using either a floating digester cover or an inflatable bladder-type cover. Since the gas stored will be at a very low pressure, only a small amount of gas (possibly a few hours' equivalent in engine operation) can be contained.

If additional gas storage is required, a separate high-pressure vessel will be needed, along with a gas compressor. Pressurized tanks are available as horizontal cylinders for small installations and large spheres for bigger plants. Even these high-pressure vessels will typically store only a few days' gas supply, eliminating the potential for storing gas excess to summer needs for the following winter's use. Assuming that some source of backup energy is available to the site, it may be difficult to justify the expense and safety requirements of high pressure gas storage for biogas cogeneration.

The piping through which biogas exits the digester may be of any standard piping material (even PVC pipe), but brass or copper fittings must be avoided because of their tendency to react with the hydrogen sulfide in the gas. Low-carbon steel is suitable for the piping. The gas exit must be situated at the highest point in the digester and equipped with a pressure-relief valve (in case the exit valve is blocked for some reason) and a flame arrester (to prevent a fire in the pipe from entering the digester). Also, a simple draindown dewatering chamber may be desired, fed by gently sloping pipes. Because of the water content of the biogas, pipes must be protected from freezing where sub-freezing temperatures occur, and condensation drain points should be provided.

Normal operating pressure within the digester is usually 6 to 8 inches water column, just enough pressure to move the gas slowly a few hundred yards, although it may reach 15 inches water column safely. The addition of a low-pressure blower, or gas pump, may be needed to satisfy engine manufacturers' intake manifold pressure requirements.

Gas pumps can be sophisticated and relatively expensive items. Although many working digesters have been constructed by "do-it-yourself" enthusiasts, this is one area, at least, where they should proceed with great caution. The pump itself must be absolutely leak proof, for apart from the obvious explosive gas hazard, a gradual depletion of gas from the digester will disturb the normal operating pressure, and could well introduce air into the anaerobic environment and so cause digester failure. On large digesters, a small amount of gas leakage would obviously be insignificant, but on smaller units gas systems must be virtually leak proof. Unless inspection is vigilant and regular, leakage can go undetected until digester performance deteriorates noticeably.

Backup energy must be available to the biogas cogenerator, if continued operation when the digester is "down" is a requirement. Unless the backup is an independent electrical bypass of the entire system, supplementary fuel will have to be used to fire the engine. Depending on the type of engine selected, standby fuel could be diesel oil, propane, or natural gas, metered by valve to match the energy value of the digester gas and requirements of the engines. Figure 11 indicates the basic plumbing connections involved with the biogas cogeneration system using purchased gas as a backup fuel, either from a pressurized storage tank or a regular gas service connection.

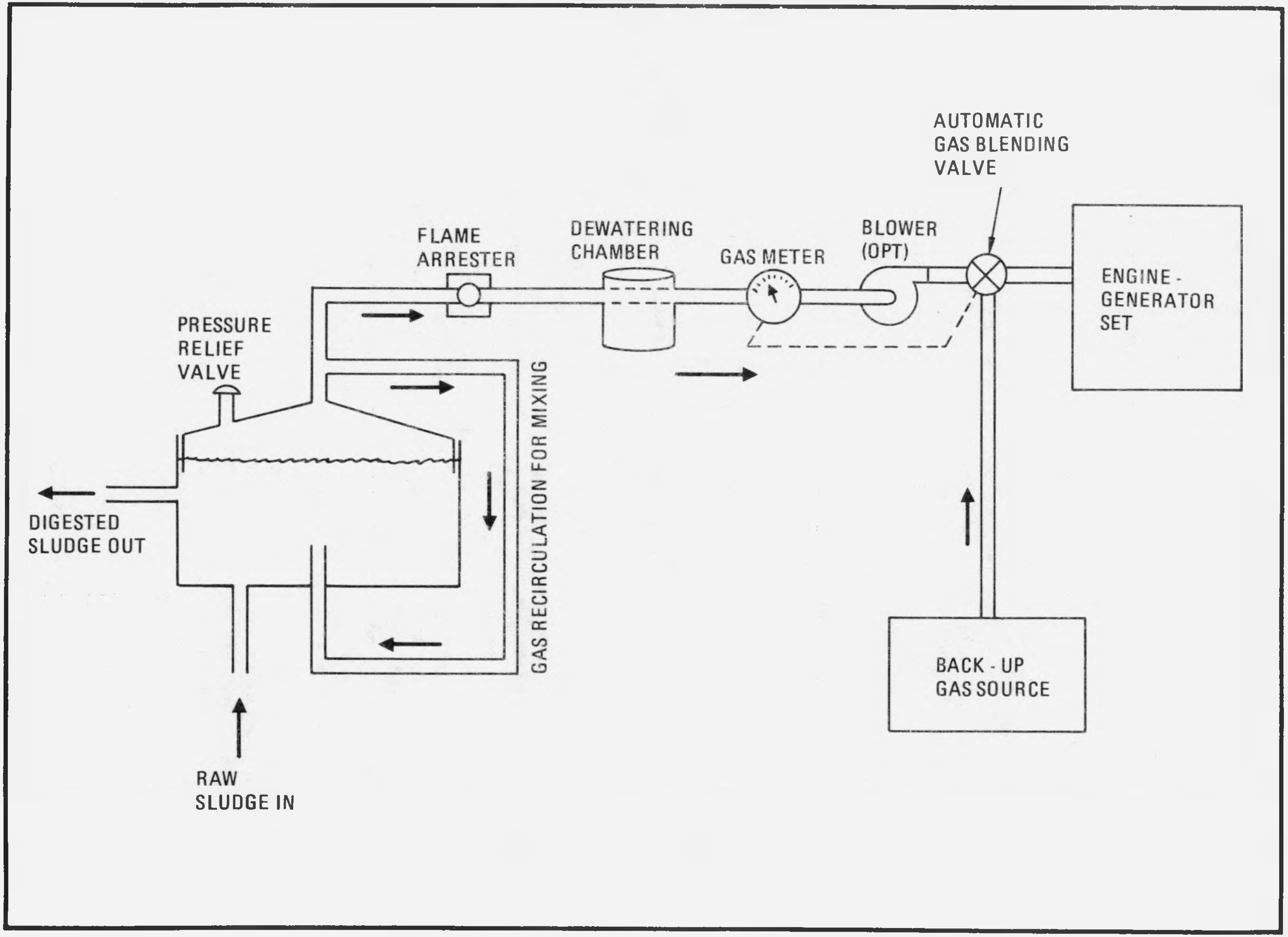

Figure 11. Biogas Plumbing.

BIOGAS CLEANUP

The chemical composition of digester gas has already been described (see Table 3). Of the common constituents, only hydrogen sulfide (H_2S) and water vapor (H_2O) are of serious concern for reliable engine operation. Much of the suspended water vapor in wet digester gas can be precipitated out with a simple water trap; along with the water vapor goes a significant portion of the H_2S. The remaining H_2S may range widely in concentration. Some plants have successfully designed and operated their engines to allow for residual H_2S by replacing critical engine parts with substitutes made from corrosion resistant metals. Others have installed devices to remove it from the digester gas. Passing the gas through heated iron oxide (iron sponge) is one of the simplest techniques to remove H_2S when concentrations are low. When H_2S levels in the digester gas are very low, successful engine operation may occur with only the water trap.

The large carbon dioxide content of most digester gas is not a problem in engine operation, although it does not combust and hence leads to engine de-rating. Some engines can function with CO_2 levels as high as 75% of total gas volume. Only if the digester gas is to be sold as pipeline-quality gas would CO_2 removal be necessary.

There are clear environmental benefits to the site producing the feedstock and to society from generating power with biogas. It is therefore ironic that flaring biogas or venting it to the atmosphere to "dispose" of it (as has been practiced for years at some wastewater treatment plants) is not subject to emission control regulations, while burning the gas in an engine to make power potentially is. Compliance with Federal, State, and local emission standards, however, should not present problems for most farm and wastewater treatment plant biogas cogenerators. The minimum regulated heat rate for stationary source power generation is 250 million Btu/hour. Given a 25% conversion efficiency from biogas to electricity, 250 million Btu/hour translates into an installed capacity of 18,300 KW. This much biogas power theoretically requires: 1) 220,000 dairy cows, 2) 330,000 feedlot steers, 3) 2,000,000 hogs, 4) 28,000,000 layer hens, or 5) a 915 mgd sewage plant (from Table 1). Regulatory requirements aside, biogas burns very cleanly, like natural gas, and the major pollutants created are oxides of nitrogen (NO_x) which result from any combustion process.

BURNING BIOGAS IN ENGINES

There are a number of different engine types which can operate on medium-Btu gas as produced in sludge digestion, including:

1) Compression ignition engines, modified for dual fuel combustion, have been used widely in large wastewater treatment plants and require from 2-15% (average, 5%) diesel fuel for ignition and top end lubrication. Two fuel delivery systems are required, as well as modified carburetion. Maximum fuel energy which can be converted to

shaft housepower is 32-36%. Twenty percent, or lower, efficiency when operating at partial load is common.

2) Spark ignition engines have had somewhat less use operating on biogas; generally in smaller horsepower sizes than the dual-fuel engines. Natural gas or propane may be used as supplemental fuel. Slow speed, high compression engines may yield 32-36% power extraction rates; high speed, low compression units, only 20-25%. Partial load again decreases engine efficiency.

3) Gas turbines have some theoretical advantages over reciprocating engines, but little successful experience with their use on digester gas has been documented and the selection of turbine sizes available under 500KW is limited. Mechanical power efficiency ranges from 17-30%, depending on the degree to which exhaust heat is recuperated.

4) Steam turbines are the engines least affected by constituents in the fuel gas because they do not come in direct contact with it; only the steam raised by fuel combustion operates the engines. The use of digester gas to produce steam is well-documented but the cost of generating power with steam turbines may be difficult to justify at facilities with less than 1 MW (1000 KW) potential.

Inquiries to engine manufacturers have yielded the specific data shown in Table 6. A summary of the size ranges available for various engine types appears at the bottom of Table 6.

Spark Ignition Engines

Spark ignition internal combustion engines have been used successfully at wastewater treatment plants, ranging from a very small (3MGD) plant in Tiffin, Ohio that uses junked automobile engines, to Orange County, California's extensive installation of 10,000 HP capacity in a 190 MGD plant. (Also see Table 7.) Spark ignition engines can operate on digester, natural, or liquid propane gas. It is also possible to design the engine plumbing and carburetion to permit the use of gasoline as backup fuel, although this arrangement is not common. Success has been recorded with both spark ignition and compression engines run on unscrubbed biogas containing up to 0.3% H_2S.

Several operational procedures are widely credited with preventing corrosion and contributing to engine reliability and life when using digester gas as the primary fuel:

1) Engines are conservatively rated as to power output.

2) Engines run at slow speed, typically 900-1200 rpm.

3) High compression ratios are used--up to 15:1.

Table 6

Available Engines Suitable for Operation with Biogas

Prime Mover	KW Range	Shaft Speed (RPM)	Exhaust Gas Flow Temp	Cost	Delivery Time	Comments
Caterpillar 3306	60-70 KW 80-93 HP	1800	1010 CFM 1100°F	$20,000 incl. gen set	12 - 16 weeks	Can be used with medium Btu gas with little modification.
Caterpillar 2206	90-160 KW 120-214 HP	1500	460 CFM 900-1020°F	$24,000 incl. gen	12 - 16 weeks	Comes matched with Cat's own generator.
Caterpillar G342	160-300 KW 214-402 HP	1200	700 CFM 1160°F	$70,000 incl. gen set	12 - 16 weeks	
Waukesha F817	75 KW 100 HP	1200	450 CFM 900°	$26,000 incl. gen set	26 weeks	Most widely used engine in wastewater treatment plants across the country. Also offer to match their own heat recovery systems to the engine-generator sets.
F195G	175 KW 234 HP	1200	475 CFM 900-1000°F	$60,000	26 weeks	
Waukesha VHP 9500 GSI	1400 KW 1876 HP	900	 900-1000°F	$411,000 incl. gen set	26 weeks	

Table 6 (Continued)

Available Engines Suitable for Operation with Biogas

Prime Mover	KW Range	Shaft Speed (RPM)	Exhaust Gas Flow Temp	Cost	Delivery Time	Comments
Superior 6G510	300 KW 402 HP	900	690 CFM 950-1000°F	$158,000 incl. gen set	32 weeks	These are gas engines. They make compression models also, however they cannot be modified by Stewart-Stevenson.
Superior 8GTL	800 KW 1072 HP	900	980 CFM 1030°F	$431,000 incl. gen set	32 weeks	
Detroit Diesel 3-50	20 KW 26 HP	1800	530 CFM 970°F	$20,000 + $4700 S&S conversion	12 - 16 weeks	Can be converted to Stewart Stevenson dual fuel engine for biogas applications. Only brand to be modified by S&S.
4-71	95 KW 127 HP	1800	989 CFM 970°F	$35,000 + $6000 conversion.	12 - 16 weeks	
16V-149T	700 KW 904 HP	1800	7931 CFM 970°F	$100,000 + $1700 conversion	12 - 15 weeks	
KG2	1000 KW 1340 HP		27,760 PPH	$250,000		KG's can be fitted with special low Btu gas fuel systems for this kind of application.
KG831	500 KW 670 HP	41000		$180,000 incl. gen set		
Garrett 831	500 KW 670 HP		928°F			
Size Summary in KW by type	SPARK ENGINES 60 KW - 1400 KW		COMPRESSION ENGINES 20 KW - 700 KW		GAS TURBINES 500 KW - 1200 KW	

Table 7

Case Histories of Engines Run on Biogas

Wastewater Plant	Plant Avg. Flow	Digester Gas Quality & Pretreatment (if any)	Power Produced & Type of Use	Engine Type	Years of Experience and Comments
Clayton Plant, Atlanta, GA	75 mgd avg.	650 Btu/ft^3	4 @ 1100 HP + 3 @ 1600 HP (usually two of each are run at a time). Power used to drive blowers.	Nordberg diesel w/ engine cooling water to HX. Common header used for dual fuel types.	Discontinued use of sludge gas in engines originally because of gas pressurization failure and mechanical gear problems. These were corrected and now problem is inflexible multiple fuel delivery system. Currently digester gas is used for incinerator & digester warming, & natural gas runs engines.
Orange County Sanitation District, CA	190 mgd	100% saturated; no scrubbing. 57,000 ft^3 of on-site storage capacity. Summer gas analysis: 600 Btu/ft^3 2900 ppm H_2S Winter gas analysis: 550 Btu/ft^3 1200 ppm H_2S	31 engines ranging from 235-1500 HP. Separate steam production; incineration & sale of gas to neighbors. All power used for mechanical drive.	Enterprise, White Superior & Waukesha; standby gas turbines by Orinda were formerly used continuously on digester gas.	Both spark & compression I.C. engines satisfactorily drive influent & effluent pumps. Aluminum bearings and vapor-phase cooling said to be important, although recent trials of high temperature water cooling have succeeded. Failure of gas turbines in fulltime mode attributed to auxiliary components.

