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# 3-CUBIC METER BIOGAS PLANT

## A CONSTRUCTION MANUAL



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### 3-CUBIC METER BIOGAS PLANT

#### A CONSTRUCTION MANUAL

### I. WHAT IT IS AND HOW IT IS USEFUL

Biofuels are renewable energy sources from living organisms. All biofuels are ultimately derived from plants, which use the sun's energy by converting it to chemical energy through photosynthesis. When organic matter decays, burns, or is eaten, this chemical energy is passed into the rest of the living world. In this sense, therefore, all life forms and their by-products and wastes are storehouses of solar energy ready to be converted into other usable forms of energy.

The kinds and forms of the by-products of the decay of organic matter depend on the conditions under which decay takes place. Decay (or decomposition) can be aerobic (with oxygen) or anaerobic (without oxygen). An example of anaerobic decomposition is the decay of organic matter under water in certain conditions in swamps.

Aerobic decomposition yields such gases as hydrogen and ammonia. Anaerobic decomposition yields primarily methane gas and hydrogen sulfide. Both processes produce a certain amount of heat and both leave a solid residue that is useful for enriching the soil. People can take advantage of the decay processes to provide themselves with fertilizer and fuel. Composting is one way to use the aerobic decay process to produce fertilizer. And a methane digester or generator uses the anaerobic decay process to produce both fertilizer and fuel.

One difference between the fertilizers produced by these two methods is the availability of nitrogen. Nitrogen is an element that is essential to plant growth. As valuable as compost is, much of the nitrogen held in the original organic materials is

lost to the air in the form of ammonia gas or dissolved in surface runoff in the form of nitrates. The nitrogen is thus not available to the plants.

In anaerobic decomposition the nitrogen is converted to ammonium ions. When the effluent (the solid residue of decomposition) is used as fertilizer, these ions affix themselves readily to soil particles. Thus more nitrogen is available to plants.

The combination of gases produced by anaerobic decomposition is often known as biogas. The principle component of biogas is methane, a colorless and odorless gas that burns very easily. When handled properly, biogas is an excellent fuel for cooking, lighting, and heating.

A biogas digester is the apparatus used to control anaerobic decomposition. In general, it consists of a sealed tank or pit that holds the organic material, and some means to collect the gases that are produced.

Many different shapes and styles of biogas plants have been experimented with: horizontal, vertical, cylindrical, cubic, and dome shaped. One design that has won much popularity, for reliable performance in many different countries is presented here. It is the Indian cylindrical pit design. In 1979 there were 50,000 such plants in use in India alone, 25,000 in Korea, and many more in Japan, the Philippines, Pakistan, Africa, and Latin America. There are two basic parts to the design: a tank that holds the slurry (a mixture of manure and water); and a gas cap or drum on the tank to capture the gas released from the slurry. To get these parts to do their jobs, of course, requires provision for mixing the slurry, piping off the gas, drying the effluent, etc.

In addition to the production of fuel and fertilizer, a digester becomes the receptacle for animal, human, and organic wastes. This removes from the environment possible breeding grounds for rodents, insects, and toxic bacteria, thereby producing a healthier environment in which to live.

## II. DECISION FACTORS

Applications: \* Gas can be used for heating, lighting, and cooking.

\* Gas can be used to run internal combustion engines with modifications.

\* Effluent can be used for fertilizer.

Advantages: \* Simple to build and operate.

\* Virtually no maintenance--25-year digester lifespan.

\* Design can be enlarged for community needs.

\* Continuous feeding.

\* Provides a sanitary means for the treatment of organic wastes.

Disadvantages: \* Produces only enough gas for a family of six.

\* Depends upon steady source of manure to fuel the digester on a daily basis.

\* Methane can be dangerous. Safety precautions should be observed.

## CONSIDERATIONS

Construction time and labor resources required to complete this project will vary depending on several factors. The most important consideration is the availability of people interested in doing this project. The project may in many circumstances be a secondary or after-work project. This will of course increase the length of time needed to complete the project. The construction times given here are at best an estimation based on limited field experience.

Skill divisions are given because some aspects of the project require someone with experience in metalworking and/or welding. Make sure adequate facilities are available before construction begins.

The amount of worker-hours needed is as follows:

\* Skilled labor - 8 hours

\* Unskilled labor - 80 hours

\* Welding - 12 hours

Several other considerations are:

\* The gas plant will produce 4.3 cubic meters of gas per day on the daily input from eight cattle and six humans.

- \* The fermentation tank will have to hold approximately 7 cubic meters in a 1.5 X 3.4 meters deep cylinder.
- \* A gas cap to cover the tank should be 1.4 meters in diameter X 1.5 meters tall.

### COST ESTIMATE

\$145-800 (U.S., 1979) includes materials and labor.

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(\*)Cost estimates serve only as a guide and will vary from country to country.

### III. MAKING THE DECISION AND FOLLOWING THROUGH

When determining whether a project is worth the time, effort, and expense involved, consider social, cultural, and environmental factors as well as economic ones. What is the purpose of the effort? Who will benefit most? What will the consequences be if the effort is successful? And if it fails?

Having made an informed technology choice, it is important to keep good records. It is helpful from the beginning to keep data on needs, site selection, resource availability, construction progress, labor and materials costs, test findings, etc. The information may prove an important reference if existing plans and methods need to be altered. It can be helpful in pinpointing "what went wrong?" And, of course, it is important to share data with other people.

The technologies presented in this series have been tested carefully, and are actually used in many parts of the world. However, extensive and controlled field tests have not been conducted for many of them, even some of the most common ones. Even though we know that these technologies work well in some situations, it is important to gather specific information on why they perform better in one place than in another.

Well documented models of field activities provide important information for the development worker. It is obviously important for a development worker in Colombia to have the technical design for a plant built and used in Senegal. But it is even more important to have a full narrative about the plant that provides details on materials, labor, design changes, and so forth. This model can provide a useful frame of reference.

A reliable bank of such field information is now growing. It exists to help spread the word about these and other technologies, lessening the dependence of the developing world on



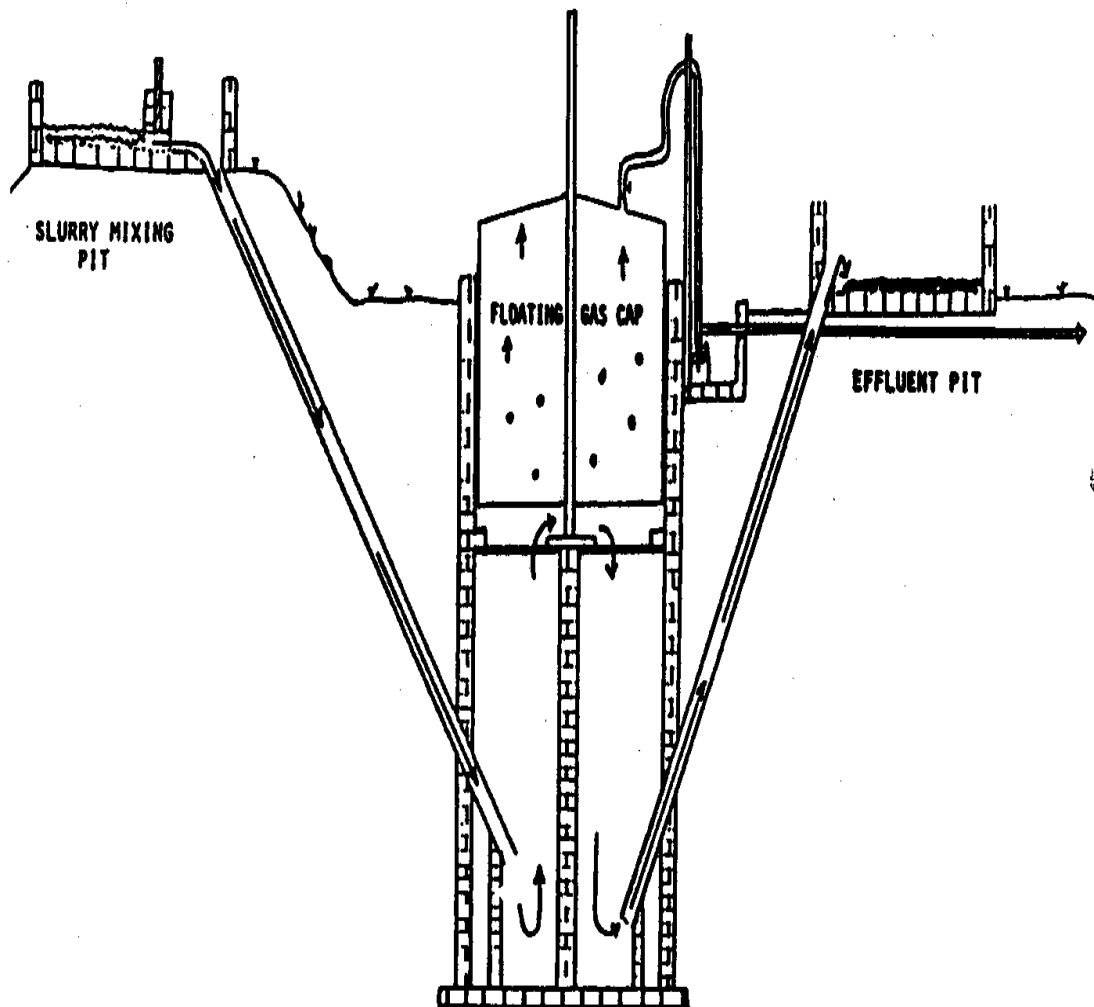
expensive and finite energy resources.

A practical record keeping format may be found in Appendix II.

#### IV. PRECONSTRUCTION CONSIDERATIONS

The design presented here <see figure 1> is most useful for temperate or

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**Figure 1. 3-Cubic Meter Biogas Digester**

tropical climates. It is a 3-cubic meter plant that requires the equivalent of the daily wastes of six-eight cattle. Other sizes are given for smaller and larger digester designs for comparison.

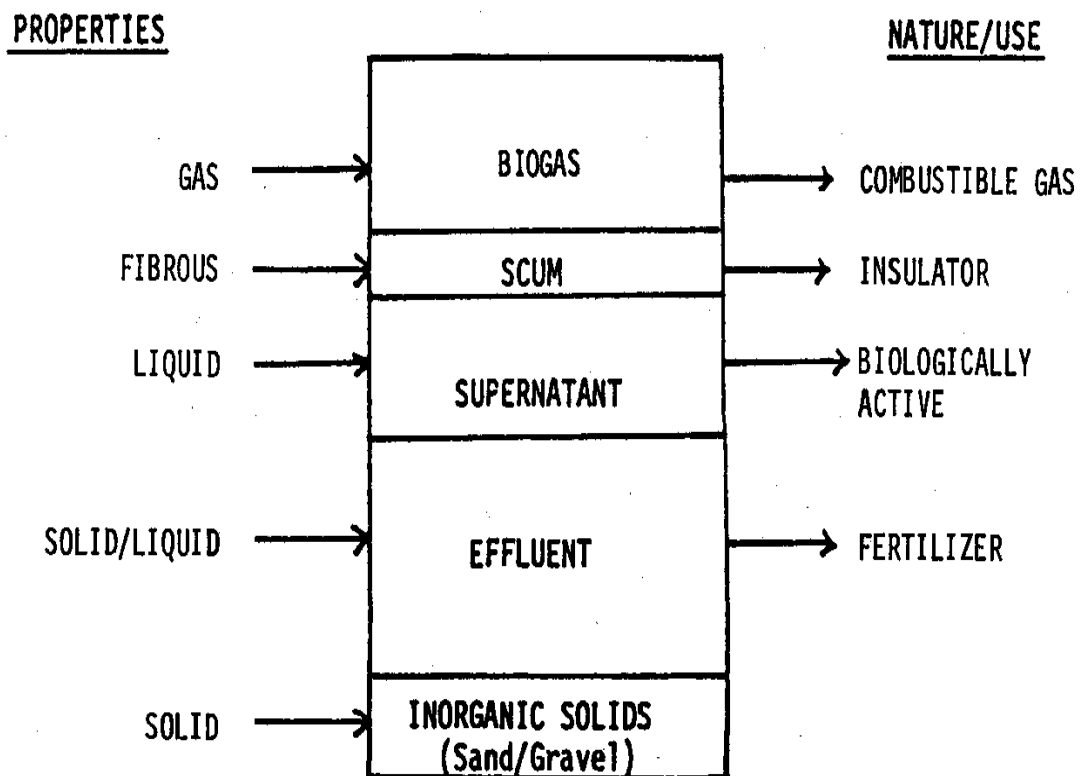
This digester is a continuous-feed (displacement) digester.

Relatively small amounts of slurry (a mixture of manure and water) are added daily so that gas and fertilizer are produced continuously and predictably. The amount of manure fed daily into this digester is determined by the volume of the digester itself, divided over a period of 30-40 days. Thirty days is chosen as the minimum amount of time for sufficient bacterial action to take place to produce biogas and to destroy many of the toxic pathogens found in human wastes.

#### BY-PRODUCTS OF DIGESTION

Table 1 shows the various stages of decomposition and the forms

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**Table 1. Anaerobic Decomposition of Organic Material in Biogas Digesters**

of the material at each stage. The inorganic solids at the bottom

of the tank are rocks, sand, gravel, or other items that will not decompose. The effluent is the semisolid material left after the gases have been separated. The supernatant is biologically active liquid in which bacteria are at work breaking down the organic materials. A scum of harder-to-digest fibrous material floats on top of the supernatant. It consists primarily of plant debris. Biogas, a mixture of combustible (burnable) gases, rises to the top of the tank.

The content of biogas varies with the material being decomposed and the environmental conditions involved. When using cattle manure, biogas usually is a mixture of:

[CH.sub.4] (Methane)	54-70%
[CO.sub.2] (Carbon Dioxide)	27-45%
[N.sub.2] (Nitrogen)	.5-3%
[H.sub.2] (Hydrogen)	1-10%
CO (Carbon Monoxide)	0-.1%
[O.sub.2] (Oxygen)	0-.1%
[H.sub.2]S (Hydrogen Sulfide)	
Small amounts of trace elements, amines, and sulphur compounds.	

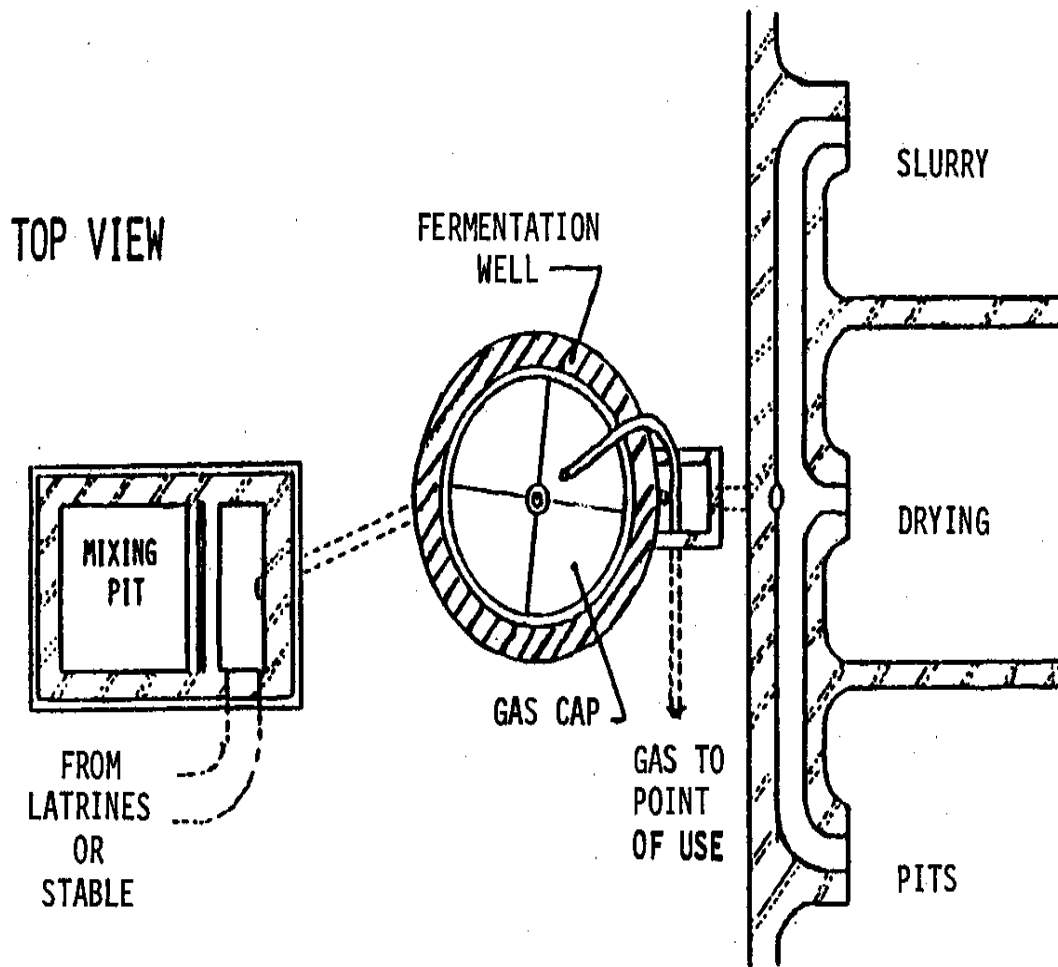
The largest, and for fuel purposes the most important, part of biogas is methane. Pure methane is colorless and odorless. Spontaneous ignition of methane occurs when 4-15% of the gas mixes with air having an explosive pressure of between 90 and 104 psi. The explosive pressure shows that biogas is very combustible and must be treated with care like any other kind of gas. Knowledge of this fact is important when planning the design, building, or using of a digester.

## LOCATION

There are several points to keep in mind before actual construction of the digester begins. The most important consideration is the location of the digester. Some of the major points in deciding the location are:

- \* DO NOT dig the digester pit within 13 meters of a well or spring used for drinking water. If the water table is reached when digging, it will be necessary to cement the inside of the digester pit. This increases the initial expense of building the digester, but prevents contamination of the drinking supply.
- \* Try to locate the digester near the stable (see Figure 2) so

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**Figure 2. Location of Digester From Fuel Source**

excessive time is not spent transporting the manure. Remember, the fresher the manure, the more methane is produced as the final product and the fewer problems with biogas generation will occur. To simplify collection of manure, animals should be confined.

- \* Be sure there is enough space to construct the digester. A plant that produces 3 cubic meters of methane requires an area approximately 2 X 3 meters. If a larger plant is required, figure space needs accordingly.
- \* Arrange to have water readily available for mixing with the manure.
- \* Plan for slurry storage. Although the gas plant itself takes up a very small area, the slurry should be stored either as

is or dried. The slurry pits should be large and expandable.

- \* Plan for a site that is open and exposed to the sun. The digester operates best and gives better gas production at high temperatures (35[degrees]C or 85-100[degrees]F). The digester should receive little or no shade during the day.
- \* Locate the gas plant as close as possible to the point of gas consumption. This tends to reduce costs and pressure losses in piping the gas. Methane can be stored fairly close to the house as there are few flies or mosquitos or odor associated with gas production.

Thus, the site variables are: away from the drinking water supply, in the sun, close to the source of the manure, close to a source of water, and close to the point where the gas will be used. If you have to choose among these factors, it is most important to keep the plant from contaminating your water supply. Next, as much sun as possible is important for the proper operation of the digester. The other variables are largely a matter of convenience and cost: transporting the manure and the water, piping the gas to the point of use, and so on.

## SIZE

The amount of gas produced depends on the number of cattle (or other animals) and how it is going to be used. As an example, a farmer with eight cattle and a six-member family wishes to produce gas for cooking and lighting and, if possible, for running a 3hp water pump engine for about an hour every day.

Some of the questions the farmer must ask and guidelines for answering them are:

1. How much gas can be expected per day from both eight head of cattle and six people?

Since each cow produces, on the average, 10kg of manure per day and 1kg of fresh manure can give .05 cubic meter gas, the animals will give  $8 \times 10\text{kg/animal} \times .05 \text{ cubic meter/kg} = 4.0 \text{ cubic meters gas}$ .

Each person produces an average of 1 kg of waste per day; therefore, six people  $\times 1\text{kg/person} \times .05 \text{ cubic meter/kg} = .30 \text{ cubic meter gas}$ .

The size of the plant would be a 4.3 cubic meter gas plant.



2. How much gas does the farmer require for each day?

Each person requires approximately 0.6 cubic meters gas for cooking and lighting. Therefore,  $6 \times 0.6 = 3.6$  cubic meters gas.

An engine requires 0.45 cubic meters gas per hp per hour. Therefore, a 3hp engine for one hour is:  $3 \times 0.45 = 1.35$  cubic meters gas.

Total gas consumption would be almost 5 cubic meters per day--somewhat more than could be produced. Running the engine will thus require conserving on lighting and cooking (or vice versa), especially in the cool season when gas production is low.

3. What will be the volume of the fermentation tank or pit needed to handle the mixture of manure and water?

The ratio of manure and water is 1 : 1.

8 cattle = 80kg manure + 80kg water = 160kg

6 people = 6kg waste + 6kg water = 12kg

-----

Total input per day = 172kg

Input for six weeks =  $172\text{kg} \times 42 \text{ days} = 7224\text{kg}$

$1000\text{kg} = 1 \text{ cubic meter}$

$7224\text{kg} = 7.2 \text{ cubic meters}$

Therefore, the minimum capacity of the fermentation well is approximately 7.0 cubic meters--a figure that does not allow for future expansion of the farmer's herd. If the herd does expand and the farmer continues to put all available manure in the tank, the slurry will exit after a shorter digestion period and gas production will be reduced. (The farmer could curtail addition of raw manure and hold it steady at the eight cattle load. If money is available and there are no digging problems, it is better to put in an oversized than undersized tank.

4. What size and shape of fermentation tank or pit is required?

The shape of the tank is determined by the soil, subsoil, and water table. For this example, we will assume that the earth is not too hard to dig and that the water table is low--even in the rainy season. An appropriate size for a

7.0 cubic meter tank would be a diameter of 1.5 meters.  
Therefore, the depth required is 4.0 meters.

5. What should the size of the gas cap be?

The metal drum serving as a gas cap covers the fermentation tank and is the most expensive single item in the whole plant. To minimize the size and to keep the price as low as possible, the drum is not built to accommodate a full day's gas production on the assumption that the gas will be used throughout the day and the drum will never be allowed to reach full capacity. The drum is made to hold between 60 and 70 percent of the volume of the total daily gas production.

70% of 4.3 cubic meters = 3-cubic-meter gas cap required

The actual dimensions of the drum may well be determined by the size of the material locally available. A 1.4-meter-diameter drum 1.5 meters tall would be sufficient for this example. See Table 2 for other digester sizes.

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Gas Plant Type (Model)	Number of Animals	1:1 Water & Dung Per Day (kg)	Volume of Well for 42 Day Digesting (cu m)	Size of Well Diameter & Depth (m)	Size of Gas Cap Diameter & Height (m)	G.I. Sheet for Gas Cap (sq m)	Number of Bricks	Number of Bags of Cement (50kg)	Quantity of Sand (cu m)	Gas Produced Per Day (cu m)	Sun Dried Fertilizer Produced Per Day (kg)	Number of People Served by Gas (Cooking, Lighting)
2 cubic meter	4	80	3.5	1.25X3	1.15X1	4.5	2800	22	9	2	4-8	4-5
3 cubic meter	6	120	5	1.5X3.4	1.4X1.25	9	3200	25	12	3	6-12	6-8
4 cubic meter	8	160	7	1.5X4	1.5X1.5	9	4000	28	12	4	8-16	9-11
5 cubic meter	10	200	8.5	1.7X3.5	1.6X1.5	10.5	4000	30	14	5	10-20	12-15
7.5 cubic meter	15	300	13	2X4	1.9X1.5	12.6	5200	32	16	7.5	15-30	15-20
10 cubic meter	20	400	17	2.2X4.3	2.1X1.5	14.3	6400	35	18	10	20-40	20-30

**Table 2. Measurements for a Number of Simple Gas Plants**

## HEATING AND INSULATING DIGESTERS

To reach optimum operating temperatures (30-37[degrees]C or 85-100[degrees]F), some measures must be taken to insulate the digester, especially in high altitudes or cold climates. Straw or shredded tree bark can be used around the outside of the digester to provide insulation. Other forms of heating can also be used such as solar water heaters or the burning of some of the methane produced by the digester to heat water that is circulated through copper coils on the inside of the digester. Solar or gas heating will add to the cost of the digester, but in cold climates it may be necessary. Consult "Further Information Resources" for more information.

## MATERIALS (For 3-Cubic-Meter Digester)

- \* Baked bricks, approximately 3200
- \* Cement, 25 bags (for foundation and wall covering)
- \* Sand, 12 cubic meters
- \* Clay or metal pipe, 20cm diameter, 10 meters
- \* Copper wire screening (25cm X 25cm)
- \* Rubber or plastic hose (see page 00)
- \* Gas outlet pipe, 3cm diameter (see page 00)
- \* Pipe, 7.5cm diameter, 1.25 meters (gas cap guide)
- \* Pipe, 7cm diameter, 2.5 meters (center guide)
- \* Mild steel sheeting, .32mm (30 gauge) to 1.63mm (16 gauge), 1.25 meters X 9 meters long
- \* Mild steel rods, approximately 30 meters (for bracing)
- \* Waterproof coating (paint, tar, asphalt, etc.), 4 liters (for gas cap)

## TOOLS

- \* Welding equipment (gas cap construction, pipe fittings, etc.)
- \* Shovels
- \* Metal saw and blades for cutting steel (welding equipment may be used)
- \* Trowel

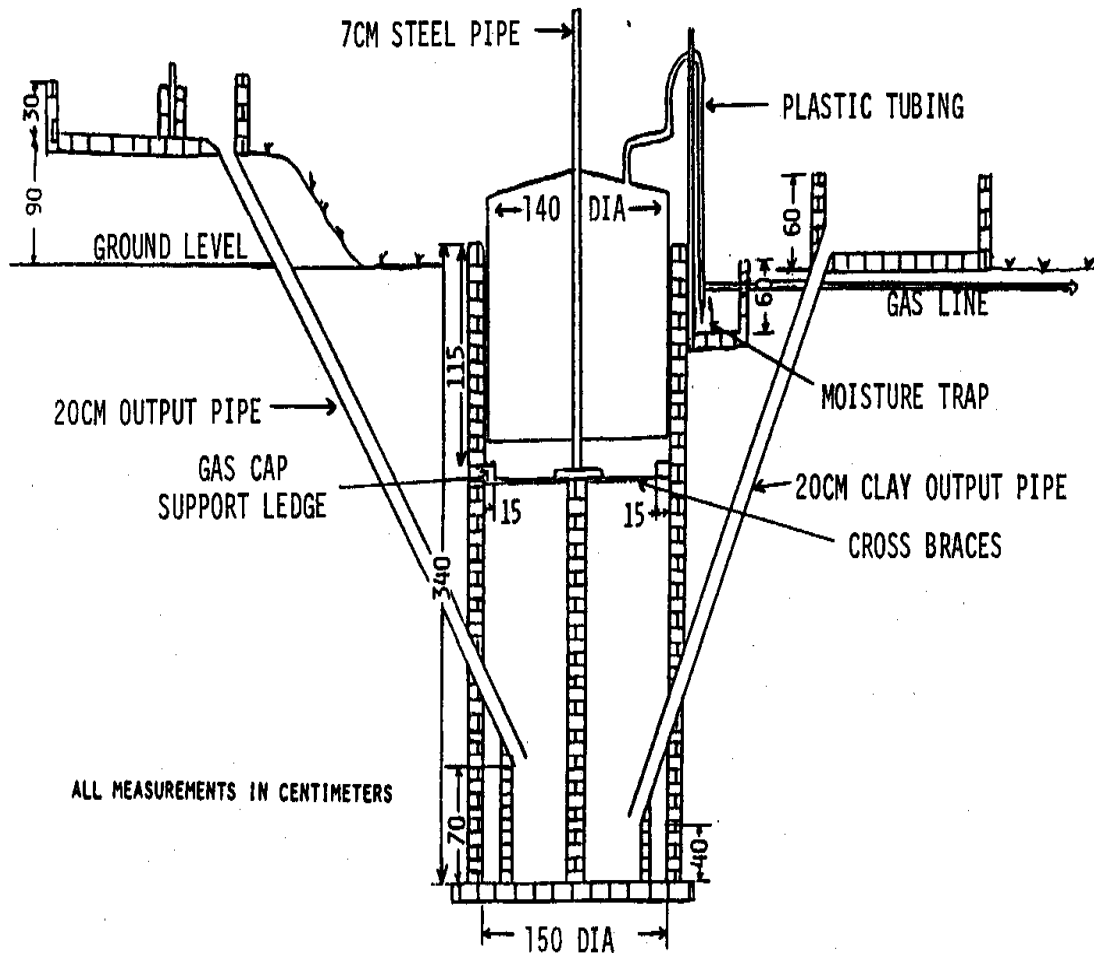
## V. CONSTRUCTION

### PREPARE FOUNDATION AND WALLS

- \* Dig a pit 1.5 meters in diameter to a depth of 3.4 meters.
- \* Line the floor and walls of the pit with baked bricks and bound it with lime mortar or clay. Any porousness in the construction is soon blocked with the manure/water mixture. (If a water table is encountered, cover the bricks with cement.)

- \* Make a ledge or cornice at two-thirds the height (226cm) of the pit from the bottom. The ledge should be about 15cm wide for the gas cap to rest on when it is empty (see Figure 3).

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**Figure 3. 3-Cubic-Meter Gas Digester**

This ledge also serves to direct into the gas cap any gas forming near the circumference of the pit and prevents it from escaping between the drum and the pit wall.

- \* Extend the brickwork 30-40cm above ground level to bring the total depth of the pit to approximately 4 meters.
- \* Make the input and output piping for the slurry from ordinary 20cm clay drainpipe. Use straight input piping. If the pipe is curved, sticks and stones dropped in by playful children



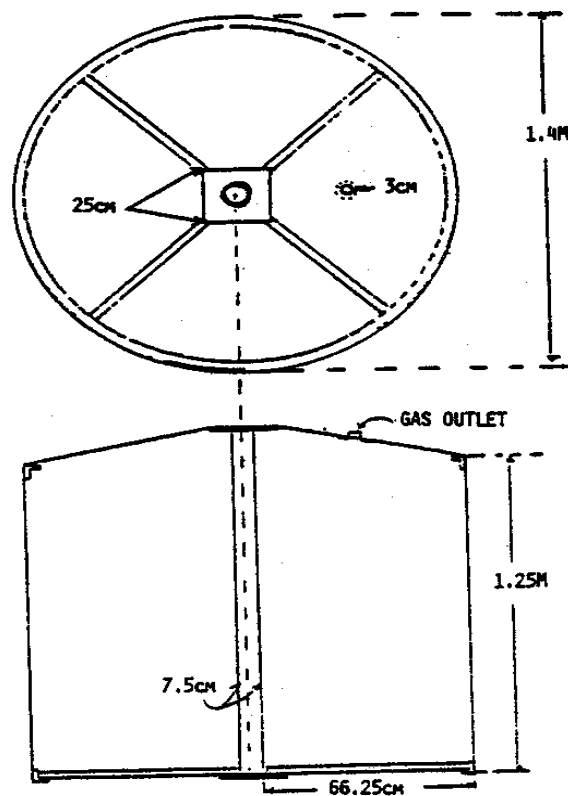
may jam at the bend and cannot be removed without emptying the whole pit. With straight piping, such objects can fall right through or can be pushed out with a piece of bamboo.

- \* Have one end of the input piping 90cm above ground level and the other end 70cm above the bottom of the pit (see Figure 3).
- \* Have one end of the output piping 40cm above the bottom of the pit opposite the input pipe and the other end at ground level.
- \* Put an iron or wire strainer (copper screening) with 0.5cm holes at the upper end of the input and the output pipes to keep out large particles of foreign matter from the pit.
- \* Construct a center wall that divides the pit into two equal compartments. Build the wall to a height two-thirds from the bottom of the digester (226cm). Build the gas cap guide in the center top of the wall by placing vertically a 7cm X 2.5 meters long piece of metal piping.
- \* Provide additional support for the pipe by fabricating a cross brace made from mild steel.

#### PREPARE THE GAS CAP DRUM

- \* Form the gas cap drum from mild steel sheeting or galvanized iron sheeting of any thickness from .327mm (30 gauge) to 1.63mm (16 gauge).
- \* Make the height of the drum approximately one-third the depth of the pit (1.25-1.5 meters).
- \* Make the diameter of the drum 10cm less than that of the pit (1.4 meters diameter) as shown in Figure 4.

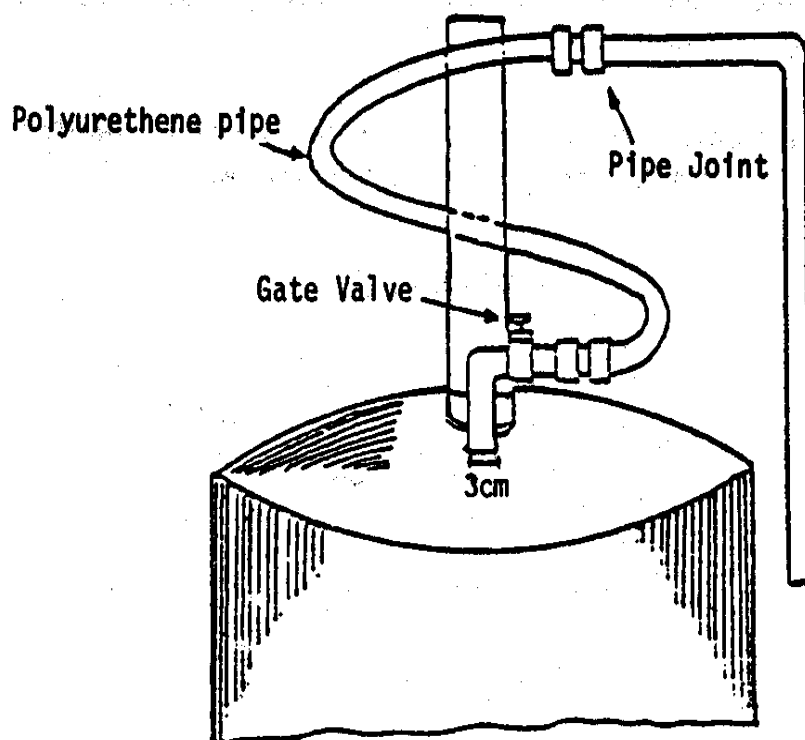
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**Figure 4. Biogas Plant Gas Cap**

- \* Using a flange, attach a 7.5cm pipe to the inside top center.
- \* Fix the lower end of the pipe firmly in place with thin, iron tie rods or angle iron. The cap now looks like a hollow drum with a pipe, firmly fixed, running through the center.
- \* Cut a 3cm diameter hole, as shown in Figure 5, in the top of

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**Figure 5. Piping on Gas Cap**

the gas cap.

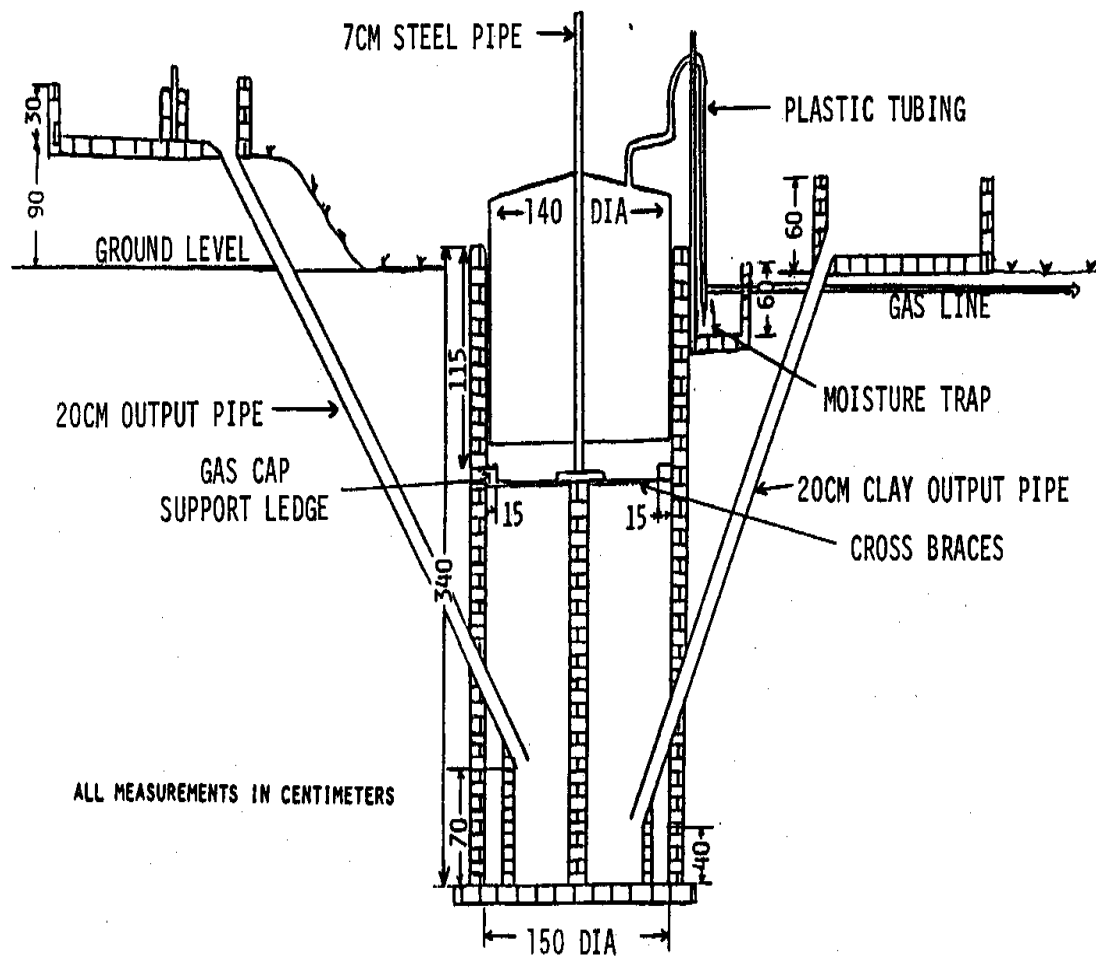
- \* Weld a 3cm diameter pipe over the hole.
- \* Fix a rubber or plastic hose--long enough to allow the drum to rise and fall--to the welded gas outlet pipe. A valve may be fixed at the joint as shown.
- \* Paint the outside and inside of the drum with a coat of paint or tar.
- \* Make sure the drum is airtight. One way to check this is to fill it with water and watch for leaks.
- \* Turn the gas cap drum so that the outlet pipe is on top and slip the 7.5cm pipe fixed in the gas cap over the 7cm pipe fixed in the center wall of the pit. When empty, the drum will rest on the 15cm ledges built on either side. As gas is produced and the drum empties and fills, it will move up and down the center pole.
- \* Attach handles to either side of the drum. These don't have to be fancy, but they will prove very helpful for lifting the drum off and for turning the drum.

- \* Weld a 10cm wide metal strip to each of the tie rod supports in a vertical position. These "teeth" will act as stirrers. By grasping the handles and rotating the drum it is possible to break up troublesome scum that forms on the slurry and tends to harden and prevent the passage of gas.

#### PREPARE MOISTURE TRAP

- \* Place a jar of water outside the pit and put into it the end of a downward projection of the gas pipe at least 20cm long. Any moisture condensing in the pipe flows into the jar instead of collecting in the pipe and obstructing the passage of gas. Water then overflows and is lost in the ground. Remember to keep the jar full or the gas will escape. An ordinary tap when opened lets the water escape. Whether using the water jar or tap, do not let the length be greater than 30cm below ground level or it becomes too difficult to reach (see Figure 3 on page 20).

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## PREPARE THE MIXING AND EFFLUENT TANKS

- \* Build or improvise a mixing tank to be placed near the outside opening of the inlet pipe. Likewise, provide a container at the outlet to catch the effluent. Some provision may also be made for drying the effluent as the plant goes into full production.

## VI. OPERATION

In order to start up the new digester, it is necessary to have 3 cubic meters (3000kg) of manure. In addition, approximately 15kg of "seeder" is required to get the bacteriological process started. The "seeder" can come from several sources:



- \* Spent slurry from another gas plant
- \* Sludge or overflow water from a septic tank
- \* Horse or pig manure, both rich in bacteria
- \* A 1 : 1 mixture of cow manure and water that has been allowed to ferment for two weeks

Put the manure and "seeder" and an equal amount of water into the mixing tank. Stir it into a thick liquid called a slurry. A good slurry is one in which the manure is broken up thoroughly to make a smooth, even mixture having the consistency of thin cream. If the slurry is too thin, the solid matter separates and falls to the bottom instead of remaining in suspension; if it is too thick, the gas cannot rise freely to the surface. In either case the output of gas is less.

When filling the pit for the first time, pour the slurry equally into both halves to balance the pressure on the thin inner wall, or it may collapse.

Mix 60kg fresh manure with 60kg water and add it to the tank every day.

The advantage of this model is that since the daily flow of slurry goes up the first side, where the insoluble matter rises, and down the second, where this matter naturally tends to fall, the outgoing slurry daily draws out with it any sludge found at the bottom. Thus having to clean out the pit becomes a comparatively rare necessity. Sand and gravel may build up on the bottom of the digester and will have to be cleaned from time to time depending on your location.

It can take four to six weeks from the time the digester is fully loaded before enough gas is produced and the gas plant becomes fully operational. The first drumful of gas will probably contain so much carbon dioxide that it will not burn. On the other hand, it may contain methane and air in the right proportion to explode if ignited. **DO NOT ATTEMPT TO LIGHT THE FIRST DRUMFUL OF GAS.** Empty the gas cap and let the drum fill again.

At this point the gas is safe to use.

## OUTPUT AND PRESSURE

The gas cap drum floating on the slurry creates a steady pressure on the gas at all times. This pressure is somewhat

lower than that usually associated with other gases that are under pressure but is sufficient for cooking and lighting.

Table 3, on the following page, shows gas consumption by liters/hour.

1	2	3(*)
Gas cooking	2" diameter burner	280
	4" diameter burner	395
	6" diameter burner	545
Gas lighting	1 mantle lamps	78
	2 mantle lamps	155
	3 mantle lamps	190
Refrigerator	18" X 18" X 12"	78
Incubator	18" X 18" X 18" Flame operated	
Running engines	Converted diesel	350-550 hp/hr

(\*)Liters/hour

Note: These figures will vary slightly depending on the design of the appliance used, the methane content of the gas, the gas delivery pressure, etc.

Table 3. Application Specification for Gas Consumption

## VII. VARIOUS APPLICATIONS OF BIOGAS

### AND DIGESTER BY-PRODUCTS

#### ENGINES

##### Internal Combustion

Any internal combustion engine(\*) can be adapted to use methane. For gasoline engines, drill a hole in the carburetor just near the choke and introduce a 5mm diameter tube connected to the gas supply through a control valve. The engine may be started on gasoline then switched over to methane while running, or vice-versa. For smooth running of the engine, the gas flow should be steady. For stationary engines this is done by counterbalancing the gas cap. (Refer to Table 3 on page 17 for gas consumption.)

## Diesel

Diesel engines are run by connecting the gas to the air intake and closing the diesel oil feed. A spark plug will have to be placed where the injector normally is and arrangement made for electricity and spark timing. Modifications will vary with the make of the engine. One suggestion is to adapt the full-pump mechanism for timing the spark.

---

(\*)Some authorities recommend that when running the internal combustion engines, the gas be first purified. This is done by bubbling it through lime water, to remove carbon dioxide, and through iron filings, to remove hydrogen sulphide.

## FERTILIZER

The sludge product of anaerobic decomposition produces a better fertilizer and soil conditioner than either composted or fresh manure. The liquid effluent contains many elements essential to plant life: nitrogen, phosphorous, potassium, plus small amounts of metallic salts indispensable for plant growth.

Methods of applying this fertilizer are numerous and conflicting. The effluent can be applied to crops as either a diluted liquid or in a dried form. Remember that although 90-93% of toxic pathogens found in raw human manure are killed by anaerobic decomposition, there is still a danger of soil contamination with its use. The effluent should be composted before use if the slurry contains a high proportion of human waste. However, when all factors are considered, the effluent is much safer than raw sewage, poses less of a health problem, and is a better fertilizer.

The continued use of the effluent in one area tends to make soils acidic unless it is diluted with water (3 parts water to 1 part effluent is considered a safe mixture). A little dolomite or crushed limestone added to the effluent containers at regular intervals will cut down on acidity. Unfortunately, limestone tends to evaporate ammonia; so it is generally best to keep close watch over the amount of effluent provided to crops until the reaction of the soil and crops is certain.

## IMPROVISED STOVE

Because gas pressure is low, it will be necessary to modify existing equipment or build special burners for cooking and heating. A pressure stove burner will work satisfactorily only after certain modifications are made to the burner. The

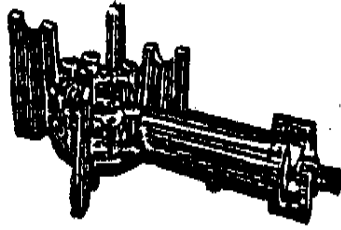
needle-thin jet should be enlarged to 1.5mm. To make a burner out of 1.5cm water pipe, choke the pipe with a metal disc having a center hole with a diameter of 1.5 to 2mm. An efficient burner is a tin can, filled with stones for balance, having six 1.5mm holes in the top. The gas enters through a pipe choked to a 2mm orifice. Or fill a chula or Lorena stove with stones and insert a pipe choked to a 2mm orifice.

If possible, it is best to use a burner with an adjustable air inlet control. The addition or subtraction of air to the gas creates a hotter flame with better use of available gas.

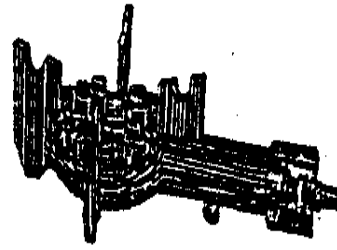
## LIGHTING

Methane gives a soft, white light when burned with an incandescent mantle. It is not quite as bright and glaring as a kerosene lantern. Lamps of various types and sizes are manufactured in India specifically for use with methane. <see image> Each mantle

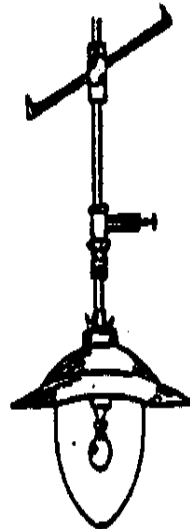
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BIOGAS BURNER



BIOGAS BURNER



BIOGAS LAMP



BIOGAS LAMP

Bengal Scientific & Technical Works (P) Ltd.  
20/3 Aswani Dutt Road, Calcutta 29

burns about as bright as a 40-watt electric bulb.

Some biogas appliances manufactured by an Indian firm are:

- |                          |                      |
|--------------------------|----------------------|
| * Indoor hanging lamp    | * Stoves and burners |
| * Indoor suspension lamp | * Bottle syphons and |
| * Outdoor hanging lamp   | pressure gauges      |
| * Indoor table lamp      |                      |

#### VIII. MAINTENANCE

A digester of this type is virtually maintenance free and has a life of approximately 25 years. As long as cow or other animal manure is used, there should be no problems. Vegetable matter can also be used for methane production but the process is much more complex. Introduction of vegetable matter in the digester

is not recommended.

A trouble-shooting guide is listed below for possible problems that may be encountered.

#### POSSIBLE TROUBLES

Defect	May be caused by	Remedy
No gas. Drum won't rise.	a) No bacteria	Add some bacteria (seeder)
	b) Lack of time	Patience! Without bacteria, it may take four or five weeks.
	c) Slurry too cold	Use warm water. Cover plant with plastic tent or use heating coil.
	d) Insufficient input	Add right amount of slurry daily.
	e) Leak in drum or pipe	Check seams, joints, and taps with soapy water.
	f) Hard scum on slurry blocking gas.	Remove drum; clean slurry surface. With sliding-drum plants, turn drum slightly to break crust.
No gas at stove; plenty in drum.	a) Gas pipe blocked by condensed water	Open escape cock.
	b) Insufficient pressure	Increase weight on drum
	c) Gas inlet blocked by scum	Remove drum and clean inlet. Close all gas-taps. Fill gas line with water; apply pressure through moisture escape. Drain water.
Gas won't burn.	a) Wrong kind is being formed.	Slurry too thick or too thin. Measure accurately. Have patience.

b) Air mixture      Check burner gas jet to  
make sure it is at  
least 1.5mm.

Flame soon dies.    a) Insufficient      Increase weight on  
drum.

b) Water in line      Check moisture escape  
jar. Drain gas line.

Flame begins far    a) Pressure too      Remove weights from  
high                  drum. Counterbalance.

b) Air mixture      Choke gas inlet at  
stove to 2mm (thickness  
of 1" long nail).

## IX. TEST GAS LINES FOR LEAKS

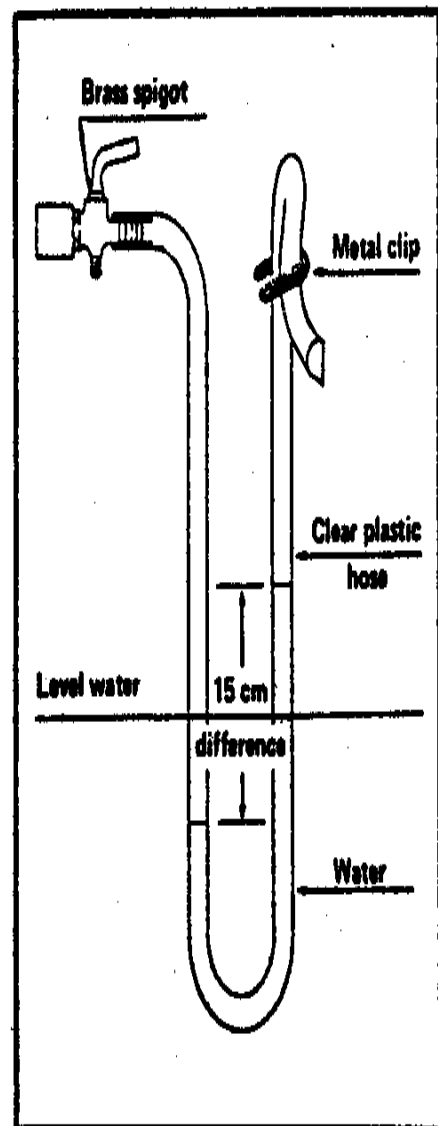
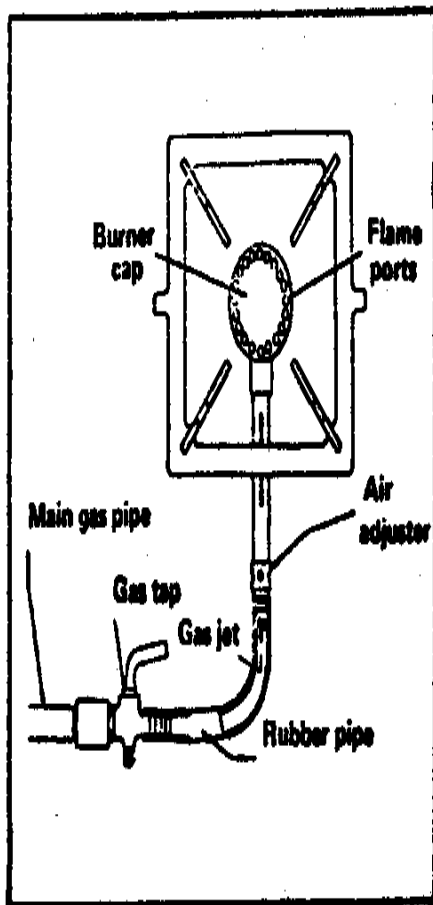
Checking for gas leaks is done by closing all gas taps, including the main gas tap beside the gas holder, except for one.

Then to the open tap, a clear plastic pipe about a meter long is attached, and a "U" is formed. The lower half of the "U" is filled with water.

Using a pipe attached to a second tap, pressure is applied until the water in the two legs of the "U" is different by 15cm. The second tap is then closed. The "U" is now what is called a "manometer."

If the water levels out when the second tap is closed, a leak is indicated and can be sought out by putting soapy water over possible leaks, such as joints, in the pipework. <see image>

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## X. DICTIONARY OF TERMS

AEROBIC--Decomposing with oxygen.

ANAEROBIC--Decomposing without oxygen.

BY-PRODUCT--Something produced from something else.

CARBON DIOXIDE--A colorless, odorless, incombustible gas ( $\text{CO}_2$ ) formed during organic decomposition.

DECOMPOSE--To rot, to disintegrate, to breakdown into component parts.

DIA (DIAMETER)--A straight line passing completely through the



center of a circle.

DIGESTER--A cylindrical vessel in which substances are decomposed.

EFFLUENT--The outflow from the biogas storage tank.

FERMENT--To cause to become agitated or turbulent.

HP (HORSEPOWER)--Unit of power equal to 747.7 watts.

INSOLUBLE--Incapable of being dissolved.

LEACHED--Dissolved and washed out by a percolating liquid.

MANTLE--A sheath of threads that brightly illuminates when heated by gas.

METHANE--An odorless, colorless, flammable gas ( $\text{CH}_4$ ) used as a fuel.

NITRATES--Fertilizers consisting of sodium and potassium nitrates.

NITROGEN--A colorless and odorless gas ( $\text{N}_2$ ) in fertilizers.

ORGANIC WASTES--Waste from living organisms or vegetable matter.

SCUM--A filmy layer of waste matter that forms on top of liquid.

SEEDER--Bacteria used to start the fermentation process.

SEPTIC TANK--A sewage disposal tank in which a continuous flow of waste material is decomposed by anaerobic bacteria.

SLUDGE--A thick liquid composed of 1 : 1 : 1 mixture of manure, seeder, and water.

SUPERNATANT--Floating on the surface.

TOXIC PATHOGENS--Harmful or deadly agents that cause serious disease or death.

## XI. CONVERSION TABLES

### UNITS OF LENGTH

1 Mile	= 1760 Yards	= 5280 Feet
1 Kilometer	= 1000 Meters	= 0.6214 Mile
1 Mile	= 1.607 Kilometers	
1 Foot	= 0.3048 Meter	
1 Meter	= 3.2808 Feet	= 39.37 Inches
1 Inch	= 2.54 Centimeters	
1 Centimeter	= 0.3937 Inches	

#### UNITS OF AREA

1 Square Mile	= 640 Acres	= 2.5899 Square Kilometers
1 Square Kilometer	= 1,000,000 Square Meters	= 0.3861 Square Mile
1 Acre	= 43,560 Square Feet	
1 Square Foot	= 144 Square Inches	= 0.0929 Square Meter
1 Square Inch	= 6.452 Square Centimeters	
1 Square Meter	= 10.764 Square Feet	
1 Square Centimeter	= 0.155 Square Inch	

#### UNITS OF VOLUME

1.0 Cubic Foot	= 1728 Cubic Inches	= 7.48 US Gallons
1.0 British Imperial Gallon	= 1.2 US Gallons	
1.0 Cubic Meter	= 35.314 Cubic Feet	= 264.2 US Gallons
1.0 Liter	= 1000 Cubic Centimeters	= 0.2642 US Gallons
1.0 Metric Ton	= 1000 Kilograms	= 2204.6 Pounds
1.0 Kilogram	= 1000 Grams	= 2.2046 Pounds
1.0 Short Ton	= 2000 Pounds	

#### UNITS OF PRESSURE

1.0 Pound per square inch	= 144 Pound per square foot
1.0 Pound per square inch	= 27.7 Inches of water(*)
1.0 Pound per square inch	= 2.31 Feet of water(*)
1.0 Pound per square inch	= 2.042 Inches of mercury(*)
1.0 Atmosphere	= 14.7 Pounds per square inch (PSI)
1.0 Atmosphere	= 33.95 Feet of water(*)
1.0 Foot of water = 0.433 PSI	= 62.355 Pounds per square foot
1.0 Kilogram per square centimeter	= 14.223 Pounds per square inch
1.0 Pound per square inch	= 0.0703 Kilogram per square centimeter

#### UNITS OF POWER

1.0 Horsepower (English)	= 746 Watt	= 0.746 Kilowatt (KW)
1.0 Horsepower (English)	= 550 Foot pounds per second	
1.0 Horsepower (English)	= 33,000 Foot pounds per minute	
1.0 Kilowatt (KW)	= 1000 Watt	= 1.34 Horsepower (HP) English

1.0 Horsepower (English)	= 1.0139 Metric horsepower (cheval-vapeur)
1.0 Metric horsepower	= 75 Meter X Kilogram/Second
1.0 Metric horsepower	= 0.736 Kilowatt = 736 Watt

---

(\*)At 62 degrees Fahrenheit (16.6 degrees Celsius).

## XII. FURTHER INFORMATION RESOURCES

### A LISTING OF RECOMMENDED RESOURCE MATERIALS

Biogas Plant: Designs With Specifications. Ram Box Singh, Gobar Gas Research Station Ajit Mal Etawah (V.P.) India. The main part of this book is taken up with very detailed technical drawings of 20 different models of methane digesters for various size operations and different climates. Also has designs for gas burners, lamps, and a carburetor. No real written instructions, but would be very useful if used in conjunction with a more general manual.

Biogas Plant: Generating Methane from Organic Wastes. Ram Bux Singh, Gobar Gas Research Station, Ajitmal Etawah (V.P.) India, 1974. The most comprehensive work on biogas. Gives the background of the subject, an extensive treatment of just how a biogas plant works, factors to consider in designing a plant and several designs, and instructions for building a plant and using the products. Profusely illustrated, this is considered by some as the "bible" of biogas.

Fuel Gas From Cow Dung. Bertrand R. Saubolle, S. J., Sahayog; Prakashan Tripureshwars, Kathmandu, April 1976, 26 pp. Fairly detailed manual for obtaining and using methane from cow manure. Includes a trouble-shooting section and specification charts for different size digesters. Written in straight forward, nontechnical language. Potential quite useful. Available from VITA.

Small-Scale Biogas Plants. Nigel Florida; Bardoli, India. Highly detailed manual. Gives step-by-step instructions for building and operating a methane digester. Includes modifications needed to cope with a variety of conditions and a detailed analysis of digested slurry and of the produced biogas. Also has a chapter on current state-of-the-art in India. Available from VITA.

### USEFUL INFORMATION FOR METHANE DIGESTER DESIGNS

Andrews, Johh F. Start-Up and Recovery of Anaerobic Digestion, 8 pp. Clemson University. Available from VITA.

"Biogas Plant: Generating Methane from Organic Wastes." Compost Science. January-February 1972, pp. 20-25. Available from VITA.

Biogas Stove and Lamp: Efficient Gas Appliances, Examples of Plant Designs, Examples of Biogas Plants, Construction Notes. 4 pp. including illustrations. Available from VITA.

"Building a Biogas Plant." Compost Science. March-April 1972. pp. 12-16. Available from VITA.

Finlay, John H. Operation and Maintenance of Gobar Gas Plants, April 1976, 22 pp. with 3 diagrams. Nepal. Available from VITA.

Gobar Gas Plant, 4 pp. Appropriate Technology Development Association, PO Box 311, Gandhi Bhawan, Lucknow 226001, UP, India.

Gobar Gas Plants, 8 pp. with 4 diagrams. Indian Agricultural Research Institute. Available from VITA.

Gotaas, Harold B. "Manure and Night-Soil Digesters for Methane Recovery on Farms and in Villages. Composting: Sanitary Disposal and Reclamation of Organic Wastes. 1956, chapter 9, pp. 171-199. University of California/Berkeley, World Health Organization. Available from VITA.

Grout, A. Roger. Methane Gas Generation from Manure, 3 pp. Pennsylvania State University. Available from VITA.

Hansen, Kjell. A Generator for Producing Fuel Gas from Manure, 4pp. Available from VITA.

Hill, Peter. Notes on a Methane Gas Generator & Water Tank Construction, June 1974, 9 pp. Belau Modekngai School. Available from VITA.

Information on Cow Dung Gas: A Manure Plant for Villages, 5 pp. Indian Agricultural Research Institute, Division of Soil Science and Agricultural Chemistry, Pusa, New Delhi, India.

Klein, S.A. "Methane Gas--An Overlooked Energy Source." Organic Gardening and Farming, June 1972, pp. 98-101. Rodale Press, Inc., 33 East Mine Street, Emmaus, Pennsylvania

18049 USA.

Oberst, George L. Cold-Region Experiments with Anaerobic Digestion for Small Farms and Homesteads. Biofuels, Box 609, Noxon, Montana 59853 USA.

The Pennsylvania State University Digester-Methane Generator, 2 pp. Available from VITA.

Shifflet, Douglas. Methane Gas Generator, 1966. Available from VITA.

Vani, Seva. "Mobile Gobar Gas Plant," Journal of CARITAS India, January-February 1976, 2 pp. Available from VITA.

## APPENDIX I

### DECISION MAKING WORKSHEET

If you are using this as a guideline for using a biogas plant in a development effort, collect as much information as possible and if you need assistance with the project, write VITA. A report on your experiences and the uses of this manual will help VITA both improve the book and aid other similar efforts.

#### VITA

1600 Wilson Boulevard, Suite 500  
Arlington, Virginia 22209 USA  
Tel: 703/276-1800 . Fax: 703/243-1865  
Internet: pr-info@vita.org

### CURRENT USE AND AVAILABILITY

- \* Note current domestic and agricultural practices that might benefit from a biogas plant: improved fertilizer, increased fuel supply, sanitary treatment of human and animal wastes, etc.
- \* Have biogas plant technologies been introduced previously? If so, with what results?
- \* Have biogas plant technologies been introduced in nearby areas? If so, with what results?
- \* What changes in traditional thinking or practices might lead to increased acceptance of biogas plants? Are such changes too great to attempt now?
- \* Under what conditions would it be useful to introduce biogas plant technology for demonstration purposes?

- \* If biogas plants are feasible for local manufacture, would they be used? Assuming no funding, could local people afford them? Are there ways to make the biogas plant technologies pay for themselves?
- \* Could this technology provide a basis for a small business enterprise?

## NEEDS AND RESOURCES

- \* What are the characteristics of the problem? How is the problem identified? Who sees it as a problem?
- \* Has any local person, particularly someone in a position of authority, expressed the need or showed interest in biogas plant technology? If so, can someone be found to help the technology introduction process? Are there local officials who could be involved and tapped as resources?
- \* Based on descriptions of current practices and upon this manual's information, identify needs that biogas plant technologies appear able to meet.
- \* Do you have enough animals to supply necessary amount of manure needed daily?
- \* Are materials and tools available locally for construction of biogas plants?
- \* What would be the main use of the methane produced by the biogas plant? For example, heating, lighting, cooking, etc.
- \* Would you be able to use all of the effluent fertilizer or would you have more than you need? Would you be able to sell the surplus?
- \* Do a cost estimate of the labor, parts, and materials needed.
- \* What kinds of skills are available locally to assist with construction and maintenance? How much skill is necessary for construction and maintenance? Do you need to train people in the construction techniques? Can you meet the following needs?
  - Some aspects of the project require someone with experience in metal-working and/or welding.
  - Estimated labor time for full-time workers is:

- \* Skilled labor - 8 hours
- \* Unskilled labor - 80 hours
- \* Welding - 12 hours

\* How much time do you have? When will the project begin? How long will it take?

\* How will you arrange to spread knowledge and use of the technology?

## FINAL DECISION

\* How was the final decision reached to go ahead--or not to go ahead--with this technology?

## APPENDIX II

### RECORD KEEPING WORKSHEET

#### CONSTRUCTION

Photographs of the construction process, as well as the finished result, are helpful. They add interest and detail that might be overlooked in the narrative.

A report on the construction process should include very specific information. This kind of detail can often be monitored most easily in charts (such as the one below). <see report 1>

tcmxrp10.gif (437x437)

## CONSTRUCTION

Labor Account

		Hours Worked							Total	Rate?	Pay?
Name	Job	M	T	W	T	F	S	S			
1											
2											
3											
4											
5											
Totals											

Some other things to record include:

- \* Specification of materials used in construction.
- \* Adaptations or changes made in design to fit local conditions.
- \* Equipment costs.
- \* Time spent in construction--include volunteer time as well as paid labor, full- and/or part-time.
- \* Problems--labor shortage, work stoppage, training difficulties, materials shortage, terrain, transport.

## OPERATION

Keep log of operations for at least the first six weeks, then periodically for several days every few months. This log will vary with the technology, but should include full requirements, outputs, duration of operation, training of operators, etc. Include special problems that may come up--a damper that won't close, gear that won't catch, procedures that don't seem to make sense to workers, etc.



## MAINTENANCE

Maintenance records enable keeping track of where breakdowns occur most frequently and may suggest areas for improvement or strengthening weakness in the design. Furthermore, these records will give a good idea of how well the project is working out by accurately recording how much of the time it is working and how often it breaks down. Routine maintenance records should be kept for a minimum of six months to one year after the project goes into operation. <see report 2>

tcmxrp2.gif (486x486)

### MAINTENANCE

#### Labor Account

Name	Hours & Date	Repair Done	Also down time Rate?	Pay?
1				
2				
3				
4				
5				
Totals (by week or month)				

#### Materials Account

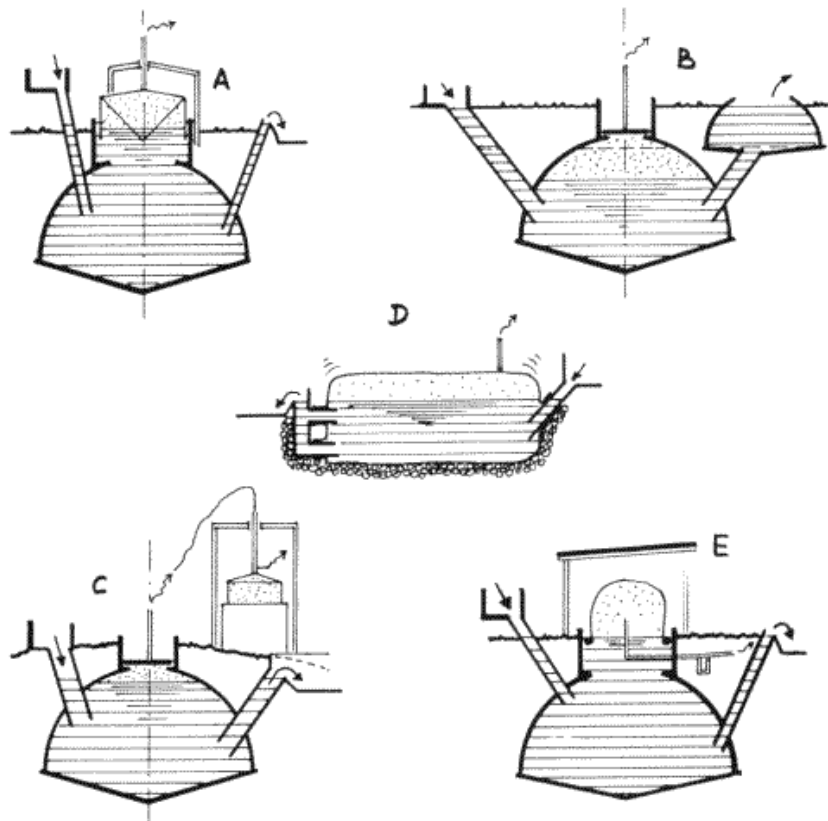
Item	Cost	Reason Replaced	Date	Comments
1				
2				
3				
4				
5				
Totals (by week or month)				

## SPECIAL COSTS

This category includes damage caused by weather, natural disasters, vandalism, etc. Pattern the records after the routine maintenance records. Describe for each separate incident:

- \* Cause and extent of damage.
- \* Labor costs of repair (like maintenance account).
- \* Material costs of repair (like maintenance account).

THE END



# ***Biogas Digest***



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# **Biogas - Application and Product Development**

## **Planning a biogas plant**

Before building a biogas plant, there are different circumstances which should be considered. For instance, the natural and agricultural conditions in the specific countries are as important as the social or the economic aspects. To consider the most important factors, we provide a checklist for the planning procedure, a planning guide and a checklist for construction of a biogas plant.

Failure or unsatisfactory performance of biogas units occur mostly due to planning mistakes. The consequences of such mistakes may be immediately evident or may only become apparent after several years. Thorough and careful planning is, therefore, of utmost importance to eliminate mistakes before they reach irreversible stages.

As a biogas unit is an expensive investment, it should not be erected as a temporary set-up. Therefore, determining siting criteria for the stable and the biogas plant are the important initial steps of planning.

A general problem for the planning engineer is the interference of the customer during planning. As much as the wishes and expectations of customers have to be taken into consideration, the most important task of the planner is to lay the foundation for a well functioning biogas unit. As in most cases the customer has no experience with biogas technology, the planner has to explain all the reasons for each planning step. Planners should have the courage to withdraw from the planning process, if the wishes of the customer will lead to a white elephant on the farm.

Moreover, all extension-service advice concerning agricultural biogas plants must begin with an estimation of the quantitative and qualitative energy requirements of the interested party. Then, the biogas-generating potential must be calculated on the basis of the given biomass production and compared to the energy demand. Both the energy demand and the gas-generating potential, however, are variables that cannot be accurately determined in the planning phase. Sizing the plant (digester, gasholder, etc.) is the next step in the planning process.

In the case of a family-size biogas plant intended primarily as a source of energy, implementation should only be recommended, if the plant can be expected to cover the calculated energy demand.

Information about the economic evaluation of a biogas plant can be found in the section on Costs and Benefits.

## **Design**

Throughout the world, a countless number of designs of biogas plants have been developed under specific climatic and socio-economic conditions. Choosing a design is essentially part of the planning process. It is, however, important to familiarize with basic design considerations before the actual planning process begins. This refers to the planning of a single biogas unit as well as to the planning of biogas-programs with a regional scope.

## **Physical conditions**

The performance of a biogas plant is dependent on the local conditions in terms of climate, soil conditions, the substrate for digestion and building material availability. The design must respond to these conditions. In areas with generally low temperatures, insulation and heating devices may be important. If bedrock occurs frequently, the design must avoid deep excavation work. The amount and type of substrate to be digested have a bearing on size and design of the digester and the inlet and outlet construction. The choice of design will also be based on the building materials which are available reliably and at reasonable cost.

## **Skills and labor**

High sophistication levels of biogas technology require high levels of skills, from the planner as well as from the constructor and user. With a high training input, skill gaps can be bridged,

but the number of skilled technicians will get smaller the more intensive the training has to be. In addition, training costs compete with actual construction costs for scarce (project) resources. Higher technical sophistication also requires more expensive supervision and, possibly, higher maintenance costs. To which extent prefabricated designs are suitable depends largely on the cost of labor and transport.

### **Standardization**

For larger biogas programs, especially when aiming at a self-supporting dissemination process, standards in dimensions, quality and pricing are essential. Standard procedures, standard drawings and forms and standardized contracts between the constructor, the planner, the provider of material and the customer avoid mistakes and misunderstandings and save time. There is, however a trade-off between the benefits of standardization and the necessity of individual, appropriate solutions.

### **Types of plants**

There are various types of plants. Concerning the feed method, three different forms can be distinguished:

- Batch plants
- Continuous plants
- Semi-batch plants

**Batch plants** are filled and then emptied completely after a fixed retention time. Each design and each fermentation material is suitable for batch filling, but batch plants require high labor input. As a major disadvantage, their gas-output is not steady.

**Continuous plants** are fed and emptied continuously. They empty automatically through the overflow whenever new material is filled in. Therefore, the substrate must be fluid and homogeneous. Continuous plants are suitable for rural households as the necessary work fits well into the daily routine. Gas production is constant, and higher than in batch plants. Today, nearly all biogas plants are operating on a continuous mode.

If straw and dung are to be digested together, a biogas plant can be operated on a **semi-batch** basis. The slowly digested straw-type material is fed in about twice a year as a batch load. The dung is added and removed regularly.

Concerning the construction, two main types of simple biogas plants can be distinguished:

- fixed-dome plants
- floating-drum plants

But also other types of plants play a role, especially in past developments. In developing countries, the selection of appropriate design is determined largely by the prevailing design in the region. Typical design criteria are space, existing structures, cost minimization and substrate availability. The designs of biogas plants in industrialized countries reflect a different set of conditions.

### **Parts of a biogas plant**

The feed material is mixed with water in the influent collecting tank. The fermentation slurry flows through the inlet into the digester. The bacteria from the fermentation slurry are intended to produce biogas in the digester. For this purpose, they need time. Time to multiply and to spread throughout the slurry. The digester must be designed in a way that only fully digested slurry can leave it. The bacteria are distributed in the slurry by stirring (with a stick or stirring facilities). The fully digested slurry leaves the digester through the outlet into the slurry storage.

The biogas is collected and stored until the time of consumption in the gasholder. The gas pipe carries the biogas to the place where it is consumed by gas appliances. Condensation collecting in the gas pipe is removed by a water trap.

Depending on the available building material and type of plant under construction, different variants of the individual components are possible. The following (optional) components of a

biogas plant can also play an important role and are described separately: Heating systems, pumps, weak ring.

## **Construction details**

The section on construction of biogas plants provides more information on:

- Agitation
- Heating
- Piping systems
- Plasters and Coats
- Pumps
- Slurry equipment
- Underground water

## **Starting the plant**

### **Initial filling**

The initial filling of a new biogas plant should, if possible, consist of either digested slurry from another plant or cattle dung. The age and quantity of the inoculant (starter sludge) have a decisive effect on the course of fermentation. It is advisable to start collecting cattle dung during the construction phase in order to have enough by the time the plant is finished. When the plant is being filled for the first time, the substrate can be diluted with more water than usual to allow a complete filling of the digester.

### **Type of substrate**

Depending on the type of substrate in use, the plant may need from several days to several weeks to achieve a stable digesting process. Cattle dung can usually be expected to yield good gas production within one or two days. The breaking-in period is characterized by:

- low quality biogas containing more than 60% CO<sub>2</sub>
- very odorous biogas
- sinking pH and
- erratic gas production

### **Stabilization of the process**

The digesting process will stabilize more quickly if the slurry is agitated frequently and intensively. Only if the process shows extreme resistance to stabilization should lime or more cattle dung be added in order to balance the pH value. No additional biomass should be put into the biogas plant during the remainder of the starting phase. Once the process has stabilized, the large volume of unfermented biomass will result in a high rate of gas production. Regular loading can commence after gas production has dropped off to the expected level.

### **Gas quality**

As soon as the biogas becomes reliably combustible, it can be used for the intended purposes. Less-than-optimum performance of the appliances due to inferior gas quality should be regarded as acceptable at first. However, the first two gasholder fillings should be vented unused for reasons of safety, since residual oxygen poses an explosion hazard.

## **Managing input- and output-material**

### **Substrate input**

For a simple, small-scale biogas system, only a minimum amount of time and effort must be spent on procuring the feedstock and preparing it for fermentation. The technical equipment is relatively inexpensive. Theoretically any organic material can be digested. Substrate pre-

processing and conveying depends on the type of material to be used. One of the most important problems in substrate management to be considered is the problem of scum.

### **Effluent sludge**

The sludge resulting from the digestion process represents a very valuable material for fertilization. The following aspects of sludge treatment and use are considered here:

- Sludge storage
- Composition of sludge
- Fertilizing effect of effluent sludge
- Sludge application and slurry-use equipment



## Biogas - Digester types

In this chapter, the most important types of biogas plants are described:

- Fixed-dome plants
- Floating-drum plants
- Balloon plants
- Horizontal plants
- Earth-pit plants
- Ferrocement plants

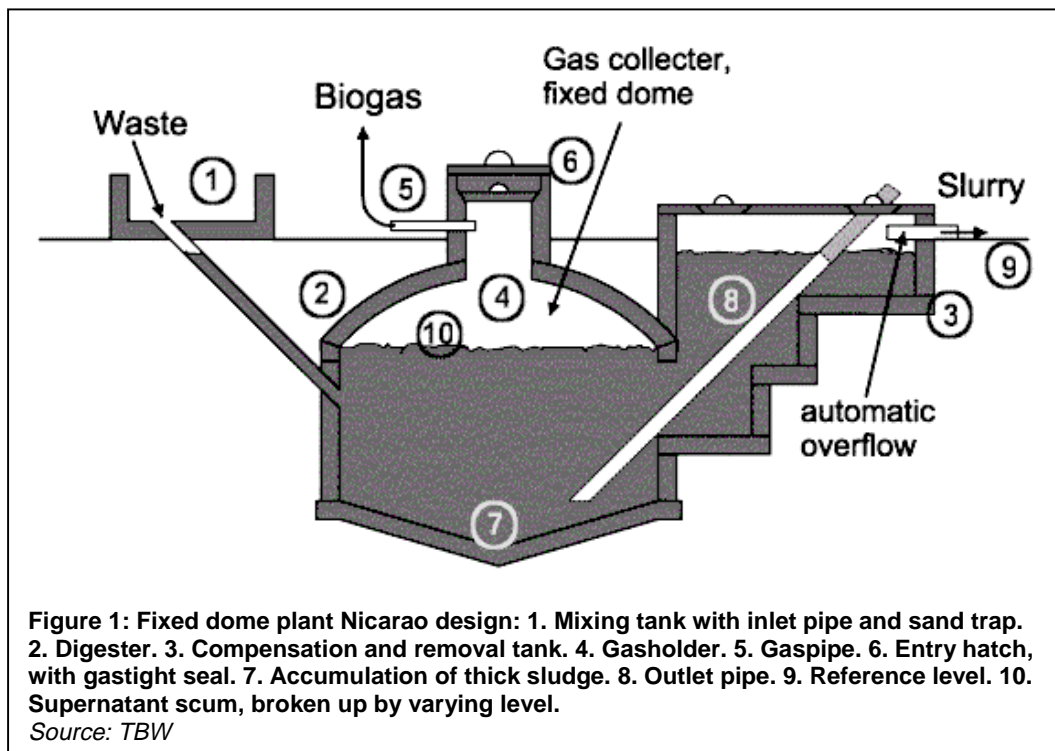
Of these, the two most familiar types in developing countries are the **fixed-dome plants** and the **floating-drum** plants. Typical designs in industrialized countries and appropriate design selection criteria have also been considered.

### Fixed-dome plants

The costs of a fixed-dome biogas plant are relatively low. It is simple as no moving parts exist. There are also no rusting steel parts and hence a long life of the plant (20 years or more) can be expected. The plant is constructed underground, protecting it from physical damage and saving space. While the underground digester is protected from low temperatures at night and during cold seasons, sunshine and warm seasons take longer to heat up the digester. No day/night fluctuations of temperature in the digester positively influence the bacteriological processes.

The construction of fixed dome plants is labor-intensive, thus creating local employment. Fixed-dome plants are not easy to build. They should only be built where construction can be supervised by experienced biogas technicians. Otherwise plants may not be gas-tight (porosity and cracks).

The basic elements of a fixed dome plant (here the **Nicarao Design**) are shown in the figure below.



## Function

A fixed-dome plant comprises of a closed, dome-shaped digester with an immovable, rigid gas-holder and a displacement pit, also named 'compensation tank'. The gas is stored in the upper part of the digester. When gas production commences, the slurry is displaced into the compensating tank. Gas pressure increases with the volume of gas stored, i.e. with the height difference between the two slurry levels. If there is little gas in the gas-holder, the gas pressure is low.

## Digester

The digesters of fixed-dome plants are usually masonry structures, structures of cement and ferro-cement exist. Main parameters for the choice of material are:

- Technical suitability (stability, gas- and liquid tightness);
- cost-effectiveness;
- availability in the region and transport costs;
- availability of local skills for working with the particular building material.

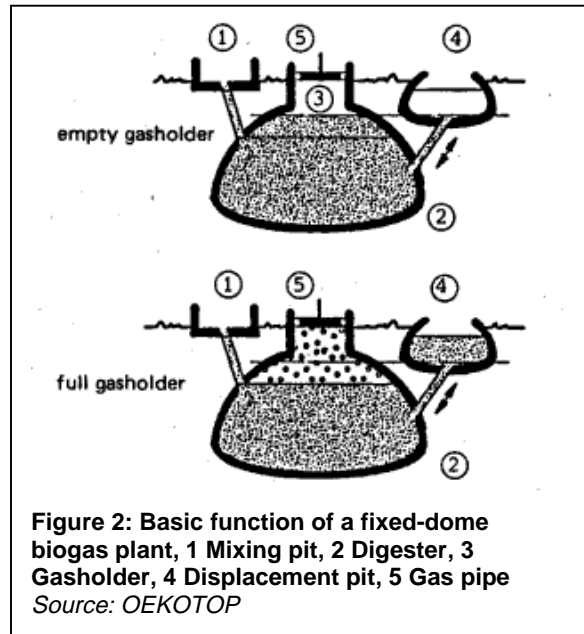
Fixed dome plants produce just as much gas as floating-drum plants, *if they are gas-tight*. However, utilization of the gas is less effective as the gas pressure fluctuates substantially. Burners and other simple appliances cannot be set in an optimal way. If the gas is required at constant pressure (e.g., for engines), a gas pressure regulator or a floating gas-holder is necessary.

## Gas-Holder



**Figure 3: Fixed-dome plant in Tunisia. The final layers of the masonry structure are being fixed.**

Photo: gtz/GATE



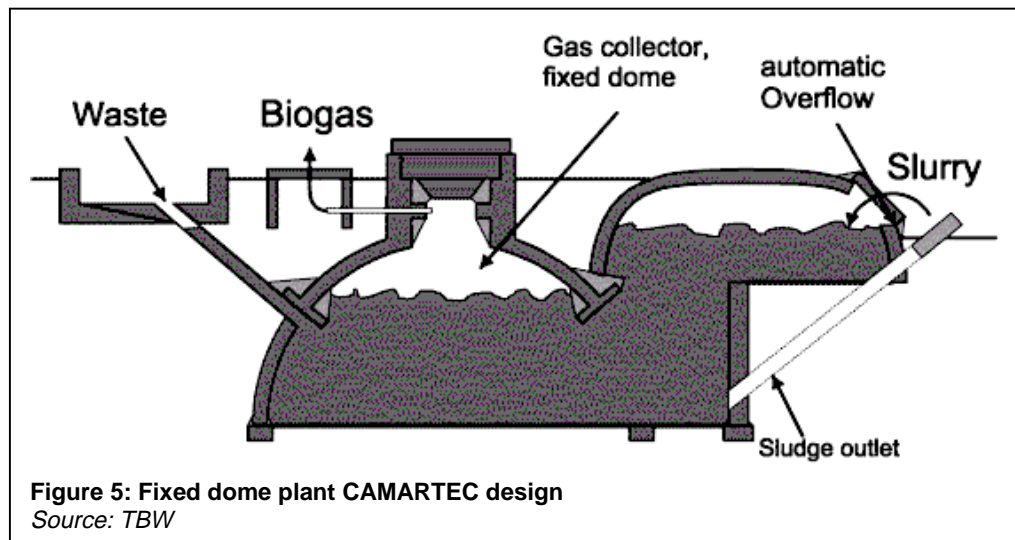
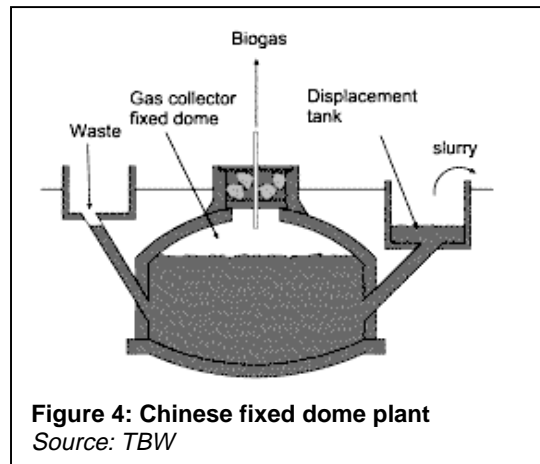
**Figure 2: Basic function of a fixed-dome biogas plant, 1 Mixing pit, 2 Digester, 3 Gasholder, 4 Displacement pit, 5 Gas pipe**  
Source: OEKOTOP

The top part of a fixed-dome plant (the gas space) must be gas-tight. Concrete, masonry and cement rendering are not gas-tight. The gas space must therefore be painted with a gas-tight layer (e.g. 'Water-proofer', Latex or synthetic paints). A possibility to reduce the risk of cracking of the gas-holder consists in the construction of a weak-ring in the masonry of the digester. This "ring" is a flexible joint between the lower (water-proof) and the upper (gas-proof) part of the hemispherical structure. It prevents cracks that develop due to the hydrostatic pressure in the lower parts to move into the upper parts of the gas-holder.

## Types of fixed-dome plants

- **Chinese fixed-dome plant** is the archetype of all fixed dome plants. Several million have been constructed in China. The digester consists of a cylinder with round bottom and top.
- **Janata model** was the first fixed-dome design in India, as a response to the Chinese fixed dome plant. It is not constructed anymore. The mode of construction lead to cracks in the gasholder - very few of these plant had been gas-tight.

- **Deenbandhu**, the successor of the Janata plant in India, with improved design, was more crack-proof and consumed less building material than the Janata plant. with a hemisphere digester
- **CAMARTEC model** has a simplified structure of a hemispherical dome shell based on a rigid foundation ring only and a calculated joint of fraction, the so-called weak / strong ring. It was developed in the late 80s in Tanzania.



### Climate and size

Fixed-dome plants must be covered with earth up to the top of the gas-filled space to counteract the internal pressure (up to 0,15 bar). The earth cover insulation and the option for internal heating makes them suitable for colder climates. Due to economic parameters, the recommended minimum size of a fixed-dome plant is 5 m<sup>3</sup>. Digester volumes up to 200 m<sup>3</sup> are known and possible.

**Advantages:** Low initial costs and long useful life-span; no moving or rusting parts involved; basic design is compact, saves space and is well insulated; construction creates local employment.

**Disadvantages:** Masonry gas-holders require special sealants and high technical skills for gas-tight construction; gas leaks occur quite frequently; fluctuating gas pressure complicates gas utilization; amount of gas produced is not immediately visible, plant operation not readily understandable; fixed dome plants need exact planning of levels; excavation can be difficult and expensive in bedrock.

Fixed dome plants can be recommended only where construction can be supervised by experienced biogas technicians.

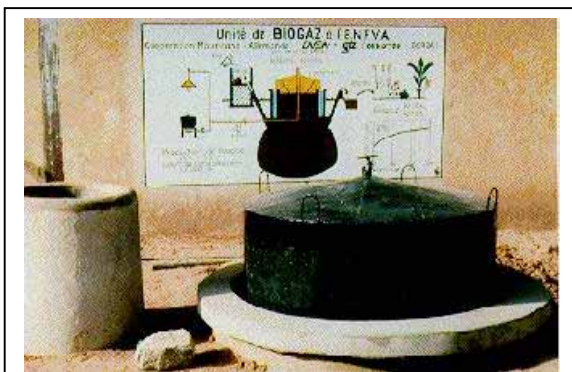


**Figure 6: Installation of a *Shanghai* fixed-dome system near Shanghai, PR China**

*Photo: L. Sasse*

## Floating-drum plants

### The drum



**Figure 7: Floating-drum plant in Mauretania**

*Photo: gtz/GATE*

In the past, floating-drum plants were mainly built in India. A floating-drum plant consists of a cylindrical or dome-shaped digester and a moving, floating gas-holder, or drum. The gas-holder floats either directly in the fermenting slurry or in a separate water jacket. The drum in which the biogas collects has an internal and/or external guide frame that provides stability and keeps the drum upright. If biogas is produced, the drum moves up, if gas is consumed, the gas-holder sinks back.