Table 7 (Continued)

Case Histories of Engines Run on Biogas

Wastewater Plant	Plant Avg. Flow	Digester Gas Quality & Pretreatment (if any)	Power Produced & Type of Use	Engine Type	Years of Experience and Comments
Hyperion, Los Angeles, CA	400 mgd avg.	500 ppm H_2S in 3,600,000 ft^3/day gas is dewatered but not scrubbed before engines.	5 1688 HP engines drive generators + 5 for blower. Also, excess gas sold to neighboring power plant.	360 rpm diesel (dual fuel) (DOE test of gas turbines currently underway.)	Satisfactory (in fact exemplary) operation since 1950's. Overhaul every 20,000 hours. Vapor-phase cooling to heat recovery for digester-warming. Full-time highly-skilled diesel operators on-site.
Racine, WI	21 mgd	Chemistry unknown; 600-700 Btu/ft^3; no scrubbing before engines; compressed to 50 psi for storage in 240,000 ft^3 sphere.	2 @ 475 HP drive blowers; 2 @ unk HP drive generators. Also some gas directly fires a boiler to supplement engine exhaust.	Waukesha I.C. diesel low rpm hi pressure ratio.	Satisfactory operation since 1967 with one major overhaul and some valve work.

Table 7 (Continued)

Case Histories of Engines Run on Biogas

Wastewater Plant	Plant Avg. Flow	Digester Gas Quality & Pretreatment (if any)	Power Produced & Type of Use	Engine Type	Years of Experience and Comments
Bloom Township Plant, Chicago area, IL	12 mgd	.5-1.5% H_2S reading, but validity questionable; unk. Btu content; no scrubbing before engines; unk. compression.	5 @ 250 HP installed for blowers but now use nat. gas (only 1 operates at a time).	Waukesha w/water jacket heat recovery.	Discontinued about 1974 (installed ca. 1955) due to sulfuric acid corrosion by water vapor + H_2S + low operating temp. (160°F).
Southerly Plant Cleveland, OH	100 mgd	Unk. chemistry; 500 Btu/ft^3; unk. pretreatment.	3 @ 900 HP + 4 @ 600 HP unknown application.	Cooper-Bessemer Diesels.	Discontinued in early 1970's (began in 1950's) for unclear reasons. Operation described as "more or less satisfactory" but competition developed between demands for heating and engine operation (clearly not a cogeneration system).
Ina Road, Tucson, AZ	13.5 mgd avg.	132,000 ft^3/day @ 550 Btu/ft^3; low H_2S content.	3 @ 685 HP to generators + 4 standby engines. Also a separate steam boiler.	Waukesha Diesel	41 years on-line with satisfactory operation. (A second plant in Tucson has 3,400 HP engines driving blowers).

4) High temperature vapor phase cooling is used to avoid condensation and the consequent formation of corrosive sulfuric acid.

5) Operation is continuous to avoid condensation during engine shutdown cooling (alternatively, the engine is flushed with air after shutdown).

However, most installations have not experienced the "automatic, low-maintenance" engine operation touted by manufacturers when burning biogas. It is a good plan to have someone generally familiar with engines available to adjust, monitor and care for the engine. This service will minimize major maintenance needs and down-time.

Spark ignition engines have the advantage of requiring no gas compressing prior to delivery to the combustion chamber. Also, they require only a single fuel system, unlike their dual fuel cousins. While the gas-fired turbine offers the prospect of greater engine efficiency and greater heat recovery, internal combustion engines have two sources of recoverable heat (engine coolant and engine exhaust), which provide built-in versatility for waste heat applications.

Dual Fuel Compression Engines

There has been some confusion of terminology in discussions of running dual fuel engines on biogas. Although the equipment is basically built as an engine fueled by #2 (diesel) oil, and the engineering literature tends to refer to them as "diesel" engines, when they burn gaseous fuels they no longer function in a true "diesel" cycle. Rather, the fundamental manner in which fuel is converted to work has been altered to what most engine manufacturers call a "dual fuel cycle." Engines utilizing this cycle will be referred to from here on as compression engines. It must be understood, however, that a "dual fuel compression engine" in this book refers only to modified diesel equipment, and not to other engine types which can accommodate multiple fuels.

The experience with dual fuel engines in burning digester gas is extensive both in numbers of installations and years of on-line operation. Some typical plants are summarized in Table 7. Manufacturers with experience in the use of medium Btu gas can readily specify a suitable engine based on gas flow rates and Btu content, and then calculate the resulting power output.

While requiring regular maintenance, compression engines are built to withstand continuous duty as a stationary power source. One of the disadvantages of a compression engine is the special carburetor needed to utilize both liquid diesel and gaseous fuel in the engine simultaneously, and the need for two separate fuel delivery systems. However, as with spark ignition engines, there are two possible sources for heat recovery, affording more flexibility in the design of a cogeneration system.

Gas Turbines

Unlike the two types of internal combustion engines described previously, gas turbines have had limited success with biogas. (See Table 7.) The 190 MGD wastewater treatment plant in Orange County, California, tried a 1500 HP Orinda gas turbine for 1½ years with digester gas as fuel. Eventual engine failure was attributed to fouling of the compressor and peripheral equipment by H_2S in the biogas.

Despite past failings, gas turbines continue to be designed into biogas cogeneration systems. One treatment plant in Knoxville, Tennessee is scheduled to start up two 500 KW gas turbines (AiResearch 831's) in mid-1981. A third unit will be used as a backup. Los Angeles County, California has just begun design of a gas turbine installation consisting of three 10,000 HP Solar MARS turbines, along with heat recovery for steam turbine operation. Scheduled startup is in 1982.

Gas turbines have some theoretical advantages over internal combustion spark ignition and compression engines, because of fewer moving parts and high operating temperature. Gas turbines provide continuous unattended operation and have enviable service records. Another attractive characteristic of gas turbines is that by designing more or less heat recuperation into the exhaust gas flow, the portion of energy transformed to mechanical work can be increased or decreased, to match the electrical or mechanical demands.

It has not been demonstrated, however, that a gas turbine can operate for an extended period on digester gas. Another drawback is the sophisticated compression equipment required to raise the pressure and flow rate of fuel into the turbine. Though gas turbines have the best energy recovery potential of any prime mover described, there is only one source of heat, which limits the flexibility or increases the complexity of the heat recovery system. Until more successful on-line experience has been documented, gas turbine technology must be considered experimental in biogas applications.

Remember, in selecting the engine appropriate for a site, the "prime mover" of the cogeneration system, there are several factors that must be considered. The type of engine, whether it is compression or spark ignition or a turbine will be determined by:

1) Power potential based on the amount of biogas fuel available for combustion, which gives a fix on engine size. It may turn out there is only one type of engine available in the needed size which only one or two manufacturers sell.

2) Experience in actual operation of the engine on a biogas fuel. This varies widely, so don't rely on just one source of information for how well or how poorly a given type or specific model of prime mover has performed. There are many factors outside of the engine itself which can determine success or failure of a biogas

cogeneration system, including the next factor.

3) Maintenance requirements. There are two parts to this concern: what the scheduled or required maintenance consists of and who is going to do it.

4) Cost. Both the original cost of the engine-generator set and the on-going operating and maintenance cost must be carefully evaluated. Be sure that comparisons are made of "apples with apples" when looking at manufacturer's quotes and be sure the overall cost includes total system requirements for heat recovery and application according to the site's energy needs.

5) Availability of the prime mover from a local, regional, or national supplier. How long will it take to get the selected equipment? Delivery times of up to 10 months from placement of order are common. Savings from the biogas cogeneration unit are lost during the wait. Also, availability of service and spare parts needs to be determined. At some point in system operation, despite promises from salespeople, both will be needed.

GENERATORS AND ELECTRICAL INTERFACE

The choice of a generator is basically a matter of matching the output of the generator (power output and shaft speed) with that of the prime mover. Depending on the type of prime mover (turbine, spark ignition, or compression engine), the gearbox joining the prime mover to the generator will usually increase the engine speed to that of the generator, or decrease the turbine speed to match that of the generator. In most cases, the manufacturers mentioned in this manual match the prime movers to the generator set, or can recommend a distributor who does. This practice is so common that some manufacturers have moved to calling engine-generator sets "enginators" and have special sections of brochures describing these sets. If a prime mover is chosen which does not come matched with a generator, consultation with an experienced A&E firm (see Appendix 1) will aid in the choice of appropriate electrical equipment. Generators are packaged with necessary electrical controls for their operation.

In addition to a generator, the cogeneration system will include electrical equipment, either for interface with the utility grid or delivery of power on-site. The Tennessee Valley Authority, like most utilities in the country, requires the cogenerator to provide, install, and maintain switchgear, wiring and controls if parallel operation of the unit with power purchased from the grid is planned. For sale of power to the utility, an additional kilowatt-hour meter must be installed. Controls which protect the unit from under/over voltage conditions and automatic circuit breakers with manual reset to separate the system from the distributor line in case of distributor line power loss are also necessary equipment.

HEAT RECOVERY

The term "cogeneration" means that the waste heat from the engine is used (sometimes supplemented by additional fuel) to satisfy some further heating requirement instead of being immediately discharged to the environment. Designing for optimum heat recovery starts with the selection of the prime mover, since the different types of engines yield different amounts of waste heat by virtue of differences in efficiency and ease with which waste heat streams can be captured. A highly inefficient engine may produce substantial recoverable heat at the expense of reduced power output, but this allocation of energy may be desirable for site applications where the thermal load is much higher than the electrical load.

Once the ratio of power to heat is determined by engine selection, the actual use of the heat will guide the design of heat exchange or recovery equipment. Waste heat will be available as a gas (the engine exhaust) and a liquid (engine coolant), and the ultimate use of the heat may require transfer to other gases or liquids. In biogas cogeneration systems, it is assumed that digester heating takes priority among possible applications of engine waste heat. Space and water heating are common secondary uses of the available thermal energy.

The amount of heat which can be recovered in cogeneration systems and put to work is the subject of much discussion by the experts. Recovery of fifty percent of the total input heat value seems a mid-range figure, with 40 to 60 percent also quoted. Given 25% engine efficiency, one source estimates that the remaining 75% of input heat is split almost evenly between exhaust and coolant. Realistically, two-thirds of that waste heat might be recovered and put to work. Using numbers for illustration, 337,000 Btu/hr of biogas makes 25KW at 25% efficiency. Fifty percent of the input heat recoverable for work amounts to about 170,000 Btu/hr, with 85,000 Btu/hr coming from engine coolant and the same amount in the engine exhaust.

Applications of Waste Heat

When sludge heating demands most of the engine waste heat, the simplest recovery scheme involves transferring both engine coolant and exhaust heat to water. Figure 12 shows such a system. Sludge is heated by being piped through a hot water bath, with a little heat diverted for building space heating. The closed engine cooling water loop requires highly efficient heat transfer in the water-to-water heat exchanger, since the fluid must again act as a coolant when it returns to the engine. In some cases, it will be simpler to pipe hot water through a sludge reservoir for heating rather than the reverse shown in Figure 12. (Also see Figures 8 and 9 for a third method.) Standard pumping techniques and materials are suitable for heat recovery systems, except PVC pipe use is limited to cool water returns.

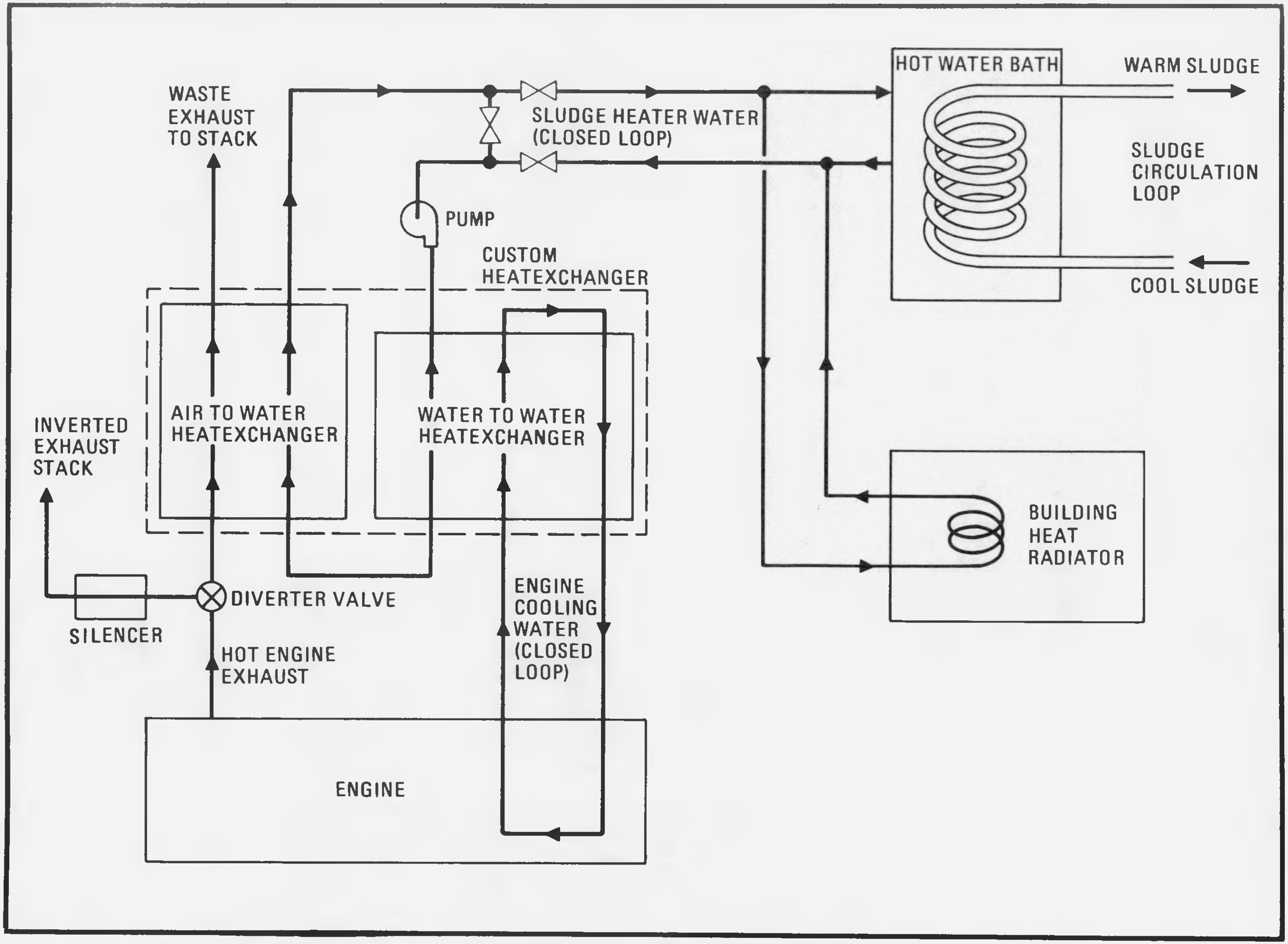

Figure 12. Application of Waste Heat to Sludge Heating.

In all designs, extra insulation of pipes, holding tanks, and the digester will reduce heating demands, leaving more heat available for other uses. Short pipe distances will also minimize heat losses. On farms, where the source of the wastes can be a matter of feet or yards from the digester, it is a good idea to remember that the manure begins its life at the ideal temperature for mesophilic digestion, and any design features which slow down cooling of the digester feedstock will pay off.

Figure 13 is a simple schematic showing separate applications of engine exhaust and coolant waste heat. Such a setup would be appropriate for heating hog buildings or chicken coops in winter, provided the animal housing is located close to the prime mover. Transferring heated air over long distances results in substantial losses as well as raising system costs due to extended ducting.

The arithmetic behind heat recovery design is somewhat complex, but some helpful calculations are provided in Chapter 7. Computing sludge heating needs is an obvious first step to system design. Table 6 also provides engine exhaust heat characteristics. Appendix 1 contains a list of firms who sell "off-the-shelf" and custom-designed heat exchange or recovery equipment. Other firms listed in Appendix 1 with complete biogas cogeneration system design capabilities will include the heat recovery component in their package of services.

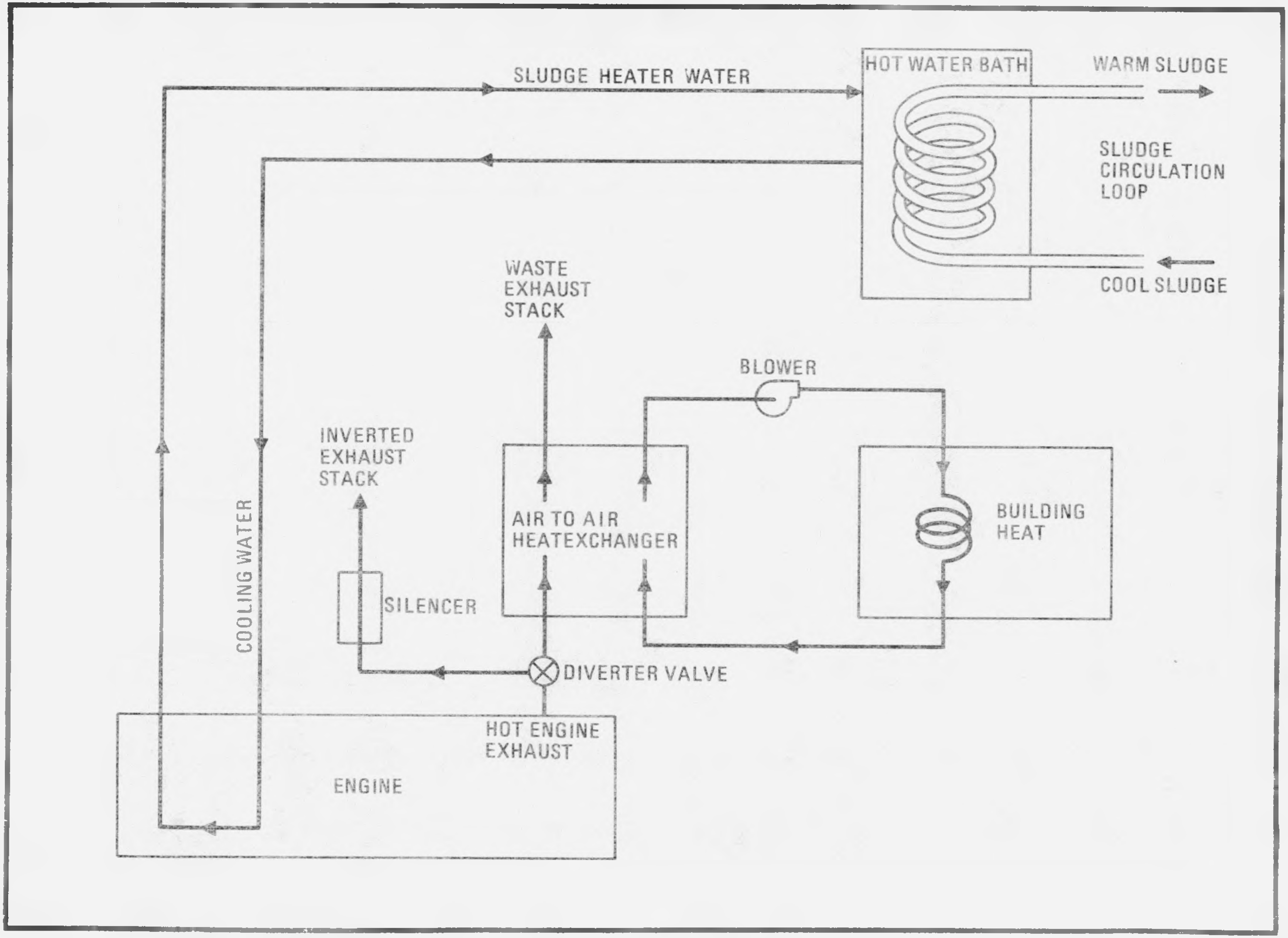

Figure 13. Application of Waste Heat to Sludge and Space Heating.

CHAPTER 6

BIOGAS COGENERATION CASE HISTORIES

This chapter reviews biogas fueled electric power cogeneration at three different sites, all with different operational needs. Each installation is in a different state of development. The dairy's cogeneration system came on-line in 1979, the cattle feedlot was in the design stage in mid-1981, and the wastewater treatment plant has run a successful biogas cogeneration operation since the late 1960's. The described systems are quite different from one another and thus illustrate a representative range of the opportunities offered for biogas cogeneration.

MASON-DIXON FARM: DAIRY

Figure 14 is a schematic of a biogas system at Mason-Dixon Farm near Gettysburg, Pennsylvania. The first unit, based on manure recovery from 700 milk cows came on-line in Fall 1979, and a second system was being completed in Spring 1981. Each of the dairy's two plug-flow digesters produces up to 44,000 cubic feet of biogas per day. At 600 Btu per ft^3, this gas production amounts to 52.8 million Btu per day. Assuming a 25% conversion efficiency to electricity, up to 160 KW can be produced continuously. Using the 8 hours of biogas storage built into the system allows even greater electricity production, covering the farm's needs. Negotiations to sell surplus electricity to the local utility were under way as of April 1981.

As described in Figure 14, the long barns from which most of the manure for digestion is collected have sloped concrete floors, with a drop of 12 inches from one end to the other. Manure is regularly washed downslope into trenches then piped to a settling tank. The slurry is stirred, then pumped to the digesters from a small adjacent basin. The loading rate per digester is approximately 13,000 gallons of manure slurry per day. The entire top of the digester is rigged with pulleys and cable for easy lifting when necessary.

Retention time in the concrete (92' x 20' x 15' deep) plug flow digesters is on the order of 20 days. The second digester is pictured in Figure 15; the structure along the right side is the lifting mechanism. Digested slurry is forced from the digester into a large holding pond by incoming material. The spent manure is then pumped up to an indoor surge manure dewatering device which squeezes out moisture. The resulting product is fluffy and odor-free and is used at the farm as a bedding material for cows. Preliminary laboratory tests have thus far revealed no hazardous microorganisms inhabiting this material.

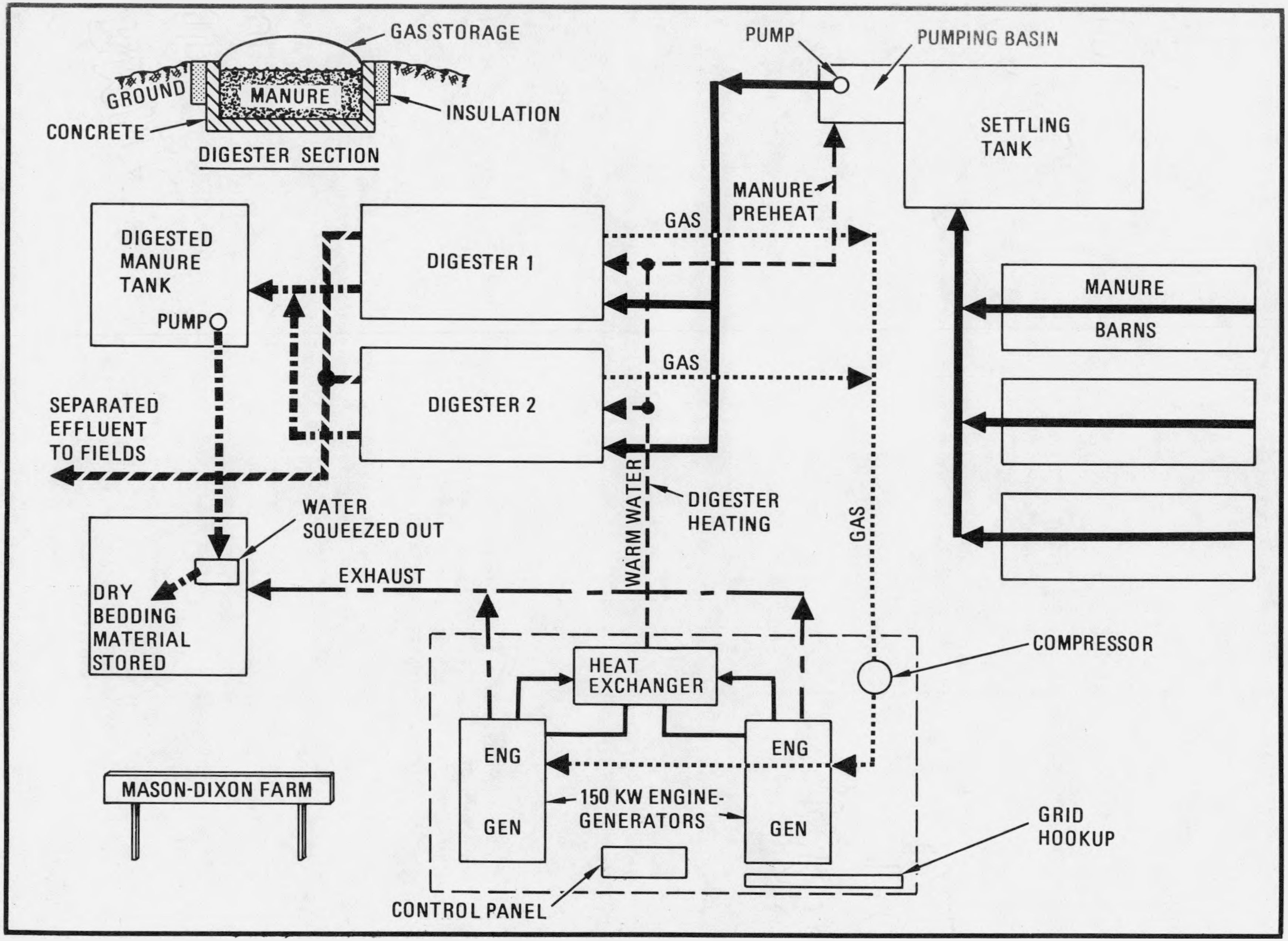

Figure 14. Mason-Dixon Farm Biogas Cogeneration System.