### Size

Floating-drum plants are used chiefly for digesting animal and human feces on a continuous-feed mode of operation, i.e. with daily input. They are used most frequently by small- to middle-sized farms (digester size: 5-15m<sup>3</sup>) or in institutions and larger agro-industrial estates (digester size: 20-100m<sup>3</sup>).

**Advantages:** Floating-drum plants are easy to understand and operate. They provide gas at a constant pressure, and the stored gas-volume is immediately recognizable by the position of the drum. Gas-tightness is no problem, provided the gasholder is de-rusted and painted regularly.

**Disadvantages:** The steel drum is relatively expensive and maintenance-intensive. Removing rust and painting has to be carried out regularly. The life-time of the drum is short (up to 15 years; in tropical coastal regions about five years). If fibrous substrates are used, the gas-holder shows a tendency to get "stuck" in the resultant floating scum.



### Water-jacket floating-drum plants

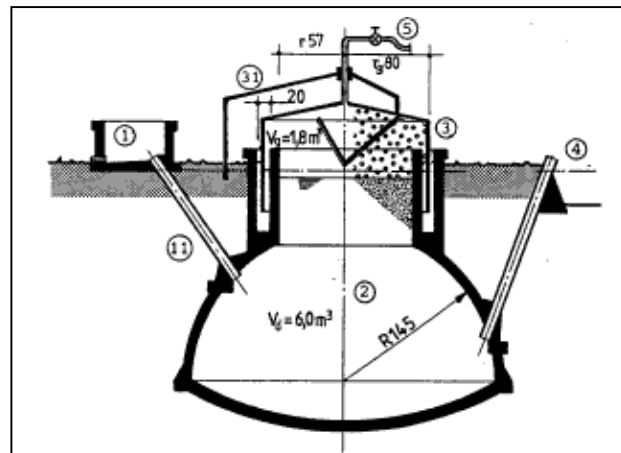
Water-jacket plants are universally applicable and easy to maintain. The drum cannot get stuck in a scum layer, even if the substrate has a high solids content. Water-jacket plants are characterized by a long useful life and a more aesthetic appearance (no dirty gas-holder). Due to their superior sealing of the substrate (hygiene!), they are recommended for use in the fermentation of night soil. The extra cost of the masonry water jacket is relatively modest.

### Material of digester and drum

The digester is usually made of brick, concrete or quarry-stone masonry with plaster. The gas drum normally consists of 2.5 mm steel sheets for the sides and 2 mm sheets for the top.

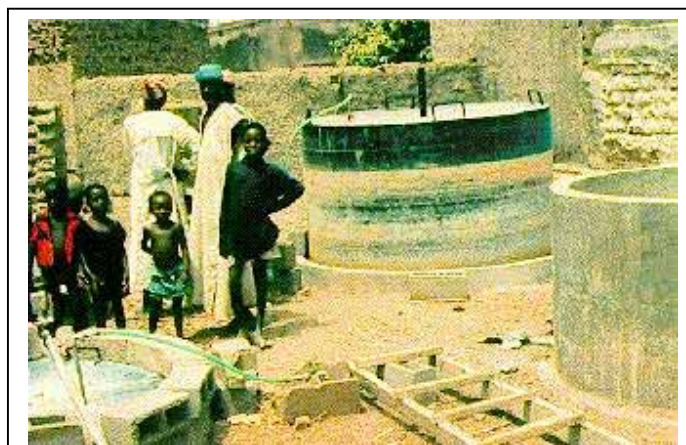
It has welded-in braces which break up surface scum when the drum rotates. The drum must be protected against corrosion. Suitable coating products are oil paints, synthetic paints and bitumen paints. Correct priming is important. There must be at least two preliminary coats and one topcoat. Coatings of used oil are cheap. They must be renewed monthly. Plastic sheeting stuck to bitumen sealant has not given good results. In coastal regions, repainting is necessary at least once a year, and in dry uplands at least every other year. Gas production will be higher if the drum is painted black or red rather than blue or white, because the digester temperature is increased by solar radiation. Gas drums made of 2 cm wire-mesh-reinforced concrete or fiber-cement must receive a gas-tight internal coating. The gas drum should have a slightly sloping roof, otherwise rainwater will be trapped on it, leading to rust damage. An excessively steep-pitched roof is unnecessarily expensive and the gas in the tip cannot be used because when the drum is resting on the bottom, the gas is no longer under pressure.

Floating-drums made of glass-fiber reinforced plastic and high-density polyethylene have been used successfully, but the construction costs are higher compared to using steel. Floating-drums made of wire-mesh-reinforced concrete are liable to hairline cracking and are intrinsically porous. They require a gas-tight, elastic internal coating. PVC drums are unsuitable because they are not resistant to UV.



**Figure 8: Water-jacket plant with external guide frame. 1 Mixing pit, 11 Fill pipe, 2 Digester, 3 Gasholder, 31 Guide frame, 4 Slurry store, 5 Gas pipe**

*Source: Sasse, 1984*



**Figure 9: Floating-drum plant in Burkina Faso**

*Photo: gtz/GATE*

## Guide frame

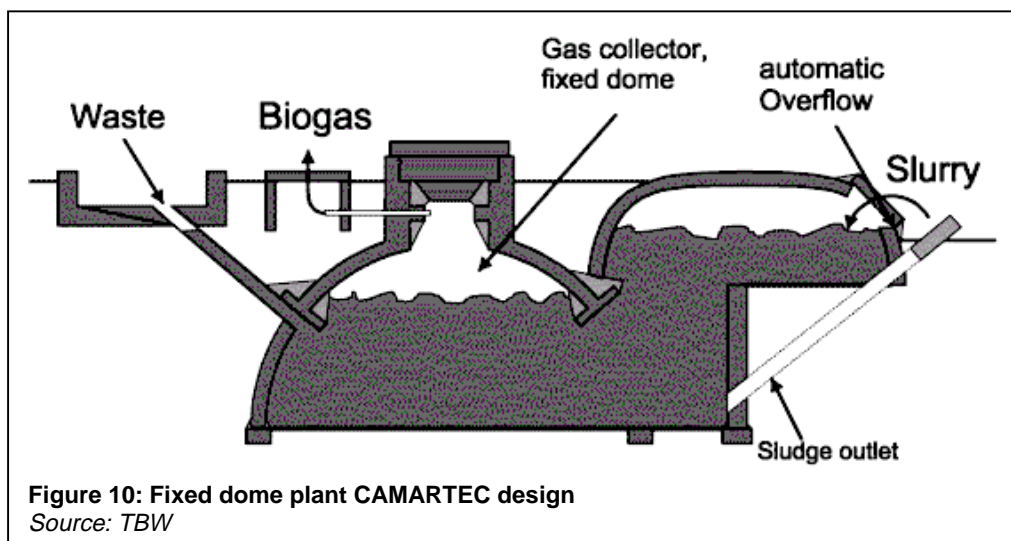
The side wall of the gas drum should be just as high as the wall above the support ledge. The floating-drum must not touch the outer walls. It must not tilt, otherwise the coating will be damaged or it will get stuck. For this reason, a floating-drum always requires a guide. This guide frame must be designed in a way that allows the gas drum to be removed for repair. The drum can only be removed if air can flow into it, either by opening the gas outlet or by emptying the water jacket.

The floating gas drum can be replaced by a balloon above the digester. This reduces construction costs but in practice problems always arise with the attachment of the balloon to the digester and with the high susceptibility to physical damage.

## Types of floating-drum plants

There are different types of floating-drum plants (see drawings under Construction):

- **KVIC model** with a cylindrical digester, the oldest and most widespread floating drum biogas plant from India.
- **Pragati model** with a hemisphere digester
- **Ganesh model** made of angular steel and plastic foil
- floating-drum plant made of pre-fabricated reinforced concrete compound units
- floating-drum plant made of fibre-glass reinforced polyester
- **BORDA model**: The BORDA-plant combines the static advantages of hemispherical digester with the process-stability of the floating-drum and the longer life span of a water jacket plant.



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# Biogas Plant Types and Design

## Digester types in industrialized countries

To give an overview, we have chosen three fictitious designs as they could be found in, for example, Europe. The designs are selected in a way that all the typical elements of modern biogas technology appear at least once. All designs are above-ground, which is common in Europe. Underground structures, however, do exist.

**Mixing pit** varies in size and shape according to the nature of substrate. It is equipped with propellers for mixing and/or chopping the substrate and often with a pump to transport the substrate into the digester. At times, the substrate is also pre-heated in the mixing pit in order to avoid a temperature shock inside the digester.

**Fermenter or digester** is insulated and made of concrete or steel. To optimize the flow of substrate, large digesters have a longish channel form. Large digesters are almost always agitated by slow rotating paddles or rotors or by injected biogas. Co-fermenters have two or more separated fermenters. The gas can be collected inside the digester, then usually with a flexible cover. The digester can also be filled completely and the gas stored in a separate gas-holder.

**Gas-holder** is usually of flexible material, therefore to be protected against weather. It can be placed either directly above the substrate, then it acts like a balloon plant, or in a separate 'gas-bag'.

**slurry store** for storage of slurry during winter. The store can be open (like conventional open liquid manure storage) or closed and connected to the gas-holder to capture remaining gas production. Normally, the store is not heated and only agitated before the slurry is spread on the field.

**Gas use element** is in Europe in 95% of the cases a thermo-power unit which produces electricity for the farm, the grid and heat for the house, greenhouses and other uses. The thermo-power unit has the advantage, that the required energy can be produced in any mixture of gas and fossil energy. It can, therefore, react to periods of low gas production and high energy requirements or vice versa.



Figure 11: Control glasses for an industrial digester for solid organic waste, TBW, Germany

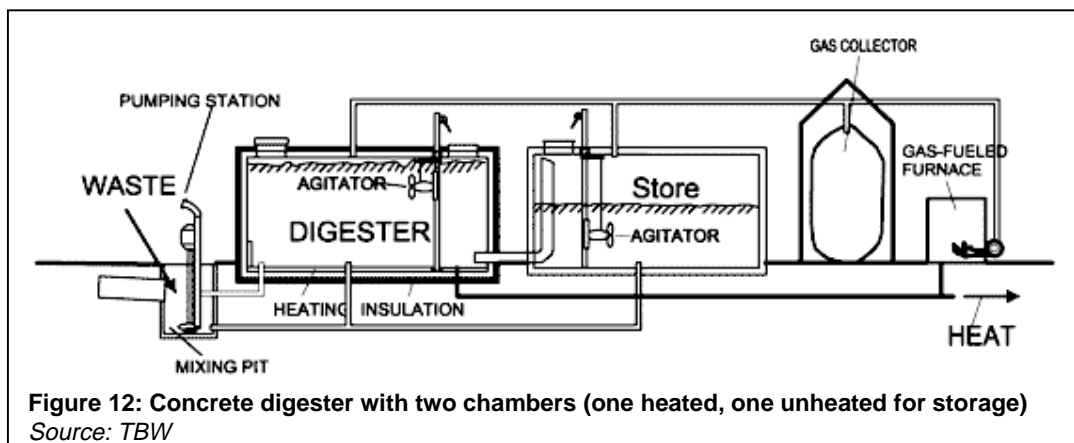
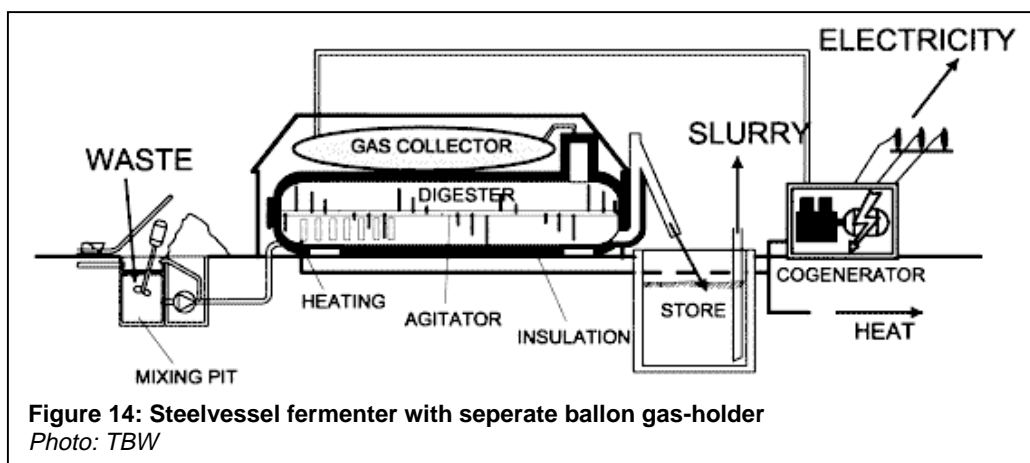
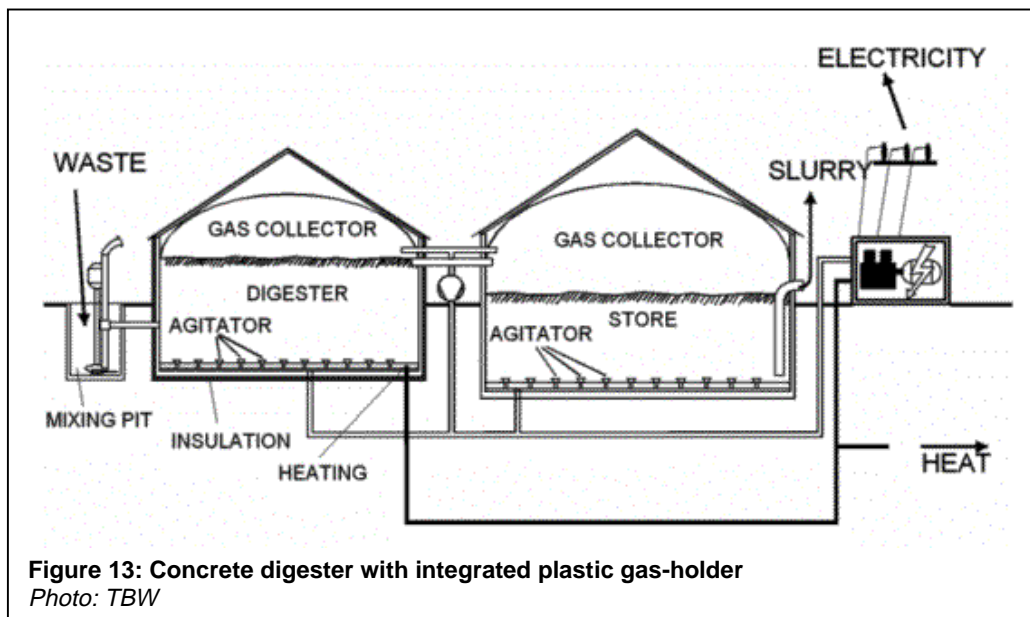


Figure 12: Concrete digester with two chambers (one heated, one unheated for storage)  
Source: TBW





## Selection of appropriate design

In developing countries, the design selection is determined largely by the prevailing design in the region, which, in turn takes the climatic, economic and substrate specific conditions into consideration. Large plants are designed on a case-to-case basis.

Typical design criteria are:

**Space:** determines mainly the decision if the fermenter is above-ground or underground, if it is to be constructed as an upright cylinder or as a horizontal plant.

**Existing structures** may be used like a liquid manure tank, an empty hall or a steel container. To reduce costs, the planner may need to adjust the design to these existing structures.

**Minimizing costs** can be an important design parameter, especially when the monetary benefits are expected to be low. In this case a flexible cover of the digester is usually the cheapest solution. Minimizing costs is often opposed to maximizing gas yield.

**Available substrate** determines not only the size and shape of mixing pit but the digester volume (retention time!), the heating and agitation devices. Agitation through gas injection is

only feasible with homogenous substrate and a dry matter content below 5%. Mechanical agitation becomes problematic above 10% dry matter.

## **Ballon plants**

A balloon plant consists of a heat-sealed plastic or rubber bag (balloon), combining digester and gas-holder. The gas is stored in the upper part of the balloon. The inlet and outlet are attached directly to the skin of the balloon. Gas pressure can be increased by placing weights on the balloon. If the gas pressure exceeds a limit that the balloon can withstand, it may damage the skin. Therefore, safety valves are required. If higher gas pressures are needed, a gas pump is required. Since the material has to be weather- and UV resistant, specially stabilized, reinforced plastic or synthetic caoutchouc is given preference. Other materials which have been used successfully include RMP (red mud plastic), Trevira and butyl. The useful life-span does usually not exceed 2-5 years.

***Advantages:*** Standardized prefabrication at low cost; shallow installation suitable for use in areas with a high groundwater table; high digester temperatures in warm climates; uncomplicated cleaning, emptying and maintenance; difficult substrates like water hyacinths can be used.

***Disadvantages:*** Low gas pressure may require gas pumps; scum cannot be removed during operation; the plastic balloon has a relatively short useful life-span and is susceptible to mechanical damage and usually not available locally. In addition, local craftsmen are rarely in a position to repair a damaged balloon.

Balloon biogas plants are recommended, if local repair is or can be made possible and the cost advantage is substantial.

## **Horizontal plants**

Horizontal biogas plants are usually chosen when shallow installation is called for (groundwater, rock). They are made of masonry or concrete.

***Advantages:*** Shallow construction despite large slurry space.

***Disadvantages:*** Problems with gas-space leakage, difficult elimination of scum.

## **Earth-pit plants**

Masonry digesters are not necessary in stable soil (e.g. laterite). It is sufficient to line the pit with a thin layer of cement (wire-mesh fixed to the pit wall and plastered) in order to prevent seepage. The edge of the pit is reinforced with a ring of masonry that also serves as anchorage for the gas-holder. The gas-holder can be made of metal or plastic sheeting. If plastic sheeting is used, it must be attached to a quadratic wooden frame that extends down into the slurry and is anchored in place to counter its buoyancy. The requisite gas pressure is achieved by placing weights on the gas-holder. An overflow point in the peripheral wall serves as the slurry outlet.

***Advantages:*** Low cost of installation (as little as 20% of a floating-drum plant); high potential for self help approaches.

***Disadvantages:*** Short useful life; serviceable only in suitable, impermeable types of soil.

Earth-pit plants can only be recommended for installation in impermeable soil located above the groundwater table. Their construction is particularly inexpensive in connection with plastic sheet gas-holders.

## **Ferrocement plants**

The ferro-cement type of construction can be applied either as a self-supporting shell or an earth-pit lining. The vessel is usually cylindrical. Very small plants (Volume under 6 m<sup>3</sup>) can be prefabricated. As in the case of a fixed-dome plant, the ferrocement gasholder requires special sealing measures (proven reliability with cemented-on aluminium foil).

***Advantages:*** Low cost of construction, especially in comparison with potentially high cost of masonry for alternative plants; mass production possible; low material input.

***Disadvantages:*** Substantial consumption of essentially good-quality cement; workmanship must meet high quality standards; uses substantial amounts of expensive wire mesh; construction technique not yet adequately time-tested; special sealing measures for the gas-holder are necessary.

Ferro-cement biogas plants are only recommended in cases where special ferro-cement know-how is available.

## Parts of Biogas Plants

- Influent collecting tank
- Inlet and outlet
- Digester
- Gasholders
- Gas pipe, valves and accessories
- Stirring facilities
- Heating systems
- Pumps
- Weak Ring

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### Influent collecting tank

#### Size and homogenization

Fresh substrate is usually gathered in an influent collecting tank prior to being fed into the digester. Depending on the type of system, the tank should hold one to two days' substrate. An influent collecting tank can also be used to homogenize the various substrates and to set up the required consistency, e.g. by adding water to dilute the mixture of vegetable solids (straw, grass, etc.), or by adding more solids in order to increase the biomass. The fibrous material is raked off the surface, if necessary, and any stones or sand settling at the bottom are cleaned out after the slurry is admitted to the digester. The desired degree of homogenization and solids content can be achieved with the aid of an agitator, pump or chopper. A rock or wooden plug can be used to close off the inlet pipe during the mixing process.

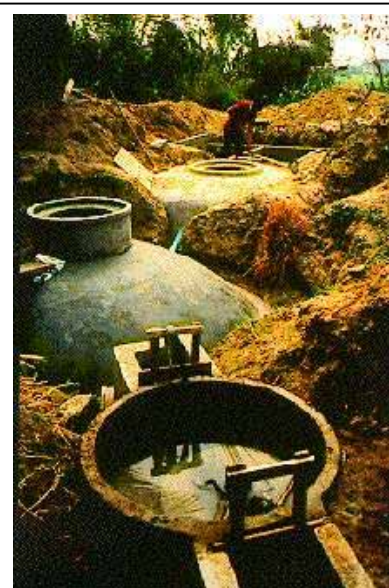
#### Location

A sunny location can help to warm the contents before they are fed into the digester in order to avoid thermal shock due to the cold mixing water. In the case of a biogas plant that is directly connected to the stable, it is advisable to install the mixing pit deep enough to allow installation of a floating gutter leading directly into the pit. Care must also be taken to ensure that the low position of the mixing pit does not result in premature digestion. For reasons of hygiene, toilets should have a direct connection to the inlet pipe.

### Inlet and outlet

#### Size and material

The inlet (feed) and outlet (discharge) pipes lead straight into the digester at a steep angle. For liquid substrate, the pipe diameter should be 10-15 cm, while fibrous substrate requires a diameter of 20-30 cm. The inlet and the outlet pipe mostly consist of plastic or concrete.



**Figure 15: Installation of a fixed-dome plant in Thailand: The influent collecting tank is in front of the photo, the digester and the outlet are located behind it.**

*Photo: Kossmann (gtz/GATE)*

## Position of inlet and outlet

Both the inlet and the outlet pipe must be freely accessible and straight, so that a rod can be pushed through to eliminate obstructions and agitate the digester contents. The pipes should penetrate the digester wall at a point below the lowest slurry level (i.e. not through the gas storage). The points of penetration should be sealed and reinforced with mortar.

The inlet pipe ends higher in the digester than the outlet pipe in order to promote more uniform flow of the substrate. In a fixed-dome plant, the inlet pipe defines the bottom line of the gas-holder, acting like a security valve to release over-pressure. In a floating-drum plant, the end of the outlet pipe determines the digester's (constant) slurry level.

Inlet and outlet pipe must be placed in connection with brick-laying. It is not advisable to break holes into the spherical shell afterwards, this would weaken the masonry structure.

## Digester

### Requirements

No matter which design is chosen, the digester (fermentation tank) must meet the following requirements:

- **Water/gastightness** - watertightness in order to prevent seepage and the resultant threat to soil and groundwater quality; gastightness in order to ensure proper containment of the entire biogas yield and to prevent air entering into the digester (which could result in the formation of an explosive mixture).
- **Insulation** - if and to which extent depends on the required process temperature, the local climate and the financial means; heat loss should be minimized if outside temperatures are low, warming up of the digester should be facilitated when outside temperatures are high.
- **Minimum surface area** - keeps cost of construction to a minimum and reduces heat losses through the vessel walls. A spherical structure has the best ratio of volume and surface area. For practical construction, a hemispherical construction with a conical floor is close to the optimum.
- **Structural stability** - sufficient to withstand all static and dynamic loads, durable and resistant to corrosion.

### Internal and external forces

Two relevant forces act on the digester. The external active earth pressure causes compressive forces within the masonry. The internal hydrostatic and gas pressures causes tensile stress in the masonry. Thus, the external pressure applied by the surrounding earth must be greater at all points than the internal forces. Round and spherical shapes are able to accept the highest forces and distribute them uniformly. Edges and corners lead to peak tensile stresses which can result in cracking.

### Shapes of digesters

From the standpoint of fluid dynamics and structural strength, an egg-shaped vessel is about the best possible solution. This type of construction, however, is comparatively expensive, so that its use is usually restricted to large-scale sewage treatment plants. The Chinese fixed-dome designs are of similar shape, but less expensive. The hemispherical CAMARTEC design is optimized in structural strength, but does not make optimal use of the excavation required.

Simplified versions of such digester designs include cylinders with conical covers and bottoms. They are much easier to build and are sometimes available on the market as prefabricated units. Their disadvantage lies in their less favorable surface-volume ratio. The cylinder should have a height equal to its diameter. *Prone cylinders* have become quite popular on farms, since they are frequently the more favorable solution for small-scale bio-methanation. *Cuboid digesters* are often employed in batch-fed systems used primarily for fermenting solid material, so that fluid dynamics are of little interest.

## Building material of digester

Digesters can be made from any of the following materials:

### Steel vessels

Steel vessels are inherently gas-tight, have good tensile strength, and are relatively easy to construct (by welding). In many cases, a discarded steel vessel of appropriate shape and size can be salvaged for use as a biogas digester. Susceptibility to corrosion both outside (atmospheric humidity) and inside (aggressive media) can be a severe problem. As a rule, some type of anticorrosive coating must be applied and checked at regular intervals. Steel vessels are only cost-effective, if second-hand vessels (e.g. train or truck tankers) can be used.



**Figure 16: Construction of the digester neck with steel reinforcement**  
*Photo: Krämer (TBW)*

### Concrete vessels

Concrete vessels have gained widespread acceptance in recent years. The requisite gas-tightness necessitates careful construction and the use of gas-tight coatings, linings and/or seal strips in order to prevent gas leakage. Most common are stress cracks at the joints of the top and the sides. The prime advantage of concrete vessels are their practically unlimited useful life and their relatively inexpensive construction. This is especially true for large digesters in industrialized countries.

### Masonry

Masonry is the most frequent construction method for small scale digesters. Only well-burnt clay bricks, high quality, pre-cast concrete blocks or stone blocks should be used in the construction of digesters. Cement-plastered/rendered masonry is a suitable - and inexpensive - approach for building an underground biogas digester, whereby a dome-like shape is recommended. For domes larger than 20 m<sup>3</sup> digester volume, steel reinforcement is advisable. Masons who are to build masonry digesters have to undergo specific training and, initially, require close supervision.



**Figure 17: Construction of the dome for a 30 m<sup>3</sup> digester in Cuba**  
*Photo: Krämer (TBW)*

## Plastics

Plastics have been in widespread use in the field of biogas engineering for a long time. Basic differentiation is made between flexible materials (sheeting) and rigid materials (PE, GRP, etc.). Diverse types of plastic sheeting can be used for constructing the entire digesting chamber (balloon gas holders) or as a vessel cover in the form of a gas-tight "bonnet".

Sheeting made of caoutchouc (india rubber), PVC, and PE of various thickness and description have been tried out in numerous systems. The durability of plastic materials exposed to aggressive slurry, mechanical stress and UV radiation, as well as their gas permeability, vary from material to material and on the production processes employed in their manufacture. Glass-fibre reinforced plastic (GRP) digesters have proven quite suitable, as long as the in-service static stresses are accounted for in the manufacturing process. GRP vessels display good gas-tightness and corrosion resistance. They are easy to repair and have a long useful life span. The use of sandwich material (GRP - foam insulation - GRP) minimizes the on-site insulating work and reduces the cost of transportation and erection.

## Wood

A further suitable material for use in the construction of biogas systems is wood. It is often used for building liquid-manure hoppers and spreaders. Wooden digesters require a vapor-proof membrane to protect the insulation. Closed vessels of any appreciable size are very hard to render gas-tight without the aid of plastic sheeting. Consequently, such digesters are very rare.

## Gasholders

Basically, there are different designs of construction for gasholders used in simple biogas plants:

- floating-drum gasholders
- fixe-domes gasholders
- plastic gasholders
- separate gasholders

### Floating-drum gasholders

Most floating-drum gas-holders are made of 2-4 mm thick sheet steel, with the sides made of thicker material than the top in order to compensate for the higher degree of corrosive attack. Structural stability is provided by L-bar bracing that also serves to break up surface scum when the drum is rotated. A guide frame stabilizes the gas drum and prevents it from tilting and rubbing against the masonry. The two equally suitable and most frequently used types are:

- an internal rod & pipe guide with a fixed (concrete-embedded) cross pole (an advantageous configuration in connection with an internal gas outlet);
- external guide frame supported on three wooden or steel legs.

For either design, substantial force can be necessary to rotate the drum, especially if it is stuck in a heavy layer of floating scum. Any gas-holder with a volume exceeding 5 m<sup>3</sup> should be equipped with a double guide (internal and external).

All grades of steel normally used for gas-holders are susceptible to moisture-induced rusting both in- and outside. Consequently, a long service life requires proper surface protection, including:

- thorough de-rusting and de-soiling
- primer coat of minimum 2 layers
- 2 or 3 cover coats of plastic or bituminous paint.

The cover coats should be reapplied annually. A well-kept metal gas-holder can be expected to last between 3 and 5 years in humid, salty air or 8-12 years in a dry climate.



Materials regarded as suitable alternatives to standard grades of steel are galvanized sheet metal, plastics (glass-fiber reinforced plastic (GRP), plastic sheeting) and ferro-cement with a gas-tight lining. The gas-holders of water-jacket plants have a longer average service life, particularly when a film of used oil is poured on the water seal to provide impregnation.

### Fixed-dome gasholders

A fixed-dome gas-holder can be either the upper part of a hemispherical digester (CAMARTEC design) or a conical top of a cylindrical digester (e.g. Chinese fixed-dome plant). In a fixed-dome plant the gas collecting in the upper part of the dome displaces a corresponding volume of digested slurry. The following aspects must be considered with regard to design and operation:

- An overflow into and out of the compensation tank must be provided to avoid over-filling of the plant.
- The gas outlet must be located about 10 cm higher than the overflow level to avoid plugging up of the gas pipe.
- A gas pressure of 1 m WC or more can develop inside the gas space. Consequently, the plant must be covered sufficiently with soil to provide an adequate counter-pressure.
- Special care must be taken to properly close the man hole, which may require to weigh down the lid with 100 kg or more. The safest method is to secure the lid with clamps.

The following structural measures are recommended to avoid cracks in the gas-holder:

- The foot of the dome (gas-holder) should be stabilized by letting the foundation slab project out enough to allow for an outer ring of mortar.
- A rated break/pivot ring should be provided at a point located between 1/2 and 2/3 of the minimum slurry level. This in order to limit the occurrence or propagation of cracks in the vicinity of the dome foot and to displace forces through its stiffening/articulating effect such that tensile forces are reduced around the gas space. Alternatively, the lowest point of the gas-holder should be reinforced by a steel ring or the whole gas-holder be reinforced with chicken mesh wire.

Normally, masonry, *mortar and concrete are not gas-tight*, with or without mortar additives. Gas-tightness can only be achieved through good, careful workmanship and special coatings. The main precondition is that masonry and plaster are strong and free of cracks. Cracked and sandy rendering must be removed. In most cases, a plant with cracked masonry must be dismantled, because not even the best seal coating can render cracks permanently gas-tight.

Some tried and proven seal coats and plasters:

- **multi-layer bitumen**, applied cold (hot application poses the danger of injury by burns and smoke-poisoning; solvents cause dangerous/explosive vapors). Two to four thick coats required;
- **bitumen with aluminum foil**, thin sheets of overlapping aluminum foil applied to the still-sticky bitumen, followed by the next coat of bitumen;
- **plastics**, e.g. epoxy resin or acrylic paint; very good but expensive;
- **paraffin**, diluted with 2-5% kerosene, heated up to 100°C and applied to the preheated masonry, thus providing an effective (deep) seal. Use kerosene/gas torch to heat masonry.
- multi-layer **cement plaster** with water-proof elements

In any case, a pressure test must be carried out before the plant is put in service.

### Plastic gas-holders

Gas-holders made of plastic sheeting serve as integrated gas-holders, as separate balloon/bag-type gas-holders and as integrated gas-transport/storage elements. For plastic



(sheet) gas-holders, the structural details are of less immediate interest than the question of which materials can be used.

### Separate gas-holders

Differentiation is made between:

- low-pressure, wet and dry gas-holders (10-50 mbar). Basically, these gas-holders are identical to integrated and/or plastic (sheet) gas-holders. Separate gas-holders cost more and are only worthwhile in case of substantial distances (at least 50-100 m) or to allow repair of a leaky fixed-dome plant. This type of separate gas-holder is also used to buffer extreme differences between gas-production and gas-use patterns.
- medium- or high-pressure gas-holders (8-10 bar / 200 bar)



**Figure 18: Biogas plant with separate gasholder in Nicaragua**

*Photo: gtz/GATE*

Neither system can be considered for use in small-scale biogas plants. Even for large-scale plants, they cannot be recommended under the conditions in most developing countries. High-pressure gas storage in steel cylinders (as fuel for vehicles) is presently under discussion. While that approach is possible in theory, it would be complicated and, except in special cases, prohibitively expensive. It would also require the establishment of stringent safety regulations.

### Gas pipe, valves and accessories

#### Biogas piping

At least 60% of all non-functional biogas units are attributable to defect gas piping. Utmost care has to be taken, therefore, for proper installation. For the sake of standardization, it is advisable to select a single size for all pipes, valves and accessories.

The requirements for biogas piping, valves and accessories are essentially the same as for other gas installations. However, biogas is 100% saturated with water vapor and contains hydrogen-sulfide. Consequently, no piping, valves or accessories that contain any amounts of ferrous metals may be used for biogas piping, because they would be destroyed by corrosion within a short time. The gas lines may consist of standard galvanized steel pipes. Also suitable (and inexpensive) is plastic tubing made of rigid PVC or rigid PE. Flexible gas pipes laid in the open must be UV-resistant.

#### Steel pipes

Galvanized steel water supply pipes are used most frequently, because the entire piping system (gas pipe, valves and accessories) can be made of universally applicable English/U.S. Customary system components, i.e. with all dimensions in inches. Pipes with

nominal dimensions of 1/2" or 3/4" are adequate for small-to-midsize plants of simple design and pipe lengths of less than 30 m. For larger plants, longer gas pipes or low system pressure, a detailed pressure-loss (pipe-sizing) calculation must be performed.

When installing a gas pipe, special attention must be paid to:

- **gas-tight, friction-type joints**
- **line drainage, i.e. with a water trap at the lowest point of the sloping pipe in order to empty water accumulation**
- **protection against mechanical impact**

## Stirring facilities

Optimum stirring substantially reduces the retention time. If agitation is excessive, the bacteria have "no time to eat". The ideal is gentle but intensive stirring about every four hours. Of similar importance is the breaking up of a scum layer which has lost contact with the main volume of substrate and is, therefore, not further digested. This top layer can form an impermeable barrier for biogas to move up from the digester to the gas holder.

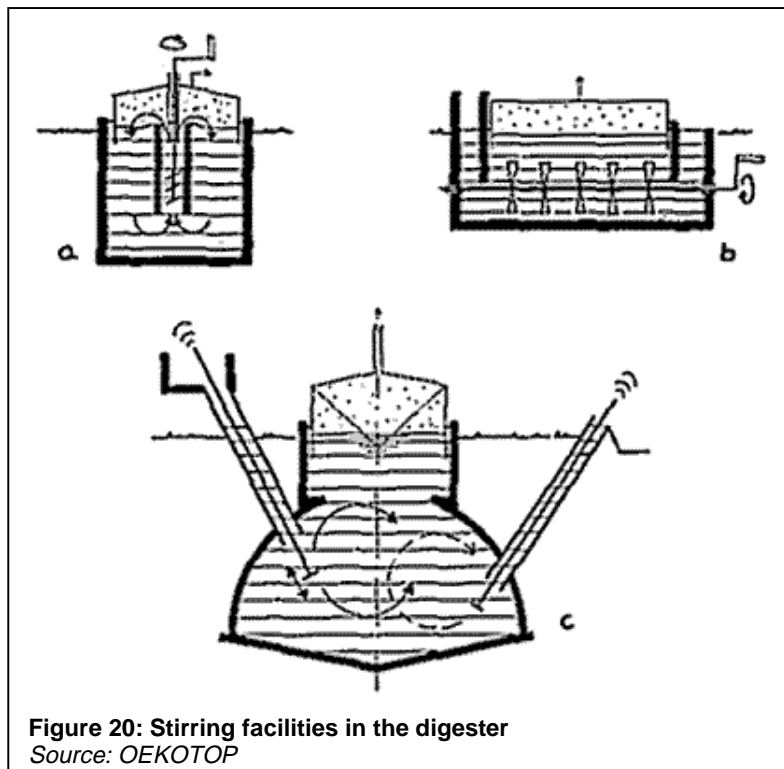
As a rule of thumb it can be stated that stirring facilities are more important in larger plants than in small scale farm plants.



**Figure 19: Stirring device for a european biodigester**

*Photo: Krieg*

## Types of stirring facilities



**Figure 20: Stirring facilities in the digester**

*Source: OEKOTOP*

- The **impeller stirrer** has given good results especially in sewage treatment plants.
- The **horizontal shaft** stirs the fermentation channel without mixing up the phases. Both schemes originate from large-scale plant practice.
- For simple household plants, **poking with a stick** is the simplest and safest stirring method.

# Optional Parts of Biogas Plants

## Heating systems

Normally, because of the rather high involved costs, small-scale biogas plants are built without heating systems. But even for small scale plants, it is of advantage for the bio-methanation process to warm up the influent substrate to its proper process temperature before it is fed into the digester. If possible, cold zones in the digester should be avoided. In the following, a number of different ways to get the required amount of thermal energy into the substrate are described. In principle, one can differentiate between:

- **direct heating** in the form of steam or hot water, and
- **indirect heating** via heat exchanger, whereby the heating medium, usually hot water, imparts heat while not mixing with the substrate.

### Direct heating

Direct heating with steam has the serious disadvantage of requiring an elaborate steam-generating system (including desalination and ion exchange as water pretreatment) and can also cause local overheating. The high cost is only justifiable for large-scale sewage treatment facilities.

The injection of hot water raises the water content of the slurry and should only be practiced if such dilution is necessary.

### Indirect heating

Indirect heating is accomplished with heat exchangers located either inside or outside of the digester, depending on the shape of the vessel, the type of substrate used, and the nature of the operating mode.

4. **Floor heating** systems have not served well in the past, because the accumulation of sediment gradually hampers the transfer of heat.
5. **In-vessel** heat exchangers are a good solution from the standpoint of heat transfer as long as they are able to withstand the mechanical stress caused by the mixer, circulating pump, etc. The larger the heat-exchange surface, the more uniformly heat distribution can be effected which is better for the biological process.
6. **On-vessel** heat exchangers with the heat conductors located in or on the vessel walls are inferior to in-vessel-exchangers as far as heat-transfer efficiency is concerned, since too much heat is lost to the surroundings. On the other hand, practically the entire wall area of the vessel can be used as a heat-transfer surface, and there are no obstructions in the vessel to impede the flow of slurry.
7. **Ex-vessel** heat exchangers offer the advantage of easy access for cleaning and maintenance.

While in Northern countries, often a substantial amount of the produced biogas is consumed to provide process energy, in countries with higher temperatures and longer sunshine hours, solar-heated water can be a cost-effective solution for heating. Exposing the site of the biogas plant to sunshine, e.g. by avoiding tree shade, is the simplest method of heating.

## Pumps

Pumps become necessary parts of a biogas unit, when the amounts of substrate require fast movement and when gravity cannot be used for reasons of topography or substrate characteristics. Pumps transport the substrate from the point of delivery through all the stages of fermentation. Therefore, several pumps and types of pumps may be needed. Pumps are usually found in large scale biogas units.

### Types of pump

There are two predominant types of pump for fresh substrate: **centrifugal pumps** and **positive-displacement pumps** (reciprocating pumps). Centrifugal pumps operate on the

principle of a rapidly rotating impeller located in the liquid flow. They provide high delivery rates and are very robust, i.e. the internals are exposed to little mechanical stress. They do, however, require a free-flowing intake arrangement, because they are not self-priming (regenerative).

### **Data of pumps**

Practically all centrifugal pump characteristics are geared to water. They show the delivery rates for various heads, the achievable efficiency levels, and the power requirement for the pump motor. Consequently, such data cannot be directly applied to biogas systems, since the overall performance and efficiency level of a pump for re-circulating slurry may suffer a serious drop-off as compared to its standard "water" rating (roughly 5-10%).

### **Substrate**

Sometimes, namely when the substrate is excessively viscous, a centrifugal pump will no longer do the job, because the condition of the substrate surpasses the pump's physical delivery capacity. In such cases, one must turn to a so-called positive-displacement or reciprocating type of pump in the form of a piston pump, gear pump or eccentric spiral pump, all of which operate on the principle of displacing action to provide positive delivery via one or more enclosed chambers.

### **Positive displacement pumps**

Positive displacement pumps offer multiple advantages. Even for highly viscous substrate, they provide high delivery and high efficiency at a relatively low rate of power consumption. Their characteristics - once again for water - demonstrate how little the delivery rate depends on the delivery head. Consequently, most of the characteristics show the delivery rate as a function of pump speed.

The main disadvantage as compared to a centrifugal pump is the greater amount of wear and tear on the internal occasioned by the necessity of providing an effective seal between each two adjacent chambers.

### **Pump delivery lines**

Pump delivery lines can be made of steel, PVC (rigid) or PE (rigid or flexible), as well as appropriate flexible pressure tubing made of reinforced plastic or rubber. Solid substrate, e.g. dung, can also be handled via conveyor belt, worm conveyor or sliding-bar system, though none of these could be used for liquid manure. When liquid manure is conducted through an open gutter, small weirs or barrages should be installed at intervals of 20-30 m as a means of breaking up the scum layer.

Each such barrier should cause the scum to fall at least 20-30 cm on the downstream side. All changes of direction should be executed at right angles (90°). Depending on the overall length, the cross gutter should be laid some 30-50 cm deeper than the main gutter. Transitions between a rectangular channel and a round pipe must be gradual. An inclination of about 14% yields optimum flow conditions. The channel bottom must be laid level, since any slope in the direction of flow would only cause the liquid manure to run off prematurely. All wall surfaces should be as smooth as possible.

### **Weak ring**

#### **Position of the weak ring**

The weak/strong ring improves the gas-tightness of fixed-dome plants. It was first introduced in Tanzania and showed promising results. The weak ring separates the lower part of the hemispherical digester, (filled with digesting substrate), from the upper part (where the gas is stored). Vertical cracks, moving upwards from the bottom of the digester, are diverted in this ring of lean mortar into horizontal cracks. These cracks remain in the slurry area where they are of no harm to the gas-tightness. The strong ring is a reinforcement of the bottom of the gas-holder, it could also be seen as a foundation of the gas-holder. It is an additional device

to prevent cracks from entering the gas-holder. Weak and strong ring have been successfully combined in the CAMARTEC design.



**Figure 21: Construction of the weak/strong ring of a 16 m<sup>3</sup>, Tanzania**  
*Photo: Kellner (TBW)*

### Materials and construction

The weak ring consists of mortar of a mixture of sand, lime and cement (15:3:1). The top of the weak ring restores the horizontal level. It is interrupted only by the inlet pipe passing through. The strong ring rests on the weak ring and is the first layer of the upper part of the hemispherical shell. It consists of a row of header bricks with a concrete package at the outside. In case of soft or uncertain ground soil one may place a ring reinforcement bar in the concrete of the strong ring. The brick of the strong ring should be about three times wider than the brickwork of the upper wall. A detailed description of the weak/strong ring construction can be found in Sasse, Kellner, Kimaro.

### Further reading:

- **Ringkamp, M.; Tentscher, W.; Schiller, H.:** Preliminary results on: statical optimization of family-sized fixed-dome digesters. Tilche, A.; Rozzi, A. (ed.): Poster Papers. Fifth International Symposium on Anaerobic Digestion, Bologna 1988, pp. 321-324
- **Sasse, L.; Kellner, Ch.; Kimaro, A.:** Improved Biogas Unit for Developing Countries. Deutsche Gesellschaft für Technische Zusammenarbeit (GTZ) GmbH, Vieweg & Sohn Verlagsgesellschaft Braunschweig, 1991

# **Balancing Biogas Production and Energy Demand**

## **Determining the biogas production**

The quantity, quality and type of biomass available for use in the biogas plant constitutes the basic factor of biogas generation. The biogas incidence can and should also be calculated according to different methods applied in parallel.

- Measuring the biomass availability
- Determining the biomass supply via pertinent-literature data
- Determining the biomass supply via regional reference data
- Determining biomass supply via user survey

It should be kept in mind that the various methods of calculation can yield quite disparate results that not only require averaging by the planner, but which are also subject to seasonal variation.

The biomass supply should be divided into two categories:

8. quick and easy to procure
9. procurement difficult, involving a substantial amount of extra work

## **Measuring the biomass availability (quantities of excrement and green substrate)**

This is a time-consuming, cumbersome approach, but it is also a necessary means of adapting values from pertinent literature to unknown regions. The method is rather inaccurate if no total-solids measuring is included. Direct measurement can only provide indication of seasonal or fodder-related variance if sufficiently long series of measurements are conducted.

## **Determining the biomass supply via literature data**

According to this method, the biomass supply can be determined at once on the basis of the livestock inventory. Data concerning how much manure is produced by different species and per liveweight of the livestock unit are preferable.

$$\text{Dung yield} = \text{liveweight} \times \text{number of animals} \times \text{specific quantity of excrements [ kg/d ]}$$

Often, specific quantities of excrement are given in % of liveweight per day, in the form of moist mass, total solids content or volatile solids content

## **Determining the biomass supply via regional reference data**

This approach leads to relatively accurate information, as long as other biogas plants are already in operation within the area in question.

## **Determining biomass availability via user survey**

This approach is necessary if green matter is to be included as substrate.

## **Determining the energy demand**

The energy demand of any given farm is equal to the sum of all present and future consumption situations, i.e. cooking, lighting, cooling, power generation etc. The following table helps to collect all data concerning the energy demand.

<b>Table 1: Outline for determining biogas demand</b>		
<b>Energy consumers</b>	<b>Data</b>	<b>Biogas demand [l/d]</b>
<b>1. Gas for cooking</b> Number of persons Number of meals Present energy consumption Present source of energy Gas demand per person and meal Gas demand per meal Anticipated gas demand Specific consumption rate of burner Number of burners Duration of burner operation Anticipated gas demand <b>Total anticipated cooking-gas demand</b>		
<b>2. Lighting</b> Specific gas consumption per lamp Number of lamps Duration of lamp operation Gas demand		
<b>3. Cooling</b> Specific gas consumption * 24 hours		
<b>4. Engines</b> Specific gas consumption per kWh Engine output Operating time Gas demand		
<b>5. Miscellaneous consumers</b> Gas demand		
<b>Anticipated increase in consumption (%)</b>		
<b>Total biogas demand</b> 1st-priority consumers 2nd-priority consumers 3rd-priority consumers		

The following alternative modes of calculation are useful:

**Determining biogas demand on the basis of present energy consumption**, e.g. for ascertaining the cooking-energy demand. This involves either measuring or inquiring the present rate of energy consumption in the form of wood, charcoal, kerosene and bottled gas.

**Calculating biogas demand via comparable-use data**: Such data may consist of

- empirical values from neighboring systems, e.g. biogas consumption per person and day,
- reference data taken from literature, although this approach involves considerable uncertainty, since cooking-energy consumption depends on local cooking and eating habits and can therefore differ substantially from case to case.

**Estimating biogas demand by way of appliance consumption data and assumed periods of use**: This approach can only work to the extent that the appliances to be used are known in advance, e.g. a biogas lamp with a specific gas consumption of 120 l/h and a planned operating period of 3 h/d, resulting in a gas demand of 360 l/d.

Then, the interested party's energy demand should be tabulated in the form of a requirements list. In that connection, it is important to attach relative priority values to the various consumers, e.g.:

1. priority: applies only when the biogas plant will cover the demand.
2. priority: coverage is desirable, since it would promote plant usage.
3. priority: excess biogas can be put to these uses.



## Biogas Planning Guide

This guide to planning is intended to serve agricultural extension officers as a comprehensive tool for arriving at decisions concerning the suitability of locations for family-sized biogas plants. The detailed planning outline has a **data** column for entering the gathered information and a **rating** column for noting the results of evaluation.

Evaluation criteria are:

- + Siting condition are favorable
- o Siting condition are unfavorable, but
  - a) compensable by project activities
  - b) not serious enough to cause ultimate failure
- Siting condition are not satisfactory

Despite its detailed nature, this planning guide is only a framework within which the extension officer should proceed to conduct a careful investigation and give due consideration, however subjectively, to the individual conditions in order to arrive at a locally practical solution. By no means is this planning guide intended to relieve the agricultural extension officer of the responsibility to thoroughly familiarize himself with the on-the-spot situation and to judge the overall value of a given location on the basis of the knowledge thus gained.

Detailed planning guide for biogas plants		
0. Initial situation	Data	Rating
<b>Addresses/project characterization</b> Plant acronym: Address of operator/customer: Place/region/country: Indigenous proj. org./executing org.: Extension officer/advisor: <b>General user data</b> Household structure and number of persons: User's economic situation: Crops: types, areas, manner of cultivation: Non-agricultural activity: Household/farm income: Cultural and social characteristics of user: <b>Problems leading to the "biogas approach"</b> Energy-supply bottlenecks: Workload for prior source of energy: Poor soil structure/yields: Erosion/deforestation: Poor hygiene and other factors: <b>Objectives of the measure "biogas plant"</b> User interests: Project interests: Other interests:		

<b>1. Natural / Agricultural conditions</b>	Data	Rating
<b>Natural conditions</b> Mean annual temperature: Seasonal fluctuations: Diurnal variation: Rating:		- 0 +
<b>Subsoil</b> Type of soil: Groundwater table, potable water catchment area: Rating:		- 0 +
<b>Water conditions</b> Climatic zone: Annual precipitation: Dry season (months): Distance to source of water: Rating:		- 0 +
<b>Livestock inventory (useful for biogas production)</b> Animals: kind and quantity: Type of stable: Use of dung: Persons responsible for animals: Rating:		- 0 +
<b>Vegetable waste (useful for biogas production)</b> Types and quantities: Prior use: Rating:		- 0 +
<b>Fertilization</b> Customary types and quantities of fertilizer/areas fertilized: Organic fertilizer familiar/in use: Rating:		- 0 +
<b>Potential sites for biogas plant</b> Combined stable/biogas plant possible: Distance between biogas plant and livestock stable: Distance between biogas plant and place of gas consumption: Rating:		- 0 +
<b>Overall rating 1</b>		- 0 +
<b>2. Balancing the energy demand with the biogas production</b>	Data	Rating
<b>Prior energy supply</b> Uses, source of energy,		

<p>consumption:</p> <p><b>Anticipated biogas demand (kwh/day or l/d)</b></p> <p>for cooking:</p> <p>for lighting:</p> <p>for cooling:</p> <p>for engines:</p> <p>Total gas demand</p> <p>a) percentage that <i>must</i> be provided by the biogas plant:</p> <p>b) desired demand coverage:</p> <p><b>Available biomass (kg/d) and potential gas production (l/d)</b></p> <p>from animal husbandry</p> <p>pigs:</p> <p>poultry:</p> <p>cattle:</p> <p>Night soil</p> <p>Vegetable waste (quantities and potential gas yield)</p> <p>1.</p> <p>2.</p> <p>Totals: biomass and potential gas production</p> <p>a) easy to procure:</p> <p>b) less easy to procure:</p> <p><b>Balancing</b></p> <p>Gas production clearly greater than gas demand -&gt; positive rating (+)</p> <p>Gas demand larger than gas production -&gt; negative rating (-); but review of results in order regarding:</p> <p>a) possible reduction of gas demand by the following measures -&gt;</p> <p>b) possible increase in biogas production by the following measures -&gt;</p> <p>If the measures take hold: -&gt; qualified positive rating for the plant location ( o )</p>		
--	--	--

If the measures do not take hold: -> site rating remains negative (-)		
<b>Overall rating 2</b>		- o +
<b>3. Plant Design and Construction</b>	Data	Rating
<b>Selection of plant design</b> Locally customary type of plant: Arguments in favor of floating-drum plant: Arguments in favor of fixe-dome plant: Arguments in favor of other plant(s): Type of plant chosen: <b>Selection of site</b> <b>Availability of building materials</b> Bricks/blocks/stone: Cement: Metal: Sand: Piping/fittings: Miscellaneous: <b>Availability of gas appliances</b> Cookers: Lamps: ... ...		
<b>Overall rating 3</b>		- o +
<b>4. Plant operation / maintenance / repair</b>	Data	Rating
<b>Assessment of plant operation</b> Incidental work: Work expenditure in h: Persons responsible: Rating with regard to anticipated implementation:		- o +
<b>Plant maintenance</b> Maintenance-intensive components: Maintenance work by user: Maintenance work by external assistance: Rating with regard too anticipated implementation:		- o +
<b>Plant repair</b> Components liable to need repair: Repairs that can be made by the user: Repairs requiring external assistance:		- o +

Requisite materials and spare parts: Rating with regard to expected repair services:		
<b>Overall rating 4</b>		- o +
<b>5. Economic analysis</b>	Data	Rating
<b>Time-expenditure accounting</b> Time saved with biogas plant Time lost due to biogas plant Rating:		- o +
<b>Microeconomic analysis</b> Initial investment: Cost of operation/maintenance/repair: Return on investment: energy, fertilizer, otherwise: Payback time (static): Productiveness (static): Rating:		- o +
<b>Quality factors, useful socioeconomic effects and costs</b> Useful effects: hygiene, autonomous energy, better lighting, better working conditions, prestige: Drawbacks: need to handle night soil, negative social impact: Rating:		- o +
<b>Overall rating 5</b>		- o +
<b>6. Social acceptance and potential for dissemination</b>	Data	Rating
<b>Anticipated acceptance</b> Participation in planning and construction Integration into agricultural setting: Integration into household: Sociocultural acceptance: Rating:		- o +
<b>Establishing a dissemination strategy</b> Conditions for and chances of the professional-craftsman approach: Conditions for and chances of the self-help oriented approach:		- o + - o +
<b>General conditions for dissemination</b> Project-executing		- o +

organization and its staffing: orgnaizational structure: interest and prior experience in biogas technology: Regional infrastructure for transportation: communication: material procurement: Craftsman involvement, i.e. which acitivities: minimum qualifications: tools and machines: Training for engineers, craftsman and users: Proprietary capital, subsidy/credit requirement on the part of user: craftsmen: Rating:		
<b>Overall rating 6</b>		<b>- o +</b>
<b>7. Summarization</b>		
<b>Siting conditions</b>	No.	Rating
Natural/agricultural conditions	1.	<b>- o +</b>
Balancing the energy demand and the biogas production	2.	<b>- o +</b>
Plant design and construction	3.	<b>- o +</b>
Plant operation/maintenance/repair	4.	<b>- o +</b>
Economic analysis	5.	<b>- o +</b>
Social acceptance and potential for dissemination	6.	<b>- o +</b>
<b>Overall rating of siting conditions</b>		<b>- o +</b>

## Step-by-Step Planning Checklist for Biogas Plants

The following table 2 gives an overview of all the steps required to build a biogas unit. The order follows a usual time-line. There are steps which can be combined. However, to skip any of them might lead to future problems.

Customer	Contractor
	organizes advertisement, awareness creation
hears about biogas, develops interest, get's in contact with the contractor	
	gives first overview over costs
	writes letter to the customer
writes a request	
	starts file
	makes a side visit, including: discussion and calculations
	makes a quantity survey,
	does object planning
	writes invoice explains warranty performances
makes first payment (50%)	organizes a customer and constructor sign contract
	hands over a list of building material to be delivered by the customer
prepares the material he agreed to deliver	
	organizes material delivery, reference line, main construction work, finishing, landscaping, slurry component, piping.
starts to fill the plant second payment (50%)	
	finishes piping installation of gas consumption accessories
discusses handing over	
makes an agreement on co-operation regarding fertiliser utilisation	
	makes a follow up on fertiliser utilisation
	does customer monitoring
	conducts technical and agricultural service visits

## Sizing a biogas plant

The size of the biogas plant depends on the quantity, quality and kind of available biomass and on the digesting temperature. The following points should be considered

### Sizing the digester

The size of the digester, i.e. the *digester volume* **Vd**, is determined on the basis of the chosen *retention time* **RT** and the *daily substrate input quantity* **Sd**.

$$\mathbf{Vd} = \mathbf{Sd} \times \mathbf{RT} \text{ [ m}^3 = \text{m}^3/\text{day} \times \text{number of days ]}$$

The retention time, in turn, is determined by the chosen/given digesting temperature. For an unheated biogas plant, the temperature prevailing in the digester can be assumed as 1-2 Kelvin above the soil temperature. Seasonal variation must be given due consideration, however, i.e. the digester must be sized for the least favorable season of the year. For a plant of simple design, the retention time should amount to at least 40 days. Practical experience shows that retention times of 60-80 days, or even 100 days or more, are no rarity when there is a shortage of substrate. On the other hand, extra-long retention times can increase the gas yield by as much as 40%.

The substrate input depends on how much water has to be added to the substrate in order to arrive at a solids content of 4-8%.

$$\text{Substrate input (Sd)} = \text{biomass (B)} + \text{water (W)} \text{ [m}^3/\text{d]}$$

In most agricultural biogas plants, the mixing ratio for dung (cattle and / or pigs) and water (**B:W**) amounts to between 1:3 and 2:1.

### Calculating the *daily gas production* **G**

The amount of *biogas generated each day* **G** [m<sup>3</sup> gas/d], is calculated on the basis of the *specific gas yield* **Gy** of the substrate and the daily substrate input **Sd**.

The calculation can be based on:

10. The *volatile solids content* **VS**

$$\mathbf{G} = \mathbf{VS} \times \mathbf{Gy}(\text{solids}) \text{ [ m}^3/\text{d} = \text{kg} \times \text{m}^3/(\text{d} \times \text{kg}) ]}$$

11. the weight of the moist mass **B**

$$\mathbf{G} = \mathbf{B} \times \mathbf{Gy}(\text{moist mass}) \text{ [ m}^3/\text{d} = \text{kg} \times \text{m}^3/(\text{d} \times \text{kg}) ]}$$

12. standard gas-yield values per livestock unit **LSU**

$$\mathbf{G} = \text{number of LSU} \times \mathbf{Gy}(\text{species}) \text{ [ m}^3/\text{d} = \text{number} \times \text{m}^3/(\text{d} \times \text{number}) ]}$$

The temperature dependency is given by:

$$\mathbf{Gy(T,RT)} = \mathbf{mGy} \times \mathbf{f(T,RT)}$$

where

**Gy(T,RT)** = *gas yield as a function of digester temperature and retention time*

**mGy** = *average specific gas yield, e.g. l/kg volatile solids content*

**f(T,RT)** = *multiplier for the gas yield as a function of digester temperature T and retention time RT*

As a rule, it is advisable to calculate according to several different methods, since the available basic data are usually very imprecise, so that a higher degree of sizing certainty can be achieved by comparing and averaging the results.

### Establishing the plant parameters

The degree of safe-sizing certainty can be increased by defining a number of plant parameters:



### Specific gas production $G_p$

i.e. the daily gas generation rate per  $m^3$  digester volume  $V_d$ , is calculated according to the following equation

$$G_p = G \div V_d \text{ [ (m}^3\text{/d) / m}^3 \text{ ]}$$

### Digester loading $L_d$

The digester loading  $L_d$  is calculated from the *daily total solids input*  $TS/d$  or the *daily volatile solids input*  $VS/d$  and the *digester volume*  $V_d$ :

$$L_{dT} = TS/d \div V_d \text{ [ kg/(m}^3\text{ d) ]}$$

$$L_{dV} = VS/d \div V_d \text{ [ kg/(m}^3\text{ d) ]}$$

Then, a calculated parameter should be checked against data from comparable plants in the region or from pertinent literature.

### Sizing the gasholder

The size of the gasholder, i.e. the *gasholder volume*  $V_g$ , depends on the relative rates of gas generation and gas consumption. The gasholder must be designed to:

- cover the *peak consumption rate*  $gc_{max}$  ( $\rightarrow V_{g1}$ ) and
- hold the gas produced during the longest *zero-consumption period*  $tz_{max}$  ( $\rightarrow V_{g2}$ )

$$V_{g1} = gc_{max} \times tc_{max} = vc_{max}$$

$$V_{g2} = G_h \times tz_{max}$$

with

$$gc_{max} = \text{maximum hourly gas consumption [m}^3\text{/h]}$$

$$tc_{max} = \text{time of maximum consumption [h]}$$

$$vc_{max} = \text{maximum gas consumption [m}^3\text{]}$$

$$G_h = \text{hourly gas production [m}^3\text{/h]} = G \div 24 \text{ h/d}$$

$$tz_{max} = \text{maximum zero-consumption time [h]}$$

The larger  $V_g$ -value ( $V_{g1}$  or  $V_{g2}$ ) determines the size of the gasholder. A safety margin of 10-20% should be added:

$$V_g = 1.15 (\pm 0.5) \times \max(V_{g1}, V_{g2})$$

Practical experience shows that 40-60% of the daily gas production normally has to be stored.

The ratio  $V_d \div V_g$  (digester volume  $\div$  gasholder volume) is a major factor with regard to the basic design of the biogas plant. For a typical agricultural biogas plant, the  $V_d/V_g$ -ratio amounts to somewhere between 3:1 and 10:1, with 5:1 - 6:1 occurring most frequently.

## Siting of the Biogas Unit

### Stable

- The stable should be built on an elevated position. This makes it possible to use gravity to collect urine and dung for feeding into the biogas plant. An elevated site on the farm also facilitates the distribution of slurry by gravity onto the farm land.
- For security reasons, the stable often is situated near the house.
- For easy access the feeding trough should be directed towards the area where fodder is grown.
- The milking place has to be at the higher end of the sloping stable floor. The milking should take place under clean conditions, away from the dung alley.
- roofed. If it is totally roofed, sun should still enter and ventilation should be assured.
- The position of the stable should allow for later extension.
- The animals need constant access to clean and fresh water and feeds.
- If the present position of the stable is unsuitable as a place for the biogas unit, it is usually better to shift the stable to the optimal position on the farm.



**Figure 22:** A digester should be as close as possible to the source of dung.



**Figure 23:** Cowshed, directly connected to the plant: A urine chamber to the right collects the liquid which can be used to wash the dung into the digester.

*Photo: Kellner (TBW)*

## Biogas plant

- A golden rule is: the plant belongs to the stable rather than to the kitchen. Preferably, the mixing chamber and inlet are directly connected to a concrete stable floor. A few meters of piping are more economic than the daily transport of dung from the stable to the biogas plant.
- The roof of the stable should neither drain on the digester nor on the soil covering the plant. Large amounts of water entering the ground around the plant weaken the soil and cause static instability. Excess rain water may cool down the slurry in the plant and cause the gas production to drop.
- The overflow point should guide into farmland owned by the plant user. It has been observed that plants which overflow on public or foreign land can cause social problems. A promise of the owner to remove the slurry daily should not convince the planner.
- Water traps in the piping are a constant source of trouble. If the site allows, the plant and its piping should be laid out in a way that a water trap in the piping can be avoided. This is only possible if the pipes are sloping all the way back to the plant.
- The piping is a major cost factor. It should not be unnecessarily long. This criterion, however, is given less priority than having the stable close to the inlet and the outlet directed towards the farm land.
- A fixed dome plant should not be located in an area required for tractor or heavy machinery movements.
- Trees should not be too close to the plant. The roots may destroy the digester or the expansion chamber. In addition older trees may fall and destroy parts of the plant. If the position of the biogas plant is too shady, the soil temperature around the plant will be low in general. This leads to a decrease in gas production.
- The area around a biogas plant should not be a playground for children. This is less important for underground fixed dome plants, more important for floating drum plants and essential for balloon plants.



**Figure 24: A model of an agricultural digester in Germany with two horizontal steel tanks, a gas storage bag and a co-generation unit in a container.**

*Photo: Krämer (TBW)*

## Substrate types and management

- Cattle dung and manure
  - Pig dung and manure
  - Goat dung
  - Chicken droppings
  - Human excrements
  - Manure yield of animal excrements
  - The problem of scum
- 

### Cattle dung and manure

**Cattle dung** is the most suitable material for biogas plants because of the methane-producing bacteria already contained in the stomach of ruminants. The specific gas production, however, is lower and the proportion of methane is around 65% because of pre-fermentation in the stomach. Its homogenous consistency is favourable for use in continuous plants as long as it is mixed with equal quantities of water.

Fresh cattle dung is usually collected and carried to the system in buckets or baskets. Upon arrival it is hand-mixed with about an equal amount of water before being fed into the digester. Straw and leftover fodder or hay is removed by hand in order to prevent clogging and reduce scum formation. Since most simple cow-sheds have dirt floors, the urine is usually not collected. When it is, it usually runs along the manure gutter and into a pail standing in a recess at the end of the gutter. The pail is emptied into the mixing pit - thereby replacing some of the mixing water - in preparation for charging the digester. Urine can considerably increase the gas production. A cemented stable floor, directly attached to the mixing pit, is the best solution to make optimum use of dung and urine and to save time for charging the digester.

**Liquid cattle manure**, a mixture of dung and urine, requires no extra water. However, the simple animal housing found on most farms in developing countries normally does not allow the collection of all animal excrement. Hence, most of the urine with its valuable plant nutrients is lost.

### Pig dung and manure

When pigs are kept in unpaved areas or pens, only the dung can be collected. It must be diluted with water to the requisite consistency for charging the digester. This could result in considerable amounts of sand being fed into the digester, unless it is allowed to settle in the mixing vessel. Once inside the digester, sand and soil accumulates at the bottom and has to be removed periodically. Some form of mechanical mixer should be used to dilute the dung with water, since the odor nuisance makes manual mixing so repulsive that it is usually neglected. Similar to cow stables, a cemented floor, sloping towards the mixing pit, is a preferable solution.

Compared to cattle, pigs are more frequently kept on concrete floors. The water used for washing out the pens yields **liquid manure** with a low solids content. Thus, whenever the topography allows, the liquid manure should be allowed to flow by gravity into the digester. Wash-water should be used as sparingly as possible in order to minimize the necessary digester volume. Very frequently, the pig manure is collected in pails, which is advantageous, even though a sand trap should be provided to prevent sand from entering the digester.

### Goat dung

For goats kept on unpaved floors, the situation is comparable to that described for pigdung. Since a goat farm is practically the only place where any substantial amount of goat dung can accumulate, and then only if the animals are kept on straw bedding, the available feed-stock for a biogas system will usually consist of a mixture of dung and straw bedding. Most

such systems are batch-fed versions into which the dung and an appropriate quantity of water are loaded without being pre-mixed. The feed-stock is usually hauled to and from the digester in wheelbarrows or baskets.

## Chicken droppings

Chicken droppings can only be used if the chickens roost above a suitable dung collecting area of limited size. Otherwise, the sand or sawdust fraction would be disproportionately high. Chicken droppings can be fed into plants which are primarily filled with cow dung without any problem. There is a latent danger of high ammoniac concentration with pure chicken dung, but despite this there are many well functioning biogas plants combined with egg or meat producing factories. The collected droppings are hard and dry, so that they have to be pulverized and mixed with water before they can be loaded into the digester. Mechanical mixing is advisable. The proportion of methane in biogas from chicken excrement is up to 60%.

## Human excrements

In most cultures, handling human excrement is loaded with taboos. Thus, if night soil is to be used in a biogas system, the toilets in question should drain directly into the system so that the night soil is fermented without pretreatment. The amount of water accompanying the night soil should be minimized by ensuring that no water taps or other external sources drain into the toilet bowls, and cleaning/flushing should be limited to rinsing out with about 0.5 - 1 liter water from a bowl. Western-style flush tanks should not be used in connection with small-size biogas plants.

In areas subject to frequent or seasonal water shortages, sand traps are a must, since wiping with stones is often the only means of cleaning after using the toilet.

## The problem of scum

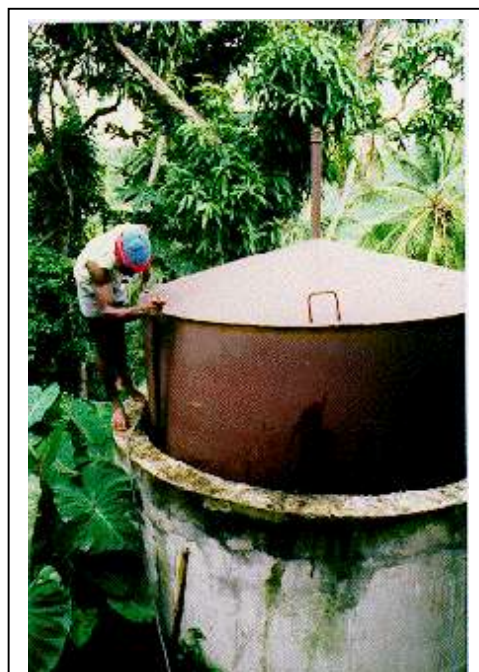
If there is heavy gas release from the inlet but not enough gas available for use, a thick scum layer is most likely the reason. Often the gas pressure does not build up because of the continuous gas release through the inlet for weeks. There is a danger of blocking the gas pipe by rising scum because of daily feeding without equivalent discharge. The lid (or man-hole) must be opened or the floating drum removed and scum is to be taken out by hand.

## Separation of material

Straw, grass, stalks and even already dried dung tends to float to the surface. Solid and mineral material tends to sink to the bottom and, in the course of time, may block the outlet pipe or reduce the active digester volume. In properly mixed substrate with not too high water contents, there is no such separation because of sufficient friction within the paste-like substance.

## Substrate

With pure and fresh cattle dung there is usually no scum problem. Floating layers will become a problem when e.g. undigestible husks are part of the fodder. This is often the case in pig feeds. Before installing a biogas plant at a piggery, the kind of fodder and consequently the kind of dung, must be checked to ensure that it is suitable for a biogas plant. It might be necessary to grind the fodder into fine powder. The user must be aware of the additional costs before deciding on a biogas unit. The problem is even bigger with poultry droppings. The kind of fodder, the sand the chicken pick up, and the feathers falling to the ground make



**Figure 25: Destruction of the scum in a floating-drum plant in the Carribean**  
*Photo: gtz/GATE*

poultry dung a difficult substrate. In case of serious doubt, the building of a biogas plant should be re-assessed.

***Scum can be avoided by stirring, but...***

Scum is not brittle but very filthy and tough. Scum can become so solid after only a short time, that it needs heavy equipment to break it. It remains at the surface after being broken up. To destroy it by fermentation, it must be kept wet. Either the scum must be watered from the top or pushed down into the liquid. Both operations demand costly apparatus. For simple biogas plants, stirring is not a viable solution for breaking the scum.

The only solution for simple biogas plants to avoid scum is by selecting suitable feed material and by sufficient mixing of the dung with liquid before entering the plant.

## Construction Details of Biogas Plants

This section provides detailed information on materials and devices used in the construction of biogas plants:

- Checklist for construction
- Agitation
- Heating
- Piping systems
- Plasters and Coats
- Pumps
- Slurry equipment
- Underground water

### Checklist for building a biogas plant

1. **Finishing the planning**, i.e. site evaluation, determination of energy demand and biomass supply / biogas yield, plant sizing, selection of plant design, how and where to use the biogas, etc., in accordance with the planning guide
2. **Stipulate the plant's location and elaborate a site plan**, including all buildings, gas pipes, gas appliances and fields to be fertilized with digested slurry
3. **Draft a technical drawing showing all plant components**, i.e. mixing pit, connection to stabling, inlet / outlet, digester, gas-holder, gas pipes, slurry storage
4. **Preparation of material / personnel requirements list and procurement of materials needed for the chosen plant:**
  - bricks / stones / blocks for walls and foundation
  - sand, gravel
  - inlet / outlet pipes
  - metal parts (sheet metal, angle irons, etc.)
  - gas pipes and fittings
  - paint and sealants
  - gas appliances
  - tools
  - mason and helper
  - unskilled labor
  - workshop for metal (gas-holder) and pipe installation
5. **Material / personnel assignment planning**, i.e. procedural planning and execution of:
  - excavation
  - foundation slab
  - digester masonry
  - gasholder
  - rendering and sealing the masonry
  - mixing pit - slurry storage pit
  - drying out the plant
  - installing the gas pipe
  - acceptance inspection
6. **Regular building supervision**

**7. Commissioning**

- functional inspection of the biogas plant and its components
- starting the plant

**8. Filling the plant**

**9. Training the user**



## Piping Systems

The piping system connects the biogas plant with the gas appliances. It has to be safe, economic and should allow the required gas-flow for the specific gas appliance. Galvanized steel (G.I.) pipes or PVC-pipes are most commonly used for this purpose. Most prominently, the piping system has to be reliably gas-tight during the life-span of the biogas unit. In the past, faulty piping systems were the most frequent reason for gas losses in biogas units.

### PVC piping

PVC pipes and fittings have a relatively low price and can be easily installed. They are available in different qualities with adhesive joints or screw couplings (pressure water pipes). PVC pipes are susceptible to UV radiation and can easily be damaged by playing children. Wherever possible, PVC pipes should be placed underground.



**Figure 26: Final touches on a piping system with PVC pipes**

*Photo: Krämer (TBW)*

### Galvanized steel piping

Galvanized steel pipes are reliable and durable alternatives to PVC pipes. They can be disconnected and reused if necessary. They resist shocks and other mechanical impacts. However, galvanized steel pipes are costly and the installation is labor intensive, therefore they are only suitable for places where PVC is unavailable or should not be used.

### Pipe diameters

The necessary pipe diameter depends on the required flow-rate of biogas through the pipe and the distance between biogas digester and gas appliances. Long distances and high flow-rates lead to a decrease of the gas pressure. The longer the distance and the higher the flow rate, the higher the pressure drops due to friction. Bends and fittings increase the pressure losses. G.I. pipes show higher pressure losses than PVC pipes. The table below gives some values for appropriate pipe diameters. Using these pipe diameters for the specified length and flow rate, the pressure losses will not exceed 5 mbar.

**Table 3: Appropriate pipe diameter for different pipe lengths and flow-rate (maximum pressure loss < 5 mbar)**

	Galvanized steel pipe			PVC pipe		
Length [m]:	20	60	100	20	60	100
Flow-rate [m <sup>3</sup> /h]						
0.1	1/2"	1/2"	1/2"	1/2"	1/2"	1/2"
0.2	1/2"	1/2"	1/2"	1/2"	1/2"	1/2"
0.3	1/2"	1/2"	1/2"	1/2"	1/2"	1/2"
0.4	1/2"	1/2"	1/2"	1/2"	1/2"	1/2"
0.5	1/2"	1/2"	3/4"	1/2"	1/2"	1/2"
1.0	3/4"	3/4"	3/4"	1/2"	3/4"	3/4"
1.5	3/4"	3/4"	1"	1/2"	3/4"	3/4"
2.0	3/4"	1"	1"	3/4"	3/4"	1"

The values in this table show that a pipe diameter of 3/4" is suitable for flow rates up to 1.5 m<sup>3</sup>/h and distances up to 100 m (PVC pipe). Therefore one could select the diameter of 3/4" as single size for the hole piping system of small biogas plants. Another option is to select the diameter of 1" for the main gas pipe and 1/2" for all distribution pipes to the gas appliances.

## Lay-out of the piping system

PVC can be used for all underground pipes or pipes that are protected against sun light and out of the reach of children. For all parts of the piping system that are above ground one should install galvanized steel pipes. Therefore it is recommended to use 1" G.I. steel pipes for the visible part of the piping system around the biogas digester. For the main pipe one uses 1" PVC pipe placed underground. The distribution pipes should be 1/2" G.I. steel pipes or PVC pipes, depending whether they are installed above or under the wall plastering. But even though G.I. pipes are less susceptible to damage, placing them underground should always be the preferred solution.

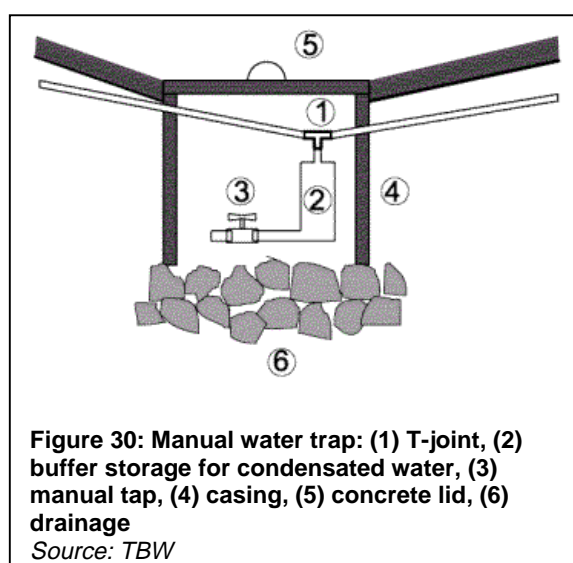
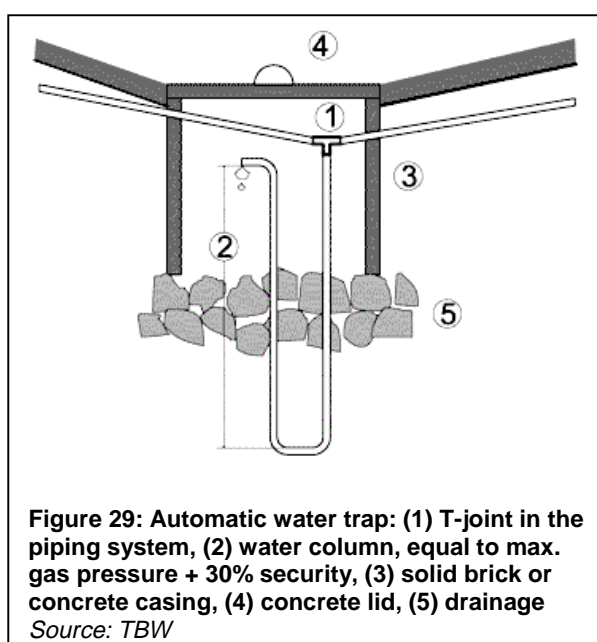
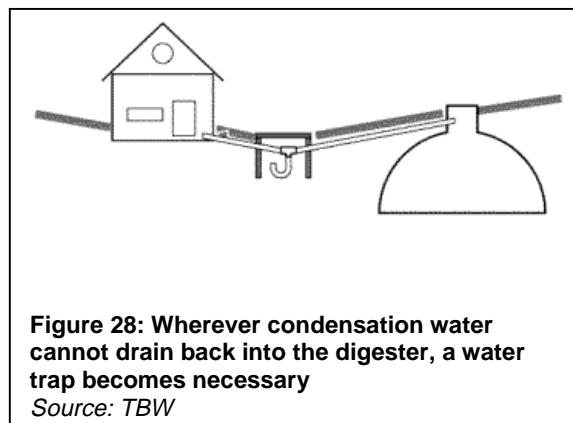
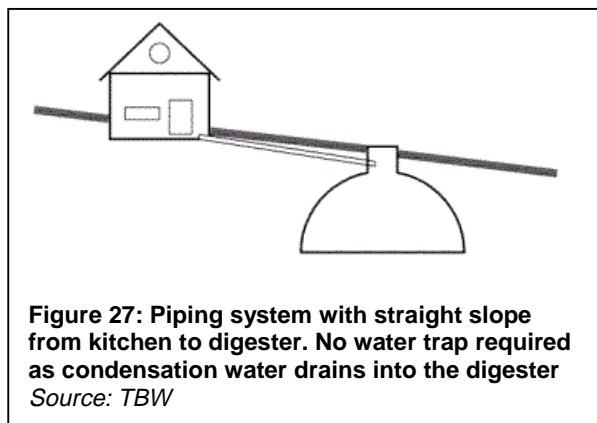
PVC pipes have to be laid at least 25 cm deep underground. They should be placed in a sand bed and be covered with sand or fine earth. One should carefully back-fill the ditches in order to avoid stones lying directly above the pipe.

When the piping is installed - and before refilling the ditches - it has to be tested for possible gas leakage. This can be done by pumping air into the closed piping system up to a pressure that is 2.5 times the maximum gas pressure of the biogas plant. If pressure loss occurs within few hours, every joint of the piping system has to be checked with soap water. Soap-bubbles indicate any leakage of gas.

## Water traps

Due to temperature changes, the moisture-saturated biogas will form inevitably condensation water in the piping system. Ideally, the piping system should be laid out in a way that allows a free flow of condensation water back into the digester. If depressions in the piping system can not be avoided, one or several water traps have to be installed at the lowest point of the depressions. Inclination should not be less than 1%.

Often, water traps cannot be avoided. One has to decide then, if an 'automatic' trap or a manually operated trap is more suitable. Automatic traps have the advantage that emptying - which is easily forgotten - is not necessary. But if they dry up or blow empty, they may cause heavy and extended gas losses. In addition, they are not easily understood. Manual traps are simple and easy to understand, but if they are not emptied regularly, the accumulated condensation water will eventually block the piping system. Both kinds of traps have to be installed in a solid chamber, covered by a lid to prevent an eventual filling up by soil.



## Valves

To the extent possible, ball valves or cock valves suitable for gas installations should be used as shutoff and isolating elements. The most reliable valves are chrome-plated ball valves. Gate valves of the type normally used for water pipes are not suitable. Any water valves exceptionally used must first be checked for gas-tightness. They have to be greased regularly. A U-tube pressure gauge is quick and easy to make and can normally be expected to meet the requirements of a biogas plant.

The main gas valve has to be installed close to the biogas digester. Sealed T-joints should be connected before and after the main valve. With these T-joints it is possible to test the digester and the piping system separately for their gas-tightness. Ball valves as shutoff devices should be installed at all gas appliances. With shutoff valves, cleaning and maintenance work can be carried out without closing the main gas valve.

## **Pumps for Biogas Plants**

Pumps are required to bridge differences in height between the levels of slurry-flow through the biogas unit. They can also be required to mix the substrate or to speed up slow flowing substrates. If substrates have a high solids content and do not flow at all, but cannot be diluted, pumps or transport belts are essential.

Pumps are driven by engines, are exposed to wear and tear and can be damaged. They are costly, consume energy and can disrupt the filling process. For these reasons, pumps should be avoided where possible and methods of dilution and use of the natural gradient be utilized instead.

If pumps cannot be avoided, they can be installed in two ways:

- Dry installation: the pump is connected in line with the pipe. The substrate flows freely up to the pump and is accelerated while passing through the pump.
- Wet installation: the pump is installed with an electric engine inside the substrate. The electric engine is sealed in a watertight container. Alternatively, the pump in the substrate is driven by a shaft, the engine is outside the substrate.

### **Types of pumps**

#### **Rotary pumps**

Rotary pumps operate with a rotor which presses the liquid against the outside wall of the rotor chamber. Due to the geometry of the chamber the liquid is pushed into the outlet pipe. Rotary pumps are very common in liquid manure technology. They are simple and robust and used mainly for substrates of less than 8% solids content. The quantity conveyed per time unit depends largely on the height of lift or the conveying pressure. The maximum conveying pressure is between 0,8 and 3.5 bar. The quantity that can be conveyed varies from 2 to 6 m<sup>3</sup>per min. at a power input of 3 - 15 kW. Rotary pumps cannot, usually, be used as a sucking device. As a special form of rotary pumps, the chopper pump deserves mentioning. It's rotor is equipped with blades to chop substrates with long fibers like straw and other fodder parts before pumping them up. Both wet and dry installation is possible with rotary pumps.

#### **Positive displacement pumps**

Positive displacement pumps are normally used for substrates with higher solids content. They pump and suck at the same time. Their potential quantity conveyed is less dependent on the conveying pressure than with rotary pumps. The direction of pumping / sucking can be changed into the opposite direction by changing the sense of rotation. In biogas units, mainly the eccentric spiral pump and the rotary piston pump (both positive displacement pumps) are used. For better access, a dry installation is the preferred option.

#### **Eccentric spiral pump**

This pump has a stainless steel rotor, similar to a cork screw, which turns in an elastic casing. Eccentric spiral pumps can suck from a depth of up to 8.5m and can produce a pressure of up to 24 bar. They are, however, more susceptible to obstructive, alien elements than rotary pumps. Of disadvantage is further the danger of fibrous material wrapping round the spiral.

#### **Rotary piston pump**

Rotary piston pumps operate on counter-rotating winged pistons in an oval casing. They can pump and suck as well and achieve pressures of up to 10 bar. The potential quantity conveyed ranges from 0.5 to 4 m<sup>3</sup>/min. They allow for larger alien objects and more fibrous material than eccentric spiral pumps.

**Table 4: Types of pumps in comparison**

	<b>rotary pumps</b>	<b>chopper pumps</b>	<b>eccentric spiral pump</b>	<b>rotary piston pump</b>
<b>solids content</b>	< 8 %	< 8 %	< 15 %	< 15 %
<b>energy input</b>	3 - 15 kW	3 - 15 kW	3 - 22 kW	3 - 20 kW
<b>quantity conveyed</b>	2 - 6 m <sup>3</sup> /min	2 - 6 m <sup>3</sup> /min	0,3 - 3,5 m <sup>3</sup> /min	0,5 - 4 m <sup>3</sup> /min
<b>pressure</b>	0,8 - 3,5 bar	0,8 - 3,5 bar	< 25 bar	< 10 bar
<b>structure of substrate</b>	medium long fibers	long fibers	short fibers	medium long fibers
<b>max. size of obstructive elements</b>	approx. 5 cm	depending on choppers	approx. 4 cm	approx. 6 cm
<b>intake</b>	<b>not</b> sucking	<b>not</b> sucking	sucking	sucking
<b>suitability</b>	suitable for large quantities; simple and robust built	suitable for long-fiber substrates which need to be chopped up.	Suitable for high pressures, but susceptible to obstructive bodies	higher pressures than rotary pumps, but higher wear and tear
<b>price comparison</b>	cheaper than positive displacement pumps	depending on choppers	similar to rotary piston pump	similar to eccentric spiral pump

## Heating

To achieve the optimum biogas yield, the anaerobic digestion needs constant environmental conditions, preferably close to the process optimum. The digester temperature is of prime importance. In temperate areas, a heating system and an insulation of the digester is necessary. Hence, the needed temperature for digestion can be reached and a loss of energy by transmission is compensated.

Because of the high costs for material and installation of a heating system, a low-cost biogas plant, as needed in developing countries, can only be built without heating. To boost the biogas yield for those plants, the building of a bigger digester to increase the retention time would be cheaper. A bigger digester reduces the required maintenance, while a heating system, increases maintenance requirements. A bigger digester serves also as a buffer for sediments, pH-variations and gas storage. For example, a fixed dome plant sized 50% bigger, is only 10% more expensive.

The mean surrounding temperature and its seasonal variations are very important. Biogas plants without heating system work, therefore, only in warmer regions for the whole year. In regions with extreme temperature variations, for instance in Turkey (hot summer, cold winter), the biogas plant should be built under the stable. Hence the biogas yield would be lower in summer, but constant over the year and at the end higher. Before implementation, at least an approximated average temperature profile and expected extremes over the year should be available for the site.

A biogas plant with heating system and co-generation can be operated with process energy. Nevertheless the dimensioning of such a heating system is difficult, as the substrate, which has to be heated up, is not homogenous.

A guiding figure for a digester with a hydraulic retention time of 20 days is  $270 \text{ W/m}^3$  digester volume. The increasing of the hydraulic retention time makes it possible to reduce the heating power per volume. With a hydraulic retention time of 40 days the digester needs only  $150 \text{ W/m}^3$ .

Following figures are for heating systems with a heating water temperature difference of 20 K:

hydr. retention time	40 days	30 days	20 days
temperature difference	20 K	20 K	20 K
heating power	$150 \text{ kW/m}^3$	$210 \text{ kW/m}^3$	$270 \text{ kW/m}^3$

A heating system located in the digester produces a thermal circulation, which is, especially for non-agitated digesters, very important.

An indirect energy transfer by heat exchanger is most common. Exceptions are steam injection, liquefying of solid manure with heated water and the heating by pre-aeration.

### Internal and external heating systems

External heating systems have a forced flow on both sides. Due to the turbulent flow patterns of both media, a very good heat transportation can be reached. Therefore, the surface of the heat exchanger can be comparatively small. Nevertheless those systems cannot be recommended for non-agitated digesters.



**Figure 31: Heating system for a biodigester under construction (Germany)**

*Photo: Krieg (TBW)*

The proper dimensioning of an internal heating system seems to be more difficult because of the different currents due to pumping, agitation, thermo-convection and the inflow of biomass.

Under-floor heating systems have been very popular, as they have no disturbing parts in the digester itself. Due to sedimentation and the resulting worsening of heat transportation into the digester, under-floor heating is no longer recommended. With the growth of digester volumes and the need of bigger heating systems, it is also more difficult to build under-floor heating big enough to provide the necessary heat.

Heating coils installed at the inner wall of the digester are a rather new practice. Heating coils made out of steel are much more expensive than heating coils out of plastic material (PE). Materials developed during the last years make such a system more stable while not increasing the costs of the heating system.

Another option is to construct two digesters connected in series, the first heated, the second unheated. The first digester can be used as sedimentation tank, in which the substrate is heated up. The second digester is well isolated to reduce loss of heat.

## Agitation

The term 'agitation' subsumes different ways of homogenising the substrate or mixing it with water and co-substrate:

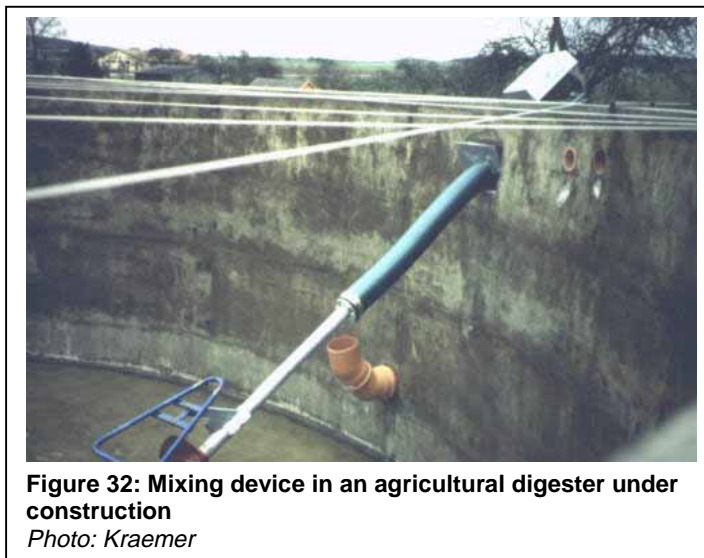
- Mixing and homogenizing the substrate in the mixing chamber
- Agitation inside the digester
- Poking through the in- and outlet pipes (small scale plants)

Agitation of the digester contents is important for the trouble-free performance of a biogas-plant. For the following reasons agitation is recommended several times a day:

- to avoid and destroy swimming and sinking layers
- to improve the activity of bacteria through release of biogas and provision of fresh nutrients
- to mix fresh and fermenting substrate in order to inoculate the former
- to arrive at an even distribution of temperature thus providing uniform conditions inside the digester

Even without mixing device, there is a certain agitation through the raising gas, through the movement of substrates with different temperatures and by the inflow of fresh substrate. This agitation, however, is usually insufficient. A well agitated substrate can, leaving other parameters constant, increase it's biogas production by 50%.

Agitation, as a general rule, should be performed *as much as necessary but as little as possible*. Too frequent mixing with fast rotating, mechanical agitation devices can disturb the biological processes in the fermenting substrate. In addition, an all-too thorough mixing of the whole digester contents may lead to half-digested substrate leaving the digester prematurely.



## Mixing methods

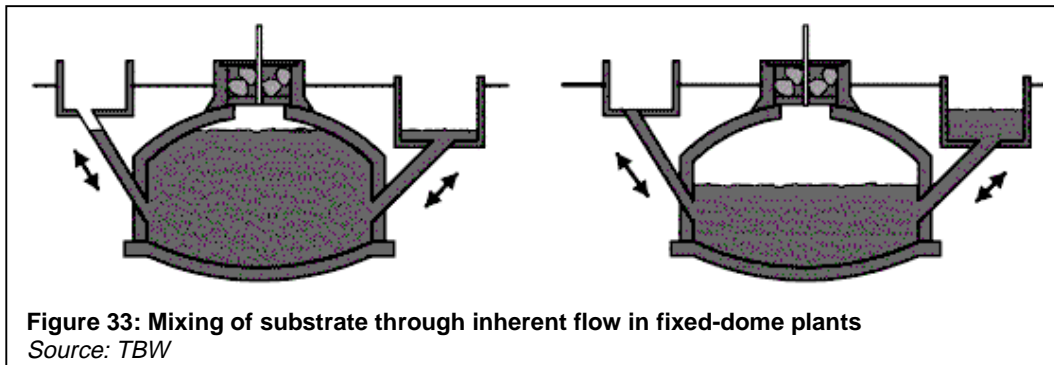
Simple mixing methods have been installed mainly in developing countries:

- tangential inlet and outlet pipes
- separation walls
- forced substrate flow
- vertical hand-operated rotors
- horizontal, hand-operated paddle rotors
- poking through inlet and outlet



### Mixing through inherent flow

In fixed dome plants, frequently found in developing countries, a certain mixing of the substrate is provided by the substrate being pushed up in the compensation tank with gas accumulation. When the stored gas is used, the substrate flows back into the digester.

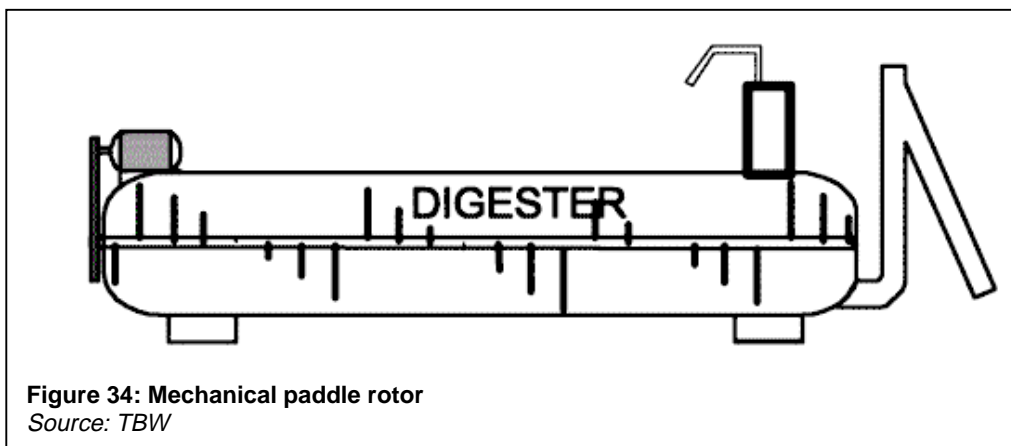


The company "VSP-Anlagen" further developed and patented this principle:

Through the pressure of the biogas, the substrate is pushed from the main digester into the subsidiary digester, resulting in a difference of levels between the two digesters. By reaching a certain difference in levels, a gas valve opens between main and subsidiary digester which equalizes the height difference. The flow-back of the substrate is guided in a way that destroys sinking and swimming layers.

### Mechanical paddle rotor

Mechanical paddle rotors are predominantly used in horizontal steel vessels. A horizontal shaft in hardwood bearings runs through the whole vessel. Attached are paddles or loop-shaped pipes. By turning the shaft the vessel contents are mixed, the swimming layer is broken up and sediments are pushed towards a drainage opening. The loop-shaped pipes can also be used as heat exchangers to warm up the substrate.



### Submerged motor with rotor stirring

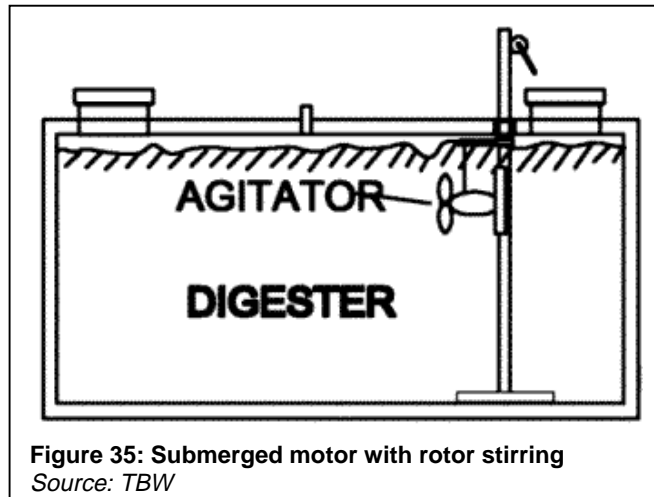
A sealed, submerged electric engine directly drives a rotor. The rotor mixes the substrate by creating a strong current. These stirring devices can usually be adjusted in height and in angle.

## Shaft-driven rotors

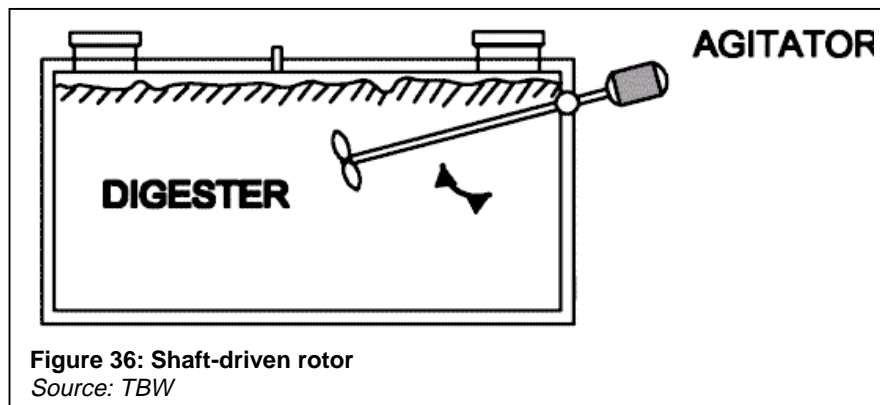
The mode of operation of a shaft-driven rotor is comparable to that of a submerged engine with rotor, only that the rotor is driven via shaft by an engine or by hand. The shaft should be movable in height and in angle to allow a mixing throughout the digester. The shaft should be long enough to reach both swimming and sinking layers.

The rotor shaft can be inserted in two principle ways:

- Through the digester wall below the slurry level with water-tight sealing
- Through the gas-holder with gas-tight sealing



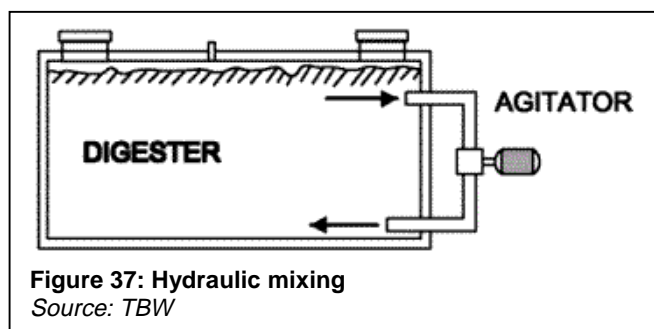
**Figure 35: Submerged motor with rotor stirring**  
Source: TBW



**Figure 36: Shaft-driven rotor**  
Source: TBW

## Hydraulic mixing

With a strong pump the whole substrate can be put in motion, provided the intake and outlet of the pump are placed in a way that corresponds with the digester shape. These pumps are often placed in a central position to cater for other tasks.

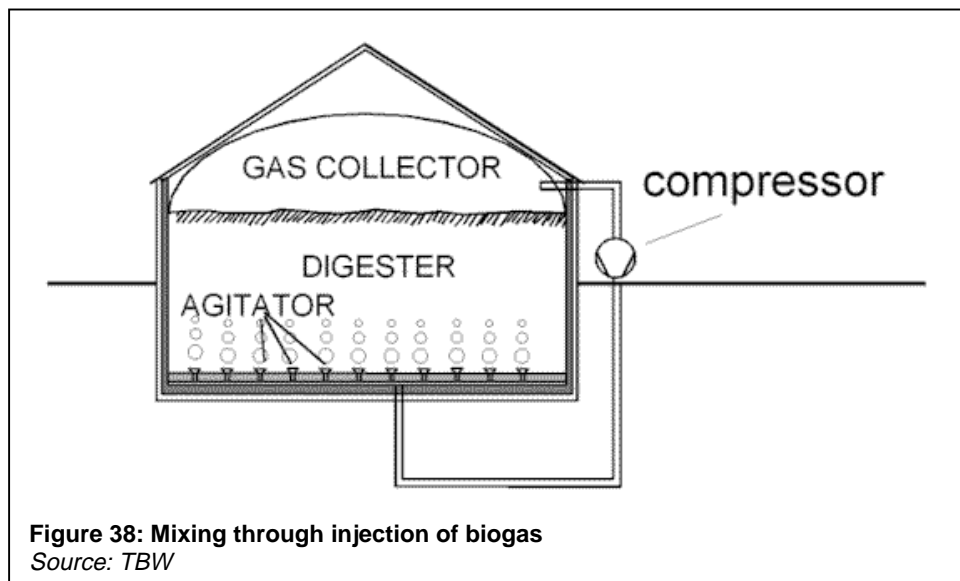


**Figure 37: Hydraulic mixing**  
Source: TBW

## Mixing through injection of biogas

A piping system with gas-jets is installed at the bottom of the digester. The raising biogas bubbles provide a gentle mixing of the substrate. The main problem with these systems is slurry entering into the piping system. This can be avoided by fixing pieces of elastic hose-pipe with stainless steel hose coupling to the jets.

Hydraulic mixing by injecting biogas should not be used if the formation of swimming layers is a prevailing problem. Gas bubbles attach themselves to larger fibrous particles and lift them upwards, thus speeding up the formation of a swimming layer. Chopping up the substrate by means of chopper pumps or chopper rotors can only partly solve this problem.



## Slurry-Use Equipment

For the use of biogas slurry, a multitude of tools and technologies have been developed. They differ mainly according to the quantities of digested material. Big differences exist as well between developing and industrialized countries, depending on the technological development and the cost of labor. Slurry use technologies range from hand-application with the help of a bucket to mechanized distribution, supported by GPS (global positioning system) and a computer on board of the liquid manure spreader. The choice of technology essentially depends on the amount of slurry and the area to be fertilized as well as on the financial means and the opportunity cost of labor.

On **small farms in developing countries**, simple but effective tools are used. They include buckets, scoops, containers with straps, wooden wheelbarrows with lids, barrels on wheels and others. These tools allow a precise application of slurry. The most economic way to apply slurry is by means of gravity, either by a network of small slurry furrows or by mixing slurry in the irrigation system. Both options require a gradient of at least 1% (for irrigation water) and 2% (for slurry distribution), sloping from the biogas plant's overflow point to the fields.

Making best and least labor-intensive use of the slurry is an important planning parameter. Especially where gravity distribution is feasible, the positioning of the biogas plant and the expansion chamber and the level of the expansion chamber overflow are of high importance. In rather flat areas, it should be considered to raise both the stable and the biogas-plant in order to allow a slurry distribution by gravity.



**Figure 39: Device for slurry distribution by tractor.**  
Photo: Krämer (TBW)

In **industrialized countries** and for **large plants in developing countries** two methods of mechanized distribution systems have evolved:

### Distribution via piping systems

The slurry is pumped directly from the slurry storage tank onto the field and is distributed there. If the pump is rather small and the pressure and transported amounts are low, the distribution can be done by hand. With increasing pressure and transported amounts, the distribution system is attached to a tractor. The tractor does not have to be very powerful as there is no need to pull a heavy tanker. The main advantage of this method is the low ground pressure and the ability to enter into fields of steep slope, of fragile soil structure and during bad weather.

The biogas slurry, if it is not too viscous, can be applied with a liquid manure rainer. The disadvantages are the costly pump and the expensive piping system. Therefore, this method is only economic for fields close to the slurry storage container.

### **Distribution via tanker**

The tanker is filled at the slurry storage and pulled to the field for distribution. Below are the principal distribution systems ex-tanker:

#### **With reflection plate**

The slurry is squirted through a nozzle against a reflection plate which, by its special form, diverts and broadens the squirt. An improvement of the simple reflection-plate-distribution is a swiveling plate which leads to a more even distribution.

#### **Direct application through sliding hoses**

The slurry is pumped into a distribution system which feeds a number of hoses which move closely to the ground. The slurry is applied directly on the soil surface, therefore reducing nutrient losses. Distances between the hoses can be adjusted to suit different plant cultures.

#### **Hoses with drill coulters**

The soil is opened with two disks (drill coulters) in a v-shape. The slurry is applied with sliding hoses into the v-furrows, which are closed behind the hose. This application method could be labeled 'sub-surface application'. It is the most advanced in terms of avoiding nutrient losses. Similar to the hose application, distances between application rows are adjustable. Alternatively to the hose application, the slurry can be positioned by a metal injector.

The application methods close to the soil surface, in contrast to the broadcasting methods, have the advantage of a higher degree of exactness and less nutrient losses to the atmosphere. Fertilization can be better adjusted to plant needs. In contrast to broadcast-spraying, direct application is possible even at later stages of plant growth without damaging the leaves. Disadvantages are the rather sophisticated machinery necessary and the high costs involved. Direct application methods are, therefore, mostly used as inter-farm operation.

### **Separation of slurry and drying of the moist sludge**

In industrialized countries, the slurry is usually separated by means of separators and sieves. The water is re-fed into the digestion process or distributed as liquid manure while the moist sludge is dried or composted. As a simple technology for separation, slow sand-filters can be used.

The moist sludge can be heaped on drying beds, filled in flat pits or simply placed on paved surfaces near the biogas plant for drying. Depending on climatic conditions, large drying areas may be necessary. Drying times and nutrient losses can be reduced by mixing dry substances with the moist sludge. A disadvantage of all drying methods, again depending on the climate, is the high loss of nutrients. In particular heavy rains can wash out the soluble nutrients. Losses of nitrogen, for example, can amount to 50% of the overall nitrogen and up to 90% of the mineral nitrogen. Drying of the moist sludge can only be recommended where long distances and difficult terrain hampers transport to the fields or if composting is difficult for lack of manpower and lack of dry biomass.

### **Composting of slurry**

Dry plant material is heaped in rows and the liquid slurry is poured over the rows. Ideally, plant material and slurry are mixed. The mixing ration depends on the dry matter content of plant material and slurry. The main advantage is the low nutrient loss. Compost, containing plant nutrients in a mainly biologically fixed form, is a fertilizer with long-term effects. Its value for improving soil structure is an additional positive effect of importance.

## Plasters and Coats for Digester and Gas-Holder

In industrialized countries, most of the new digesters are built of gas-tight concrete or steel. Additives are mixed into the concrete to render it gas-tight. If existing concrete vessels are used, their gas-tightness has to be checked. Often, they have not been built from gas-tight concrete or cracks have formed over time which allow the gas to escape.

It is important to check the digester and piping system for gas-tightness prior to putting the biogas unit in service. If leakage is detected only during operation, the digester has to be emptied, cleaned and plastered again. Rectifying a leakage before the initial filling is a lot cheaper.

In developing countries, digesters are usually masonry structures. The plastering has to be watertight up to the lowest slurry level and gas-tight from the lowest gas level upwards (gas-holder). The plaster has to resist moisture and temperatures up to 60°C reliably. The plaster must be resistant to organic acid, ammonia and hydrogen sulfide. The undercoat must be absolutely clean and dry.



**Figure 40: Inside plaster of the gastight section of a fixed dome digester**

*Photo: Kellner (TBW)*

### Cement plaster with special additives

Good results in water- and gas-tightness have been achieved by adding 'water-proofer' to the cement plaster. For gas-tightness, double the amount of water-proofer is required as compared to the amount necessary for water-tightness. The time between the applications of the layers of plaster should not exceed one day, as the plaster becomes water-tight after one day and the new plaster cannot adhere to the old plaster. The following 'recipe' from Tanzania guarantees gas-tightness, provided the masonry structure has no cracks:

1. layer: cement-water brushing;
2. layer: 1 cm cement : sand plaster 1 : 2.5;
3. layer: cement-water brushing;
4. layer: cement : lime : sand plaster 1 : 0.25 : 2.5;
5. layer: cement-water brushing with water-proofer;
6. layer: cement : lime : sand plaster with water proofer and fine, sieved sand 1 : 0.25 : 2.5;
7. layer: cement screed (cement-water paste) with water-proofer.

The seven courses of plaster should be applied within 24 hours.

A disadvantage of cement plaster is their inability to bridge small cracks in the masonry structure as, for example, bituminous coats can do.

### Bitumen (several layers)

Bitumen coats can be applied easily and remain elastic over long periods of time. Problems arise in the application as the solvents are inflammable (danger of explosion inside the digester) and a health hazard. Bitumen coats cannot be applied on wet surfaces. The drying of masonry structures requires several weeks, unless some heating device (e.g. a charcoal stove) is placed inside the digester for two to three days. Furthermore, the bituminous coat can be damaged by the up-and-down movement of the slurry.

### **Bitumen coat with aluminum foil**

On the first still sticky bitumen coat, aluminum foil is mounted with generous overlaps. A second layer of bitumen is applied on the aluminum foil. Gas-tightness is usually higher compared to the several layers of bitumen without foil.

### **Water-thinnable dispersion paint**

These paints are free from fire- or health hazards. Most of them, however are not gas-tight and not resistant to moisture. Only those dispersion paints should be used which are explicitly recommended for underwater use and which form a gas-tight film.

### **Single- and dual component synthetic resin paints**

Synthetic resin paints form elastic, gas-tight coats which can resist rather high physical load. They are comparably expensive, their use seems only justified if the coating has to resist mechanical stress. This is usually the case with fixed dome plants. Measurements have given evidence that the masonry structure of a fixed dome stretches, though minimally, after filling and under gas pressure.

### **Paraffin**

Paraffin, diluted with new engine oil, is warmed up to 100 -150°C and applied on the plaster which has been heated up with a flame-thrower. The paraffin enters into the plaster and effects a 'deep-sealing'. If paraffin is not available, simple candles can be melted and diluted with engine oil.

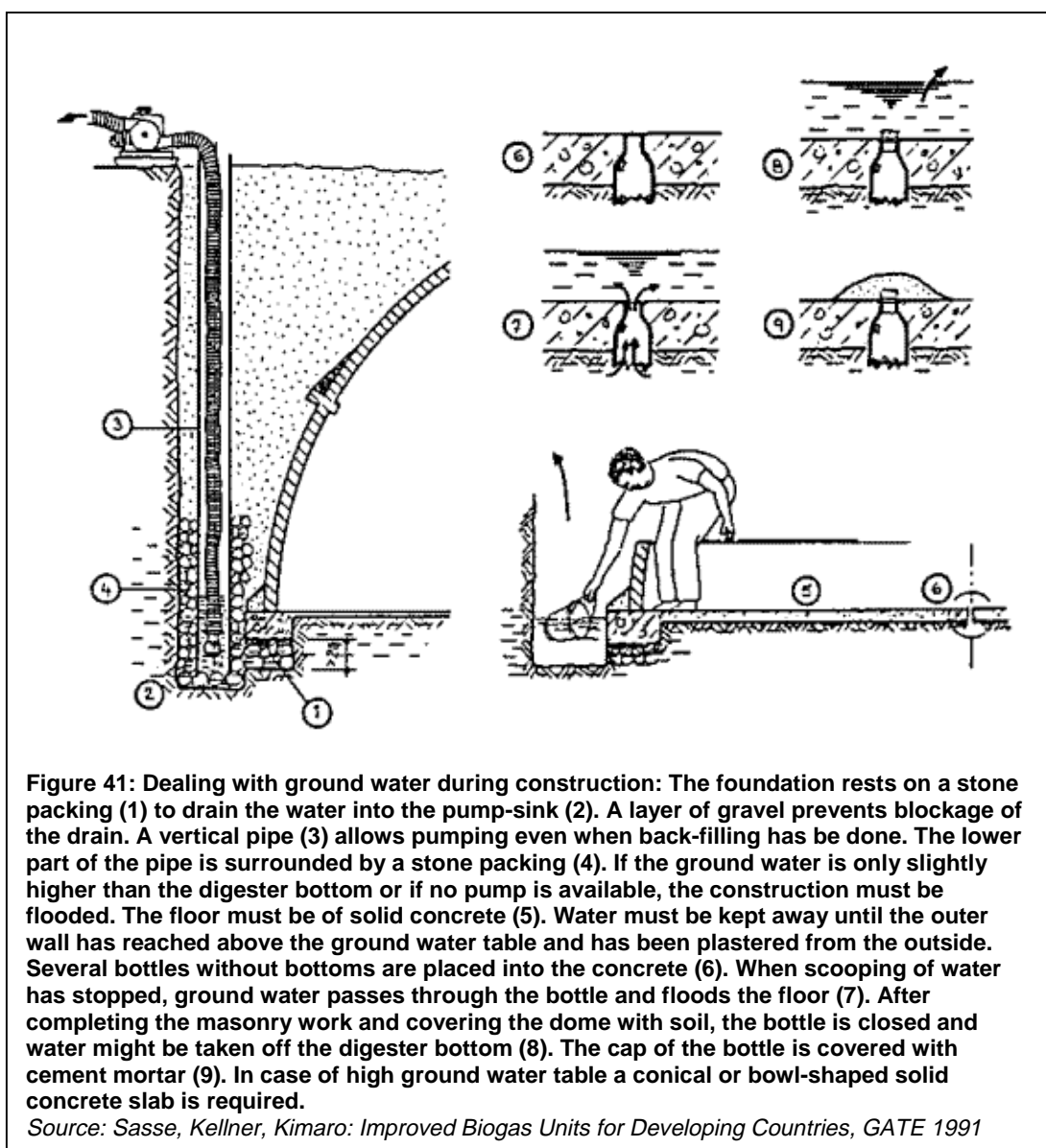
## Underground Water

Underground water features in all three steps of biogas implementation:

- During planning, the site selection and design of the digester can eliminate most of the problems caused by groundwater and threats to groundwater.
- During construction, groundwater can be a nuisance, effecting additional costs. But it is during construction, that serious leakage can be avoided.
- During operation, little can be done but to monitor the quality of water and to avoid surface spilling.

By positioning the biogas plant and the well, a great deal of drinking water safety can be achieved. First, the distance should be at least 30 m, second, the biogas plant should be downstream of surface- and groundwater flows and third, the well should be above the biogas unit to avoid contamination through surface spilling.

During construction, ground water must be drained. An empty biogas digester can develop such buoyancy, if surrounded by water, that the whole shell is lifted. The figure below illustrates some simple techniques how to deal with ground water during construction of small biogas plants.





During the operation of the biogas plant further attention has to be paid to keeping the groundwater clean. Seeping biogas digesters and unprotected slurry storage can pollute water sources chemically (nitrate poisoning can be fatal for infants) and biologically (mainly with toilet biogas plants). Reasons may be wrong configuration of security devices like the pressure relief valves or because of leakage in lower parts of the digester. Smaller cracks, however, close up in the course of time through particles in the slurry.

Trace metals applied to natural systems do not pose a threat to groundwater quality because trace metals are usually removed from the percolating water by adsorption or chemical precipitation within the first few meters of soil, even in rapid infiltration systems with high hydraulic-loading rates.

Bacterial removal from effluents passing through fine soils is quite complete. It may be less complete in the coarse, sandy soil used for rapid infiltration systems. Fractured rock or limestone cavities may provide a passage for bacteria that can travel several hundred meters from the point of application. This danger can be avoided by proper geological investigations during site selection.

## Operation and Use

The day-to day operation of a biogas unit requires a high level of discipline and routine to maintain a high gas production and to ensure a long life-span of the biogas unit. Many problems in the performance of biogas plants occur due to user mistakes or operational neglect. Often, these problems can be reduced,

- by less complicated designs that are adapted to the substrate, the climatic conditions and the technical competence of the user,
- by high-quality and user-friendly appliances,
- by design and lay-out of the biogas for convenient work routine,
- by proper training and easy access to advice on operation problems.

During design selection, planning, construction, handing over and follow-up, the biogas extension program should emphasize further on a reduction of the users' workload for operating the biogas unit and using the gas and the slurry. In particular during work peaks for farm work, it is important that the biogas unit relieves the user from work rather than adding to the workload. As a general rule, the farming family should have *less work with a biogas unit than without it*, while enjoying the additional benefits in terms of a clean fuel and high quality fertilizer.

### Daily operation

#### Feeding of the digester

In larger biogas units, the dung, urine and other substrate usually enter the plant by pipes, channels, belts or pumps. The available substrate has to enter the digester as soon as it is available to avoid pre-digestion outside the digester. The functioning of the feeding mechanisms has to be checked daily. Separators for unsuitable material have to be checked and emptied. The amounts of substrate fed into the digester may be recorded to monitor the performance of the biogas plant.

Smaller plants in developing countries are fed by hand. The substrates, often dung and urine, should be thoroughly mixed, plant residues should be chopped, if necessary. Obstructive materials like stones and sand should be removed from the mixing chamber. Simple tools like a rubber squeegee, a dipper, forks to fish out fibrous material, proper buckets and shovels greatly facilitate this work. Filling work is further made easier by smooth concrete stable-floors and a minimized distance between the stable and the plant.

#### Agitation

In industrialized countries and for large plants in developing countries, engine driven stirring devices are the norm. Usually, but not always, they are operated automatically. The user, however, should check the operation of the stirring device daily.

Small size biogas plants have manual stirring devices that have to be turned by hand as recommended. If there is no stirring device, poking with sticks through the inlet and outlet is recommended. The stick should be strong, long enough but not too heavy. It should have a plate fixed at the end (small enough to fit in the inlet-/outlet pipes) to produce a movement of the slurry. Regular poking also ensures that the inlet/outlet pipes do not clog up. The drums of floating drum plants should be turned several times a day.

Experience shows that stirring and poking is hardly ever done as frequently as it should be. Farmers should be encouraged to run a trial on gas production with and without stirring. The higher gas production will convince the user more than any advice.

#### Controlling the overflow

A special problem of small scale fixed dome plants is the clogging up of the overflow point. This can lead to over-pressure (the hydraulic pressure increases with the slurry level in the expansion chamber) and to clogging of the gas outlet if too much slurry flows back into the digester. The overflow point should, therefore, be checked and cleaned daily.

## **Slurry distribution**

If the slurry distribution is done directly by gravity, the slurry furrows need to be checked and slurry diverted accordingly. Slurry may be applied from the furrows directly to the plant with the help of dippers or shovels.

## **Weekly / monthly operation**

- Controlling of the water separator
- Renewing the agents of the gas purification system (if existing)
- Mixing the swimming and sinking layers of in the expansion chamber of fixed dome plants
- The water sealing of the lid in the man hole of a fixed dome plant should be checked and filled up
- Gentle cleaning of the drum of a floating drum plant
- Checking and filling up the water jacket of water jacket plants
- Flexible pipes above ground should be checked for porosity
- Slurry storage tanks should be checked and emptied, if required and slurry flows diverted accordingly

## **Annual operation**

- Swimming layers should be removed from the digester
- The whole plant and digester should be exposed to a pressure test once a year to detect lesser leakages

## **Security**

When operating a biogas plant special attention has to be paid to the following dangers:

- Breathing in biogas in a high concentration and over longer periods of time can cause poisoning and death from suffocation. The hydrogen sulfide contents of biogas is highly poisonous. Unpurified biogas has the typical smell of rotten eggs. Purified biogas is odorless and neutral. Therefore, all areas with biogas operating appliances should be well ventilated. Gas pipes and fittings should be checked regularly for their gas-tightness and be protected from damage. Gas appliances should always be under supervision during operation. Everybody dealing with biogas, in particular children, should be instructed well and made aware of the potential dangers of biogas.
- After emptying biogas plants for repair, they have to be sufficiently ventilated before being entered. Here the danger of fire and explosion is very big (gas/air mixture!). The so-called chicken test (a chicken in a basket enters the plant before the person) guarantees sufficient ventilation.
- Biogas in form of a gas-air mixture with a share of 5 to 12 % biogas and a source of ignition of 600°C or more can easily explode. Danger of fire is given if the gas-air mixture contains more than 12 % of biogas. Smoking and open fire must therefore be prohibited in and around the biogas plant.
- The initial filling of a biogas plant poses a particular danger, when biogas mixes with large empty air-spaces. A farmer may want to check with an open flame how full the plant is already and cause an explosion.
- The digester of a biogas plant and the slurry storage facilities should be built in such a way that neither persons nor animals are in danger of falling into them.
- Moved and movable parts should have a protective casing to avoid catching persons or animals.

- Appliances operating on biogas normally have high surface temperatures. The danger of burning is high, in particular for children and strangers. A casing of non-heat-conducting material is advisable.
- The mantle of the gas lamp is radioactive. The mantle has to be changed with utmost caution. Especially the inhalation of crumbling particles must be avoided. Hands should be washed immediately afterwards.
- The piping system can form traps on the farm compound. As much as possible, pipes should be laid some 30 cm underground. Pits for water traps, gas meters, main valves or test-units should be cased by a concrete frame and covered with a heavy concrete lid.

# Biogas - Sludge Management

## Sludge storage

To retain the maximum fertilizing quality of digested slurry, i.e. its nitrogen content, it should be stored only briefly in liquid form in a closed pit or tank and then applied on the fields. Preferably, it should be dug into the soil to prevent losses on the field.

Sludge storage is normally effected according to one or the other of the following three techniques

- Liquid storage
- Drying
- Composting

## Liquid storage

The effluent outlet of the biogas system leads directly to a collecting tank. Loss of liquid due to evaporation or seepage must be avoided. Just before the sludge is needed, the contents of the tank is thoroughly agitated and then filled into a liquid manure spreader or, if it is liquid and homogenous enough, spread by irrigation sprinklers. The main advantage of liquid storage is that little nitrogen is lost. On the other hand, liquid storage requires a large, waterproof storage facility entailing a high initial capital investment.

The practice of spreading liquid slurry also presents problems in that not only storage tanks are needed, but transport vessels as well. The amount of work involved depends also on the distance over which the slurry has to be transported. For example, loading and transporting one ton of slurry over a distance of 500 m in an oxcart (200 kg per trip) takes about five hours. Distributing one ton of slurry on the fields requires another three hours.

## Drying

It is only possible to dry digested sludge as long as the rate of evaporation is substantially higher than the rate of precipitation. The main advantage of drying is the resultant reduction in volume and weight. Drying can also make the manual spreading easier. The cost of constructing shallow earthen drying basins is modest. On the other hand, drying results in a near-total loss of inorganic nitrogen (up to 90%) and heavy losses of the total nitrogen content (approx. 50%).

## Composting

Nitrogen losses can be reduced by mixing the digested sludge with organic material. As an additive to crop residues for composting, biogas sludge provides a good source of nitrogen for speeding up the process. At the same time it enriches the compost in nitrogen, phosphorus and other plant nutrients. Furthermore, the aerobic composting process, by its temperature, effectively destroys pathogens and parasites that have survived the anaerobic digestion treatment. The ready-made compost is moist, compact and can be spread out by simple tools. With most available transport facilities in developing countries, it is easier to transport than liquid manure.

## Composition of sludge

### Process of biomethanation

Anaerobic digestion draws carbon, hydrogen and oxygen from the substrate. The essential plant nutrients (N,P,K) remain largely in the slurry. The composition of fertilizing agents in digested slurry depends on the fermented substrate and can, therefore, vary within certain limits.



**Figure 42: Drying of digested sludge and sludge disposal in Thailand**

*Photo: Kossmann (gtz/GATE)*

For an average daily substrate feed rate of 50 kg per livestock unit (LSU = 500 kg live weight) and a daily gas yield of 1 m<sup>3</sup> biogas/LSU, the mass of the influent substrate will be reduced by some 2% through the process of bio-methanation (volumetric weight of biogas: 1.2 kg/m<sup>3</sup>).

### Viscosity

The viscosity of the slurry decreases significantly, because the amount of volatile solids is reduced by about 50% in the course of a stable process of fermentation. In addition, the long carbon chains (cellulose, alcohol and organic acids) are converted into short carbon chains.

### Odor

The effluent sludge is much less odorous than the influent substrate (dung, urine). Given sufficient retention time, nearly all odorous substances are completely digested.

### Nutrients

The fertilizing properties of digested slurry are determined by how much mineral substances and trace elements it contains. In tropical soil, the nitrogen content is not necessarily of prime importance - lateritic soils, for example, are more likely to suffer from a lack of phosphorus. All plant nutrients such as nitrogen, phosphorous, potassium and magnesium, as well as the trace elements essential to plant growth, are preserved in the substrate. The C/N ratio is reduced by the simultaneous loss of carbon, thus generally improving the fertilizing effect of the digested sludge, since a lower C/N ratio (ca. 1:15) has a favorable phytophysiological effect. Table 5 below lists the approximate nutrient contents of various substrates, whereby it should be remembered that the actual values may vary considerably, depending on fodder eaten by the animals.

The phosphate content ("P<sub>2</sub>O<sub>5</sub>" is the form of phosphorous available for plants) is not affected by fermentation. Some 50% of the total phosphorous content is available for plants in the form of phosphate. Similarly, anaerobic fermentation does not alter the rate of plant-available potassium (75 to 100% of the total potassium).

### Nitrogen compounds

In contrast to the above nutrients, however, some nitrogen compounds undergo modification during anaerobic digestion. About 75% of the nitrogen contained in fresh manure is built into organic macromolecules, and 25% is available in mineral form as ammonium. The effluent sludge contains roughly 50% organic nitrogen and 50% mineral nitrogen. The stated levels can only be taken as approximate values, since they vary widely, depending on the type of animal involved, the fodder composition, the retention time, etc. Mineral nitrogen can be directly assimilated by plants, while organic nitrogen compounds must first be mineralized by microorganisms in the soil.

### Fertilizing effect of effluent sludge

Digested slurry is most effective when it is spread on the fields shortly before the beginning of the vegetation period. Additional doses can be given periodically during the growth phase, with the amounts and timing depending on the crop in question. For reasons of hygiene, however, leafy vegetables should not be top-dressed.

Assuming that the soil should receive enough fertilizer to replace the nutrients that were extracted at harvesting time, each hectare will require an average dose of about 33 kg N, 11 kg P<sub>2</sub>O<sub>5</sub> and 48 kg K<sub>2</sub>O to compensate for an annual yield of 1-1.2 tons of, for example,



**Figure 43: Sludge disposal in Thailand**

*Photo: Kossmann (gtz/GATE)*

sorghum or peanuts. Depending on the nutritive content of the digested slurry, 3-6 t of solid substance per hectare will be required to cover the deficit. For supply with a moisture content of 90%, the required quantity comes to 30-60 t per hectare and year. That roughly corresponds to the annual capacity of a 6-8 m<sup>3</sup> biogas plant.



**Figure 44: Field experiments with sludge in Thailand**  
*Photo: Kossmann (gtz/GATE)*

### **Caustic effect on grassland**

Digested sludge has much less caustic effect on grassland than does fresh liquid manure. Effluent sludge is also very suitable for use as a "top-dressing" whenever its application is deemed to have the best fertilizing effect.

### **Eutrophication**

Serious ecological damage can be done by applying fertilizing sludge in excessive amounts or at the wrong time, namely when the assimilative capacity of the plants is low. Nitrogen "washout" can cause over-fertilization (eutrophication) of ground and surface water.

## Annual Manure Yield and Nutrient Content of Animal Excrements

**Table 5: Annual manure yield and nutrient content of cow, pig and chicken excrements; compiled from various sources**

Total annual yield [kg/LSU/a] and percentage shares							
	Total Wt.	TS		VS		N	
	kg/a	kg/a	[%]	kg/a	[%]	kg/a	[%]
Cow	16,100	1850	11.6	1400	8.7	77	0.5
Pig	13,500	1130	8.4	900	6.7	102	0.8
Chicken (fresh droppings)	18,250	4020	22.0	3170	17.4	232	1.3
Chicken (dry droppings)	4,230	3390	80	2560	60	146	3.5

Total annual yield [kg/LSU/a] and percentage shares					Nutritive ratio (P <sub>2</sub> O <sub>5</sub> = 1)		
	P <sub>2</sub> O <sub>5</sub>		K <sub>2</sub> O		N	P <sub>2</sub> O <sub>5</sub>	K <sub>2</sub> O
	kg/a	[%]	kg/a	[%]			
Cow	34	0.2	84	0.5	2.3	1	2.5
Pig	56	0.4	35	0.3	1.8	1	0.6
Chicken (fresh droppings)	194	1.0	108	0.6	1.2	1	0.6
Chicken (dry droppings)	193	4.6	106	2.5	0.8	1	0.6

*Source: Production and Utilization of Biogas in Rural Areas of Industrialized and Developing Countries, Schriftenreihe der gtz, No. 97, pp. 71-72; after: Rager, K. Th.: Abwassertechnische und wasserwirtschaftliche Probleme der Massentierhaltung; Darmstadt, FRG, 1971, p. 38*

**LSU** = livestock unit (= 500 kg live weight)

**TS** = Total solids

**VS** = Volatile solids



## Maintenance, Monitoring and Repair

The maintenance of a biogas plant comprises all work which is necessary to guarantee trouble-free operation and a long working life of the plant. Repair reacts to breakdowns of the biogas system. Maintenance services should be carried out by the manager or main operator of the biogas plant or a well-trained biogas technician. One has to bear in mind that measurements indicating problems may be wrong. All doubtful measurements have to be verified. Often, one symptom has a variety of possible reasons.

### Daily maintenance work

Control	Mistakes	Removal
gas pressure	gas pressure too high; (gas pressure rises, if gas consumption is lower than the production and if the gas storage is full)	The pressure relief valve malfunctions - it should be cleaned or renewed;
	gas pressure too low; (gas pressure falls, if the consumption (including leakage!) is higher than the production and if the gas storage is empty);	leakage in gas conducting parts: find out the leakage and seal; gas production has fallen: check the sludge's quality;
substrate temperature (heated plants) (bacteria are very sensitive to temperature extremes and fluctuations);	temperature too high;	defective heating control system. Check control system and repair or exchange part(s) concerned;
	temperature too low;	defective heating control system. Check control system and other concerned part(s), repair or exchange; sediment layer on the heating surface: remove layer;
gas production	gas production clearly under normal levels;	biological reasons: temperature, substrate, antibiotics, change of pH-value; leakage in digester or piping system; blocked gas pipes due to water or alien elements; identify problem and act accordingly;
strong sludge odor	plant is overloaded or fermenting conditions are sub-optimal;	reduce substrate intake; correct pH-value with adequate means;

## Weekly/monthly (prophylactic) maintenance work

- clean gas appliances;
- lubricate movable parts (slides, guiding frame of floating drum plants, taps etc.);
- servicing of biogas-driven engines within the prescribed time intervals;
- maintenance of pressure relief valves and under pressure valves;
- maintenance of slurry agitator / mixer;
- control gas appliances and fittings on tightness and function

## Control of functions

Control	Mistakes	Removal
water separator	non-automatic water separator is full;	empty the water separator;
pipng system	no water is collected in the water separator; gradient of the pipes is wrong;	Reinstall pipes in a way that condensation flow leads to the water separator;
pressure relief and under pressure valves	non-functioning	clean valves or renew them

## Annual maintenance work

- Check the plant in respect of corrosion and, if necessary, renew protective coating material;
- Check the gas pipes for gas tightness (pressure check). If necessary, search the leakage and repair the parts concerned. Note: minor gas leakage is usually undetected during normal operation as it is 'compensated' by gas production

## Monitoring

Monitoring subsumes all activities of data collection regarding an individual biogas unit or biogas programs. Collecting data on the performance of biogas units is necessary to

- detect problems in the unit's performance;
- to have a base for economic evaluation;
- to have a base for comparing different models and different modes of operation

Measurements and other data which become necessary for the optimization of the existing biogas unit should be recorded by the owner or by a person appointed by him/her. The records should include the following data:

- The amount and type of substrate, incl. the amounts of mixing water.
- The substrate temperature, if necessary at various stages of the substrate flow (heated plants). By measuring the substrate temperature, faults in the heating system can be detected.
- Gas production: measurements are carried out with a gas meter between the digester and the gas-holder (gas production) or between the gas-holder and the points of consumption (gas consumption). In simple plants, the gas production can be estimated during times of no consumption. Changes in gas production and the speed by which these changes occur give valuable hints on the nature of the problem.
- Electricity and heat production from co-generation units;
- pH-value (monthly); recorded substrate intake;
- content of hydrogen sulfide in the gas (monthly);
- analysis of the fertilizing value of biogas slurry (annually or seasonally) to determine the optimal amount of slurry to be spread on the fields.

- Records on breakdowns and their causes. By means of previously recorded breakdowns it is easier to compare the breakdowns and detect the reasons for failure.

Beyond this, there are various institutions, associations and companies which carry out series of measurements for different kinds of biogas plants. These series of measurements, records and evaluations analyze errors with the objective to disseminate and optimize biogas technology as well as to avoid mistakes of the past.

## Repair

Breakdowns which might appear when operating biogas plants are described in the following. The most frequently occurring disturbance is insufficient gas production which can have a variety of different reasons. Sometimes observations and experiments might take weeks until a perfect solution is found.

<b>Disturbances</b>	<b>Possible reasons</b>	<b>Measures to be taken</b>
blocked inlet/outlet pipe	fibrous material inside the pipe or sinking layer blocking the lower end of the pipe	cleaning up the pipe with a pole; removing sinking layer by frequent 'poking' through inlet and outlet pipe.
floating drum is stuck	swimming layer	turn the dome more frequently; if turning not possible, take off the dome and remove the swimming layer
	broken guiding frame	weld, repair and grease guiding frame
sinking sludge level	digester not water-tight	if cracks in the digester do not self-seal within weeks, empty digester and seal cracks;
insufficient gas storage	gas store not gas-tight due to cracks or corrosion	seal cracks, replace corroded parts;
blocked taps	corrosion	open and close several times, grease or replace taps;
gas pipe is not tight	corrosion or porosity; insufficient sealing of connections;	identify leaking parts; replace corroded or porous parts; re-seal connections
sudden gas loss	8. crack in the gas pipe 9. automatic water trap blown empty 10. open gas tap	4. repair or replace 5. add/refill water, detect reason for over-pressure; check dimensioning of the water-trap 6. close tap
throbbing gas pressure	1. water in the gas pipe 2. blocked gas pipe	1. check functioning of water trap; install water traps in depressions of piping system or eliminate these depressions; 2. identify the blocked parts (start with gas outlet, connections to appliances and bends); clean the respective parts;

Repair measures are being taken in case of acute disturbances or during routine maintenance work. Repair measures which go beyond routine maintenance work have to be carried out by specialists, since the biogas plant owner in most cases does not have the required tools and the necessary technical know-how. In any case, annual maintenance service should be carried out by a skilled biogas technician.

In industrialized countries with large plants and good infrastructure, a professional biogas service can cover a large area. In developing countries with scattered small scale biogas units, logistical problems can severely hamper the evolution of a professional and commercial biogas service. To ensure that built biogas units are maintained and, if necessary, repaired, the following approaches are conceivable:

- ***The farmer technician approach:*** out of a group of biogas farmers, an outstanding individual is encouraged to undergo maintenance and repair training to take this up as a side job. Emphasis has to be placed on management training. To make his enterprise sustainable, the farmer technician should gain a reasonable income.
- ***The cluster approach:*** if the demand for biogas plants is high, the biogas project or the biogas company can attempt to install biogas units in a regional clustering to minimize distances for the maintenance service.
- ***The subsidized transport approach:*** a professional biogas technician is supported with transport by the biogas project or government departments (e.g. agricultural extension, veterinary service). The technician can also receive a bicycle or small motorbike as an initial input, running costs can either initially be shared by the biogas project or directly be charged to the farmers.

However the logistical problems may be solved, the critical ingredient for the evolution of a professional and commercial biogas service is the training of the technicians-to-be both in technical and managerial terms. Experience shows, that this can take several years. Biogas projects should, therefore, plan with a not too narrow time horizon.

# Biogas Utilization

## Gas production

If the daily amount of available dung (fresh weight) is known, gas production per day in warm tropical countries will approximately correspond to the following values:

- 1 kg cattle dung 40 liters biogas
- 1 kg buffalo dung 30 liter biogas
- 1 kg pig dung 60 liter biogas
- 1 kg chicken droppings 70 liter biogas

If the live weight of all animals whose dung is put into the biogas plant is known, the daily gas production will correspond approximately to the following values:

- cattle, buffalo and chicken: 1,5 liters biogas per day per 1 kg live weight
- pigs, humans: 30 liters biogas per day per 1 kg weight

## Conditioning of biogas

Sometimes the biogas must be treated/conditioned before utilization. The predominant forms of treatment aim at removing either **water**, **hydrogen sulfide** or **carbon dioxide** from the raw gas:

### Reduction of the moisture content

The biogas is usually fully saturated with water vapor. This involves cooling the gas, e.g. by routing it through an underground pipe, so that the excess water vapor condenses at the lower temperature. When the gas warms up again, its relative vapor content decreases. The "drying" of biogas is especially useful in connection with the use of dry gas meters, which otherwise would eventually fill up with condensed water.

### Reduction of the hydrogen-sulfide content

The hydrogen sulfide in the biogas combines with condensing water and forms corrosive acids. Water-heating appliances, engines and refrigerators are particularly at risk. The reduction of the hydrogen sulfide content may be necessary if the biogas contains an excessive amount, i.e. more than 2%  $\text{H}_2\text{S}$ . Since most biogas contains less than 1%  $\text{H}_2\text{S}$ , de-sulfurization is normally not necessary.

For small- to mid-size systems, de-sulfurization can be effected by absorption onto ferric hydrate ( $\text{Fe}(\text{OH})_3$ ), also referred to as bog iron, a porous form of limonite. The porous, granular purifying mass can be regenerated by exposure to air.

The absorptive capacity of the purifying mass depends on its iron-hydrate content: bog iron, containing 5-10%  $\text{Fe}(\text{OH})_3$ , can absorb about 15 g sulfur per kg without being regenerated and approximately 150 g/kg through repetitive regeneration. It is noteworthy that many types of tropical soils (laterite) are naturally ferriferous and suitable for use as purifying mass.

Another de-sulfurization process showing good results has been developed in Ivory Coast and is applied successfully since 1987. Air is pumped into the gas store at a ratio of 2% to 5 % of the biogas production. The minimum air intake for complete de-sulfurization has to be established by trials. Aquarium pumps are cheap and reliable implements for pumping air against the gas pressure into the gas holder. The oxygen of the air leads to a bio-catalytic, stabilized separation of the sulfur on the surface of the sludge. This simple method works best, where the gas holder is above the slurry, as the necessary bacteria require moisture, warmth (opt. 37°C) and nutrients.

In industrialized countries and for large plants, this process has meanwhile reached satisfactory standard. For small scale plants in developing countries, however, using an electric pump becomes problematic due to missing or unreliable electricity supply. Pumping in air with a bicycle pump works in principle, but is a cumbersome method that will be abandoned sooner or later.

Avoiding de-sulfurization altogether is possible, if only stainless steel appliances are used. But even if they are available, their costs are prohibitive for small scale users.

### Reduction of the carbon-dioxide content

The reduction of the carbon-dioxide content is complicated and expensive. In principle, carbon-dioxide can be removed by absorption onto lime milk, but that practice produces "seas" of lime paste and must therefore be ruled out, particularly in connection with large-scale plants, for which only high-tech processes like micro-screening are worthy of consideration. CO<sub>2</sub> "scrubbing" is rarely advisable, except in order to increase the individual bottling capacity for high-pressure storage.

### Biogas burners

In developing countries, the main prerequisite of biogas utilization is the availability of specially designed biogas burners or modified consumer appliances. The relatively large differences in gas quality from different plants, and even from one and the same plant (gas pressure, temperature, caloric value, etc.) must be given due consideration.

The heart of most gas appliances is a biogas burner. In most cases, atmospheric-type burners operating on premixed air/gas fuel are preferable. Due to complex conditions of flow and reaction kinetics, gas burners defy precise calculation, so that the final design and adjustments must be arrived at experimentally. Compared to other gases, biogas needs less air for combustion. Therefore, conventional gas appliances need larger gas jets when they are used for biogas combustion. About 5.7 liters of air are required for the complete combustion of one liter of biogas, while for butane 30.9 liters and for propane 23.8 liters are required.

The modification and adaptation of commercial-type burners is an experimental matter. With regard to butane and propane burners, i.e. the most readily available types, the following pointers are offered:

- Butane/propane gas has up to three times the caloric value of biogas and almost twice its flame-propagation rate.
- Conversion to biogas always results in lower performance values.

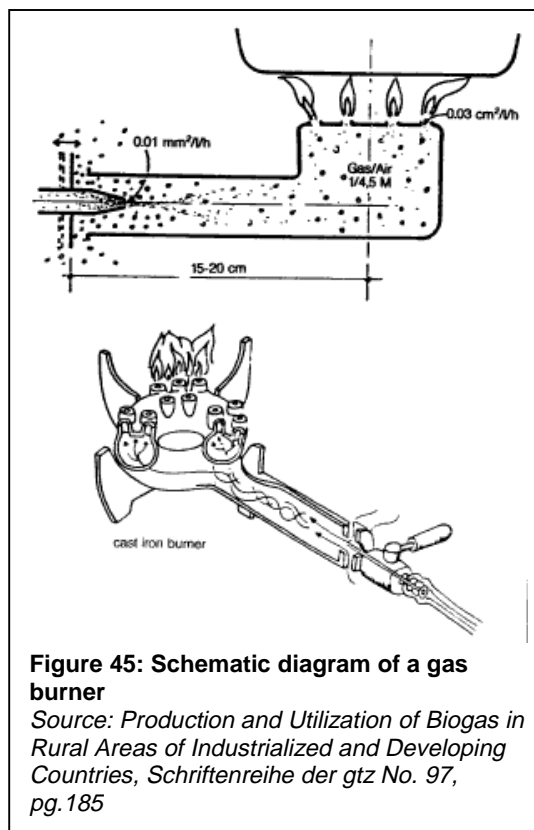
Practical modification measures include:

- expanding the injector cross section by factor 2-4 in order to increase the flow of gas;
- modifying the combustion-air supply, particularly if a combustion-air controller is provided;
- increasing the size of the jet openings (avoid if possible).

The aim of all such measures is to obtain a stable, compact, slightly bluish flame.

### Efficiency

The calorific efficiency of using biogas is 55% in stoves, 24% in engines, but only 3% in lamps. A biogas lamp is only half as efficient as a kerosene lamp. The most efficient way of using biogas is in a heat-power combination where 88% efficiency can be reached. But this is only valid for larger installations and under the condition that the exhaust heat is used



**Figure 45: Schematic diagram of a gas burner**

Source: *Production and Utilization of Biogas in Rural Areas of Industrialized and Developing Countries*, Schriftenreihe der gtz No. 97, pg.185

profitably. The use of biogas in stoves is the best way of exploiting biogas energy for farm households in developing countries.

<b>appliances</b>	gas lamps	engines	gas stoves	power-heat
<b>efficiency [%]</b>	3	24	55	88



**Figure 46: Different types of Biogas burners at an agricultural exhibition in Beijing/China**

*Photo: Grosch (gtz/GATE)*

For the utilization of biogas, the following consumption rates in liters per hour (l/h) can be assumed:

- household burners: 200-450 l/h
- industrial burners: 1000-3000 l/h
- refrigerator (100 l) depending on outside temperature: 30-75 l/h
- gas lamp, equiv. to 60 W bulb: 120-150 l/h
- biogas / diesel engine per bhp: 420 l/h
- generation of 1 kWh of electricity with biogas/diesel mixture: 700 l/h
- plastics molding press (15 g, 100 units) with biogas/diesel mixture: 140 l/h

Biogas can also be used for various other energy requirements in the project region. Refrigerators and chicken heaters are the most common applications. In some cases biogas is also used for roasting coffee, baking bread or sterilizing instruments.



**Figure 47: Co-generation unit (electricity and heat utilisation)**

*Photo: Krämer (TBW)*

## **Gas demand**

In developing countries, the household energy demand is greatly influenced by eating and cooking habits. Gas demand for cooking is low in regions where the diet consists of vegetables, meat, milk products and small grain. The gas demand is higher in cultures with complicated cuisine and where whole grain maize or beans are part of the daily nourishment. As a rule of thumb, the cooking energy demand is higher for well-to-do families than for poor families. Energy demand is also a function of the energy price. Expensive or scarce energy is used more carefully than energy that is effluent and free of charge.

The gas consumption for cooking per person lies between 300 and 900 liter per day, the gas consumption per 5-member family for 2 cooked meals between 1500 and 2400 liter per day.

In industrialized countries, biogas almost always replaces existing energy sources like electricity, diesel or other gases. The objective of biogas production may be less to satisfy a certain demand, but to produce biogas as much and as cheap as possible. Whatever surplus is available can be fed as electricity into the grid. The gas demand is market-driven, while in developing countries, the gas demand is needs-driven.



## Gas Yields and Methane Contents for Various Substrates

**Table 6: Gas yields and methane contents for various substrates at the end of a 10-20 day retention time at a process temperature of roughly 30°C.**

Substrate	Gas yield (l/kg VS <sup>*</sup> )	Methane content (%)
Pig manure	340-550	65-70
Cow manure	90-310	65
Poultry droppings	310-620	60
Horse manure	200-300	
Sheep manure	90-310	
Barnyard dung	175-280	
Wheat straw	200-300	50-60
Rye straw	200-300	59
Barley straw	250-300	59
Oats straw	290-310	59
Corn straw	380-460	59
Rape straw	200	
Rice straw	170-280	
Rice seed coat	105	
Flax	360	59
Hemp	360	59
Grass	280-550	70
Elephant grass	430-560	60
Cane trash (bagasse)	165	
Broom	405	
Reed	170	
Clover	430-490	
Vegetables residue	330-360	
Potato tops/greens	280-490	
Field/sugar beet greens	400-500	
Sunflower leaves	300	59
Agricultural waste	310-430	60-70
Seeds	620	
Peanut shells	365	
Fallen leaves	210-290	58
Water hyacinth	375	
Algae	420-500	63
Sewage sludge	310-740	

*Source: Production and Utilization of Biogas in Rural Areas of Industrialized and Developing Countries, Schriftenreihe der gtz, No. 97, pg. 63, after: Felix Maramba, Biogas and Waste Recycling - The Phillipine Experience; Metro Manila, Phillipines, 1978*

<sup>\*</sup> VS = Total volatile solids, e.g. ca. 9% of total liquid manure mass for cows .

# Agricultural Anaerobic Digestion

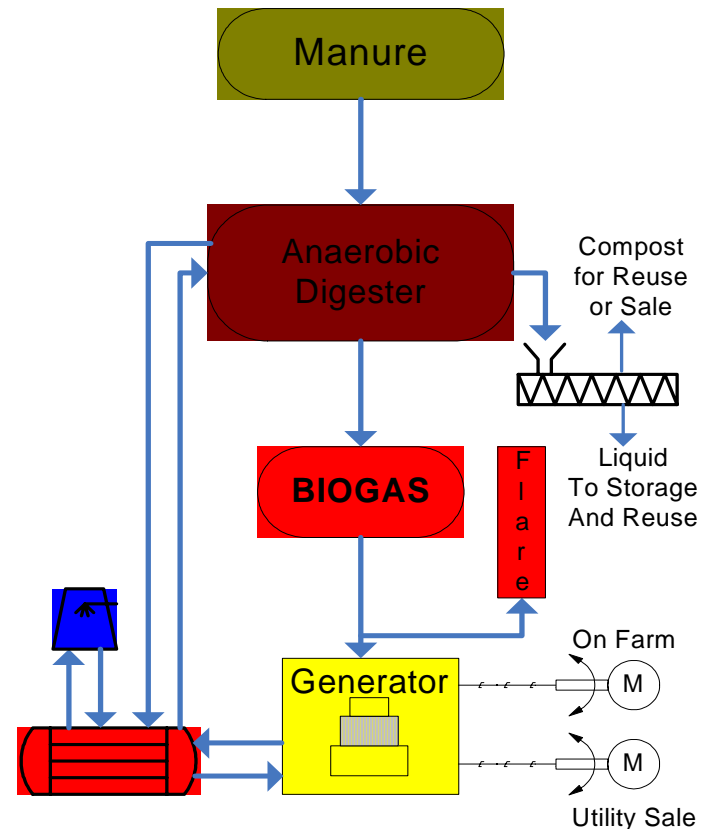
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## General Overview

# General Process

- Natural biological (bacterial) process that primarily converts organic carbon from large molecules (carbohydrates, sugars, fats and proteins) to simple molecules (carbon dioxide, methane and water)
- The primary advantages are
  - Energy recovery
  - Reduced greenhouse gas emissions
  - Odor mitigation
  - Proactive nutrient management.

## Manure Digestion





# General Economics

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- The net economics of applying AD varies dramatically based on
  - geography
  - facility size
  - electrical rates and usage
  - utility cooperation with buy-back programs



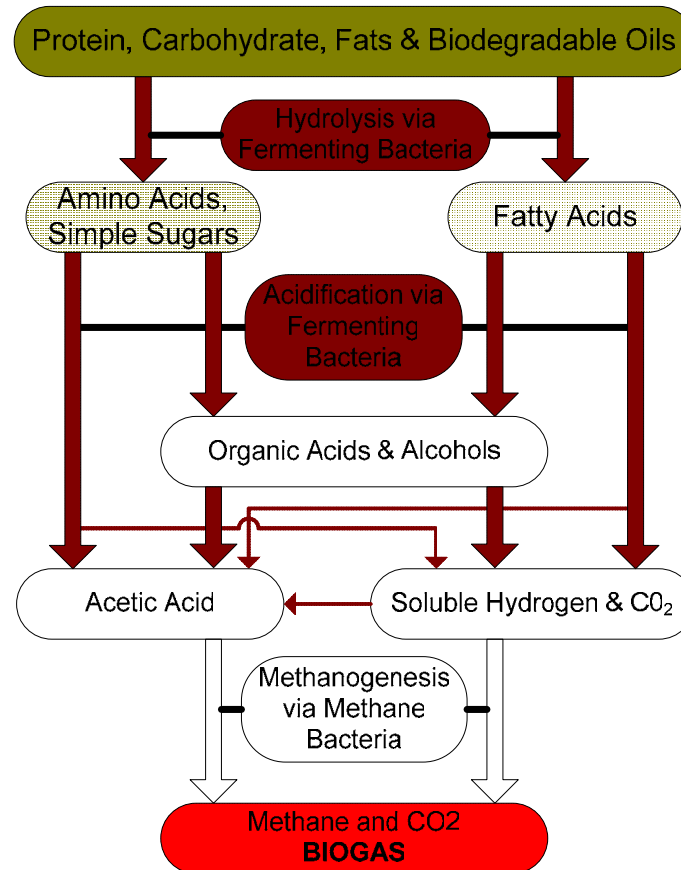
# General Co-Digestion Concept

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- ❑ Co-Digestion is being defined as an operation where non-farm organic sources are blended with those from the farm
- ❑ The primary advantages are;
  - Production of greater quantities of methane for increased energy recovery and revenue
  - Tipping fees for hauling, processing and disposal

# General Metabolic Process

## Anaerobic Metabolic Process



# General Metabolic Considerations

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- ❑ Like all biological processes, temperature impacts the rate of both metabolic steps.
- ❑ The vast majority of AD systems operate at or near 95-105 degrees F (mesophilic).
- ❑ Some systems utilize temperature ranges at or above 125 degrees F (Thermophilic).
- ❑ Experience has shown that mesophilic digesters are most desirable due their overall stability and ease of operation.
- ❑ It is important to note that all systems can be inhibited by indiscriminant use of persistent antimicrobial agents.

# Common Approaches - On Farm Manure Handling and Digestion

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- ❑ Open Lagoon
- ❑ Membrane Covered Lagoon
- ❑ Heated and Mixed Membrane Covered Lagoon
- ❑ Plug Flow Digester
- ❑ Complete Mix and Hybrid Digesters
- ❑ Fixed Film Digester
- ❑ Upright Cylinder Digester



# Manure Nature and Handling

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- ❑ Efficient and appropriate manure handling at the front and back is crucial to the overall success of any on-farm digestion system.
- ❑ The considerations that must be evaluated include:
  - Bedding (Straw, wood chips, sand, compost)
  - Bedding Material Recovery
  - Scrape and flush
  - Flush
  - Vacuum collection
- ❑ Each containment, digestion and management approach can be severely impacted if the manure is not properly conditioned prior to entering the system. In general the least impact is caused by compost bedding and the greatest negative impact is caused by sand bedding. A complete analysis of the overall costs involved in managing each material is imperative to financial and operational success.

# Manure Handling Impacts

---

- ❑ Each containment, digestion and management approach can be severely impacted if the manure is not properly conditioned prior to entering the system.
- ❑ In general the least impact is caused by compost bedding and the greatest negative impact is caused by sand bedding.
- ❑ A complete analysis of the overall costs involved in managing each material is imperative to improving the chances for financial and operational success.

# Open Lagoon

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- ❑ Open lagoons and pits have been the prevalent approach for holding and managing manure since farms began processing and containing the animals in large enough quantities that substantial manure volumes required containment.
- ❑ Open lagoons and pits are rapidly being eliminated due to odor and insect nuisance issues.
- ❑ Lined open lagoons are still used where neighbors or urban development are not an issue.
- ❑ These require large land areas but if land is low cost, are the lowest initial cost systems and require little or no operation other than final disposal

# Membrane Covered Lagoon

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- ❑ Membrane covered lagoons are rapidly appearing as the low cost method of choice to mitigate odors and insect issues.
- ❑ Most are designed to contain the off gases so that they can either be burned in a flare to eliminate odors or often, the gas is fully utilized for energy and heat recovery.
- ❑ Similar to open lagoons, these require large land areas but again, if land is low cost, they are generally the next lowest cost systems and require little or no operation attention other than final disposal.
- ❑ Several liner/cover system vendors are available with high quality and reliable equipment.

# Heated and Mixed Covered Lagoon

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- ❑ This modification is the next step for a lagoon and can be quite cost effective.
- ❑ The capital and operations cost of the insulated cover is substantially higher than a simple cover but the lagoon size drops substantially and energy recovery can be very good.
- ❑ Limited vendors have successful systems available.

# Plug Flow Digestion

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- ❑ The plug flow (PF) digester is the next step down in size requirement and generally represents a substantial increase in capital and operations effort.
- ❑ A PF digester functions like its name in that the manure is kept viscous enough to pass as a “plug” through the vessel.
- ❑ PF digesters are typically sized for a 20 day holding time and can achieve reasonable volatile solids reduction and biogas production.
- ❑ Numerous designs have been developed and many have either failed or have been abandoned due to operational issues or net economics.
- ❑ Several successful systems are in operation and are currently being designed and built as well.

# Plug Flow Digestion

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- ❑ The most common systems typically have biogas supported membrane covers that resemble air structures used for sport facility enclosures.
- ❑ Fixed covers have been used but have experienced many more operational challenges than floating covers.
- ❑ A PF digester *must* be heated in order to accomplish methane production. The most common heating system consists of internal hot water piping placed along the bottom outside edges.
- ❑ These pipes are most commonly schedule 40 uncoated carbon steel. A properly operating digester is a non corrosive environment and these pipes have been found to last many years.
- ❑ PF digesters must be cleaned periodically due to the buildup of materials that restrict volume and efficiency. Typical times between cleanings average about 10 years. It is common to find as much as 40% of the digester rendered ineffective in this time.
- ❑ The symptoms of plugging are reduced volatile solids reduction and biogas production. Particular care relative to operations and reference checking should be exercised prior to system selection.

# Complete Mix Digester

- Complete mix digesters are typically designed with similar material holding times to plug flow digesters and generally consist of a covered bolted steel vessel with external pumps and heating equipment.
- The term complete mix implies that the contents are continuously mixed and heated.
  - This may or may not be true as it has often been found that the continuous mechanical operation leads to significantly increased maintenance and operations costs.
  - These are often operated intermittently with reasonable success.
  - Complete mix digesters have often been chosen for their smaller footprint, cleaner overall design, easier management and somewhat improved gas production from plug flow and lagoons.
- Generally, both capital and operations costs are higher than plug flow or lagoons. Like plug flow systems, there are several variations/modifications to the complete mix approach. The variations (hybrids) typically incorporate techniques or technological approaches that are very similar to classic wastewater treatment processes. These generally involve some form of solids concentration step that is either mechanical (DAF) or gravity based (clarifier). Prior to selection, check for sound design and preferably operations experience with the type of bedding system being planned or used. When operated in the sequencing batch reactor (SBR) mode, batch feeding is utilized and mixing is intermittent. Biogas production is highly variable with SBR designs which lead to unique energy recovery challenges.



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- ❑ When operated in the sequencing batch reactor (SBR) mode, batch feeding is utilized and mixing is intermittent.
- ❑ Biogas production is highly variable with SBR designs which lead to unique energy recovery challenges.

# Fixed Film Digester

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- ❑ This type of digester uses a vessel similar to the complete mix system but contains plastic media over which the manure is spread and allowed to trickle down to the bottom.
- ❑ Fixed film designs require very dilute well screened material to prevent plugging and are generally only considered when flushed manure management is used. With proper screening and separation nearly any bedding material can precede a fixed film system.
- ❑ There is limited experience with this approach but much research has indicated that a sound design is possible.
- ❑ Capital costs are generally higher than plug flow and similar to complete mix but excellent volatile reduction and gas production have been achieved.

# Upright Cylinder Digester

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- ❑ Upright cylinder digesters (UCD) use a small diameter, tall design much like the classic silage storage silo commonly seen on farms.
- ❑ This design has been shown to achieve very good volatile solids reductions at about 1/4th the detention time of plug flow or complete mix systems.
- ❑ The reason for this focuses on the physical and hydraulic contact achieved with a long column of material through which all new material must pass. Also, solids accumulation and proactive mixing at the top and bottom of the UCD allow much more intimate contact with high solids (high bacterial concentration) than plug flow or complete mix systems.

# Upright Cylinder Digester

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- ❑ UCD can be designed in a much more modular approach than other designs requiring large vessels and long holding times.
- ❑ The combination of modularity, small footprint, shorter holding times and mechanical simplicity all may lead to improved initial and long term economic advantages for the UCD design as more are implemented.
- ❑ This design is compatible with all but high volume flush systems common to sand bedding operations.
- ❑ When applied properly, the UCD design has been shown to provide a number of capital and operations advantages to classic designs.
- ❑ This design is also very compatible with co-digestion of offsite organics due to the continuous feeding and recirculation allowing efficient blending and microbial exposure

# What is Biogas?

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- ❑ Methanogenic metabolism produces essentially equal quantities of methane (CH<sub>4</sub>) and carbon dioxide (CO<sub>2</sub>).
- ❑ However, biogas in nearly all manure digesters will typically be 65% CH<sub>4</sub> and 35% CO<sub>2</sub>.
- ❑ This variance is due solely to the high solubility of CO<sub>2</sub> and low solubility of CH<sub>4</sub>.
- ❑ A point to note is that this characteristic also explains why landfill biogas has a lower BTU content and is nearly always close to the 50-50 ratio as there is no water for the CO<sub>2</sub> to dissolve into.
- ❑ Biogas energy value or BTU content is directly proportional to the % CH<sub>4</sub>. Pure CH<sub>4</sub> has a BTU level of approximately 1000 BTU's per cubic foot so the BTU content of biogas is linearly reduced by the percentage, leaving a common content of about 650 BTU's per cubic foot. Any variations claimed by a system provider will be strictly associated with the dilution. In this regard, flushed manure systems will generally produce higher BTU gas due to the CO<sub>2</sub> being dissolved in the higher volume of water. Though the biogas is higher in BTU's flush systems must consume more onsite energy to heat all that water for digestion and thus there is generally a negative net energy benefit.
- ❑ Hydrogen sulfide (H<sub>2</sub>S) is the other trace gas commonly present in manure biogases and is the one responsible for nearly all the negative press. It may range from 0.2% to over 1%. Bovine manure will generally be just above 0.2% while porcine manure is generally at or above 0.5%. H<sub>2</sub>S solubility, like CH<sub>4</sub> is relatively low. This characteristic explains why containing any manure in either a covered lagoon or vessel and combusting the biogas resolves most odor issues. When adequately contained and ventilated, digester effluent releases most of the sulfur in the biogas and thus is more neighbor friendly when exposed in either open storage vessels or when land applied. The odor is eliminated because the H<sub>2</sub>S is converted to SO<sub>2</sub> when combusted in a flare or generator.
- ❑ Unfortunately, sulfur emissions can become an issue in large systems and must be carefully considered in any biogas utilization plan. The issues will range from system design to equipment selection and air quality permitting. The most common solution when sulfur emissions must be reduced is an iron sponge scrubber. The iron in the sponge (wood particles) reacts with the sulfur to yield iron sulfide. The sponge may be regenerated and/or disposed as a soil amendment. Some care is required depending on the scrubber design and operation.

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# Biogas Utilization

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- In general, biogas utilization is accomplished with one or more of the following steps whose order in the process will depend on the system:
  - Collection piping
  - Moisture and sediment control
  - Pressure management and control
  - Hydrogen Sulfide management and control
  - Utilization rate and/or storage
  - Combustion and energy utilization

# Energy Recovery

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- Regardless of the circumstances, some of the factors that must be considered when energy recovery is involved are:
  - Energy equipment capital and operations costs.
  - Local electrical energy costs.
  - Onsite electrical and heat usage that will be offset.
  - Cooling requirements for adsorption chilling options.
  - Air emissions restrictions for combusting biogas.
  - Utility energy buy-back program opportunities or obstacles.



# The Community Digester Concept

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- ❑ As knowledge and experience with agricultural manure digesters have grown, it has become readily apparent that many designs are capable of accommodating fairly substantial quantities of outside biodegradable organic materials.
- ❑ The two general benefits to this practice are
  - increased biogas production which translates to greater energy recovery
  - tipping or hauling fees which can often be collected from the entity generating the organic material.

# The Community Digester Concept

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- ❑ Almost without exception, the organics are coming from a food production facility.
- ❑ The following industries commonly have the need to dispose of high strength organics either onsite or via offsite disposal or land application systems:
  - All aspects of dairy processing, including ice cream, cheese, yogurt, sour cream, milk condensing and bottling.
  - Brewing and beverages of all types, (beer, distilled spirits, wine, juice, soda).
  - Nutraceutical Production (Nutrient Drinks such as Slim Fast, Ensure).
  - Fruit and Vegetable processing.
  - Prepared foods production, frozen meals to salad dressing.

# Implementation - Concept

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- Conceptual Review – This first step could also be termed the litmus test in that some very basic issues are tabulated and given a general analysis relative to need, cost and value. The basic questions that should be asked and answered are:
  - Is manure handling either an insect or an odor problem?
  - Are electrical costs either high or burdensome?
  - Is there a reasonable utility energy buy-back program?
  - Are there grants, rebates or low interest loans available?
  - Is there any pending or encroaching land zoning/use limitation?
  - Questions 1 & 2 are deal breakers in many cases in that a project to contain the manure may be required to remain operational at the current location. At this point, the incremental costs of capturing and utilizing the biogas are often very attractive.
  - of economic objectives.

# Implementation - Economics

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- Macro Economics – If a full scale energy project appears to have some financial feasibility after initial evaluation, a macro economic assessment should be completed. This should be accomplished with the guidance of an experienced company or individual. The evaluation should include an initial manure handling and digestion process assessment along with general capital, operations costs along with the value of potential rebates, energy savings and sales.
- Detailed System Economics and Financing – If the macro economic assessment indicates an attractive return on investment, then a complete system analysis and selection process should be completed. This step is often referred to as a Design Memorandum where every process is sized, layouts proposed and all equipment is quantified. A detailed capital, operations and benefit analysis is completed at this point. Work through this step is generally required to receive funding commitments for either loans, grants or rebates. In general, successful and sustainable projects should be financially attractive with no grants or rebates and only enhanced by their availability.
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# Implementation – Design and Construction

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- Design – Using the design memorandum as the guiding document, the system will then proceed to formal design where professional engineers are retained to properly develop plans and specifications for construction. This process can be expected to take 4-6 months for most digesters and longer for large and/or more complicated systems.
- Construction – This step may take several contract forms depending on the owner's level of sophistication and the system's size. The project can range from a turnkey design build to classic bidding and general contracting. Much will depend on the system selected and capability of the related vendors and/or contractors. Again, depending on the owner and the project size and complexity, 4-8 months may be required for construction.

# Implementation - Sustainability

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- Operations and Maintenance – Most successful systems have been so due to overall simplicity and relatively low operations and maintenance costs. This should be clear during the macro economic evaluation stage where complex systems can be ruled out if there are no net economical advantages. It should be considered critical for most operations that O&M be simple and reliable.
- Sustainability – The sustainability of a project should be well determined prior to selection and design so that after startup, the system becomes the process and economic combination that was anticipated. The items that will affect sustainability are:
  - Thorough and proper process selection
  - Process reliability
  - Quality of design and process equipment
  - Quality and commitment of owner and operations & maintenance staff
  - Attainment of economic objectives

# Summary

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- ❑ **Overview** – Determining the feasibility of using agricultural AD is fairly complex but attaining a reasonable level of success is achievable if systematically approached
- ❑ **Metabolism** – Anaerobic metabolism within an anaerobic digester is a very robust process that when properly managed can yield many benefits to an agricultural operation.
- ❑ **Systems** – A modern agricultural AD operation is comprised of several integral processes or systems.
- ❑ **Designs** – Many AD designs have been developed. Each design has specific characteristics that when optimized will lead to a successful installation and operation.
- ❑ **Co-Digestion** – The concept of co-digestion is a fairly recent development in agricultural AD systems.
- ❑ **Energy & Economics** – Interest in agricultural AD systems is usually initiated by the energy value realized when CH<sub>4</sub> is produced and utilized. In addition to energy however is the growing factor of odor control. In many locations animal operations can not continue without minimizing the normal odors associated with animal manure.
- ❑ **Implementation** – A successful AD project demands that a systematic approach be followed. The steps include preliminary evaluations, macro economic analysis, micro economic analysis, financing plans and design memos, system design, construction, startup and sustainable operations plans. Failure to follow the systematic approach greatly increases the chance for financial disappointment or complete system failure. On the other hand, following a systematic approach generally leads to proper system selection and success.

# Summary

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## Colorado Agriculture IOF Technology Assessments: Anaerobic Digestion



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Finally, despite our best efforts at editing and revisions, mistakes may still remain within this document. Any mistakes or omissions are the sole responsibility of the authors. Any questions or comments should be addressed to McNeil Technologies Inc., 143 Union Blvd. Suite 900 Lakewood CO 80228. McNeil staff who worked on this project included

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## List of Acronyms

°F.....	degrees Fahrenheit
\$.....	U.S. Dollars
AD.....	Anaerobic Digestion
BOD .....	Biological Oxygen Demand
Btu.....	British thermal unit
CDPHE .....	Colorado Department of Public Health and the Environment
cf .....	cubic feet
COD .....	Chemical Oxygen Demand
EPA .....	Environmental Protection Agency
ESCO .....	energy services company
ESPC.....	energy savings performance contracting
ft .....	feet
ft <sup>3</sup> .....	cubic feet
gal.....	gallon
H <sub>2</sub> S .....	hydrogen sulfide
HP .....	horsepower
HRT.....	hydraulic retention time
kW.....	kilowatt
kWh.....	kilowatt-hour
lbf .....	pounds force
MMBtu.....	million British thermal units
MBtuh .....	MBtu per hour
Mcf.....	thousand cubic feet, a volume measure for natural gas. Equal to 1 MMBtu assuming that 1 cubic foot of natural gas has 1,000 Btu. The Btu content of a cubic foot of natural gas may vary.
MW .....	megawatt
MWh .....	megawatt-hour
OEMC .....	Colorado Governor's Office of Energy Management and Conservation
tpd.....	tons per day
U.S. ....	United States of America
USDA.....	United States Department of Agriculture
WRBEP.....	Western Regional Biomass Energy Program (U.S. Department of Energy)

## 1 INTRODUCTION

The overall objective of this project is to expand the existing Colorado state IOF program to include agriculture. Technology assessments were conducted to identify new markets and assess barriers and opportunities for state industry to deploy new energy, water, waste management and biobased product manufacturing technologies.

The goal of Colorado's agriculture IOF is to deliver near-term, cost-effective solutions that address the day-to-day operational realities facing the industry, while simultaneously laying the groundwork to develop future technologies and markets. OEMC seeks to develop a program that not only creates new market opportunities for biofuels and biobased products, but will also work to make the existing industry as efficient as possible in terms of energy use and production, water consumption, waste generation and overall environmental impact. Maximizing the performance of today's industry will improve long-term economic opportunities for developing and deploying new technologies and markets. The OEMC strongly feels that the state IOF must be cross-cutting and include both crop-based as well as livestock-based industries. Both of these sectors are important to the Colorado economy, and both sectors offer opportunities for integrated deployment of new energy, biobased product and waste management technologies. In terms of economic impact on the state's economy, livestock has more than twice the revenue of crop-based products. One of our primary interests in working with livestock operations is to see whether they can serve as niche markets for biofuels, biolubricants and biofertilizers.

### *Project Approach*

Both novel and commercially available technologies were evaluated for their ability to meet industry needs. Technology areas evaluated include:

- Biobased Products
- Liquid Fuels
- Anaerobic Digestion
- Compost
- Wind Farms
- Precision Agriculture
- Precision Irrigation
- Integrated Pest Management
- Soil Conservation
- Cropping Systems
- Operations Management Improvement
- Energy Efficiency Improvements & Audits
- Solar Applications in Agriculture

All of these technologies/practices have the potential to reduce direct energy use or embodied energy use in all sectors of the state's agricultural industries. For example, biobased products and biodiesel can widen available manufacturing opportunities, create jobs, and improve rural economies. State livestock producers can be encouraged to switch

to biodiesel for their back-up generators and lubricants thereby creating new niche markets for those products and improving operational efficiency and renewable energy balances. The technology focus areas were based on input from the steering committee and workshops.

### *Structure of Report*

There is one overall report including all 13 technology assessments. Furthermore, there are individual break out reports for each assessment. The results will be incorporated into the Colorado IOF Program Internet web site, providing pictures and data illustrating technology applications for stakeholders.

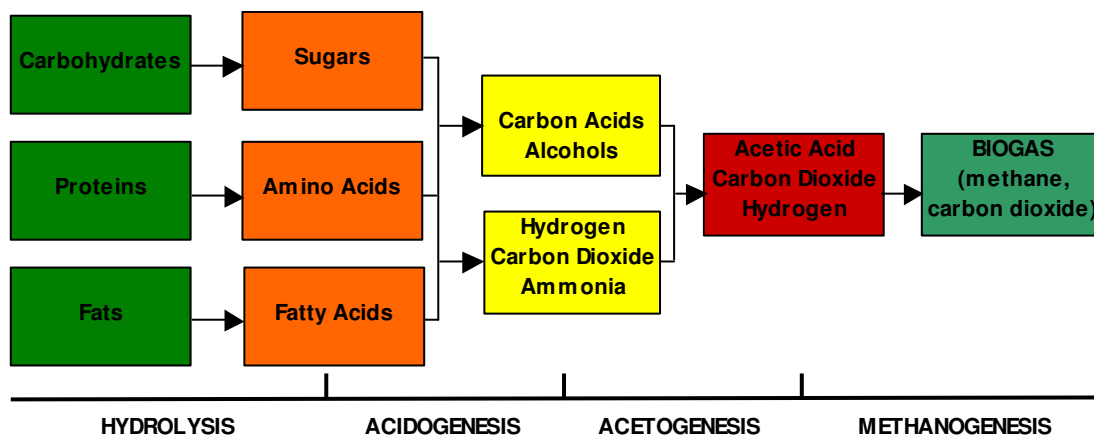
Technology assessments include a general introduction, current status of technology, benefits, and technology barriers. Some assessments did not fall into the aforementioned categories and are written up with an introduction and applicable subject areas. Where appropriate, assessments include a comparison between conventional technology and new technologies. For example, total embodied energy use, nitrate and phosphate runoff potential and cost factors for the use of compost will be compared with commercial fertilizer use. Where possible, assessments include information on capital and operating costs.

## 2 TECHNOLOGY ASSESSMENT AND OVERVIEW

### 2.1 Anaerobic Digestion

Anaerobic Digestion is the natural, biological degradation of organic matter in absence of oxygen yielding biogas. Volatile solids in organic matter are converted to biogas consisting of methane, carbon dioxide and trace amounts of other gases. Biogas is capable of operating in nearly all devices intended for natural gas with minimal adjustments to account for lower Btu content. This section will focus on AD of livestock manure as ample resources are available in Colorado. This is an effective manure management technique with great potential for energy generation at Colorado CAFOs.

The degradation and conversion process occurs in four steps with different classes of bacteria responsible for each phase. In manure digestion, hydrolysis is often the rate-limiting step due to lignin's resistance to degradation. Figure 1 illustrates the microbial process where the first two steps are facultative and the latter two are strictly anaerobic.



**Figure 1: Anaerobic digestion process**

There are several potential utilization options for biogas such as generation of electricity or heat. A portion of generated biogas is required to maintain temperature and provide energy for other functions of the digestion process. Remaining energy is available for electricity generation or direct combustion for heating purposes or use in farm equipment. There is also the potential to connect and export excess energy to the grid if a favorable power purchase agreement can be arranged with the local utility.