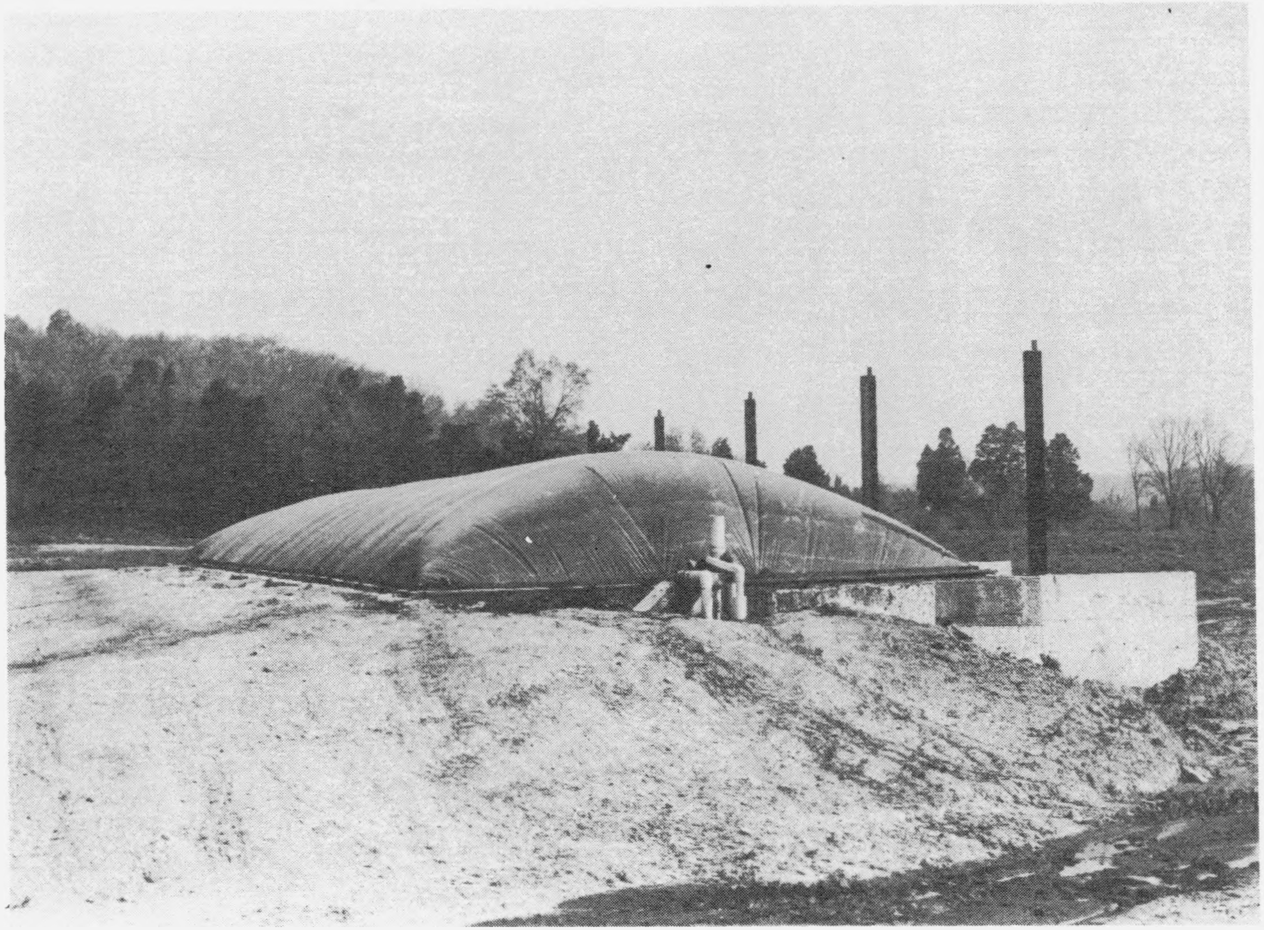

Figure 15. Mason-Dixon Plug-Flow Digester. Posts at the right will support the lid-lifting system. Pipes in the center of the picture handle 1) incoming sludge, 2) incoming hot water, 3) water return, and 4) exiting biogas. Exposed wall shows 2 inches of R-10 insulation.

Biogas collects in the expandable, nylon-reinforced hypalon bag attached to each digester. The newer digester has much less storage capacity than the original. (See Figure 15.) No other gas storage is provided. The biogas is piped to the nearby shed housing cogeneration equipment, where it is compressed, and delivered to two internal combustion engines. In April 1981, Mason-Dixon Farm operated an industrial grade spark ignition engine and dual-fuel compression engine on biogas. The dual-fuel engine required 10% diesel fuel and attained very low efficiencies when operated at partial load. The owner has decided to replace it with another spark ignition unit which will operate on biogas alone.

A water-to-water heat exchanger reclaims heat from engine cooling water. Hot water is circulated in pipes through the digesters to keep them at proper mesophilic temperatures and also prewarms sludge in the pumping basin before it enters the digester. Plumbing is all PVC pipe except for high temperature waste heat streams. There are four pipes poking out of the end of the digesters pictured in Figure 15. The largest delivers manure, the smallest collects biogas, and the remaining pipes deliver and return heating water. Thus far, the recovered engine heat has adequately provided all winter heating needs. The two inches of R-10 foamed glass insulation protruding around the top several feet (see cross-section on Figure 14) of the digester contribute to heating efficiency. Engine exhaust is piped to the barn where digested sludge is dried to contribute to that process.

The cost of one 700-cow biogas unit at Mason-Dixon Farm was about $100,000 in 1979. The owner built the system himself, so the design firm estimates a cost of $160,000 for complete installation by contractor. The success of this biogas cogeneration facility can be attributed to the simplicity of its design and the perseverance and innovation of the farm owner.

AGRIFUELS, INC.: CATTLE FEEDLOT

A cattle feedlot near Tupelo, Mississippi was faced with the problem of ultimate disposal of the wastes produced by an average 1200 head of beef cattle. The owner was also a member of a farmers' cooperative with plans to build and operate an alcohol fuel production plant using agricultural products as a feedstock. A biogas cogeneration system appeared to be a solution to the waste disposal problem and an energy source for the alcohol project. A schematic of the proposed alcohol plant and digester cogeneration subsystem is shown in Figure 16.

While this installation presented a unique opportunity, it also had some special problems. Firms specializing individually in alcohol fuel plants, digesters, and cogeneration units were known, but not organizations experienced in integrating the operation and satisfying the requirements of all three parts of the planned facility. The initial result was that an alcohol plant, using green wood chips as its primary fuel, was designed. However, the digester,

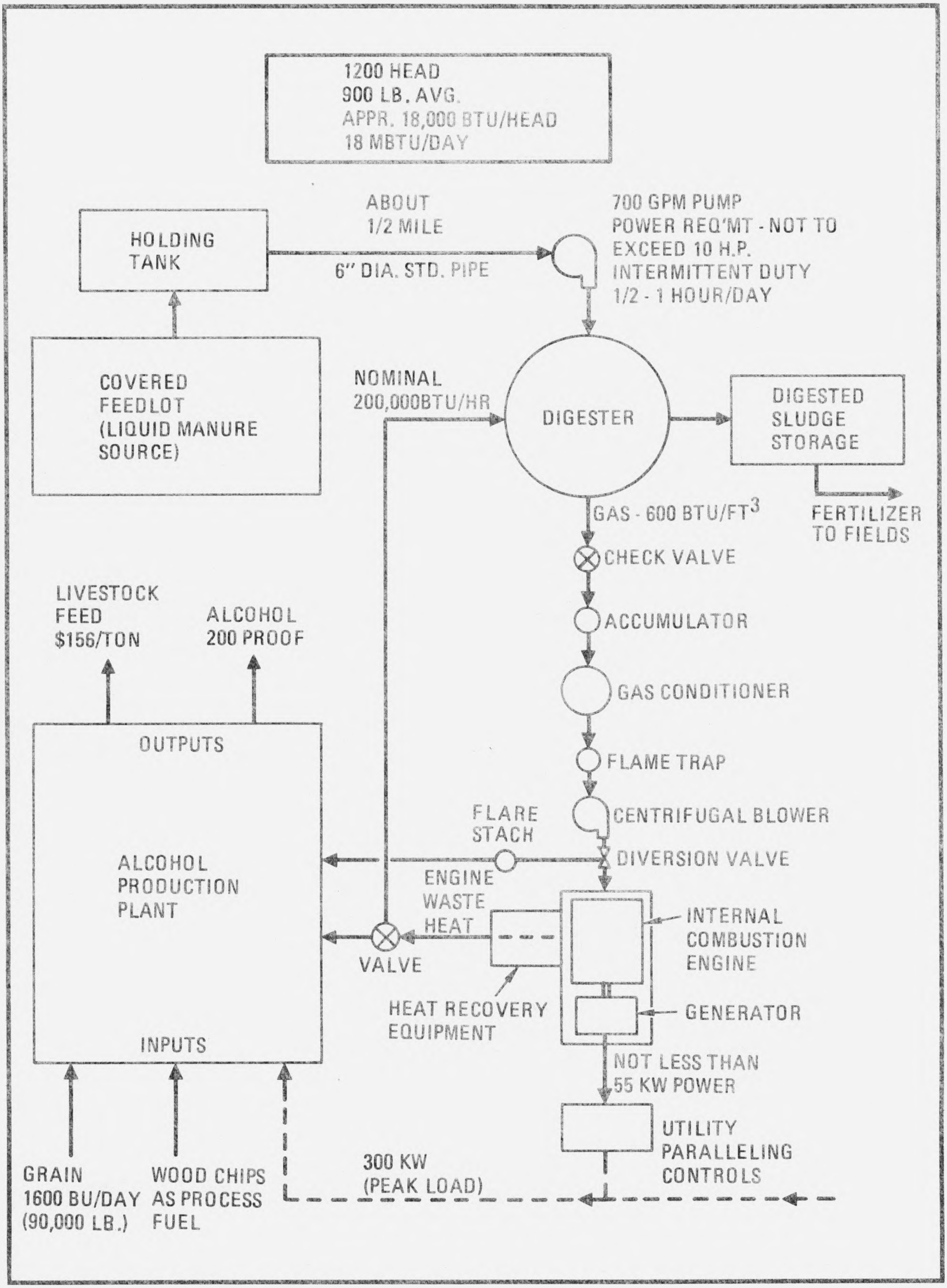

Figure 16. Agrifuels Biogas Cogeneration System.

cogeneration unit, and how these parts of the facility tied into the feedlot and the alcohol plant were not.

At this point, the Tennessee Valley Authority provided technical assistance to AgriFuels, Inc. While a design specification for the alcohol plant showed how that facility would be laid out, there was no performance specification for the facility or for the many different functions being performed by the total system.

In order to stay on schedule, a system performance specification describing required inputs and outputs at each point in the process was prepared. Any design that could satisfy the performance requirements would be acceptable. TVA's intent was to allow as many firms and contractors as were competent to bid on the installation, regardless of the particular design they offered to meet the overall project goals.

AgriFuels, Inc. was to award one or more contracts for the final design and construction of a facility with two main functions. The description of the installation, and how it was specified for bid, follows.

The primary facility function is the production of 200 proof alcohol. The plant feedstock is to be corn and the primary fuel source, green wood chips (up to 50 percent moisture content). Design specifications for the alcohol plant were detailed in other documents provided to potential bidders.

A secondary, but critical, function of the facility is the collection, transport, and stabilization through digestion of cattle feedlot wastes produced in proximity to the facility site (less than a half-mile away) with the production of thermal and electric energy for use in the alcohol fuels facility. This document addresses only the latter portion of the project by defining performance requirements.

A digester designed and constructed according to the performance requirements described in the following sections will have two usable products: 1) biogas with an estimated heating value of 500-600 Btu/ft^3, 2) a stabilized sludge appropriate for use as a fertilizer and soil enhancement of crop-producing farmland.

The biogas is to be combusted in a cogeneration unit consisting of an internal combustion engine, an electric generator set with output appropriately matched to engine size, and a method for heat recovery and utilization of waste heat produced by the engine: both exhaust and cooling flows.

Any surplus biogas is to be combusted to supplement other fuel requirements in the alcohol plant. Any gas that remains surplus to both of the above uses is to be automatically flared.

The electrical power is to be used to partially meet the electric energy demands of the alcohol plant and the heat recovered is to be applied in two prioritized ways:

1) to the digester, in order to maintain an accelerated digestion operating temperature appropriate for gas production. (The temperature in the digester is to be maintained between 95-100°F.)

2) to the alcohol plant to meet a portion of the process heat requirements, including wood fuel processing feedstock and product drying, or other heat requirements of the plant. The amount of recovered heat available is to be matched to that end use where it can best meet the amount of heat required using applied cost-effectiveness as a criterion.