As of March 24, 2004, EPA AgStar reports 49 animal manure anaerobic digesters producing biogas in the United States.<sup>1</sup> One complete mix digester is in operation at a

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<sup>1</sup> K. Roos, *Status of Existing and Emerging Biogas Production and Utilization Systems*, EPA Agstar, March 2004

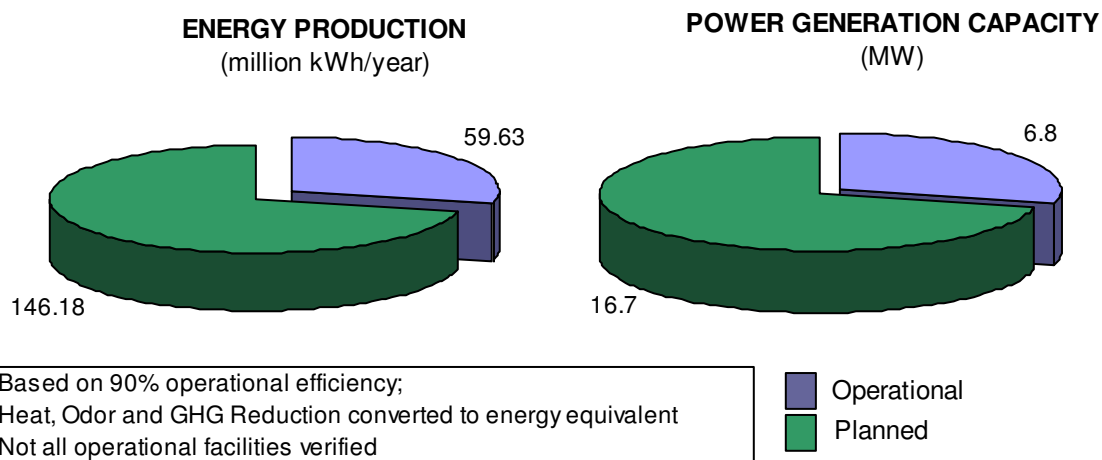
large swine facility in Fort Lupton, CO. The same report identifies 57 more digesters in planning or building phase. Digesters are used for energy generation, odor control and green house gas emission reductions. Table 1 identifies operational and planned digester types.

**Table 1: Farm-based anaerobic digesters in the United States**

Digester Type	Operational	Planned
Mesophilic Plug Flow	19	31
Mesophilic Complete Mix	15	8
Unheated Covered Lagoon	10	9
Centralized	4	5
Unheated Attached Media	1	
Mesophilic Attached Media		1
Other		3
<b>TOTAL</b>	<b>49</b>	<b>57</b>

source: K. Roos, *Status of Existing and Emerging Biogas Production and Utilization Systems*, EPA Agstar, March 2004

The majority of operational and planned digesters are mesophilic plug flows. This digester type is designed to digest scrapped dairy manure. It has lower capital and operating costs when compared with mesophilic complete mix and can operate in warm or cold climates. Figure 2 identifies the energy generation from operating digesters and expected generation from planned digesters.

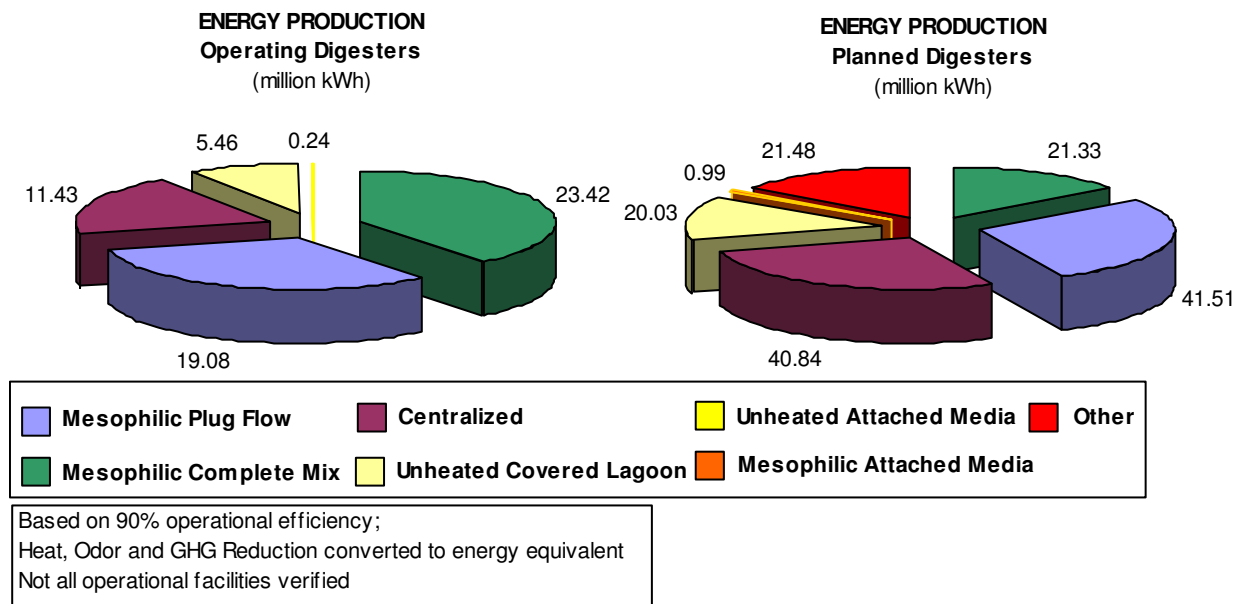


source: source: K. Roos, *Status of Existing and Emerging Biogas Production and Utilization Systems*, EPA Agstar, March 2004

**Figure 2: Energy production capacity of operating and planned manure digesters**

Biogas composition and methane quantity is a function of manure type, method of manure removal and digester technology. Biogas is generally comprised of 55-70% methane and 30-45% carbon dioxide with trace amounts of other gases. Figure 3 details the energy or energy equivalent obtained from each type of digester. Energy production from planned digesters is based on the assumption that each will be built and operate at planned output.





source: source: K. Roos, *Status of Existing and Emerging Biogas Production and Utilization Systems*, EPA Agstar, March 2004

**Figure 3: Energy production capacity by digester technology**

### 2.1.1 Current Status of Technology

AD technologies are commercially available and 49 farm-based digesters are currently in operation nationwide. The USDA NRCS in conjunction with the EPA developed ‘Conservation Practice Standards for Methane Recovery’ from anaerobic digesters. The NRCS recognizes three digester technologies: unheated covered lagoon, plug-flow and complete mix. These standards can be viewed and printed at <http://www.epa.gov/agstar/pdf/handbook/appendixf.pdf>. Other types of anaerobic digesters, such as attached media filters and sludge blankets, may serve to provide technical and economic benefits in future installations.

The EPA AgSTAR Handbook: *A Manual for Developing Biogas Systems at Commercial Farms in the United States* is a comprehensive guide for evaluating the feasibility of on-farm manure biogas generation. This handbook and software to determine economic viability are available online at <http://www.epa.gov/agstar/resources/handbook.html>. AgStar estimates that cost effective methane collection could be achieved at 3000 US livestock farming operations.<sup>2</sup>

A lagoon digester is the simplest and lowest cost method to capture methane from manure. A lagoon manure pool can be transformed into a lagoon digester by adding a floating cover. An industrial strength cover rests on solid floats on the lagoon surface. Methane is trapped under the cover and collected by a perforated pipe located near the sealed end of the lagoon (Figure 4).

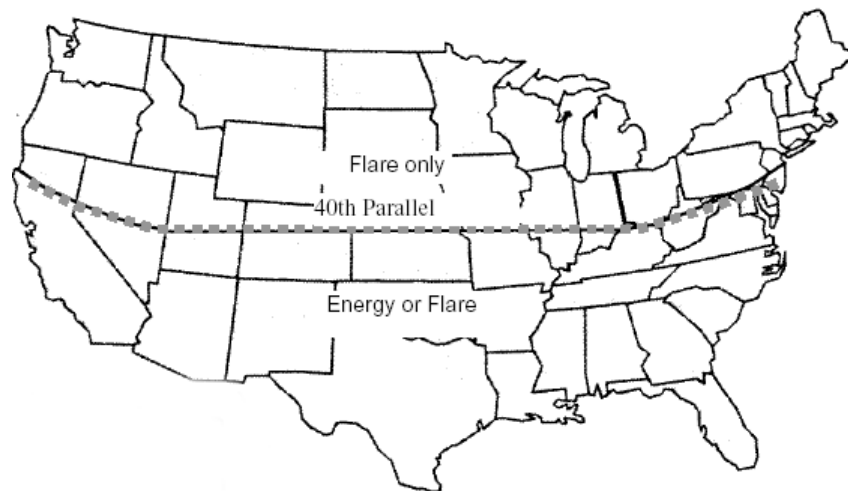
<sup>2</sup> J. Balsam, *Anaerobic Digestion of Animal Wastes: Factors to Consider*, ATTRA, October 2002.

Considerations for anaerobic lagoon methane recovery:

- Economic biogas recovery in warm climates only (Figure 5)
- Lagoon is unheated and biogas production varies seasonally
- Ideal for hydraulic flushing manure systems due to low solids (2-3%)
- Typically takes 1-2 years to achieve steady state for economic methane recovery
- Requires significant land
- Not appropriate for geographic regions with high water table due to potential for ground water contamination



**Figure 4: Example of anaerobic covered lagoon and biogas recovery**



Source: EPA. (July 1997). AgStar Handbook: A Manual for Developing Biogas Systems at Commercial Farms in the United States. EPA 430-B-97-015. pp. 4-12

**Figure 5: 40<sup>th</sup> Parallel: climate limitation for biogas energy recovery from lagoons**

The plug-flow is another NCRS approved anaerobic digester. Plug-flows are long, linear troughs usually sited above ground. Fresh manure is added daily and this action pushes previous days' plugs of manure through the trough. The AD process occurs as the plugs

of manure move through the length of the trough. An airtight, expandable cover captures the methane. A photo shows this digester type in Figure 6.

Information for plug flow digesters:

- Ideal for dairy farms that mechanically remove manure (scrapping)
- Length of the digester is determined by daily manure volume
- Dimensions of height to width are typically 1:5
- Requires mix pit with volume of daily manure load to ensure solids of 11-13%
- Digester operates in the mesophilic temperature range (90-110°F)
- Waste heat from engine and cooling systems or generated biogas heat the digester
- Hot water pipes through the length of the trough maintain temperature
- Typically takes 6 months to achieve steady state for economic methane recovery



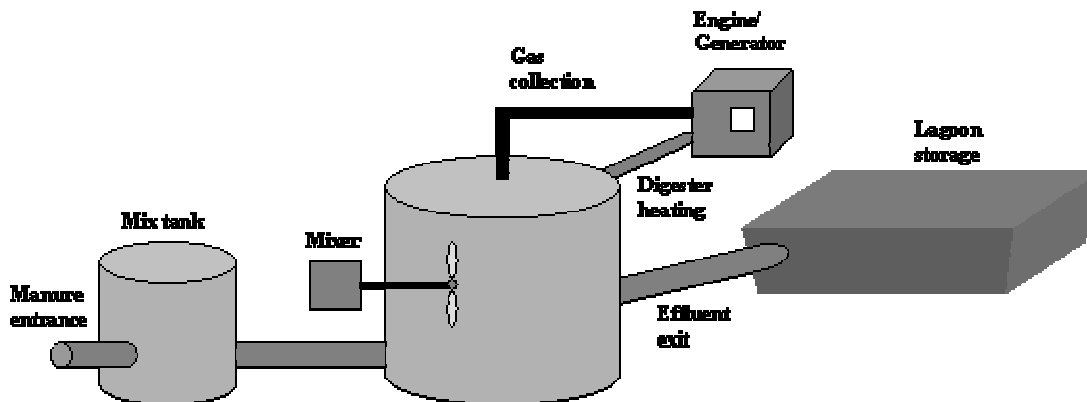
courtesy of RCM Digesters, Inc. <http://64.225.36.90/Default.htm>

**Figure 6: Stencil Dairy plug flow digester for 1200 cows**

Complete mix digesters consist of a large above or below ground steel or concrete reactor. Waste is mechanically mixed providing good contact between microbes and volatile solids leading to efficient biogas production. The mixing also provides a homogenous effluent useful as a fertilizer or soil conditioner. Figure 7 is a schematic of this digester type.

Considerations for complete mix digesters:

- Best suited for large farming operations that remove manure by washing
- Volumes range from 3500- 70000 ft<sup>3</sup> with capacity of 25,000-500,000 gallons manure
- Operate in mesophilic (90-110°F) or thermophilic (120-140°F) temperature range
- Installation and heat exchangers maintain temperature from biogas or waste heat recovered from engine exhaust and cooling systems
- Typically takes 5-6 months to achieve steady state for economic methane recovery
- Sewage sludge from a waste water plant is initially placed in digester for establishment of microbes prior to loading manure



Source: EPA. (February 1997). AgStar Technical Series: Complete Mix Digesters – A Methane Recovery Option for All Climates. EPA 430-F-97-004. Washington,

**Figure 7: Complete Mix Digester Schematic**

There is also a variation of complete mix termed temperature-phased anaerobic digester (TPAD). This two reactor digester design was developed by Iowa State University to separate microbial processes in order to optimize parameters for both. Research has demonstrated that a two-stage reactor design leads to higher biogas and methane yields although dual reactors increase construction and materials costs. Table 2 offers a comparison of the three anaerobic digesters recognized by NCRS.

**Table 2: Comparison of NCRS Recognized Digesters**

	Lagoon	Plug Flow	Complete Mix
Total Solids Concentration	>3%	11-13%	3-10%
Animal Manure Type	Any	Dairy	Any
Hydraulic Retention Time	>60 days	20-30 days	>10 days
Operating Temperature	Ambient	Mesophilic	Mesophilic or Thermophilic
Orientation	Horizontal	Horizontal	Vertical
Operation & Maintenance	Simple	Moderate	Complex
Capital Costs	Low	Moderate	High

source: [www.biogasworks.com](http://www.biogasworks.com)

Attached media, or anaerobic filters, are another type of digester technology. There is one unheated attached media digester operating in Florida . Microbes responsible for the digestion process are immobilized in a filter (often plastic) and do not leave the digester with the effluent as in other technologies. Retaining microbes reduces the size of the digester because time to treat wastes is greatly reduced to 2-6 days.<sup>3</sup> The capital costs are high and maintenance may occasionally require for periodic removal of solids accumulation in the filter.

<sup>3</sup> AgStar Digest, EPA, Winter 2003, table 1 Operating US Digesters as of October 2002.  
online at: <http://www.epa.gov/agstar/pdf/2002digest.pdf>

Utah State University has developed an upflow anaerobic sludge blanket (UASB). A blanket of bacteria digests manure and biogas is released. This system reduces the time to treat waste because the microbes remain in the digester rather than leaving with the effluent. The anaerobic sludge blanket digester is also an attractive alternative because installation costs are lower than those of plug flow and complete mix. A UASB may be built in Fort Morgan to handle slightly more waste than the Utah State University research digester.<sup>4</sup>

Microgy, a subsidiary of Environmental Power Cooperation, has licensed a digester technology from Europe that significantly increases biogas production by heating a complete mix digester to thermophilic temperatures. Construction has begun on digesters at two dairy farms in Wisconsin each digesting manure from 1000 cows to drive a 775kW generator. The digesters will be owned by each farmer whereas the generation equipment will be owned by Dairy Land Power Corporation, a power company with customers in five Midwestern states.

There are several important control parameters that require monitoring to ensure methane production. Table 3 lists the most important parameters.

**Table 3: Control Parameters for Anaerobic Digesters**

Parameter	Acceptable Range	Other Information
pH	6.5-7.5	self regulating by anaerobic microbes; methanogens unlikely to grow <6.5
Alkalinity	.133 ounce/gallon	self regulating by converting hydrogen ions in waste to biocarbonate ions
VFA	<.013 ounce/gallon	high concentration will inhibit acetate production directly and greatly reduce biogas generation
Acidity to Alkalinity Ratio	.3 to .5	Easier to measure than alkalinity or VFA
COD/BOD of Manure and Effluent	Effluent 10% of Manure	COD (chemical oxygen demand) and BOD (biological oxygen demand) can measure the efficiency of the digester to convert volatile solids to methane

source: Biomass Course, Loughborough University, Fall 2003

It is essential to standardize the organic loading rate (manure volatile solids) to a digester to optimize methane production and minimize risk of a system shutdown. Overloading a digester with organic materials will shock the system resulting in reduced or discontinued digestion and methane production. A farm should consider constructing a manure holding tank or pond in order to regulate flow into the digester.

The cost to install and operate a farm-based digester is dependent on technology used. EPA AgStar provides estimated installation costs and operational output in kW for

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<sup>4</sup> Telephone conversation with Jon Euwing of Environmental Systems and Solutions, LLC July 15, 2004

digesters producing electricity. These figures do not include the value of hot water or heat produced from biogas. Digesters serve other purposes that are not monetarily quantified including manure management and odor and leachate control. Digesters flaring biogas spent an average of \$191,750 per installation without gaining any benefit from energy or heat generation. Table 4 details costs associated with each digester type.

**Table 4: Comparison of Digester Costs**

Digester Type	Approximate Installed Cost(\$)	Operational Output (kWh)	Average Cost per kWh (\$)	Average Cost per Animal Unit (\$)
Lagoon	\$220,000-290,000	25-41	\$7,727	\$119/swine
Plug-Flow	\$125,000-1,800,000	28-500	\$3,475	\$379/cow
Complete Mix	\$325,000-1,400,000	33-425	\$4,045	\$500/cow, \$98/swine

source: *AgStar Digest*, EPA, Winter 2003, table 1.

The 2002 Farm Bill section 9006 provides cost sharing grants through the USDA Rural Development Program to purchase renewable energy systems for agricultural producers. Funding is available in amounts between \$2500-500,000 through 2007 and can help reduce farmers' cost to purchase and install anaerobic digesters.

Building a digester as a cooperative can mitigate initial capital costs. A community digester enables economies of scale, more financing opportunities and an increased likelihood of establishing a power purchase agreement with the local utility. Another cost reduction method is to co-digest food production wastes or other wastes compatible with manure. As an example, Matlink Dairy Farm in Clymer, New York profits \$240,000 annually from their plug flow digester by accepting wastes from nearby food processing facilities and selling heat to an on-site food drying operation.<sup>5</sup>

There are several end uses for biogas produced through AD. Electricity generation with an internal combustion engine is the most common end-use of biogas. Minimal adjustments to the carburetion and ignition systems of an internal combustion engine are necessary due to the lower Btu value of biogas. Heat exchangers collect steam from the engine's exhaust and cooling systems to provide hot water or heat. Waste heat recovery systems can recover up to 7000 Btu/hour for each installed kW increasing overall system efficiency by 40-50%.<sup>6</sup>

Minimal adjustments to the carburetion and ignition systems of an internal combustion engine are necessary prior to burning biogas because it has a lower Btu value than natural gas. Most internal combustion engines with capacity of less than 200kW achieve conversion efficiencies of biogas to electricity less than 25%.<sup>7</sup> The remaining 75% of

<sup>5</sup> S. Inglis, P. Wright, *An Economic Comparison of Two Anaerobic Digestion Systems on Dairy Farms*, Cornell University, July 2003, table 1.

<sup>6</sup> T. Rooney, S. Haase, *Assessment of Biogas-to-Energy Generation Opportunities at Commercial Swine Operations in Colorado*, State of Colorado OEMC, Nov 1, 2000, chapter 4.

<sup>7</sup> Energy and Anaerobic Digestion, Biogas Works online at:  
<http://www.biogasworks.com/Index/Energy%20&%20AD.htm>

energy results in waste heat that can be used to heat mesophilic and thermophilic digesters or provide hot water or space heating.

Biogas can be directly combusted in boilers or furnaces to provide heat for on-farm use. Boiler modifications must be made to enlarge jets and alter the fuel to air ratio to burn low energy biogas. Direct combustion in furnaces requires extensive biogas clean up to remove hydrogen sulfide to prevent corrosion. Further processing to remove carbon dioxide, hydrogen sulfide and water allows biogas to be used as a compressed alternative fuel. However, this is a limited market as there are only a few thousand vehicles designed to operate on compressed natural gas (CNG).

### **2.1.2 Benefits**

AD of animal manure offers extensive benefits over other manure management systems. As livestock farms grow in size and become more geographically concentrated, anaerobic digesters provide an excellent way to address manure handling regulations, odor issues and environmental contamination concerns.

Benefits include:

- Waste Treatment Benefits
  - Natural waste treatment process
  - Low land requirements
  - Reduces waste volumes
  - Effluent provides nutrient rich compost and fertilizer
- Environmental Benefits
  - Odor reduction
  - Reduces leachate risk
  - Destroys most weed seeds and pathogens
  - Immense reductions of carbon dioxide and methane
- Energy Benefits
  - Results in net energy gain
  - Biogas has numerous end uses

Animal wastes are an increasing problem on U.S. farms as all manure cannot be spread on land. Over application of raw manure elevates the risk of nutrients leaching and water contamination. Manure odor is a considerable issue as residential development expands to rural areas. AD reduces odor and environmental risks through enclosed digesters and the anaerobic conversion process. Methane is a significant green house gas, trapping over 21 more times more heat per molecule than carbon dioxide. In 2002, farm based anaerobic digesters reduced methane emissions by 112,945 tons carbon equivalent.<sup>8</sup> AD is the only waste management system that captures biogas for energy production. On-site

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<sup>8</sup> AgStar Digest, EPA, Winter 2003, table 1 Operating US Digesters as of October 2002.  
online at: <http://www.epa.gov/agstar/pdf/2002digest.pdf>

energy generation can serve to reduce farm dependence on fossil fuels and costs to purchase heat and electricity.

The effluent of AD consists of biosolids and wastewater. The wastewater can be recycled back into manure flushing systems or spread through irrigation systems as a liquid fertilizer. AD processes increase concentrations of nitrogen, phosphorous, potassium and other trace elements. Additionally, effluent nitrogen is in mineralized form, same as commercial fertilizer, thus increasing availability to plants when compared with composted or raw organic nitrogen. Biosolids can be composted for use as a soil amendment.

There is potential future financial benefit to farmers in carbon trading. Carbon trading or sequestering is an emissions reduction method where companies exceeding green house gas emissions compensate farmers that use techniques that keep carbon in the soil or otherwise reduce emissions. One such qualifying practice is to capture and use biogas from AD of animal manure. More information on carbon sequestering is available at [http://www.fb.com/news/fbn/html/agriculture\\_s.html](http://www.fb.com/news/fbn/html/agriculture_s.html)

### ***2.1.3 Technology Barriers***

There are several issues to consider for anaerobic digester including:

- Cost of digester and biogas recovery equipment
- Digester operation
- System reliability

Building a digester and energy generation system requires considerable capital. These costs can be mitigated by applying for a USDA cost-sharing grant and by maximizing the sales of all usable products: electricity, biosolids/fertilizer and heat. In some cases, large farming operations with significant biogas generation can sell excess electricity to the grid with an acceptable power purchase agreement. Many utilities are interested in earning credits for green house gas emission reductions and may be willing to pay farmers a fair price to prevent federal legislation mandating such practices.

Digesters require regular monitoring for proper operation. Temperature and organic loading rate are the most important parameters to ensure optimal digestion and biogas production. It is also necessary to separate manure wastes from other wastes such as copper sulfate and other parlor washing chemicals. A farming operation must establish a management plan to monitor critical digestion parameters in order to identify and repair potential problems.

System reliability is important as many early anaerobic digester designs failed on U.S. farms. It is essential to select a qualified contractor and quality equipment and monitor the digester at regular intervals. The reliability of systems should improve with newer installations utilizing updated digester designs and control systems.



#### 2.1.4 Comparison with other Manure Management Systems

Other manure management methods have high installation costs and do not offer the benefit of electrical or fertilizer sales potential associated with anaerobic digesters. They are simply absorbed expenses and Table 5 illustrates the costs associated with other manure management systems.

**Table 5: Comparison of manure management systems costs**

Manure Management System	Cost Range (\$/1000 lbs live weight)
Covered Lagoon Digester with open storage pond	150-400
Heated Digester (plug flow or complete mix) with open storage tanks	200-400
Aerated lagoons with open storage pond*	200-450
2-cell separate treatment lagoon and storage pond	200-400
Storage ponds and tanks	50-500

source: *Managing Manure with Biogas Recovery Systems: Improved Performance at Competitive Costs*, EPA AgSTAR, 2002, Program. 8 p. (no O&M costs included)

\*aerated lagoons require energy costing \$35-50 per 1000 lbs live weight

In 1999, manure management systems were the eighth largest emitter of greenhouse gases in all industrial sectors in Colorado.<sup>9</sup> Emissions of methane were 43,049 tons with nearly 50% coming from cattle operations. Lagoon manure management systems accounted for 15,273 tons accounting for 37% of total manure methane emissions. Such emissions could be significantly reduced by covering, collecting and using biogas generated in lagoon manure management systems. Methane is a significant green house gas as it traps over 21 times more heat per molecule than carbon dioxide. In 2002, farm based anaerobic digesters reduced methane emissions by 123,961 tons carbon equivalent.<sup>10</sup>

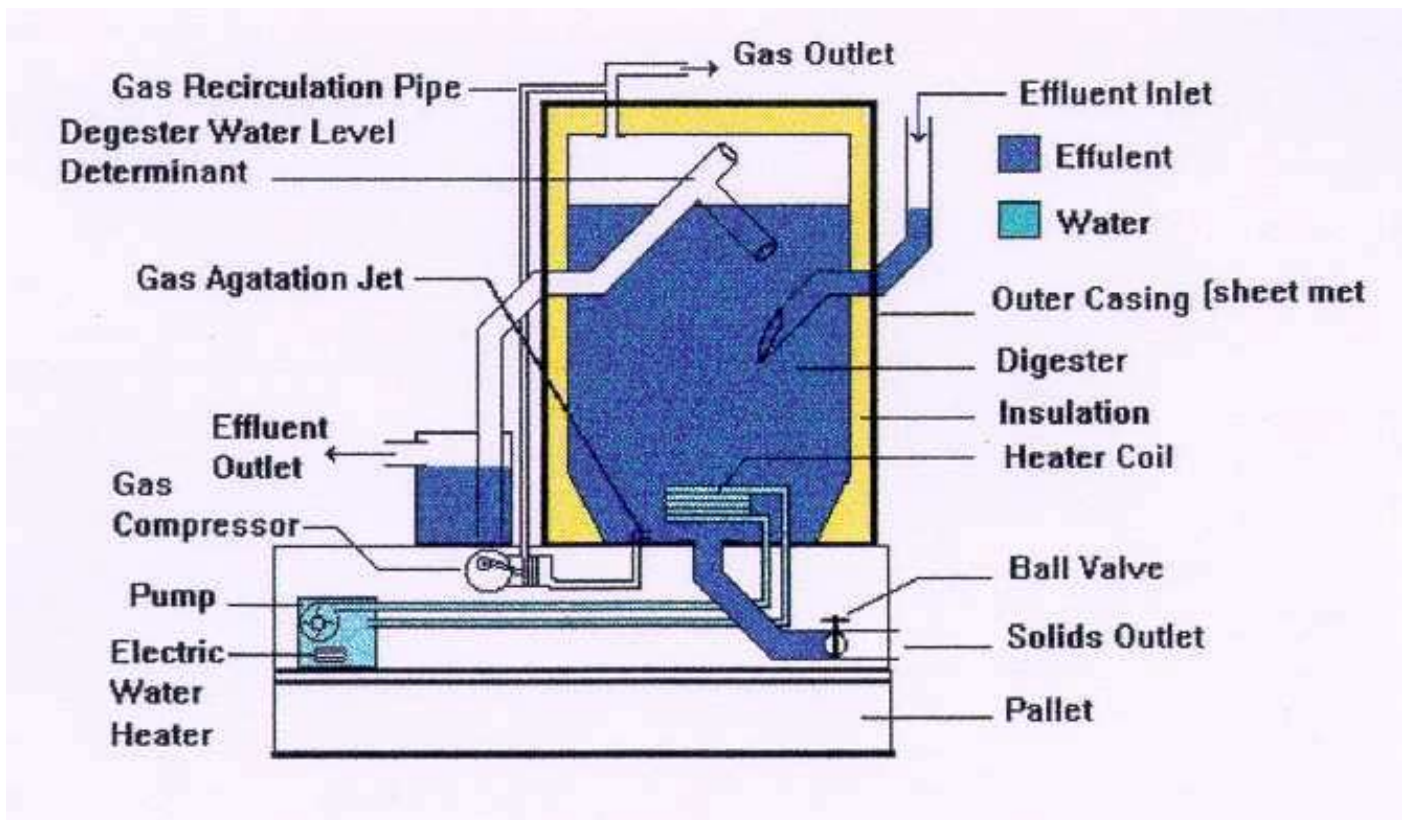
AD offers a manure management solution with the added benefit of energy generation for CAFO's facing new requirements. Recent legislation regulates and limits use and application of raw manure on fields in an effort to decrease risk of environmental contamination.

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<sup>9</sup> 2000 Colorado Emissions Update to Chapter Three of the 1998 Climate Change Report, Colorado Department of Public Health and the Environment, November 2000.

<sup>10</sup> AgStar Digest, EPA, Winter 2003, table 1 Operating US Digesters as of October 2002.

# The Design and Theory of a Basic Anaerobic Digester



by

**Simon Knowles**

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## **Abstract**

With environmental issues such as the greenhouse effect and correct waste disposal methods gaining much attention throughout the community, the concept of controlled anaerobic digestion is perhaps a much overlooked example of a way to reduce green house gas emissions and provide a better waste disposal method for organic waste.

## **Introduction**

Controlled anaerobic digestion is by no means a radical or new concept. Large scale industrial digesters and small domestic digesters are in operation in many places around the world. The purpose of all these digesters is to produce combustible biogas which can be burned to provide energy for a whole range of uses. Here in Australia, there is quite a bit of ideological interest in anaerobic digestion and biogas production, particularly from intensive farmers, but there are not many examples of digesters in operation. These farmers are interested in this topic primarily as an alternative energy source (biogas), and secondly, as part of an efficient effluent waste disposal system for the farm. Somehow there seems to be a problem in finding ways to put controlled anaerobic digestion into practice on the average Australian farm. There is almost a small library of information from all over the world on this topic, but this information doesn't seem to be reaching the average intensive farmer with some interest in this topic. Why isn't this concept being utilized more? There could be a number of possible reasons for this including the capital cost of setting up an anaerobic digester project, a lack of working models and / or a lack of a source of ideas to base individual projects on, i.e. - trouble shooting and project development at a technical 'on farm' level. The purpose of this project was to develop a small scale working prototype possibly suited to operate on the average farm. The focus of this project was the production of usable (combustible) biogas. This project is definitely not supposed to be revolutionary or radically new, but rather to be a starting point for further research and development in this area.

The purpose of this report is not to provide a method for the fabrication of the project produced (although a basic materials list will be provided). Rather, this report will aim to identify key aspects of the design, concentrating on their function and the theory behind their function. Therefore, the aim of this report is to provide the reader with a basic explanation of the mechanics of a small, continuous flow anaerobic digester.

## **The Brief**

The purpose of this project was to design and build an anaerobic digester to meet the following criteria.

The design should

- attempt to maximize the amount of biogas produced per unit time,
- be a continuous flow anaerobic digester. This has been specified because it seems that this will be the most practical design for continuous operation in a farm situation.
- be simple and easy to understand so that the average person is able to grasp the function and theory behind each component of the design with only a small amount of guidance. The idea here is to encourage people looking at the design to think and understand the requirements for controlled anaerobic digestion and the continuous flow model.
- be a durable, compact, versatile design which is capable of being shifted around if necessary to be displayed.
- be operated with a minimum of monitoring, regulating, and adjusting (in other words, be easy to operate).
- attempt to reduce time and money costs associated with maintenance

- attempt to minimize the cost of setting up and running the digester without compromising the performance of operation or the other specifications of the brief
- look aesthetically pleasing as another mechanism to effectively sell the concept!

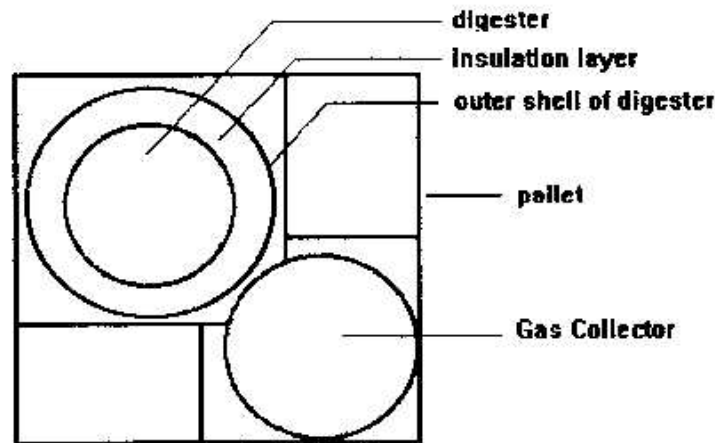
## **Basic Summary of Materials Required**

- 1 x Hardwood pallet;
- 1 x 200lt plastic drum suitable to act as a digester;
- various timber and fabricated timber supplies for the purpose of building platforms and housings for the digester and gas collection units;
- 1 x 200lt metal (44 gallon) oil drum (with bung holes as the only openings) to be used for the gas collector
- insulation
- sheet metal as a cover over the insulation
- various PVC fitting including glue, primer, various diameter pressure pipes and their associated joining fittings
- guttering silicon
- various tech screws, screws and other fasteners
- ~10m x 16mm black irrigation poly pipe (to be used for heater coil and aeration line)
- 1 x 60mm ball valve for solids outlet
- 1 x 20mm ball valve for gas outlet

## **Discussion of the Design**

Because the gas produced in an anaerobic digester is hopefully combustible, there are safety issues to firstly be considered when designing and operating the digester. Adequate ventilation is required and the best way to ensure that the environment around the digester is well ventilated is to position the digester in an open area, preferably outdoors. This means that the digester must be weather proof. Any possible ignition sources should be kept well away from the digester. For this reason, the location of the digester on a farm should be in a low traffic area away from maintenance sheds etc.

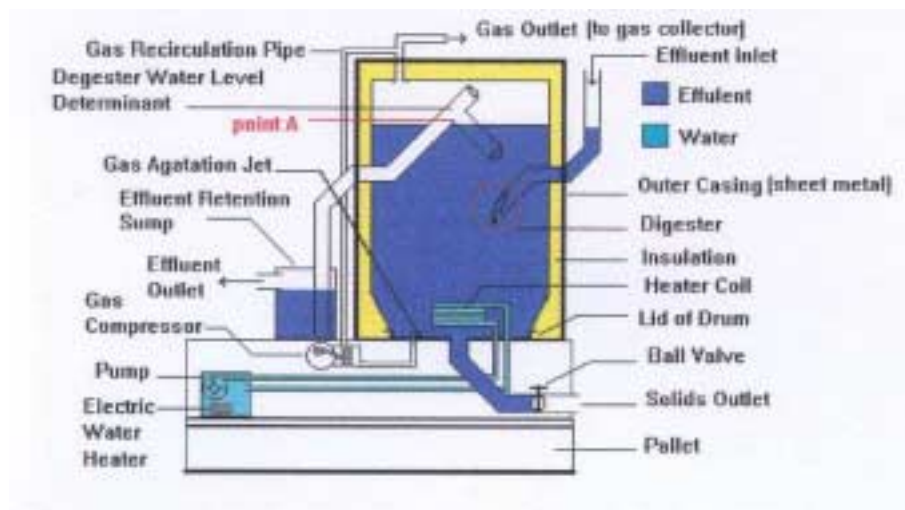
For the purpose of this project, I decided that the best way to make the digester unit transportable was to build the whole unit on a pallet. From the area available on the top of the pallet, I formed the basic layout and determined the location of the digester and the gas collector (fig. 1).



**Figure 1 The basic layout of the digester and gas collector to fit on the area of a standard pallet.**

The first thing I had to do was to build a platform for the digester to sit on. The reason why the digester had to be elevated slightly was to allow for a solids outlet pipe in the bottom of the digester (refer fig. 2). The digester was made from a 200lt plastic drum with a 'clip-on' lid, held on with a compression ring. The lid of the drum was fastened to the platform so that the drum was in an up-side down position (refer fig. 2). The up-side down position was used for a number of reasons

- to minimize the chance of gas leaks through the lid
- to enable 'easy' access to the heating coil, gas agitation jet and solids outlet in the event of an overhaul
- to provide easier assembly of the gas outlet, effluent inlet and outlet.



**Figure 2 A diagram of the continuous flow digester that was built for this project.**

In the bottom left corner of figure 2, a small box containing a pump and an electric water heater can be found. In order to maximize gas production, it is important to keep the conditions within the digester suitable for the anaerobic microbes which are actually producing gas. This means keeping the digester warm (no hotter than 40°C). For the purpose of this project, I have used a small electric heating element and a small pump which will circulate warm water through a coil of 13mm poly pipe inside the digester. Ultimately, on a large scale digester, it would be best to use the gas produced from the digester to provide heating energy for the operation. At the small scale, this is not practical.

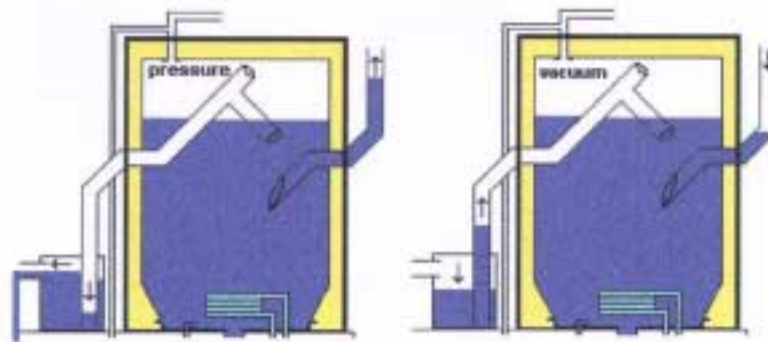
Above the water heater and pump in figure 2, a compressor icon can be found. The compressor is used to re-circulate gas through the digester for the purpose of agitation. The effluent being put through the digester will be made up of a mixture of solids, suspended solids and liquids. If this mixture is not agitated periodically, the solids will settle out and cause a scum build-up on the bottom of the digester. In time this scum build-up will cause reduced performance in the digester and it will have to be overhauled and cleaned out. Mechanical agitation can also be used however, problems can occur with mechanical failure and keeping the digester water tight.

The yellow shaded area around the digester in figure 2 represents insulation. Insulation is used mainly to reduce heating costs and to help maintain a homogeneous temperature within the digester. I used a sheet metal layer around the insulation as weather proofing. It is important to keep the insulation well sealed in as birds particularly like the insulation for nesting material.

On the right side of the digester, the effluent inlet pipe can be found. In the diagram you can notice that the inlet pipe is not cut off squarely where it ends inside the digester (see inside the red circle in Fig.2). The microbes within the effluent solution are producing gases which bubble up through the liquid to the gas cavity above. If the inlet pipe was to be cut off squarely, gas may accumulate in the pipe and escape to the outside environment. You will also notice that the inlet pipe extends upwards beyond the level of the effluent in the digester. When the digester is operating, the production of gas will mean that the system will be under a small amount of pressure. This gas pressure may push the effluent level down, forcing the effluent back up the pipe (see fig. 3 below - pressure). Therefore, outside the digester, the inlet pipe must extend above the effluent line to contain the liquid under operating conditions. Inside the digester, the inlet pipe must also extend a sufficient distance below the effluent line to allow for the situation where the gas pressure increases, forcing the effluent level down (see fig. 3 below - pressure).

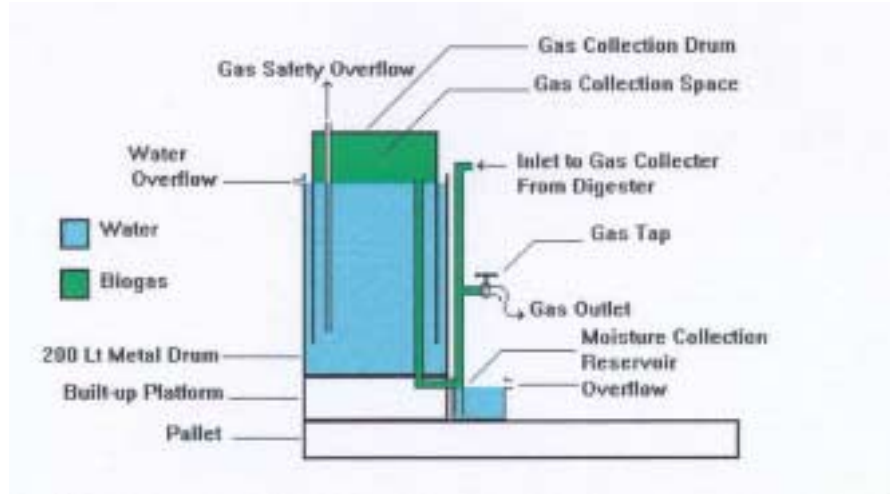
On the other side of the digester, the outlet pipe can be found. You will notice that this pipe enters the digester and extends up toward the top where there is a tee piece. The stem of the tee goes back down below the effluent level to avoid collecting surface scum from the effluent and also to prevent gas escaping if pressure increases in the system. The point where the outlet pipe meets this pipe will determine the level of the effluent in the digester with no pressure in the system (this point is labeled point A in Fig.2). The other side of the tee piece which is left open above the effluent level serves two purposes. It allows any gas which accumulates in the pipe to escape to the gas cavity and it also prevents a siphoning effect from occurring when the outlet is being used.

The outlet pipe feeds into the effluent retention sump (figure 2). This device basically acts as a large 'S' bend. It provides a reserve of liquid so that in the case of a vacuum occurring inside the digester, liquid will be sucked into the digester rather than air (refer fig. 3 below - vacuum). Such a situation may arise when the solids valve is opened. It is of paramount importance that outside air (containing oxygen) is not allowed to get inside the digester. This is logical when you consider that "anaerobic digestion" means digestion in an environment absent of oxygen.



**Figure 3 The first digester is showing the effects of pressure on the system. This situation can occur when gas pressure builds up in the system. The second digester is showing the effects of vacuum on the system. This occurs when the solids valve is opened.**

The gas outlet on top of the digester in figure 2 goes to the gas inlet on the collector below (Fig. 4).



**Figure 4 A plan diagram of the gas collector used in this project.**

The gas collector shown above is basically a drum that is inverted and inside another drum filled with water. The water acts as a barrier, preventing the gas from escaping from the drum. This device provides a simple gas storage area with a variable volume. The real beauty of this design is that no gas pump is required to shift the gas from the digester to the collector. It simply fills from gas pressure built up in the digester. This part of the design offers significant savings in initial capital costs, running costs, and monitoring costs.

When the gas flows out of the digester and into the collector inlet pipe, it is moving from a warm environment to the cooler outside temperature. The warm environment allows the air to be highly humidified. As the temperature falls, the moisture is no longer able to be suspended in the air and it condenses on the sides of the pipe. If this moisture is allowed to accumulate in any part of the system, it can cause blockages which may lead to increased pressure and possibly even ruptured pipes or vessels. For this reason there is a moisture collection reservoir at the bottom of the inlet pipe in figure 4. This device serves two purposes; to capture and prevent any build up of water in the tube; and also to prevent the gas collection vessel from sucking air in the case that a vacuum is created in the pipe. The moisture collection vessel has an overflow to prevent too much water from collecting.

The gas collection tube has an overflow tube which allow excess gas to be vented off well above ground level. This is simply a tube which extends from about 50mm above the bottom rim of the gas collection drum and travels up through the top of the drum. When the collection drum is full, the bottom of the overflow tube is exposed from the water and the gas is able to escape.

The tap shown in figure 4 is the main gas outlet where the gas can be tapped off and utilized.

## Summary

From the above description of the design features of this project, I believe that I have succeeded in meeting the requirements of the brief. I am hopeful that the explanations above have given some incite to the design, theory and operation of an anaerobic digester of this type. As mentioned in the introduction, this design is not meant to be revolutionary or radical, it is only aiming to present this concept in a simple, easy to understand format.

With farmers continually facing rising production costs and environmental issues such as the green house effect and waste disposal methods, I believe that controlled anaerobic digestion certainly has the potential to provide some solutions to these issues.



# Gas Bio-digester Information and Construction Manual For Rural Families



Fundación Cosecha Sostenible Honduras

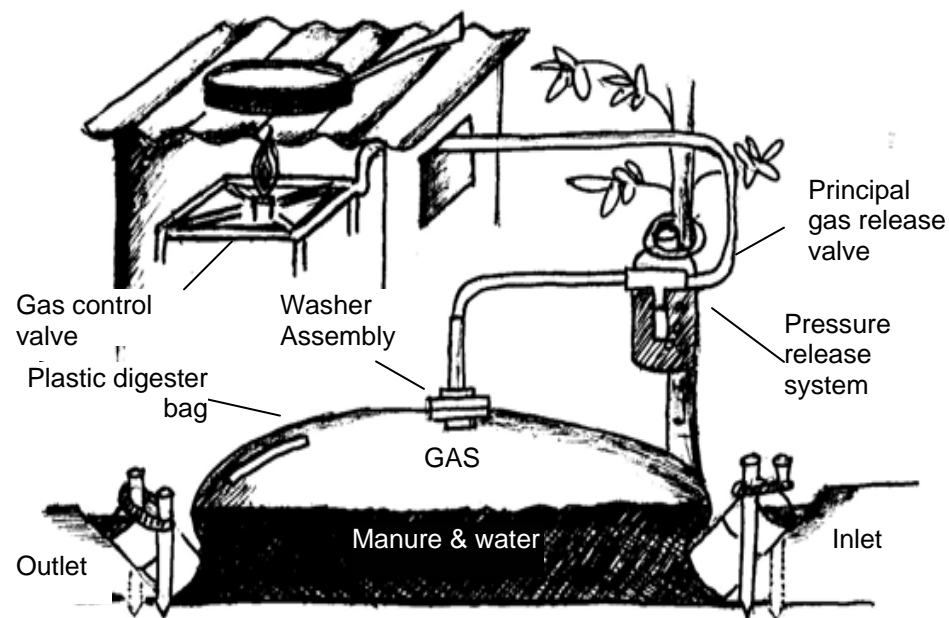
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*Written and compiled by Laura Brown, November 2004. This report is based on information gathered by Bruce Maanum, Stuart Green, and the agricultural extensionists employed by FUCOSOH. FUCOSOH has provided technical and financial support for the construction of 25 bio-digesters in rural Honduras.*

## I. What is a bio-digester?

For many years rural families around the world have used bio-digesters to convert readily accessible animal or plant waste into gas fuel. Bio-digesters use a process of oxygen free decomposition in which bacteria in the animal or plant waste produce a mixture of methane, carbon dioxide, and other gasses that are stored inside. Bio-digesters are relatively simple to build and operate, and require little more than a steady supply of organic matter and water.

**Bio-digesters provide benefits to families and communities by:**

- *Reducing the amount of wood fuel used by the household*
- *Preserving forests that naturally clean the water and air and provide habitats for thousands of species of unique plants and animals*
- *Producing high-quality organic fertilizer as a by-product*
- *Improving household air quality by reducing reliance on smoky wood burning stoves*
- *Providing a method for treating raw waste and reducing the flow of raw waste into clean streams and rivers*

## II. Considerations before building a bio-digester

### Fuel needs

A family sized bio-digester will provide about 4 hours of fuel per day. Most families will still use some wood fuel for daily cooking or lighting needs.

### Space

Bio-digesters require about 16 square meters of open space in a location below the ground level of the household.

### Cost

At the time of publication the cost of parts (not including the plastic bag or stove) for a family sized bio-digester was about \$10 (in Honduras). At this time FUCOHSO is able to provide support for plastic and technical support for most bio-digesters. Ask your local extensionist for more information about the costs of a bio-digester for your family.

### Maintenance

Bio-digesters must be refueled and checked for proper functioning daily and may require some annual maintenance. The cost of replacement of most parts

is minimal but polyethylene plastic tubes can be expensive. If maintained properly the plastic and parts of your bio-digester will last for up to 7 years.

### Materials

Bio-digesters work best when fueled with pig manure, but cow manure, coffee millings (miel de café), human waste, conchas de banana, and any other clean, chemical and pesticide free, biodegradable material can also be used. Digesters require about 1-2 shovels of clean, chemical and contaminant free manure every day. If you have more than 10 pigs, you may want to consider constructing a larger digester system to allow manure and water from the pens to flow directly into your bio-digester. The water used to fuel the digester must also be at a moderate pH level and free of chemicals. Consult your extensionist if you are unsure about the water quality or materials you plan to use in the digester.

### Time

It will take about 2 days to complete installation of your bio-digester. Plan one day to dig the trench and another to assemble the materials.

## III. Instructions for installing a non-industrial family sized bio-digester

### Materials



NOTE: We recommend that you read the entire instruction manual carefully before purchasing materials as some sizes and dimensions may vary based on the location of the digester and your family's needs. This list does not include materials necessary for the installation of your stove. See "Completing the gas line" in this section for more information on stove installation.

- 2 clear plastic tubes (Use # 6 or # 8 thick clear polyethylene plastic. This type of plastic is common and is usually available as a tube (a flat sheet with the two long sides sealed to each other). A tube 4

feet in diameter and 25 feet in length will supply a family with 4 hours of gas per day.

- 2: 5-gallon pails with the bottoms cut out
- 2–3: used rubber tire inner tubes cut into 3-4 foot long, 2" ties
- 1: 1/2" male adaptor threaded to compression joint PVC
- 1, 1/2" female adaptor threaded to compression joint PVC
- 2: large aluminum washers to fit male threaded PVC adaptor. (These can be fashioned from used metal if necessary.)
- 2: rubber washers, (1-2 cm larger than aluminum washers)
- 1: 1/2" PVC "T"
- 1: piece of steel wool or fine mesh steel window screening
- 1: 1/2" PVC pipe (about 3-4 feet, this will vary depending on the location of your digester)
- 1: 1/2" flexible tubing (length will depend on distance to water source and to gas use site)
- 1: 1 or 2 liter soda bottle.
- 4: 3' sturdy wooden stakes
- 1: small tube of PVC cement
- 1: piece of rope 5-10 feet longer than the digester
- 2: pieces of rope 8-10 feet each

You will also need a hacksaw, scissors, a machete or large knife, a hand or foot pump (if available) and shovels for digging the trench. A wrench will be helpful for tightening the washer assembly.

### Choosing and preparing the site for your bio-digester

In order to protect your bio-digester from animal and weather damage it must be located in a smooth flat-bottomed and flat walled trench. Locate a site that is free of large trees, stones, and free of any chemical contaminants (pesticides, fertilizers, herbicides etc.). The site should be no more than 60 feet (20 meters) from the house. Because gas rises, the site

must also be below the ground level of your house. Begin preparing the bio-digester site by clearing it of all brush, roots, and trees.

Dig the trench to the following dimensions:

**Width:** diameter of the plastic tube

**Length:** about 2-4 feet shorter than the length of the plastic

**Depth:** diameter of the plastic tube

In mountainous areas it may be necessary to dig a terrace and create walls with rocks and mud. Make the bottom of the trench as level as possible. Run your hands over the entire surface of the trench. Clear all roots or rocks as they may puncture the bio-digester bag.

### Preparing Materials

1. Find an open flat area (a sports field works well) and lay out the plastic tubes end to end. Remove your shoes and carefully crawl through one of the bio-digester bags holding the end of the other. Be very careful not to puncture the bags. Once the bag is threaded completely through, remove any folds or wrinkles.



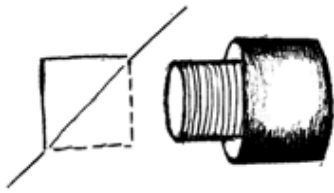
Above: Threading bio-digester bags. Be careful not to tear the bags.

2. Now is a good time to cut the hole for the washer assembly. Holding both corners and both bags, fold the plastic in half lengthwise about 6 feet from one end. Cut a hole as shown below that will allow the 1/2" PVC adapter to fit through both bags on one sealed side of the plastic.



Above: Bio-digester trench





If you will need to transport the bags to a different location, fold and secure them so the elements or the heat of a motor will not damage them.

### Assembling the Gas Outlet

- Place one washer and one gasket on the male adaptor (as shown below) and thread through the inner side of the plastic bags. Push the male adaptor through the hole. Assemble the remaining washer and gasket on the outside of the bags. Apply PVC cement to the male adaptor and secure the female adaptor firmly. Tighten with a wrench if available.



*Above: Installing the washer assembly in the digester bag.*



- Attach the long solid PVC pipe to the washer assembly with cement.  
NOTE: Unless otherwise indicated, all PVC attachments in the bio-digester should be cleaned sandpaper or a knife to ensure a proper cement seal.

### Installing Inlet and Outlet Buckets

- Lay your bio-digester carefully in the trench being sure that the gas outlet is centered. Cut out the bottoms of the 5-gallon buckets and sand or file the edges to remove any sharp areas that may damage the plastic. Slide one side of the tied digester bag through the bottom of one of the 5-Gallon buckets. Leave about 1 ½ -2 feet of plastic coming out the top of the pail. Carefully fold the ends of the bag over 2-3 times and tie off each end with straps of rubber.
- Push the bucket into the trench so it sits at about a 45-degree angle. At this time it may be necessary to dig ramps at the entrance or exit of the digester to accommodate the angle of the buckets. You may also consider digging a terrace that will allow for easy accessibility to the entrance bucket. Repeat on the other end of the bag.
- To secure the buckets pound stakes on each side of the inlet between the pails and the bag. Stakes should be placed a distance slightly smaller than the diameter of the bucket so the bucket will fit very snugly between them. Be very careful not to puncture the bag.

### Positioning and Filling the Digester

- Before filling your digester you must ensure that it sits snugly in the trench without fold or wrinkles. Any folds or wrinkles that remain when the bag is filled with water may chafe and form holes. This may be accomplished in several ways:

- If a diesel motor is available the digester may be filled with exhaust. Attach one side of a flexible hose



*Above: Bio-digester bag is hanging between two trees while filling with water.*

(do not glue) to the PVC pipe extending from the washer assembly and the other to the exhaust source. Fill just until the bag is smooth.

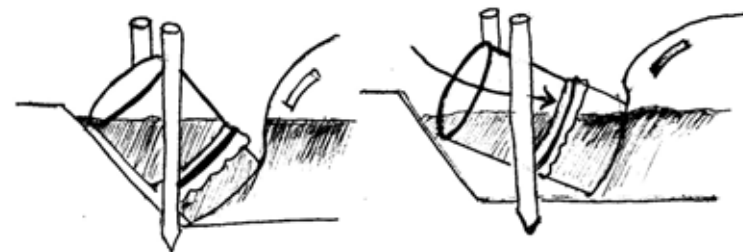
- If a diesel motor is not available thread a long piece of rope through the digester bag and secure ends to nearby trees. The bottom of the bag should sit on the floor of the trench and the top should be raised slightly. Fill the bag with water as described below.
  - Fill the bag with air using a small hand or foot pump.
9. Attach one end a flexible plastic tube (do not glue) to the PVC pipe from the washer assembly and the other to a spigot. Fill the digester to 60%-75% capacity with water.

**Below:** Threading bags through the plastic bucket inlet tube. Only one bucket was used in this model.

NOTE: Water used to fill the digester must be clean and have neutral pH (not too acidic or basic). Ask your extensionist if your water source is suitable for filling the digester.

### Completing Inlet and Outlet Tubes

10. Untie the ends of the digester bag and fold the remaining plastic over the top of the bucket. Reach your hand through to smooth the plastic along the insides of the bucket. Slide another plastic bucket bottom end first inside the first bucket through the plastic tube. The plastic should be sandwiched between the two buckets. Wrap rubber ties around the bucket to secure the extra plastic.



CORRECT

INCORRECT

*Below: Placing and securing Inlet and outlet buckets. The bottom of the bucket should be submerged at least 6 inches below the water level.*



11. If necessary reposition the angle of the inlet and outlet tubes so the bottoms are well below water level and fluid can easily flow out of the digester. Tie a long piece of rope between the two vertical stakes to hold the tubes firmly in place.

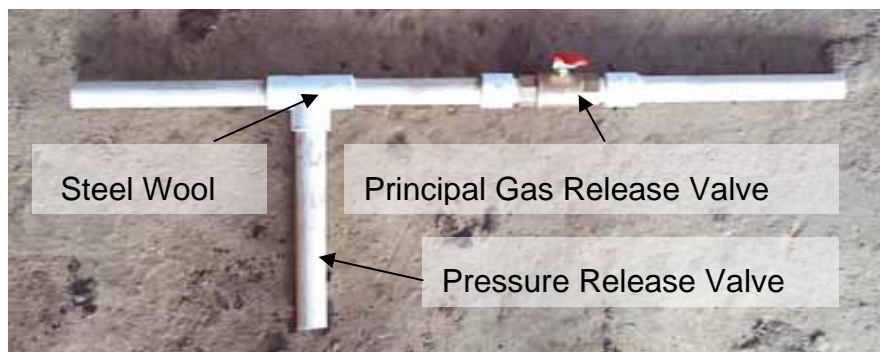
**VERY IMPORTANT:** Bio-digesters rely on water seals to maintain an oxygen free environment. If oxygen is allowed to enter the bacteria that produce gas in the digester will die. To ensure a good seal inlet and outlet tubes must be secured so the bottoms are **AT LEAST 6 INCHES** below water level.

### Assembling the Pressure Release Valve

12. Begin assembling the gas valve by rolling the steel screen or steel wool into a ½" tube. Push the tube into the PVC "T" as shown.



*Below: Completed valve assembly.*



13. Assemble PVC pieces and valve as shown. **VERY IMPORTANT:** Leave one site of the PVC "T" unglued to allow steel wool to be replaced every 6-7 months.
14. The flexible plastic gas outlet tube may now be attached to the filled biogas digester. The length of this tube will vary depending on the distance between the digester and the tree or stake where the pressure release valve will be located. Soften one side of the flexible plastic tube with a flame or boiling water. Coat with cement and push the PVC gas outlet tube firmly into the flexible plastic (3-4 inches). Wrap tightly with a rubber tie. Attach the other end of the flexible tube to the valve assembly using the same procedure.

15. Cut a 1" hole  $\frac{3}{4}$  up the side of a large soda bottle. Insert the PVC T assembly into the bottle. Cut an additional hole using a hammer about 3 inches from the bottom of the T. Secure the bottle to the T assembly with a rubber tie. Locate a tree or tall stake that will hold the pressure release assembly. Secure the entire assembly with rubber ties. Fill the soda bottle with water. The water will maintain an airtight seal but will allow excess gas to escape before damaging the digester bag.

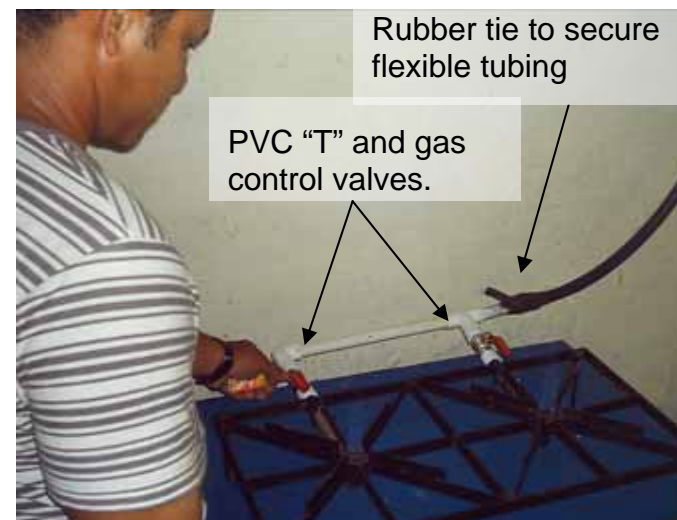


*Above: Pressure release valve secured to a tree.*

## Completing the gas line

16. Run a piece of flexible plastic tubing from the pressure release valve to the location where the gas will be used (this distance will vary). Secure the gas line to the valve assembly as in step 14.
17. If your gas line will be attached to a gas stove, create a secure PVC assembly as shown in the picture below. The gas control valves located on your stove should be closed securely. Connect the gas line to the PVC assembly on the stove using the method described in step 14.

*Right:  
Attaching the  
stove to the  
plastic gas  
tube.*



## Charging and preparing the digester for use

18. Be sure the gas valve is closed before charging. The digester should be initially charged with about 20 buckets of manure and water mixture for the first day only. **IMPORTANT:** After the initial charge, your digester will require only **TWO BUCKETS** of charge each day. Use any of the following mixtures:
- 1 shovel of cow Ganado manure: 1 bucket of water
  - $\frac{1}{2}$  shovel of pig manure: 1 bucket of water
  - 1-2 lbs banana, coffee, or other biodegradable plant waste: 1 bucket of water. **IMPORTANT:** Never use sharp or very hard materials such as bone or wood.

## IV. Operating and maintaining your bio-digester

Bio-digesters take 50-70 days to begin producing gas regularly. If maintained properly your bio-digester will last for about 7 years. Polyethylene plastic degrades in the sun. If your digester is located in a sunny area constructing a simple roof made of plastic, bamboo, or leaves may increase the life of your digester by several years. A solid plastic cover functions well because it will trap the sun's heat and could improve gas production in your digester.

Construct a fence around your digester if there is any chance of damage by animals.

**Daily maintenance:** Charge your bio-digester with two buckets of manure or plant wastes and water mixed to the ratios above. Check the inlet and outlet buckets to ensure that the level of water in the bag is adequate. Check the pressure release valve to ensure that the bottle is filled with water up to the small water hole. If the water in the pressure release valve is bubbling then the digester is functioning properly. Check inlet and outlet buckets to be sure no air is entering. Check for damage to the digester bag. Clean off any mud, stones, or foreign material on the bag.

**Periodic maintenance:** The steel wool inside the PVC "T" assembly must be replaced every 7 months. Check gas lines for cracks and leakage.

The discharge from your digester is a clean organic fertilizer. Do not divert this discharge directly into lakes or streams. Consult your extensionist for more information about best uses for this fertilizer.

Contact your extensionist if you note any problems with your bio-digester.



*Left: Initially charge your bio-digester with up to 20 buckets of manure mixed with water. After this the digester requires only 2 buckets of charge each day.*

## V. Common Questions and Problems

**The bio-digester does not seem to be producing any gas.**

Bio-digesters take 50-70 days to begin producing gas regularly. If your bio-digester is new, wait and continue charging with 2 buckets of manure and water mixture each day.

Gas production may drop or cease for many reasons including the entrance of air into the bag, changes in temperature, water pH, and contamination in the wastes used to charge the digester. Check to be sure that no air is entering the bio-digester from the inlet or outlet tubes. Next check the digester for any bag damage from foreign objects or animals that may allow gas to enter. If necessary increase the water level inside the bag.

Some producers have noted a drop in bio-digester gas production in winter months and during long periods of rain.

**Soil around the bio-digester is washing onto and compressing the bag.**

When soil or mud fall on the biodigester they can deflate the bag, seal off the inlet, destroy the trench, and cause sedimentation to occur inside the bag. To avoid this problem construct a barrier to keep mud, rain, and soil out.

Many producers have constructed simple fences or barriers to prevent erosion from damaging the bio-digester bag. These may be constructed from wooden stakes and slats of wood. Any mud that washes onto the bag must be cleaned off daily.

**There appears to be gas in the bag, but there is no gas coming out of the stove/lamp outlet.**

Check to be sure the gas valve is open. Occasionally pipes crack causing a leak in the gas line. Regularly inspect your gas lines for damage. Seal any damaged lines securely with glue and rubber ties.

**Animals are damaging the digester bag**

Animals can quickly cause permanent damage to your biodigesters. Be sure that your bio-digester is well protected from animals.

**Do I have to use the same type of waste in my digester every day?**

No. Bio-digesters work best with pig waste but you can use any clean, biodegradable material mixed with plenty of water.

**Sedimentation is occurring inside the biodogester. Is this OK?**

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No. Over time sediment can destroy the bag, reduce the production of gas, and reduce the gas storage capacity of the bag. Be sure that the charging mixture is free of heavy hard materials and that inlet and outlet tubes are not blocked by sediment.



# Biogas Digesters in India

by Robert Jon Lichtman

Illustrations by William Gensel  
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## Preface

An important common theme underlies much of the current literature on the application of technology within both developed and developing nations. Any technology has a complex series of impacts on the environment in which that technology operates. The concern over a technology's "appropriateness" is based on the need to determine clearly who will be affected by use of the technology and in what ways.

Behind the concept of "appropriate technology" is the belief that the complex interactions between a technology and its environment should be made "visible." Only then can a technology be evaluated properly. By describing explicitly the impact of a technology, the selection criteria for the technology also

become explicit. If we choose a technology that pollutes a river, but which also provides permanent jobs for 10,000 workers, we presumably either value employment benefits over environmental costs or else were ignorant of the pollution effects at the time we made the decision.

The choice of a technology is "appropriate" or "inappropriate" only in the context of the demands we place upon it. The subtle trade-offs between these often conflicting demands are at the real core of any debate over the choice of a technology. Appropriate technology is less a problem of hardware than of appropriate data collection, decision-making, financing, installation, and use--with all the problems of sorting out competing demands and value judgements in each of these tasks.

This study is an assessment of the "appropriateness" of biogas technology in meeting some of the needs of India's rural population. Such an assessment is quite complicated, despite claims that a biogas system is a simple village-level technology. While there is evidence that biogas systems have great promise, they are subject to certain constraints. It is impossible to describe here all the factors that one might study to assess any technology. I only hope that the approach used in this study will help others.

One difficulty in studying biogas technology is the fragmented and often anecdotal nature of the research and development work. In order to provide this snapshot of the state-of-the-art in India, I have had to enlist the aid of a bewildering number of government officials, industrialists, university researchers, missionaries, social workers, journalists, voluntary groups, farmers, merchants, and villagers. While I will never be able to express fully my gratitude to the hundreds of people who have helped me piece this puzzle together, I am particularly indebted to the following:

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Finally, I am deeply indebted to Dr. Y. Nayudamma, Distinguished Scientist, Central Leather Research Institute, Madras. without his guidance, friendship, and unyielding support, none of this would have been possible. All of these individuals have immeasurably deepened my understanding of biogas technology, as well as of India itself. Any errors or omissions contained in this study are due to my own failure to utilize their considerable insights.

Robert Jon Lichtman  
December 1982

#### Abbreviations and Terminology

BHP = brake horsepower

crore = 10,000,000 rupees

hr = hour

kcal = kilocalorie (1,000 calories)

kwh = kilowatt-hour

lakh = 100,000 rupees

[m.sup.3] = cubic meter

MT = million tonnes

MTCR = million tonnes of coal replacement

Rs = Indian rupee(s)

tonne = metric ton (1,000 kg)

Rs 1.00 = US\$0.125 at the time of this study

## Introduction

The term "biogas" system is somewhat of a misnomer. Though biogas systems are often viewed as an energy supply technology, the Chinese regard their systems primarily as a means to provide fertilizer and the sanitary disposal of organic residues.

Gas is considered a useful by-product.(1) In India, interest in biogas is due to its potential as a fuel substitute for firewood, dung, kerosene, agricultural residues, diesel, petroleum, and electricity, depending on the particular task to be performed and on local supply and price constraints. Thus, biogas systems provide three primary products: energy, fertilizer, and waste treatment. For the sake of convenience, the term "biogas system" in this study will refer to the technology of digesting organic wastes anaerobically to produce an excellent fertilizer and a combustible gas, and to dispose of agricultural residues, aquatic weeds, animal and human excrement, and other organic matter.

While use of biogas systems is not restricted to rural areas, the difficulties of retrofitting such systems in urban areas, supplying a balanced charge of biomass, generating adequate pipeline pressure, and minimizing capital costs all suggest that biogas systems will be more easily adapted, in the short term, to rural areas. This study therefore is focused on rural utilization of biogas systems.(2)

### I. Rural Energy Consumption and Biogas Potential

Biogas has great potential for supplying energy for cooking, lighting, and small-scale industry in rural India. This section will show through a series of calculations that biogas theoretically can play a significant, if not major, role in meeting many of these needs, as well as in supplying fertilizer and helping to solve other development problems. Readers not interested in these calculations should skip to Section II on Page 11; the important point is that biogas holds considerable promise and deserves further study.

To assess properly the potential of biogas systems for meeting a variety of rural needs, one would have to know the total amount of organic material (biomass) available annually; that is, material for which there are no other more productive uses. Biomass that could be employed as feed material would have to be studied carefully with respect to the annual output of each material, the average biogas yield per unit of material, collection

and transportation costs, and the availability of the material over time.

Unfortunately such data do not exist in India with any degree of reliability. No accurate data exist on the annual supply of water hyacinth, congress grass, banana stems, and other biomass that can serve as a feed material to a biogas system.

Since many agricultural residues are used as fodder, knowledge of the net availability of these residues is important to avoid conflicting demands on their use. Statistics on the amount of residue per crop, though available, tell nothing of the end use of the residue. Revelle cites aggregate figures of 34-39 MT of crop residues consumed annually as fuel.(3)

Even annual dung output is a matter of some controversy. Desai estimates that out of the 114-124 MT (dry weight) of dung produced annually, about 36 MT dry weight are burned as fuel.(4) The Working Group on Energy Policy calculates that 73 MT of dung are used as fuel,(5) without specifying if this is a dry weight figure (dry weight = approximately 1/5 of wet weight). Revelle uses a World Bank estimate of 68 MT burned as fuel (out of a total of 120-310 MT) and suggests that 83 percent of this, 56 MT (dry weight), is consumed in rural areas.(6)

The Indian Ministry of Agriculture offers data on livestock Population and dung voided per animal per annum as shown in Table I-1. Again, there is uncertainty about the percentage of dung produced in rural areas. To be conservative, we will assume that there are roughly 237.5 million cattle, buffalo, and young stock (from Table I-1), and that their collectible daily yield from night droppings (when cattle are tied up near a dwelling) is approximately 8.0 kg per head.(7) Using Revelle's estimate of rurally produced dung at 83 percent of the total, annual rural dung production would be over 575.6 MT wet weight, or 115.1 MT dry weight.

Various estimates shed little light on the percentage of dung collected, or on factors affecting dung output, such as cattle species, body weight, diet, etc. Data will also vary regionally and seasonally. If we assume that there is a 20 percent weight loss during collection of the 115.1 MT dry weight of rural dung (calculated above), then the net available dung is 92.1 MT. To this can be added 34 MT dry weight of crop residues that are burned annually. This gives a total of about 126 MT (dry) of biomass that is available for biogas systems. Assuming an average gas yield of 0.2 [m.sup.3]/kg (dry) for the biomass(8) and a calorific value of 4,700 kcal/[m.sup.3] for biogas(9), the available biomass would yield roughly 25 billion [m.sup.3] for biogas. This is

Table I-1 Potential Annual Availability of Dung (1972)(10)

Livestock	Number of Animals (Millions)	Annual Daily Output/ Head (kg)	Output/hd. (millions of tonnes)	Total (millions of tonnes)
Cattle (3 + years old)	131.4	10	3.65	479.6
Buffalo (3 + years old)	37.8	10	3.65	138.0
Young stock	68.3	3.3	1.20	82.0
Sheep and goats	108.4	1.1	.4	43.4
TOTAL			743.0	

Total = 743 MT (wet weight)

Total minus 20 percent collection loss = 594.4 MT (wet weight)  
= 118.9 MT (dry weight)

equivalent to 118 trillion kcal. This estimate probably is low, because it does not include numerous weeds and aquatic biomass that might be used as a feedstock for biogas plants, but which currently have no alternative uses.

Assuming biogas burners have a thermal efficiency of 60 percent, the potential net energy for cooking from biogas is roughly 71 trillion kcal per annum. Approximately 975 trillion kcal are currently consumed during the burning of dung, firewood, charcoal, and crop residues for domestic use (cooking, water heating, etc.).(11) Of that figure, 87 percent is used in cooking.(12) Therefore, approximately 848 trillion kcal per annum is consumed in cooking in rural India. This figure, when combined with a 10 percent average thermal efficiency of "chulahs"(13) (mud/clay stoves) and the vast number of open cooking fires, gives a net energy consumption of approximately 85 trillion kcal per annum for cooking. We will assume that rural cooking needs consume about 85 percent of this figure, so that the annual net energy consumption for rural areas is 72.3 trillion kcal. Thus, biogas can essentially provide the net usable energy currently consumed in cooking from all noncommercial fuel sources in rural India.

The amount of total solids in biogas slurry prepared from 126 billion kg (dry weight) of organic matter, the minimum amount annually available for fuel and fertilizer (from our previous

calculations), is roughly 630 billion kg (wet weight), assuming for simplification that both plant wastes and dung contain 20 percent solids.

Given current practices, this biomass would be mixed with water at a 1:1 ratio if it was to be fed into a biogas system. The total influent would weigh 1.2 trillion kg. Twenty percent of this would be lost during microbial digestion. Of the remainder, the percentage of total solids per kg of weight of slurry would be about 6.4 percent. The digested biomass thus would contain 61 MT of solids.

Table I-2 shows the relative fertilizer content of biogas slurry and farmyard manure.(14) Based on this table, 61 MT of the total solids in biogas slurry would yield approximately 1.037 MT of nitrogen (N), .976 MT of phosphorus pentoxide ([P.sub.2][O.sub.5]), and .610 MT of potassium monoxide ([K.sub.2.O]) per annum.

Without a more detailed picture of the current end uses of organic residues, it is difficult to assess accurately the potential impact of a large-scale biogas program on overall fertilizer supply. Importation of chemical fertilizer is a function of the gap between demand and domestic production. Domestic production is comprised of indigenous production of chemical fertilizers and the use of organic residues and wastes that are composted as farmyard manure. Any net increase in the

Table I-2

#### Average Fertilizer Value of Biogas Slurry and Farmyard Manure

(Percentage of dry weight)

Substance	N	[P.sub.2][O.sub.5]	[K.sub.2.O]	Total
Biogas slurry	1.7	1.6	1.0	4.25
Farmyard manure + compost	1.0	0.6	1.2	2.8

amount of fertilizer derived from organic residues can be used to offset imports, assuming of course that domestic production of chemical fertilizers remains constant. The net increase in available fertilizer attributable to biogas slurry is derived from the following calculations:(15)

$$a) [F.sub.n] = [F.sub.ba] + ([F.sub.fyma] - [F.sub.fym])$$

where:

[F.sub.n] = the net increase in fertilizer

[F.sub.ba] = fertilizer value of currently burnt biomass, if it was digested anaerobically instead.

[F.sub.fyma] = fertilizer value of biomass currently composted as farmyard manure, if it was digested anaerobically.

[F.sub.fym] = fertilizer value of biomass currently composted as farmyard manure.

- b) Surveys from 13 states during 1962-69 found that 72 percent of total dung is collected on an average from urban and rural areas. When this figure is combined with earlier calculations, we find that 92.1 MT of rural dung (dry weight) X 72 percent = 66.3 MT of dung (dry weight) that is actually used as manure in rural areas each year. An estimated 10 MT (dry weight) of a possible 34 MT of agricultural residues are added to this. This produces a total of 76.3 MT of dung and agricultural residues that currently are being used for fertilizer in rural areas. The remaining 25.8 MT of dung and 24 MT of agricultural residues, or a total of 49.8 MT (dry weight), currently are consumed as fuel, assuming the same rate of collection and distribution as explained above.
- c) Using the calculations from (b) above and Table II, the values for [F.sub.ba], [F.sub.fyma], and [F.sub.fym] are shown below. Values are in MT:

	N	[P.sub.2][O.sub.5]	[K.sub.2O]
[F.sub.ba]	.847	.797	.498
[F.sub.fyma]	1.297	1.221	.763
[F.sub.fym]	.763	.458	.916

- d) Therefore, the net increase in fertilizer due to digesting available organic material in biogas is approximately:

$$[F.sub.ba] + ([F.sub.fyma] - [F.sub.fym]) = [F.sub.n] \text{ (a)}$$

$$.847 + (1.297 - .763) = 1.381 \text{ MT of N.}$$

$$.797 + (1.221 - .458) = 1.560 \text{ MT of [P.sub.2][O.sub.5]}$$

$$.498 + (.763 - .916) = .345 \text{ MT of [K.sub.2]O}$$



In 1979-1980, 1.295 MT of N, .237 MT of P, and .473 MT of K were imported at a cost of Rs 887.9 crores with additional subsidies of Rs 320 crores.(16) While our calculations show the enormous potential of biogas slurry in meeting domestic fertilizer needs, it must be noted that to organize such an effort would be a massive task. Manure would have to be collected from very diffuse points and transported to farms as needed. Fertilizer requirements will increase dramatically as India's population approaches one billion people shortly after 2000 A.D., including an increased demand for chemical fertilizers. Organic fertilizers from the slurry of biogas systems could certainly contribute to fertilizer supply needs. Our analysis is probably somewhat understated in that, as additional residues will be available from increased crop production, a potential increase in cattle population or improved cattle diet will mean more dung. Also, a variety of organic materials such as water hyacinth, forest litter, and other under-utilized biomass could all be digested, increasing the fertilizer derived from biogas slurry.

The above discussion is intended only to illustrate the order of magnitude of the potential impact of large-scale utilization of biogas systems. Much of the data used were aggregated from small and often inaccurate sample surveys, causing considerable margins of error. This problem will be discussed further at the end of this section.

Additional insight into the potential contribution of biogas systems can be obtained from recent projections of rural energy demand. Commercial and noncommercial energy demand, based on the Report of the Working Group on Energy Policy, is shown in Table I-3.

This data is the basis of the Reference Level Forecast of the study, an extrapolation of current trends. It is interesting to note that the household sector (90 percent of India's households are in rural areas) is assumed to account for almost all noncommercial fuel consumption throughout this period, except for 50 MTCR of firewood, agricultural residues, and bagasse that are used in industry. The Working Group also suggests that noncommercial fuels, as a percentage of total household demand, will gradually decline from the current 83.9 percent to 49.7 percent, and that the percentage of the total noncommercial fuel demand in all of India will drop from 43.5 percent to 11.5 percent.

Table I-3

Reference Level Forecast  
Energy Demand (1976 - 2000)

In Household and All-India  
In Millions of Tonnes of Coal Replacement (MTCR)(17)

Commercial Fuels MTCR (percent of total)			
	1976	1983	2000
Household	37.4 (16.1)	51.6 (20.2)	165.5 (50.3)
All-India	252.7 (56.5)	390.2 (65.7)	1,261.3 (88.5)
Non-Commercial Fuels MTCR (percent of total)			
	1976	1983	2000
Household	194.6 (83.9)	204.1 (79.8)	163.5 (49.7)
All-India	194.6 (43.5)	204.1 (34.3)	163.5 (11.5)

Note: Indian coal contains 5,000 kcal/kg.

The Working Group does not view this situation as desirable, and offers an Optimal Level Forecast based on a series of policy recommendations. This is shown in Table I-4.

For this optimistic projection to be realized (assuming total demand remains the same), commercial fuels will need to be substituted increasingly by noncommercial fuels. By 1983, noncommercial demand for all-India must increase by 1.3 MTCR over present projections.

Table I-4

Optimal Level Forecast(\*)  
Energy Demand (1982 - 2000)  
For Household Sector and All-India  
In Millions of Tonnes of Coal Replacement (MTCR)(18)

Commercial Fuels MTCR (percent of total)		
	1983	2000
Households	51.6 (20.0)(*)	134.3 (41.0)(*)
All-India	388.9 (65.4)	1,017.8 (71.3)
Non-Commercial Fuels		

	MTCR (percent of total)	
	1983	2000
Households	204.1 (80.0)	194.7 (59.0)
All-India	205.4 (34.6)(*)	407.0 (28.7)(*)

(\*) Note: The author has calculated commercial fuel demand for households and non-commercial fuel demand for All-India on the assumption that the Reference Level Forecast total demand for each category remains constant. A relative increase in demand for commercial fuels would cause a relative decrease in demand for non-commercial fuels. Conservation measures would reduce overall demand, and thus reduce the amount of non-commercial fuels needed to bridge the gap between supply and demand.

The actual figures are not included in the Report of the Working Group on Energy Policy.

By the year 2000, the household noncommercial fuel demand must increase by 31.2 MTCR, and noncommercial fuel demand in all of India must increase by 273.5 MTCR if commercial fuel consumption is to remain at the level suggested in the Optimal Forecast (without additional conservation).

Though these projections can be criticized for relying on suspect sample data(19) or questionable assumptions,(20) The Report of the Working Group nonetheless shows clearly that an increase in energy from noncommercial, renewable resources is a high priority. The report specifically describes biogas systems as "the most promising alternative energy technology in the household sector," although it does not minimize some of the problems associated with the technology.(21)

The optimal level forecast for irrigation and lighting (based on a series of recommended conservation measures) is shown in Table I-5.

Table I-5

Electricity and Diesel Demand: Irrigation and Rural Lighting  
(1976 - 2000)(22)

	1978	1983	Increase	
			2000	1978-2000
IRRIGATION				

Diesel (billion liters)	2.6	4.6	6.6	+ 4.0
Electricity (billions of KWH)	14.2	16.0	28.0	+13.8
HOUSEHOLD ELECTRICITY (billions of KWH)	4.4	10.7	32.2	+21.5
(With rural households at 90 percent of total)	(3.7)	(9.6)	(29.0)	(+25.3)
Total Rural Electric Demand (billions of KWH)	17.9	25.6	57.0	+39.1

NOTE: Electric pumps consume approximately 3,000 KWH/year/pumpset (at about 5 HP/pumpset).

Diesel pumps consume approximately 1,000 liters (.8 tonnes) of diesel fuel/year/pumpset.

In 1978-1979, an estimated 360,000 electric pumpsets and 2.7 million diesel pumps were used for irrigation. Future growth is projected to increase to 5.4 million electric pumpsets and 3.3 million diesel pumps by 1983. The estimated ultimate potential of 15.4 million energized wells optimistically is reached by the year 2000, when there will be 11 million electric pumpsets and 4.4 million diesel pumps in operation. Animal-power lifting devices are expected to decline from around 3.7 million in 1978 to 660,000 by the year 2000.(23)

As shown in Table I-5, the total increase in projected diesel fuel demand for irrigation between 1978-2000 is 4 billion liters or 16 billion BHP-hrs, since .25 liters of diesel generate 1 BHP-hr. For the same period, rural electricity demand (irrigation and household lighting) is expected to increase by 39.1 billion kwh. Modified diesel engines can run on a mixture of 80 percent biogas and 20 percent diesel. Since .25 liters of diesel = 1 BHP, .05 liters can be mixed with .42 [m.sub.3] of biogas to generate the same power. Using a conversion factor of 1 BHP = .74 kwh, .07 liters of diesel mixed with .56 [m.sub.3] of biogas will generate 1 kwh.(24) Therefore, the 16 billion BHP-hrs required by the year 2000 to run diesel pumpsets could be supplied by a little over 6.7 billion [m.sub.3] of biogas and .8 billion liters of diesel fuel. Alternatively, the 39.1 billion kwh required for rural electricity needs could be supplied by 21.9 billion [m.sup.3] of biogas and 2.74 billion liters of diesel fuel.

We have previously calculated that at least 25 billion [m.sub.3] of biogas is potentially available from current patterns of biomass use. If, and it is a big "if", an alternative cooking fuel could be supplied to those areas that presently rely on dung and plant wastes, perhaps with fuelwood plantations, this biomass could be shifted toward meeting a large share of increased demand for commercial fuels in rural areas. Since food production and cattle population will have to increase to keep pace with population growth, the amount of available biomass, and hence biogas, will expand similarly. The total increase in rural commercial fuel demand could be met by a mix of 28.6 billion [m.sub.3] of biogas and 3.6 billion liters of diesel, which is less than the 4 billion liters projected in Table I-5. Such a substitution seems well within the range of technical possibilities.

Some of the economic aspects of substituting biogas for diesel and electricity are discussed in section VI. In many villages, the costs of connection to the nearest central grid are prohibitive even if the load were increased to include lighting, pumpsets, etc.(25) For some areas, biogas may represent the only viable technology, whether or not the gas is burned directly or converted to electricity. As the Working Group notes, despite the fact that roughly half of India's villages are electrified, population increases have kept the percentage of total households that are electrified relatively constant at 14 percent. Within "electrified" villages, only 10-14 percent of the houses obtain electricity for household applications. Only 5 percent of rural houses use electricity for lighting because rural family incomes cannot support the high installation cost of electricity.(26)

As an alternative, a benefit of a large-scale biogas program could be to free up the millions of tonnes of firewood that are consumed annually for cooking. Using the Working Group on Energy's norm of 1 MT of firewood (all types) = .95 MTCR, this represents almost 66.8 MTCR, which is over 30 percent of the increased demand for noncommercial fuels, or 10 percent of the increased demand for commercial fuels in the optimal level forecast for the year 2000. While the actual use of this vast amount of energy would depend on the economic, social, and managerial constraints associated with various thermal conversion processes, the possibilities for converting this energy into electricity, gas, or pyrolytic oil deserve serious consideration.

Before biogas could be used as a substitute for commercial fuels, a number of complex energy demand, investment, and development issues would need to be analyzed carefully. Such an

analysis is far beyond the scope of this study. Nevertheless, it is in India's interest to raise these questions since there are many different energy supply mixes that are technically possible, given India's resources. The preceeding discussion is intended only to show the magnitude of the potential contribution that biogas systems could make to India's energy and fertilizer needs.

A number of technical, political, and organizational problems must be solved before a large-scale biogas program can be undertaken. The remainder of this study is devoted to exploring these problems in some detail.

## II. An Overview of Biogas Systems

Most biogas systems consist of a basic series of operations, which is described briefly in this chapter. There may be certain variations or additions to this basic schematic design, especially if the system is integrated with other "biotechnologies," such as algae ponds or pisciculture, or if additional uses can be found for carbon dioxide ([CO.sub.2]) that is present in biogas. A brief description of the different aspects of a biogas system is necessary before discussing the economic and social dimensions of the technology.

## RAW MATERIAL (BIOMASS) COLLECTION

Almost any organic, predominantly cellulosic material can be used as a feed material for a biogas system. In India, the Hindi name for these systems, "gobar" (dung) gas plants, is imprecise. This is shown by the following list of common organic materials that may be used in gobar gas plants:(27)

- \* algae
- \* animal wastes
- \* crop residues
- \* forest litter
- \* garbage and kitchen wastes
- \* grass
- \* human wastes
- \* paper wastes
- \* seaweed
- \* spent waste from sugar cane refinery
- \* straw
- \* water hyacinth and other aquatic weeds

Table II-1 on the following page shows some laboratory yields associated with different biomass. It is important to remember that the amount of gas produced from different kinds of biomass depends on a number of variables. The most important of these

include the temperature and the amount of time that the biomass is retained in the digester, which is called the loading rate. Unless stated otherwise, all biomass has been tested at 35 [degrees] C and retained for a 35-day period.

Despite the obvious sanitation benefits of feeding human feces into a biogas digester, this practice produces a per capita daily gas yield of only about .025 [m.sup.3]. This means that the excrement from perhaps 60 people would be needed to provide enough gas for the cooking needs of a family of five people. In addition, excessive slurry dilution can result from uncontrolled

Table II-1 Gas Yields for Selected Organic Materials(28)

Material	Gas yield in [m.sup.3]/kg of volatile solids
cattle dung	.20
human feces	.45
banana stems	.75
water hyacinth	.79
eucalyptus leaves	.89

rinsing in a community latrine, since all the latrine water will enter the digester. Corrosive hydrogen sulfide ([H.sub.2]S) is more prevalent in human waste than in animal dung. This may adversely affect engines run on the biogas unless the gas is passed through iron filings for purification. Nevertheless, the role of human enteric pathogens in the communication of disease is well established. Therefore, latrines could be incorporated into a biogas system, provided they are accepted by villagers, affordable, not disruptive of the digestion process, and not harmful to any engine operation. Safe procedures for handling both influent and effluent also must be developed. More research is needed to understand the effects of different combinations of temperatures and retention times in killing harmful pathogens that could remain in the digested slurry.

Water hyacinth is particularly appealing because it is not used as animal fodder, and therefore does not present any "food or fuel" choices. In addition to its higher gas yield, water hyacinth produces gas that appears to have a greater methane content and more soil nutrients than digested dung. However, there are some drawbacks to using water hyacinth. One is that its water requirements are vast. Through transpiration from its leaves, hyacinth absorbs from three to seven times the amount of water that would normally be lost to surface evaporation from the water occupied by the hyacinth. Water hyacinth also can become a breeding ground for mosquitoes and snails, although these can be controlled by introducing predator fish.(29)

There are certain annoyances associated with the use of this and other plant materials. Younger plants yield more gas than older plants, which may necessitate greater discrimination in the manner in which biomass is collected. Plants may have to be dried and shredded to ensure proper mixing, dilution, and digestion. It may often be necessary to add urine to maintain a proper carbon to nitrogen (C/N) ratio. There have been many field reports of scum build-up, clogged inlet tanks, and toxicity to methanogenic bacteria (due to the "shock" caused by the introduction of different biomass materials). However, these reports are sketchy, and the problems could be due to improper digester design or operation. Water hyacinth is almost always mixed with dung; there is little reliable field experience using water hyacinth as the sole input, although this has been done successfully in laboratories, as will be discussed shortly.

Several Indian research groups have been experimenting with "bio-dung"--a fuel cake and/or biogas feed material made from dried and partially composted organic matter of varying combinations.(30) Excellent gas yields have been reported with this still experimental idea, but documentation is insufficient. Nonetheless, this practice of "partial digestion" of the biomass in plastic bags seems similar to the 10-day "predigestion" period observed in China, where organic material is composted prior to batch loading in family digesters.(31) The Chinese report faster gas production if material is partially digested. The process probably reduces the [CO.sub.2] present in the early phases of digestion by simply releasing it in the atmosphere as the gas percolates up through the compost pits.

There are many advantages claimed by proponents of "bio-dung," such as its greater gas yield, higher calorific value, potential for generating revenue as a saleable product, eradication of harmful weeds, and making family-scale digesters affordable to those who own fewer than three to four cattle. There is little evidence currently available to evaluate these possibilities.

## MIXING AND FEEDING RAW MATERIAL INTO THE DIGESTER

There has been a good deal of experimentation with the digestion of organic materials in various combinations. Regardless of the biomass used, it must be loaded without being diluted excessively with water. Most researchers mix fresh dung and/or sun-dried organic matter with water at roughly a 1:1 ratio. If the plant matter is still green or the cattle diet is rich in straw, the ratio should be changed slightly to about 1:0.8. Materials should have a C/N ratio of roughly 30:1 due to the digestive requirements of methanogenic bacteria. The relative



proportions of different material should be adjusted to maintain this ratio.(32)

The inlet tank can become clogged when assorted feeds of different sizes and composition materials are mixed. Fibrous material can be shredded to avoid this. Different digester designs, incorporating larger inlets, may alleviate this problem. Most Indian systems work best if the biomass and water are mixed thoroughly in the inlet tank prior to injection into the digester. Many of these inlet tanks have a removable plug to block the inlet pipe during mixing. Alternatively, the Chinese seem to use less water and spend less time mixing material. This is perhaps due to their batch feeding process, which eliminates the need to add slurry daily.(33)

## DIGESTION(34)

Anaerobic digestion consists broadly of three phases:

1. Enzymatic hydrolysis--where the fats, starches, and proteins contained in cellulosic biomass are broken down into simple compounds.
2. Acid formation--where acid-forming bacteria break down simple compounds into acetic acids and volatile solids.
3. Methane formation--where methanogenic bacteria digest these acids and solids and give off  $[CH_4]$ ,  $[CO_2]$ , and traces of  $[H_2]$ .

Any remaining indigestible matter is found in either the "supernatant" (the spent liquids from the original slurry) or the "sludge" (the heavier spent solids). These two products are often described as "slurry" because the influent in most Indian plants is diluted with water at about a 1:1 ratio to form a relatively homogenous, liquid-like mixture. In China, the supernatant and sludge generally settle into separate layers in either the digester itself or in the output tank, and are removed separately by buckets that are lowered to different depths.

During the first phase of digestion, a great deal of  $[CO_2]$  is produced and pH drops off to roughly 6.2 (pH values of less than 6.2 are toxic to the bacteria needed for digestion). After about ten days, pH begins to rise, stabilizing at between 7-8. Temperatures below 15 [degrees] C (60 [degrees] F) significantly reduce gas production. During the winter months, many family-scale biogas systems in northern India reportedly produce only 20-40 percent of their summer yields. Similarly, Chinese plants often produce almost no gas during winter, and more than half the annual energy required for cooking must be provided by burning crop

residues directly. However, the need for a backup source of energy to supplement a biogas system can probably be eliminated with some of the design modifications suggested in the next section. Higher temperatures generally increase gas production, reduce retention time, and increase loading rates, once the bacteria adjust to the warmer environment. Mesophilic bacteria favor temperatures near 35 [degrees] C (95 [degrees] F). Thermophilic bacterial strains are found in the 50-60 [degrees] C (122-140 [degrees] F) range. The addition of nitrogen-rich urine seems to aid in gas production during winter, especially when it is combined with plant wastes. Digesting the wet straw flooring from cattle sheds, if available, is a convenient way to add urine to the influent.

The microbial population of methanogenic bacteria will decrease as slurry flows out from the digester. These bacteria have a doubling rate of roughly 40 hours. However, this slow growth rate can be overcome by greatly increasing the microbial population. There has been informal discussion among experts about a process, reportedly developed in Belgium, that uses a membrane to retain the methanogenic bacteria inside the digester. Gas yield per kg of biomass reportedly increases by a factor of 5-10 when the membrane is used. If these claims can be documented, and if the membrane is both affordable and durable, it would be an important development. There also is sketchy evidence that methanogenic bacteria are pressure sensitive. This might be a problem in some fixed dome systems, which can generate pressure above a water column of 80-90 cm. More research is needed on this point.

The effect of animal diet on gas yield has received far less attention than it deserves. Cattle can be either well fed or near starvation, depending on the income of a farmer and the time of year. Farmers often barely maintain their cattle until just prior to plowing season, when the diet is increased to fatten the cattle for work. Obviously, the less an animal eats, the less dung it produces. The more cellulose, especially in fibrous materials, that it eats, the greater the gas yield will be. More research is needed to determine the optimal diet for cattle given their use as a source of milk, motive power, and combustible energy (biogas), and also considering local resources, available capital, and knowledge constraints.(35) Even without this research, however, it is clear that diet, grazing habits, and costs of collection will greatly affect the net available dung yield per animal.

Many statistics quoted in the literature simply may not apply to a particular locale. These include data on dung yield of animals, gas yield of dung, temperature, the nature and nutrient content of other materials digested, and the [CH<sub>4</sub>] content, which can vary 50-70 percent for a given quantity of biogas,

depending on diet. Inaccuracies usually manifest themselves in an overestimation of gas availability and overall benefits. Norms mentioned in numerous studies are useful guides to these questions but cannot replace micro-analysis.

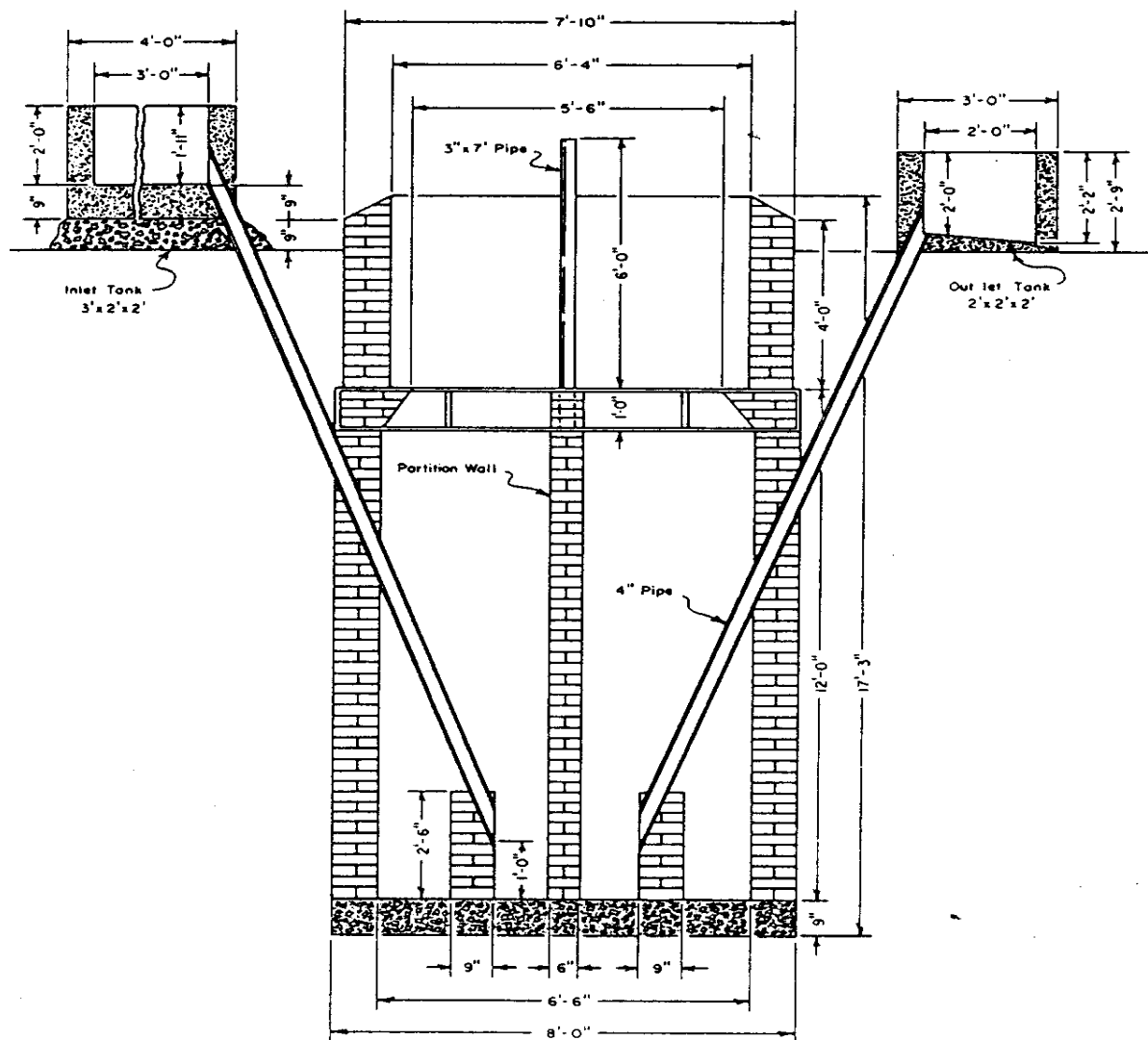
A great deal of research is furthering our understanding of the microbiological aspects of biogas systems.(36) If gas yield could be increased and retention time reduced, production costs would decrease, since a smaller volume of biomass per cubic meter of gas would be required. Some of the areas of research include ways to increase the growth rate of methanogenic bacteria, improve the digestibility of lignin, develop microbiological inoculums that would increase gas production, develop bacterial strains that are less sensitive to cold weather, identify micro-organisms involved in digestion, and separate acid-forming and methanogenic bacteria. As of the writing of this study, there have been no major documented performance breakthroughs achieved as a result of this research.

### III. Digester Designs

There are many ways to design biogas systems. The designs discussed in this study are by no means the only possibilities. They either have been tested extensively or were in the midst of serious research and development during the writing of this study. Groups attempting to develop their own systems should use the illustrations in this section only as guides. The characteristics and costs of labor, construction materials, land, etc., will vary according to local conditions and the end uses of the system's gas and slurry.

The Khadi and Village Industries Commission (KVIC) design has been developed over the past 15 years and is similar to the

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majority of systems currently operating in India (see Figure III-1).(37) As of 1981, KVIC claims to have built about 80,000 of these systems, although there are no reliable data on how many of the units are actually operating, temporarily shut down, or nonfunctioning. The KVIC system consists of a deep well and a floating drum that usually is made of mild steel. The system collects the gas and keeps it at a relatively constant pressure. As more gas is produced, the drum gas holder rises. As the gas is consumed, the drum falls. Actual dimensions and weight of the drum are functions of energy requirements. A long distribution pipeline that might necessitate greater pressure to push gas through its length would require a heavier drum, perhaps weighted with concrete or rocks. Biomass slurry moves through the digester because the greater height of the inlet tank creates more hydrostatic pressure than the lower height of the outlet tank. A partition wall in the tank prevents fresh

material from "short circuiting" the digestion process by displacement as it is poured into the inlet tank. Only material that has been thoroughly digested can flow up and over the partition wall into the outlet tank.

Most KVIC systems are designed to retain each daily charge for 50 days, although this has been reduced to 35 days in newer units. The slurry should be agitated slightly to prevent any chance of stratification. This is accomplished by daily rotation of the drum about its guide post for about 10 minutes. In Nepal, some gas holders have been painted to look like prayer wheels. They are turned during frequent religious ceremonies, or "puja" (individual prayer). The Nepali group, Development and Consulting Services (DCS), Butwal, also has modified the KVIC gas pipe connection. It has attached an underground fixed pipe to the guidepost, feeding gas through the guidepipe rather than connecting a flexible hose to the roof of the gas holder.

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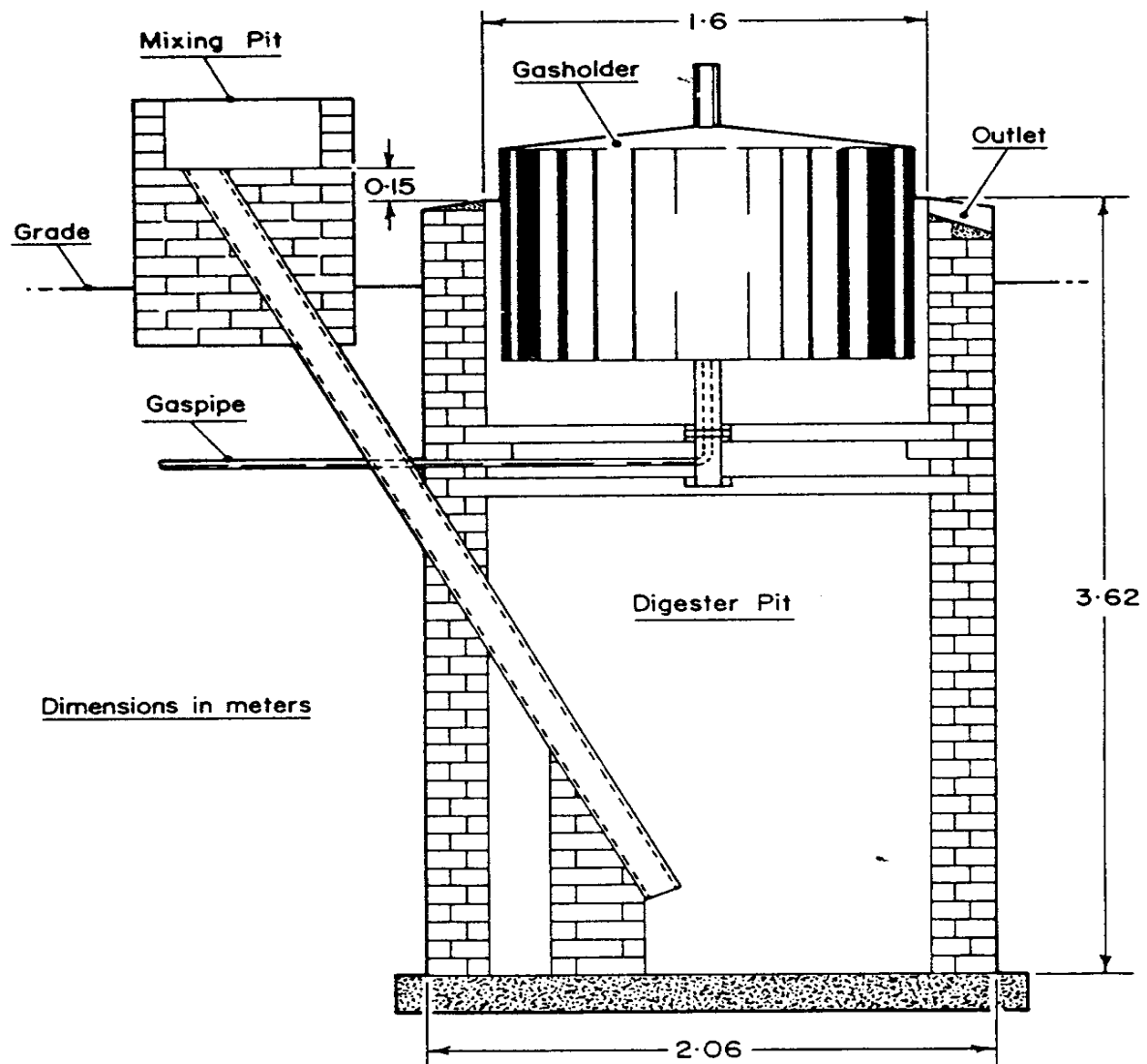


Figure III-2. DCS-taper design

DCS uses a taper design for high water table areas (see Figure III-2) and a straight design for low water table areas (see Figure III-3).

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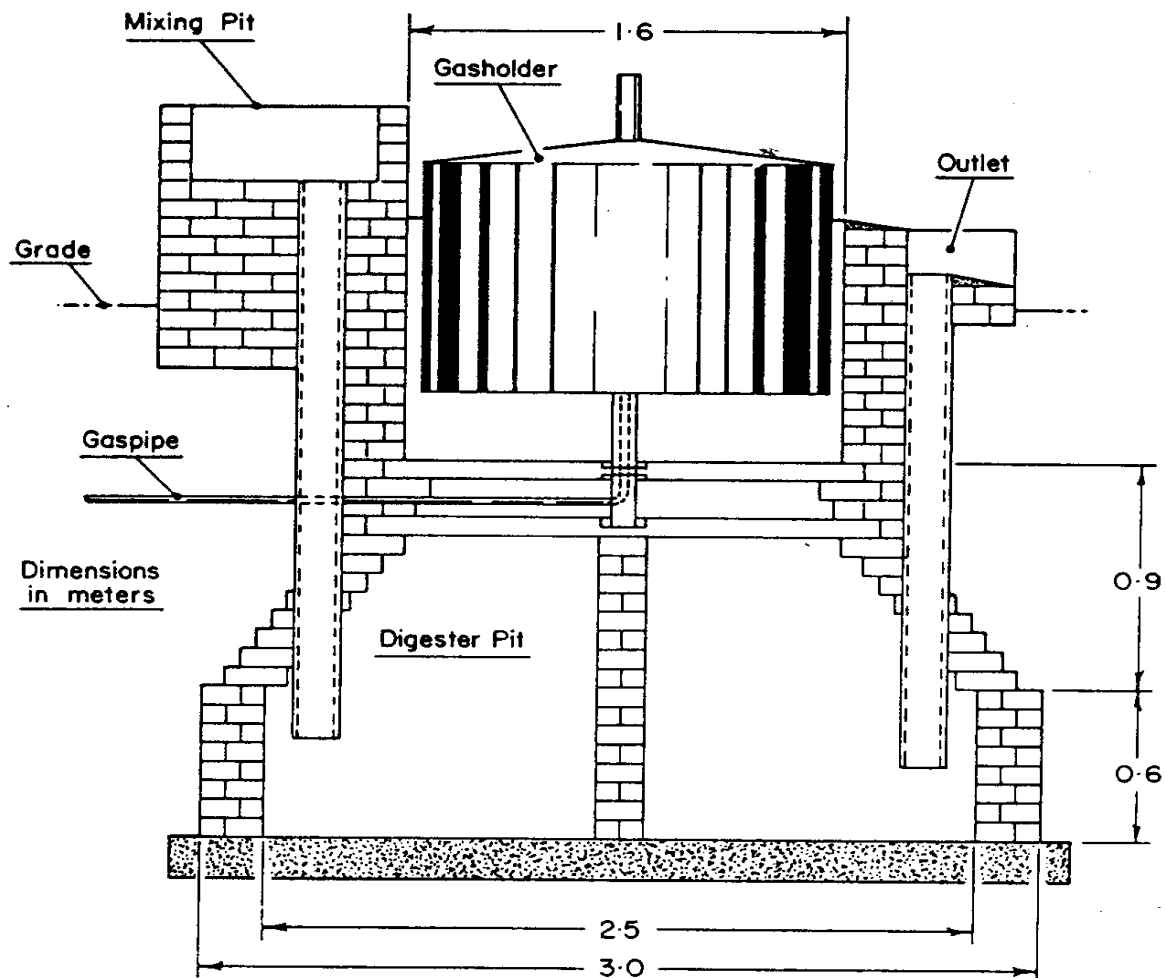


Figure III-3. DCS-straight design

KVIC systems are reliable if properly maintained, although drum corrosion has historically been a major problem. It appears that the quality of steel manufactured in India may have declined during the early 1960s. There are anecdotes of unpainted systems built before then that are still functioning. Drums should be coated once a year with a rustproof bitumin paint. Oil can also be introduced into the top of the digester slurry, effectively coating the steel drum as it rises and falls.

KVIC designs of over 100 [m.sup.3] have been constructed for institutions such as schools, dairies, and prisons. Though construction economies of scale exist for all digesters, the use of mild steel accounts for 40 percent of the system cost. KVIC systems are relatively expensive. The smallest family KVIC system costs well over Rs 4,000 (US\$500) to install. KVIC has experimented

with a number of materials, including plastics, for dome construction. The Structural Engineering Research Center, Rourkee, has done work with ferrocement, reducing costs somewhat. Ferrocement gas holders become extremely heavy as their scale increases, and they require proper curing and a fair amount of manufacturing skill. The curing process requires that domes be either submerged in water for 14 days or else wrapped in water-soaked cloth or jute sacks for 28 days. This raises questions about their use, or at least their fabrication, in many villages. KVIC would like to prefabricate both gas holders and digester sections at regional centers and then transport these out to villages. This would create rural industry and employment, and introduce quality control into the manufacturing process.

Dr. A.K.N. Reddy and his colleagues at the Cell for the Application of Science and Technology to Rural Areas (ASTRA), and the Indian Institute of Science, Bangalore, have modified the KVIC design in several important ways. The result is a shallower, broader digester than the KVIC design. Table III-1 shows some statistical comparisons between the two designs.(38)

ASTRA also examined the retention time for a charge of biomass, given Bangalore climatic conditions, and reduced the 50-day retention period suggested by KVIC to 35 days. It observed that since almost 80 percent of the total amount of gas produced was generated within the shorter time, the increase in digester capacity necessary to more completely digest slurry did not seem justified. Further research on cutting down retention time as a way to reduce system costs may suggest other design modifications. The shorter the retention period, the less digester volume (and hence, lower cost of construction) is required for the storage of the same volume of organic material. As shown in Table III-I, the ASTRA unit, though almost 40 percent cheaper than the KVIC unit, had a 14 percent increase in gas yield. Its improved performance needs to be monitored over time.(39)

Table III-1

Comparison of KVIC and ASTRA designs  
for similar Biogas Plants(40)

	KVIC	ASTRA
Rated daily gas output	5.66	5.66
Gas holder diameter (m)	1.83	2.44
Gas holder height (m)	1.22	0.61
Gas holder volume ([m.sup.3])	3.21	2.85
Digester diameter (m)	1.98	2.59



Digester depth (m)	4.88	2.44
Digester depth-diameter ratio	2.46	0.94
Digester volume ([m.sup.3])	15.02	12.85
Capital cost of plant (Rs)	8,100.00	4,765.00
Relative costs	100.00	58.80
Daily loading (kg fresh dung)	150.00	150.00
Mean temperature (Celsius)	27.60	27.60
Daily gas yield ([m.sup.3]/day)	4.28 [+ or -] 0.47	4.39[+ or -] 0.60
Actual capacity/rated capacity	75.6%	86.4%
Gas yield (cm <sup>3</sup> /g fresh dung)	28.5 [+ or -] 3.2	32.7 [+ or -] 4.0
Improvement in gas yield	--	+14.2%

The ASTRA group conducted a series of tests on existing biogas systems and found that there was uniform slurry temperature and density throughout the digester,(41) and that the heat lost in biogas systems occurs mainly through the gas holder roof. It also found that when the colder-temperature water was mixed with dung to make slurry, the charge shocked the indigenous bacteria and retarded gas production. The result was a 40 percent or more reduction in gas yield.(42)

An important goal thus was to control the temperature of the slurry. This raised a number of problems: maintaining the slurry temperature at the 35 [degrees] C (95 [degrees] F) optimum; heating the daily charge to minimize temperature loss due to colder ambient temperatures; and providing insulation for the floating drum gas holder. ASTRA found an ingenious solution to all these needs. It installed a transparent tent-like solar collector on

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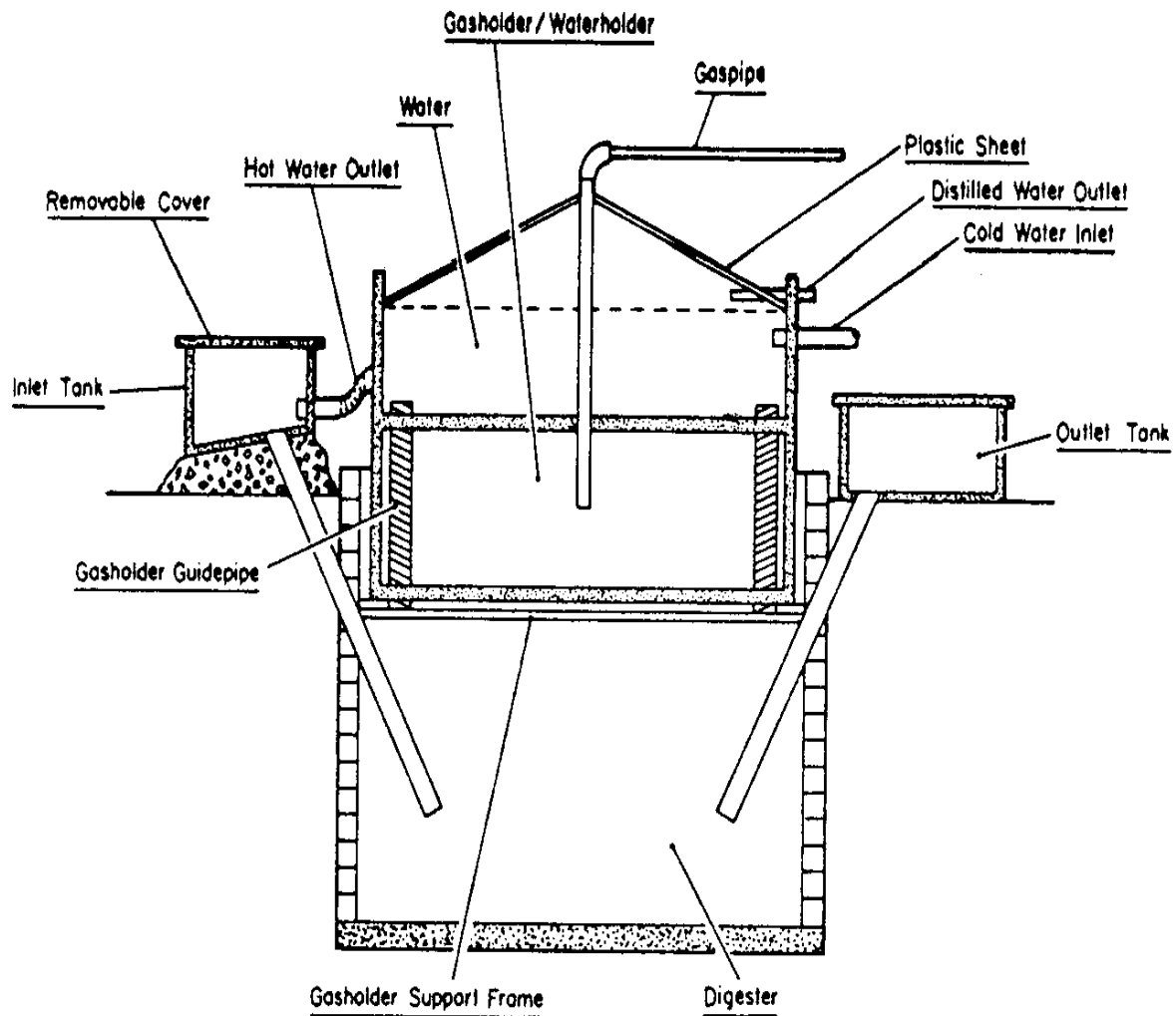


Figure III-4. ASTRA design with solar water heater

top of an ASTRA floating drum gas holder (see Figure III-4).(43)

This was done by modifying the drum design so that its side walls extended up beyond the holder roof, forming a container in which to place water. This water was drawn from the collector, heated by the sun, and mixed with the daily charge of dung. Preliminary data from the 1979 Bangalore rainy season showed an increase in gas yield of about 11 percent with this solar heating system. During this often cloudy period, the temperature of the water in the collector was only 45 [degrees] C (112 [degrees] F) compared with the 60 [degrees] C (140 [degrees] F) temperature recorded during the summer months. More work is needed to improve the cost and performance of this solar heating method, but its potential for reducing system costs seems promising, especially on a village scale. In addition, distilled water can be obtained by collecting the condensate as it runs down the inclined collector roof.

The ASTRA group is constructing a 42.5 [m.sup.3] biogas system in Pura village, Tumkur District, near Bangalore, that eventually will incorporate ferrocement gas holders and solar heating systems, enabling the group to evaluate its ideas in an actual village context. Dr. C. Gupta, Director of the TATA Energy Research Center, Pondicherry, is constructing an ASTRA design biogas system with a community latrine in Ladakh, Jammu and Kashmir State, where the 3,600-meter altitude and chilly winter temperatures will provide valuable data on the performance of this design. Most recently, ASTRA has reportedly constructed a 2.3 [m.sup.3] fixed dome plant for Rs 900 (US\$112). It may be possible to reduce this cost further by experimenting with a compacted earth pit that would be covered by a brick dome. The costs of constructing the brick digester would thereby be eliminated. Such experiments are still quite recent and the data on performance and durability are not yet available. Parts of Karnataka have large, brick-producing activities, and the easy availability of inexpensive bricks may account partially for this low cost. Nevertheless, the potential exists for large reductions in system costs, which could alter dramatically the economics of biogas systems.

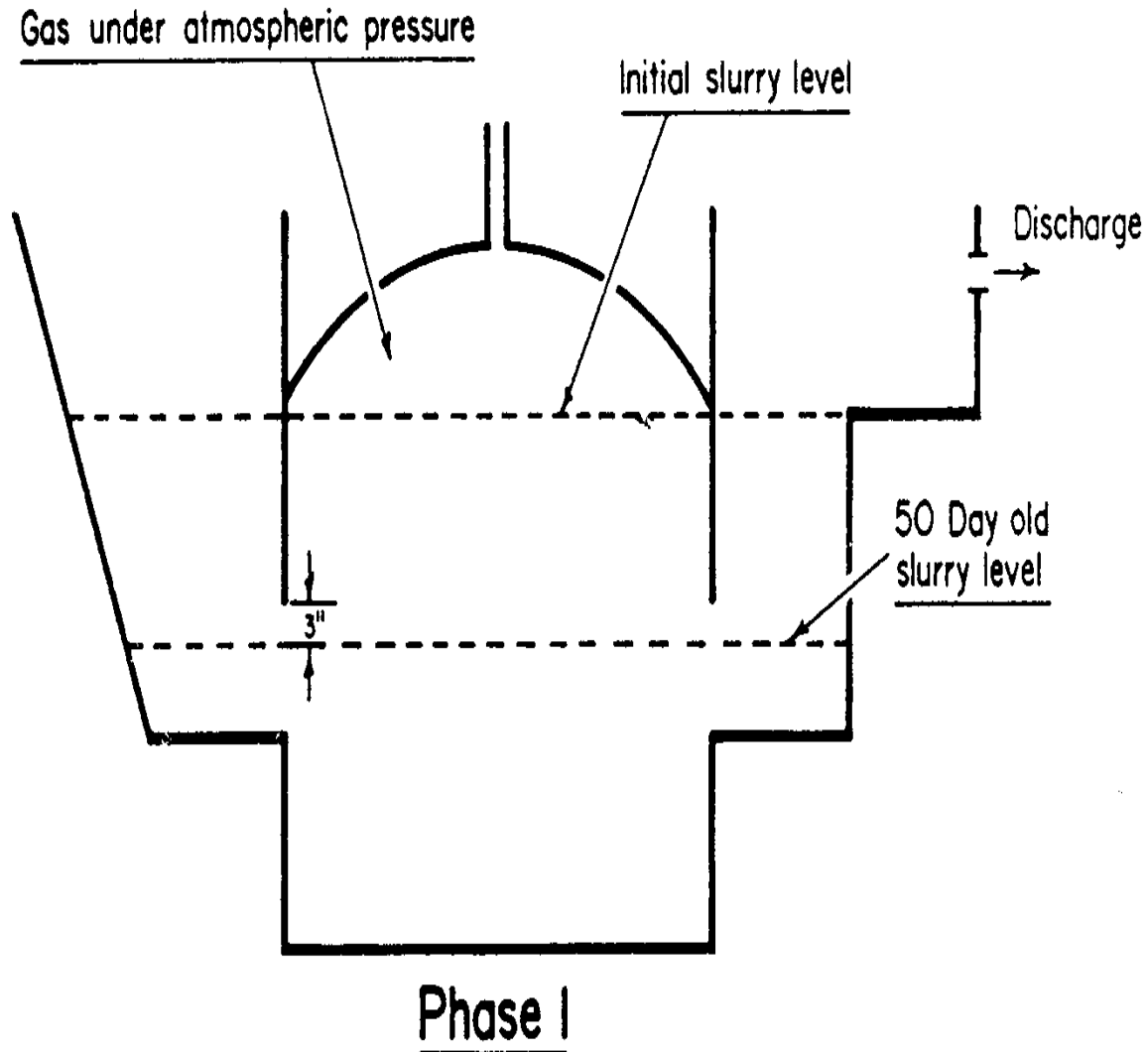
The Planning Research and Action Division (PRAD) of the State Planning Institute, Lucknow, has been conducting biogas research at its Gobar Gas Experimental Station, Ajitmal (near Etawah), Uttar Pradesh, for more than 20 years. PRAD constructed the 80 [m.sup.3] community system in the village of Fateh Singh-Ka-Purva, which will be discussed later in this study. After several years of experimentation with designs modified from the fixed dome systems popular in the People's Republic of China, PRAD developed the "Janata" fixed-dome plant.(44)

The PRAD design has several advantages. A Janata plant system can be built for about two-thirds the cost of a KVIC system of similar capacity, depending on local conditions, prices, and the availability of construction materials. The magnitude of savings due to the all-brick Janata design may diminish with increased capacity, but there is little data regarding large fixed-dome plants. One of the key features of the Janata and other fixed-dome designs is that inlet and outlet tank volumes are calculated to ensure minimum and maximum gas pressures due to the volumes displaced by the changing volumes of both gas and slurry inside the system.

Janata designs are relatively easy to construct and maintain because they have no moving parts and because corrosion is not a problem. One drawback is that Janata plants may require periodic cleaning due to scum build-up. As gas pressure increases in a fixed volume, the pressure pushes some of the slurry out of the digester and back into both the inlet and outlet tanks,

causing the slurry level in each tank to rise. As gas is consumed, the slurry level in the tanks drops and slurry flows

53p250.gif (600x600)



**Figure III-5a. Slurry and pressure levels in Janata design**

back into the digester itself (See Figures III-5a through III-5d). Such movement probably acts as helpful agitation, but the motion may also cause heavier material to settle on the bottom of the digester. The result then is that only the supernatant flows through the system. Such buildup has been reported occasionally, and may result in a gradual accumulation of sludge that could cause clogging.

The more serious problem is posed by the heterogeneous nature of even the most well-mixed influent. Lighter material can form a layer of scum that remains unbroken precisely because the

plants are designed to prevent the slurry level from descending below the top of the inlet and outlet tank openings in the digester, which might allow gas to escape through the tanks. This problem of scum build-up may be more serious in large-scale plants, and may require the installation of stirring devices.

The digester must be cleaned if build-up does occur. Someone must descend into the unit through the outlet tank and scrape out the sludge. The Janata plant has no sealed manhole cover in the dome. This differs from Chinese plants, for which sludge removal is assumed to be a regular part of normal operation. With the Janata plant, extreme caution must be used when entering the digester since concentrated [CH.sub.4] is highly toxic and potentially explosive. The Chinese often test this by lowering a caged bird or small animal into an emptied digester, exposing it to the gases for some time, and then descending only if the animal lives.

More research is needed on the kinetics and fluid dynamics of fixed-dome plants. The ASTRA observation of homogeneous slurry density in the KVIC unit would seem to conflict with some field reports, although poor maintenance and lack of thorough mixing may account for such discrepancies.

An important advantage of Janata plants is that their required construction materials are usually available locally. Lime and mortar can substitute for concrete. Neither steel (which often is scarce) nor ferrocement are needed, which reduces dependence on often unreliable outside manufacturing firms and suppliers. The dome of the Janata plant does require a good deal of skilled masonry, including several layers of plastering, to ensure a leak-proof surface. Many early plants leaked badly. PRAD reports this is no longer a problem due to extensive construction experience and the fact that it has trained many local masons in Uttar Pradesh who can competently construct such units.

Although PRAD recommends constructing a raised platform to support the earthen mound that serves as the form for the construction of the brick dome, the Chinese build brick domes with little or no support scaffolding. It is difficult to learn this technique unless one visits a construction team in China. The few manuals that exist are inadequate in explaining the construction method, often omitting details such as the angle at which bricks should be laid to form the correct arc for the dome, or the number of rings required for bricks of unknown dimensions.

Using some PRAD diagrams and A Chinese Biogas Manual, translated

by the Intermediate Technology Development Group (London, 1980), the author directed the construction of a modified 2 [m.sup.3] Janata plant to be used as an experimental digester at the Indian Institute of Technology, Madras. A free-standing dome was successfully constructed, but the process took three days and required vigilant monitoring of cracks that occasionally began to spread around different areas of the brick rings that formed the dome. The safety of masons working under the emerging dome was cause for some concern. The weight of the partially formed arc sections easily could have proven fatal if someone had been caught underneath a collapsing section. It also was difficult to set the bricks at a proper angle. The dome emerged somewhat misshapen, despite the use of a two-pole system in which one pole defined the vertical axis and the other, equal to the radius of a sphere formed by "extending" the dome, pivoted about a nail. By rotating the vertical pole 360 [degrees] and lining up each brick ring with the angle formed by pivoting the "radius" pole between 45 [degrees] and 135 [degrees] (off the horizontal), the correct dome arc, and hence each brick's proper angle, should have been readily apparent. However, due to the irregular surface of the bricks, the varying amounts of concrete applied to the bricks, and the reluctance of the masons, for whatever reason, to use the device frequently, the dome construction became a matter of educated guesswork.

Given the short time many of the Janata systems have been operating, the possibility still exists that micro-cracks may develop in the dome over several years. The Center for Science for Villages, Wardha, has covered the top of its fixed-dome plants with water so that any leaks will be visible as bubbles. This idea could be further modified to incorporate an ASTRA type solar collector to produce warm water for hot charging. However, one of the additional advantages of the fixed-dome designs is that they are largely underground. This frees the surface land area for alternative use. Improved system performance due to solar heating must be evaluated against other possible uses of the land.

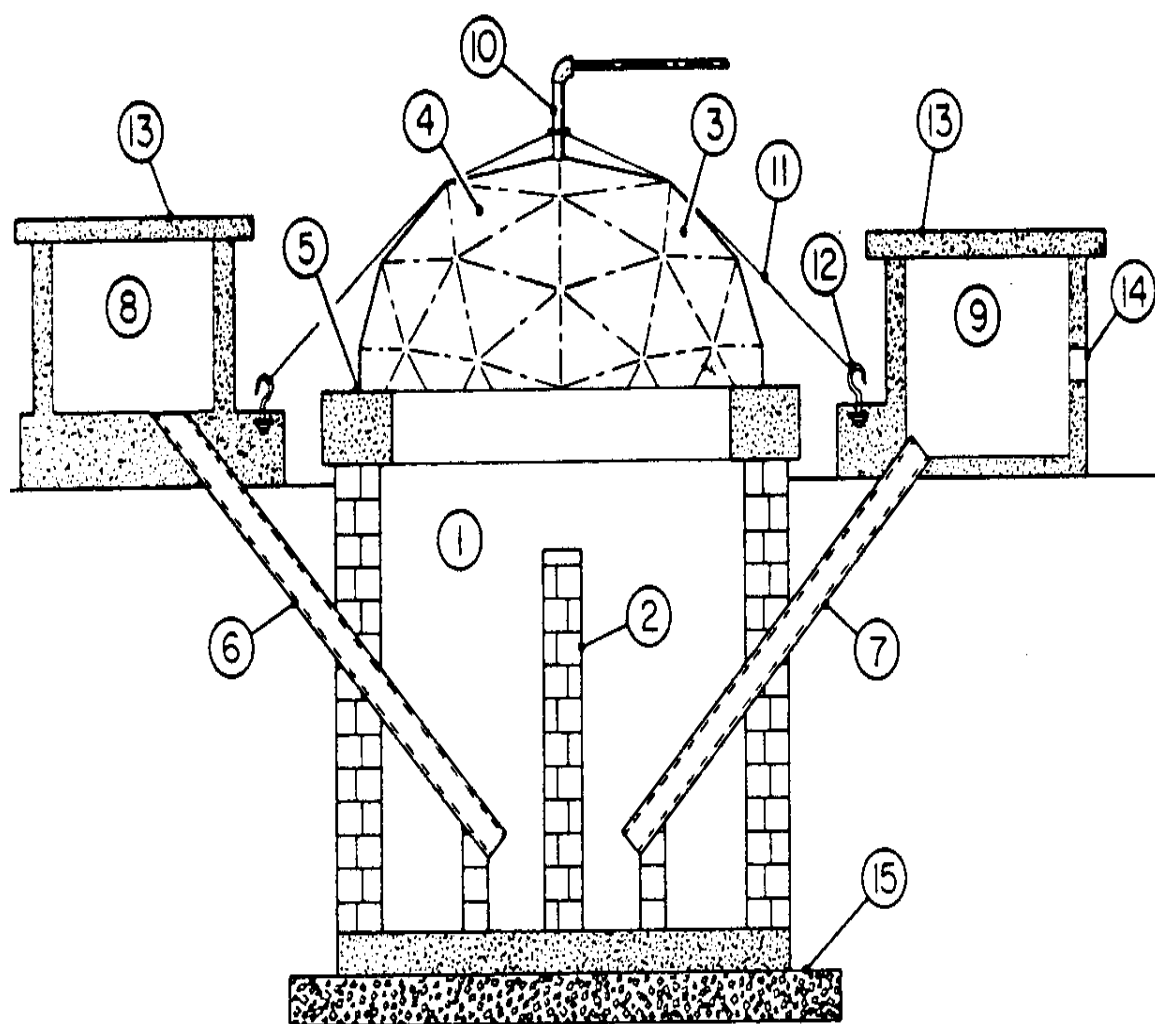
Fixed-dome plants release stored gas at pressures as high as 90 cm (36") of water column. As gas is consumed, and in spite of the changing slurry level, pressures do drop. The amount of gas inside the dome at any time can be estimated crudely by measuring changes in the slurry level in the inlet and outlet tank (as long as the daily charge has settled in the digester).

There is some concern that flame temperatures drop with lower pressures, increasing cooking time and gas consumption. However, there seems to be little complaint from individual users on this point. Minimizing gas consumption during cooking can be of great importance in a village system that requires gas for

uses other than cooking. There are few data on the economic and thermodynamic efficiencies of diesel or petrol engines or of generators powered by a fixed-dome system. Presumably, more diesel would be consumed as pressure drops. Gas pressure regulators have been discussed periodically as a way to alleviate this problem. Regulators can ensure that enough pressure is maintained throughout a distribution system, and that occasional high pressure will not blow out valves or pipe joints. Work is now under way in Sri Lanka near the University of Peradeniya, in Uttar Pradesh, and in Bihar on fixed-dome plants as large as 50 [m.sup.3]. Plants of this size have been reported in China, but little information is available to confirm this. It remains to be seen if cost reductions observed in small-scale, fixed-dome plants will be repeated or even improved with increased scale. Constructing large domes from bricks, or even from ferrocement, may prove difficult and/or expensive since their performance and durability remain a matter of speculation.

Variations on the fixed-dome design have been reported in Taiwan, where heavy gauge collapsible Hypalon/Neoprene bags have been used as digesters.(45) The Sri A.M.M. Murrugappa Chettiar Research Center (MCRC), Madras, has developed a brick digester with a high-density polyethylene gas holder supported

53p30.gif (600x600)



**Figure III-6. MCRC Biogas plant**

by a geodesic frame (see Figure III-6). The frame is bolted to the digester walls, and the plastic gas holder is retained by a water seal. The MCRC plant is still being tested in several Tamil villages and few performance data are available. The plant is less expensive than the PRAD Janata design and has the advantage of being easily and quickly installed. However, major questions remain concerning this design's durability and safety. Only small-scale systems have been constructed, although larger systems are planned.(46)

Development and Consulting Services (DCS) of the Butwal Technical Institute, Butwal, Nepal, has begun field testing a horizontal plug-flow digester design based on the work of Dr. William Jewell of Cornell University (USA). A long, shallow, horizontal system might require less water, be less susceptible to scum formation and clogging, and foster greater gas production.



A plug-flow system should be easier to clean, and would require less excavation, helping to reduce costs. This system has great promise; a prototype should be developed within a year.(47)

The Jyoti Solar Energy Institute, Vallabh Vidynagar, Gujarat (near Anand), has done some interesting design work in conjunction with the research on agricultural residues discussed earlier. JSEI researchers found that a scum layer was forming in experimental digesters that were fed with banana stems, water hyacinth, and eucalyptus leaves. This layer gradually reduced gas production to almost zero. The researchers concluded that the scum layer formed because the fresh biomass contained a good deal of oxygen between its cell walls. Since the shredded sections were lighter than the water they displaced, the biomass tended to float to the surface of the slurry. During experimental batch feeding, this scum layer was observed to sink gradually to the digester floor as digestion progressed. The scum layer that has troubled many of the digesters used for agricultural residues seems to form when fresh biomass, entering at the bottom of the digester, pushes up against heavier, older biomass that is settling toward the digester floor. The lighter biomass causes the heavier layer to rise, creating the thick scum layer. JSEI engineers devised an ingenious system of loading fresh biomass through the top of the gas holder to the surface of the slurry by means of a plunger arrangement (see

53p31.gif (600x600)

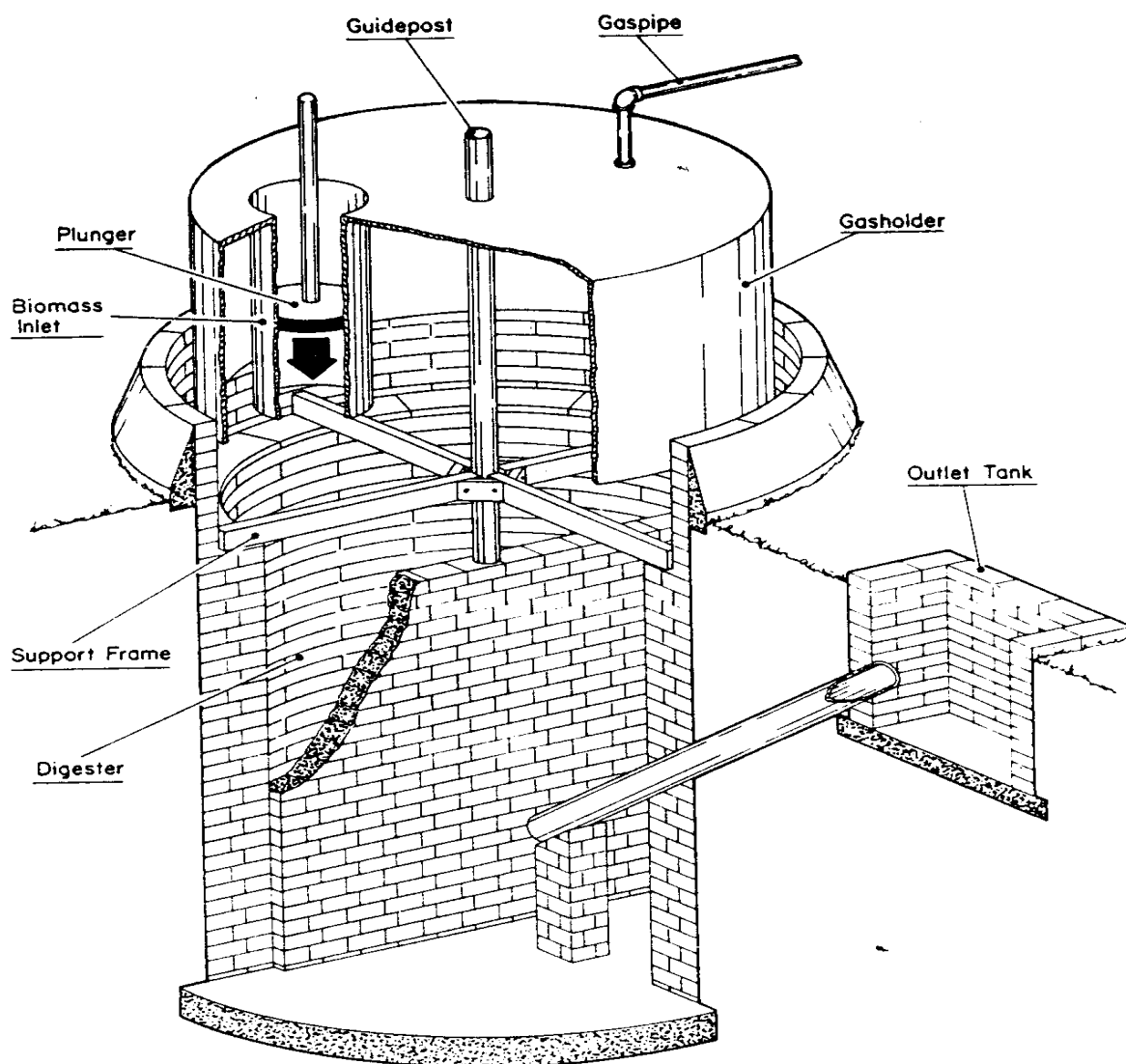


Figure III-7. JYOTI - Top loaded digester

Figure III-7). This ensures that the heavier, partially digested material settles to the digester floor unimpeded by the lighter biomass. The JSEI innovation could be an important breakthrough in the use of agricultural and forest residues in biogas systems. In addition to solving the problem of scum build-up, the JSEI technique also seems to eliminate the necessity of excessive shredding or drying of residues, making the handling of these materials far less cumbersome and time-consuming. Biomass is merely chopped into 2-3 cm (.75-1.25") squares and then is pushed into the digester through a cylindrical tube inserted into the floating gas holder. The tube is always in contact with the slurry, even with the dome at maximum height, so that no gas can escape.

There remain a number of questions concerning the relative performance of fixed-dome plants versus floating drum plants.

Conflicting data have been reported concerning equipment life, material durability, gas production, delivered gas pressure, and installation and maintenance costs. The Department of Science and Technology has established five regional testing centers where different designs of similar capacity are being monitored under symmetrical, controlled conditions in different agro-climatic regions. One such station visited by the author, in Gandhigram, Tamil Nadu, appears to have insufficient resources to assess accurately the performance of the different biogas systems that have been constructed. More rigorous comparative research on fixed-dome plants is needed, especially after further design improvements, such as those done by ASTRA, are completed. The effects of agitation, digester wall protrusions, and partition walls to improve gas yield need to be analyzed in different digester designs. It is not yet clear if the cost advantages of fixed-dome digesters outweigh the performance advantages of floating-drum digesters. This may be a function of the uses of the gas in a particular village, which determines the relative importance of providing gas at a constant pressure and the effectiveness and cost of pressure regulators currently under development. More research is needed before any conclusions can be made.

There are numerous experimental digesters with modifications of the designs described in the preceeding discussion. MCRC is planning to link its biogas plants with other biotechnology projects, such as pisciculture, algae growth, and organic farming. The Indian Institute of Technology - Delhi Center for Rural Development and Appropriate Technology is developing a system that will grow algae in the supernatant of a fixed-dome system. It will recycle the algae to supplement the daily raw material charge. The system will provide fertilizer, gas, oxygenated water for irrigation, and animal nutrients such as single cell proteins for fodder.(48) The idea is to generate the maximum yield per unit of local resources. Integrated systems have a great deal of potential, although their often elegant simplicity requires a great deal of skilled operation and effective maintenance.

#### IV. System Operation

The appropriate role of a biogas system in producing heat, light, refrigeration, and motive power can be determined after end-use energy requirements over time have been assessed carefully, including any anticipated demand from population growth. The system's capacity should be based on a careful analysis of costs, local climate and soil conditions, and the net availability of biomass. This latter consideration must account for competing uses of crop wastes and dung, animal diet, grazing

habits, difficulty of biomass collection, and the availability of labor. Also, the probabilities of the survey data remaining constant over time must be assessed.

Many family-sized systems have been designed with insufficient capacity to produce gas when it is needed at different times during the day or year. In India's colder northern climates, the drop in gas production during winter often has been underestimated. Great care should be exercised in preparing plant feasibility studies so that different contingencies can be accommodated without disrupting the operation of the system. For example, farmers often sell cattle during droughts (if the cattle survive), and this obviously reduces dung availability. Baseline surveys of available biomass can be distorted if conducted during periods of exceptionally good harvests or failed monsoons.

It probably is wise to build two or more medium-size plants in a village rather than one large plant, even though the total cost may increase. If problems or maintenance force a temporary shutdown in one of the digesters, the entire system will not be disrupted. If small-scale, fixed-dome system costs can be reduced to around Rs 400-500 (US\$50-62), which does not seem impossible, clusters of small systems might be a more cost-effective way to provide energy than one large system. Some of the complexities of planning village energy systems are discussed in the following section on the economic analysis of biogas systems.(49)

Biogas plants require certain care during their initial starting up or "charging." If a digester contains a partition wall, slurry must be added from both the inlet and outlet tanks to

This chapter presents certain points that are not usually covered in discussions about biogas systems. The author recommends John Finlay's *Operation and Maintenance of Gobar Gas Plants*[N] (1978) for a more complete description of how biogas systems operate.

equalize pressure and prevent collapse of the wall. While not essential, introducing either composted manure or digested slurry as seed material to the digester will speed up the initial charging. There is some disagreement over how best to start up a plant. One suggestion is to fill the digester as rapidly as possible until the outlet tank begins to overflow,(50) ensuring that the seed material is twice the volume of the fresh biomass initially fed into the system. Another is to increase gradually over a three-week period the amount of biomass mass introduced daily to the system.(51) The inlet and outlet tanks are then covered and digestion begins.

The plant should begin producing gas within 7-20 days, depending on temperature, agitation, etc. This initial gas is largely [CO.sub.2] and should be released into the atmosphere; it will burn poorly, if at all. This step may have to be repeated. Within a month after charging, however, the system usually will have developed a kind of critical mass of bacteria that is stable enough to digest the daily biomass charge and produce gas.

Care should be taken to ensure that the biomass fed into the system is relatively free from sand, gravel, and coarse fibers. Many inlet tanks have a floor that slopes away from the opening through which material flows into the digester. The opening is blocked during slurry mixing and the slurry is allowed to settle for several minutes. The plug is then removed and, as the slurry drains into the digester, heavier sediments and foreign matter collect at the lower end of the sloped inlet tank floor. This material can be removed after the slurry has drained into the digester. Material should be mixed thoroughly. Shredders, screens, and mixing devices may be required for village scale systems that handle a large amount of different raw materials. These precautions are recommended to reduce the chances of the digester becoming clogged in either the inlet or outlet tanks, or of having a scum layer form in the digester itself. More research is needed to understand the sensitivity of biogas systems to variations in the biomass charge. Similarly, ideal rates of loading different materials at different temperatures need to be determined. Many of the guidelines for operating biogas systems are based on trial and error observation in the field. The systems work, but their efficiency could be increased and their costs reduced.

Systems should be built in a sunny area to take advantage of solar radiation. They should be at least 5-10 meters from a source of drinking water sources, especially if human wastes are used. This is particularly important with large-scale systems, which could represent concentrated sources of enteric (intestinal) pathogens if they leak. Adequate space should be provided for raw material and water-mixing as well as for slurry handling and storage. Land and water requirements are a critical and often underemphasized part of a biogas system.

Care must be taken to minimize water condensation in the gas lines (possibly by including water traps), isolate sparks and flames from the gas lines (by including flame traps), and prevent pipe freezing in winter. Provision must be made for frequent inspection and maintenance of the system (including pipelines). There also must be proper handling of the slurry to conserve nutrients and minimize contact with pathogens in both the influent and effluent.

If a biogas system is not performing as it should, the following trouble-shooting sequence is suggested.(52)

1. Check temperature of the influent mixture. Sudden cooling of the slurry in the digester can impede microbiological digestion. Temperature variations should be kept to a minimum.
2. Check loading rate of organic materials. Overloading will cause material to flow out of the digester before the slurry has been digested.
3. Check pH levels, which may drop below the 6.0-7.0 minimum. Add lime to increase the pH level, if necessary.
4. Check for toxic material in the influent, and alter the composition of materials - mixed in the slurry.

Whenever daily feeding procedures are altered, the change should be introduced gradually so that the microbial population has time to adjust to the new environment.

## V. Gas Distribution and Use

Gas distribution systems can cost from several hundred rupees for a family system to as much as three/fourths the total cost of a village scale digester (exclusive of pumpsets, engines, generators, etc.). Distribution costs can offset the scale economies of larger digesters. The distribution system in a particular village will be determined by local conditions, e.g., the distance between the points to which the gas must be distributed (houses, pumpsets, or industries), the availability of organic material, the difficulty of collection, and the availability and cost of construction materials.

Because the gas is usually released from a floating drum holder at a pressure of less than 20 cm of water column, the total length of the distribution pipeline is probably limited to less than 2 kilometers unless booster pumps are used, which increases costs. As delivery pressure decreases with pipeline distance, the flame velocity gradually becomes too low to support a stable flame. Similarly, pumpsets for biogas that are too far from the digester will require either an expensive pipeline, a gas storage vessel/bag of some sort, or possible conversion of the biogas to electricity.

Many different materials have been used in constructing pipelines, such as GI pipe and PVC or HDP plastics. It would seem possible to use clay or earthen pipe as well. Problems of gas leaks, durability, and rodent damage vary with material characteristics

and care in construction. Generally, plastic pipes with a diameter greater than 35 mm seem best for cost optimization, ease of construction, and favorable friction characteristics to aid in gas flow.(53) The availability of large quantities of plastic piping may be a problem in certain locales.

One way to reduce the cost of pipelines might be to use the same pipeline for delivering drinking or irrigation water as well as gas.(54) Water condensation in the pipeline would have to be monitored carefully, as would any possible health hazards.

There are several descriptive accounts from China and Sri Lanka of using bags to store and transport gas to run pumpsets and tractors, and possibly to meet household cooking and lighting needs.(55) Kirloskar Oil Engines, Limited, is experimenting with a rayon-coated rubber bag that has enough capacity to power a 5 hp pumpset for two hours. It would cost approximately Rs 500 (US\$40). The general problem with such bags is that they must be large enough to enable the gas to be released at the 10-12 cm water column pressure that is required for stove or engine use. Unless compressed in some way, a bag to provide enough gas for the daily cooking and gas requirements for a single family would have to be almost as big as the hut to which it was attached. In addition, the safety and durability of such a system are debatable, given the rigors of village use and the susceptibility of such a system to vandalism. Despite the presence of [CO.sub.2] in biogas, puncturing a bag in the vicinity of a flame could cause a large fire. The danger is magnified if the gas is purified by bubbling it through time to increase its calorific value.

Nonetheless, a centralized delivery scheme where a few "regional" pipelines are laid near clusters of huts, and from which individual consumers fill their own storage bags, might have certain advantages. It may ultimately be cheaper than a full-scale pipeline system. It could expand easily if demand increased, and would free families from being restricted to using gas only during certain times of the day. Most community systems have several uses for gas and deliver gas only during fixed times of peak demand, especially during morning and evening cooking periods. This staggered delivery is designed to minimize gas waste, but can be inconvenient for villagers, who occasionally have to work during the time gas is delivered in their area.(56) A decentralized "gas bag" system might facilitate plant management and the easy monitoring of gas consumption. It might also allow for more efficient use of the gas. There are problems with this concept, but it has not yet received adequate attention from biogas system designers.

The costs of pressurized biogas cylinders, similar to Liquid

Propane Gas (LPG), seem prohibitive. Biogas can only be liquified at -83 [degrees] C (-117 [degrees] F) and at a pressure of approximately 3.2 meters of water column. Reddy has estimated that such a gas cylinder system could almost double the cost of a pipeline in Pura village.(57) It is doubtful that individual families would have sufficient capital to purchase cylinders (Rs 300-700/cylinder). However, this concept should not be completely dismissed. The revenue-generating potential of a large-scale biomass system might justify an investment in a pressurized gas cylinder system. The compressor itself could be powered by the biogas system.

Using biogas for cooking is more complicated than the literature suggests. KVIC (1980), Finlay (1978), National Academy of Sciences (1977), Bhatia (1977), the Indian Council of Scientific and Industrial Research (1976), and Parikh and Parikh (1979) all suggest that gas requirements for cooking vary between 0.2 and 0.4 [m<sup>3</sup>]/person/day, although some anecdotal field reports suggest that these figures may be high.(58)

The difficulty in establishing norms for gas required for cooking is due to our scanty knowledge of rural cooking habits. The key to formulating cooking norms is to determine the usable or net energy used by a family to prepare meals. There are several levels of analysis needed to generalize about net available cooking energy. Diet varies regionally according to climate, custom, income, etc. Even the quality (calorific value) of identical fuel sources, such as firewood, varies regionally. Finally, the efficiencies of stoves (often a group of stoves), and consequently the thermal efficiencies of different fuels, are also highly variable.

A detailed investigation of these variables would begin to shed some light on village cooking needs. These are more difficult to determine than the cooking needs of a wealthier farmer, who is the most likely consumer of a family-sized biogas plant, and on whom data do exist. At the moment, there is no accurate way to generalize about the gas required for village cooking. KVIC did attempt to generate data on the calorific value, thermal efficiency, and "effective heat" of different fuels,(59) but no description of its methodology is included in its report. It also assigned calorific values of biogas and wood, which conflict with other analyses, thus leaving KVIC information open to question.

Gas requirements for cooking can affect significantly the performance and economic viability of a village system, depending on competing uses for the gas. This is especially true if non-cooking uses of biogas are a source of revenue. More research and development are needed on cooking burners, stoves, and



cooking vessels (and on their heat conducting properties), which collectively affect the efficiency of gas consumption. The relative system efficiencies of metal and terracotta cookware need to be analyzed. Though metal is a better conductor of heat, it also cools faster. Terracotta vessels take longer to heat yet they retain their heat. Rice cooked in terracotta vessels often is cooked only until half-done. The vessel is then removed from the fire, and the remainder of the cooking is done with the heat that radiates from the walls of the terracotta vessel. This is why both energy consumption and cooking costs need to be analyzed with respect to cooking systems, i.e., the fabrication of all utensils, their collective thermal properties, the costs of the various components (energy source, stove, vessel) over their useful lives, and the nature of the foods or liquids being heated.

The Gas Crafters' iron burner recommended by KVIC costs Rs 100. Though "rated" at 60 percent efficiency, there have been complaints about its air valve becoming clogged with fat and oil, and that not all cooking vessels rest upon it equally well. Developing and Consulting Services, Butwal, Nepal, claims to have both improved this design and reduced its cost to Rs 80.(60) There have been other attempts by the Gandhigram Trust and PRAD to develop simple ceramic burners for as little as Rs 20, but these are still experimental and little is known about their performance or durability. There are many photographs of a variety of ceramic, bamboo, and stone-filled tin can burner designs from China,(61) but again, no performance, durability, or cost data exist. The stove used for cooking with biogas may itself have to be modified to achieve maximum efficiency. The Chinese often seem to set their cooking vessels on top of simple burners in deep stoves that surround the vessels, thereby using heat more efficiently.(62)

Social or cultural factors must be considered when designing a distribution system. The flame properties of biogas make burners difficult to light unless a cooking vessel is resting on the burner prior to lighting the gas. This can conflict with certain religious ceremonies that reverse the procedure as part of the need to show reverence toward fire.(63) Village cooking requirements may be significantly affected by season. In many areas, when labor demand increases during harvesting and planting, groups of workers are fed at staggered times throughout the day. During these peak times, stoves often are kept hot all day for as long as two months of the year. Such increases in cooking energy requirements need to be studied by anyone involved with the establishment of a village system.

The decision to use gas directly for lighting gas lamps, as opposed to running a diesel generator to produce electricity

for electric lights, depends on the local demand for electricity. Ghate found that while electric lighting consumed less gas than direct gas lighting, gas lamps are far cheaper in terms of cost per delivered candle power. Electric lights are brighter and more reliable than gas lamps. Roughly .13 [m.sup.3]/hr of gas is needed to energize one gas lamp. Slightly less gas is needed for electric lighting, depending on the generator output.(64) Ghate admits that his data are open to question and that the high cost of electric lighting might make sense if a generator also was used for other operations.

Biogas has been used successfully to power all types of internal combustion engines. This raises the technical possibility of biogas providing energy for rural agriculture as well as for industrial machinery and transportation. There are various reports of tractors powered by methane stored in huge bags towed behind the tractor. The practicality and economics of such a scheme are open to question, given little hard data. Stationary motive power for operating pumpsets, milling and grinding operations, refrigerators, threshers, chaffers, and generators, etc., seems to be a more appropriate match between energy source and end-use demand. Petrol engines have been run solely on biogas by the KVIC, several of the Indian Institutes of Technology, and PRAD, among others. Since most agricultural engines are diesel powered, the remainder of this discussion will be confined to biogas-diesel (dual fuel) engine operation. The use of biogas in engines could be of great importance to rural development projects, providing motive power to areas where the availability or cost of commercial energy (diesel fuel or electricity) has precluded mechanized activities.

A diesel engine carburetor is easily modified to accommodate biogas. The necessary conversion skills and materials exist in most villages. Kirloskar Oil and Engines, Limited has marketed dual fuel biogas-diesel engines for several years at a price roughly Rs 600 more than regular diesel engines. Their line features a modified carburetor and a grooved head for swirling the biogas, which was found to improve performance. Kirloskar does not sell the carburetor separately. The firm encourages farmers to consider "the option" when they purchase a new engine. Kirloskar engineers report that good engine performance occurs with a biogas to diesel mixture of 4:1, which works out to .42 [m.sup.3] of biogas per BHP/hr.(65) In actual operation, the ratio may exceed 9:1. The mixture is regulated by a governor that reduces the amount of diesel flow as more gas is introduced, keeping power output constant. There is an observed drop in the engine's thermal efficiency with greater gas consumption. However, research at IIT-Madras has shown that this may be due to the leanness of the biogas mixture. Reducing incoming air improves performance except at full power output. Generally,

efficiency increases with power output.(66) The gas should be delivered to the engine at a pressure of 2.57-7.62 cm water column.(67) Removal of [CO.sub.2] also improves engine performance.

Biogas makes engines run hotter, and therefore proper cooling is important. Biogas slurry should not be used to cool engines since the suspended solids can clog the cooling mechanism and act as an insulator, thereby trapping heat. Air-cooled engines must be used if slurry is mixed with irrigation water that normally would be used as a coolant.

There is little available data on the potentially corrosive effects of the [H.sub.2]S present in biogas, although engines have been run for some time with no reported corrosion. Iron filings can be used to filter out [H.sub.2]S. In addition to the reduced operating costs for fuel engines, removing [H.sub.2]S has produced the following benefits:

1. Reduced emission of CO.
- 0 2. Increased engine life (up to four times normal life).
3. At least a 50 percent reduction in maintenance costs due to longer life of lubrication oil. Freedom from gum, carbon, and lead deposits.
4. Lower idling speed and immediate power response.(68)

When energy conversion efficiency losses are calculated for diesel generators, roughly 1 kwh is generated for every 0.56 [m.sup.3] of biogas. A 15-KVA diesel generator (12 kw) running two 3.75 kw electric pumps (5 hp) for eight hours a day would require almost 53.8 [m.sup.3]/day, compared to 33.6 [m.sup.3] if the pumps were powered with dual fuel engines. This is because of the difficulty of finding electrical generators that are matched exactly to peak power requirements.

### Slurry Use and Handling

The effluent from a biogas plant can be either sludge, supernatant, or slurry depending on the design and operation of the system. Most Indian systems have slurry as their output. The remainder of this discussion pertains to slurry that is formed primarily by mixing dung and water, although it probably applies to any digested biomass.

The main advantage of anaerobic digestion is that it conserves nitrogen if the slurry is handled properly. Though approximately 20 percent of the total solids contained in the organic

material are lost during the digestion process, the nitrogen content remains largely unchanged. The nitrogen is in the form of ammonia, which makes it more accessible when the effluent is used as fertilizer. Aerobic digestion, on the other hand, produces nitrates and nitrites. These are likely to leach away in the soil, do not become as readily fixed to clay and humus, and are not as easily used by water-borne algae.(69) Bhatia cites earlier observations that the amount of ammoniated nitrogen increases to almost 50 percent of the total nitrogen content of anaerobically digested dung, as compared to 26 percent in fresh dung.(70)

The quality of organic manures is greatly affected by handling and storage methods. Table V-1 shows nitrogen loss related to storage time.

Biogas slurry can be handled in any of the following ways, with the choice depending on both cost and convenience:

1. Semi-dried in pits and carried/transported to the fields.
2. Mixed with cattle bedding or other organic straw in pits to absorb slurry, and then transported to the fields.
3. If a high water table exists and (1) or (2) are done, then the "reformed" slurry that has been mixed with ground water can be lifted out of the pit in buckets and dried further.
4. Applied directly to fields with irrigation water or through aerial spraying.(72)

Table V-1(71)

Nitrogen Lost Due to Heat and Volatilization  
in Farmyard Manure (FYM) and Biogas Slurry

Manure	Loss as Percentage of Total N
FYM applied to fields immediately	0
FYM piled for 2 days before application	20
FYM piled for 14 days before application	45
FYM piled 30 days	50
Biogas slurry applied immediately	0
Biogas slurry (dried)	15

Biogas slurry can be a problem to store and transport, depending on local land use, the amount of effluent produced daily, the distance from the digester to the fields, and the willingness of workers to handle slurry and deliver it to either household pits or fields. There may be some merit to evaporating the water from the slurry, thereby reducing storage space requirements, and then recycling the water back into the biogas system. This should aid the digestion process, facilitate slurry handling, and reduce net water consumption.

The following are additional benefits of using biogas slurry:

- \* Potentially decreasing the incidence of plant pathogens and insects in succeeding crops.(73)
- \* Speeding the composting process by using additional organic materials that can be added to a compost pit.
- \* Reducing the presence of odor, white ants, flies, mosquitoes, and weed seeds in the compost pits.
- \* Making it difficult to steal manure.(74)

It is necessary to compare the nutrient content of biogas slurry with that of other composting methods to determine the best use of resources and evaluate alternative investments. A well-managed compost pit may yield manure that is only marginally inferior to that from a biogas system. The cost of a biogas system must be compared with the utility of its effluent. There is a great deal of confusing literature on the subject, which analyzes fertilizer contents, handling, and application methods. More scientific research in this area is needed so that accurate comparisons between different composting methods can be made.

The most practical and perhaps most useful kind of research would be to study field conditions by applying chemical fertilizers, composted manures, and digested slurry to experimental plots and carefully monitoring the crop yields for each group. There have been reports from China indicating that use of biogas slurry increases crop yields 10-27 percent per hectare compared areas that receive manure that is aerobically composted.(75) Unfortunately, and as is the case with much of the literature on the Chinese experience, there is insufficient data to substantiate descriptive reports. In any case, care should be taken to ensure that handling and application techniques follow exactly either those methods currently in use in villages or those that could easily be adopted by villagers. Too often, the laboratory tells us nothing about actual practice

in the field.

## VI. Economic Analysis of a Village System

Numerous articles and books, have attempted to examine the economics of biogas systems.(76) Most of these analyses have been concerned with family-scale systems, hypothetical village systems, or the Fateh Singh-Ka-Purva system in Uttar Pradesh.

Often the conclusions of these studies are based on certain critical assumptions over which, not surprisingly, there is considerable disagreement. These assumptions range from values assigned to capital and annual costs, calorific values for fuels, and thermal efficiencies, to per capita energy consumption, market prices, and the opportunity costs of labor, energy, organic residues, and capital. The nutrient content and end-uses of different organic materials also are subject to debate.(77)

It is beyond the scope of this study to untangle these disagreements. Many of them are due to our limited knowledge of rural life. Others are rooted in basic disagreements over "correct" economic theory, which sometimes approach the level of a theological dispute or metaphysical debate in which one either "believes" or "does not believe." This is especially true in the cases of social rates of discount and opportunity costs. Such questions employ many economists, and it is unlikely that the following discussions will either threaten those positions or reconcile such divergent opinions.

Many economic studies attempt to assess the overall impact of the large-scale adoption of biogas plants. These include the costs and benefits to society as a whole, as well as the macro-level resource demands for steel, cement, manpower, and other factors required for a massive biogas program. Such analysis is valuable when the range of costs and benefits of individual and village systems is known. However, this range cannot be determined accurately at the present time because so little is known about rural energy consumption patterns.

The analysis presented here has the relatively modest objective of assessing the performance of a particular biogas system in a particular village. It studies a large village-scale system. Such systems have been more exhaustively analyzed than small family plants, and also hold more promise for realistically meeting the energy needs of the rural poor. Two measures of performance will be examined.

1. The net impact of the biogas system on the village economy as a whole, determined by the net present value (NPV) of quantifiable annual benefits minus costs. NPV measures the

value of future benefits and costs and discounts them back to the present using a given interest rate.

2. The ability of the biogas system to bring in enough revenue to ensure its self-sufficient operation. This is measured in terms of an undiscounted payback period derived from annual income minus annual capital and operating expenditures.

These two performance measurements are useful in determining if the village "product" is increased as a result of the introduction of the system and if the system can pay for itself. Four limits to these measurements require further discussion.

1. There are serious shortcomings to such social benefit-cost analyses due to the difficulty of quantifying many of the effects of a project.(78) For example, some important values pertaining to this study are difficult to measure:
  - \* Labor freed from gathering firewood or other fuels, and from cooking meals. The greater amount of useful energy from biogas could reduce the time required for cooking by one-half to two-thirds.
  - \* Decreased incidence of eye and lung diseases and irritations, improved cleanliness in the kitchen, and greater ease in cleaning cooking utensils due to the clean burning biogas. This is in sharp contrast to chulahs, which spread smoke and carbon deposits throughout the kitchen area.
  - \* The improved quality and quantity of food consumed due to crop yields that are increased because energy is available for water pumping, and because the nutrient and humus content of the slurry make it a better fertilizer than that derived from traditional village composting methods.
  - \* Freeing manure piles from white ants, weed seed, and odor, and making the manure more difficult to steal due to its semi-liquid state. Theft of manure has been a problem in some villages where the manure is scarcer than in the village under study here.
  - \* Effects of better lighting on education by creating more time for reading and study, on the possible reduction in birth rates, and on increased equality among villagers because prestigious electric lighting is available to all.
  - \* The increased sense of confidence and self-reliance that a successful biogas system might instill in the villagers, with the long-term potential for greater intra-village cooperation, innovation and invention, and employment

generation and investment.

- \* Changes in the demand for various resources such as fossil fuels, chemical fertilizers, etc., and some secondary effects associated with these changes such as foreign exchange requirements, release of atmospheric hydrocarbons, rate of soil depletion, and deforestation. Overall soil quality might increase if large quantities of biogas slurry, which is rich in nitrogen and humus, were spread over the fields.
- \* Development of rural industries that require a cheap, dependable energy supply, such as biogas.
- \* Impact of the system on the village distribution of income, which may vary according to income, cattle, and land ownership.

All of these important effects are excluded from the analysis because of the difficulty of assigning a cardinal value to them. This results in lost data and will distort the cost and benefit calculations.

2. Net present value (NPV) calculations suffer from a number of theoretical limitations, the most serious being the inability of an NPV figure to represent fully the real utility of a project. Certainly, a negative or zero NPV indicates that a project is not worth pursuing. However, a positive NPV, even if quite large, does not necessarily imply that a project should be implemented. The NPV of a particular project must be evaluated along with the NPV of all other projects that could be implemented with the same factor inputs of natural resources, labor, and capital. However, these other projects may or may not achieve similar goals. The criteria used to select projects may themselves vary according to the perceived priority of the goals. This often depends on who is doing the perceiving. A landless peasant, a block development officer, or a social scientist all may have quite different ideas about the needs of the poor. Such are the methodological and political complexities of determining the best use of resources. This problem is fundamental to development planning.
3. Even if one project stands out among many as having the greatest NPV, this tells us nothing about the critical problems of cash flow and access to capital. The inclusion of cash flow and payback data in the economic analysis that follows is presented to help remedy this deficiency. However, even a project that seems financially viable is not automatically guaranteed access to capital. Local and



national politics, lending institutions' perceptions of the project's risks, and/or government perception of a project's importance (which affects a variety of possible incentives such as price controls, subsidies, loan guarantees, taxes, compulsory legislation, etc.) dramatically influence a project's financial viability. The problem of access to capital is excluded from the analysis.

4. All prices used in these calculations are market prices, which are affected by the performance of the larger economy --inflation, material availability, infrastructure performance, government price setting, etc. Shadow price calculations do not alter the fact that benefits and costs will occur within the prevailing economic context. These benefits and costs may be subjected to many political and economic distortions. Thus, any analytical framework for assessing the project may well distort the "real" impact of the project. On the other hand, while reliance on prevailing prices and rates of discount may reduce the precision of the following analysis, it does account for the actual market constraints that a village biogas system would face, defining minimal performance requirements.

The village system discussed in the following analysis is being constructed by the ASTRA group in Pura Village. It will incorporate advanced design features and be self-supporting in terms of its annual operating costs. (The Karnataka State Government is providing the capital investment.) The data base for the analysis is obtained from A.K.N. Reddy, et al., A Community Biogas System for Pura Village (1979).

ASTRA has provided information on Pura village and cattle population, cooking needs, dung availability, and some of the biogas system component costs. Unfortunately, much of the actual data necessary for an accurate analysis are simply not available. All estimates and assumptions are explained in detail and are the sole responsibility of the author, who is grateful to Dr. Reddy for his kind permission to use some of the preliminary data in this study. Readers should note that conclusions that may be drawn from the following discussion should in no way be used to judge the performance of the actual system under construction in Pura. The following analysis proceeds from certain assumptions that differ slightly from those upon which the Pura system is based. Some of the data and cost estimates for the actual Pura system will be subject to revision. Nonetheless, the available data from the Pura system will enable us to obtain a fair picture of how well a village biogas system will fare financially.

The ASTRA biogas system under construction in Pura village has four main functions:

1. Provide cooking gas for each household.
2. Operate a pumpset for 20 minutes a day to fill an overhead storage tank with water. This should satisfy village domestic water requirements and provide the water needed to dilute the dung and clean the inlet and outlet tanks.
3. Operate a generator for three hours to provide electric lighting in the 42 households that currently are not connected to the central grid.
4. Operate a dual fuel engine to run a ball mill as part of a rice husk cement manufacturing operation.

The original feasibility study for Pura specified the construction of a single 42.5 [m.sup.3] ASTRA design digester with a mild steel floating-drum gasholder. It would provide enough biogas for all the above operations. The release of gas would be synchronized with various end-uses throughout the day. The 42.5 [m.sup.3] capacity was determined by the biogas requirements of the various system tasks, and allowed for some population increase.

The ASTRA team estimated that the 56 households (357 people) in Pura would require 11,426 [m.sup.3] of gas per year for cooking. This averages about 0.088 [m.sup.3] per person per day. Although this is less than the 0.2-0.3 [m.sup.3] per person per day norms cited by KVIC and others, we will assume that ASTRA's figure is correct for the level of subsistence and diet in Pura village.

The annual gas required to operate all of the engines is estimated at 3,767 [m.sup.3]. This is calculated as shown in Table VI-1 on the following page.

Total system requirements for cooking and engine operations are 15,193 [m.sup.3] of gas per year. Based on ASTRA observations, an estimated average of 7.35 kg fresh dung per animal can be collected from the night droppings of tied cattle. Added to this figure is an estimated 401.5 kg of collected organic matter--which also could be 2.65 kg more dung per head. This gives an equivalent of 10 kg of dung or dung equivalent per animal per day. Regardless of the actual amount of biomass fed into the system, a 5 percent loss is assumed in collection and handling. So, of the 532,900 kg available, 506,255 kg/biomass/year is actually used. This is roughly 1,387 kg/biomass that could be fed into the system daily. These estimates are very conservative. Cattle population is held constant, and cropping patterns

are unchanged from the present mix. Both of these factors are likely to change during the life of the system in a way that probably will increase the availability of biomass.

The maximum amount of gas produced from these estimates of Pura's available biomass is described in the analysis as the maximum output scenario. The cost of a system designed to produce only enough biogas to perform specified tasks is described as the minimum cost scenario. The two scenarios differ in the amount of biomass that will be fed into the system. This affects the required digester volumes and digester costs.

Table VI-1. Annual Gas Requirement

Function	Gas Requirement
1. Water pumping	(20 minutes/day) X (.42 [m.sup.3] gas/BHP/hr) X (5 hp) X (358 days) = 251 [m.sup.3]
2. Operating diesel generator for lighting	(3 hr/day) X (.42 [m.sup.3] gas/BHP/hr) X (5 hp) X (358 days) = 2,256 [m.sup.3]
3. Operating ball mill for rice husk cement manufacturing	(2 hr/day) X (.42 [m.sup.3] gas/BHP/hr) X (5 hp) X (300 days) = 1,260 [m.sup.3]
TOTAL	3,767 [m.sup.3]

The system is shut down one week each year for repairs, cleaning, etc., which may become less over time. It is assumed that there is no unforeseen vandalism, natural disasters, etc.

The daily biomass charge is determined by the gas requirements of the tasks to be performed. It equals the daily gas demand for all uses divided by the gas yield per kg of biomass. The analysis considers three different levels of demand, which correspond to three different biogas systems. For each of these three systems, which are described as Models 1, 2, and 3, both the minimum cost and maximum output scenarios are examined. It should be noted that the digester with sufficient capacity to digest all the net available biomass--the maximum output scenario--is identical for all three models. Because the gas demand is different in each model due to the different tasks performed, any surplus gas that will be available in the maximum output scenario will vary with each model, even though the digester costs will remain constant.

The three models are described below:

Model 1: Provides enough biogas for cooking, electric lighting, and domestic water requirements for the village, as well as water to operate the biogas system.

Model 2: Provides gas for cooking, electric lighting, water, and operating the ball mill to grind rice husks to produce rice husk cement.

Model 3: Provides gas only for electric lighting and the rice husk cement operation.

Table VI-2 shows the gas and biomass requirements for the models, based on earlier calculations.

The Pura village plan calls for two digesters of roughly 21.5 [m.sup.3] capacity each. Two smaller systems were decided upon after a risk analysis demonstrated that this reduced the "downtime" the system due to repairs and maintenance. At a given moment, only one of the digesters should be out of service so that service will not be disrupted completely, as would be the case with one large digester. As described in Table VI-1, the system is assumed to have an annual repair and maintenance period of one week.

The system used in the following economic analysis is based on the redesigned ASTRA system with one major modification: the analysis assumes that a small volume of water covered by a sheet of polyethelene is held on top of the gas holders by retaining walls similar to the ASTRA design described earlier. The polyethelene is treated for ultraviolet radiation. This simple solar water heater reduces system cost and improves performance due to the increased gas yield that can be expected from "hot charging" the slurry mixture. Field reports indicate that the "hot charge" system, when combined with the practice of mixing dung with other organic materials, could easily increase gas yield by 25 percent.

This means the biogas system, which normally would produce gas at the rate of roughly .038 [m.sup.3]/kg of fresh biomass, now has a gas yield of .0475 [m.sup.3]/kg of fresh biomass. This is a very conservative estimate. Empirical results may show that gas yield almost doubles. While actual gas production rates will fluctuate slightly due to seasonal ambient temperature changes, the gas yield of .0475 [m.sup.3]/kg fresh biomass represents an average or minimum gas production figure, and is used for year round calculations.

A number of system costs need to be described in detail, since they differ for each of the models. The capital costs for two biogas systems that each have half the total system capacity,

and which are built with ferrocement gas-holders and solar water heater attachments, are shown in Table VI-3. Information is based on detailed calculations and discussions with ASTRA biogas engineers. Table VI-4 shows system costs in addition to digester costs.

ASTRA surveys also indicate that approximately 150,000 kg of firewood are collected for cooking purposes. Of that, 4 percent is purchased at Rs 0.04/kg. While time spent gathering firewood is reduced by almost 36,950 hours, the direct annual monetary savings that accrue from the biogas system's operation are only about Rs 240 (150,000 kg of firewood) X (4 percent purchased) X (Rs .04 kg firewood) = approximately Rs 240. Despite a relative

Table VI-2 Gas and Biomass Requirements for Different models  
Under Minimum Cost and Maximum Output Scenarios  
(in [m.sup.3] per day)

	Model 1		Model 2		Model 3	
	Cooking, Lighting, and Pumping		Cooking, Lighting, Lighting, Pumping, Pumping, and Ball and Ball Mill Mill Operation Operation			
System Design	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Maximum Scenario	Cost	Output	Cost	Output	Cost	Output
Cooking	31.3	31.3	31.3	31.3	--	--
Water Pumping	0.7	0.7	0.7	0.7	0.7	0.7
Lighting	6.3	6.3	6.3	6.3	6.3	6.3
Ball Mill	--	--	4.2	4.2	4.2	4.2
Surplus Gas	--	26.7	--	22.5	--	53.8
Total Gas Required (Approximately)	38.3	65.0	42.5	65.0	11.2	65.0
Total Annual Biomass Required (fresh dung equivalent)	294,306kg	506,255kg	326,579kg	506,255kg	86,021kg	506,255kg

Note: Biomass required for each model is based on a gas yield of .0475 [m.sup.3]/kg.