Performance requirements for the biogas system components are described in the following paragraphs:

1) Interface between feedlot collection tank and digester is to provide for accumulation and transport of up to 18,000 gal/day of 10% solids slurry. Approximately 2500 feet of pipe in an economically determined diameter must be protected by entrenchment or equivalent and attain a 4 ft/sec minimum slurry velocity in the pipe. An automatically timed pump of not greater than 10 HP shall operate at a duty cycle which provides for the daily flow requirement.

2) The digester, designed to produce biogas and stabilized sludge, may be of any type which provides for a minimum 20 day retention time at the 18,000 gal/day input rate. Storage of a minimum of 12 hours of gas production at the maximum rate of digester generation is required. Cleaning, temperature, sludge removal and maximum annual downtime were also specified.

3) Interface between the digester and the digested sludge storage basin, which is to provide for up to 60 days of storage capacity and removal for field irrigation and soil enhancement.

4) Interface between digester and the prime mover of the cogeneration unit, expected to be an internal combustion engine fueled by the digester gas, must be sized to flow a minimum of 1500 ft^3/hr. Piping, valving, gas conditioning requirements, flame trap, and an excess gas flare stack are also specified. Insulation is required on all wet gas lines.

5) The cogeneration unit, consisting of the prime mover, an electric generator, heat recovery from cooling and exhaust flows, all necessary controls and switchgear, is to provide a minimum of 55KW electric power, burning 18 million Btu/day of biogas. Approximately 500,000 Btu/hr in waste heat is expected to be available for recovery.

6) Interface between cogeneration unit and digester for sludge heating to maintain accelerated digestion requires a heat recovery unit to capture heat from the engine coolant flow and transmission of this heat to the digester for temperature maintenance on demand. From 150,000-200,000 Btu/hr are calculated to be available for

digester warming.

7) Interface between cogeneration unit and alcohol production plant for heat application and electricity. Waste heat not required for digester warming is to be automatically transmitted to the alcohol production plant through insulated lines for application to one or more functions in that process. The electrical interface shall include switchgear and wiring necessary for connection of the generator with the facility's main power supply for complete parallel service. Phase and voltage is to be matched to the plant electrical service for compatibility.

Bids and proposals of work were to be prepared according to this performance specification and, subsequently, to be evaluated for contract award on the basis of the stated requirements. This type of specification can serve as a model for soliciting proposals and cost to design and install biogas-fueled cogeneration units of over 25KW.

The AgriFuels project is intended to function as described in the preceding paragraphs in order to derive maximum benefit from digester gas cogeneration which, in this case, is supporting an alcohol fuels plant.

Of the contractors' bids received, three were judged complete enough to be responsive to the invitation for bid sent out by AgriFuels, Inc.

Since biogas cogeneration is a fairly young (or "reborn") industry, all of the bidders had some holes in their proposals where items requested were not provided or described. The lesson to be learned here is to make it clear that each and every part of the system performance specification must be addressed, either in terms of equipment or problem solution as appropriate. A biogas cogeneration facility simply will not operate unless intake, digestion, disposal, gas combustion, power production and heat recovery are <u>all</u> accomplished in an integrated manner.

Key elements from the proposals of Bidders 1, 2, and 3 are discussed briefly in following paragraphs and some general conclusions drawn for the benefit of those planning to contract the work of a biogas cogeneration installation at their site.

Bidder #1 proposed an above ground steel tank digester, fully mixed with an external water boiler for sludge heating to mesophilic temperature. The cogeneration set prime mover was a Caterpillar 3306 with a 100 KW nominal rating. Power output operating on digester biogas is 55KW (in the worst case situation) to 77KW in normal operation. The proposed cost is $519,450.

Bidder #2 offered to provide an in-ground plug-flow digester with an inflatable hypalon cover. The cogeneration prime mover to be used for biogas combustion was a Waukesha F187GU enginator set rated at approximately 103 HP for a 77KW power output. The low bid of $355,000 did not include any provision for manure slurry collection and transport, sludge holding tank or ultimate disposal, nor the interfaces to the alcohol plant.

Bidder #3's design was based on an above-ground epoxy-lined steel tank with no mixing save that occurring through sludge convection current flows. Digester heating is accomplished through a tube-type heat exchanger on the outside tank wall. Cogeneration with the biogas fuel is to be accomplished with five FIAT Totem units, each providing 12KW of power and 131,000 Btu/hr of heat energy for recovery. The total cost is $497,800.

The major problems with all the bids fell into five general categories:

1) None of the proposals addressed heat recovery clearly or completely. There were serious questions in the minds of the Agri-Fuels evaluators as to whether this requirement was understood.

2) The thermal and electrical connections to the alcohol fuels plant were not described or were inadequately described. One bidder flatly said they would not provide these interfaces, which were described in the specification.

3) Provision of insulation to minimize heat loss and description of the insulation to be offered (for example, "R" values) was inconsistent or nonexistent in the proposals received.

4) The level and amount of operator training and contractor support proposed during installation and digester start-up was uneven and, when proposed, not specific as to how long such support and training would be provided.

5) Finally, the areas of controls, metering, and safety equipment were either not addressed or not described in sufficient detail to permit an evaluation as to their functional adequacy. The omission extended to the very important area of electrical power generation in parallel with power purchased from the grid.

The critique of these proposals, all by reputable firms in their business, is provided as a guide to the preparation of biogas cogeneration system specification and the subsequent evaluation of contractor's proposals.

The lesson to be learned is that the specification must be complete, need not be overly restrictive as to how or with what equipment the job gets done but that the contractor must be required to provide a proposal for <u>all</u> the components and functional elements of the biogas facility; then specify how to bring the system into operation.

Also, beware of hidden costs. It's best to require an itemized cost sheet which shows exactly what equipment and services are covered by the bid price.

RACINE, WISCONSIN: MUNICIPAL WASTEWATER TREATMENT PLANT

The City of Racine, Wisconsin has successfully used the gas from its sewage sludge in a partial cogeneration system since the late 1960's. The plant receives a daily average of 25 million gallons of municipal wastewater which is treated to primary and secondary (activated sludge) levels.

Anaerobic digestion is used to stabilize waste sludge, producing an average of 120,000 ft^3/day of gas which is piped directly to three internal combustion engines, a boiler, and a gas storage sphere. Figure 17 illustrates the sludge production, gas flows and heat exchanges in such a system. The Btu content of the plant's digester gas varies from 600-700 Btu/ft^3 (60-70% methane); the hydrogen sulfide content is unknown. Even though the gas is not scrubbed prior to use in the engines, no corrosion problems have been reported.

The plant has three Waukesha engines of different sizes, the largest being 420 HP, but the three are seldom on-line at once. The engines are used to drive air compressors for the activated sludge process, and backup energy is provided with electric motors. Because the system recovers only the heat from engine cooling water and allows the exhaust heat to be wasted, there is insufficient heat recovered to meet the digester warming needs. A digester gas-fired boiler is used to make up the balance of heat needed to warm the digesters and plant buildings.

The plant is equipped with a gas storage sphere of 240,000 ft^3 at 50 psi, enabling the storage of excess gas produced on weekends for use during the week. (Aeration demands are greater on weekdays.)

Plant operators seem very pleased with the engines' performance and report only one major overhaul during their 12 years of operation.

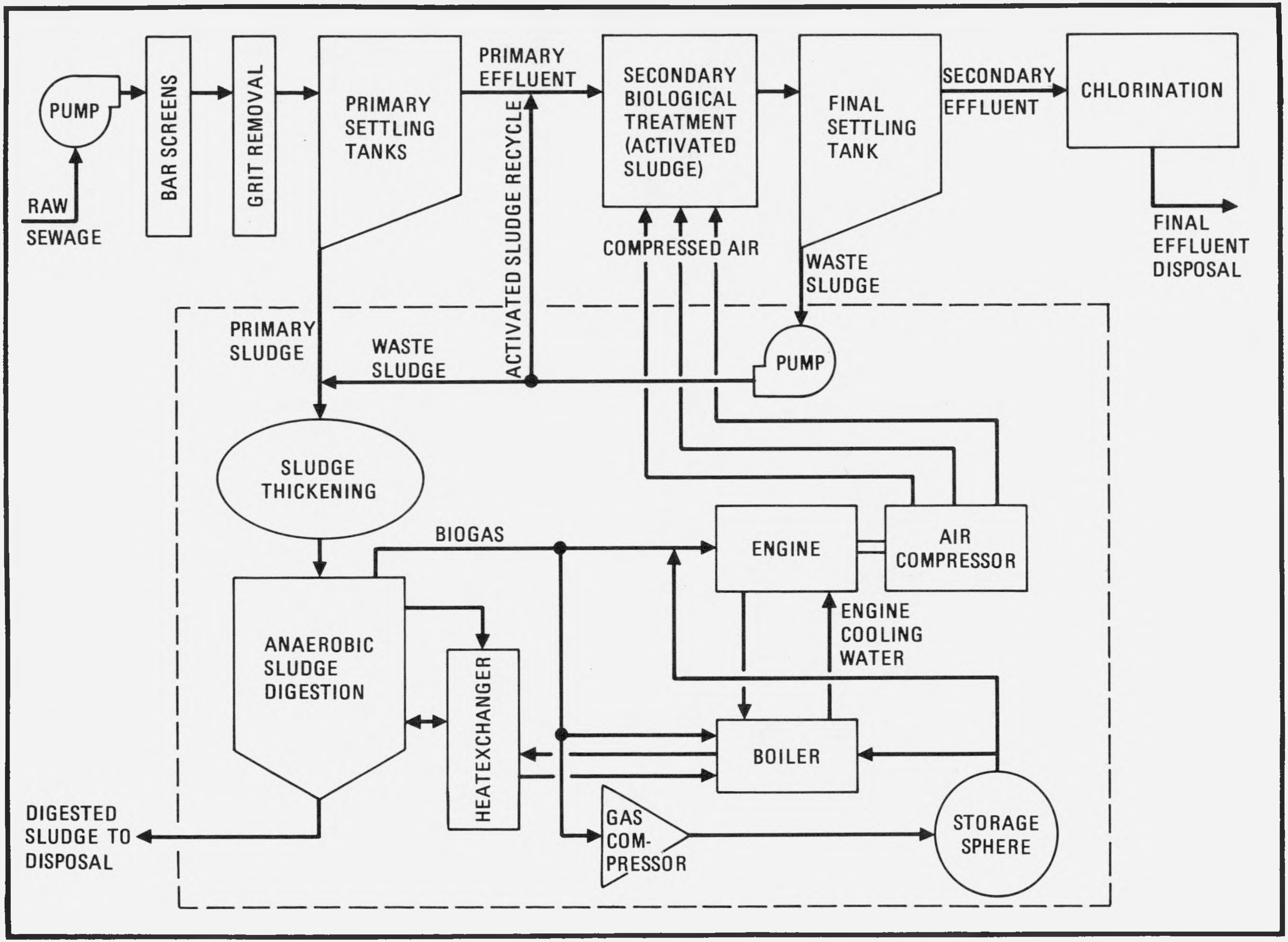

Figure 17. Racine, Wisconsin Wastewater Treatment Plant Biogas Cogeneration System.

CHAPTER 7

SITE EVALUATION GUIDELINES

Based upon the material in Chapters 2-6, the following pages provide a step-by-step procedure for evaluating biogas cogeneration at a specific site. By collecting data and completing the necessary calculations, the reader can derive a first-cut indication of the technical and economic feasibility of using biogas to cogenerate at his or her location. The analysis should provide enough information to determine whether or not the services of a professional engineering firm are warranted to actually proceed with the project design.

Because there are climatic and operational conditions which vary during the course of the year and affect the energy balances of a cogeneration system, much of the suggested analysis should be re-evaluated for several time periods. A minimum analysis in the TVA region will include one run-through for summer conditions and one for winter. More rigorous evaluations might include four iterations for the four seasons, twelve iterations for monthly analysis, or some other number suggested by cyclical process schedules. The analytical procedures as outlined below will be exactly repeated for each time period, but the data used will change from one period to the next. Briefly, the steps of analysis are these:

For each selected time period:

1) Determine the quantity of manure or sludge available.

2) Calculate the biogas producible from (1).

3) Estimate electric and thermal output compatible with (2) and select an engine.

4) Select and size the digester to fit (1).

5) Calculate the heat needed for digester (4) and other heating needs at the site.

6) Note historical electricity use at the site.

7) Compare (3) to (5) and (6).

8) Calculate the value of electricity produced by cogeneration.

9) Calculate the value of fuel saved by cogeneration.

Finally, consult Appendix 3 for regulatory steps.

A convenient worksheet for data collection appears at the conclusion of this chapter.

STEP 1: DETERMINE QUANTITIES OF SLUDGE OR MANURE AVAILABLE

There are two values which must be known or estimated about the sludge/manure supply: volume (ft^3/day) and volatile solids content (lbs/day). The volume will determine digester size and the volatile solids will predict biogas production.

The most reliable values to use for these variables are, of course, actual measurements of current collections. Wastewater sludges should be (and generally are) metered and their volatile solids content known. On a farm, however, this information is not readily available and even in a wastewater plant there may be anticipated changes in processes or flows that would make existing data obsolete. For a ballpark estimate the following suggested values, which are derived from Table 1 (Chapter 2) may be used:

Production Unit	Undiluted Volume (ft^3/day)	Diluted Volume Necessary for Pumping @7% Solids (ft^3/day)	Volatile Solids @ 80% Volatiles (lb/day)
1 mgd sewage plant*	620	-	1550
1 dairy cow	1.6	2.3	8
1 feedlot steer	1.1	1.7	5.5
1 hog	0.16	0.39	1.4
1 chicken	0.0053	0.021	0.07

*Primary and conventional activated sludge treatment.