Table VI-3 Biogas Digester Capital Costs for Models 1-3

	Model 1		Model 2		Model 3	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum

	Cost	Output	Cost	Output	Cost	Output
Daily Gas Capacity ([m.sup.3]	38.3	65.0	42.5	65.0	11.2	65.0
Digester System Cost (Rs)	13,400	22,100	15,000	22,100	4,500	22,100

Table VI-4 System Costs for models 1-3 (in Rs)

	Model 1	Model 2	Model 3
Equipment			
5 hp engine and KVA generator	15,500	15,500	15,500
Electrical system	5,500	5,500	5,500
Pumpset	700	700	700
Ball mill	--	4,750	4,750
Shed for equipment	3,000	6,000	6,000
Water tank	550	550	550
Miscellaneous (including roughly Rs 1,500 for technical supervision)	8,000	8,000	8,000
Subtotal	33,250	41,000	41,000
Gas pipeline for village	10,000	10,000	--
Total	43,250	51,000	41,000

abundance of forests, Pura villagers spend an average of three hours per day collecting firewood. In other areas, where deforestation pressures are far more serious, the price of firewood would be much higher, increasing the value of savings from reduced firewood consumption. In such areas, more dung would be burned as fuel, so greater benefits would be realized by recapturing the fertilizer value of the dung. Another possibility might be that some of the Rs 8,000 used to purchase miscellaneous material for Model 3 could be freed up, since items like pipe fittings, valves, etc., would not be needed if the distribution pipeline were not constructed. Some of these savings could be used to purchase improved wood-burning stoves that could reduce firewood consumption by as much as 50 percent. This would amount to only Rs 120 in total reduced village firewood purchases, but would save more than 18,400 hours in collecting firewood. Additional benefits and costs that might accrue from the creation of village woodlots have not been considered.

No direct government subsidy for the biogas system is considered in this analysis. There may be some cases where the NPV of the system in a village is positive, but the system generates insufficient cash flow to be viable financially. Such

cases might justify a possible subsidy if shadow prices and shadow wage rates are included in the NPV calculations and the NPV remains positive.

It may be possible for Pura villagers to form an "association" if they can prove that the project will largely benefit the poor. Indian lending institutions can be somewhat flexible about the criteria used to determine if a particular group can qualify as an "association." Associations are eligible to obtain loans at 4 percent interest. We have assumed such eligibility in our calculations, although the effects of a loan at 10 percent also have been analyzed. To simplify calculations, it has been assumed in the analysis that loans will be amortized over 5 years, in equal installments, with a one-year grace period. The equal installments are calculated using coefficients from standard annuity payment tables. For a 4 percent loan paid back over 5 years in equal installments, the annual payment equals the total borrowed capital divided by 4.452. For a loan at 10 percent with similar terms, the annual payment equals the total borrowed capital divided by 3.791. The use of annuity formulas tends to spread capital costs over time, increasing the NPV of a project. The distortions caused by this simplified way of calculating loan payments are very small in this analysis due to the large operating costs of the system. In addition, the impact of inflation on the various costs and benefits has been ignored. Rural wage rates are the largest component of operating costs, and are not expected to rise significantly. If they did rise, the increase probably would be canceled out by the increased savings caused by the reduced consumption of increasingly costly commercial fuels.)

We have assumed further that dung is provided to the system free of charge except for labor costs, which are discussed below. Slurry also will be distributed freely on the basis of the amount of dung contributed by each household. We have assumed that water and land will be made available for free to the system by the villagers who have agreed to do so as a demonstration of their willingness to participate in the project.

At the time of this writing, there was little information readily available on the distribution of and crop yields from land holdings in Pura. Given a village of Pura's size and population, the land under cultivation could be approximately 60 hectares. A typical yield of rice paddy for these holdings would be 1,500 kg/hectare/year. An estimate of the average price a farmer obtains for this paddy is about Rs 90/quintal (100 kgs). There is no information on the percentage of agricultural production consumed by the villagers themselves versus the percentage that might be sold in markets outside the

village. To simplify the calculations, we will assume that the village consumes all that it grows. Furthermore, we will assume that the nutrient and humus content of biogas slurry (consisting of at least all the dung currently applied as manure) is such that it has the net effect of increasing agricultural yields by 10 percent over those obtained through current fertilizer practices, even if these include the application of chemical fertilizers.

Increases of greater than 10 percent have been reported in China, where the extensive recycling of agricultural and animal wastes, including aerobic composting of wastes, is an ancient tradition. The 10 percent increase in yield is assumed to be a net increase over existing methods of "scientific composting." Thus, if the villagers sold the expected increase in crop yields, the net increase in village revenue from agriculture (IA), attributable to the use of biogas slurry equals  $(60 \text{ hectares}) \times (10 \text{ percent increase/hectare}) \times (1,500 \text{ kg of paddy/hectare}) \times (\text{Rs } 90/100 \text{ kg of paddy})$ . This equals Rs 8,100 for the maximum output scenario. In the minimum cost scenarios, proportionately less revenue would be generated because less biomass would be digested. The specific IA's for the minimum cost scenario of each of the three models is calculated by multiplying Rs 8,100 by the ratio of biomass consumed in each minimized cost scenario. That figure then is divided by 506,255, which is the biomass consumed in the maximum output scenario in all three models.

This measure of the benefit of biogas slurry is used because it represents a tangible cash benefit. Many economic analyses derive monetary benefits from the use of slurry by assessing the nutrient content of biogas slurry, determining the equivalent quantity of chemical fertilizer, and converting this to a monetary benefit by multiplying the quantity by the unit price of chemical fertilizer. The problem with this method is that it implies that a farmer would have purchased the marginal equivalent amount of fertilizer. It is not clear at all that farmers would have made such purchases in the absence of available biogas slurry; whether the money is actually "saved" is a matter of debate. What is clear is that some increase in agricultural productivity will occur due to the superior nutrient and humus characteristics of biogas slurry. This will result in increased earnings. Even so, while the 10 percent increase in yield is a reasonable estimate, it needs to be corroborated by empirical results from field tests that also analyze the yield empirical alternative composting techniques.

The increased agricultural productivity for the minimum cost scenario for each Model is calculated by multiplying the ratio



of biomass required for the minimum cost system times the ratio of biomass required for the maximum output system times Rs 8,100, as explained earlier. The increased Agricultural productivity resulting from using the slurry in each of the minimum cost systems is shown below:

$$\text{Model 1} = \frac{294,306 \text{ kg}}{506,255 \text{ kg}} \times \text{Rs } 8,100 = \text{Rs } 4,709$$

$$\text{Model 2} = \frac{326,579 \text{ kg}}{506,255 \text{ kg}} \times \text{Rs } 8,100 = \text{Rs } 5,225$$

$$\text{Model 3} = \frac{86,021 \text{ kg}}{506,255 \text{ kg}} \times \text{Rs } 8,100 = \text{Rs } 1,376$$

According to ASTRA surveys, Pura village annually consumes 1,938 liters of kerosene, at Rs 2.25 per liter, for lighting. This annual expenditure of Rs 4,360 for lighting will be reduced as follows:

$$(42 \text{ households}) \times (40 \text{ watt bulb/house}) \times (3 \text{ hrs/days}) \times (358 \text{ days}) \times (\text{Rs } 0.44/\text{kwh}) = \text{Consumption (C)}$$

$$C = \frac{\text{approximately Rs } 791}{1,000/\text{kw}}$$

However, because the Rs 791 is paid by villagers to the village biogas operation, it also appears as a village benefit, i.e., income from the sale of energy. Therefore, the village as a whole saves all money previously spent on kerosene purchases (Rs 4,360). In terms of the cash flow position of the biogas system, the sale of electricity for lighting is treated as revenue of approximately Rs 791.

A series of costs and benefits related to each model requires more detailed explanation. Labor costs for the different models are as follows:

#### Model 1: Cooking, Lighting and Pumping

$$1 \text{ skilled laborer/supervisor} = (\text{Rs } 7.50/\text{day}) \times (363 \text{ days}) = \text{Rs } 2,737.50$$

$$3 \text{ unskilled laborers} = (\text{Rs } 5/\text{day}) \times (3 \text{ persons}) \times (365 \text{ days}) = +5,475.00$$

$$\text{Total labor costs} = \text{Rs } 8,212.50$$

#### Model 2: Cooking, Lighting, Pumping and Ball Mill Operation

and

### Model 3: Lighting, Pumping and Ball Mill Operation

Same as Model 1 = Rs 8,212.50  
 Plus the cost of 1 supervisor at  
 (Rs 300/month) X (12 months) = 3,600.00  
 Total = Rs 11,812.50

These labor costs are reflected in the cash flow calculations. However, in the village benefit calculations, it is assumed for purposes of simplicity and lack of actual data that wages paid to operate the system will be spent within the village itself. Therefore, labor "costs" to the village are cancelled by an equal amount of village "benefits" that would accrue from those wages being spent on village goods and services. This clearly is a gross oversimplification of complex capital flows. However, given the orders of magnitude involved, this approach will suffice for our purposes.

Operation and maintenance costs for each model are shown in Table VI-5.

Table VI-5 Annual Operation and Maintenance Costs

	Model 1	Model 2	Model 3
Digester Maintenance	250.00	250.00	250.00
Diesel Fuel (a)			
for running pumpset	79.75	79.75	79.75
generator	724.95	724.95	724.95
ball mill	--	--	--
Lubrication Oil (b)			
for running pumpset	47.25	47.25	47.25
generator	429.60	429.60	429.60
ball mill	--	240.00	240.00
Raw Material Purchase (c)	--	4,800.00	4,800.00

(a) A 5 hp dual fuel engine requires .05 liters of diesel fuel/BHP/hour. At Rs 2.70/liter, a 5 hp engine costs Rs 0.675/hr to operate. Diesel fuel consumption figures are derived by:

Pumping: (20 minutes/day) X (358 days) X (Rs 675) = 79.75  
 Generator: (3 hours/day) X (358 days) X (Rs 675) = 724.95  
 Ball Mill: (2 hours/day) X (300 days) X (Rs 675) = 405.00

(b) Similarly, lubrication costs for a 5 hp engine/hr are: (.008

liters of lube oil/BHP/hr) X (Rs 10/liter of oil) X (5 hp) = Rs .40. This cost is multiplied by the same running times as shown above.

(c) 24,000 kg of lime will be purchased from a nearby village at Rs 0.20/kg, and will be mixed with the ground rice husks to produce cement.

Finally, we will assume that the surplus gas generated in the maximum output scenario could be sold at the equivalent diesel or electricity price, and that demand will keep pace with supply. This represents a potentially large source of revenue to the system. The conversion factors for the equivalent prices of diesel and electricity can be calculated as follows:

Surplus gas sold as diesel. The value of surplus gas sold as diesel equals the difference between the cost of running an engine on biogas and the cost of running it on diesel fuel, as is shown in Table VI-6.

Table VI-6 Fuel Costs of Generating 1 BHP with a Diesel and a Dual Fuel Engine

	Standard Diesel engine	Dual fuel biogas engine
Diesel fuel consumed	(.25 liters/BHP/hr) X Rs 2.70 = Rs .68	(.05 liters/BHP/hr) X Rs 2.70 = Rs .14
Lubricating oil consumed	(.015 liters/BHP/hr) X Rs 10 = Rs .15	(.008 liters/BHP/hr) X Rs 10 = Rs .08
Total	Combined cost of diesel fuel and lubricating oil = Rs .83	Combined cost of diesel fuel and lubricating oil = Rs .22

The total difference in the combined cost of diesel fuel and lubricating oil for a standard diesel engine and for a dual fuel biogas engine is Rs 0.83 - Rs 0.22 = Rs 0.61/BHP/hr. A dual fuel biogas engine thus saves Rs 0.61 in fuel and lubricating oil costs for each hour it operates.

We know that 0.42 [m.sup.3] of biogas are needed to generate one BHP/hr. We can use the following formula to calculate the Equivalent Diesel Price/[m.sup.3] (EDP/[m.sup.3]):

$$(0.42 \text{ [m.sup.3] biogas/BHP/hr}) \times (\text{EDP/[m.sup.3]}) = \text{Rs } 0.61.$$

$$\frac{\text{EDP/[m.sup.3]} \times \text{Rs } 0.61}{\text{Rs } 0.42/\text{[m.sup.3]}} = \text{Rs } 1.48/\text{[m.sup.3]}$$

This shows that biogas is competitive with diesel fuel when it can be sold at a price no greater than Rs 1.48/[m.sup.3]. This calculation uses current prices and assumes that a dual fuel engine will reduce by half the amount of lubricating oil consumed.

Surplus gas sold as electricity. The value of surplus gas sold as electricity is calculated by equating the cost of running a diesel generator with biogas with the cost of purchasing a kwh from the central grid. We know that 1 BHP = .74 kwh, the running cost of operating a diesel engine to produce 1 BHP-hr = Rs .22 (from above), and the local cost of electricity is Rs .44/kwh. Therefore, the equivalent electricity price (EEP) = (.42 [m.sup.3]/BHP-hr) x (EEP/[m.sup.3]) + Rs 0.22 = (.74 kwh/BHP) x (Rs .44) = Rs .25.

The analysis of an energy or development project is only as good as the quality of its assumptions. Many studies bury these assumptions in obscure appendices. Conclusions and generalizations made in the body of such studies are rarely subjected to a critical eye; instead, they are taken by the reader as given. This study includes the detailed intermediate calculations for the models to facilitate the reader's understanding and criticism of the simulations. Some of the notations--such as the use of the underline (  ) sign--are awkward. They are written in this way to correspond in appearance to the computer printouts in the Appendix, which describe the detailed baseline simulation for all of the models. Readers not interested in the mathematical derivation of the NPV and payback calculations may skip to pages 61-62 and skim the left-hand column for a sense of the key benefits and costs. Conclusions from the analysis begin on page 75.

Table VI-7 shows the notation, including all constant values, that is used through the analysis to describe all system variables for the three models under each scenario.

Table VI-7 Analysis to Describe All System Variables

- D = Total biomass yield per annum, corrected for handling losses and system down-time as a function of the Minimized Cost or Maximized Output scenario.
- D\_L = Diesel required for running a generator set (genset) per annum: (.05 liters/hr/BHP) X (3 hrs) X (5 hp) (358 days) = 268.5 liters.
- D\_LC = Cost of the digester, gas holder, and solar water heater, as a function of system capacity.

D\_P = Diesel required for pump operation per annum: (.05 liters/hr/BHP) X (5 hp) X (20 min/day) X (358 days) = 29.5 liters.

D\_RC = Diesel required for running the ball mill used to produce rice cement: (.05 liters/hr/BHP) X (5 hp) X (2 hrs X (300 days) = 150 liters.

E = Cost of all accessories, connections, electrical wiring, shelters, pumpsets, genset gas burners, and miscellaneous equipment, as a function of tasks to be performed in the three Models.

G = The gas yield of .0475 [m.sup.3]/kg fresh biomass.

G\_C = Gas required for cooking per annum. Calculated earlier as approximately 11,425 [m.sup.3].

G\_L = Gas required for electric lighting per annum = 2,255 [m.sup.3] biogas (previously calculated).

G\_P = Gas required for pumping water = 251 [m.sup.3] (previously calculated).

G\_RC = Gas required for operating the ball mill that is used in the production of rice husk cement per year: 1,260 [m.sup.3] biogas (previously calculated).

IA = Marginal increase in agricultural income due to nutrient and humus content of biogas slurry as a function of total quantity of organic material digested, in rupees/annum. Though the actual value of IA will fluctuate due to changing crop yields and market prices, IA is treated as a constant for the sake of simplicity.

L = Labor costs at a function of the different models, in rupees/year.

LO\_P = Lubricating oil for pumping per annum: (.008 liters/BHP/hr) X (5 hp) X (20 min/day) X (358 days) = 4.7 liters.

LO\_L = Lubricating oil for lighting per annum: (.008 liters/BHP/hr) X (3 hrs) X (5 hp) X (358 days) = 43 liters.

LO\_RC = Lubricating oil for lighting per annum: (.008 liters/BHP/hr) X (2 hrs) X (5 hp) X (300 days) = 24 liters.

LO = Total annual cost of lubricating oil: LO\_P + LO\_L + LO\_RC.

M = Material cost (lime) for manufacturing rice husk cement, in rupees/year.

N = The economic life of the system: 15 years.

N<sub>LC</sub> = Period in which the loan will be amortized: five years.

P = Cost of distribution pipeline to supply cooking gas: Rs 10,000.

P<sub>D</sub> = Unit price of diesel fuel at Rs 2.70/liter.

P-DS = Unit price of surplus energy sold as diesel at Rs 148/[m.sup.3] or Rs .74/[m.sup.3].

P-ES = Unit price of surplus energy sold as electricity at Rs .44/kwh, the current rate in Karnataka, at Rs .2.5/[m.sup.3].

P-FW = Unit price of firewood at Rs .04/kg.

P-K = Unit prices of kerosene at Rs 2.25/liter.

P-LO = Unit price of lubricating oil at Rs 10.00/liter.

R = Revenue from commercial operations--the annual sales of rice husk cement. The Pura village operation hopes to produce 80 tonnes of rice husk cement per year. This will be sold at Rs 400/tonne, or a total of Rs 32,000. For the purposes of analysis, the effects of four levels of annual sales--Rs 0, Rs 10,000, Rs 20,000, and Rs 30,000--have been calculated. To simplify the analysis, revenue is held constant over time. In actuality, it would fluctuate with demand.

R-LC = Interest rate of loan, calculated at both 4 percent and 10 percent.

\*\*\*

The following equations have been used for certain intermediate calculations:

#### 1. Annual Recurring Cost Calculations

Capital Cost of System (K) = (D<sub>LC</sub>) + P + E + the Amortization Coefficient (a function of N<sub>LC</sub>) and (R<sub>LC</sub>), as explained previously).

Cost of Diesel for Operating the System (DF) =  $(P\_D) \times [(D\_P) + (D\_L) + D\_RC]$ .

Cost of Lubricating Oil for Operating System (LO) =  $(P\_L) \times [(LO\_L) + (LO\_P) + (LO\_RC)]$ .

Cost of Operation and Maintenance =  $L + M + \text{Rs } 250$  (miscellaneous annual maintenance).

## 2. Annual Benefit Calculations

Energy saved from Reduced Kerosene Consumption =  $(P\_K) \times 1,983$  liters of kerosene saved annually

Energy saved from Reduced Firewood Consumption =  $(150,000 \text{ kg}) \times (.04) \times (P\_FW)$ , as explained previously.

Total Gas Produced Annually (G-T) =  $D \times G$ .

Surplus Gas Available Annually (G S) =  $(G\_T) - [(G\_C) + (G\_L) + (G\_P) + (G\_RC)]$ .

Sale of Surplus Gas Converted to Diesel =  $(G\_S) \times (P\_DS) \times (0.9)$ . The (0.9) is a utilization factor, since not all energy produced would be used.

Sale of Surplus Gas Converted to Electricity =  $(G\_S) \times (P\_DS) \times (0.9)$ , as explained above.

3. Net Benefits--Costs to village = [Expenditures Saved From Reduced Consumption of Kerosene and Firewood + IA + (Sales of Surplus Energy at either Diesel or Electricity Equivalent Price) + R] - [Annual Capital Cost + Diesel Cost + LO + M + Rs 250]. Labor costs are excluded from this calculation as explained earlier. The Rs 250 is for routine maintenance.

Finally, although all costs are calculated on the basis of the system operating at full capacity, we will assume that there will be periodic maintenance delays, and that the system will not supply gas every day each year. This will affect the amount of surplus gas available, and will reduce the benefits realized from fuel savings of firewood, kerosene, etc. The daily amount of biomass still will be fed into the system, so the IA will

remain unaffected. Since the rice husk cement operation runs only 300 days a year, the seven-day maintenance is assumed to occur during the 65-day slack period. To correct the calculations for the system's "down time," energy saved from reduced kerosene and firewood consumption, and sale of surplus gas are multiplied by one week divided by 52 weeks = 0.981.

## Discussion of Modeling Results

We are interested primarily in whether or not the biogas systems described earlier enable the village to be "better off."

This is measured by the positive NPV, as explained earlier. We also are studying whether the systems generate sufficient revenues to cover their operating and capital costs, as measured by the undiscounted payback period. The computer program developed for this analysis was designed to enable the user to modify any of the 27 variables to isolate and examine their effect on economic performance. For the purposes of this analysis, two main types of variables were examined.

1. The interest rate of the loan ( $R_{LC}$ ) was examined at 4 percent and 10 percent for all models.
2. The system revenues for the models, the sale of surplus gas ( $P_{DS}$ ), and the revenues from the sale of rice husk cement ( $R$ ) were set at various levels. Revenue from the sale of gas, available only in the maximum output scenarios for all models, was examined at zero, as well as at the equivalent price of: diesel fuel ( $\text{Rs } 1.48/[\text{m.sup.3}]$ ), one-half the equivalent price of diesel fuel ( $\text{Rs } .74/[\text{m.sup.3}]$ ), and the equivalent price of electricity ( $\text{Rs } .25/[\text{m.sup.3}]$ ). Revenue from the sale of rice husk cement was set in Models 2 and 3 at zero, Rs 10,000, 20,000, and 30,000. Model 1 has no provisions for running an industry.

In addition, the impact of a hypothetical technological break-through that somehow reduces the cost of the digesters by 50 percent ( $1/2 D_{LC}$ ) was examined. In this simulation, interest rates and revenues from the sale of rice husk cement vary, as explained earlier, and revenues from the sale of surplus gas are set at zero and the diesel equivalent.

The results from these combinations of different interest rates, sales of surplus gas, sales of rice husk cement, and digester costs are shown in the summary Tables VI-10a through VI-10d.

Before discussing the results of this analysis in detail, it must be remembered that all the figures are rough and indicative



only of orders of magnitude. For example, in evaluating the NPV figures, it is most important to note whether or not the values are positive and "large," such as more than Rs 10,000. This enables us to state with reasonable confidence whether a particular biogas system would provide a village with a net gain.

Payback figures need to be viewed more exactly. As the data will show, differences in the loan repayment schedule, amortized over five years with a one-year grace period, dramatically affect the ability of systems to pay for themselves. Any system that does not repay the loan in the first year, in addition to covering its operating costs, will require working capital from a source that is external to the biogas system. Even though the system pays for itself in the long run, the cash flow generated from its operation may be insufficient to meet short-term debt servicing, especially through the sixth year of the project. Thus, if operations are to continue, the deficit must be offset by an external source of funds. This might include user charges or subsidies, as will be discussed later.

In this analysis, the economic life of system components is held constant at 15 years for all calculations. The biggest source of error here could be a shorter life of the diesel engine. But with proper maintenance and the reduced deterioration observed in laboratory engines run on biogas, an equipment life of 15 years seems reasonable. Of the 144 cases examined, there were seven in which the payback occurred only in the ninth year or later. In those seven cases, a 10-year economic life for system components would mean that the project would not be financially viable.

The basic challenge to any village embarking on a large-scale biogas project, of course, is to cover the running capital costs of the system. Tables VI-8 and VI-9 below show these costs in some detail. The figures in these tables are taken from the detailed baseline benefit-costs calculations found in the photocopied computer printouts in the Appendix.

Interest rates will be discussed in greater depth shortly. However, if the capital for the system were borrowed at the higher rate of 10 percent, the annual cash flow during the repayment of the loan would be only 8-10 percent higher than if the money were obtained at the preferred rate for associations of 4 percent (as shown in Table VI-8). In view of the sum of money involved, the interest is not of great importance.

Table VI-8

Baseline Data: Annual Operating Deficit (in Rupees)  
for Models 1-3 (Full Cost Digesters)

MODEL 1

Years	Min. Cost	Max. Output
1, 7-15	8,993	8,993
2-6 at 4 percent interest	21,718	23,672
at 10 percent interest	23,936	26,231

MODEL 2

Years	Min. Cost	Max. Output
1, 7-15	18,038	18,038
2-6 at 4 percent interest	32,863	34,458
at 10 percent interest	35,448	37,320

MODEL 3

Years	Min. Cost	Max. Output
1, 7-15	18,038	18,038
2-6 at 4 percent interest	28,258	32,211
at 10 percent interest	30,040	34,683

Similarly, as shown in Table VI-9, if the costs of the digester are cut in half due to a technological breakthrough, the annual cash deficits during repayment of the loan range from only 2-11 percent less than those obtained with the digester at "full" cost. Since the other fixed costs of the systems are so large, savings resulting from reducing the digester costs are surprisingly trivial when spread over the five-year loan repayment period.

None of the systems pay for themselves as a result of cash savings derived directly from operations. Savings "derived directly from operations" would include reduced fuel and fertilizer consumption expenditures and, technically, any multiplier effect stemming from the alternative use of saved capital. It would not include revenues from the sale of surplus gas, surplus slurry, or products or services provided by industries run on the gas. This distinction between savings and revenues is important because the savings will be far less likely to fluctuate than revenues, which are affected by market forces. Savings will accrue as long as demand, prices, and system performances do not decline. Of the three models examined, only model 1 (cooking gas, electric lighting, and village water pumping) yields a positive NPV from the direct savings accruing to the village over the system's 15 operating years (see Table VI-8). The size of the NPV increases slightly for the systems

with digesters at half cost. Only in the case of the Model 3 maximum output system (with capital borrowed at 4 percent) does a negative NPV become positive. Yet even here, the NPV is an insignificant Rs 1,497. Even with no direct revenue from operations, the Model 1 village gains economically from constructing the system. Of course, it may be somewhat unfair to criticize a village system designed to run a small industry when the projected revenue from the industry is arbitrarily set at zero. However, the critical importance of that revenue is underscored by doing so.

Table VI-9

Baseline Data: Annual Operating Deficit (in Rupees)  
for Models 1-3, with Digester Costs Reduced 50 Percent

#### MODEL 1

Years	Min. Cost	Max. Output
1, 7-15	8,893	8,893
2-6 at 4 percent interest	20,213	21,190
at 10 percent interest	22,169	23,316

#### MODEL 2

Years	Min. Cost	Max. Output[N]
1, 7-15	18,038	18,038
2-6 at 4 percent interest	31,178	31,976
at 10 percent interest	33,496	34,406

#### MODEL 3

Years	Min. Cost	Max. Output
1, 7-15	18,038	18,038
2-6 at 4 percent interest	27,753	29,729
at 10 percent interest	29,447	31,768

With all these cautionary notes, we now move to examine the economic performance of the biogas systems, using different levels of annual revenue obtained from either the sale of surplus gas or the sale of rice husk cement (or both). All data can be found in Tables VI-10a through VI-10d below.

Table VI-10a Net Present Value (NPV) and Payback Period at Different Interest Rates for the Three Models

#### With No Revenue from Sales of Rice Husk Cement

Note: NPV in rupees is listed first. Calculations assume a 15-year life of the system. Payback period in years is in parentheses. If the system will not pay back over 15 years, (0) is listed.

MODEL THREE		MODEL TWO					
INTEREST RATE		MODEL ONE		COOKING, LIGHTING			
LIGHTING & INDUSTRY		BIOGAS		COOKING & LIGHTING		& INDUSTRY	
OF THE LOAN		PRICE		Min Cost	Max Output	Min Cost	Max Output
Min Cost	Max Output						
(R_LC)	(Rs/[m.sup.3])	Model	Model	Model	Model	Model	Model
Model	Model						
4%	0.00	14,454	33,512	-30,274	-13,902	-44,577	-
7,057		(0)	(0)	(0)	(0)	(0)	
4%	0.25	50,180		680		26,438	
		(0)	(0)	(0)	(0)	(0)	
4%	0.74	82,849		29,261		92,087	
		(0)	(0)	(0)	(0)	(0)	
4%	1.48	132,187		72,425		191,231	
		(0)	(0)	(0)	(9)	(9)	
10%	0.00	6,809	24,692	-39,182	-23,768	-50,718	-
15,573		(0)	(0)	(0)	(0)	(0)	
10%	0.25	41,360		-9,186		17,921	
		(0)	(0)	(0)	(0)	(0)	
10%	0.74	74,029		19,395		83,571	
		(0)	(0)	(0)	(0)	(0)	
10%	1.48	123,366		62,558		182,715	
		(0)	(0)	(0)	(11)	(11)	

4% = Interest rate charged to associations. 10% = Higher interest rate.

Rs 0/[m.sup.3] assume no revenues from the sale of biogas; Rs 0.25/[m.sup.3] = Equivalent price of electricity;

Rs 0.74/[m.sup.3] = One-half Equivalent price of diesel fuel; Rs 1.48/[m.sup.3] = Equivalent price of diesel fuel.

Table VI-10b Net Present Value (NPV) and Payback Period at Different Interest Rates for the three Models

With Revenues of Rs 10,000 from Sales of Rice Husk Cement

Note: NPV in rupees is listed first. Calculations assume a 15-year life of the system. Payback period in years is in parentheses. If the system will not pay back over 15 years, (0) is listed.

MODEL THREE		MODEL ONE		MODEL TWO COOKING, LIGHTING & INDUSTRY		
INTEREST RATE		BIOGAS		COOKING & LIGHTING		& INDUSTRY
LIGHTING & INDUSTRY		PRICE		Min Cost	Max Output	Min Cost Max Output
OF THE LOAN		Min Cost Max Output		Model	Model	Model Model
(R_LC)		(Rs/[m.sup.3])		Model	Model	Model Model
Model	Model					
4%	0.00			45,788 (0)	62,159 (0)	31,485 (0) 69,004
4%	0.25				76,741 (0)	102,499 (0)
4%	0.74				105,322 (0)	168,149 (15)
4%	1.48				148,486 (0)	267,293 (1)
10%	0.00			36,880 (0)	52,293 (0)	25,344 (0) 60,488
10%	0.25				66,875 (0)	93,983 (0)
10%	0.74				95,456 (0)	159,632 (0)
10%	1.48				138,620 (0)	258,776 (1)

4% = Interest rate charged to associations. 10% = Higher interest rate.

Rs 0/[m.sup.3] assumes no revenues from the sale of biogas; Rs 0. 25/[m.sup.3] = Equivalent price of electricity;

Rs 0.74/[m.sup.3] = One-half Equivalent price of diesel fuel; Rs 1.48/[m.sup.3] = Equivalent price of diesel fuel.

Table VI-10c Net Present Value (NPV) and Payback Period at Different Interest Rates for the Three Models

With Revenues of Rs 20,000 from Sales of Rice Husk Cement

Note: NPV in rupees is listed first. Calculations assume a 15-year life of the system. Payback period in years is in parentheses. If the system will not pay back over 15 years, (0) is listed.

MODEL TWO  
MODEL ONE COOKING, LIGHTING MODEL

THREE INTEREST RATE OF THE LOAN (R_LC) Model		BIOGAS PRICE (Rs/[m.sup.3])	COOKING & LIGHTING Min Cost Model		& INDUSTRY Max Output Model		Min Cost Model
4%	0.00		121,849 (0)	138,220 (0)	107,546 (0)	145,066	
4%	0.25			152,803 (0)		178,560 (12)	
4%	0.74			181,384 (11)		244,210 (1)	
4%	1.48			224,547 (7)		343,354 (1)	
10%	0.00		112,941 (0)	128,354 (0)	101,405 (0)	136,549	
10%	0.25			142,936 (0)		170,044 (14)	
10%	0.74			171,518 (13)		235,693 (1)	
10%	1.48			214,681 (8)		334,837 (1)	

4% = Interest rate charged to associations. 10% = Higher interest rate.

Rs 0/[m.sup.3] assumes no revenues from the sale of biogas; Rs 0.25/[m.sup.3] = Equivalent price of electricity;

Rs 0.74/[m.sup.3] = One-half Equivalent price of diesel fuel; Rs 1.48/[m.sup.3] = Equivalent price of diesel fuel.

Table VI-10d Net Present Value (NPV) and Payback Period at Different Interest Rates for the Three Models

With Revenues of Rs 30,000 from Sales of Rice Husk Cement

Note: NPV in rupees is listed first. Calculations assume a 15-year life of the system. Payback period in years is in parentheses. If the system will not pay back over 15 years, (0) is listed.

THREE		MODEL TWO	MODEL ONE	COOKING, LIGHTING	MODEL
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INTEREST RATE LIGHTING & INDUSTRY OF THE LOAN Cost Max Output (R_LC) Model	BIOGAS PRICE (Rs/[m.sup.3])	COOKING & LIGHTING		& INDUSTRY		Min
		Min Cost	Max Output	Min Cost	Max Output	
		Model	Model	Model	Model	
4%	0.00	197,910 (7)	214,281 (7)	183,607 (1)	221,127	
4%	0.25		228,864 (1)	254,621 (1)		
4%	0.74		257,445 (1)	320,271 (1)		
4%	1.48		300,608 (1)	419,415 (1)		
10%	0.00	189,002 (8)	204,415 (9)	177,466 (7)	212,610	
10%	0.25		218,998 (7)	246,105 (1)		
10%	0.74		247,579 (1)	311,754 (1)		
10%	1.48		290,742 (1)	410,899 (1)		

4% = Interest rate charged to associations. 10% = Higher interest rate.

Rs 0/[m.sup.3] assumes no revenues from the sale of biogas; Rs 0.25/[m.sup.3] = Equivalent price of electricity;

Rs 0.74/[m.sup.3] = One-half Equivalent price of diesel fuel; Rs 1.48/[m.sup.3] = Equivalent price of diesel fuel.

Table VI-11a Net Present Value (NPV) and Payback Period at Different Cement Revenue and Interest Rates

With the Cost of the Digester Reduced by One-half

Note: NPV in rupees is listed first. Calculations assume a 15-year life of the system. Payback period in years is in parentheses. If the system will not pay back over 15 years, (0) is listed.

REVENUE FROM INTEREST MODEL THREE CEMENT LIGHTING & INDUSTRY	RATE OF BIOGAS PRICE	MODEL TWO		COOKING & LIGHTING & INDUSTRY
		MODEL ONE	COOKING, LIGHTING	
		COOKING & LIGHTING		

SALES Min Cost (Rs) Model	THE LOAN Max Output (R_LC)	PRICE (Rs/[m.sup.3])	Min Cost Model	Max Output Model	Min Cost Model	Max Output Model
0	0.04	0.00	19,641 (0)	42,566 (0)	-24,468 (0)	-5,348 (0)
0	0.04	1.48	141,740 (0)	80,978 (0)	199,785 (8)	
0	0.10	0.00	12,899 (0)	34,737 (0)	-32,364 (0)	-13,723 (0)
0	0.10	1.48	133,411 (0)	72,603 (0)	192,760 (9)	
10,000	0.04	0.00		51,593 (0)	70,713 (0)	33,226 (0)
10,000	0.04	1.48		157,039 (0)	275,846 (1)	
10,000	0.10	0.00		43,697 (0)	62,338 (0)	27,389 (0)
10,000	0.10	1.48		148,665 (0)	268,821 (1)	

4% = Interest rate charged to associations. 10% = Higher interest rate.

Rs 0/[m.sup.3] assumes no revenues from the sale of biogas; Rs 0.25/[m.sup.3] = Equivalent price of electricity;

Rs 0.74/[m.sup.3] = One-half Equivalent price of diesel fuel; Rs 1.48/[m.sup.3] = Equivalent price of diesel fuel.

Table VI-11b Net Present Value (NPV) and Payback Period at Different Cement Revenue and Interest Rates

With the Cost of the Digester Reduced by One-half

Note: NPV in rupees is listed first. Calculations assume a 15-year life of the system. Payback period in years is in parentheses. If the system will not pay back over 15 years, (0) is listed.

REVENUE FROM INTEREST MODEL THREE	MODEL TWO MODEL ONE	MODEL TWO COOKING, LIGHTING & INDUSTRY
CEMENT RATE OF BIOGAS LIGHTING & INDUSTRY	COOKING & LIGHTING	
SALES THE LOAN PRICE Min Cost Max Output	Min Cost Max Output	Min Cost Max Output



(Rs) Model	(R_LC)	(Rs/[m.sup.3])	Model	Model	Model	Model	Model
20,000	0.04	0.00	(0)	127,654 (0)	146,774 (0)	109,288 (0)	153,619
20,000	0.04	1.48		233,100 (1)		351,907 (1)	
20,000	0.10	0.00	(0)	119,759 (0)	138,339 (0)	103,450 (0)	146,594
30,000	0.10	1.48		224,726 (7)		344,882 (1)	
30,000	0.04	0.00	(1)	213,715 (1)	222,835 (1)	185,349 (1)	229,680
30,000	0.04	1.48		309,162 (1)		427,969 (1)	
30,000	0.10	0.00	(7)	195,820 (7)	214,460 (1)	179,511 (1)	222,655
10,000	1.10	1.48		300,787 (1)		420,943 (1)	

4% = Interest rate charged to associations. 10% = Higher interest rate.

Rs 0/[m.sup.3] assumes no revenues from the sale of biogas; Rs 0.25/[m.sup.3] = Equivalent price of electricity;

Rs 0.74/[m.sup.3] = One-half Equivalent price of diesel fuel; Rs 1.48/[m.sup.3] = Equivalent price of diesel fuel.

### Model 1--Cooking and Lighting

As discussed earlier, Model 1 has a positive NPV in both the minimum cost and maximum output cases. The size of the NPV is larger in the maximum output case since surplus gas is sold for profit. Under the most optimistic conditions--with digester costs cut in half, the highest price obtained from gas sales (Rs 1.48, the diesel equivalent), and the 4 percent interest rate on borrowed capital--the NPV is Rs 140,740. Even so, as in all cases of Model 1, the system is unable to generate sufficient revenue to pay for its annual operating deficits. These deficits range from almost Rs 9,000 for years 1 and years 7-15, to Rs 20,200-26,200 during the loan repayment years, 2-6. The system therefore would require either a subsidy or user charge to finance construction and operation.

### Model 2--Cooking, Lighting, and Small Industry

In the minimum cost case, annual cash deficits range from Rs 18,000 for year 1 and years 7-15 to between Rs 31,200-Rs 35,500 in years 2-6 (see Tables VI-8 and VI-9). Without revenue from the sale of rice husk cement, the system has a negative NPV and cannot pay for itself. When annual sales are greater than Rs 10,000, the NPV becomes positive. But it is only after sales reach Rs 30,000 per year that the system pays for itself. The higher interest rate only slows payback by one year. However, the payback period is 7-8 years, which still necessitates an external cash source. The one exception to this is the combination of the half cost digester with a 4 percent loan, which pays for itself during the first year.

If the Model 2 system capacity is expanded to accommodate more biomass input (the maximum output case), then the baseline annual cash deficits (from Tables VI-8 and VI-9) range from Rs 18,000 in years 1 and years 7-15 to Rs 32,200-Rs 37,300 in years 2-6. NPVs are positive if surplus gas is sold at the price of diesel fuel, at half the price of diesel fuel, and, of course, if the digester cost is halved and surplus gas is sold as diesel fuel. If surplus gas is sold at the equivalent price of electricity and there are no cement sales revenues, the NPV is barely positive with a 4 percent loan. It becomes negative if the loan is 10 percent, but reverts back to positive if sales revenues are at least Rs 10,000. The maximum output case pays back in 7-8 years (depending on interest rates) if revenues are at least Rs 20,000 and if the surplus gas is sold at the diesel equivalent. It pays back in 11-13 years if the gas is sold at half the diesel equivalent. The system does not pay back if the gas is sold at the electricity equivalent price. The half-cost digester case pays back in the first year if revenue is at least Rs 20,000, if gas is sold at the diesel equivalent, and if the interest rate is 4 percent. It takes seven years if the rate is 10 percent. If revenue is Rs 30,000 and no surplus gas is sold, the situation is much like the minimum cost case. There is a payback of 7-9 years, or of 1-7 years if the digester costs are halved. If revenue is at least Rs 30,000, and if surplus gas is sold, the payback occurs during the first year. However, there is a seven-year payback when gas is sold at the electricity equivalent and the loan is made at 10 percent.

### Model 3--Lighting and Industry

Based on annual deficits of Rs 18,038 for years 1 and years 7-15, and of Rs 27,700-Rs 30,000 in years 2-6, the minimum cost systems have positive NPV if revenues from the sale of rice husk cement are at least Rs 10,000. They pay back in the first year if revenues are at least Rs 30,000. A system designed for

the maximum output case, with either revenue of at least Rs 10,000 or surplus gas sales (at the electricity or diesel equivalent), shows a positive NPV when the baseline annual deficit is Rs 18,030 in years 1 and years 7-15, and Rs 29,700-Rs 34,600 in years 2-6.

Payback periods are more complicated. In the case of a full-price digester, selling surplus gas at the diesel equivalent without any revenue from cement sales results in a payback of 9-11 years, depending on the loan rate. Under similar conditions, reducing the digester cost by half improves the payback position only slightly to 8-9 years. Surplus gas sold at half the diesel, or electricity, equivalent does not enable the system to be viable financially. If no gas is sold, but cement sales are Rs 10,000, none of the systems pay back. With sales of Rs 10,000 and surplus gas sold at the diesel equivalent, payback occurs during the first year for both the full- and half-cost digester systems. With similar cement sales, but with surplus gas sold at half-diesel equivalent, payback occurs only in the fifteenth year with a 4 percent loan. It does not occur at all at 10 percent or when the gas is sold at the electricity equivalent. If no surplus gas is sold, the system does not pay back if revenue from cement sales are Rs 20,000. At the diesel equivalent, and with surplus gas sold in addition to a profit of Rs 20,000 on cement sales, a system with a full- or halfcost digester will pay back in the first year. The same is true with Rs 20,000 in cement sales, and the surplus gas sold at the half-diesel equivalent combination. On the other hand, when the same level of cement sale is combined with surplus gas sold at the electricity equivalent, it only yields a 12-14 year payback. If cement sales are Rs 30,000 and no surplus gas is sold, the system pays back in either the first or seventh year, depending on the interest rate. However, in the half-cost digester case, the same system pays back immediately, regardless of the interest rate. The system has a one year payback period if cement sales exceed Rs 30,000, and if surplus gas is sold at any of the three prices.

## SOME CONCLUSIONS

Certain generalizations can be made from the summary data in Tables VI-10a through VI-10d:

1. Of the 144 different ways in which the three models of biogas systems might perform, the systems pay back during the life of the system in 55 cases (38 percent of the total). Of the cases in which payback occurred, 35 (25 percent) had payback within the first year of the project's existence. One-fourth of the cases examined seem extremely economical when they have an adequate cash flow. In addition, only 32

of the 144 cases (22 percent) showed a negative NPV. This suggests that the village will show a net gain from building one of these systems in almost 80 percent of the situations that were modeled. However, these optimistic findings presume a source of revenue from the sale of rice husk cement or surplus gas.

2. Half of the 144 cases were examined with a 4 percent interest rate for borrowed capital; the other half had a 10 percent rate. Thirty-two of the 72 cases analyzed at 4 percent interest paid back during the life of the project. Thirty-one cases paid back at 10 percent. The one remaining situation at 4 percent paid back only in the fifteenth year of the project. The remaining eight cases do not pay back at all. Interest rates for borrowed capital do not seem to affect the total number of projects that pay back. Twenty two cases pay back during the first year at 4 percent while 15 cases pay back during the first year at 10 percent. The lower interest rate increases by 10 percent the number of systems with an immediate payback. (Thirty percent of the 4 percent situations pay back within one year versus 20 percent for the higher interest cases). In most cases, the higher interest rate extended the payback period by only one to two years. Lower interest rates clearly improve the chances for a system to pay back immediately. But, the number of viable projects is relatively unaffected by interest rates. Viable projects are considered to be those with those with a means of covering the deficits occurring prior to payback, and which require no external source of cash during the years of loan repayment.
3. Of the three basic models examined, Model 1 (cooking, gas and electric lighting) does not pay back even when the sale of surplus gas and digester costs are cut in half. Model 2 (cooking, lighting, and small industry--rice husk cement production) payback occurs in 26 of the 64 possible cases. Of these, 10 cases (16 percent) pay back during the project's first year. In Model 3 (lighting, rice husk cement production), payback occurs in 37 of the 64 possible cases (58 percent). Of these, 27 cases (42 percent) pay back in the first year. Again, the data show the substantial impact of being able to sell surplus gas and rice husk cement.

All things being equal, it is more profitable to maintain a village system as a public utility and fertilizer plant than as a source of cooking gas. However, such an approach only is possible in a village in which:

- a. An alternative energy source such as wood from carefully managed woodlots could be supplied at an affordable price

to every household in the village. This is necessary since the system would take away people's only cooking fuel.

- b. An alternative source of animal fodder could be found. This is necessary because the biogas system reduces the amount of village biomass available for fodder. This might be done by using some of the biogas slurry to grow algae or other sources of protein and roughage. However, both algae and roughage cultivation, as well as village woodlots, will require more project money, organization building, and technical support. These additional costs might be financed with the profits from a system with quick payback. Nonetheless, the opportunity costs of such resources cannot be ignored.

Given the greater managerial complexity and increased resource demands of Model 3, in most cases it seems far more preferable to link a village system that supplies cooking gas with either a small industry or the sale of surplus gas. The concept of using a biogas system as an industrial energy unit deserves further study in view of the competitive unit energy costs derived from even a village-scale system.

- 4. Of the 36 cases pertaining to the minimum cost models, eight (22 percent) pay back within the life of the project and five (14 percent) pay back within the 15 year project life. Of these, 32 (30 percent) pay back in the first year. Resource opportunity costs, as well as the problem of estimating effective demand for surplus gas and rice husk cement, bear directly on these findings. If sufficient resources and demand exist, there does seem to be a greater chance of economic viability with the larger systems that can run an industry and provide additional energy. But it is essential that this question be examined in a particular village with its unique set of opportunities and constraints.
- 5. The minimum cost Models (both 2 and 3) that run an industry must realize income of at least Rs 30,000 during the period of loan repayment if they are to be viable, even if digester costs are halved (see Tables VI-8 and VI-9). Payback occurs in eight of 24 cases. Of these, five pay back in the first year. The case that comes closest to modeling the expected performance of the Pura system (full-cost digester, no sale of surplus gas) shows a payback of 7-9 years, depending on interest rates. This result is interesting because it does not assume that capital would be provided free of charge, as the Karnataka State Government is doing for Pura. Nonetheless, the project would need assistance during the loan

repayment years to cover the operating deficit that would occur during that period.

6. In the 18 maximum output cases for each of the Models, surplus gas was set at different prices to examine the effect of those prices on economic performance. At the equivalent price of diesel (Rs 1.48/[m.sup.3]), 12 cases (67 percent) pay back during the life of the project. Eight of these (44 percent) pay back during the first year. Setting the price at one-half the diesel equivalent (Rs .74), nine cases (50 percent) pay back. Six of these (30 percent) pay back in the first year.

As one would expect, the lower price of the electricity equivalent (Rs .25/[m.sup.3]) yields only six cases that paid back (30 percent), and of these, only three paid back in the first year (17 percent). In each of the models, the price of surplus gas interacts with the different sales levels of rice husk cement. In 75 percent of these cases, payback occurs only if cement sales exceed Rs 20,000. Systems that sell gas at half the equivalent price of diesel fuel perform surprisingly well when compared to those that sell gas at the full diesel equivalent. Making energy available at half price might well attract certain small-scale industries to rural areas. However, quantities of surplus gas are limited since a village must use most of the available biogas to meet basic cooking, pumping, and lighting needs.

7. The effect of cutting digester costs in half was studied, assuming that surplus gas sold at the diesel equivalent in the maximum output system. Of the 54 cases examined, digesters at full cost paid back in 20 instances (40 percent of the total). Half-cost digesters also paid back in the same 20 situations. Full-cost digesters paid back during the first year in 11 of these cases (20 percent). Half-cost digesters paid back during the first year in 15 (28 percent) of these cases, a slight improvement over the more expensive design. This suggests that, based on the limited number of systems examined here, there may be only limited justification in devoting a great deal of effort towards reducing digester costs. The effect of cutting digester costs in a large-scale system is marginal unless the "fixed costs" of labor, diesel engines, generators, and the gas pipeline are also reduced. Even if one could assume that 56 individual family-scale plants could be built at Rs 500 each, and if labor were free, the costs of installing these plants to provide cooking gas and gas lighting easily would approach Rs 31,000. This is not much less than the Rs 43,000 proposed for Model 1. It also ignores the problems of providing an

adequate supply of water for mixing with the biomass and resolving struggles over "dung rights" that might occur with family-size plants.

This analysis by no means exhausts all the possibilities of various system components. In particular, there are two possible sources of revenue that have not been included: user charges, and returning to the project a portion of income raised from increased agricultural yields. Due to the historical reluctance of many villagers to pay for cooking gas that substitutes for energy that was perceived as "free," it seemed sensible to first examine the conditions under which biogas systems might pay for themselves. Similarly, given the uncertainties surrounding the magnitude of increased agricultural productivity that would be attributed to a biogas system, the effects of returning to the project a portion of any marginal increase in agricultural income were excluded from our calculations. Still, one can speculate about the impact of including these potential sources of revenue.

From Table VI-8, we know that the annual operating deficit for the maximum output Model 1 system is Rs 8,993 in years 1 and 7-15, and Rs 23,672-Rs 26,231 in years 2-6, depending on the interest rate charged on borrowed capital. If Rs 4,000 of the Rs 8,100 expected increase in agricultural income were somehow returned to the project, the annual operating deficit would be cut to Rs 4,993 in years 1 and years 7-15 and to Rs 19,672-Rs 22,231 in years 2-6. If these deficits somehow were divided among the 56 families, the average cost per family would be approximately Rs 7.50 per month (Rs 90 per year) for years 1 and 7-15, which seems quite affordable. The average costs during the period of loan repayment still would be prohibitive (Rs 397 per year per family). This figure might be a justification for a government grant for the cost of system construction. Since we know that operating costs can be covered by the village, and the system can sell surplus gas at the diesel equivalent, the annual revenue would increase by  $(26.7 \text{ [m.sup.3]/day}) \times (358 \text{ days/yr}) \times (0.9 \text{ utilization factor}) \times (\text{Rs } 1.48/\text{[m.sup.3] Diesel Equivalent Price})$ , which equals Rs 12,730. If a little over Rs 5,000 of the increased agricultural revenue were returned to the project, the average user charge per family would be about Rs 100 per year during the period of loan repayment (years 2-6). At all other times, the system would show a profit. We have not discussed the willingness of villagers, especially larger land holders, to return a portion of their increased income to the project.

If nothing else, it should be obvious that the question of whether or not village-scale biogas systems are economic is one of considerable complexity. Under certain assumptions, the biogas

systems analyzed here seem to perform well. These assumptions are related to two types of demand:

1. Rural Energy Demand. Would villagers be willing to pay user charges for gas used for cooking and lighting? Would small-scale industries purchase surplus gas if it were sold at prices competitive with diesel fuel and electricity?
2. Small-Scale Industries Demand. Which goods and services could be produced by small-scale industries that are powered by biogas? Could these goods and services be sold in sufficient quantities to provide biogas systems with needed revenue?

We know very little about these questions, although the methodology exists for deriving some empirical answers. Increased knowledge of rural capital flows and distribution is desperately needed to determine both the priority that villagers ascribe to rural energy systems and the economic viability of these systems. This is only another way of stating the obvious, which is that rural energy problems cannot be separated from the problem of development within a larger political economy.

## VII. Village Utilization

As shown in the previous section, the economics of a village-scale biogas system can be deceptively complex. Yet of all the various aspects of biogas systems, the least studied is perhaps the most important: how do such systems affect people's lives? The experience with biogas systems to date sheds little useful information on this question. The Chinese claim that they will have installed as many as 20 million biogas plants by the end of the early 1980's--depending on which of the various estimates one reads. Technical teams sponsored by the UN; the Intermediate Technology Development Group (ITDG), London; the International Development Research Center (IDRC), Ottawa; and others all have reported observing or hearing about "large" biogas systems. These usually are connected to an institution such as a dairy or school. There is no detailed study available that documents the existence and performance of an integrated Chinese biogas production and distribution system that is used by an entire community. In fact, the Chinese experience seems to be distinguished by a reliance on individual family ownership and maintenance of biogas systems, although the labor, biomass, and delivery of construction materials may be provided "free" by a communal production brigade.(79)

Even in China, there is little information available on the number of biogas plants actually working versus the total number installed, nor on the performance levels of the working



systems. S.K. Subramanian, discussing the efforts of other Asian countries, says that while some nations report the installation of tens of thousands of systems, the systems are almost exclusively small-scale family plants.(80)

For many years prior to the watershed 1973 oil embargo, the KVIC served as an undaunted promoter of biogas systems in India. Progress since then has been slow but steady. At the close of the fifth Five-Year Plan in 1980, KVIC claimed to have installed 80,000 family-sized systems in India. There is no reliable data on how many of these plants are actually in operation. An estimate of 50-75 percent was made by several independent observers contacted during the preparation of this study. Despite the fact that the KVIC has trained more than 2,000 people to provide technical assistance throughout India as part of a youth self-employment project, biogas plant owners frequently complain about poor servicing and inadequate access to technical information. Some of the problems of drum and pipe corrosion, clogging and scum build-up, and low gas yield are undoubtedly due to faulty management, improper maintenance, and insufficient amounts of biomass fed into the digester. Yet, because so little effort has been mounted to popularize biogas systems, and because travel budgets for technical personnel are so meager, plant operators are rarely informed about solutions to technical problems.

The government subsidy program designed to stimulate the adoption of biogas systems is cumbersome and, to a certain extent, regressive. Plants with a capacity of more than 6 [m.sup.3] presently are ineligible for any direct subsidy since they are considered quite economical. The result is that wealthier farmers who own the three or more cattle currently necessary to operate a small system can receive a subsidy, whereas a village project that would benefit rich and poor alike is ineligible. Though the specific terms of the subsidy have varied over the last several years, the current program is based on a central government grant allotted to the state governments. State governments actually manage the program by determining the specific guidelines that will be followed. In general, 20-25 percent of the system installation cost is subsidized. Fifty percent of the cost generally is borrowed at 9-12 percent interest, payable over three to five years. The remainder is paid in cash by the user, although the relative size of the loan and down payment vary. Subsidies usually go directly to the bank to reduce the size of the loan or to act as collateral. Few state governments have authorized designs other than the expensive KVIC model as eligible for the subsidy. The government of Uttar Pradesh has approved the Janata system, but most other state governments are not aware of the fixed-dome design. Plants using night soil also are ineligible. Delays of one year in obtaining the subsidy

are common. Many banks do not have a competent staff to manage the program. An informal sample of several banks in Madras revealed that even the chief agricultural loan officers knew very little about biogas systems and the subsidy program.

The Chinese and, to a lesser extent, the Nepalese biogas programs are managed by local or regional organizations that were established specifically to help coordinate funding for and provide technical assistance to biogas system construction and operation. The Chinese seem to have linked regional extension organizations with macro-level planning bodies so that sufficient capital and construction materials are generated to fulfill production targets. In addition, an extensive promotional campaign using radio broadcasts, permanent exhibitions, films, and posters is used to generate interest in biogas plants. Finally, the Chinese social structure seems to lend itself to the rapid diffusion of biogas technology. The traditions of waste recycling and collective effort are strong. The system of government eliminates the need to appeal to individual families if the communal leadership accepts an idea. An effective extension system, in which people are trained to construct and operate biogas plants and then help train others, generates technology dissemination by "chain reaction." At the same time, a decentralized research and development system appears to have encouraged a great deal of autonomous local innovation. Funds presumably were provided for local experimentation with different biogas system designs.(81) Other countries would do well to study the particulars of the Chinese experience to judge more accurately which aspects of China's biogas development program could be adapted to different socio-cultural settings.

The Biogas Corporation, a public/private sector company in Nepal, guarantees system performance for five years and does its own installation. The Agricultural Development Bank of Nepal provides loans at six percent.

In sharp contrast to both the Chinese and Nepalese programs, the Indian effort has been fragmented among the KVIC (which also is charged with promoting more than 20 other small-scale industries), the Ministries of Agriculture and Rural Reconstruction, State Khadi Gramodyog (village industry) Boards, banks, contractors and builders, state agricultural departments, and agro-industries corporations. It is remarkable perhaps that the Indian program has achieved even its modest success(82) despite the serious problems of inadequate technical assistance, cumbersome financing procedures, and overlapping or conflicting institutional jurisdictions.

The KVIC has proposed a program to reach the 12 million families who own sufficient (three to five) cattle to operate a

family-size biogas system. The KVIC believes that regional mass production of prefabricated ferrocement digester/gasholder segments could significantly lower the costs of small-scale systems. Even assuming that individual families pay for installation and operation of their own systems so that the government does not have to subsidize biogas systems directly, and also assuming that the overhead costs (including subsidies, credit facilities, technical assistance, and staff requirements) to the government for a large-scale biogas manufacturing program are only Rs 100 per family, the total overhead costs of such a program could easily approach Rs 120 crores (\$156 million).

Such a program raises a number of important questions regarding the equitable use of scarce capital and the effects of such a program on rural income distribution.

Dung is a source of both fuel and income for the poor who, in addition to using dung they are able to find for cooking and space heating, also sell dung to generate a meager income. If "free" dung becomes monetized, then the poor, who will not have access to family-scale systems, may be deprived of both income and fuel. It may be possible to lessen the cattle-ownership constraint by a combination of solar heated digesters and the use of biomass other than dung. However, the capital costs and land requirements of these systems would still be beyond the means of the vast majority of poor village families.

The KVIC scheme also raises the question of tradeoffs between centralized versus decentralized fabrication of biogas plants. It is possible that both rapid installation and quality control would be more easily accomplished if units could be mass-produced. The possibility does exist for production economies of scale. Yet, a more decentralized approach, in which individual villagers would become skilled in and develop a business from building and operating biogas systems, might generate far more employment, consume less steel and cement, and rely more on local materials that are renewable and have a low opportunity cost. Furthermore, it would be likely to foster greater rural self-reliance and innovation, reducing the potential for bureaucratic delays, corruption, and infrastructure obstructions that often plague large-scale, centrally directed projects. The challenge of a decentralized scheme is how to develop effective ways of providing technical assistance and financing for these systems. Some suggestions for such a program are contained in the conclusion of this study.

As biogas systems become more dependable and less expensive, the task of defining the appropriate role of the government in promoting them assumes greater importance. It is possible that

a government-sponsored production effort might itself become an obstacle to the large-scale use of biogas systems.

The most immediate need in the development of biogas systems is to gain considerably more experience with actual village-scale systems. There have been several attempts to develop such systems in India. One of these in Kodumenja village, Karimnagar district, Andhra Pradesh, was sponsored by the Rural Electrification Corporation, Limited, and the Indian Council of Scientific and Industrial Research (CSIR). The system consists of a ring of 24 interconnected ferrocement floating-drum digesters, with a total capacity of 128 [m.sup.3]. It is designed to provide cooking gas and lighting for 60 families, and to operate five pumpsets. The system's capital costs are more than Rs 1.25 lakhs (\$15,625). There have been many problems with the ferrocement domes cracking due to improper fabrication, and the defective domes have been replaced. As of May 1980, however, the system was operating at only half its capacity because the village was in the midst of a political feud. Half the population refused to contribute dung to support a system that would also benefit their rivals.

Another community-scale plant in the village of Fateh Singh-Ka-Purva, Bhagayanagar Block, near Ajitmal, Etawah District, Uttar Pradesh, was designed and installed by PRAD with a grant from UNICEF. The system required a capital investment of about Rs 1.65 lakhs (\$20,625) for two plants of 35 [m.sup.3] and 45 [m.sup.3] respectively, a dual fuel 5 hp engine, a generator, gas distribution pipeline, cooking burners, electrical wiring, and miscellaneous equipment. The 80 [m.sup.3] system was to have provided cooking and lighting (electric) for 27 households (177 people) in addition to running pumpsets, a chaff cutter, and a thresher.

Fatah Singh-Ka-Purva is an unusual village in that the residents are relatively comfortable economically. Almost every household owns land, and income is distributed rather evenly. The villagers are of the same occupational caste (shepherds), and were enthusiastic about building the biogas system. The spatial layout of the village is such that all households are clustered around one or two areas, which simplifies gas distribution

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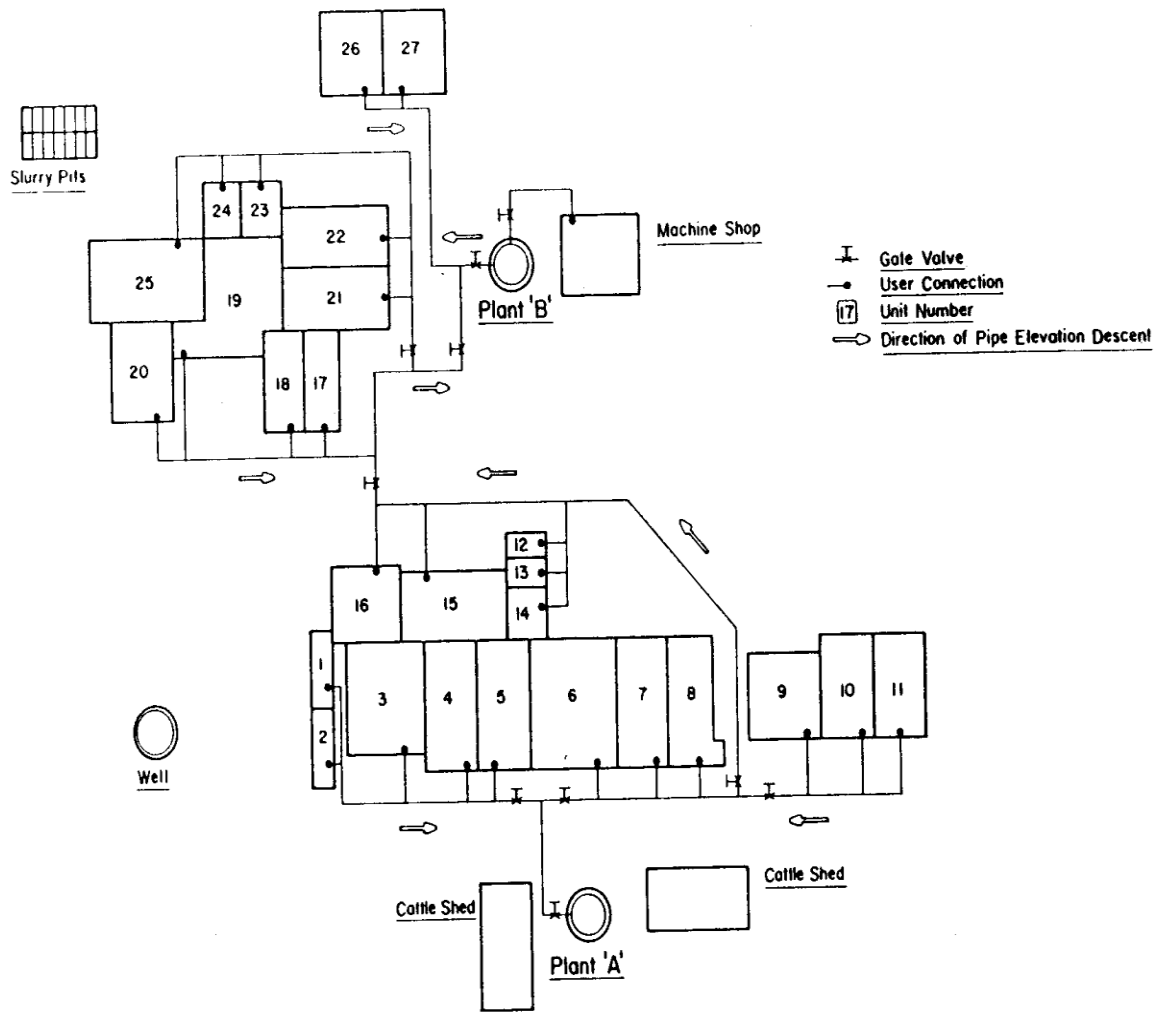


Figure VII-1. Fatah Singh-Ka-Purva biogas pipeline layout

(see Figure VII-1). Finally, the village initially had an unusually high cattle to family ratio (4:1), compared to the national average of 2.5:1.

The advantages Fatah Singh-Ka-Purva enjoyed due to its socio-economic conditions, the technical competence of PRAD, the financial and organizational assistance of the local and state government authorities, and the good offices of UNICEF all were cast aside somewhat rudely by the unpredictable changes of nature. A serious drought resulted in the death or forced sale of a number of cattle, reducing the cattle population by almost 13 percent (from 117 to 97). This reduced the amount of dung available to the system. The system continues to struggle just to meet cooking and lighting needs. It will not be possible in the immediate future for the biogas system also to run machinery.

During the author's visit, a substantial number of dung cakes were observed drying in the sun. Ironically, they were spread around the southern exposure of one of the digester bases. The residents of the village are not contributing the required amount of dung, perhaps 30 percent less than needed. Some villagers seem to prefer the taste of milk when it is slowly boiled over the more diffused heat of dung cakes. Similarly, the cooking of rotis, a kind of thin fritter, requires special burners to distribute heat over a broad surface area. People are sometimes inconvenienced by the fixed timings of gas release, restricted to two hours in the morning and two hours in the evening, especially if they have to work late in the fields. Some fuel is saved to heat water for bathing, washing, and cooking, especially during the winter months when gas production falls anyway due to the effect of lower temperature on microbial digestion. Finally, the author also observed some frustration on the part of the site engineer who, having left the project for two weeks, found certain tasks uncompleted or improperly executed. This seems to be related to village politics; some families do not support the president of the project "association."

Both these community systems distribute cooking gas freely. Slurry is distributed proportionately on the basis of per-household contribution. People are reluctant to pay for lighting, which is not perceived as a real need. Since cooking fuel formerly was "free," they are unwilling to pay for it now even though biogas is more convenient and cleaner. Villagers, while enthusiastic about the potential of the system, also have the political accumen to realize that these projects are really not theirs. They see that the systems are the showpieces of scientists and development agencies that cannot afford to let the projects fail. When a central government team visited Fateh Singh-Ka-Purva, villagers inquired what else could be "given" to them similar to the biogas plant. No mention was made of paying for additional services. The incentive to assume managerial and operational responsibility for these projects is simply lacking on the part of the villagers, and eventual self-sufficient management seems problematic.

Neither system is financially viable, in terms of cash flow, net present value calculations, or other economic performance measurements. In fairness to these projects, it must be remembered that they were pioneering efforts designed to demonstrate the technical feasibility of village-scale biogas systems. They also are intended to help technologists and planners understand some of the impact of this technology on village life. These goals were accomplished. While the analyses of economists are

helpful in developing analytical methods and generating useful data on village household energy consumption patterns,(83) any criticism of these particular projects on economic grounds, even if only implied, seems somewhat unfair. By contrast, the ASTRA system under construction in Pura village is designed to be both profitable and self-sustaining. As such, it represents the next logical and necessary step in the development of village biogas systems.

Two of the largest village systems yet attempted in India, each with a daily capacity of about 200 [m.sup.3], are under construction in the Gujarati villages of Khoraj, Gandhigram District, and Khubthal, Ahmedabad District. These systems are based on the ASTRA-modified KVIC design, which includes the solar water heater. Designed and constructed, and to be managed, by the Gujarat AgroIndustries Corporation, both systems will supply more than 100 families in each village with gas for cooking. Biomass inputs will include dung, human wastes from a community latrine, and agricultural residues. According to the unpublished feasibility report, families will have to pay to connect their homes to the main gas pipeline. In addition, all dung will be purchased, slurry will be sold, and villagers will have to pay for the gas. Both systems require an investment of just over Rs 2 lakhs (\$25,000) each. These systems will receive subsidies from the state government for approximately one-third of this investment cost. It will be interesting to monitor the progress of these projects, especially the willingness of the villagers to pay for gas, the performance of the systems and community latrines, and the long-term financial viability of the systems.

### Technical Questions

Based on what we know about biogas systems, a number of problems must be resolved before a program can be disseminated on a large scale. Relatively little data exists on the net energy needed to prepare particular meals, nor on how this is affected by agro-climatic variations, income levels, and local customs. Such information is necessary to determine the required capacity of a biogas system in conjunction with whatever other operations are fueled by the biogas. More information is needed on the most efficient stove and burner designs, and on the effect of different types of cookware materials on gas use.

One of the few benefits of the inefficient and often smoky chulahs is that the smoke or odor aids in controlling mosquitoes and termites. Use of a clean burning fuel such as biogas might upset this balance. It may be that biogas systems can be introduced in certain local situations only in conjunction with different housing construction techniques or pest control

measures.

Slurry handling and distribution can be both time consuming and annoying. Villagers express little interest in contributing free labor to biomass collection and slurry mixing, although in Fateh Singh-Ka-Purva they do assist in the delivery of slurry to individual compost piles, central storage pits, or crop lands. A large-scale community plant run on a continuous basis produces more slurry than can be used daily; convenient storage facilities must be provided. Alternative means of handling biogas slurry require further research within the context of village skills and capital constraints. These include possible mechanized distribution, direct application of manure versus "seeding" existing compost pits, or incorporation into integrated feed/fertilizer/fuel systems such as algae ponds, pisciculture, etc.

Water and land use requirements of biogas systems can be substantial. Large-scale underground plants can reduce land requirements unless plants are covered by a solar pond. Villagers will have to assess the opportunity cost of land occupied by a biogas system. Community biogas technical teams have in the past viewed the free donation of land and water for biogas systems as a kind of litmus test of a village's commitment to the system. This may not be an unreasonable approach, but it should not be assumed that land and water will always be available or close enough to points of use to prevent high distribution costs. In addition, ways to recycle the water and reduce the system's water demand, currently almost equal to the weight of biomass added, need to be developed. Finally, the spatial distribution of huts, sheds, wells, etc., in many villages may increase gas distribution costs dramatically. This is due to both the cost of the pipe and to the need to compensate for pressure losses over long distances. These distribution concerns, coupled with villager complaints about the inconvenience of fixed timings for the release of gas for both cooking and lighting,(84) suggest that alternative techniques for the decentralized storage of gas need to be investigated. Storage sacks with a compressible inner bag to maintain sufficient gas pressure could be developed. Safety problems--the danger of explosion due to puncture--and of practical storage volume need to be surmounted. The potential advantages of a more decentralized system have been discussed earlier.

Of course, these technical questions are in addition to numerous other areas requiring further research and development, as discussed in Section III. These include the use of agricultural and forest residues, the merits of fixed-dome versus floating-drum and plug-flow designs, the relative importance of constant gas pressure, and ways to increase gas production throughout



the year.

## Financial Viability

The most obvious economic challenge to community biogas systems is to make them viable financially. The economic analysis of the previous section shows that, given the reluctance of villagers to accept user charges, community biogas systems will have to find some other way to generate revenue or "cross-subsidization," even with significant cost reductions and improved system performance. Alternatives could be in the form of a "subsidiary" commercial operation or the direct sale of surplus gas to a small-scale industry. As was mentioned earlier, speculating on potential revenues is a far cry from actually generating rural industrial energy demand. In fact, it is unclear if the increased availability of inexpensive energy would be a sufficient stimulus to generate rural industries. Community biogas systems somehow must demonstrate that external revenue sources will materialize as expected. Whether or not lending institutions develop confidence in such assessments remains to be seen.

The difficulty in getting villagers to accept user charges will vary from village to village. Villages spending a significant proportion of the "village product" on energy will naturally be less resistant to some of the progressive pricing schemes suggested by Parikh and Parikh and by Moulik and Srivastava.(85) These authors suggest various pricing policies that combine higher unit prices for wealthier families, and either "free" (subsidized) community cooking and latrine facilities or the allocation of gas on the basis of free labor contributions by the poor.(86) These sensible pricing policies rely on a series of untested assumptions regarding the detailed keeping of records and monitoring of consumption that would be required to make such systems work. Furthermore, in many if not most villages, biogas is a substitute for what villagers perceive to be "free" fuels: dung, agricultural residues, or even firewood. Admittedly, such a perspective may seem somewhat shortsighted given deforestation, population growth pressures, and the high cost in time to a woman who has to walk for hours to gather fuel. But it is difficult for a villager to justify paying for something that can be obtained at the low cost of his, or more likely, her labor.

This outlook raises a much larger question concerning the perception of both villagers and economists regarding the utility of investing scarce capital in energy systems. Are village energy projects a response to clearly stated village demands, or are potable water, adequate shelter, an affordable supply of food, and a sufficient income to release a family from

perpetual debt perceived as more important? The problem of "what is to be done" certainly will vary from village to village. It probably even varies from season to season. The village energy bandwagon should be jumped on first by villagers, and only then by economists and planners.

The overall effect of biogas systems on the local distribution of income is unknown. Bhatia and Nairam found that, as one would expect, energy consumption increases with income. Even in a relatively homogeneous village such as Fateh Singh-Ka-Purva, free cooking gas increases discretionary income the most for those with the most income.(87) Some potentially harmful effects already have been mentioned. Dung currently is sold by members of the lower castes to earn a meager income. A biogas system might take away that income source from them. Furthermore, an increased demand for dung or crop residues might deprive the poor of fuel. In addition, people who own more land and cattle clearly will benefit more from a proportionate distribution of biogas slurry. One could even speculate that, over time, increased agricultural productivity, energy, and income might make it possible for wealthier villagers to substitute capital for labor, gradually mechanizing their agricultural operations, and displacing some farm laborers.

While no one would deny the serious threats posed by deforestation, it is by no means clear that such ecological damage is always caused by the increasing rural demand for cooking fuel. While this undoubtedly may be an important cause in many specific areas, discussions with staff in the Ministry of Forestry revealed a great deal of uncertainty about whether it is the main one. For example, some large construction firms allegedly do not report the full number of trees they cut, harvesting more than they are allowed by permit.

Finally, there has been no attempt to assess the costs of providing the technical assistance, servicing, financing mechanisms, and performance monitoring that would have to be an integral part of any large-scale biogas promotion program. These overhead costs will occur regardless of whether a large-scale program creates the decentralized, "spontaneous" adoption advocated by many village technology groups, or the large, centrally coordinated, mass-production and installation programs favored by some in government and industry. The high costs of even unprofitable experimental village systems can only heighten apprehension on this point. The goal of research and development efforts must be to generate system designs that will minimize the dependence of villages on outside money, material, and technical assistance.

## Sociological Questions

The paucity of sociological, anthropological, and organizational analyses, even of the two community systems discussed earlier, makes any treatment of such questions a matter of speculation.(88) Perhaps the most basic concern is the extent to which a real sense of community exists in villages where biogas systems are installed. It is clear that many villages are in fact "communities," i.e., they exhibit a shared sense of values and goals, have cooperative networks that enable the ebb and flow of daily events to occur reasonably peacefully, and enjoy a sense of trusted or accountable village leadership. However, many villages are less fortunate. Village life can be quite tempestuous, with an abundance of rivalries and struggles related to the rights of caste, marital or family discord, and indebtedness. For example, it remains to be seen if people of one caste will always be willing to consume gas distributed by the same pipeline that is used by lower castes.

There already is evidence that a serious political feud has effectively curtailed the operation of the village system in Kodumunja. To a lesser extent, factionalism also is operating in Fateh Singh-Ka-Purva. This form of protest or manipulation could seriously affect the cash flow position of a particular system, especially if loan payments are outstanding or if the biogas system is linked to one or more external commercial operations. If such a disruption, caused either by the withholding of organic raw material or by outright sabotage, continues for a long time, the long-term financial viability of the system and its dependent industries could be threatened. A related point is how rugged or durable biogas systems need to be to survive in the village, and how this affects costs.

An attitude of either cooperation or obstruction may prevail, depending on the relationship of different interest groups to the flow of benefits derived from the operation of the biogas system. A political minority might want to prevent those in power from receiving praise from villagers for successfully operating a biogas system. Such behavior has been observed in successful attempts to block the construction of irrigation canals that clearly would have benefited a village as a whole. The costs of potential loss of political power resulting from the construction of the canal were perceived by the victorious opposition as far greater than whatever gains would have been realized with the canal's operation. In addition, the detailed record keeping necessary for the technical and economical operation of the system would have conferred a great deal of power and responsibility on the plant supervisor. The range of potential abuse of such power has not been examined in this study since the dedicated efforts of the technical teams involved in the current village projects effectively preclude malevolence

and corruption. However, such individuals may not always be present in many villages. The dependence of the villagers on the ethical conduct of the system manager creates the conditions for abuse. Some system of making supervisory personnel accountable to the villagers clearly is essential. This might be done through the Panchayat governments; however, even the record of these bodies in safeguarding the interests of the poor is mixed at best.

If villagers, especially women, spend a good portion of their day collecting fuel and cooking, a biogas system could create a fair amount of leisure time. It is not clear how this would be viewed and utilized by villagers. Many benefits of a biogas system will be most attractive to women: ease and cleanliness in cooking, freedom from smoky kitchens and associated eye and respiratory diseases, and freedom from tedious grinding, threshing, and chaffing operations that could be mechanized with the use of dual fuel engines. Will men agree that these benefits are desirable? It is unclear how much influence women enjoy over major investment decisions in the family. This could be an important consideration in promoting or marketing biogas systems.

The ability of villagers to accept the concepts of collective ownership and communal living will vary. Collective ownership of the land occupied by the biogas system, as well as of the system itself, cannot be taken for granted. Similarly, people may or may not respond positively to community kitchen and latrine facilities. Community latrines pose special complications. First, the flow of water from the latrines to the system somehow must be regulated so as not to result in excessive dilution of the biomass fed into the system. Second, the ritual of walking to the field early in the morning is one of the few times during the day when women find the privacy to socialize among themselves, free from other responsibilities. This may also be true for the time spent collecting firewood. It is not clear that these practices will be discontinued easily.

Finally, some people view biogas, and "appropriate technology" in general, as an agent of social change. They reason that because these technologies require a great deal of both stewardship and cooperative action on the part of users, the introduction of appropriate technologies will foster the necessary behavior and attitudes, even if these are outside the villagers' own experience. Such "technological determinism" may indeed exist, and there certainly are examples of it. However, the critical question remains: to what extent can a technology be "beyond" the present village culture and still be adopted by the villagers without causing undesirable socio-economic effects? Given that there is resistance to change, who will

decide that "this" technology is in fact appropriate for "these" villagers, or that the social change required by a technology is desirable? Biogas systems affect some basic aspects of village life: the distribution of land, water, fertilizer, fuel, and income. It remains to be seen whether biogas systems can be adopted on a large scale without a political struggle to secure equitable access to these resources.

These choices, if they are in fact choices, force us to confront the "appropriateness" of biogas systems. After much more experience with these systems, we might be in a position to evaluate biogas systems as a whole, voicing a collective approval or disapproval. But at this stage of development, such a pronouncement is unwise and potentially destructive.

The problem of actually introducing a technology, such as village-scale biogas systems, is one of staggering complexity. No one has analyzed fully how to transfer such a technology from the laboratory to the village as a necessary phase of research and development. It often is assumed that once technical problems are solved and biogas systems can pay for themselves on paper, villagers will accept biogas because it is a good idea whose time has come. For example, there is an extremely dedicated, private group of village energy specialists and biotechnologists who are working in a number of Tamil Nadu villages. This group has worked closely with a particular village for several years and still has a difficult time convincing certain families to experiment with small family-scale digesters. The families agree that biogas is a good thing, but are engaged in a highly profitable, but illegal, venture, producing arrak (a strong alcoholic beverage) and selling it in Madras. These families feel that their lives are progressing quite nicely and seem threatened by the presence of outsiders pushing biogas systems. Far too little attention has been devoted towards understanding under what conditions villagers will actually use biogas systems. How will they adapt to these systems without massive, unrealistic, and possibly undesirable intervention by government officials, engineers, technologists, or international lending agencies?

An extensive training program undertaken by a voluntary agency, Action for Food Production (AFPRO), New Delhi, to train masons to construct fixed-dome Janata design plants has been only partially successful. AFPRO has found that even though masons know what to do, they lack the self-confidence to construct these plants without supervision. AFPRO's experience suggests that training and extension work for promoting biogas systems (as well as for technology in general) must deal with psychological issues as well as with technical knowhow. If biogas systems cannot be designed, constructed, operated, and maintained

largely by the people who will use them, their "appropriateness" in providing energy, fertilizers, and that messy thing called rural development seems dubious at best.

Nevertheless, it is important to acknowledge that despite the potentially serious managerial and sociological problems that may occur during the operations of village biogas systems, this does not mean such problems necessarily will occur. There are numerous examples of villagers adapting to radical departures from their traditional way of life once they were convinced of the merits of the new way. While vested interests will attempt to control any change, the judicious intervention by a village elder, popular chief minister, or perhaps even the prime minister, can immobilize obstructionist forces. Before such "marketing" is done, village-scale biogas systems must be economical and reliable, and their impact on different village groups better understood.

The point behind this discussion of questions still to be resolved is not to condemn biogas systems. Rather, it is to show that despite a great deal of promise, serious questions do remain. By specifying these uncertainties, a much clearer sense emerges of what is needed in the future.

#### VIII. Conclusions and Recommendations

In 1974, Prasad, Prasad, and Reddy published "Biogas Plants: Prospects, Problems, and Tasks" in the Economic and Political Weekly. This highly influential article is a masterful synthesis of a great amount of seemingly unrelated data. It remains the most concise and comprehensive statement about biogas systems. In the years since, the ASTRA group, Bangalore, has conducted extensive research and development to improve system designs and increase gas yield through the use of solar energy. ASTRA has also begun to deepen our understanding of village resource and energy flows. PRAD, in Lucknow, has undertaken development and extension of small brick, fixed-dome digester designs with reasonable success. Other groups like MCRC, Madras, have experimented with low-cost hybrid digester designs and integrated energy-food-fertilizer systems. Two village-scale systems have been built and are functioning with mixed degrees of success, and at least three promising systems are under construction. The Department of Science and Technology of the Government of India has spent Rs 56 lakhs (roughly \$700,000) on its three year, "All-India Coordinated Project on Biogas." This program sponsors research on the microbiology of digestion, ferrocement gas-holder construction, dual fuel engines, etc., and has established several regional biogas system testing centers. Other groups are also conducting experiments with biogas, as discussed earlier.

After numerous on-site visits and discussions, it seems that small, nongovernmental, often undercapitalized groups have contributed most to the further development of biogas systems. The government All-India Coordinated Project has not matched the autonomous small research groups in terms of the quality, creativity, and long-term usefulness of their research. The small teams are often constrained by lack of resources and insufficient "clout" to secure access to materials and monitoring equipment. Furthermore, their often tenuous financial situation makes it difficult for them to keep dedicated and competent research, development, and implementation teams intact. Such groups are especially difficult to maintain due to the system of rewards and incentives in Indian research. These incentives are either heavily biased toward Western basic research or else respond to the needs of Indian industry and government agencies.

Despite the achievements of some groups, it is clear that many of the basic questions posed in the 1974 biogas article in the Economic and Political Weekly still remain unanswered. System performance must improve; costs must be reduced, a variety of organic matter still awaits practical field level digestion, the relative advantages of fixed-dome vs. floating-drum gas-holders must be established, and the unknowns surrounding the operation and management of village-scale systems remain. Much more work needs to be done to piece together the data to answer these questions more definitively. In fairness, it must be noted that system construction, start-up, and operation must be evaluated for at least one year before any conclusions may be drawn concerning performance of a particular system. Even more time-consuming, and perhaps of greater necessity, is the difficult process of identifying a village that could use a biogas system to meet local needs. Promoters would then need to establish the trust and credibility to work there, collecting all relevant data, and finally designing and constructing a large-scale system. Biogas systems research also must compete with the full range of energy technology research, from solar collectors to breeder reactors.

Happily, the pace of biogas systems work is accelerating. The Pura village project will be quite helpful in assessing the potential contribution of biogas systems in meeting rural needs. The Pura system is based on detailed resource surveys and will be coupled with an industry. The system is an advanced design, and has village operation and self-management as a primary goal. PRAD is reportedly constructing several large 50-80 [m.sup.3] fixed-dome village-scale systems that should help answer some of the questions about both the cost and performance of the fixed-dome design. There are plans for constructing 6-20 village-scale systems as part of the Department of Science

and Technology's further work in collaboration with KVIC, PRAD, the Center for Science for Villages, and the Indian Institute of Management, Ahmedabad.

While more village experience is needed, it is unclear whether the government sponsored approach will include the most cost-effective designs, integration of a small industry, and a genuine attempt to design and implement the systems with the equal participation of villagers. Even if the executing group plans to march into a number of villages and, in the space of several months, "drop" large-scale biogas systems in those villages and then monitor system operation, some technical data will be generated. However, these systems will be operating in the peculiar context of an "outside" project that villagers will treat with the same range of bemused, annoyed, bewildered, and manipulative attitudes that have been observed in similar projects. Such a scheme would be grandiose in scale, but limited in usefulness.

If the experiences of the dedicated research and extension groups such as ASTRA, PRAD, Center for Science for Villages, MCRC, Butwal Technical Institute, Appropriate Technology Development Association, and others are any guide, the nurturing of an equal relationship with villagers based on mutual learning and respect is a difficult, slow process that demands a complex mix of scientific, management, and communications skills, coupled with a great deal of commitment on the part of the technical assistance team. Effective village energy technology work and, probably, effective rural development are possible only if done at the micro-level.

Most of the remaining technical questions concerning biogas systems could be resolved easily within two to three years given adequate funding and proper coordination of research efforts. Some ways to do this, in order of increasing difficulty, are suggested below:

1. Create a network among the small biogas research groups so that their work becomes complementary and a greater exchange of experiences and knowledge occurs. The smaller groups understandably, and probably correctly, wish to preserve their autonomy. They are wary of any incorporation into a large government-sponsored research effort. However, these groups also suffer from an ignorance of each other's work due to poor communications, financial constraints precluding frequent contacts, and reluctance for a variety of reasons to take time away from their own work and share their findings with others.

This network must evolve from the groups themselves so that the autonomy of each remains unthreatened. Any external funding for



this type of network, whether from private foundations, government ministries, or international lending agencies, must protect the autonomy of the participating groups. There may be some tension between the needs of the funding source to have accountability for its sponsored projects and the desire of some network participants to merely exchange information and not publish until their work is completed. This is not a question of jealously guarding trade secrets to protect potential profits or prestige. Many of these groups have had many painful experiences with outside interests that distort or exploit their years of work. The smaller groups often have special relationships with villages; outside interference can potentially undo years of establishing credibility and trust. Despite these challenges, the advantages of small groups sharing their work among themselves are numerous, and a framework for cooperation can be developed if the groups themselves are willing to do so.

2. Create a more harmonious relationship among national planners, national laboratories, and the smaller research and development groups. The exact nature of this relationship is difficult to specify, and a discussion of Indian institutional politics and bureaucratic jurisdictions is beyond the scope of this study. It would appear possible that smaller research and development groups could suggest areas of basic research in which they lack resources or competence. These areas could then be taken up by national laboratories and planning bodies.

There are several such research areas worth mentioning:

- a. Analyses of the thermal efficiencies of different fuels as a function of the appliances in which the fuels are burned. The variations found in different agroclimatic regions must be identified so that reliable energy consumption norms can be established.
- b. Surveys of energy flows in rural areas to establish a set of norms for different agroclimatic areas. It is essential to reduce the number of possible permutations due to customs, diet, geography, local costs, appliance efficiency, crop and animal husbandry patterns, etc., if rural energy planning is to move beyond macro-level guesswork and costly micro-level analyses.
- c. Identification of small industries that can make use of the type of energy available from biogas systems. These industries must have a high probability of achieving a profit to enable a village system to be viable financially. Their various financial, technical, organizational, and marketing aspects need to be understood thoroughly. Some industries

that seem to have promise are: dairies; refrigeration; use of  $\text{Ca}[\text{CO}_3]$ -based products; grinding; milling; threshing; chaffing; food processing, rice husk cement manufacturing; brick and tile making; some melting operations; fertilizer manufacturing; animal feed and fodder; pyrolytic processes; and oil expelling and extraction.

3. Effective village energy planning will be possible only if an organizational infrastructure is created to deliver usable energy technologies to villages. Such an infrastructure must be able to undertake:

- a. An assessment of needs, conducted jointly by villagers and planners.
- b. The development of responses to those needs which may or may not involve the installation of such hardware as a biogas system.
- c. The implementation and monitoring of work.