STEP 2: DETERMINE BIOGAS PRODUCTION

The amount of biogas produced in anaerobic digestion is a function of volatile solids supplied to the process and operating efficiency of the digester. Assuming 40% destruction of volatiles in digestion (a conservative but realistic value), the amount of gas produced is simply:

____lb/day volatiles x 7 ft^3/lb = ____ft^3/day gas production.

An alternative rule-of-thumb for use in municipal wastewater applications is to expect about 1 ft^3/day per capita gas production. There is likely to be slightly greater gas yield with a complete mix digester and less gas from a plug-flow unit regardless of the estimating technique used.

STEP 3: ESTIMATE ELECTRIC AND THERMAL OUTPUTS COMPATIBLE WITH (2) AND SELECT AN ENGINE

The biogas production rates derived in Step 2 can be easily converted to hourly energy production as follows:

$$\_\_\_\_\ ft^3/day \times 600\ Btu/ft^3 \times \frac{1}{24}\ day/hr = Btu/hr \text{ (from Step 2).}$$

Where 600 Btu/ft^3 is a commonly cited heating value for digester gas.

The next step is to calculate roughly how many horsepower or kilowatts can be extracted from this energy flow rate, and subsequently how much residual heat will be left over for useful recovery. Assuming an engine which extracts 25% of fuel energy as mechanical power, the calculation proceeds as follows:

____Btu/hr x 0.25 ÷ 2544 Btu/HP-hr = ________HP
(maximum engine output)

Continuing to calculate electricity production:

________HP		x 0.746 KW/HP	x	0.92	=	____________KW
(from previous entry)		(conversion factor)		(assumed generator efficiency)		(maximum generator output)

For the computation of useable waste heat, it is not necessary at first to distinguish between engine exhaust heat and cooling water heat (as explained in Chapter 5). For an initial assessment, it is reasonable to assume that about 75% of the gross fuel energy which is <u>not extracted</u> as mechanical energy (that is, the remaining 75% after 25% is spent) will be recoverable for digester warming or other heating tasks. This assumption yields a heat recovery fraction of 56% of gross fuel input energy. Values cited in the cogeneration literature range from 40% to 60%. Therefore, the calculation follows:

________Btu/hr	x	0.75	x	0.75	=	______Btu/hr
(from first entry in Step 3)		(assumed waste heat fraction)		(assumed efficiency of heat recovery system)		(useable waste heat)

Select an engine from Table 6 (Chapter 5) with a horsepower rating about twice that calculated above, or, if convenient, contact the engine manufacturer's sales rep for a recommendation. The oversizing compensates for the lower Btu value of biogas relative to other fuels. Given the hourly Btu rate they should easily be able to specify an engine model, rate its output and quote a price. It may take some persistence to learn the characteristics of the engine exhaust, special requirements for digester gas operation and other technical details, but such information is not critical for this preliminary evaluation.

If none of the engines listed in Table 6 Chapter 5 matches the gas rates calculated earlier, check for possible engine pairs, whose combined fuel demand could match the predicted supply.

STEP 4: SELECT AND SIZE THE DIGESTER

From the discussion in Chapter 4, the reader must select either a high rate or plug-flow type digester. Then, in order to estimate the approximate cost and heating requirements of the digester, it is necessary to calculate its size. Based on high rate digester loadings of 0.2 lb volatile solids/day/ft^3 of digester fluid volume, and assuming a cylindrical shape for a high rate, complete mix reactor, the volume of this type of vessel can be computed as follows:

____ lb VS/day ÷ 0.2 lb VS/day/ft^3 ÷ 0.75 (assumed active fluid volume) = ________ ft^3 (required total volume of digester)

As a check that this volume will be sufficient to handle the manure/sludge volume predicted in Step 1, the following calculation is suggested:

______ ft^3 (total volume from previous entry) × 0.75 (assumed active fraction) ÷ ____ ft^3/day (sludge flow from Step 1) = ____ days (fluid retention time)

The resulting retention time should be between 10 and 20 days for the complete mix reactor.

The dimensions of the digester tank may vary somewhat and still provide the required fluid volume, but for simplicity, it will be assumed that the tank is cylindrical in shape with height equal to diameter (this configuration will minimize surface area). Thus, dimensions are:

$$\text{height} \_\_\_\_\_\_ \text{(ft)} = \sqrt[3]{\frac{4}{\pi}\ \text{Volume (ft}^3\text{)}}$$

and radius is one-half the height.

From the plug-flow type digester, the required volume calculation is the same as before, but a lower volatile solids loading rate must be used:

______ lb VS/day (from Step 1) ÷ 0.05 lb VS/day/ft^3 (loading rate for unmixed reaction) ÷ 0.75 (assumed active fraction) = ________ ft^3 (required fluid volume of digester)

As a volume check, the retention time can again be computed by:

____ ft^3 (total volume from previous entry) × 0.75 (assumed active fraction) ÷ _______ ft^3/day (sludge Flow from Step 1)

= _____ days (fluid retention time).

In the plug flow case, the resulting retention time should be on the order of 50 days for maximum gas production. The trade-off between retention time and digester size (therefore cost) should be considered.

The dimensions selected for a plug flow type digester will depend largely on the reader's individual site characteristics. As a starting point, the trough should be wide enough to admit whatever scooping vehicle is to be used for cleaning out the solids accumulation (refer to Chapter 4). Secondly, the fluid depth should be half to three-quarters of the width and the length should not generally exceed 100 feet. Following these guidelines, the digester dimensions can be calculated as follows:

_____ ft^3	$\div$	_____ ft	$\div \frac{1}{2}$ W ft		=	_____ ft
(required volume)		(estimated vehicle width, W)	(depth, expressed as a fraction of width)			(length)

Depending on the resulting length, the 100 foot limitation and the land area available for digester installation, the reader may decide to split the total required volume into two or more separate digesters. The length-to-width ratio of the digester should not exceed four or five to one.

When actual digester design begins, one to two feet of freeboard clearance should be allowed above the fluid level in the trough.

STEP 5: CALCULATE DIGESTER AND OTHER HEAT NEEDS

In Step 3 the amount of engine waste heat which is available for low-grade heating loads was calculated. Although this heat can be used for any reasonably nearby heating task, it is generally dedicated to digester warming first with any leftover heat going to building heating, sludge drying or other points of use. It must be re-emphasized that these heat requirements will vary substantially among seasons, making it very important that these calculations be made at least for summer and winter conditions.

Ideally, the temperature of the incoming sludge should be known to calculate the heat needed to raise it to digestion temperature, but lacking this information some substitutes can be used:

T_1 incoming sludge temp. $\approx$ Average daily temp. (T_2) − 20°F (summer)
$\approx$ Average daily temp. (T_2) + 5°F (winter)
(but sludge temperature should not be less than 40°F)

The formula for calculating heat needed to raise the sludge temperature to an assumed 95°F digestion temperature is:

______ ft^3/day	x 62.4 lb/ft^3	x $(95 - T_1)$°F	= ______ Btu/day
(sludge volume from Step 1)	(conversion factor)	(temperature increase needed)	(daily influent heat demand)

The Btu/hr rate at which this heat allowance is used will depend on the sludge feeding schedule. It might be that sludge is slowly trickled into the system around the clock, making hourly heat demand 1/24th the daily allowance; or a single hour of pumping might feed all the influent to the digester, making that one hour's heat demand equal to the entire day's allowance. However, since the engine's waste heat will be produced at a constant rate, it may be necessary to heat the influent sludge up slowly over most of the day in order to stay within the available waste heat flow rates.

A second heat requirement for digestion is to maintain the 95° temperature inside the tank in spite of heat losses through the sides, floor and roof. The general formula for these losses is:

______ ft^2	x $(95 - T_2)$°F	x U Btu/hr/ft^2/°F	= ______ Btu/hr
(wall, floor or roof surface area)	(difference between inside and outside temperatures)	(a factor describing insulating qualities of building materials)	(heat losses)

Since the digester surfaces are not all the same construction, and hence have different U factors (which, incidentally are the inverse of the more familiar "R" values), the calculation must be done separately for each surface and then the resulting Btu/hr heat losses can be added together. The surface areas can be obtained from the dimensions established in Step 4 according to these formulas:

	Cylindrical High Rate Digester	Rectangular Plug Flow Digester
Flat Roof or Floor Area*	πR^2	L x W
Domed Roof	$2 \pi R^2$	1.5 x L x W
Wall Area	$2 \pi R H$	2H(L + W)

(* most gas-filled storage covers will be between these two values)

Where R = radius of the cylindrical digester
L = length of the horizontal digester
W = width of the horizontal digester
H = wall height of either digester

Some U values likely to be needed for the calculation are:

Material	U
Wood floating cover	.33
¼" Steel floating cover	.48
¼" Steel floating cover with 2" insulating concrete	.22
¼" Steel floating cover with 3" insulating concrete	.17
12" concrete exposed to air	.86
12" concrete exposed to 1" air + 4" brick	.27
12" concrete next to 10 ft of wet earth	.11
12" concrete next to 12 ft of dry earth	.06
1" polystyrene foam (top of plug flow digester under "ballon" cover)	.24

Clearly, the addition of earth embankments around concrete tank sides improves the digester's heat retention significantly.

If calculations indicate leftover heat is available even after the digester heating requirements are met, then the following calculations can be made.

For an existing heat application, such as process or space heating, the historical energy used to accomplish the task must be known. For comparison to the cogeneration waste heat available, the following conversion factors may be used:

1 therm (100 ft^3) natural gas	= 100,000 Btu
1 KWH (1000 watts on for one hour) electric heat	= 3,413 Btu
1 gallon fuel oil	= 140,000 Btu
1 gallon propane	= 91,500 Btu
1 pound coal	= 10,000 Btu
1 pound wood (dry)	= 7,000 Btu

The timing, as well as quantity, of heat demanded must always be considered so that conflicting needs for engine waste heat are avoided. Because the digesters will need less heat in summer than in winter, this would be an ideal time to divert some cogeneration surplus heat to other jobs.

For new heating tasks with no existing fuel records, the heat input must be estimated. Several possible applications follow:

- For heating only fluid, apply the same energy calculations used for sludge heating and temperature maintenance.

- For heating a well-sealed building, use the heat loss calculations explained for a rectangular digester.

- For drying wet sludge, use this formula:

$$\underline{\qquad} \text{ft}^3/\text{day} \times 62.4 \text{ lb/ft}^3 \times \left[1 - \frac{\%\text{ Solids incoming}}{\%\text{ Solids desired}}\right]$$

(wet sludge flow rate) (conversion factor)

$\times$ 1040 Btu (heat required to vaporize one pound of water) = ______________Btu/day

STEP 6: EVALUATE ELECTRICITY NEEDS AT THE SITE

For each time period that cogeneration is evaluated (monthly, seasonally, etc.) the following information about electricity use is needed:

- average daily KWH usage for the period, based on at least one year's records (the monthly KWH appears on power bills)
- average KW demand (monthly KWH ÷ 720 hrs/month)
- peak KW demand (large power users will find this information on their bill; others must estimate it by adding up all the electrical devices they have which might be operated simultaneously)

At most installations the electricity produced by cogeneration will merge with purchased energy on the plant power bus, so that no specific device will operate on cogenerated power. If a completely dedicated load for the cogenerated electricity is desired, the system must be electrically isolated from the site's existing power lines.

In addition to historical energy use, two adjustments must be made as a result of the cogen installation:

- If any electric heating is to be replaced with engine waste heat, that electric load must be removed from the inventory of electricity uses.
- New electric devices to operate the digester must be added to the inventory. Probably the major addition will be an influent pump, whose energy needs are calculated in two steps:

$$\underline{\qquad} \text{ft}^3/\text{day} \div \underline{\qquad} \text{hrs/day} \div 3600 \text{ sec/hr} = \underline{\qquad} \text{ft}^3/\text{sec}$$

(sludge flow rate from Step 1) (time pump is run daily) (conversion factor) (sludge flow rate when pump is running)

____ ft^3/sec ×	____ ft ÷	0.7 ÷	11.8 ft^4/sec-KW =	____ KW
(pumped sludge flow rate from previous entry)	(digester depth from Step 4)	(assumed efficiency factor)	(conversion factor)	(electric power required by pump)

The electric energy usage of the pump (kilowatt hours) can be computed by multiplying the KW just calculated by the number of hours per day or per month the pumps will be on.

Other electric devices which will be needed to digest the sludge/manure and cogenerate with the resulting biogas may include:

- gas circulation blowers or mechanical stirrers

- small gas compressor

- hot water circulating pump

- air compressor for engine air-start motor

- lights, instruments, etc.

These items are not large energy users, however, and can be expected to consume less than 10% of the cogeneration system's power output in most cases.

STEP 7: COMPARE ENERGY PRODUCTION TO ENERGY USE

Looking back through calculations in Steps 1 through 6, a summary can be extracted that indicates how well the cogeneration system will meet the electric and thermal energy needs of its host site. Because the digestion process generates a relatively constant flow of gas from day to day, and because most engines operate best if they are not turned on and off frequently, it is desirable to have a cogeneration system which runs uniformly 24 hours a day. Due to seasonal variations in biogas production and digester heating requirements, it will not be possible to meet winter energy needs as successfully as summer loads. Comparisons should be made during each time period among the following factors:

Compare cogenerator electric output (KW)	to	(1) Average electric load (KW) (from KWH/MO ÷ 720 HRS/MO) (2) Peak electric load (KW)
Compare cogenerator thermal output (Btu/day)	to	(1) Digester heating needs (Btu/hr x 24) (2) Total heating load of digester and other tasks (Btu/day)

It is often helpful to plot the energy balances for each period of evaluation. Two examples of such plots appear in Figures 18 and 19.

During periods when the waste heat of the cogeneration system is insufficient to warm the sludge, some action must be taken to maintain temperature and prevent digester shutdown. The choices are:

- Divert biogas from engine directly to sludge heater
- Supplement biogas with purchased standby fuel
- Increase concentration of influent sludge, thus reducing heat demand.

STEP 8: VALUE OF COGENERATED ELECTRICITY

In order to evaluate the economics of biogas cogeneration, the following steps will be taken <u>just once</u>, for a one year period. The annual electricity produced by the system is easily calculated:

_____KW	x 8760 hrs/yr x	0.8	=	_________KWH/yr
(power output from Step 3)		(assumed 80% of maximum output)		(electric energy output)

The value of this electricity depends to some extent on how it is to be used. If all of it will be used on-site, then the value is the price which the site owner pays his utility for electricity, usually shown on the power bill (¢/KWH). Be sure to include taxes and fuel adjustment fees but not fixed charges such as service charges.

If the electricity will be wholly or partially sold to the utility, then the value of the sold energy is the price paid to the owner by the utility for his electricity. It may be necessary to divide the energy output into two blocks with different values in order to compute the total energy value.

Two other factors must be considered in the value of cogenerated electricity. First is the demand charge ($/KW/MO) which large users must pay for their peak power use. If the cogeneration system reduced the owner's peak demands, then it creates a second economic value in addition to energy charge reductions. Second is the possible imposition of a "stand-by charge" which the cogenerator may have to pay the utility as compensation for providing emergency generating capacity. This will be a reduction in the annual energy value. Rules governing standby charges may be obtained from the local electric distributor.

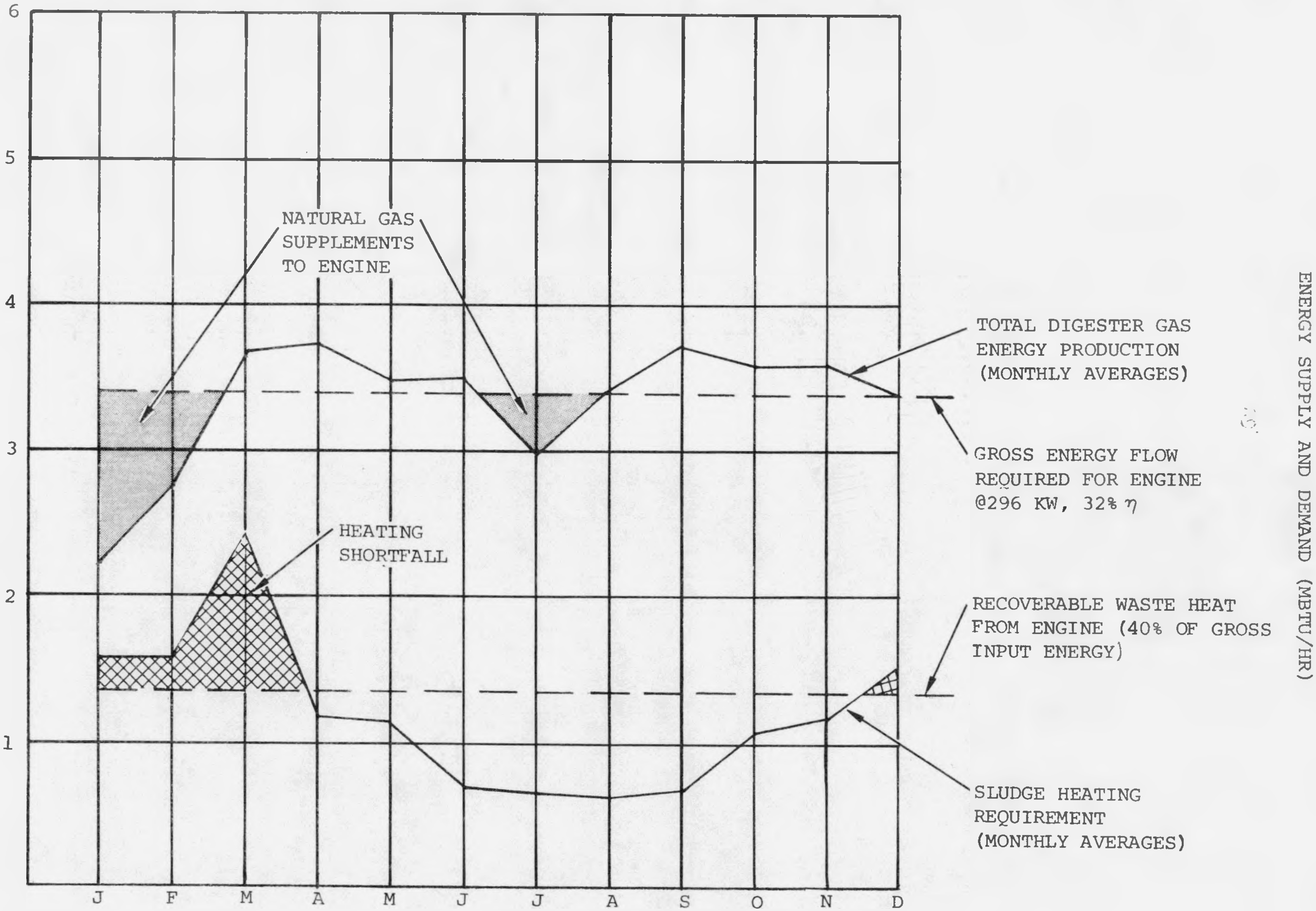

Figure 18. Whites Creek Wastewater Treatment Plant Energy Balance.

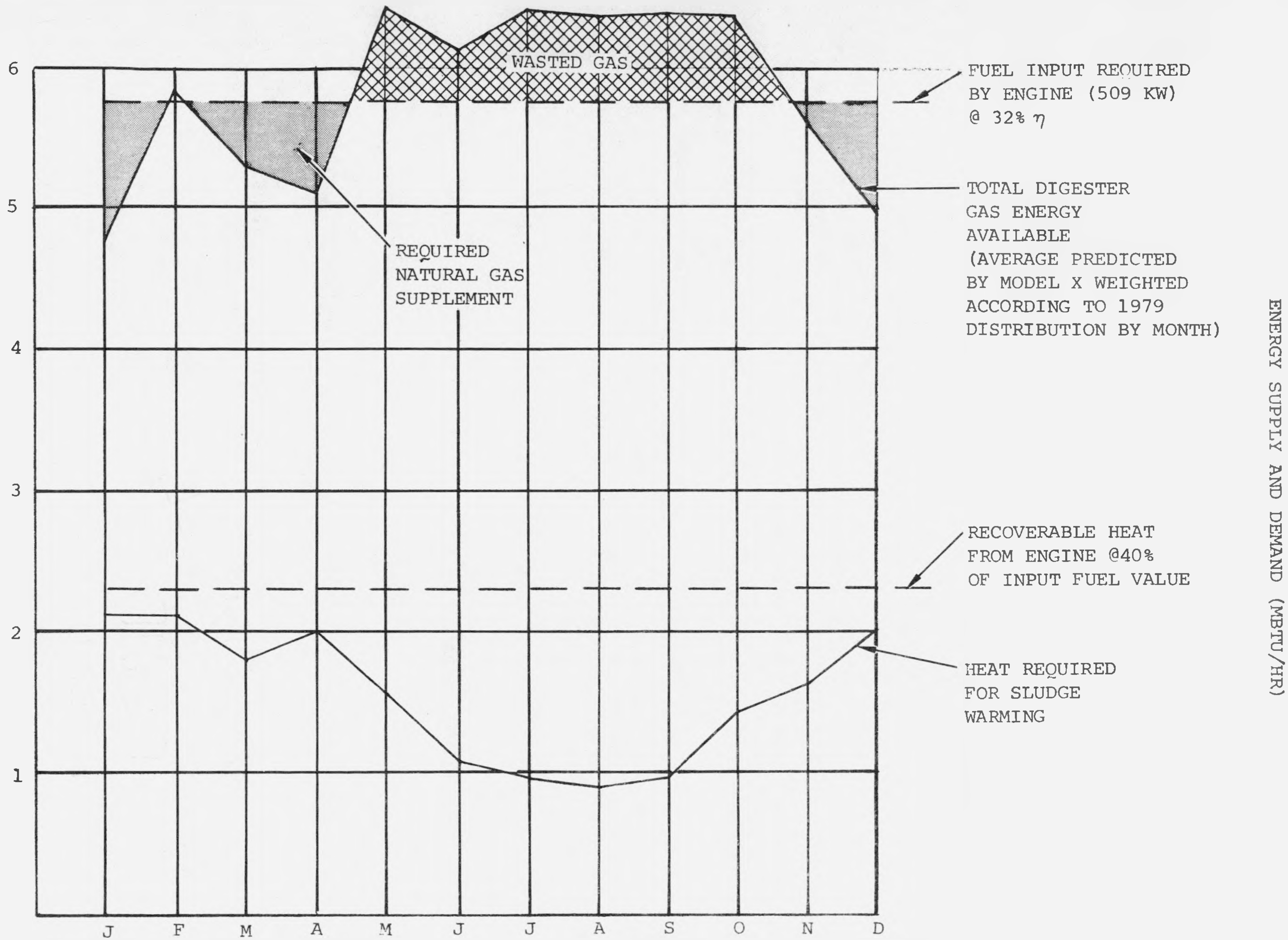

Figure 19. Dry Creek Wastewater Treatment Plant Energy Balance.

STEP 9: VALUE OF COGENERATED HEAT

The value of the heat produced by cogeneration is generally much less than the electricity because most of it goes into sustaining the digestion process. However, the excess heat can be valued at the cost of the fuel which is displaced:

_____Btu/day	x 365 days/yr x 0.8 x	___$/unit	÷ Btu/unit	=	____$/hr
(excess useable heat from cogeneration)		(price of standard fuel)	(conversion factor)		(fuel value)

Possibly offsetting this fuel savings, however, is the supplemental fuel that may be used during times of biogas shortage, as in Figures 18 and 19.

An indirect value of cogeneration heat may be taken into account if the digestion process in some way increases the value of the treated sludge/manure.

STEP 10: VALUE OF DIGESTER SLUDGE BY-PRODUCT

If the digester wastes can be used on-site to offset some current expense or sold to a local market, this economic benefit will enter the analysis:

_____ft^3/day	x 365 days/year x	____$/$ft^3$	=	_____$/yr
(digester product in final form)		(local value of digested product)		

STEP 11: ESTIMATING COGENERATION SYSTEM COSTS

There are many sources of variation in the cost to install a biogas cogeneration system, such as the size of the operation, generic types and brand names of equipment selected, owner's preference for automatic versus manual controls, degree to which installation labor will be contracted out, site layout, availability of existing facilities and equipment for use in cogeneration. The range of system cost as indexed by electrical capacity is suggested by a few examples of biogas cogeneration:

FACILITY	CAPITAL COST
A very large wastewater plant is building a combined cycle (gas and steam turbine) power plant to run on digester gas (1981).	\$2200/KW (excl. digester)
Two medium sized wastewater treatment plants have studied biogas cogeneration with spark ignition engines (1980).	\$850-1230/KW (excl. digester & engineering.)

A large wastewater treatment plant has studied biogas cogeneration using spark ignition engines (1976).	\$1400/KW (excl. digester)
A large dairy with 700 cow units, including plug-flow digester with gas storage and cogeneration system (1979).	\$1000/KW (incl. digester)
Small dairy with 100 cow units, including simple complete-mix digester, gas storage, and cogeneration system (1981).	\$3400/KW (incl. digester)
500 cow dairy, including concrete digester with no storage and cogeneration system (1981).	\$1500/KW (incl. digester)

What follows is a "shopping list" for a biogas cogeneration system. A few items are optional, as indicated, or others may already be available at the site, but in general any bid for a system should include these elements.

- Digester
- Sludge pump and piping
- Gas compressor
- Gas storage tank (optional)
- Valves, meters, piping and misc.
- Engine-generator set
- Heat recovery equipment
- Grid protection equipment
- Digester/engine building (optional)
- Engineering services
- Licensing and permits

Quotes for these items can vary tremendously, as implied by the example facilities. Therefore, for the purpose of preliminary economic assessment, some general cost indices, rather than component costs, will be used for estimating biogas cogeneration system costs. Below are ballpark figures provided by companies who package biogas cogeneration systems or part of them. Use digester volume calculated in Step 4.

Traditional (Wastewater Treatment Plant) Complete-Mix Digester System

Digester, sludge heating, plumbing, gas storage, and digester control building (<u>no</u> engine-generator set, but see Table 6, Chapter 5).

\$35/ft^3 of digester for 5000 ft^3 total volume

\$15/ft^3 of digester for 5000-25000 ft^3 total volume

\$ 9/ft^3 of digester for over 25000 ft^3 total volume

Simple Complete-Mix Digester System:

Entire biogas cogeneration package.

$16/ft^3 of digester for 9000 ft^3 total volume

$13/ft^3 of digester for 18000 ft^3 total volume

$12/ft^3 of digester for 30000 ft^3 total volume

$ 4/ft^3 of digester for 60000 ft^3 total volume

Plug-flow Digester System:

Entire biogas cogeneration package.

$22/ft^3 of digester for 4000 ft^3 total volume

$7.50/ft^3 of digester for 27000 ft^3 total volume

Biogas cogeneration system costs developed with these indices should be inflated by about 30% to cover engineering services, possible permitting, and a contingency allowance.