These three phases of rural energy planning must be integrated, which clearly is a difficult management problem. This integration will require some creative organizational development.

Many of the existing groups concerned with rural energy issues have considerable individual strengths, but are isolated from each other. They frequently approach energy planning in a fragmented way due to limited resources. The result is that technologists experiment in laboratories with technologies that are of questionable use to villagers, while many social scientists criticize the technologists' R&D efforts, often without understanding adequately the potential of the technology. Meanwhile, voluntary agencies often use unproven technologies whose many impacts are only dimly appreciated and for which sufficient financing and technical assistance resources do not exist. Invariably, these three groups--technologists, social scientists, and village voluntary agencies--engage in destructive rounds of recriminations. A way must be found to bring them together.

One way to nurture the kind of integration required would be to form state level rural energy groups. The state level seems an appropriate scale in terms of available resources, common language, politics, and existing institutions and programs. These groups would consist of representatives from private research teams, universities, state government officials, industry, lending institutions, and voluntary agencies. While some of these individual representatives might serve as advisers, there would also be a need for a full-time staff. The energy group would have the following functions:

1. Coordinate the state-wide rural research and development efforts of existing institutions, eliminating duplication and ensuring that research designs incorporate the perspectives of economists, anthropologists/sociologists, and voluntary agencies.
2. Organize the extensive exchange of rural energy information within the state, among other Indian states, and with other countries, especially throughout Asia. The considerable difficulties encountered by the author in obtaining reliable information for this study, necessitating repeated personal visits throughout India, underscores the need for information exchange.
3. Fund and evaluate demonstration projects, and, if necessary, create new research groups to do this.
4. Organize a "rural energy corps." The corps would consist of people trained in conducting energy/ecological surveys and would help villagers select technologies that seem appropriate to local needs. It would do this by helping people to obtain financing, secure access to materials, organize construction or training programs, and ensure the proper operation and maintenance of hardware. The corps would live in strategically chosen villages for several years to maximize the effect of demonstration projects, provide ongoing technical assistance, and monitor progress carefully. If corps members work with existing voluntary groups that already have established themselves in villages, so much the better. Where no such organizations exist, the corps could form the nucleus of a larger rural development effort that would be a natural outgrowth of "energy" work.

Aided by coordination from the rural energy group and the vast field experience of the rural energy corps, energy planning would become an important aspect of development planning. Energy planning cannot be separated from land use, ownership patterns, caste relations, the division of labor between men and women, access to credit, and the economic and political relationships between urban and rural areas. It is a dangerous delusion to treat rural energy planning as a matter of developing and installing "appropriate" hardware. A firm link between the multidisciplinary coordination of the energy group and the local planning and implementation work of the rural energy corps, each learning from the other, will help protect against such myopic planning.

If promising energy technologies, like biogas systems, are to

contribute to rural life, the almost infinite number of system designs and variations must be reduced and simplified to a few basic systems. As Dr. A.K.N. Reddy suggests, this work must be based on a much deeper understanding of the village economy and ecosystem. It may be possible to classify villages broadly by the nature of their resource flows, and to use biogas system designs that would correspond to established patterns of consumption. At a minimum, a methodology must be developed to allow a technical team to assess easily, quickly, and accurately a village's resource flows. Such a methodology is vital for determining the best investments in energy and other technologies, and also for the broader development problem of the optimal use of local resources. The organization of state-level energy groups and a rural energy corps would be an important first step toward addressing some of these questions.

None of this work will be possible without the help and trust of villagers themselves. Efforts must be made to reduce the divisions of caste, religion, and education that have so crippled India. One way to begin building a cooperative village environment is to have a technical team work with a receptive village leadership to define simple projects that require collective work. These projects should be executed easily and have immediate and demonstrable results, such as improved village road drainage, construction of pit toilets, or a collective lift irrigation system. This would demonstrate the technical team's credibility and competence, and would provide the villagers with a sense of confidence and willingness to cooperate.(89)

Using this experience as a foundation, more complex projects, such as a village biogas system, could be discussed to see if villagers felt this system made sense to them, given their perception of their needs. In this way, villagers could correctly feel that they chose a biogas system because it would make their lives easier, and thus would feel a sense of responsibility and ownership toward the system. They also would have confidence in the technical team and themselves, as proved by the successful completion of the earlier project.

As discussed earlier, a number of areas require more research and development work to improve the performance of biogas systems. However, far more effort is needed to link the laboratory with villagers. The shifting of emphasis toward joint research and development in partnership with villagers, responding to their sense of their needs, would be a radical departure from the current thrust of much rural energy research, which prefers the isolation of the laboratory and the cleanliness of the conference room. However romantic this approach may sound, it poses great challenges to scientists, planners, and villagers alike, even assuming that the will exists to embark upon this path. At the moment, it is difficult to be hopeful about the

likelihood of such a commitment. There are numerous barriers that make this approach difficult. Even so, the barriers must be overcome. Women and children spend one-third to one-half of their waking hours collecting fuel. Crops are lost because there is no energy to run even installed pumpsets. Mountainsides are denuded and croplands destroyed. Entire generations of children cannot study in the evening because there is no light. While many of these conditions have existed for perhaps thousands of years, one can only wonder how much longer villagers will tolerate them, especially given the rising expectations caused by increasingly modern communications systems and political and commercial marketing.

During the preparation of this study, the author met literally hundreds of college students, government officials, university faculty, and industrialists who were at least convincingly sincere in their expressed desire to live and work with villages on rural energy problems. The often cited obstacle preventing these educated and committed individuals from doing so is the absence of an organization that would provide adequate technical and financial support, both for their work and their personal lives. There is a vast, potentially renewable energy source--human talent--that remains untapped in India. All that is needed is the vision to organize it.

#### Notes

(1) China: Recycling of Organic Wastes in Agriculture (1978), FAO Soils Bulletins 40-41; China: Azolla Propagation and Small-Scale Biogas Technology (1979). Also see: M.N. Islam, "A Report on Biogas Programme in China" (1979).

(2) C.R. Prasad, K.K. Prasad, and A.K.N. Reddy, "Biogas Plants: Prospects and Problems and Tasks," in *Economic and Political Weekly* (1974). Bombay has had a large-scale municipal sewage gas plant in operation for some time, as have several other cities in India. R.K. Pachauri, *Energy and Economic Development in India* (1977) suggests that there is great promise for biogas systems in urban areas. There are reports from the People's Republic of China of municipal plants used to generate electricity. See Chen Ru-Chen et al., "A Biogas Power Station in Fashan: Energy from Night Soil" (1978).

(3) Roger Revelle, "Energy Use in Rural India," in *Science* (June 1976), p. 971.

(4) Ashok Desai, *India's Energy Economy: Facts and Their Interpretation* (1980), pp. 44-61.

(5) N.B. Prasad, et al., *Report of the Working Group on Energy Policy* (1979), p. 27.

(6) Revelle, op. cit., p. 970.

(7) A.K.N. Reddy et al., A Community Biogas Plant System for Pura Village (1979). Sheep and goat dung are not included in the calculations due to the difficulty in collection. The 8.0 kg/head average fits well with one set of detailed observations.

(8) Based on empirical observations, *ibid.*

(9) KVIC, "Gobar Gas: Why and How" (1977), p. 14. Reddy, *ibid.*, p. 18, observes a higher calorific value biogas (5,340-6,230 kcal/[m.sup.3]) but the conservative KVIC figures are used to account for variations in methane content due to temperature and cattle diet variation in India. Also, the calorific value for crop residues is slightly overstated. However, in view of the large amount of biomass, such as water hyacinth, that has been omitted from the calculations, this calorific value will suffice.

(10) S.S. Mahdi and R.V. Misra, "Energy Substitution in Rural Domestic Sector--Use of Cattle Dung as a Source of Fuel" (1979), pp. 3-11. No data are given for yield of goat dung; 0.1 kg/goat/day has been assumed and the calculation corrected accordingly.

(11) Revelle, op. cit., p. 973.

(12) Reddy, op. cit., p. 21. This figure, based on data collected in Pura Village, is a very crude measure of the percentage of total energy used in cooking. Little is known about the all-India range of variations of this figure, especially in the north where water heating and space heating requirements will vary seasonally. The figure probably overstates energy consumed in cooking. This is acceptable for our purpose since we are looking for conservative estimates.

(13) *Ibid.*, p. 11.

(14) Fertilizer Association of India, Handbook of Fertilizer Usage (1980), p. 76. The calculations of the fertilizer content of organic materials are therefore conservative estimates.

(15) Madhi and Misra, op. cit., p. 5.

(16) The Hindu, 27, July 1980, p. 6, and discussions with the Fertilizer Association of India.

(17) N.B. Prasad et al., op. cit., pp. 14-16, 32.

(18) Ibid., pp. 16, 32.

(19) See Ashok Desai, *op. cit.* National Sample Survey Data and NCAER fuel consumption surveys are notorious for relying on interviews rather than actual measurement of fuel consumption. An all-India survey of energy consumption currently being prepared by NCAER attempts to improve data collection by establishing local norms for energy consumed in cooking, heating water, etc., and then interviewing people about their eating habits, daily routines, etc. From this data, energy consumption is computed based on the norms, rather than by asking people to "remember" or visualize how much firewood they collect daily. However, the latter information may be used to crosscheck survey data.

(20) One assumption that seems questionable is the rate of substitution of noncommercial fuels by commercial fuels. This is based on rapid progress in coal production and delivery, village electrification, greater availability of kerosene, increased hydrogeneration, conservation measures, greater use of nuclear power, and increased petroleum production to name a few. Recent power sector performance would suggest that such coordination and efficiency is not likely. Similarly, with population increasing to an estimated 920 million by the year 2000, it is hard to imagine noncommercial fuel consumption dropping as the Working Group suggests. Finally, the effects of increased agricultural production and the associated increased availability of crop residues and cattle population (and therefore dung) are not discussed in any detail.

(21) Ibid, pp. 35-36.

(22) Ibid, pp. 70-71.

(23) Ibid, pp. 37-39.

(24) These consumption figures are based on discussions with Kirloskar Oil Engines, Ltd. Experiments have shown that actual diesel consumption is reduced 90 percent. The 80 percent norm is used to account for performance fluctuations in engines of different ages, condition, etc.

(25) Reddy estimates for Pura Village that although a pumpset cost Rs 5,000, the electricity board can spend upwards of Rs 11,000 connecting the pumpset to the Central Government system. See Reddy, *op. cit.*, p. 24.

(26) N.B. Prasad, *et al.*, *op. cit.*, p. 78.

(27) See National Academy of Sciences (USA), Methane Generation from Human, Animal, and Agricultural Wastes, (1977), pp. 66-69; C.R. Das and Sudhir D. Ghatnekar, "Replacement of Cow Dung by Fermentation of Aquatic and Terrestrial Plants for use as Fuel Fertilizer and Biogas Plant Feed" (1970); private communication with R.M. Dave, Jyoti Solar Energy Institute, Vallabh Vidyanagar; B.R. Guha et al., "Production of Fuel Gas and Compost Manure from Water Hyacinth and its Techno-Economical Aspects (sic) (1977); P. Rajasekaran et al., "Effects of Farm Waste on Microbiological Aspects of Biogas Generation" (1980); T.K. Ghose et al., "Increased Methane Production in Biogas" (1979); P.V.R. Subrahmanyam, "Digestion of Night Soil and Aspects of Public Health" (1977); N. Sriramulu and B.N. Bhargava, "Biogas from Water Hyacinth" (1980); FAO, China: Azolla Propagation and Small-Scale Biogas Technology (1978); N. Islam, "A Report on Biogas Programme of China" (sic) (1979), and Barnett et al., Biogas Technology in the Third World (1978).

(28) Personal correspondence with R.M. Dave, op. cit.

(29) K.V. Gopalakrishnan and B.S. Murthy, "The Potentiality of Water Hyacinth for Decentralized Power Generation in Developing Countries," (sic) in Regional Journal of Energy, Heat, and Mass Transfer, vol. 1, no. 4. (1979), pp. 349-357.

(30) C.R. Das and S. Gatnekar, op. cit.

(31) Islam and FAO, op. cit.

(32) National Academy of Sciences, op. cit.

(33) Islam, op. cit.

(34) Sources of information on the microbiological and engineering aspects of digestion include sources previously cited (c.f. 30) as well as FAO, China: Recycling of Organic Wastes in Agriculture (1978); John L. Fry; Practical Building of Methane Power Plants for Rural Energy Independence (1974); John Finlay, "Efficient, Reliable Cattle Dung Gas Plants: Up-to-date Development in Nepal" (1978); and the United Nations University, Bioconversion of Organic Residues for Rural Communities (1979).

The information contained in the text has been obtained from the above sources and is a representative compilation of observed results from both laboratory and field tests. It cannot be overemphasized that the figures cited will vary depending on local conditions. Any project team referring to this study or the references cited would be wise to analyze thoroughly site conditions rather than to use these figures as the database for a particular project.



(35) See T.R. Preston, "The Role of Ruminants in the Bioconversion of Tropical By-Products and Wastes into Food and Fuel," in United Nations University, *op. cit.*, pp. 47-53. The author is grateful to Dr. C.V. Seshadri, Director, Murugappa Chettiar Research Centre (MCRC) (Madras) for several helpful discussions on this topic.

(36) Some of the centers of microbiological research in India are ASTRA, Indian Institute of Science (Bangalore); Center for Science for Villages (Wardha); Indian Institute of Sciences (New Delhi); Maharashtra Association for the Cultivation of Science (Pune); Shri A.M.M. Murugappa Chettiar Research Centre (Madras); The National Environmental Engineering Research Institute (Nagpur); Tamil Nadu Agricultural University (Coimbatore); and Jyoti Solar Energy Institute, Vallabh Vidyanagar.

(37) See Khadi and Village Industries Commission, *Gobar Gas: Why and How*, 1979.

(38) D.K. Subramanian, P. Rajabapaiah and Amulya K.N. Reddy, "Studies in Biogas Technology, Part II: Optimisation of Plant Dimensions," in *Proceedings of the Indian Academy of Sciences*, vol. c2, Part 3 (September 1979), *op. cit.* 365-379.

(39) *Ibid*, p. 368.

(40) *Ibid*, p. 373.

(41) P. Rajapapaiah et al., "Studies in Biogas Technology, Part I: Performance of a Conventional Biogas Plant," in *ibid*, pp. 357-63.

(42) C.R. Prasad and S.R. Sathyanarayan, "Studies in Biogas Technology, Part III: Thermal Analysis," in *ibid*, pp. 377-86.

(43) Amulya K.N. Reddy et al., "Studies in Biogas Technology, Part IV: A Novel Biogas Plant Incorporating a Solar Water Heater and Solar Still," in *ibid*, pp. 387-93.

(44) S. Bahadur and K.K. Singh, *Janata Biogas Plants* (1980).

(45) See E.I. DeSilva, "Biogas Generation: Development Problems and Tasks--An Overview," in United Nations University, *op. cit.*, p. 89. For additional biogas experiences, see S.K. Subramanian, *Biogas Systems in Asia* (1977) and Subramanian's later abridgement of the same in Barnett et al., *Biogas Technology in the Third World: A Multidisciplinary Review* (1978), pp. 97-126.

- (46) Personal discussions with MCRC staff, Madras.
- (47) Personal discussions with John Finlay and David Fulford, Development and Consulting Service, Butwal, Nepal.
- (48) Personal discussions with Dr. S.V. Patwardhan, Director, Center for Rural Development, Indian Institute of Technology (Delhi). MCRC (Madras) is also researching and developing integrated biomass systems for villages.
- (49) Although the National Academy of Sciences, op. cit., pp. 61-83, contains some helpful illustrations of system planning, Reddy et al., A Community Biogas Plant System for Pura Village (1979) is a more comprehensive treatment of the type of analysis needed to design an appropriate biogas system. A more generalized, relatively simple methodology needs to be developed to enable technical teams and villagers to design energy systems jointly.
- (50) John Finlay, "Operation and Maintenance of Gobar Plants" (1978), p. 3.
- (51) National Academy of Sciences, op. cit., p. 85
- (52) Ibid, pp. 92-93. For an excellent, extremely detailed troubleshooting methodology, see Finlay, op. cit., pp. 10-16.
- (53) G.L. Patankar, Recent Developments in Gobar Gas Technology (1977), United Nations Economic and Social Commission for Asia and the Pacific (ESCAP), Report of the Workshop on Biogas Technology and Utilization (1975), p. 16.
- (54) Suggested by Amulya K.N. Reddy.
- (55) FAO, China: Azolla Propagation and Small-Scale Biogas Technology (1978), p. 59, and Intermediate Technology Development Group, A Chinese Biogas Manual (1979), p. 64.
- (56) Discussions with villagers using the community system in Fateh Singh-Ka-Purva.
- (57) Reddy et al., A Community Biogas Plant System for Pura Village (1979), pp. 36-37.
- (58) Ibid, p. 80. This figure (.07 [m.sup.3]/person/day) seems low, but the methodology deriving it is correct. This suggests that a re-examination of the database may be necessary.
- (59) KVIC, ibid, p. 13. See also: Ramesh Bhatia, "Economic

Appraisal of Biogas Units in India: A Framework for Social Benefit Cost Analysis," in *Economic and Political Weekly* (1977), pp. 1515-516, for a related discussion concerning the need for research in this area.

(60) Finlay, op. cit., pp. 4-5.

(61) Intermediate Technology Development Group, op. cit., and FAO, op. cit., pp. 50-55.

(62) See photograph, FAO, op. cit., p. 59.

(63) The author is grateful to John Finlay for this interesting aspect of prayer rituals in Nepal.

(64) P.B. Ghatge, "Biogas: A Pilot Project to Investigate a Decentralized Energy System" (1978), pp. 21-22.

(65) Kirloskar Oil Engines Limited, "Kirloskar Gobar Gas Dual Fuel Engine" (1980), p. 6.

(66) K. Kasturirangan et al., "Use of Gobar Gas in a Diesel Fuel Engine" (1977).

(67) ESCAP, op. cit., p. 21.

(68) Ibid and personal discussions with Kirloskar Engineers. See also: Ramesh Bhatia, "Energy Alternatives for Irrigation Pumping: Some Results for Small Farms in North Bihar" (1979).

(69) John L. Fry, *Practical Building of Methane Power Plants for Rural Energy Independence* (1974), p. 39.

(70) Bhatia, op. cit., p. 1507.

(71) Cited by John Finlay, op. cit., from an earlier study by Yarwalker and Agrawal, "Manure and Fertilizers" (Nagpur: Agricultural-Horticultural Publishing House) (n.d.).

(72) Finlay, *ibid*.

(73) National Academy of Sciences, op. cit., p. 51.

(74) S.K. Subramanian, "Biogas Systems in Asia: A Survey" in Bennett et al., op. cit., p. 99.

(75) See the brief references to 17 percent increased wheat yield in Wu Chin County and subsequent discussion concerning Jiongsu Province, in FAO Soils Bulletin #40, op. cit., p. 47.

(76) See Andrew Barnett, "Biogas Technology: A Social and Economic Assessment," in Barnett et al., *Biogas Technology in the Third World* (1978), pp. 69-96; Ramesh Bhatia, "Economic Appraisal of Biogas Units in India: A Framework for Social Cost-Benefit Analysis" (1977).

"Energy Alternatives for Irrigation Pumping: Some Results for Small Farm in North Bihar" (1978); Bhatia and Miriam Naimar, "Renewable Energy Sources, The Community Biogas Plant" (1979); P.B. Ghate, "Biogas: A Pilot Project to Investigate a Decentralized Energy System" (1978); KVIC, "Gobar Gas: Why and How" (1980); Indian Council of Agricultural Research, "The Economics of Cow Dung Gas Plants" (1976); Arjun Makhiajani and Alan Poole, *Energy and Agriculture in the Third World* (1975); T.K. Moulik, and U.K. Strivatsava, *Biogas Plants at the Village Level: Problems and Prospect in Gujarat* (1976) and *Biogas Systems in India: A Socio-Economic Evaluation* (1978); J.K. Parikh and K.S. Parikh, "Mobilization and impacts of Biogas Technologies" (1977); C.R. Prasad, K.K. Prasad, and A.K.N. Reddy, "Biogas Plants: Prospects, Problems and Tasks" (1977); K.K. Prasad and A.K.N. Reddy, "Technological Alternatives and the Indian Energy Crisis" (1977); and A.K.N. Reddy et al., *A Community Biogas Plant System for Pura Village* (1979).

(77) See Shishir Mukherjee and Anita Arya, "Comparative Analysis of Social Cost-Benefit Studies of Biogas Plants" (1978).

(78) See Andrew Barnett, "The Social and Economic Assessment of Biogas Technology" (1979), David French, "The Economics of Energy Technologies" (1979), and L. Squire and Herman van der Tak, *Economic Analysis of Projects* (1975).

(79) Islam, op. cit., p. 18.

(80) Subramaniam, S.K., *Biogas Systems in Asia* (1977).

(81) Islam, op. cit., pp. 46-52.

(82) For an excellent discussion of the performance of KVIC biogas systems, a socio-economic profile of users, and a solid analysis of the organizational weaknesses of the Indian biogas programme, see T.K. Moulik, U.K. Srivastava and P.M. Shingi, *Biogas System in India: A Socio-Economic Evaluation* (1978). The author is indebted to Dr. Srivastava for several helpful discussions on these issues.

(83) Ramesh Bhatia and Miriam Naimar, op. cit. This is a thoughtful analysis of the Fateh Singh-ka-Purva Project. See also: P.B. Ghate, "Biogas: A Pilot Project to Investigate a Decentralized Energy System" (1978), and Shahzad Bahadur and

S.C. Agarwal, "Community Biogas Plant at Fateh Singh-Ka-Purva: An Evaluation Report" (Lucknow: PRAD, 1980).

(84) Bhatia and Naimar, *ibid*, point out that villages may actually prefer kerosene for lighting since they control the timing of its use. It would be interesting to conduct an analysis of energy consumption over time, comparing kerosene lamps and direct biogas lamps. Despite potentially higher energy efficiencies with biogas lighting methods, it is possible that a good deal of gas would be wasted due to the timed release. Once the gas is in the pipeline it is subject to pressure losses, conversion losses (running generators with no storage battery), and losses due to venting into the atmosphere if people forget to close a valve or have inefficient lamps.

(85) These reasons, coupled with an unfamiliarity with the concept of paying for a "municipal service," cast doubt on the Parikhs' notion of charging different progressive prices for the biogas. See Jyoti K. Parikh and Kirit S. Parikh, "Mobilization and Impact of Biogas Technologies," in *Energy* (1977). The other problem with this otherwise sensible idea is that it is not clear that poor people would be willing to cook in community kitchens even if they would receive gas free or at nominal cost. It has proven historically difficult to "purchase" such cooperative, collective living.

(86) *Ibid*, and T.K. Moulik and U.K. Srivastava, *Biogas Plants at the Village Level: Problems and Prospects in Gujarat* (1975), pp. 110-11.

(87) Bhatia and Naimar, *op. cit.*, pp. 26-28.

(88) This section is based on discussions with a great number of rural social workers, sociologists, private voluntary organizations, and even a few difficult conversations with some villagers. I am especially grateful to Dr. Shivakumar of the Madras Institute of Development Studies, Dr. Amulya K.N. Reddy, Indian Institute of Science (Bangalore), Dr. K. Oomen, Department of Sociology, Jawaharlal Nehru University (New Delhi), Dr. C.V. Seshadri and Rathindranath Roy, MCRC (Madras), and Dr. Y. Nayudamma, Central Leather Research Institute (Madras). See also a very thoughtful article by Hermalata Dandekar, "Gobar Gas Plants: How Appropriate are They?" in *Economic and Political Weekly* (1980), pp. 887-92.

(89) *Ibid*. This excellent idea is the way many rural development teams establish their credibility and create a sense of the possible through collective effort. The Sarvodaya Movement in Sri Lanka is an example of this approach, although it goes one, perhaps necessary, step further by presenting this narrow

concept of technological change within a highly developed sense of Buddhist values. Villagers respond to this because it is a natural extension of their traditional cultural ethos.

## Appendix

### NPV and Payback Analysis for Baseline Data

#### Models 1-3

(Full cost digester, no revenue from either the sale or surplus gas or rice husk cement)

Note: For a detailed explanation of symbols used, please refer to pp. 59-61 in the text.

VITA is grateful to the Department of Computer Sciences, Indian Institute of Technology, Madras, India, for providing this printout.

#### MODEL 1: COOKING & LIGHTING

D = 294306.00 R = 0.00 P\_DS = 0.00 R\_LC = 0.04

D = 2943 6.000 G = 0.047 L = 9212.500 N\_LC = 5.000 P\_LC = 10.000  
D\_L = 273.750 G\_C = 11425.000 LO\_L = 43.800 P = 10000.000 R = 0.000  
D\_LC = 13400.000 G\_L = 2300.000 LO\_P = 4.800 P\_D = 2.700 R\_LC = 0.040  
D\_P = 30.120 G\_P = 253.000 LO\_RC = 0.000 P\_DS = 0.000  
D\_RC = 0.000 G\_RC = 0.000 M = 0.000 P\_FW = 0.040  
E = 33250.000 I = 4709.000 N = 0.000 P\_K = 2.250

YEAR	1	2	3	4	5	6	7-1C	11-15
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#### ANNUAL RECURRING COSTS

LOAN AMORTIZATION		0.00	12724.62	12724.62	12724.62	13724.62		
	12724.62	0.00	0.00					

ENERGY (DIESEL)		820.45	820.45	820.45	820.45	820.45		
	820.45	3281.75	4102.24					

LUBE OIL		486.00	486.00	486.00	486.00	486.00	486.00	
----------	--	--------	--------	--------	--------	--------	--------	--

1944.00 2430.00

(LABOR) 8212.50 8212.50 8212.50 8212.50 8212.50 8212.50  
32850.00 41062.50

OPERATIONS AND MAINTENANCE 250.00 250.00 250.00 250.00  
250.00 250.00 1000.00 1250.00

TOTAL RECURRING COSTS 1556.45 14281.06 14281.06 14281.06  
14281.06 14281.06 6225.75 7782.24

#### ANNUAL BENEFITS

ENERGY SAVED - KEROSENE 4360.50 4360.50 4360.50 4360.50  
4360.50 4360.50 17442.00 21802.50

FIREWOOD 240.00 240.00 240.00 240.00 240.00 240.00  
960.00 1200.00

INCREASED AGRI PRODUCTIVITY 4709.00 4709.00 4709.00 4709.00  
4709.00 4709.00 18836.00 23545.00

SURPLUS ENERGY INTO DIESEL 0.00 0.00 0.00 0.00 0.00  
0.00 0.00 0.00

ELECY 0.00 0.00 0.00 0.00 0.00 0.00 0.00  
0.00

REVENUE FROM CCMM OPNS 0.00 0.00 0.00 0.00 0.00  
0.00 0.00 0.00

TOTAL ANNUAL BENEFITS 9222.09 9222.09 9222.09 9222.09  
9222.09 9222.09 36388.34 46110.43

BENEFITS-COSTS TO VILLAGE =

((((ENERGY SAVED (WOOD + KEROSENE)

+ SALE OF SURPLUS GAS) < .981)

+ COMMERCIAL REVENUE + INCREASED

AGRICULTURAL YIELD - LOAN

AMORTIZATION + DIESEL + LUBE OIL

+ OPERATIONS & MAINTENANCE) 7665.64 -5058.97 -5058.97 -5058.97 -  
5058.97 -5058.97 30662.55 38329.18

NET PRESENT WORTH (15 YEARS): 14454.44

ANNUAL CASH FLOW

((SALE OF SURPLUS GAS + 791.00)

< .991 + COMMERCIAL REVENUE) - (LOAN

AMORTIZATION + DIESEL + LUBE OIL

+ LABOR + DP. & MAINTENANCE) -8992.97 -21717.59 -21717.59 -21717.59 -  
 21717.59 -21717.59 -35971.89 -44564.86

NO PAYBACK

# MODEL 1: COOKING & LIGHTING

D = 294306.00 R = 0.00 P\_DS = 0.00 R\_LC = 0.10

D = 294306.000 G = 0.047 L = 8212.500 N\_LC = 5.000 P\_LD =  
 10.000  
 D\_L = 273.750 G\_C = 11425.000 LO\_L = 43.800 P = 10000.000 R =  
 0.040  
 D\_LC = 13400.000 G\_L = 2300.000 LO\_P = 4.800 P\_D = 2.700 R\_LC  
 = 0.100  
 D\_P = 30.120 G\_P = 253.000 LO\_RC =  
 0.000 P\_DS = 0.000  
 D\_RC = 0.000 G\_RC = 0.000 M = 0.000 P\_FW = 0.040  
 E = 33250.000 I = 4709.000 N = 0.000 P\_K = 2.250

YEAR	1	2	3	4	5	6	7-10	11-15
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## ANNUAL RECURRING COSTS

LOAN AMORTIZATION		0.00	14943.29	14943.29	14943.29	14943.29	14943.29	
	14943.29	0.00	0.00					

ENERGY (DIESEL)		820.45	820.45	820.45	820.45	820.45		
	820.45	3281.79	4102.24					

LUBE OIL		486.00	486.00	486.00	486.00	486.00	486.00	
	1944.00	2430.00						

(LABOR)		8212.50	8212.50	8212.50	8212.50	8212.50	8212.50	
	32850.00	41062.50						

OPERATIONS AND MAINTENANCE		250.00	250.00	250.00	250.00	250.00		
	250.00	250.00	1000.00	1250.00				

TOTAL RECURRING COSTS		1556.45	16499.73	16499.73	16499.73	16499.73		
	16499.73	16499.73	6225.79	7782.24				

## ANNUAL BENEFITS

ENERGY SAVED - KEROSENE		4360.50	4360.50	4360.50	4360.50	4360.50		
	4360.50	4360.50	17442.00	21802.50				



FIREWOOD	240.00	240.00	240.00	240.00	240.00	240.00
960.00 1200.00						

INCREASED AGRI PRODUCTIVITY	4709.00	4709.00	4709.00	4709.00
4709.00 4709.00 18836.00 23545.00				

SURPLUS ENERGY INTO DIESEL	0.00	0.00	0.00	0.00	0.00
0.00 0.00 0.00					

ELECY	0.00	0.00	0.00	0.00	0.00	0.00
0.00						

REVENUE FROM CCMM OPNS	0.00	0.00	0.00	0.00	0.00
0.00 0.00 0.00					

TOTAL ANNUAL BENEFITS	9222.09	9222.09	9222.09	9222.09
9222.09 9222.09 36388.34 46110.43				

BENEFITS-COSTS TO VILLAGE =  
 (((ENERGY SAVED (WOOD + KEROSENE)  
 + SALE OF SURPLUS GAS) < .981)  
 + COMMERCIAL REVENUE + INCREASED  
 AGRICULTURAL YIELD - (LOAN  
 AMORTIZATION + DIESEL + LUBE OIL  
 + OPERATIONS & MAINTENANCE) 7665.64 -7277.64 -7277.64 -7277.64 -  
 7277.64 -7277.64 30662.55 38323.13

NET PRESENT WORTH (15 YEARS): 6808.51

ANNUAL CAST FLOW =  
 ((SALE OF SURPLUS GAS + 791.00)  
 < .991 + COMMERCIAL REVENUE) - (LOAN  
 AMORTIZATION + DIESEL + LUBE OIL  
 + LABOR + DP. & MAINTENANCE) -8992.97 -2353.25 -23936.25 -23936.25 -  
 23536.25 -23936.25 -35971.89 -44564.86

NO PAYBACK

# MODEL 1: COOKING & LIGHTING

D = 506255.00 R = 0.00 P\_DS = 0.00 R\_LC = 0.04

D = 506255.000 G = 0.047 L = 8212.500 N\_LC = 5.000 P\_LC = 10.000  
 D\_L = 273.750 G\_C = 11425.000 LO\_L = 43.800 P = 10000.000 R = 0.000  
 D\_LC = 22100.000 G\_L = 2300.000 LO\_P = 4.800 P\_D = 2.700 R\_LC

= 0.040

D\_P = 30.120 G\_P = 253.000 LO\_RC =  
0.000 P\_DS = 0.000  
D\_RC = 0.000 G\_RC = 0.000 M = 0.000 P\_FW = 0.040  
E = 33250.000 I = 8100.000 N = 0.000 P\_K = 2.250

YEAR	1	2	3	4	5	6	7-10	11-15
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#### ANNUAL RECURRING COSTS

LOAN AMORTIZATION		0.00	14678.80	14678.80	14678.80	14678.80	14678.80	
	14678.80	0.00	0.00					

ENERGY (DIESEL)		820.45	820.45	820.45	820.45	820.45		
	820.45	3281.75	4102.24					

LUBE OIL		486.00	486.00	486.00	486.00	486.00	486.00	
	1944.00	2430.00						

(LABOR)		8212.50	8212.50	8212.50	8212.50	8212.50	8212.50	
	32850.00	41062.50						

OPERATIONS AND MAINTENANCE			250.00	250.00	250.00	250.00		
	250.00	250.00	1000.00	1250.00				

TOTAL RECURRING COSTS		1556.45	16235.24	16235.24	16235.24			
	16235.24	16235.24	6225.79	7782.24				

#### ANNUAL BENEFITS

ENERGY SAVED - KEROSENE		4360.50	4360.50	4360.50	4360.50			
	4360.50	4360.50	17442.00	21802.50				

FIREWOOD		240.00	240.00	240.00	240.00	240.00	240.00	
	960.00	1200.00						

INCREASED AGRI PRODUCTIVITY		8100.00	8100.00	8100.00	8100.00			
	8100.00	8100.00	32400.00	40500.00				

SURPLUS ENERGY INTO DIESEL		0.00	0.00	0.00	0.00	0.00		
	0.00	0.00	0.00					

ELECY		0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00							

REVENUE FROM CCMM OPNS		0.00	0.00	0.00	0.00	0.00		
	0.00	0.00	0.00					

TOTAL ANNUAL BENEFITS	12613.09	12613.09	12613.09	12613.09
12613.09	12613.09	50452.34	63065.43	

BENEFITS-COSTS TO VILLAGE =  
 (((ENERGY SAVED (WOOD + KEROSENE)  
 + SALE OF SURPLUS GAS) < .981)  
 + COMMERCIAL REVENUE + INCREASED  
 AGRICULTURAL YIELD - (LOAN

AMORTIZATION + DIESEL + LUBE OIL + OPERATIONS & MAINTENANCE)	11056.64	-3622.15	-3622.15	-3622.15	-
	3622.15	-3622.15	44226.55	55283.18	

NET PRESENT WORTH (15 YEARS): 33512.33

ANNUAL CASH FLOW =  
 ((SALE OF SURPLUS GAS + 791.00)  
 < .991 + COMMERCIAL REVENUE) - (LOAN  
 AMORTIZATION + DIESEL + LUBE OIL  
 + LABOR + DP. & MAINTENANCE)

	-8992.97	-23671.77	-23671.77	-23671.77	-
	23671.77	-23671.77	-35971.89	-44564.86	

NO PAYBACK

MODEL 1: COOKING & LIGHTING

D = 506255.00 R = 0.00 P\_05 = 0.00 R\_LC = 0.10

D = 506255.000 G = 0.047 L = 8212.500 N\_LC = 5.000 P\_LO = 10.000  
 D\_L = 273.750 G\_C = 11425.000 LO\_L = 43.800 P = 10000.000 R = 0.000  
 D\_LC = 22100.000 G\_L = 2300.000 LO\_P = 4.800 P\_D = 2.700 R\_LC = 0.100  
 D\_P = 30.120 G\_P = 253.000 LO\_RC = 0.000 P\_DS = 0.000  
 C\_RC = 0.000 G\_RC = 0.000 M = 0.000 P\_FW = 0.040  
 E = 33250.000 IA = 8100.000 N = 0.000 P\_K = 2.250

YEAR	1	2	3	4	5	6	7-10
11-15							

ANNUAL RECURRING COSTS

LOAN AMORTIZATION	0.00	17238.20	17238.20	17238.20	
17238.20	17238.20	0.00	0.00		
ENERGY (DIESEL)	320.45	320.45	820.45	820.45	820.45

820.45	3281.75	4102.24					
LUBE OIL		486.00	486.00	486.00	486.00	486.00	
486.00	1944.00	2430.00					
(LABOR)		8212.50	8212.50	8212.50	8212.50	8212.50	
8212.50	32950.00	41062.50					
OPERATIONS AND MAINTENANCE			250.00	250.00	250.00	250.00	
250.00	250.00	1000.00	1250.00				
TOTAL RECURRING COSTS			1536.45	18794.64	18794.64	18794.64	
18794.64	18794.64	6225.79	7782.24				

#### ANNUAL BENEFITS

ENERGY SAVED - KEROSENE		4360.50	4360.50	4360.50	4360.50	
4360.50	4360.50	17442.00	21802.50			
FIREWOOD		240.00	240.00	240.00	240.00	
240.00	960.00	1200.00				
INCREASED AGRI PRODUCTIVITY		8100.00	8100.00	8100.00	8100.00	
8100.00	8100.00	32400.00	40500.00			
SURPLUS ENERGY INTO DIESEL		0.00	0.00	0.00	0.00	
0.00	0.00	0.00	0.00			
ELEC Y		0.00	0.00	0.00	0.00	
0.00	0.00					
REVENUE FROM COMM OPNS		0.00	0.00	0.00	0.00	
0.00	0.00	0.00	0.00			
TOTAL ANNUAL BENEFITS		12613.09	12613.09	12613.09	12613.09	
12613.09	12613.09	50452.34	63065.43			

#### BENEFITS-COSTS TO VILLAGE =

(((ENERGY SAVED (WOOD + KEROSENE)  
+ SALE OF SURPLUS GAS) + .981)  
+ COMMERCIAL REVENUE + INCREASED  
AGRICULTURAL YIELD - (LOAN  
AMORTIZATION + DIESEL + LUBE OIL  
+ OPERATIONS & MAINTENANCE)

11056.64	-6181.55	-6181.55	-6181.55
-6181.55	-6181.55	44226.55	55283.13

NET PRESENT WORTH (15 YEARS): 24692.20

#### ANNUAL CASH FLOW =

((SALE OF SURPLUS GAS + 791.001  
% .981 + COMMERCIAL REVENUE) - (LOAN  
AMORTIZATION + DIESEL + LUBE OIL  
+ LABOR + DP. & MAINTENANCE)

-8992.97	-26231.16	-26231.16	-26231.16
-26231.16	-26231.16	-35971.39	-44964.86

NO PAYBACK

#### MODEL 2: COOKING, LIGHTING & INDUSTRY

D = 326579.00 R = 0.00 P\_DS = 0.00 R\_LC = 0.04

D = 326579. 0    G =    0.047    L = 11812.500    N\_LC = 5.000    P\_LO = 10.000  
 D\_L = 273.750    G\_C = 11425.000    LO\_L = 43.800    P = 10000.000    R = 0.000  
 D\_LC = 15000.000    G\_L = 2300.000    LO\_P = 4.800    P\_D = 2.700    R\_LC = 0.040  
 D\_P = 30.120    G\_P = 253.000    LO\_RC = 0.000    P\_DS = 0.000  
 C\_RC = 150.000    G\_RC = 1260.000    M = 4800.000    P\_FW = 0.040  
 E = 41000.000    IA = 5225.000    N = 0.000    P\_K = 2.250

YEAR	1	2	3	4	5	6	7-10
11-15							

#### ANNUAL RECURRING COSTS

LOAN AMORTIZATION	0.00	14824.80	14824.80	14824.80		
14824.80	14324.80	0.00	0.00			
ENERGY (DIESEL)	1225.45	1225.45	1225.45	1225.45		
1225.45	1225.45	4901.79	6127.24			
LUBE OIL	726.00	726.00	726.00	726.00	726.00	
726.00	2904.00	3630.00				
(LABOR)	11812.50	11812.50	11812.50	11812.50	11812.50	
11812.50	47250.00	55062.50				
OPERATIONS AND MAINTENANCE	5050.00	5050.00	5050.00	5050.00	5050.00	
5050.00	5050.00	20200.00	25250.00			
TOTAL RECURRING COSTS	7001.44	21826.24	21826.24	21826.24	21826.24	
21826.24	21826.24	28005.77	35007.21			

#### ANNUAL BENEFITS

ENERGY SAVED - KEROSENE	4360.10	4360.50	4360.50	4360.50		
4360.50	4360.50	17442.00	21802.50			
FIREWOOD	240.00	240.00	240.00	240.00	240.00	
140.00	960.00	1200.00				
INCREASED AGRI PRODUCTIVITY	5225.00	5225.00	5225.00	5225.00	5225.00	
5225.00	5225.00	20900.00	20125.00			
SURPLUS ENERGY INTO DIESEL	0.00	0.00	0.00	0.00	0.00	
0.00	0.00	0.04	0.00			

ELEC Y	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00					
REVENUE FROM COMM OPNS	0.00	0.00	0.00	0.00	0.00	
0.00	0.00	0.00	0.00			
TOTAL ANNUAL BENEFITS	9738.09	9738.09	9738.09	9738.09	9738.09	
9738.09	9738.09	38952.34	48690.43			

BENEFITS-COSTS TO VILLAGE =  
 (((ENERGY SAVED (WOOD + KEROSENE)  
 + SALE OF SURPLUS GAS) + .981)  
 + COMMERCIAL REVENUE + INCREASED  
 + AGRICULTURAL YIELD) - (LOAN  
 AMORTIZATION + DIESEL + LUBE OIL  
 + OPERATIONS & MAINTENANCE)      2736.60    -12088.15    12088.15    -  
 12088.15   -12088.15   -12088.15   -10946.58   13683.22

NET PRESENT WORTH (15 YEARS):    20273.67

ANNUAL CASH FLOW =  
 ((SALE OF SURPLUS GAS + 791.001  
 % .981 + COMMERCIAL REVENUE) - (LOAN  
 AMORTIZATION + DIESEL + LUBE OIL  
 + LABOR + DP. & MAINTENANCE)    -19037.57    -32862.77    -32862.77    -32862.77  
    -32862.77    -32862.77    -72151.88    -90189.8

NO PAYBACK

## MODEL 2: COOKING, LIGHTING & INDUSTRY

D = 326579.00 R =    0.00    P\_DS = 0.00    R\_LC = 0.10

D = 326579.000    G =    0.047    L = 11812.500    N\_LC = 3.001    P\_LC =  
 10.000  
 D\_L = 273.750    G\_C = 11425.000    LC\_L = 43.800    P = 10000.000    R =  
 0.000  
 D\_LC = 15000.000    G\_L = 2300.000    LC\_P = 4.800    P\_D = 2.700    R\_LC  
 = 0.100  
 D\_P = 30.120    G\_P = 253.000    LC\_RC =  
    0.000    P\_DS = 0.000  
 C\_RC = 150.000    G\_RC = 1260.000    M = 4800.000    P\_FW = 0.040  
 E = 41000.000    IA = 5225.000    N = 0.000    P\_K = 1.250

YEAR	1	2	3	4	5	6	7-10
11-15							

ANNUAL RECURRING COSTS

LOAN AND AMORTIZATION			0.00	17409.66	17409.66	17409.66
	17409.66	17409.66	0.00	0.00		
ENERGY (DIESEL)			1225.45	1225.45	1225.45	1225.45
	1225.45	1225.45	4901.79	6127.24		
LUBE OIL			726.00	726.00	726.00	726.00
	726.00	2904.00	3630.00			
(LABOR)			11812.50	11812.50	11812.50	11812.50
	11812.50	47250.00	59062.50			

OPERATIONS AND MAINTENANCE	5050.00	5050.00	5050.00	5050.00
5050.00 5050.00 20200.00 25250.00				
TOTAL RECURRING COSTS	7001.44	24411.10	24411.10	24411.10
24411.10 24411.10 28005.77 35007.21				

#### ANNUAL BENEFITS

ENERGY SAVED - KEROSENE	4360.50	4360.50	4360.50	4360.50
4360.50 4360.50 17442.00 21802.50				
FIREWOOD	240.00	240.00	240.00	240.00
240.00 960.00 1200.00				
INCREASED AGRI PRODUCTIVITY	5225.00	5225.00	5225.00	5225.00
5225.00 5225.00 20900.00 26125.00				
SURPLUS ENERGY INTO DIESEL	0.00	0.00	0.00	0.00
0.00 0.00 0.00 0.00				
ELEC Y	0.00	0.00	0.00	0.00
0.00 0.00				
REVENUE FROM COMM OPNS	0.00	0.00	0.00	0.00
0.00 0.00 0.00 0.00				
TOTAL ANNUAL BENEFITS	9738.09	9738.09	9738.09	9738.09
9738.09 9738.09 38952.34 48690.43				

BENEFITS-COSTS TO VILLAGE =

((ENERGY SAVED (WOOD + KEROSENE)

+ SALE OF SURPLUS GAS) + .9811

+ COMMERCIAL REVENUE + INCREASED

AGRICULTURAL YIELDS - (LOAN

AMORTIZATION + DIESEL + LUBE OIL

+ OPERATIONS & MAINTENANCE) 2736.64 -14673.01 -14673.01 -14673.01

-14673.01 -14673.01 10946.58 13683.22

NET PRESENT WORTH (15 YEARS): -39181.57

ANNUAL CASH FLOW =

((SALE OF SURPLUS GAS + 791.001

% .981 + COMMERCIAL REVENUE - (LOAN

AMORTIZATION + DIESEL + LUBE OIL

+ LABOR + OP. & MAINTENANCE) -18037.97 -35447.63 -35447.63 -35447.63

-35447.63 -35447.63 -72151.88 -90189.81

NO PAYBACK

#### MODEL 2: COOKING, LIGHTING & INDUSTRY

D = 506255.00 R = 0.00 P\_DS = 0.00 R\_LC = 0.04

D = 506255.000 G = 0.041 11812.500 N LC = 5.000 P\_LC = 10.000

D L = 273.750 G\_C = 11425.000 LO\_L = 43.800 P = 10000.000 R =

0.000

D\_LC = 22107.100 G\_L = 2300.000 LO\_F = 4.800 P\_D = 2.700 R\_LC = 0.040

D\_P = 30.120 G\_P = 253.000 LO\_RC = 0.000 P\_DS = 0.000

C\_RC = 150.000 G\_RC = 1260.000 M = 4800.000 P\_FW = 0.040

E = 41000.000 IA = 8100.000 N = 0.000 P\_K = 2.250

YEAR	1	2	3	4	5	6	7-
10 11-15							

#### ANNUAL RECURRING COSTS

LOAN AMORTIZATION		0.00	16419.59	16419.59	16419.59		
16419.59 16419.59 0.00 0.00							
ENERGY (DIESEL)		1225.45	1225.45	1225.45	1225.45		
1225.45 1225.45 4901.79 6127.24							
LUBE OIL		726.00	726.00	726.00	726.00	726.00	
726.00 2904.00 3630.00							
(LABOR)		11812.50	11812.50	11812.50	11812.50	11812.50	
11812.50 47250.00 59062.50							
OPERATIONS AND MAINTENANCE		5050.00	5050.00	5050.00	5050.00		
5050.00 5050.00 5050.00 20200.00 25250.00							
TOTAL RECURRING COSTS		7001.44	23421.03	23421.03	23421.03	23421.03	
23421.03 23421.03 28005.77 35007.21							

#### ANNUAL BENEFITS

ENERGY SAVED - KEROSENE		4360.50	4360.50	4360.50	4360.50		
4360.50 4360.50 17442.00 21802.50							
FIREWOOD		240.00	240.00	240.00	240.00	240.00	
240.00 960.00 1200.00							
INCREASED AGRI PRODUCTIVITY		8100.00	8100.00	8100.00	8100.00	8100.00	
8100.00 8100.00 32400.00 40500.00							
SURPLUS ENERGY INTO DIESEL		0.00	0.00	0.00	0.00		
0.00 0.00 0.00 0.00							
ELEC Y		0.00	0.00	0.00	0.00	0.00	
0.00 0.00							
REVENUE FROM COMM OPNS		0.00	0.00	0.00	0.00	0.00	
0.00 0.00 0.00							
TOTAL ANNUAL BENEFITS		12613.09	12613.09	12613.09	12613.09	12613.09	
12613.09 12613.09 50452.34 63065.43							

BENEFITS-COSTS IN VILLAGE =  
((( ENERGY SAVED (WOOD + KEROSENE)

+ SALE OF SURPLUS GAS) + .981)  
+ COMMERCIAL REVENUE + INCREASED  
+ AGRICULTURAL YIELD - (LOAN  
AMORTIZATION + DIESEL + LUBE OIL  
+ OPERATIONS & MAINTENANCE) 5611.64 -10807.94 -10807.94 -



10807.94 -10807.94 -10807.94 22446.58 28058.22

NET PRESENT WORTH (15 YEARS): -13902.12

ANNUAL CASH FLOW =

((SALE OF SURPLUS GAS + 191.001

% .981 + COMMERCIAL REVENUE - (LOAN

AMORTIZATION + DIESEL + LUBE OIL

+ LABOR + DP. & MAINTENANCE) -13037.57 -34457.55 -34457.55 -

34457.55 -34457.55 -34457.55 -72151.66 -90185.61

NO PAYBACK

MODEL 2: COOKING, LIGHTING & INDUSTRY

O = 506255.00 R = 0.00 P\_OS = 0.00 R\_LC = 0.10

O = 506255.000 G = 0.047 L = 11812.500 N\_LC = 5.000 P\_LC = 10.000

O\_L = 273.750 G\_C = 11425.000 LO\_L = 43.800 P = 10000.000 R = 0.000

O\_LC = 22100.000 G\_L = 2300.000 LC\_P = 4.800 P\_D = 2.700 R\_LC = 0.100

O\_P = 30.120 G\_P = 253.000 LC\_RC = 0.000 P\_DS = 0.000

0.000 P\_FW = 0.040

O\_RC = 150.000 G\_RC = 1260.000 M = 4800.000

E = 41000.000 1A = 8100.000 N = 0.000 P\_K = 2.250

YEAR	1	2	3	4	5	6	7-10	11-15
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ANNUAL RECURRING COSTS

LOAN AMORTIZATION	0.00	19282.51	19282.51	19282.51	19282.51	19282.51	19282.51	19282.51
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19282.51	0.00	0.00						
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ENERGY (DIESEL)	1225.45	1225.45	1225.45	1225.45	1225.45	1225.45	1225.45	1225.45
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4901.79	6127.24							
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LUBE OIL	726.00	726.00	726.00	726.00	726.00	726.00	726.00	726.00
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2904.00	3630.00							
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(LABOR)	11812.50	11812.50	11812.50	11812.50	11812.50	11812.50	11812.50	11812.50
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47250.00	59062.50							
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OPERATIONS AND MAINTENANCE	5050.00	5050.00	5050.00	5050.00	5050.00	5050.00	5050.00	5050.00
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5050.00	5050.00	20200.00	25250.50					
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TOTAL RECURRING COSTS	7001.44	26283.95	26283.95	26283.95	26283.95	26283.95	26283.95	26283.95
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26283.95	28005.77	35007.21						
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ANNUAL BENEFITS

ENERGY SAVED - KEROSENE	4360.50	4360.50	4360.50	4360.50	4360.50	4360.50	4360.50	4360.50
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4360.50	17442.00	21802.50						
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FIREWOOD	240.00	240.00	240.00	240.00	240.00	240.00	240.00	240.00
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960.00	1200.00							
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INCREASED AGRI PRODUCTIVITY	8100.00	8100.00	8100.00	8100.00	8100.00	8100.00	8100.00	8100.00
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8100.00	8100.00	32400.00	40500.00						
SURPLUS ENERGY INTO DIESEL				0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00								
	ELEC Y	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
0.00									
REVENUE FROM COMM OPNS				0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00								
TOTAL ANNUAL BENEFITS				12613.09	12613.09	12613.09	12613.09	12613.09	12613.09
12613.09	50452.34	63065.43							

BENEFITS-COSTS TO VILLAGE =  
 (((ENERGY SAVED (WOOD + KEROSENE)  
 + SALE OF SURPLUS GAS) + .9811  
 + COMMERCIAL REVENUE + (INCREASED  
 AGRICULTURAL YIELDS) - (LOAN  
 AMORTIZATION + DIESEL + LUBE OIL  
 + OPERATIONS & MAINTENANCE) 5611.64 -13670.87 -13670.87 -13670.87 -  
 13670.87 -13670.87 22446.58 28058.22

NET PRESENT WORTH (15 YEARS): -23768.18

ANNUAL CASH FLOW =  
 ((SALE OF SURPLUS GAS + 791.001  
 +.981 + COMMERCIAL REVENUE) - (LOAN  
 AMORTIZATION + DIESEL + LUBE OIL  
 + LABOR + OP. & MAINTENANCE) -18037.97 -37320.48 -37320.48 -37320.48 -  
 37320.48 -37320.48 -72151.88 -90189.81

NO PAYBACK

MODEL 3: LIGHTING & INDUSTRY  
 O = 86021.00 R = 0.00 P\_DS = 0.00 R\_LC = 0.04

O = 86121.000 G = 0.041 L = 11812.500 N\_LC = 5.000 P\_LC =  
 10.000  
 O\_L = 273.750 G\_C = 0.000 LO\_L = 43.800 P = 0.000 R = 0.000  
 O\_LC = 4500.000 G\_L = 2300.000 LO\_F = 4.800 P\_D = 2.700 R\_LC =  
 0.040  
 O\_P = 30.120 G\_P = 253.000 LO\_RC =  
 0.000 P\_DS = 0.000  
 O\_RC = 150.000 G\_RC = 1260.000 M = 4807.000 P\_FW = 0.020  
 E = 41000.000 IA = 1376.000 N = 0.000 P\_K = 2.250

YEAR	1	2	3	4	5	6	7-10	11-15
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ANNUAL RECURRING COSTS

LOAN AMORTIZATION	0.00	10220.13	10220.13	10220.13	10220.13
10220.13	0.00	0.00			

ENERGY (DIESEL)	1225.45	1225.45	1225.45	1225.45	1225.45
1225.45 4901.79 6127.24					
LUBE OIL	726.00	726.00	726.00	726.00	726.00
2904.00 3630.00					
(LABOR)	11812.50	11812.50	11812.50	11812.50	11812.50
11812.50 47250.00 55062.50					
OPERATIONS AND MAINTENANCE	5050.00	5050.00	5050.00	5050.00	5050.00
5050.00 5050.00 20200.00 25250.00					
TOTAL RECURRING COSTS	7001.44	17221.57	17221.57	17221.57	17221.57
17221.57 17221.57 28005.77 35007.21					

#### ANNUAL BENEFITS

ENERGY SAVED - KEROSENE	4360.50	4360.50	4360.50	4360.50
4360.50 4360.50 17442.00 21802.50				
FIREWOOD	120.00	120.00	120.00	120.00
480.00 600.00				
INCREASED AGRI PRODUCTIVITY	1376.00	1376.00	1376.00	1376.00
1376.00 1376.00 5504.00 6880.00				
SURPLUS ENERGY INTO DIESEL	0.00	0.00	0.00	0.00
0.00 0.00 0.00				
ELEC Y	0.00	0.00	0.00	0.00
0.00				
REVENUE FROM COMM OPNS	0.00	0.00	0.00	0.00
0.00 0.00 0.00				
TOTAL ANNUAL BENEFITS	5771.36	5771.36	5771.36	5771.36
5771.36 5771.36 23085.45 28856.82				

#### BENEFITS-COSTS IN VILLAGE =

(((ENERGY SAVED (WOOD + KEROSENE)  
+ SALE OF SURPLUS GAS) + .9811  
+ COMMERCIAL REVENUE + INCREASED  
AGRICULTURAL YIELDS) - (LOAN  
AMORTIZATION + DIESEL + LUBE OIL  
+ OPERATIONS & MAINTENANCE) -1230.08 -11450.20 -11450.20 -11450.20 -  
11450.20 -11450.20 -4920.31 -6150.89

NET PRESENT WORTH (15 YEARS): -44576.51

#### ANNUAL CASH FLOW =

((SALE OF SURPLUS GAS + 791.001  
+ .981 + COMMERCIAL REVENUE) - (LOAN  
AMORTIZATION + DIESEL + LUBE OIL  
+ LABOR + OP. & MAINTENANCE) -18087.97 -28258.09 -28258.09 -28258.09 -  
28258.09 -28258.09 -72151.88 -90189.81

NO PAYBACK

#### MODEL 3: LIGHTING & INDUSTRY

O = 86071.00 R. 0.00 P\_DS = 0.00 R\_LC = 0.10

O = 86021.00 G = 0.047 I = 11812.500 N\_LC = 5.000 P\_LD = 10.000  
 O\_L = 273.750 G\_C = 0.000 LO\_L = 43.800 P = 0.000 R = 0.000  
 O\_LC = 4500.000 G\_L = 2300.000 LO\_P = 4.800 P\_D = 2.100 R\_LC =  
 0.100  
 O\_P = 30.120 G\_P = 253.000 LO\_RC = P\_DS = 0.000  
 0.000 P\_FW = 0.020  
 O\_RC = 150.000 G\_RC = 1260.000 M = 4800.000 P\_K = 2.250  
 E = 41000.000 IA = 1376.000 N = 0.000

YEAR	1	2	3	4	5	6	7-10	11-15
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#### ANNUAL RECURRING COSTS

LOAN AMORTIZATION			0.00	12002.11	12002.11	12002.11		
12001.11	12002.11	0.00	0.00					
ENERGY (DIESEL)			1225.45	1225.45	1225.45	1225.45	1225.45	
1225.45	4901.75	6127.24						
LUBE OIL		726.00	726.00	726.00	726.00	726.00	726.00	
2904.00	3630.00							
(LABOR)		11812.50	11812.50	11812.50	11812.50	11812.50	11812.50	
11812.00	47250.00	59062.50						
OPERATIONS AND MAINTENANCE			5050.00	5050.00	5050.00	5050.00	5050.00	
5050.00	5050.00	20200.00	25250.00					
TOTAL RECURRING COSTS			7001.44	19003.55	19003.55	19003.55	19003.55	
19003.55	19003.55	28005.77	35007.21					

#### ANNUAL BENEFITS

ENERGY SAVED - KEROSENE			4360.50	4360.50	4360.50	4360.50		
4360.50	4360.50	17442.00	21802.50					
FIREWOOD		120.00	120.00	120.00	120.00	120.00		
120.00	480.00	600.00						
INCREASED AGRI PRODUCTIVITY			1376.00	1376.00	1376.00	1376.00		
1376.00	1376.00	5504.00	6880.00					
SURPLUS ENERGY INTO DIESEL			0.00	0.00	0.00	0.00		
0.00	0.00	0.00	0.00					
ELEC Y		0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00								
REVENUE FROM COMM OPNS			0.00	0.00	0.00	0.00	0.00	
0.00	0.00	0.00						
TOTAL ANNUAL BENEFITS			5771.36	5771.36	5771.36	5771.36		
5771.36	5771.36	23085.45	28856.82					

BENEFITS-COSTS IN VILLAGE =  
 (((ENERGY SAVED (WOOD + KEROSENE)  
 + SALE OF SURPLUS GAS) + .9811  
 + COMMERCIAL REVENUE + INCREASED  
 AGRICULTURAL YIELDS) - (LOAN

AMORTIZATION + DIESEL + LUBE OIL  
+ OPERATIONS & MAINTENANCE)      -1230.08 -13232.19 -13232.19 -13232.19  
-11232.19 13232.19 -4920.31 -6150.35

NET PRESENT WORTH (15 YEARS):      -50717.55

ANNUAL CASH FLOW =  
((SALE OF SURPLUS GAS) + 791.001  
+ .981 + COMMERCIAL REVENUE) - (LOAN  
AMORTIZATION + DIESEL + LUBE OIL  
+ LABOR + OP. & MAINTENANCE)      -18037.51 -30040.08 -30040.08 -30040.08 -  
30040.08 -30040.08 -72151.88 -90189.81

NO PAYBACK

### MODEL 3: LIGHTING & INDUSTRY

D= 506255.00 R= 0.00 P\_DS = 0.00 R\_LC = 0.04

O = 506255.000 G = 0.041 L = 11812.500 N\_LC = 5.000 P\_LC =  
10.000  
O\_L = 273.750 G\_C = 0.000 LO\_L = 43.800 P = 0.000 R = 0.000  
D\_LC = 22100.000 G\_I = 2300.000 LO\_F = 4.800 P\_D = 2.700 R\_LC =  
0.040  
O\_P = 30.120 G\_P = 253.000 LO\_RC =  
0.000 P\_DS = 0.000  
O\_RC = 150.000 G\_RC = 1260.000 M = 4800.000 P\_FW = 0.020  
E = 41000.000 IA = 8100.000 N = 0.000 P\_K = 2.250

YEAR	1	2	3	4	5	6	7-10	11-15
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### ANNUAL RECURRING COSTS

LOAN AMORTIZATION		0.00	14173.41	14173.41	14173.41	14173.41	14173.41	14173.41
	14173.41	0.00	0.00					
ENERGY (DIESEL)		1225.45	1225.45	1225.45	1225.45	1225.45	1225.45	1225.45
	1225.45	4901.79	6127.24					
LUBE OIL		726.00	726.00	726.00	726.00	726.00	726.00	726.00
	2904.00	3630.00						
(LABOR)		11812.50	11812.50	11812.50	11812.50	11812.50	11812.50	11812.50
	11812.50	47250.00	59062.00					
OPERATIONS AND MAINTENANCE		5050.00	5050.00	5050.00	5050.00	5050.00	5050.00	5050.00
	5050.00	5050.00	20200.00	25250.00				
TOTAL RECURRING COSTS		7001.44	21174.85	21174.85	21174.85	21174.85	21174.85	21174.85
	21174.85	21174.85	28005.77	35007.21				

### ANNUAL BENEFITS

ENERGY SAVED - KEROSENE		4160.50	4360.50	4360.50	4360.50	4360.50	4360.50	4360.50
	4360.50	4360.50	17442.00	21802.50				

BENEFITS-COSTS TO VILLAGE =				
(((ENERGY SAVED (WOOD + KEROSENE)				
+ SALE OF SURPLUS GAS) + .9811				
+ COMMERCIAL REVENUE + INCREASED				
AGRICULTURAL YIELD) - (LOAN				
AMORTIZATION + DIESEL + LUBE OIL				
+ OPERATIONS & MAINTENANCE)				
5493.92	-8679.98	-8679.48	-8679.48	-
8679.48	-8679.48	21975.69	27469.61	

ANNUAL CASH FLOW =  
 ((SALE OF SURPLUS GAS) + 791.001  
 +.981 + COMMERCIAL REVENUE) - (LOAN  
 AMORTIZATION + DIESEL + LUBE OIL  
 + LABOR + OP. & MAINTENANCE)      -18037.57 -32211.38    -32211.38    -32211.38 -  
 32211.38    -32211.38    -72151.88    -90189.81

D=	506255.00	G=	0.041	L=	11812.500	N_LC=	5.000	P_LO=	10.000
O_L=	273.750	G_C=	0.000	LO_L=	43.800	P=	0.000	R=	0.000
O_LC=	22100.000	G_L=	2300.000	LC_F=	4.800	P_D=	2.700	R_LC=	0.100
O_P=	30.170	G_P=	253.000	LC_RC=	0.000	P_DS=	0.000		
O_BC=	150.000	G_RC=	1260.000	M=	4300.000	P_PW=	0.020		
E=	41000.000	L=	8100.000	A=	0.000	P_X=	2.250		

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16644.68	0.00	0.00						
ENERGY (DIESEL)	1225.45	1225.45	1225.45	1225.45	1225.45	1225.45	1225.45	
4901.79	6127.24							
LUBE OIL	726.00	726.00	726.00	726.00	726.00	726.00	726.00	2904.00
3630.00								
	11812.50	11812.50	11812.50	11812.50	11812.50	11812.50	11812.50	
47250.00	59062.50							
OPERATIONS AND MAINTENANCE	5050.00	5050.00	5050.00	5050.00	5050.00	5050.00	5050.00	
5050.00	5050.00	20200.00	25250.00					
TOTAL RECURRING COSTS	7001.44	23646.13	23646.13	23646.13	23646.13	23646.13	23646.13	
23646.13	28005.77	35007.21						

#### ANNUAL BENEFITS

ENERGY SAVED - KEROSENE	4360.50	4360.50	4360.50	4360.50	4360.50	4360.50		
4360.50	17442.00	21802.50						
FIREWOOD	120.00	120.00	120.00	120.00	120.00	120.00	110.00	
480.00	600.00							
INCREASED AGRI PRODUCTIVITY	8100.00	8100.00	8100.00	8100.00	8100.00	8100.00		
8100.00	8100.00	32400.00	60500.00					
SURPLUS ENERGY INTO DIESEL	0.00	0.00	0.00	0.00	0.00	0.00		
0.00	0.00	0.00						
ELECY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
REVENUE FROM COMM OPNS	0.00	0.00	0.00	0.00	0.00	0.00		
0.00	0.00	0.00						

TOTAL ANNUAL BENEFITS	12495.66	12495.36	12495.36	12495.36	12495.36	12495.34		
12495.36	49981.45	62476.32						

#### BENEFITS-COSTS IN VILLAGE =

((((ENERGY SAVED LOAN KEROSENE)

\* SALE OF SURPLUS GAS) (.981)

\* COMMERCIAL REVENUE - INCREASED

AGRICULTURAL YIELDS - (LOAN

AMORTIZATION & DIESEL + LURF OIL

\* OPERATIONS & MAINTENANCE) 5493.92 -11150.76 -11150.76 -11150.76 -

11150.16 -11150.76 21915.65 27469.61

NET PRESENT WORTH (15 YEARS): -1557 .17

#### ANNUAL CASH FLOW =

((SALE OF SURPLUS GAS (751.00)

1.981 \* COMMERCIAL REVENUE - (LOAN

AMORTIZATION \* DIESEL \* LURF OIL

\* LABOR \* OP. & MAINTENANCE) -18037.57 -34682.65 -34682.65 -34682.65 -

34682.65 -34682.65 -78151.89 -90189.81

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## Biogas production from solid wastes removed from fish farm effluents

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**Abstract** – An experimental small scale partial recirculating system for rainbow trout was assembled. The system components were two 1.3-m<sup>3</sup> fish tanks with sloping bottoms, each connected to a sedimentation column and containing 50 kg rainbow trout biomass, an anaerobic up-flow digester (total volume 0.424 m<sup>3</sup>, available volume 0.382 m<sup>3</sup>) connected to the funnel shaped bottom of the sedimentation column by means of a peristaltic pump, an aerobic submerged plug-flow filter (total volume 1 m<sup>3</sup>; filled with 0.83 m<sup>3</sup> plastic rings with a specific surface of 194 m<sup>2</sup>·m<sup>-3</sup>) and a submerged pump. Aeration was provided through porous stones. The anaerobic digester was filled with 35 mm cubes of expanded polyurethane foam (25 pores·cm<sup>-2</sup>, specific surface 1.375 m<sup>2</sup>·m<sup>-3</sup>, filtering volume 0.291 m<sup>3</sup>) and kept at a temperature of 24–25 °C using an electric heater. The gas chamber at the top of the anaerobic digester was connected to a gas meter and to an infrared continuous gas analyser. Measures on system performance with a recirculation rate of 60 % were done following three feeding levels (1, 1.5 and 2 % live weight). At the highest feeding rate, 2.8 L of faecal sludge collected from the trout tanks were pumped every four hours in the anaerobic digester. Slurry characteristic were: total N 0.197 g·L<sup>-1</sup>, TAN 0.014 g·L<sup>-1</sup>, volatile solids (VS) 16.91 g·L<sup>-1</sup>, suspended solids (SS) 21.39 g·L<sup>-1</sup> and pH 6.9. Biogas production was 144 L·d<sup>-1</sup> (mean value) with a methane content higher than 80 %. Methane volumetric production was 0.3 m<sup>3</sup>·m<sup>-3</sup>·d<sup>-1</sup> and methane daily yield was 0.4 and 0.32 m<sup>3</sup>·kg<sup>-1</sup> VS and SS respectively. After passing through the anaerobic digester, effluents were characterized by a total N content of 0.243 g·L<sup>-1</sup>, TAN 0.222 g·L<sup>-1</sup>, VS 1.1 g·L<sup>-1</sup>, SS 1.32 g·L<sup>-1</sup> and pH 6.8. The anaerobic digester was able to significantly reduce VS and SS content of wastewater and the zeolite ion-exchange column significantly improved water quality of effluent produced by the digester. The aerobic biofilter significantly reduced the ammonia content of the water leaving the fish tanks. © Ifremer/Elsevier, Paris

**Fish wastewater treatment / aerobic submerged plug-flow filter / anaerobic digester / biogas production / zeolite exchange column / rainbow trout**

**Résumé** – Production de biogaz provenant des déchets solides d'un élevage de truites. Un système de recyclage semi-fermé a été réalisé sur une petite échelle pour l'élevage de la truite arc-en-ciel. Le système est composé de deux bacs d'élevage de 1,3 m<sup>3</sup> avec un fond incliné. Les bacs, contenant 50 kg de truites, sont reliés à deux colonnes de sédimentation, un réacteur anaérobie avec un flux ascendant (volume total 0,424 m<sup>3</sup>, volume utilisable 0,382 m<sup>3</sup>) alimenté par une pompe péristaltique qui est connectée à la base conique des colonnes de sédimentation, d'un filtre aérobie immergé (volume total 1 m<sup>3</sup>, contenant 0,83 m<sup>3</sup> de matière plastique de remplissage, anneaux d'une surface spécifique de 194 m<sup>2</sup>·m<sup>-3</sup>) et d'une pompe immergée. L'aération est réalisée au travers de diffuseurs (pierres poreuses). Le réacteur anaérobie est rempli avec des cubes de 35 mm de mousse de polystyrène expansé (25 pores·cm<sup>-2</sup>, surface spécifique 1,375 m<sup>2</sup>·m<sup>-3</sup>, volume filtrant 0,291 m<sup>3</sup>) et la température est réglée à 24–25 °C par un système de chauffage. Le conduit de sortie du biogaz, placé sur le côté en haut du réacteur anaérobie, est connecté à un indicateur de débit du gaz et à un analyseur en continu à rayons infrarouges. Les analyses de rendement du système avec une recirculation d'eau de 60 % sont effectuées par rapport à trois niveaux d'alimentation (1, 1,5 et 2 % de poids vif). Lorsque le niveau d'alimentation est le plus fort (2 % de poids vif), le réacteur anaérobie est alimenté avec 2,8 L de déchets déposés au fond du bac toutes les 4 heures. Les caractéristiques chimiques de ces déchets sont : 0,197 g·L<sup>-1</sup> d'azote total, 0,014 g·L<sup>-1</sup> d'azote ammoniacal total, 16,91 g·L<sup>-1</sup> de matières solides volatiles (VS), 21,39 g·L<sup>-1</sup> de matières solides en suspension (SS), pH 6,9. La production volumétrique du méthane est de 0,3 m<sup>3</sup>·m<sup>-3</sup>·j<sup>-1</sup> et les indices journaliers de conversion pour le méthane sont de 0,4 et 0,32 m<sup>3</sup>·kg<sup>-1</sup> respectivement pour VS et SS. Les effluents du réacteur anaérobie contenant 0,243 g·L<sup>-1</sup> d'azote total, 0,222 g·L<sup>-1</sup> d'azote ammoniacal total, 1,1 g·L<sup>-1</sup> de solides volatiles, 1,32 g·L<sup>-1</sup> de solides en suspension et pH 6,8. Le réacteur anaérobie est capable de réduire de façon significative le contenu de VS et SS dans les déchets, alors que la colonne à échange cationique de zéolites améliore de façon significative la qualité des effluents du réacteur anaérobie. Le filtre biologique aérobie réduit efficacement la concentration de l'ammoniaque de l'eau à la sortie des bacs d'élevage. © Ifremer/Elsevier, Paris

**Traitement de l'eau / filtre aérobie / réacteur anaérobie / production du biogaz / colonne à échange cationique à zéolithes / truite arc-en-ciel**

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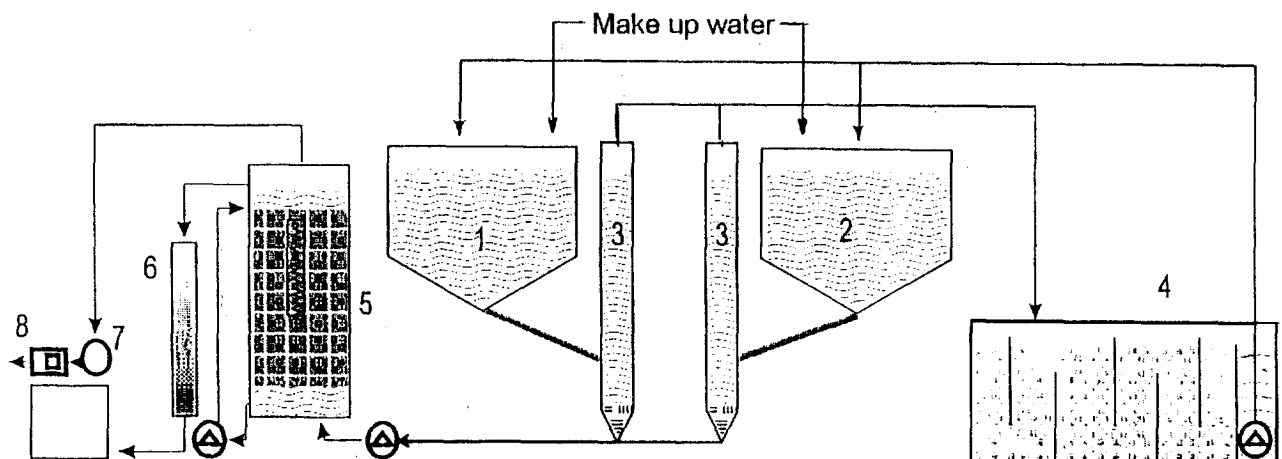
## 1. INTRODUCTION

Traditional production practices for species of major commercial importance require large amounts of good quality water, a limited resource in many areas. The decline of clean water has shifted farms to high-density aquaculture with water re-use and recirculating systems. In these systems, fish are confined at a high density, and water is treated by several processes before it is recirculated to the culture units. The principal treatment processes used in recirculating plants are solids removal, ammonia oxidation, aeration and disinfection. Daily recycle rate can vary from 50–60 % to a maximum of 90 %; higher rates are impossible to reach as a daily partial water exchange is necessary to control nitrate, remove pollutants and replenish minerals and trace elements. Recirculating culture systems have been used for many years in marine aquariums, research, hatcheries and more recently commercial fish production. These systems are well suited especially for thermophilic species like eels [8, 10, 19, 21] and prawns [18], where there is the need to spare energy for maintaining the desired water temperature. In salmonid production, some recirculation systems have been used in hatcheries when a production goal is to be achieved and water availability is limited [11]. In trout farming, semiclosed systems appear to fit this species the best, satisfying water characteristics requirements, providing necessary pollution abatement and increasing culture density [7]. In all these plants, removed solids are allowed to settle in open sedimentation basins and after a variable period of time (from 6 months to 1 year) are spread on the fields as organic fertilizers. This system is cumbersome and costly as large concrete basins are required and moreover, the use as fertilizer can be limited by climatic conditions, soil quality and national regulations. Another possibility is offered by the anaerobic degradation of removed

solids using the supernatant from the digestion basin to fuel nitrate removal by denitrifying organisms. This process was studied [23] but in that particular case, the authors limited their investigation to fish feed. Other researchers [1] considered anaerobic treatment of effluent and the use of volatile fatty acids released as fuel for the denitrifying activity. The use of solid wastes for anaerobic digestion and biogas production can represent a valid alternative as this technique can drastically reduce pollution in effluents water and at the same time, produce biogas whose methane content can be utilized for heating or electricity production. The literature on biogas production from cattle manure, piggery waste waters, by products of aquaculture, agroindustries and urban wastes is wide [3, 12, 14, 15, 17, 20] while no information was found on anaerobic digestion using solid wastes from fish plants. This trial was performed in order to evaluate the possibility of using solid wastes, removed from fish-farm effluents to produce biogas in a close system where water was partially recirculated.

## 2. MATERIALS AND METHODS

The recirculating system was composed of two fiber-glass cylindrical fish tanks (total volume 1.53 m<sup>3</sup>, working volume 1.3 m<sup>3</sup>) with funnel shaped bottom each equipped with a PVC sedimentation column (0.3 m internal diameter, 2 m height), an up-flow cylindrical anaerobic digester, connected to the sedimentation columns, a plug flow submerged biological filter and by a zeolite ion-exchange column connected to the anaerobic digester for final treatment of effluents (figure 1). A submerged centrifugal pump at the end of the tank containing the biological filter was used to carry water to the fish tanks. Recycle rate varied from 100 to 60 %, the exchange water being supplied from a well.



**Figure 1.** Scheme of the experimental recirculating plant: 1–2 fish tank; 3 sedimentation column; 4 aerobic biofilter; 5 anaerobic digester; 6 zeolite column; 7 gas flow-meter; 8 methane analyser.

**Table I.** Anaerobic digester and aerobic filter characteristics.

Parameters	Anaerobic digester	Aerobic filter
Type	Cylindrical random packed up-flow digester with adherent biomass	rectangular, plug-flow, submerged
Total volume (m <sup>3</sup> )	0.424	1.18
Working available volume (m <sup>3</sup> )	0.382	0.83
Volume of filter media (m <sup>3</sup> )	0.291	0.83
Operating temperature (°C)	24–25	13–14
Filter media characteristics:		
1. Material	polyurethane cubes	PVC cylinders
2. Size (mm)	35	25 diameter × 30 height
4. Specific area (m <sup>2</sup> ·m <sup>-3</sup> )	1 375	194
5. Void fraction (%)	—	0.86

## 2.1. Digester design

The up-flow anaerobic digester was made using a fibre-glass cylindrical tank (height 1.50 m, diameter 0.6 m) randomly packed with cubes in reticulated polyurethane and isolated with glass wool (*table I* contains details of the digester). Two perforated stainless steel plates were used to maintain the filtering media in the desired position. Psychrophilic conditions (24–25 °C) were assured by an electrical heater. A centrifugal pump mounted on the bottom of the digester assured an even temperature within the digester and content recirculation. Feed material coming from the two sedimentation columns was pumped by a peristaltic pump to the bottom of the cylinder. Biogas produced was collected by means of a plastic tube on the top of the digester and passed through a gas meter and a continuous infrared gas analyser.

## 2.2. Biological filter

The submerged plug flow biological filter was constructed in a rectangular fiber-glass tank with internal baffles and filled with a filter media comprising 2.5 cm diameter polyvinylchloride cylinders. Details of this filter are given in *table I*. Water mixing and oxygen addition were assured by air lift pumps. The biological filter received effluent water from the top of the two sedimentation columns. A submerged centrifugal pump situated at the end of the tank recirculated water to the fish tanks.

## 2.3. Zeolite ion-exchange column

The anaerobic digester effluent, was eluted through a column made from plastic tube (length 0.95 m, internal diameter 0.04 m) packed with natural zeolites (*table II*), in order to reduce its TAN (total ammonia nitrogen =  $\text{NH}_3 + \text{NH}_4^+$ ) content. The saturated zeolites were replaced every three days.

## 2.4. Operation

Anaerobic digester was seeded three times with sludge from anaerobic digester of a domestic wastewater treatment plant. Each time 20 L of sludge were added. Aerobic filter was first inoculated with 100 mL

**Table II.** Characteristics of the zeolite ion-exchange column used for the TAN abatement in effluent leaving the anaerobic digester.

Parameters	Description
Type	Packed column
Total volume (L)	2.9
Zeolites characteristics:	
1. Type	clinoptilolite
2. Granular media size (mm)	2–3
3. Cationic exchange capacity (meq·100 g <sup>-1</sup> )	120–150
Ammonium ion retention (g·100 g <sup>-1</sup> )	2.6
Zeolite volume (L)	0.6
Zeolite weight (g)	610
Daily hydraulic load (L·d <sup>-1</sup> )	10–17

of a mixed culture of bacteria (Sera-Nitrivec) and then fed a solution of ammonium chloride and ammonium sulphate to obtain an initial total ammonia nitrogen concentration of 2.9 mg·L<sup>-1</sup>. During the activation period, water was recirculated at a 100 % rate. Fish (230 rainbow trouts, 218 g average live weight, total biomass 50 kg) were transferred to the tanks when the biofilter became completely functional. Water recirculating rate was reduced to 60 % when fish were introduced in the tanks. Thereafter, recirculation was maintained at the same rate till the end of the trial. Fish were fed a commercial extruded diet at 1 % biomass twice a day (at 9:00 h and 15:00 h). This feeding level was maintained until the whole plant worked properly and gas production was constant for several days. The duration of this period was four months. Thereafter, the 6-week experimental period took place. After two weeks, the feeding level was increased to 1.5 % biomass for two weeks and further increased to 2 % biomass for two more weeks. Chemical analysis were performed on influent and effluent water of aerobic biological filter (TAN, N-NO<sub>2</sub>, N-NO<sub>3</sub>, pH, DO), on influent and effluent slurry of anaerobic digester (pH, total N, TAN, TS, SS, VS) and on influent and effluent water of ion-exchange column (pH, total N, TAN, COD). pH was determined with a Gibertini laboratory pHmeter, dissolved oxygen by mean of an oxymeter (YSI), total ammonia nitrogen (TAN) according to Goltermann et al. [4], N-NO<sub>2</sub>, N-NO<sub>3</sub>, total solids (TS), volatile solids (VS), suspended solids (SS) and COD (dichromate reflux method) as previously described [2] and total N by means of the Kjeldhal

**Table III.** Effect of trout daily feeding allowance (1, 1.5, and 2 % of live weight) on chemical and physical characteristics of influent (I) and effluent (E) water in plug-flow aerobic filter subjected to a flow rate of 40 L·min<sup>-1</sup> (means ± SD).

Feeding allowance	1		1.5		2	
Average fish weight (g)	507		541		585	
Daily feed allowance (g·d <sup>-1</sup> )	929.7		1 443.2		1 860.3	
	I	E	I	E	I	E
pH	7.76	7.75	7.73	7.71	7.65	7.60
TAN (mg·L <sup>-1</sup> )	0.63 ± 0.154	0.26 ± 0.117	1.05 ± 0.212	0.37 ± 0.111	1.05 ± 0.204	0.32 ± 0.106
TAN removal rate (mg·m <sup>-2</sup> ·d <sup>-1</sup> )	130		230		260	
N-NO <sub>2</sub> (mg·L <sup>-1</sup> )	0.02 ± 0.005	0.04 ± 0.011	0.04 ± 0.010	0.07 ± 0.020	0.06 ± 0.013	0.09 ± 0.029
N-NO <sub>3</sub> (mg·L <sup>-1</sup> )	4.80 ± 0.097	5.21 ± 0.137	5.08 ± 0.063	5.66 ± 0.102	5.35 ± 0.124	6.19 ± 0.130
Dissolved oxygen (mg·L <sup>-1</sup> )	5.6	7.3	5.1	6.8	6.3	6.7

TAN: total ammonia nitrogen.

method. Water chemical and physical analyses were performed weekly during the initial period (four months) and during the experimental phase, while gas production and composition, and water temperature were measured daily. Influent and effluent water from the aerobic biofilter were further monitored at each feeding level for 24 h, sampling water every 2 h. The first analysis was performed at 10:00 h one hour after the first feeding.

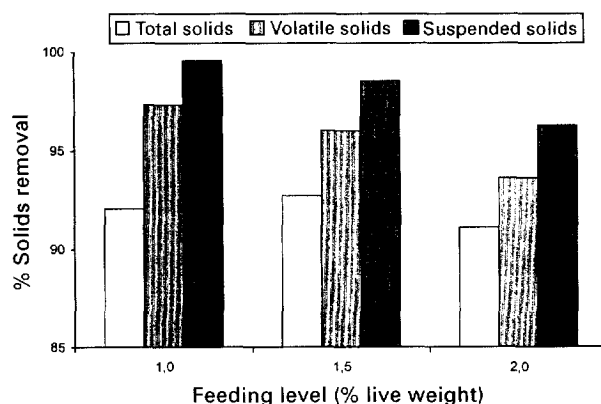
### 3. RESULTS

No health problems were encountered during the trial and fish showed a good growth rate, reaching an average live weight of 585 g and a stocking rate of 35.8 kg·m<sup>-3</sup> at the end of the trial. Water temperature varied slightly during the experiments (13.3–14.8 °C) and can be considered optimal for rainbow trout. In *table III*, data on characteristics of water entering and leaving the aerobic biofilter are reported. The hydraulic retention time was 18 min. TAN, N-NO<sub>2</sub> and N-NO<sub>3</sub> in effluent water increased as feeding level augmented from 1 to 1.5 % biomass without further increase when feeding rate reached 2 %. TAN level was significantly reduced by the biofilter and roughly 60–70 % of TAN was oxidized. At the same time N-NO<sub>2</sub> and N-NO<sub>3</sub> concentration increased as expected. Daily TAN removal rate for the unit of filtering media doubled (from 0.13 to 0.26 g·m<sup>-2</sup>·d<sup>-1</sup>) as feeding rate increased. The oxygen level in the effluent and influent water was always sufficient to assure the stoichiometric requirements for ammonia oxidation. In *table IV*, the composition of the faecal waste entering the digester and the liquid discharge are summarized. Faecal waste was characterized by high levels of total nitrogen, TAN and solids (TS, SS, VS) which increased following feeding rate increase. After passage through the anaerobic digester, faecal waste characteristics varied greatly as total N, and TAN increased significantly while total solids were reduced by 92 % and suspended solids and volatile solids by 93–97 %. The reduction in solids content took place irrespective of the feeding rate (*figure 2*). Daily biogas production (*table V*) increased with feeding rate from 49.8 to 78.8

**Table IV.** Effect of trout daily feeding allowance (1, 1.5, and 2 % of live weight) on chemical and physical characteristics of influent (I) and effluent (E) water in up-flow anaerobic digester.

Feeding allowance	1		1.5		2	
	I	E	I	E	I	E
pH	6.9	6.9	6.9	6.8	6.9	6.8
Total nitrogen (g·L <sup>-1</sup> )	0.061	0.157	0.161	0.203	0.197	0.243
TAN (mg·L <sup>-1</sup> )	7.2	133.3	12.4	148.0	13.6	222.1
Total solids (g·L <sup>-1</sup> )	13.50	1.07	18.74	1.36	23.78	2.1
Soluble solids (g·L <sup>-1</sup> )	1.87	1.02	1.95	1.12	2.39	1.32
Suspended solids (g·L <sup>-1</sup> )	11.63	0.05	16.85	0.24	21.39	0.78
Volatile solids (g·L <sup>-1</sup> )	8.67	0.23	11.65	0.46	16.91	1.07
Fixed residue (g·L <sup>-1</sup> )	5.76	0.83	6.09	0.89	6.86	1.02

and 144.2 L·d<sup>-1</sup> with a methane content of 80 % (*table V*). Volumetric CH<sub>4</sub> yield increased from 0.10 to 0.30 L·L<sup>-1</sup>·d<sup>-1</sup> of digester following the increase of feeding level and consequently of volumetric load. Methane production ranged from 0.40 to 0.46 L·g<sup>-1</sup> VS and from 0.31 to 0.32 L·g<sup>-1</sup> SS, and was only slightly influenced by the amount of feed material entering the digester. The zeolite exchange column greatly reduced TAN and total N content of the liquid leaving the digester as 97–99 % TAN and 87–89 % total nitrogen

**Figure 2.** Total solids (TS), volatile solids (VS), and suspended solids (SS) removal (%) by the up-flow anaerobic digester at increasing feeding levels.