STEP 12: EVALUATE PROJECT ECONOMICS

Notwithstanding the rigorous economic tools developed for energy project evaluations, in a preliminary feasibility assessment simple economics will do. From the investor's standpoint, the fundamental issue is whether the purchase of a cogeneration system will earn a better return on his money than other investment opportunities. The debt-financed project must satisfy a similar hurdle: the earnings on a cogeneration system must at least be sufficient to repay the borrowed funds. These criteria can be evaluated with a simple return-on-investment calculation.

1) Grouping Costs and Benefits

Throughout this book many technical points have been discussed which boil down to dollars and cents effects on the cogenerator. In order to evaluate the project's economics, these factors must all be identified, quantified and sorted into the categories below.

	Costs I	Benefits II	Net III
One time only (at least near onset).	Engineering, design, permit licensing, etc. Purchase and installation of of equipment. Construction of facilities.	Govt. grants (if any) Avoided cost of another system. Tax credit.	I-II= Net initial investment.
Annually (or periodically occurring).	Operating and maintenance including periodic parts replacement (converted to uniform $ per year allowance).	Electricity savings. Fuel savings. Reduction in waste disposal costs (if any). Value of digester residue.	II-I= Net Annual Benefit.

2) <u>Calculating Return on Investment or Payback</u>

Depending on which economic index is more familiar to the investor, either the ROI or the payback criterion may be used for preliminary economic evaluation. Although these measures are not theoretically rigorous, for a first-cut evaluation the level of certainty in the data is not high enough to warrant detailed computations.

Simply stated, each of the four cost-benefit boxes developed in 1) is totalled and then the net values entered in column three as indicated. The return on investment is computed as:

$$ROI = \frac{\text{Net Annual Benefits}}{\text{Net Initial Investment}}$$

and payback is just the inverse of this ratio.

3) <u>Comparing Returns on Competing Investments</u>

If the resulting ROI lies much below the investor's return on other investments (or his cost to borrow money for the project) then the project's economic outlook is not good as it's currently planned. Conversely, an ROI which is substantially higher than the other investment return, warrants further work toward implementation. If the biogas cogeneration ROI is about par with competing investment opportunities, then an effort should be made to further refine the cost-benefit data before a decision is made.

Two additional factors must be included in the comparison of investment returns. The first of these is the effect of income taxes on earnings from traditional investments. Since the cost of taxes on a biogas cogeneration system was included in the annual cost box in 1), the rates of return on competing investments must also be considered after taxes to be comparable. Secondly, the likelihood that energy prices will continue to go up in future years tends to make a cogeneration system more attractive than its ROI would suggest. Since the system is characterized by a large fixed capital outlay followed by years of ever increasing energy benefits, the one-year ROI will understate the value of the system's long-term benefits.

EVALUATION WORKSHEET

Site Name & Location:____

(a) Time period to which Data Apply (specify which month, season or other):____

(b) Type & Number of Organic Waste Producers________________________

(c) Organic Waste Flow Rate_________________________________ft^3/day

(d) Volatile Solids Collection Rate__________________________lb/day

(e) Biogas Production ('d' x 7 or 1 ft^3/dapita/day)__________ft^3/day

(f) Energy Availability ('e' x 600/24)________________________Btu/hr

(g) Horsepower Producible ('f' x 0.25 ÷ 2544)____________________HP

(h) Kilowatts Producible ('g' x 0.746 x 0.92)____________________KW

(i) Waste Heat Usable ('f' x 0.75 x 0.75)_____________________Btu/hr

(j) Preliminary Engine Selection:____________Mnftr_______Model______

(k) High Rate Digester volume ('d' ÷ 0.2 ÷ 0.75)_________________ft^3

(l) High Rate Volume Check ('k' x 0.75 ÷ 'c')___________________days

(m) High Rate Digester Height ($\sqrt[3]{4/\pi \times 'k'}$)____________________ft

(n) High Rate Digester Radius ($\frac{1}{2}$ x 'm')__________________________ft

(o) Plug Flow Digester Volume ('d' ÷ 0.05 ÷ 0.75)________________ft^3

(p) Plug Flow Volume Check ('o' x 0.75 ÷ 'c')___________________days

(q) Plug Flow Digester Width (from vehicle size)__________________ft

(r) Plug Flow Digester Depth ($\frac{1}{2}$ x 'g')___________________________ft

(s) Plug Flow Digester Length ('o' ÷ 'q' ÷ 'r')____________________ft

(t) Number of Troughs and Lengths_______________________________ft

(u) Incoming Sludge Temperature________________________________^oF

(v) Daily Heat Needed for Influent____________________________Btu/day

(w) Roof material and U-value______________________________________

(x) Roof area (1.4 π 'n'^{2} for high rate)________________________
(1.25 x 's' x 'q' for plug flow)________________________ ft^2

(y) Roof heat losses ('x' x (95 - T_2) x 'w')________________ Btu/hr

(z) Wall material and U-Value________________________

(aa) Wall area (2π x 'n' x 'm' for high rate)
(s x 'r' x ('q' + 's') for plug flow)________________ ft^2

(bb) Wall heat losses ('aa' x (95 - T_2) x 'z')________________ Btu/hr

(cc) Floor material and U-value ________________________

(dd) Floor area (π x 'n'^{2} for high rate)
('q' x 's' for plug flow)________________________ ft^2

(ee) Floor heat losses ('dd' x(95 - T_2) x 'cc')________________ Btu/hr

(ff) Total hourly heat losses ('y' + 'bb' + 'ee')________________ Btu/hr

(gg) Total daily digester heat needs (('ff') x 24 + 'v')______ Btu/day

(hh) Total daily waste heat supply (24 x 'i')________________ Btu/day

(ii) Excess Waste Heat ('hh' - 'gg')________________________ Btu/day

(jj) Next Heat Load (if 'hh' > 'gg')________________________ Btu/day

(kk) Heat rate needed for 'jj' ________________________ Btu/day

(ll) Average electricity use (from bills)________________ KWH/day

(mm) Average electricity demand ('ll' ÷ 24)________________ KW

(nn) Peak electric demand (from bill or inventory)________________ KW

(oo) Load adjustment due to Cogeneration (±)________________ KW

(pp) Average electric load after cogeneration ('mm' + 'oo')________ KW

(qq) Peak electric load after cogeneration ('nn' + 'oo')__________ KW

(rr) Average daily electricity use after cogeneration
('ll' + ('oo' x 24))________________________ KWH/day

(ss) Energy summary:
Cogen power output ('h')________________ KW
Average power load ('mm')________________ KW
Peak Power Load ('nn')________________ KW
Cogen thermal output ('i' x 24)__________ Btu/day
Digester thermal load ('gg')__________ Btu/day
Other thermal load ('gg')__________ Btu/day

THE REMAINDER OF THE WORKSHEET IS FOR ONE FULL YEAR

(tt) Annual on-site electricity demand to be cogenerated (smaller of 'h' x 7008 or 'll' x 365)________________KWH/yr

(uu) Price paid for electricity (composite from bill)__________¢/KWH

(vv) Annual value of cogenerated on-site electricity ('tt' x 'uu' ÷ 100)________________$/yr

(ww) Annual cogenerated electricity to be sold to utility ('h' x 7008 - 'tt') if any________________KWH/yr

(xx) Price offered by utility for purchasing electricity_______¢/KWH

(yy) Annual value of electricity sales ('ww' x 'zz' ÷ 100)_______$/YR

(zz) Reduction in peak demand ('h')________________KW

(aaa) Demand charges, if any ($ from bill)________________$/KW/mo

(bbb) Annual value of reducing demand (12 x 'aaa' x 'zz')________$/yr

(ccc) Added standby charge (ask distributor)________________$/KW/mo

(ddd) Annual cost of standby service ('ccc' x 'h' x 12)__________$/yr

(eee) Total annual electricty value ('vv' + 'yy' + 'bbb' - 'ddd')

________________$/yr

(fff) Standard fuel used on site________________

(ggg) Price (from bill, transformed to BTU equivalent)________$/MBTU

(hhh) Annual value of cogen heat ('ii' x 365 x 'ggg')__________$/yr

(iii) Annual Value of Digested Sludge________________$/yr

(jjj) Estimated Annual O&M Cost________________$/yr

(kkk) Net Annual Benefit ('eee' + 'hhh' + 'iii' - 'jjj')________$/yr

(lll) Biogas Cogeneration System Cost________________$

(mmm) Total Investment Tax Credit, Energy Tax Credit, and Grants

________________$

(nnn) Net Initial Investment ('lll - 'mmm') ______________________ $

(ooo) ROI ('kkk' ÷ 'nnn') ______________________ per year

(ppp) Simple payback (1/'ooo') ______________________ years

Note: Line 'nnn' assumes an all cash investment with tax credits claimed the first year. To compute ROI and simple payback for a financed project with tax credits carried forward, net initial investment ('nnn') becomes down payment minus grants and first year tax credit, and net annual benefit ('kkk') needs annual debt payment subtracted from it and carried forward tax credits added to it.

APPENDIX 1

ARCHITECTURAL AND ENGINEERING FIRMS EXPERIENCED IN BIOGAS COGENERATION SYSTEM DESIGN

Anaerobic Energy Systems PO Box 1477, 170 N. Florida Ave. Bartow, Florida 33830	813/533-4161
AWARE PO Box 16778 Greenville, South Carolina 29606	615/373-3243
Biogas of Colorado 5620 Kendall Ct., Unit G Arvada, CO 80002	303/422-4354
Cal Recovery Systems Inc. 160 Broadway, Suite 200 Richmond, California 94804	415/232-3066
Consoer Townsend 44 James Robertson Parkway Nashville, Tennessee 37219	615/244-8864
Dames and Moore 3399 Tate's Creek Road Lexington, Kentucky 40502	606/269-3693
Energy Harvest Inc. Suite 602 1735 I. Street, N.W. Washington, DC 20006	202/659-3030
Engineering-Science Inc. Suite 590 57 Executive Park South Atlanta, Georgia 30329	404/325-0770
Engineering-Science Inc. Harmon Engineering and Testing Auburn Industrial Park Auburn, Alabama 36830	205/821-9250
Environmental Dynamics Inc. PO Box 16778 Greenville, South Carolina 29606	803/292-1921

ER&A, Inc. 213/452-4905
1820 14th Street
Santa Monica, California 90404

Hoyle Tanner and Associates, Inc. 603/669-5420
One Technology Park
Londonderry, New Hampshire 03053

James Montgomery Consulting Engineers, Inc. 703/860-2400
Reston International Center
11800 Sunrise Valley Drive
Reston, Virginia 22091

Perennial Energy Inc. 417/261-2204 - 2547
Box 15
Dora, Missouri 65637

Resource Conservation Consultants 503/227-1319
1615 NW 23rd Avenue
Portland, Oregon 97210

HEAT EXCHANGER MANUFACTURERS

Alpha United, Inc. 213/322-9570
1301 E. El Segundo Boulevard
El Segundo, California 90245

Bobbitt Company, Inc. 919/273-4743
PO Box 9122, Dept. TR
Greensboro, NC 27408

Gaston County Fabrication 704/263-4765
PO Box 208
Stanley, NC 28164

Industrial Heat Exchanger Manufacturing Corp. 901/423-0385
PO Drawer 1056
Jackson, Tennessee 38301

Industrial Piping Inc. 704/588-1100
PO Box 518
Route 2, Downs Road
Charlottsville, NC 28134

Metal Equipment Company, Inc. 912/236-3378
PO Box 153
Savannah, Georgia 31402

APPENDIX 2

DIGESTER MANUFACTURERS

Anaerobic Energy Systems PO Box 1477, N. Florida Ave. Bartow, Florida 33830	813/522-4161
Biogas of Colorado 5620 Kendall Court Unit G Avada, Colorado 80002	303/422-4354
Dorr-Oliver 2964 Peachtree Road NW Atlanta, Georgia 30305	404/394-6200
Energy Harvest, Inc. Suite 602 1735 I Street, NW Washington, DC 20006	202/659-3030
Envirex 1901 S. Prarie Avenue Waukesha, Wisconsin 53186	414/547-0141
Perennial Energy, Inc. PO Box 15 Dora, Missouri 65637	417/261-2204 - 2547

APPENDIX 3

LEGAL AND REGULATORY CHECKLIST

The following is a list of government agencies which should be contacted regarding permitting and licensing for a biogas cogeneration installation.

FEDERAL ENERGY REGULATORY COMMISSION (FERC)

The Federal Power Act requires all power generating facilities except those exempted by the Act be licensed. FERC issues such permits.

STATE PUBLIC UTILITY BOARD

This commission sets the rates for power sales, and will help in case of conflict with the local utility.

ELECTRIC POWER DISTRIBUTOR

The local utility will provide information on electricity buyback rates and on the equipment requirements for grid interface.

COUNTY PLANNING BOARD

This body dispenses all of the building permits, and checks plans to make sure that they conform to the uniform building, plumbing, and electrical codes. The board will have copies of these code requirements available.

OCCUPATIONAL SAFETY AND HEALTH ADMINISTRATION (OSHA)

OSHA sets the standards for safety in industry. If the installation is part of a commercial entity, and people will be working at the cogeneration site, check with this body about required safety features.

STATE ENERGY OFFICE

Contact this office for information about various energy demonstration, financing, and research programs.

APPENDIX 4

LIST OF REFERENCES

The following sources were consulted in the preparation of this manual and are recommended further reading:

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