**Table V.** Effect of trout daily feeding allowance (1, 1.5, and 2 % of live weight) on operational data and biogas production from up-flow anaerobic digester (means  $\pm$  SD).

Feeding allowance	1	1.5	2
Hydraulic load (L·d <sup>-1</sup> )	10	12	17
Hydraulic retention time (d)	38	31	22
Biogas production (L·d <sup>-1</sup> )	49.8	78.8	144.2
	$\pm 5.97$	$\pm 6.06$	$\pm 28.10$
CH <sub>4</sub> content in biogas (%)	> 80	> 80	> 80
CH <sub>4</sub> production (L <sup>-1</sup> ·d <sup>-1</sup> )	39.84	63.04	115.36
CH <sub>4</sub> volumetric production (L·L <sup>-1</sup> ·d <sup>-1</sup> )	0.10	0.16	0.30
Volumetric load:			
Volatile solids (VS) (g·L <sup>-1</sup> ·d <sup>-1</sup> )	0.227	0.345	0.751
Suspended solids (SS) (g·L <sup>-1</sup> ·d <sup>-1</sup> )	0.303	0.528	0.952
Methane yield (L·g VS <sup>-1</sup> ·d <sup>-1</sup> )	0.46	0.45	0.40
(L·g SS <sup>-1</sup> ·d <sup>-1</sup> )	0.34	0.31	0.32

**Table VI.** Effect of trout daily feeding allowance (1, 1.5, and 2 % of live weight) on chemical characteristic of influent (I) and effluent (E) water from ion-exchange column filled with zeolites.

Feeding allowance	1		1.5		2	
	I	E	I	E	I	E
Hydraulic load (L·d <sup>-1</sup> )	10		12		17	
TAN (mg·L <sup>-1</sup> )	133.3	0.8	148.0	3.3	222.1	6.1
Total Nitrogen (mg·L <sup>-1</sup> )	157	20	203	21	243	25
COD (mg·L <sup>-1</sup> )	340	289	605	390	1 063	589
pH	6.9	7.4	6.8	7.3	6.8	7.5

COD: chemical oxygen demand

were fixed by the zeolites which were less effective in reducing COD level (*table VI*).

#### 4. DISCUSSION

With a water flow of 40 L·min<sup>-1</sup> and a system working volume of 3.5 m<sup>3</sup>, the turnover time was of 89 min while the new water turnover time, at a recirculating rate of 60 %, was 221 min. Other authors [7] obtained good performances with trouts reared in a semiclosed system with a new water turnover time of 9.2 h and a steady rate of fish biomass of 66 kg·m<sup>-3</sup>. Changes in water pH entering and leaving the biofilter were minimal either because of the limited recirculation rate (60 %) or because of the high total hardness of water (243 mg·L<sup>-1</sup> as CaCO<sub>3</sub>). The range of pH values can be considered optimal for a biofilter [6]. Undissociated ammonia level in water leaving fish tanks and entering the biofilter was always less than 0.01 mg·L<sup>-1</sup>. TAN entering biofilter increased with feeding rate as expected although the increase was not linear. The biofilter reduced TAN from 59 % to 64–70 % as TAN concentration increased resulting in effluent concentrations ranging from 0.26 to 0.37 mg·L<sup>-1</sup>. This removal rate can be considered satisfactory for a plug flow sub-

merged stationary filter. Higher values have been reported [7] using a fluidized bed biofilter. TAN oxidation rates of filtering media increased from 0.13 to 0.26 g·m<sup>-2</sup>·d<sup>-1</sup>. These values compared favourably with those measured by other authors [19] on a recirculating system for eels with a bead filter or with a rotating bed contactor (56.2 and 256.7 mg·d<sup>-1</sup>·m<sup>-2</sup> TAN removed). Nitrite concentration increased following the increase in feeding rate and during the passage to the aerobic biofilter. This effect appears difficult to explain as N-NO<sub>3</sub> concentration augmented noticeably in water leaving the aerobic biofilter thus indicating that the oxidation of N-NO<sub>2</sub> to N-NO<sub>3</sub> was not hindered by inhibitory factors [22].

The anaerobic digester demonstrated excellent SS and VS removal at all the feeding levels and at all the hydraulic retention times (HRT) tested. The mechanism of SS removal must involve a filtering system in the first step, followed by biodegradation and gasification. SS removal was higher than 99 % and showed a small drop (96 %) when the HRT decreased to 22 days and the amount of feed material increased with increasing feeding rate. Equal removal rates on an anaerobic filter for pig wastewater were noted in other trials [17]. The quality of the gas produced was stable over the duration of the investigation, a finding in agreement with those of other researchers [9]. The methane content of the gas was higher than 80 % and was not influenced by HRT. Similar data were observed in other experiments [17] and can be explained by the lack of coarse cellulose material. Other researchers [12, 14] using, dairy cattle manure as feed material, obtained a biogas with a significantly lower methane content (55–65 % and 38–51 % respectively).

Biogas and methane daily production increased as feeding rate and volumetric load increased. CH<sub>4</sub> volumetric production increased accordingly from 0.1 to 0.3 L·L<sup>-1</sup> reactor volume following a trend already reported in other papers [20]. Higher yields per unit of volume of the digester were reported in literature [12–14] using an anaerobic digester of approx. 5-L volume. It is suggested that in this experiment, the reactor was probably oversized relative to the volumes required. Methane yield obtained from digested volatile solids ranged from 0.4 to 0.46 L·d<sup>-1</sup>. These results seem particularly high in comparison with the data reported by other investigators [14] who obtained a yield ranging from 0.05 to 0.18 L·g<sup>-1</sup>·d<sup>-1</sup> VS added using a fixed film reactor fed dairy cattle manure. The good yield obtained in this investigation could be attributed to the characteristics of the waste used whose composition is probably closer to that of pig-gery waste as the data found in literature [17] (0.44 L·g<sup>-1</sup> COD added) seem to indicate.

Clinoptilolite was effective in reducing TAN and total N levels in liquid discharged by the anaerobic digester. In a review [16] on the application of natural zeolites in aquaculture, the positive results obtained by



several authors in reducing TAN content in freshwater fish farms following the use of naturally occurring ion exchange zeolite which are cheaply available have been underlined. Clinoptilolite is one such material and is highly selective for ammonium nitrogen. Moreover, ammonium uptake is maximized at high liquid flow rate with high and small zeolite particle size [5].

Part of these requirements were satisfied by the product used in this trial. The reduction in COD content must be attributed to the filtering capacity of the packed column. The pH increase in eluted water is a common positive secondary effect of natural zeolites.

In considering a possible practical use of this approach for handling suspended solids in effluent waters there are still many points to be elucidated and improved. First of all, a system for collecting faecal wastes from high flow rates has to be studied. In this experiment by using appropriate settling columns, most of the settleable and suspended solids have been collected. In large fish farms with large flow rates, suspended solids can be separated using microsiege filters but in this case a dewatering system is needed in order to increase the total dry matter (TDM) content of waste

sludge from 0.5–1 g·L<sup>-1</sup> to 20–23 g·L<sup>-1</sup> as used in this trial. Secondly, the anaerobic digester and the whole auxiliary apparatus used need substantial improvement or a new layout of the digester has to be done and tested.

The third problem relates to biogas utilization. This can be used directly in a burner to produce thermal energy or, following depuration, can be employed as fuel in a cogeneration plant to obtain thermal and electrical or mechanical energy. When all these points are elucidated the minimum operational size of the digester can be calculated. From rough estimates, it can be said that to produce thermal energy, the minimal operational size of the digester should be between 50 and 70 m<sup>3</sup> of total capacity. Again from rough estimates, the fish biomass needed to produce sufficient faecal waste to feed the digester would vary from 22 to 30 t depending on the quality of the feed, the feeding management and the efficiency of the waste sludge collecting system. As can be seen from the previous paragraphs, at the moment the number of unknown variables involved is too high to estimate the cost of such a plant.

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# **Training Material on Biogas Sanitation**

## **Ecosan Training Course**

*“Capacity Building for Ecological Sanitation in India”*

Compiled by Ecosan Services Foundation (ESF)  
and seecon gmbh in the context of the  
Innovative Ecological Sanitation Network India  
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## **DISCLAIMER**

The use of these training materials is open to everyone. However, the responsibility for correct application lies with the user and respective legal or administrative regulations have to be followed. This applies in particular for the choice of the application rates and design parameters described in this training material, which should only be regarded as a rough 'guideline' and not as a manual. The materials might be a helpful but not the only source of information for correct application of concepts and technologies described.

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# 1 INTRODUCTION

## 1.1 Biogas definition

Biogas originates from bacteria in the process of bio-degradation of organic material under anaerobic (without air) conditions. The natural generation of biogas is an important part of the biogeochemical carbon cycle. Methanogens (methane producing bacteria) are the last link in a chain of micro-organisms which degrade organic material and return the decomposition products to the environment. In this process biogas is generated, a source of renewable energy [1].

## 1.2 Composition and properties of biogas

Biogas is a mixture of gases that is composed chiefly of:

- **methane** ( $\text{CH}_4$ ): 40 - 70 vol. %
- **carbon dioxide** ( $\text{CO}_2$ ): 30 - 60 vol. %
- **other gases**: 1 - 5 vol. %

including

- hydrogen ( $\text{H}_2$ ): 0 - 1 vol. %
- hydrogen sulfide ( $\text{H}_2\text{S}$ ): 0 - 3 vol. %

Like those of any pure gas, the characteristic properties of biogas are pressure and temperature-dependent. They are also affected by the moisture content. The factors of main interest are:

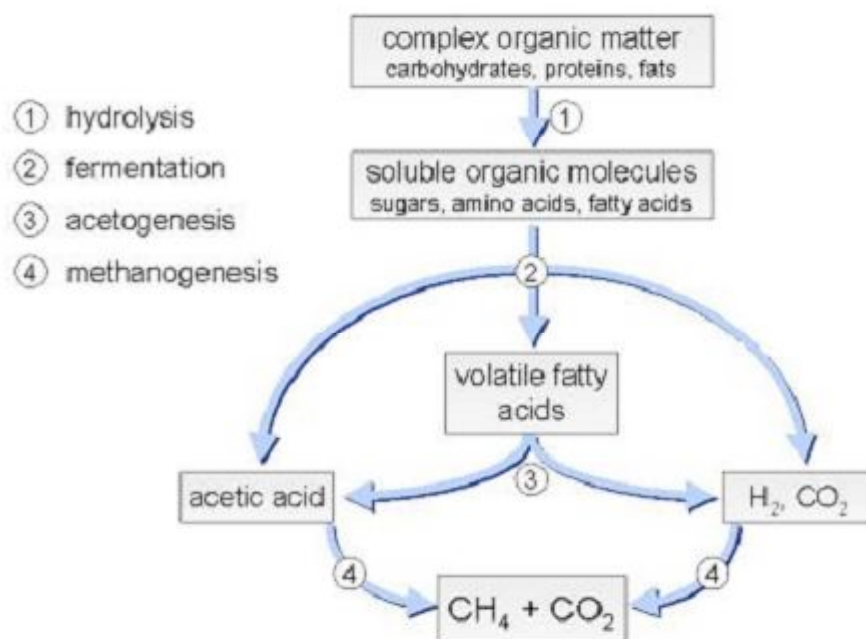
- change in volume as a function of temperature and pressure,
- change in calorific value as a function of temperature, pressure and water-vapor content, and
- change in water-vapor content as a function of temperature and pressure.

Biogas is used as an ecologically friendly and future oriented technology in many countries. The calorific value of biogas is about  $6 \text{ kWh/m}^3$  - this corresponds to about half a litre of diesel oil. The net calorific value depends on the efficiency of the burners or appliances. Methane is the valuable component under the aspect of using biogas as a fuel [1].



### 1.3 How is it produced (the three steps of biogas production)

The general model for degradation of organic material under anaerobic conditions operates principally with three main groups of bacteria: fermenting, acetogenic and methanogenic bacteria, which degrade organic mater in four stages viz., hydrolysis, fermentation, acidification and methane formation (see figure 1).



(source: [2])

figure 1: Anaerobic digestion pathway

#### 1.3.1 Hydrolysis and fermentation

In the first step (hydrolysis), the organic matter is enzymolyzed externally by extracellular enzymes (cellulase, amylase, protease and lipase) of microorganisms. Bacteria decompose the long chains of the complex carbohydrates, proteins and lipids into shorter parts. For example, polysaccharides are converted into monosaccharides. Proteins are split into peptides and amino acids [1].

#### 1.3.2 Acidification

Acid-producing bacteria, involved in the second step, convert the intermediates of fermenting bacteria into acetic acid (CH<sub>3</sub>COOH), hydrogen (H<sub>2</sub>) and carbon dioxide (CO<sub>2</sub>).

These bacteria are facultatively anaerobic and can grow under acid conditions. To produce acetic acid, they need oxygen and carbon. For this, they use the oxygen solved in the solution or bound oxygen. Hereby, the acid-producing bacteria create an anaerobic condition, which is essential for the methane producing microorganisms. Moreover, they reduce the compounds with a low molecular weight into alcohols, organic acids, amino acids, carbon dioxide, hydrogen sulphide and traces of methane. From a chemical standpoint, this process is partially endergonic (i.e. only possible with energy input), since bacteria alone are not capable of sustaining that type of reaction [1].

### **1.3.3 Methane formation**

Methane-producing bacteria, involved in the third step, decompose compounds with a low molecular weight. For example, they utilize hydrogen, carbon dioxide and acetic acid to form methane and carbon dioxide. Under natural conditions, methane producing microorganisms occur to the extent that anaerobic conditions are provided, e.g. under water (for exemple in marine sediments), in ruminant stomachs and in marshes. They are obligatory anaerobic and very sensitive to environmental changes [1].

### **1.3.4 Symbiosis of bacteria**

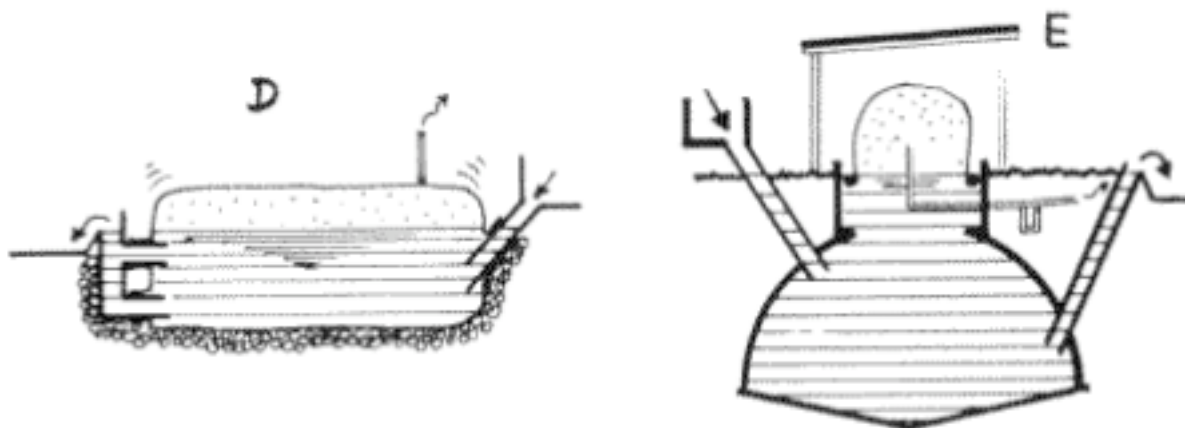
Methane- and acid-producing bacteria act in a symbiotical way. On the one hand, acidproducing bacteria create an atmosphere with ideal parameters for methane-producing bacteria (anaerobic conditions, compounds with a low molecular weight). On the other hand, methane-producing microorganisms use the intermediates of the acid-producing bacteria. Without consuming them, toxic conditions for the acid-producing microorganisms would develop.

In practical fermentation processes the metabolic actions of various bacteria all act in concert. No single bacterium is able to produce fermentation products alone [1].

## **1.4 Description of smale scale biogas plants**

### **1.4.1 Balloon digester**

The balloon plant (figure 2, left hand side) consists of a digester bag (e.g. PVC) in the upper part of which the gas is stored. The inlet and outlet are attached directly to the plastic skin of the balloon. The gas pressure is achieved through the elasticity of the balloon and by added weights placed on the balloon. A variation of the balloon plant is the channel-type digester, which is usually covered with plastic sheeting and a sunshade



(source: [1])

figure 2: Conceptual sketches of balloon-type digesters

(figure 2, right hand side). Balloon plants can be recommended wherever the balloon skin is not likely to be damaged and where the temperature is even and high [1].

Pros and cons of balloon digesters are summarized in table 1.

table 1: Pros and cons of balloon digesters

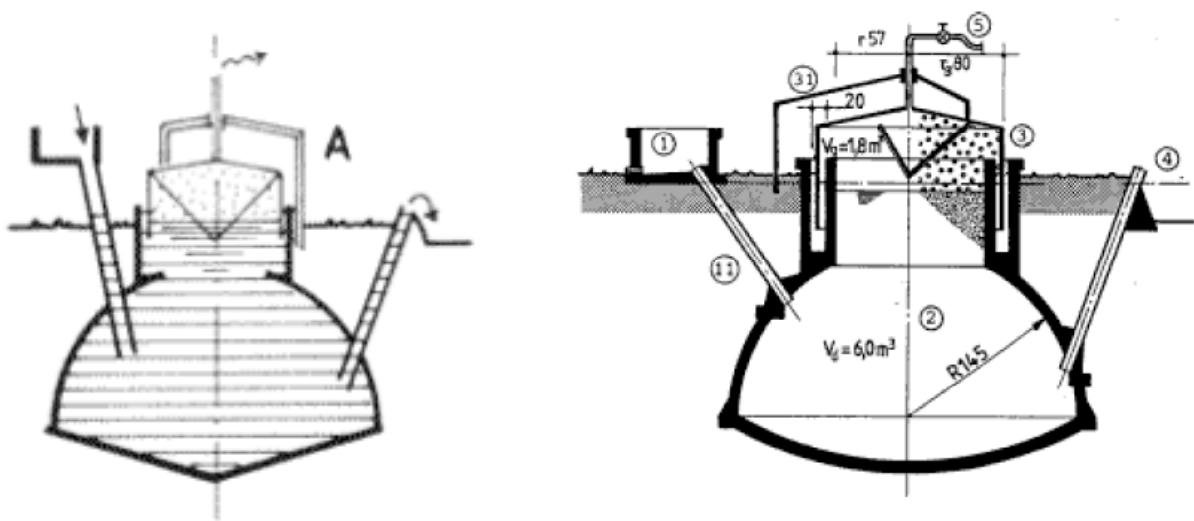
Pros:	Cons:
<ul style="list-style-type: none"> <li>• low cost;</li> <li>• ease of transportation;</li> <li>• low construction sophistication;</li> <li>• high digester temperatures;</li> <li>• uncomplicated cleaning, emptying and maintenance;</li> </ul>	<ul style="list-style-type: none"> <li>• relatively short life (about five years);</li> <li>• susceptibility to damage;</li> <li>• little creation of local employment;</li> <li>• limited self-help potential;</li> <li>• little knowledge for repairing by local craftsmen [3]</li> </ul>

(source: [1])

### 1.4.2 Floating-drum digester

Floating-drum plants consist of an underground digester and a moving gasholder. The gasholder floats either directly on the fermentation slurry (figure 3, left hand side) or in a water jacket of its own (figure 3, right hand side). The gas is collected in the gas drum,

which rises or moves down, according to the amount of gas stored. The gas drum is prevented from tilting by a guiding frame [1]. Water-jacket digesters are universally applicable and especially easy to maintain. The drum won't stick, even if the substrate has a high solids content. Floating-drums made of glass-fibre reinforced plastic and high-density polyethylene have been used successfully, but the construction cost is higher than for its steel counterpart. Floating-drums made of wire-mesh-reinforced concrete are liable to hairline cracking and are intrinsically porous. They require a gastight, elastic internal coating. PVC drums are unsuitable because they are not resistant to UV radiation [3].



(source: [1])

figure 3: Conceptual sketches of floating-drum type digesters

Pros and cons of floating-drum type digesters are summarized in table 2.

table 2: Pros and cons of floating-drum type digesters

Pros:	Cons:
<ul style="list-style-type: none"> <li>• simple, easily understood operation;</li> <li>• they volume of stored gas is directly visible;</li> <li>• the gas pressure is constant (determined by the weight of the gas holder);</li> </ul>	<ul style="list-style-type: none"> <li>• high material costs of the steel drum;</li> <li>• susceptibility of steel parts to corrosion (because of this, floating drum plants have a shorter life span than fixed-dome plants);</li> <li>• regular maintenance costs for the painting of the drum</li> </ul>

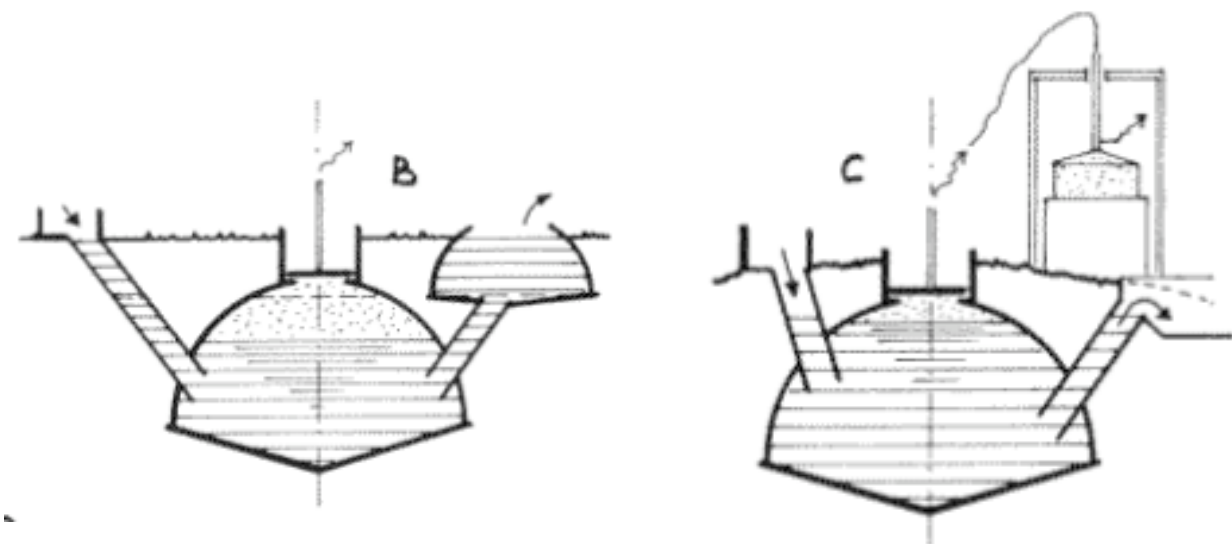
- construction is relatively easy;
- if fibrous substrates are used, the gasholder shows a tendency to get "stuck" in the resultant floating scum [3];
- construction mistakes do not lead to major problems in operation and gas yield;

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(source: [1])

### 1.4.3 Fixed-dome digester

The fixed-dome plant consists of a digester with a fixed, non-movable gas holder, which sits on top of the digester. When gas production starts, the slurry is displaced into the compensation tank. Gas pressure increases with the volume of gas stored and the height difference between the slurry level in the digester and the slurry level in the compensation tank [1].



(source: [1])

figure 4: Conceptual sketches of fixed-dome type digesters

Pros and cons of fixed-dome type digesters are summarized in table 3.

table 3: Pros and cons of fixed-dome type digesters

Pros:	Cons:
<ul style="list-style-type: none"> <li>• relatively low construction costs;</li> <li>• absence of moving parts and rusting steel parts;</li> <li>• long life span if well constructed;</li> <li>• underground construction saves space and protects the digester from temperature changes;</li> <li>• construction provides opportunities for skilled local employment;</li> </ul>	<ul style="list-style-type: none"> <li>• frequent problems with the gas-tightness of the brickwork gas holder (a small crack in the upper brickwork can cause heavy losses of biogas);</li> <li>• gas pressure fluctuates substantially depending on the volume of the stored gas;</li> <li>• even though the underground construction buffers temperature extremes, digester temperatures are generally low;</li> </ul>

(source: [1])

## 2 BIOGAS SANITATION CONCEPTS

### 2.1 Domestic wastewater quantification and characterisation

Domestic wastewater contains organic and inorganic matter in suspended, colloidal and dissolved forms. The concentration in the wastewater depends on the original concentration in the water supply, and the uses to which the water has been put. The climate, and the wealth and habits of the people have a marked effect on the wastewater characteristics [4].

Raw domestic wastewater characteristics are shown in table 4.

table 4: Domestic wastewater characteristics (excerpt)

item	Range in values contgributed in wastes [4]
Biochemical oxygen demand, 5 days, 20 °C (BOD <sub>5</sub> )	45 - 54
Chemical oxygen demand	1.6 - 1.9 x BOD <sub>5</sub>
Total organic carbon	0.6 - 1.0 x BOD <sub>5</sub>
Total solids	170 - 220
Suspended solids	70 - 145
Grit (inorganic, 0.2 mm and above)	5 - 15
Grease	10 - 30
Total nitrogen N	6 - 12
Organic nitrogen	~ 0.4 x total N
Free ammonia	~ 0.6 x total N
Nitrite	-
Nitrate	0.0 - 0.5 x total N
Total phosphorus, P	0.6 - 4.5
Organic phosphorus	~ 0.3 x total P
Inorganic (ortho- and polyphosphates)	~ 0.7 x total P
Potassium (as potassium oxide K <sub>2</sub> O)	2.0 - 6.0

The per capita daily water usage ranges from 180 to 300 litres im most sewerred communities [4] though water consumption may be much higher. The values of biological oxygen demand (BOD) generally average 54 grams per person per day where the sewage collection system is separate from the storm collection system and is reasonably efficient [4].

According to the Central Public Health and Environmental Engineering Organisation (CPHEEO) water supply demand for Indian cities provided with piped water supply with sewerage amounts to 135 litres per capita per day. Break up of water demand is shown in table 5. At least 80 - 85 % of the water supplied returns as wastewater [4].

table 5: Break up of water requirements for domestic purposes according to CPHEEO „Manual on Water Supply and Treatment“

description	quantity of water [5] [l/cap/d]
bathing	55
washing of clothes	20
flushing of WC	30
washing of house	10
washing of utensils	10
cooking	5
drinking	5
<b>total</b>	<b>135</b>

## 2.2 Objectives of reuse-oriented wastewater management

The very basic objective of wastewater management is to protect public health and the environment in a socio-culturally and economically sustainable manner. Wastewater management systems should also account for the willingness and ability of users to operate their own system (user-friendliness). The basic objectives of a household or community wastewater management system can be summarised as follows (adopted from [12]):

- **Protection of public health:** A wastewater management system should create an effective physical barrier between contaminated blackwater and user, as well as avoid odour emissions and stagnant water leading to breeding sites for mosquitoes.
- **Protection of the environment:** A wastewater management system should prevent eutrophication and pollution of sensitive aquatic systems (surface water, groundwater, drinking water reservoirs) as well as terrestrial systems (irrigated soil).
- **Socio-culturally and economically acceptable:** wastewater management systems have to be adapted to the socio-cultural and economic settings of the household or neighbourhood. If waste reuse is culturally not anchored for example, blackwater management systems aiming at irrigation are likely to fail.
- **Simple and user-friendly:** Household or neighbourhood wastewater management systems should be manageable by the user, technically simple and robust and possibly not rely on external fuel, power supply or chemicals.
- **Compliance with national and international regulations and standards:** Qualitative and quantitative effluent standards have to maintain or even enhance the quality of receiving waters, to ensure soil fertility and protect public health.

## 2.3 Physical appearance of biogas sanitation concepts

In this training material the following biogas sanitation concept will be discussed:

- on-site pre-treatment of domestic wastewater in a biogas settler and advanced treatment of the effluent in a vertical flow constructed wetland (VFCW)

### 2.3.1 On-site pre-treatment of domestic wastewater in biogas settlers

Biogas settlers (sometimes also referred to as “Biodigester Septic Tanks” or “UASB Septic Tanks”) have been introduced as cost-effective pre-treatment or treatment step for domestic wastewater or blackwater in countries such as Jamaica [6], South Africa [7], China [8] and India [9] by various organisations.



Biogas settler are designed to:

- facilitate solid-liquid separation;
- provide a high sludge retention time, that facilitates almost complete degradation of organics;
- enable production and collection of biogas for direct use (e.g. lighting, cooking, etc.).

Depending upon the hydraulic retention time (HRT) a biogas settler may be considered a pre-treatment or treatment unit. Biogas settlers that are designed for pre-treatment of domestic wastewater (combined greywater and blackwater) provide a HRT of 24 hours or less [10]; subsequent treatment of the effluent in an anaerobic baffle reactor and constructed wetland system may be required. With an increased HRT (8 to 10 days and ca. 15 days with and without urine-separation, respectively) anaerobic treatment of the liquid phase happens and advanced treatment of the effluent may be done in a constructed wetland system only [8].

Pros and cons of on-site treatment of wastewater in biogas settlers are summarized in table 6.

table 6: Pros and cons of on-site treatment of wastewater in biogas settlers

Pros:	Cons:
<ul style="list-style-type: none"><li>• no handling of raw (unprocessed) wastewater;</li><li>• biogas may be used as a substitute to LPG in cooking;</li></ul>	<ul style="list-style-type: none"><li>• external energy required for lifting of pre-treated wastewater to VFCW surface;</li></ul>

## 2.4 Key factors for the successful implementation of biogas sanitation concepts

For the successful and sustainable implementation of blackwater management schemes it's crucial to:

- create awareness amongst future users (sanitation related problems in general and value of wastewater in particular);
- participatory planning and decision making;

- training of users on how to operate and maintain the wastewater system;
- training of caretakers and operators;

### 3 SIZING OF BIOGAS SANITATION SCHEMES

#### 3.1 On-site pre-treatment of domestic wastewater in biogas settler

Anaerobic on-site treatment of wastewater requires pre-treatment of wastewater in a biogas settler for solid-liquid separation up-stream a VFCW and an optional tank for the collection of the VFCW effluent. The required facilities are summarized below:

- primary treatment of raw wastewater in a biogas settler,
- secondary treatment of (pre-treated) wastewater in a VFCW and
- optional tank for collection of treated wastewater, direct application without storage, infiltration or discharge to receiving water bodies.

##### 3.1.1 Calculation of wastewater production

Daily wastewater production is calculated using equation (1):

$$Q_D = N \cdot Q_S \quad \text{equation (1)}$$

where:

$Q_D$  ..... daily wastewater production [l/d]

$N$  ..... number of people contributing to wastewater production [p/d]

$Q_S$  ..... specific wastewater production [l/p/d]

BOD<sub>5</sub>- and COD concentration of raw wastewater are calculated as follows:

$$C_{BOD-RAW} = \frac{L_{BOD} \cdot 1,000}{Q_S} \quad \text{equation (2)}$$

$$C_{COD-RAW} = 2 \cdot C_{BOD-RAW} \quad \text{equation (3)}$$

where:

$C_{BOD-RAW}$ .....BOD<sub>5</sub> concentration of raw wastewater [mg/l]

$L_{BOD}$  .....specific BOD<sub>5</sub> load [g/p/d]

1,000..... conversion factor

$Q_S$  .....specific wastewater production [l/p/d]

$C_{COD-RAW}$  .....COD concentration of raw wastewater [mg/l]

2.....conversion factor

### 3.1.2 Sizing of biogas settler

While calculating the net volume of the biogas settler for pre-treatment of raw wastewater, four distinct volumes viz., the sludge accumulation volume, the volume for recommended hydraulic detention time, the volume for the scum layer and the volume for gas storage, have to be considered.

$$V_{BS} = V_{SL} + V_D + V_{SC} + V_G \quad \text{equation (4)}$$

where:

$V_{BS}$  .....net volume of biogas settler [m<sup>3</sup>]

$V_{SL}$  .....sludge accumulation volume [m<sup>3</sup>]

$V_D$ .....volume for recommended hydraulic detention time [m<sup>3</sup>]

$V_{SC}$  .....volume for scum layer [m<sup>3</sup>]

$V_G$  .....volume for gas storage [m<sup>3</sup>]

The required sludge accumulation volume is calculated by multiplying the specific sludge production rate, “removed” BOD<sub>5</sub>, daily wastewater production and desludging frequency.

$$C_{BOD-EBS} = C_{BOD-RAW} \cdot (1 - BOD_{REM-BS}) \quad \text{equation (5)}$$

$$V_{SL} = \frac{V_{SSV} \cdot (C_{BOD-RAW} - C_{BOD-EBS}) \cdot Q_D \cdot 30 \cdot P_{DS}}{1,000 \cdot 1,000} \quad \text{equation (6)}$$

where:

$C_{\text{BOD-EBS}}$  ..... BOD<sub>5</sub> concentration of biogas settler effluent [mg/l]

$C_{\text{BOD-RAW}}$  ..... BOD<sub>5</sub> concentration of raw wastewater [mg/l]

$\text{BOD}_{\text{REM-BS}}$  ..... BOD “removal” in biogas settler [%]

$V_{\text{SL}}$  ..... sludge accumulation volume [m<sup>3</sup>]

$V_{\text{SSV}}$  ..... specific sludge production [l/g BOD<sub>REM</sub>]

$Q_D$  ..... daily wastewater production [l/d]

30 ..... days per month

$P_{\text{DS}}$  ..... desludging frequency [month]

1,000 ..... conversion factor

Hydraulic detention volume is calculated using equation (7):

$$V_D = \frac{Q_D \cdot T_D}{1,000} \quad \text{equation (7)}$$

where:

$V_D$  ..... volume for recommended hydraulic detention time [m<sup>3</sup>]

$Q_D$  ..... daily wastewater production [l/d]

$T_D$  ..... detention time [d]

1,000 ..... conversion factor

At 24 hours HRT, 15 – 20 % of the liquid volume can be taken for estimating the volume to be provided for the scum layer:

$$V_{\text{SC}} = PC \cdot V_D \quad \text{equation (8)}$$

where:

$V_{SC}$  ..... volume for scum accumulation [ $m^3$ ]

$PC$  ..... percentage of recommended hydraulic detention volume [%]

$V_D$  ..... volume for recommended hydraulic detention time [ $m^3$ ]

The required gas storage volume is calculated by multiplying the specific gas production rate, “removed” COD and daily wastewater production. Provide additional gas storage capacity for period of non-use of gas of 20% of liquid storage capacity (at 24 hours HRT).

$$C_{COD-EBS} = C_{COD-RAW} \cdot (1 - COD_{REM-BS}) \quad \text{equation (9)}$$

$$V_G = \frac{V_{SL} \cdot (C_{COD-RAW} - C_{COD-EBS}) \cdot Q_D}{1,000 \cdot 1,000} + \frac{PC \cdot V_D}{1,000} \quad \text{equation (10)}$$

where:

$C_{COD-EBS}$  ..... COD concentration of biogas settler effluent [mg/l]

$C_{COD-RAW}$  ..... COD concentration of raw wastewater [mg/l]

$COD_{REM-BS}$  ... COD “removal” in biogas settler [%]

$V_{GS}$  ..... volume for gas storage [ $m^3$ ]

$V_{SL}$  ..... specific gas production [l/g  $COD_{REM}$ ]

$Q_D$  ..... daily wastewater production [l/d]

1,000 ..... conversion factor

$PC$  ..... percentage of recommended hydraulic detention volume [%]

$V_D$  ..... volume for recommended hydraulic detention time [ $m^3$ ]

The volume of a half round biogas settler is determined by using equation (11), which can be rearranged and used to calculate the halfmeter (radius). Both forms of the equation are shown below.

$$V_{BS} = \frac{2 \cdot R_{BS}^3 \cdot \pi}{3} \quad \text{equation (11)}$$

$$R_{BS} = \sqrt[3]{\frac{3 \cdot V_{BS}}{2 \cdot \pi}} \quad \text{equation (11)}$$

where:

$V_{BS}$  ..... volume of biogas settler [ $m^3$ ]

$R_{BS}$  ..... halfmeter (radius) of biogas settler [m]

The net volume of the compensation tank equals the gas storage capacity. A common design for the compensation tank is to provide a hemisphere with the overflow at height H above the base (or zero line). The net volume of the compensation tank is calculated by subtracting the volume of the free space above the overflow ( $R_{EC} - H$ ) from the volume of the hemisphere:

$$V_{CT} = \frac{2 \cdot (R_{CT} - 0.02)^3 \cdot \pi}{3} - \left[ (R_{CT} - H)^2 \cdot \pi \cdot \left( R_{CT} - \frac{R_{CT} - H}{3} \right) \right] \quad \text{equation (12)}$$

where:

$V_{CT}$  ..... net volume of compensation tank [ $m^3$ ]

$R_{CT}$  ..... halfmeter (radius) of compensation tank [m]

0.02 ..... thickness of plaster [m]

H ..... hight of overflow above the base of compensation tank [m]

Maximum gas pressure occurs at a level P below the overflow level of the compensation tank, which is also the lowest slurry level. For calculation of level P equation (13) is applied to the total volume - equation (14) - of the free space above maximum slurry level (lowest gas pressure) and the net volume of the compensation tank.

$$P^2 \cdot \pi \cdot \left( R_{BS} - \frac{P}{3} \right) = V_{F+V_{CT}} \quad \text{equation (13)}$$

$$V_{F+V_{CT}} = H^2 \cdot \pi \cdot \left( R_{BS} - \frac{H}{3} \right) + V_{CT} \quad \text{equation (14)}$$

where:

P .....vertical distance of lowest slurry level and overflow level [m]

R<sub>BS</sub> .....halfmeter (radius) of biogas settler [m]

V<sub>F</sub> ..... volume of the free space above maximum slurry level [m<sup>3</sup>]

V<sub>CT</sub> .....net volume of compensation tank [m<sup>3</sup>]

H .....hight of overflow above the base of displacement chamber [m]

### 3.1.3 Sizing of siphon tank or pump sump

Application of pre-treated blackwater to the VFCW has to be done intermittently. The volume of each batch is calculated using equation (15):

$$Q_B = \frac{Q_D}{N_B} \quad \text{equation (15)}$$

where:

Q<sub>B</sub> .....batch volume [l]

Q<sub>D</sub> ..... daily wastewater production [l/d]

N<sub>B</sub> .....number of batches per day

### 3.1.4 Sizing of VFCW

The surface area of the VFCW is determined by comparing the impact of hydraulic and organic loading criteria, and adopting the larger of the two surface areas.

$$A_{HYD} = \frac{Q_D}{HSL} \quad \text{equation (16)}$$

$$A_{BOD} = \frac{C_{BOD-EBS} \cdot Q_D}{OSL_{VFCW-MAX} \cdot 1,000} \quad \text{equation (17)}$$

$$A = MAX[A_{HYD}; A_{BOD}] \quad \text{equation (18)}$$

where:

$A_{HYD}$  ..... surface area of VFCW [ $m^2$ ]

$Q_D$  ..... daily wastewater production [l/d]

HSL..... hydraulic surface load [l/ $m^2$ /d]

$A_{BOD}$  ..... surface area of VFCW [ $m^2$ ]

$C_{BOD-EST}$  .....  $BOD_5$  concentration of biogas settler effluent [mg/l]

$OSL_{VFCW-MAX}$  maximum organic surface load of VFCW [g  $BOD_5$ / $m^2$ /d]

1,000..... conversion factor

A ..... larger of the two surface areas [ $m^2$ ]

$BOD$  concentration of the final effluent is estimated based upon average  $BOD$  “removal” values from literature:

$$C_{BOD-EVFCW} = C_{BOD-EBS} \cdot (1 - BOD_{REM-VFCW}) \quad \text{equation (19)}$$

where:

$C_{BOD-EVFCW}$  ...  $BOD_5$  concentration of VFCW effluent [mg/l]

$C_{BOD-EBS}$  .....  $BOD_5$  concentration of biogas settler effluent [mg/l]

$BOD_{REM-VFCW}$   $BOD$  “removal” in VFCW [%]

### 3.1.5 Sizing of collection tank

Net storage capacity of the collection tank is calculated taking daily wastewater production and desired storage time into account:



$$V_{CT} = \frac{Q_D \cdot T}{1,000} \quad \text{equation (20)}$$

where:

$V_{CT}$  ..... net volume of collection tank [ $m^3$ ]

$Q_D$  ..... daily wastewater production [l/d]

$T$  ..... desired storage time [d]

1,000..... conversion factor

## 4 SAMPLE DESIGN PROBLEM

Please note that design parameters (e.g. specific wastewater production, specific BOD load, etc.) have been chosen solely to exemplify designing of a biogas sanitation system presented as sample design problem in this training material and must not be applied for designing of real-life wastewater management systems without verification.

For proper designing of real-life projects, measuring of wastewater production and BOD load of the raw wastewater is recommended. If measuring of e.g. wastewater production and/or BOD load of the raw wastewater is not possible (e.g. designing of biogas sanitation system for an up-coming project, etc.) design parameters have to be set in all conscience.

### 4.1 On-site treatment of wastewater

Calculate the required volume for a biogas settler and surface area for a VFCW where wastewater is from a housing society.

#### 4.1.1 Calculation of wastewater production

For calculation of daily wastewater production assume that 88 people are living in the society and that specific wastewater production is 135 litres per person per day. Specific BOD load per person per day is set with 54 grams [4].

Designing of the wastewater management scheme shall be based upon the following assumptions:

- number of users (N): 88
- specific wastewater prod. ( $Q_S$ ): 135 l/p/d

- specific BOD load ( $L_{BOD}$ ): 54 g BOD<sub>5</sub>/p/d

$$Q_D = 88 \cdot 135 \approx 12,000 \text{ l / d} \quad \text{equation (1)}$$

$$C_{BOD-RAW} = \frac{54 \cdot 1,000}{135} = 400 \text{ mg / l} \quad \text{equation (2)}$$

$$C_{COD-RAW} = 2 \cdot 400 = 800 \text{ mg / l} \quad \text{equation (3)}$$

Daily wastewater production arises to ca. 12,000 litres (12.0 m<sup>3</sup>). BOD and COD level of the raw wastewater are ca. 400 mg/l and 800 mg/l, respectively.

#### 4.1.2 Sizing of biogas settler

A common design rule is for biogas settlers to provide a minimum hydraulic detention time of at least 1 day (24 hours) at maximum depth of sludge and scum layer.

Sizing of the biogas settler and estimation of BOD<sub>5</sub> concentration of the effluent shall be based upon the following assumptions:

- BOD<sub>5</sub> raw wastewater ( $C_{BOD-RAW}$ ): 400 mg BOD<sub>5</sub>/l
- BOD<sub>5</sub> removal (BOD<sub>REM</sub>): 36 %
- specific sludge volume ( $V_{SSV}$ ): 0.0037 l/g BOD<sub>REM</sub>
- daily wastewater prod. ( $Q_D$ ): 12,000 l/d
- desludging frequency ( $T_D$ ): every 18 months
- hydraulic detention time (HRT): 1 day (24 hours)
- COD removal (COD<sub>REM</sub>): 34 %
- Specific biogas production ( $V_{SL}$ ): 0.35 l/g COD<sub>REM</sub>
- additional gas storage capacity: 20 % of  $V_D$

$$C_{BOD-EBS} = 400 \cdot (1 - 0.36) = 256 \text{ mg BOD}_5 / \text{l} \quad \text{equation (5)}$$

$$V_{SL} = \frac{0.0037 \cdot (400 - 256) \cdot 12,000 \cdot 30 \cdot 18}{1,000 \cdot 1,000} \approx 3.5 \text{ m}^3 \quad \text{equation (6)}$$

$$V_D = \frac{12,000 \cdot 1}{1,000} = 12.0 \text{ m}^3 \quad \text{equation (7)}$$

$$V_{SC} = 0.20 \cdot 12.0 = 2.4 \text{ m}^3 \quad \text{equation (8)}$$

$$C_{COD-EB5} = 800 \cdot (1 - 0.34) = 528 \text{ mg COD / l} \quad \text{equation (9)}$$

$$V_G = \frac{0.35 \cdot (800 - 528) \cdot 12,000}{1,000 \cdot 1,000} + \frac{0.2 \cdot 12,000}{1,000} \approx 3.5 \text{ m}^3 \quad \text{equation (10)}$$

$$V_{BS} = 3.5 + 12.0 + 2.4 + 3.5 = 21.4 \text{ m}^3 \quad \text{equation (4)}$$

$$R_{BS} = \sqrt[3]{\frac{3 \cdot 21.4}{2 \cdot \pi}} \approx 2.17 \text{ m} \quad \text{equation (11)}$$

$$V_{CT} = \frac{2 \cdot (R_{CT} - 0.02)^3 \cdot \pi}{3} - \left[ (R_{CT} - 0.45)^2 \cdot \pi \cdot \left( R_{CT} - \frac{R_{CT} - 0.45}{3} \right) \right] \quad \text{equation (12)}$$

$$3.6 = \frac{2 \cdot (1.70 - 0.02)^3 \cdot \pi}{3} - \left[ (1.70 - 0.45)^2 \cdot \pi \cdot \left( 1.70 - \frac{1.70 - 0.45}{3} \right) \right] \quad \text{equation (12)}$$

$$P^2 \cdot \pi \cdot \left( R_{BS} - \frac{P}{3} \right) = 0.45^2 \cdot \pi \cdot \left( 2.20 - \frac{0.45}{3} \right) + 3.6 \quad \text{equation (13)}$$

$$P^2 \cdot \pi \cdot \left( 2.20 - \frac{P}{3} \right) = 4.9 \quad \text{equation (13)}$$

$$0.91^2 \cdot \pi \cdot \left( 2.20 - \frac{0.91}{3} \right) = 4.9 \quad \text{equation (13)}$$

ad equation (12): by trial and error (for  $V_G = 3.5 \text{ m}^3$ ),  $R_{CT}$  lies between 1.6 and 1.7 meter, adopt 1.7 meter for a volume of  $3.6 \text{ m}^3$ .

ad equation (13) by trial and error (for  $V_F + V_{CT} = 3.5 \text{ m}^3$ ),  $P$  is 0.91 meter.

#### 4.1.3 Sizing of siphon tank or pump sump

Intermittent feeding of pre-treated wastewater shall be done in 3 to 4 batches per day.

Sizing of the siphon tank or pump sump for intermittent feeding of pre-treated wastewater to the VFCW shall be based upon the following assumptions:

- daily blackwater prod. (QD): 12,000 l/d
- number of batches per day (NB): 3

$$Q_B = \frac{12,000}{3} = 4.0 \text{ m}^3 / \text{batch} \quad \text{equation (15)}$$

### ***Construction details and other important information***

- All civil works have to comply with local as well as national standards and regulations.
- The siphon tank or pump sump must be watertight.
- A manhole has to be provided in the cover slab for maintenance.
- The manhole or the whole cover slab must be raised above the surrounding ground level to prevent surface run-off water from entering the tank.
- If possible, the siphon tank or pump sump is to be provided a fail-safe overflow that diverts water to low lying areas or a sewer in case of break-down of the pump or power cut.

#### **4.1.4 Sizing of VFCW**

Maximum organic surface load ( $OSL_{VFCW-MAX}$ ) for VFCWs is given as follows:

- organic surface load: 20 to 40 [11] and up to 60g [12]  $BOD_5/m^2/day$

Common hydraulic surface loads (HSL) for HFCWs are given as follows:

- hydraulic surface load: 50 to 130 [11] and up to 200  $l/m^2/day$

Sizing of the vertical flow constructed wetland shall be based upon the following assumptions:

- daily wastewater prod. (QD): 12,000  $l/d$
- hydraulic surface load (HSL): 200  $l/m^2/d$
- $BOD_5$  settler eff. ( $C_{BOD-EBS}$ ): 256  $mg\ BOD_5/l$
- max. OSL ( $OSL_{VFCW-MAX}$ ): 20  $mg\ BOD_5/m^2/d$

$$A_{HYD} = \frac{12,000}{200} = 60.0\ m^2 \quad \text{equation (16)}$$

$$A_{BOD} = \frac{256 \cdot 12,000}{30 \cdot 1,000} \approx 100.0\ m^2 \quad \text{equation (17)}$$

$$A = MAX[60.0; 100.0] = 100.0\ m^2 \quad \text{equation (18)}$$

$$C_{BOD-EVFCW} = 256 \cdot (1 - 0.75) \approx 65\ mg\ BOD_5 / l \quad \text{equation (19)}$$

### *Construction details and other important information*

- The location of the VFCW is to be selected in such a manner that it's safe from flooding.
- VFCW should be designed in such a way that they are integrated into landscape as much as possible.
- Surface water must be diverted away from the VFCW.
- If the existing soil has a permeability coefficient  $< 10^{-8}$  m/s, no artificial sealing layer is necessary for sewage treatment applications. In this case a density test (after Procter) has to be performed. Constructed wetland systems in soil with higher permeability require sealing of the bottom and sides so that untreated or partly treated wastewater cannot infiltrate to the groundwater. This can be achieved by: [11]
  - Using concrete or plastic tank.
  - Providing plastic liner, UV resistant, if exposed to the sun, thickness  $\geq 1$  mm, root resistant, preferably from polyethylene or equivalent material. The liner has to be protected against damages caused by rocks of the existing soil and by sharp edged gravel of the drainage layer. Geotextiles may be used for prevention of such damages.
  - Providing clay sealing with a verified thickness of  $\geq 30$  cm. It has to be compacted properly.
  - Improvement of existing soil by admixture of bentonite or very fine clay (two layers of 20 cm each, mixed and compacted separately).

After finishing the sealing a leakage test should be carried out by filling the bed with water. If the loss is less than 2 mm overnight, the sealing is to be considered as satisfactory.

- Washed river sand and gravel are the preferred filter media;
  - top layer: 10 cm fine gravel ( $\varnothing$  8/16 mm),
  - main layer: 60 to 80 cm coarse sand ( $\varnothing$  1/4 mm),
  - intermediate layer: 10 cm fine gravel ( $\varnothing$  4/8 mm),
  - drainage layer: 20 cm coarse gravel ( $\varnothing$  16/32 mm).
- A freeboard of at least 25 cm (distance from bed surface to the upper edge of the lateral sealing) is to be provided.
- PVC pipes ( $\varnothing$  50 to 75 mm) with drilled holes are acceptable for inlet and outlet manifolds. The distribution system has to be designed and constructed in such a way that they distribute the incoming wastewater uniformly over the surface of the VFCW

without leading to the formation of erosion furrows on the bed surface. After each application the pipes of the inflow construction should run empty. This prevents bacterial growth and resulting clogging problems.

- PVC pipes (Ø 100 mm) with drilled holes are acceptable for outlet manifolds.
- The construction of in- and outflow devices must allow for cleaning with mechanical or high pressure flushing tools.
- Local plant species should be used on the bed. The preferred species include: cattail, sedge, rush, soft stem bulrush, and reeds. Decorative, flowering plants can be used around the edges of the bed.
- The VFCW should be protected from unauthorized access, but be accessible for maintenance. There should be free access to all operational points, like manholes, pumping stations, maintenance locations and sampling points. The access has to be constructed in a way, that crossing of the VFCW is avoided.

#### 4.1.5 Sizing of collection tank

Net storage capacity of the collection tank should be at least one-days wastewater production.

Sizing of the collection tank shall be based upon the following assumptions:

- daily blackwater prod. (QD): 12,000 l/d
- storage time (T): 1 d

$$V_{CT} = \frac{12,000}{1,000} = 12,0 \text{ m}^3 \quad \text{equation (20)}$$

#### *Construction details and other important information*

- All civil works have to comply with local as well as national standards and regulations.
- The collection tank must be watertight.
- A manhole has to be provided in the cover slab for maintenance.
- The manhole or the whole cover slab must be raised above the surrounding ground level to prevent surface run-off water from entering the tank.
- If possible, the collection tank is to be provided a fail-safe overflow that diverts water to low lying areas or a sewer in case of break-down of the pump or power cut.

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## **6 SKETCHES, TECHNICAL DRAWINGS**



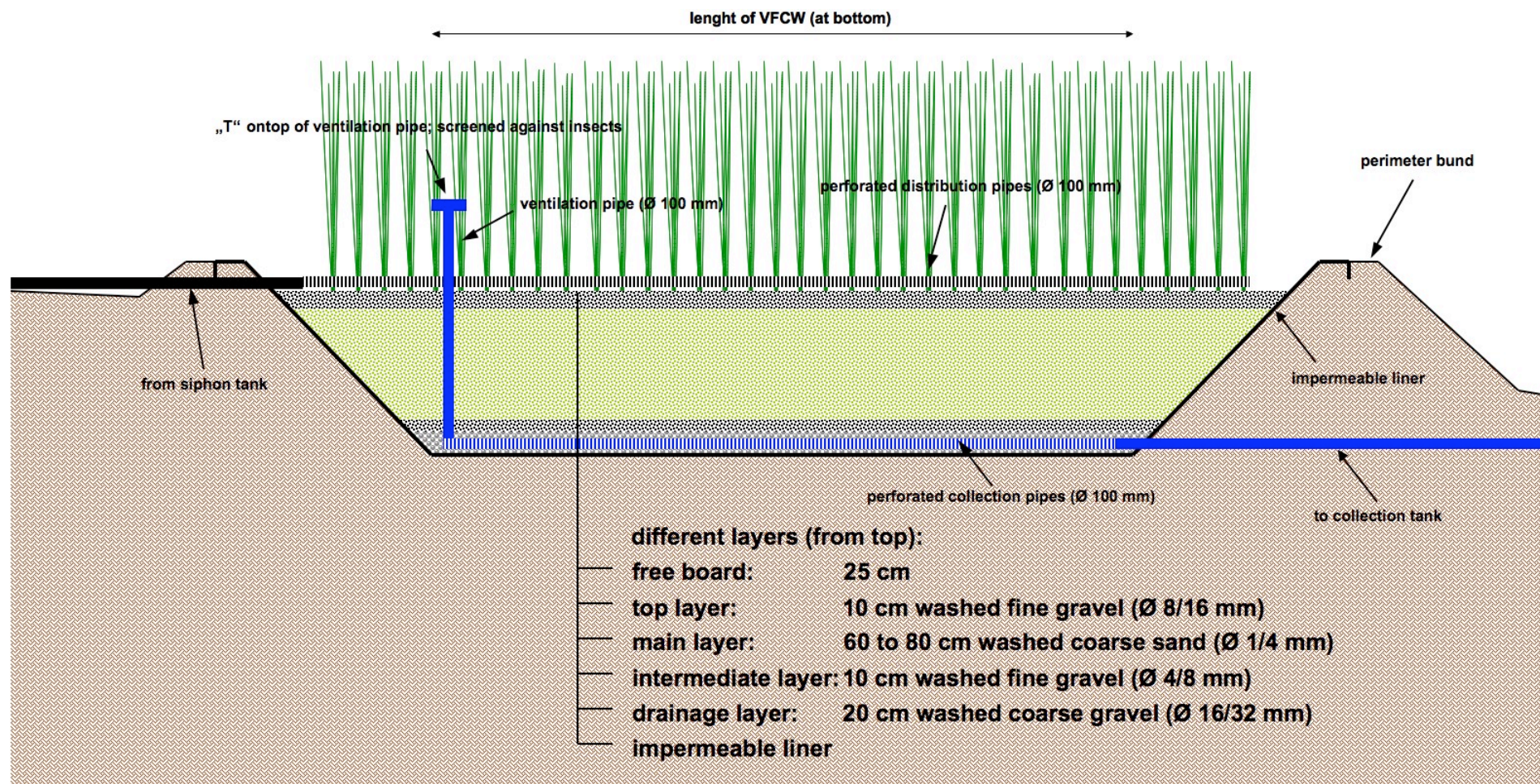


figure 5: Conceptual sketch VFCW (longitudinal section)



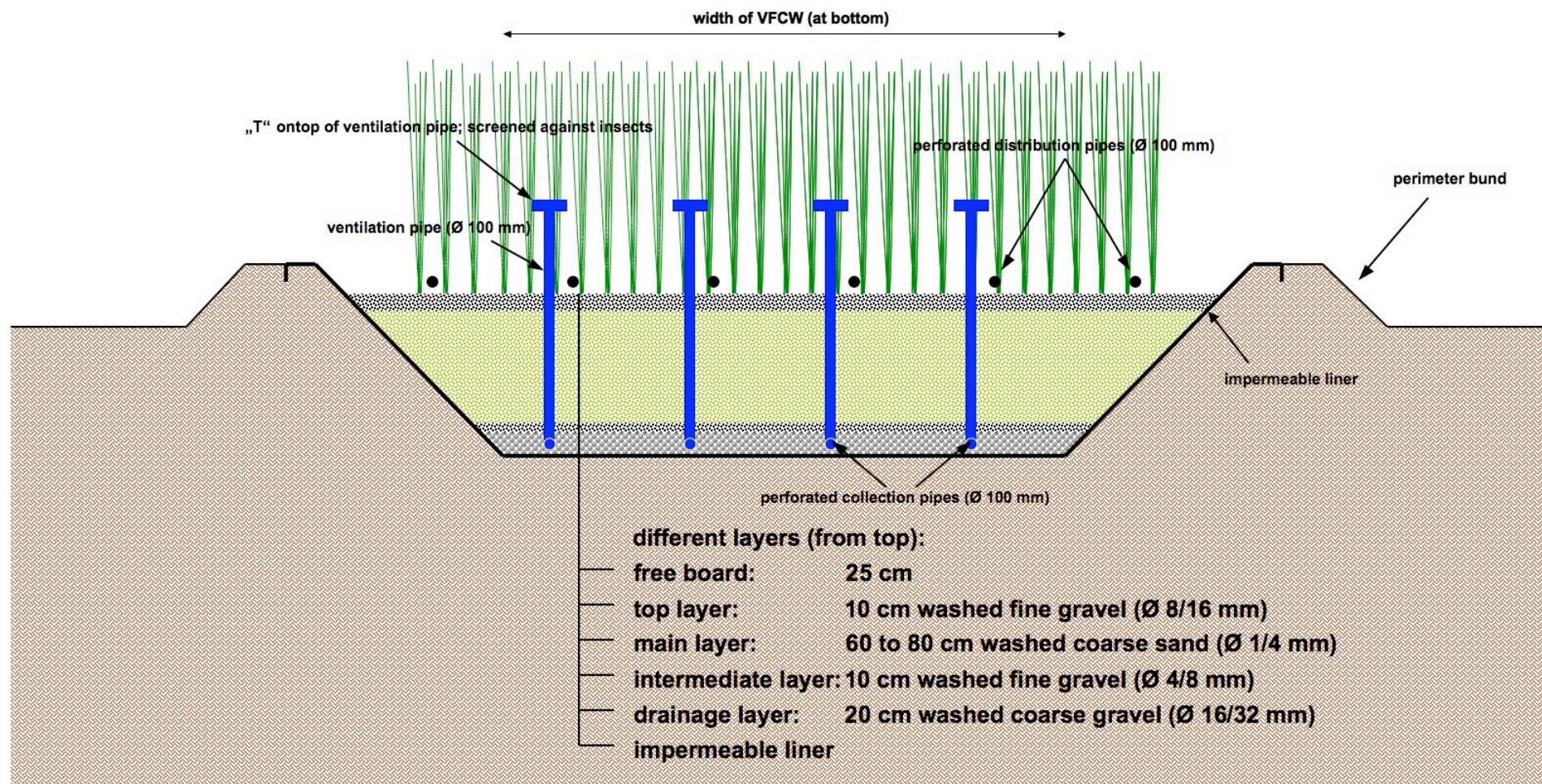


figure 6: Conceptual sketch VFCW (cross section)

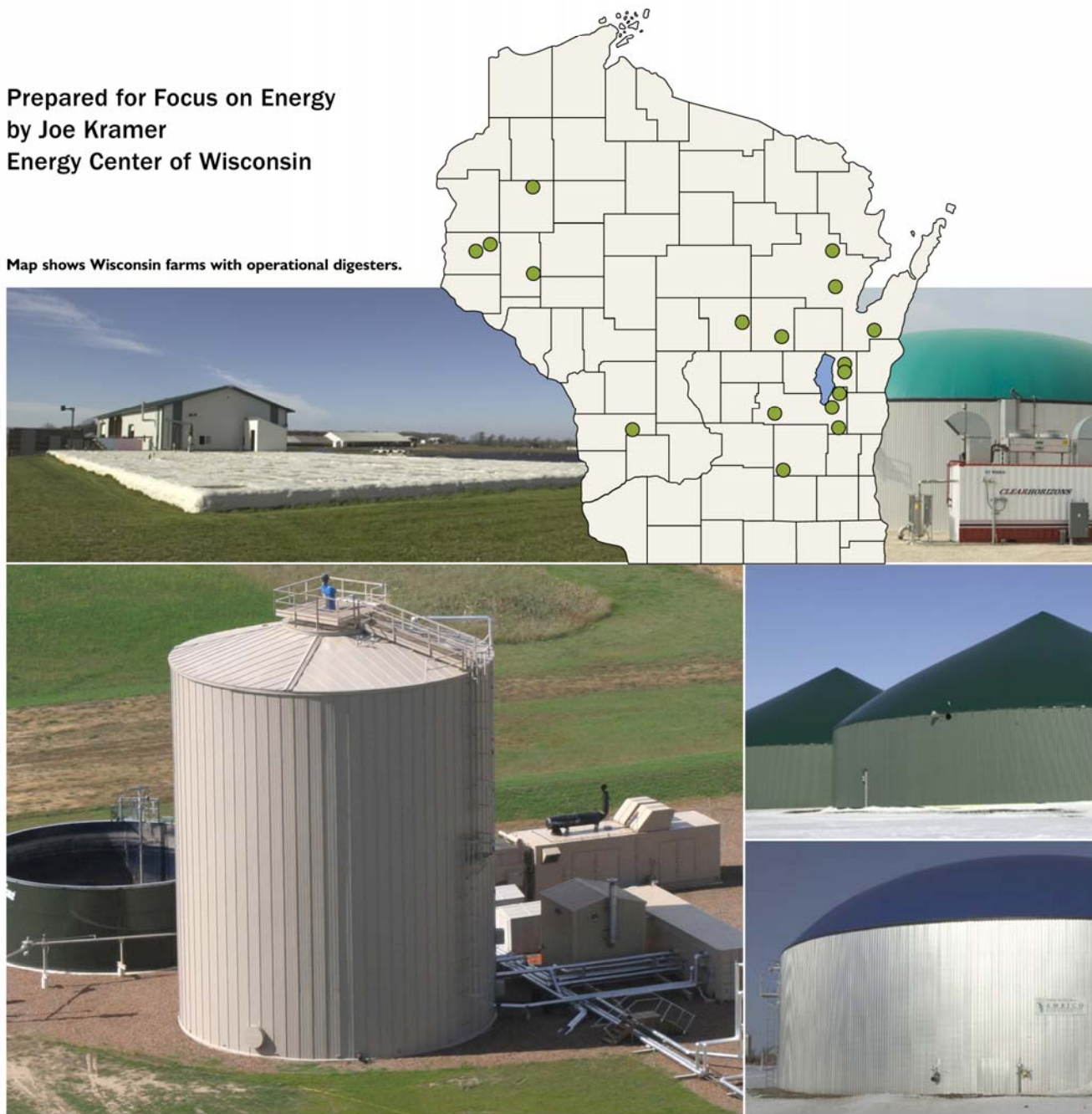


# Wisconsin Agricultural Biogas Casebook

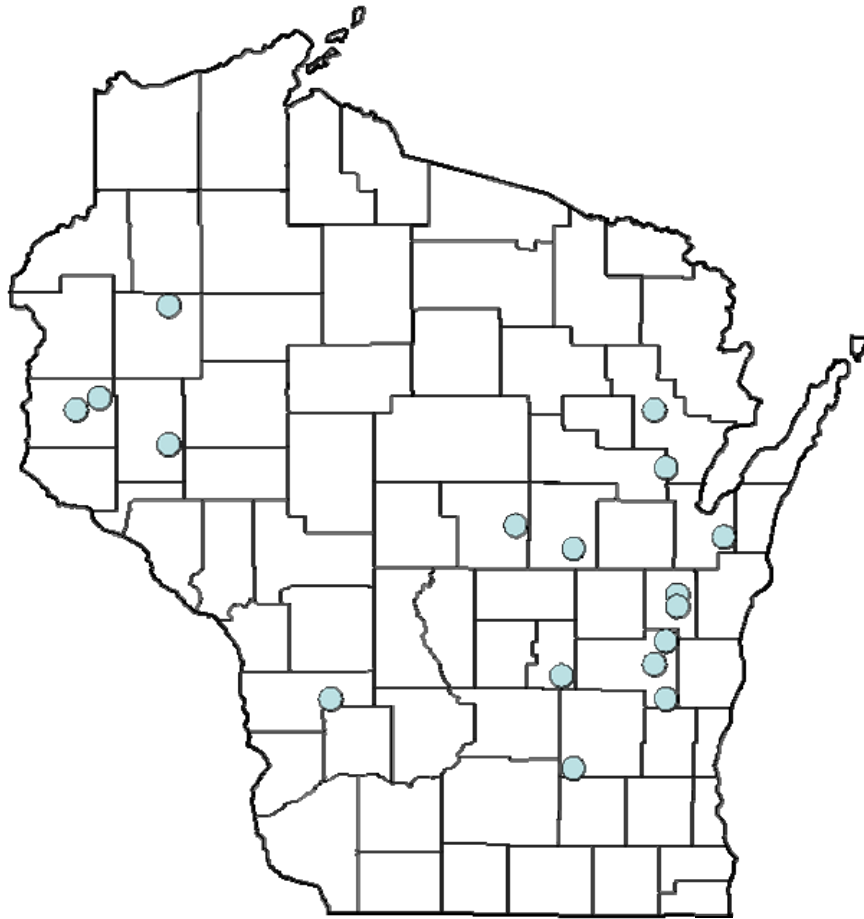
JULY 2008 EDITION

Prepared for Focus on Energy  
by Joe Kramer  
Energy Center of Wisconsin

Map shows Wisconsin farms with operational digesters.



## Wisconsin Agricultural Biogas Casebook



July 2008 Edition

Prepared for Wisconsin Focus on Energy – Renewables Program

By Joe Kramer

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## Common Abbreviations and Terms

Abbreviation	Meaning
AD	anaerobic digestion
ASBR	anaerobic sequencing batch reactor
CHP	combined heat and power
HRT	hydraulic retention time
RAS	return activated sludge
SRT	solids retention time
TPAD	temperature-phased anaerobic digester
Units	
AU	animal units
Btu	British thermal units
cfm (ft <sup>3</sup> /day)	cubic feet per day
gpd	gallons per day
kW	kilowatt
kWh	kilowatt hours

Term	Definition
Acidogenic	acid producing
AgSTAR	a voluntary program jointly sponsored by the USEPA, US Department of Agriculture and the US Department of Energy, that encourages the use of biogas technologies at confined animal feeding operations that manage manures as liquids or slurries < <a href="http://www.epa.gov/agstar/index.htm">http://www.epa.gov/agstar/index.htm</a> >
Anaerobic Digestion (AD)	the biological, physical and or chemical breakdown of animal manure in the absence of oxygen
Anaerobic Sequencing Batch Reactor (ASBR)	a suspended growth reactor treating waste in four distinct phases over a 12-hour cycle, including digester feeding, digester mixing and gas production, biomass and solids settling, and liquid effluent discharge
Aquaponics	the symbiotic cultivation of plants and aquatic animals in a recirculating environment <sup>1</sup>
Biogas	the gas produced as a by-product of the anaerobic decomposition of livestock manure consisting of about 60-80 percent methane, 30-40 percent carbon dioxide, and trace amounts of other gases
Combined Heat and Power (CHP)	a system for producing electricity while capturing and using heat
Combined Phase	digestion phases are in the same vessel
Complete-Mix Digester	a controlled temperature, constant volume, mechanically

<sup>1</sup> This definition was taken from Wikipedia.com.

<b>Term</b>	<b>Definition</b>
	mixed vessel designed to maximize biological treatment, methane production and odor control as part of a manure management facility with methane recovery
Composting	a process of aerobic biological decomposition characterized by elevated temperatures
Construction Phase	the period during which the anaerobic digester is under construction
Covered Lagoon Digester	an anaerobic lagoon fixed with an impermeable, gas- and airtight cover designed to promote decomposition of manure and produce methane
Digestate	the liquid discharge of a manure treatment system
Digested Solids	the solids portion of digested materials
Digester	a vessel or system used for the biological, physical or chemical breakdown of animal manure
Hydraulic Retention Time (HRT)	average length of time any particle (liquid or solid) of manure remains in a manure treatment or storage structure. The HRT is an important design parameter for treatment lagoons, covered lagoon digesters, complete-mix digesters, and plug-flow digesters
Hydronics	a system for the circulation of heated liquid for various on-farm purposes
Induction Generator	a generator that will operate in parallel with the utility and cannot stand alone (induction generation derives its phase, frequency and voltage from the utility)
Influent	the materials entering the manure treatment system
Mesophilic	of, relating to, or being at a moderate temperature of about 100 degrees F
Methanogenic	methane producing
Microturbine	small-scale energy generation system that involves the direct combustion of gas and electricity generation in a single unit
Net Metering	an arrangement where distributed generation facilities can offset their associated load consumption and are compensated for any extra energy delivered to their electric provider as specified by their tariff
Operational Phase	biogas production is stabilized in the digester
Plug-Flow Digester	a constant volume, flow-through, controlled temperature biological treatment unit designed to maximize biological treatment, methane production, and odor control as part of a manure management facility with methane recovery
Psychrophilic	of, relating to, or being at a relatively low temperature of about 60 degrees F
Return Activated Sludge (RAS)	a process by which some of the digester bacteria are returned to the digester reducing the amount of energy



<b>Term</b>	<b>Definition</b>
	the biological system depends on growth of new bacteria as well as the reaction time required for digestion
Solids Retention Time (SRT)	average length of time any solid particle of manure remains in a manure treatment or storage structure. This is calculated by the quantity of solids maintained in the digester divided by the quantity of solids wasted each day (in digesters without RAS, HRT = SRT; in retained biomass reactors, the SRT exceeds the HRT).
Startup Phase	the digester is being fed manure, but biogas production is not yet stabilized
Struvite	a white crystalline substance consisting of magnesium, ammonium, and phosphorus in equal molar concentrations
Substrates	materials other than manure, bedding and wash water that is added to a digester for digestion
Synchronous Generator	a generator that can operate either isolated (stand-alone) or in parallel with the utility (i.e., it can run even if utility power is shut down). It requires a more expensive and sophisticated utility intertie to match generator output to utility phase, frequency and voltage.
Temperature-phased Anaerobic Digester (TPAD)	a controlled temperature, constant volume manure treatment system in which the manure treatment process is split into separate phases using different temperature ranges
Thermophilic	of, relating to, or being at a relatively high temperature of about 130 degrees F
Two Phase	acidogenic and methanogenic digestion phases occur in separate vessels

## Introduction and Methodology

Anaerobic digestion of livestock manure is a manure treatment option with benefits. Raw manure is processed using a heated, oxygen free container, allowing digestion that began in the cow's stomach to continue and be enhanced. Products of anaerobic digestion of livestock manure include a combustible gas (i.e. biogas), liquid effluent, and digested solids. The gas is often used for energy generation (electricity and or heat). The liquid effluent is a low-odor fertilizer with characteristics closer to commercial fertilizers that provide more flexibility to farmers in land application. This can often be substituted for the increasingly expensive commercial fertilizers. The phosphorus (P) rich digested solids are commonly used as bedding for cows, but also have value as soil supplements either on agricultural lands or for landscapers and greenhouses.

Wisconsin continues to be one of the leading states in operating farm-based anaerobic digester systems. The Wisconsin Agricultural Biogas Casebook includes brief case studies of farm-based anaerobic digesters installed in Wisconsin. This report gives a snapshot with some history of the 17 operating anaerobic digester systems in Wisconsin as of June 2008. This information is presented to give those interested in digesters some insight into how these systems are working in Wisconsin. In addition, digester owners have generously shared experiences, ideas and innovations that may prove invaluable to those evaluating similar options for their farms.

The sources chosen for information in compiling these case studies are:

1. digester owners – information on farm characteristics, operation, and experiences
2. technology providers – digester designs and characteristics, assumptions about the farm that went into designing the digesters, biogas utilization systems
3. utility representative – energy generation, power purchase agreements, interconnection issues

Sources were interviewed over the period of March 2008 through July 2008. Digester owners were given the opportunity to review draft versions of their case study write-ups to improve accuracy. Electricity generation information was requested from utilities (with the owners' prior written consent) for the previous 18 months for all systems that have utility power purchase agreements. This information was ultimately obtained for 12 of the 15 systems generating electricity from biogas.

This casebook represents an early step in a larger and ongoing effort to provide coordinated and consistent digester performance information to the general public using uniform methods. The Association of State Energy Research and Technology Transfer Institutions (ASERTTI), USDA Rural Development and EPA AgSTAR program have worked together to produce a standardized performance protocol.<sup>2</sup> Information gathered in this casebook is broader in scope and generally lacks independent third party verification (application of the protocol to these systems was well beyond the scope of this project). Focus on Energy (Focus) has instituted contracting measures in their grant

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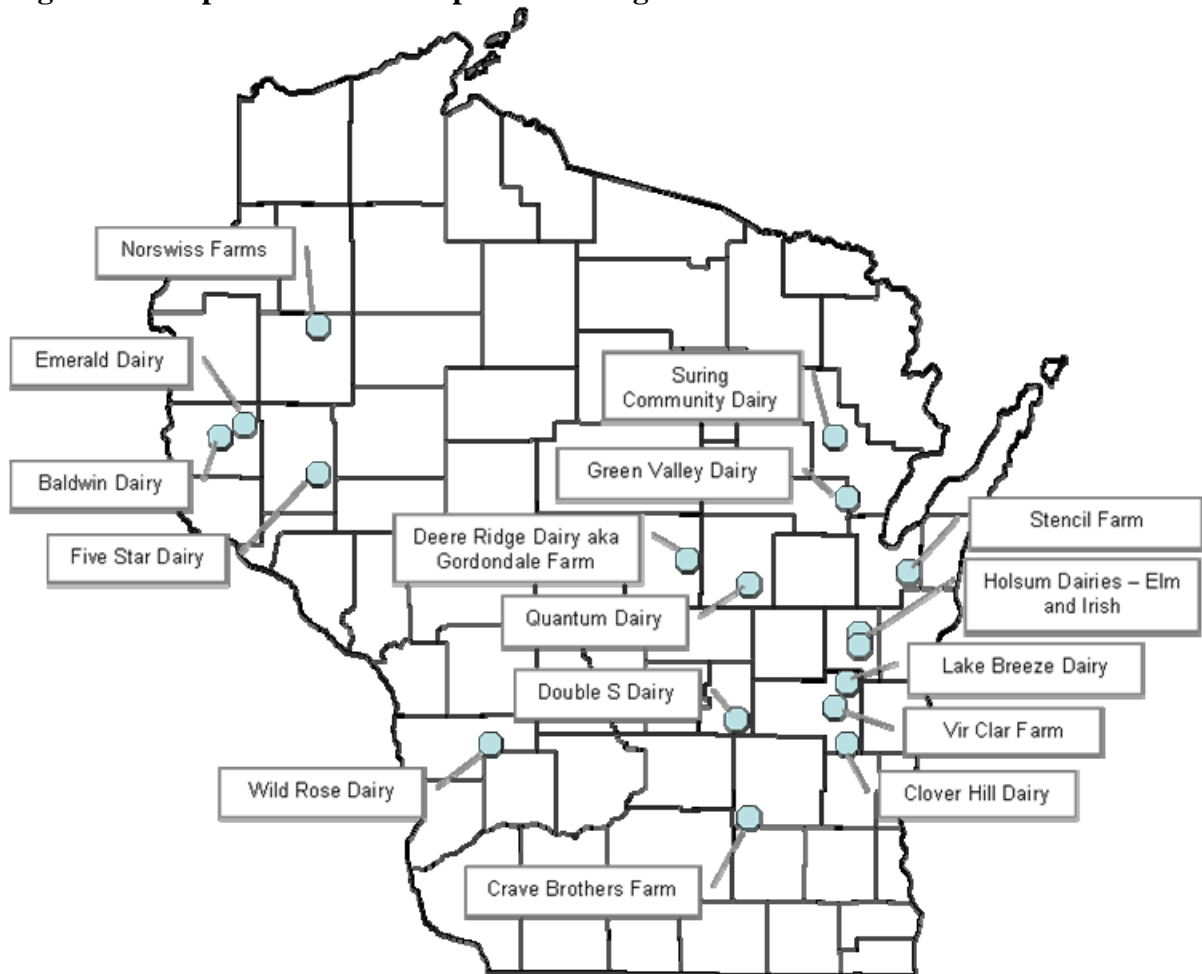
<sup>2</sup> A copy of the current protocol and additional information can be obtained from the ASERTTI Web site at: <http://www.asertti.org/programs/digester/index.html>.

language to enable monitoring and collection of more detailed information for current grant recipients which will make it easier to include more elements of the protocol for these systems in future editions of the casebook. Current plans are to include greater detail on system economics and biogas production, and to include consistent protocol adherent data whenever possible.

## Summary Information

As of July 2008, there were 17 farms with operating anaerobic digester systems in Wisconsin. This number includes five farms that have two digesters bringing the total digesters in the state to 22. All of the operational systems are on dairy farms.<sup>3</sup> The farms with digesters are spread throughout the state. Figure 1 below shows a map of the general locations for these farms.

**Figure 1 – Map of Farms with Operational Digesters**



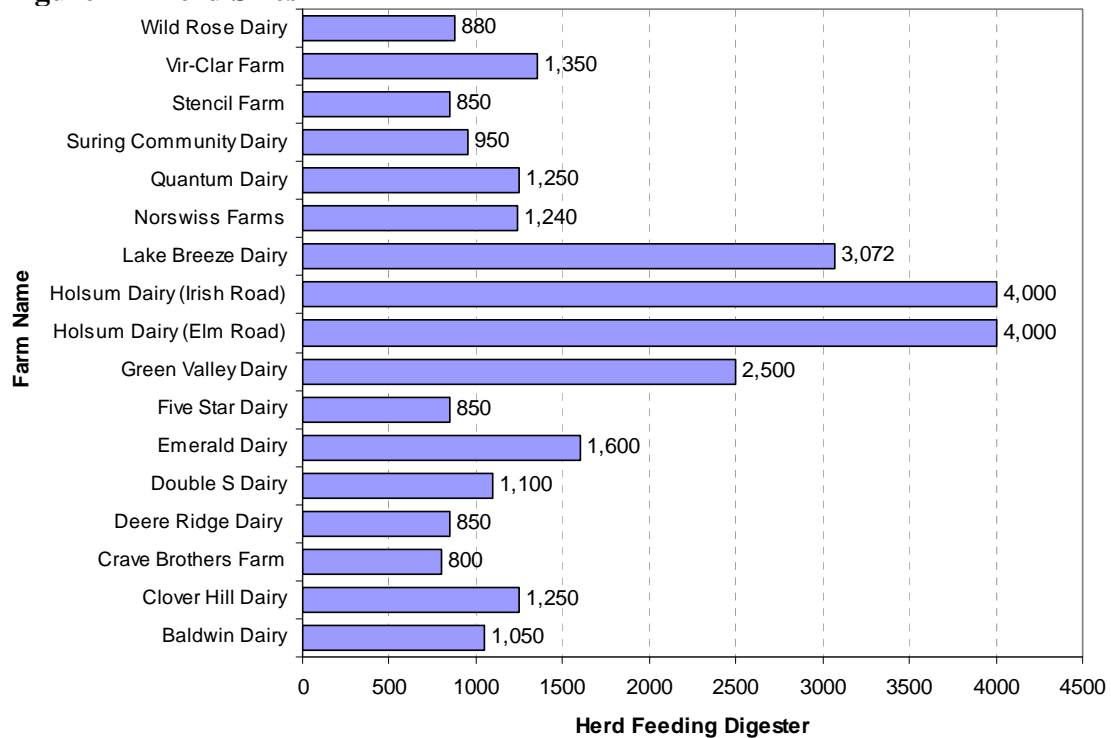
Additional information on the farms including number of animals feeding the digester, how manure is collected and type of bedding used is listed in Table 1 on the following page.

<sup>3</sup> Maple Leaf Farms, a duck farm in Franksville, Wisconsin, was the only non-dairy livestock operation with an anaerobic digester. They closed their Wisconsin operations in May of 2008.

**Table 1 – Farm Details**

Farm name	Locality	Herd Feeding Digester	Collection Type	Collection Frequency	Bedding Type
Baldwin Dairy	Baldwin	1,050	scrape	4x a day	digested solids
Clover Hill Dairy	Campbellsport	1,250	scrape	continuous	digested solids
Crave Brothers Farm	Waterloo	800	gravity flow to pit	continuous	digested solids
Deere Ridge Dairy (aka Gordondale Farms)	Nelsonville	850	scrape	3x a day	digested solids
Double S Dairy	Markesan	1,100	scrape	3x a day	digested solids
Emerald Dairy	Emerald	1,600	scrape	3x a day	digested solids
Five Star Dairy	Elk Mound	850	scrape	3x a day	digested solids
Green Valley Dairy	Green Valley	2,500	scrape	3x a day	digested solids
Holsum Dairy (Elm Road)	Hilbert	4,000	scrape	3x a day	digested solids
Holsum Dairy (Irish Road)	Hilbert	4,000	scrape	3x a day	digested solids
Lake Breeze Dairy	Malone	3,072	flush	hourly	sand
Norswiss Farms	Rice Lake	1,240	scrape	3x a day	digested solids
Quantum Dairy	Weyauwega	1,250	scrape	3x a day	digested solids
Stencil Farm	Denmark	700-1,000	scrape	hourly	digested solids
Suring Community Dairy	Suring	950	scrape	continuous	digested solids
Vir-Clar Farm	Fond du Lac	1,350	scrape	continuous	digested solids
Wild Rose Dairy	La Farge	880	scrape	3x a day	kiln-dried sawdust

Figure 2 illustrates the herd sizes on farms with operating digesters.

**Figure 2 – Herd Sizes**

Herd sizes for operational digester systems range from about 800 to 4,000 head. The AgSTAR Handbook gives a minimum number of dairy cows and steers of about 500 for successful use of an anaerobic digester.<sup>4</sup>

There are several system types being installed and a total of seven different digester design companies with active systems in Wisconsin. Table 2 below lists some details on individual systems and design companies, and Table 3 shows the number of systems for each company installed in Wisconsin.

**Table 2 – Digesters and Designers**

Dairy Name	Type of Digester(s)	System Designer	Temperature	Operational
Baldwin Dairy	modified mixed plug-flow	Bob Komro	mesophilic	2006
Clover Hill Dairy	mixed plug-flow	GHD, Inc.	mesophilic	2007
Crave Brothers Farm	complete mix	Clear Horizons, LLC	mesophilic	2007
Deere Ridge Dairy	mixed plug-flow	GHD, Inc.	mesophilic	2002
Double S Dairy	mixed plug-flow	GHD, Inc.	mesophilic	2004
Emerald Dairy	mixed plug-flow	GHD, Inc.	mesophilic	2006
Five Star Dairy	complete mix	Microgy, Inc.	thermophilic	2005
Green Valley Dairy	complete mix (x2)	Biogas Direct, LLC	mesophilic	2007
Holsum Dairy (Elm Road)	mixed plug-flow (x2)	GHD, Inc.	mesophilic	2007
Holsum Dairy (Irish Road)	mixed plug-flow (x2)	GHD, Inc.	mesophilic	2004
Lake Breeze Dairy	mixed plug-flow (x2)	GHD, Inc.	mesophilic	2006
Norswiss Farms	complete mix	Microgy, Inc.	thermophilic	
Quantum Dairy	mixed plug-flow	GHD, Inc.	mesophilic	2005
Stencil Farm	plug-flow	RCM Digesters, Inc.	mesophilic	2002
Suring Community Dairy	complete mix	American Biogas Co., Inc.	mesophilic	2006
Vir-Clar Farm	complete mix (x2)	Biogas Direct, LLC	mesophilic	2004
Wild Rose Dairy	complete mix	Microgy, Inc.	thermophilic	2005

**Table 3 – Total Systems for Designers**

Digester Type	Designer	Farms	Digesters
Mixed plug-flow, mesophilic	GHD, Inc.	8	11
Modified mixed plug-flow, mesophilic	Komro International	1	1
Plug-flow	RCM Digesters, Inc.	1	1
Complete mix, thermophilic	Microgy, Inc.	3	3
Complete mix, mesophilic	Biogas Direct, LLC	2	4
Complete mix, mesophilic	American Biogas Co., Inc.	1	1
Complete mix, mesophilic	Clear Horizons	1	1
Total		17	22

<sup>4</sup> The AgSTAR Handbook can be downloaded at: <http://www.epa.gov/agstar/resources/handbook.html>. Technological and practice innovations may make digester use an economic and technical possibility for farms with smaller herd sizes.

The most common choice for digester owners to use their biogas is to run it through an engine generator set to generate electricity for sale. Table 4 lists the biogas uses and information on the equipment.

**Table 4 – Biogas Uses**

<b>Farm name</b>	<b>Biogas utilization</b>	<b>Type of prime mover</b>	<b>Generator Manufacturer and Capacity</b>
Baldwin Dairy	flared	none	none
Clover Hill Dairy	electricity and heat	engine generator set, synchronous	Guascor MGG-355, upgraded to 300 kW
Crave Brothers Farm	electricity and heat	engine generator set, synchronous	Deutz, (spark ignited), 230 kW
Deere Ridge Dairy	electricity and heat	engine generator set, induction	Caterpillar 140 kW net, NG natural gas rated
Double S Dairy	electricity and heat	engine generator set, induction	Caterpillar 200 kW
Emerald Dairy	upgrade gas to pipeline quality and sale	biogas conditioning for sale into pipeline	none
Five Star Dairy	electricity and heat	engine generator set, synchronous, but not operated to stand alone*	Waukesha 775 kW, 750 kW net
Green Valley Dairy	electricity and heat	engine generator set, synchronous	Caterpillar 600 kW, ordered a second engine
Holsum Dairy (Elm Road)	electricity and heat	two engine generator sets, synchronous	Guascor 2 sets at 600 kW each, 1200 kW total net
Holsum Dairy (Irish Road)	electricity and heat	2 engine generator sets, induction	Deutz 500 kW and Caterpillar 200 kW
Lake Breeze Dairy	electricity and heat	2 engine generator sets, synchronous	Caterpillar 300 kW x2 (600 kW)
Norswiss Farms	electricity and heat	engine generator set, synchronous, but not operated to stand alone*	Jenbacher JGS316 GS-B.L. (made in Austria) 848 kW production engine
Quantum Dairy	electricity and heat	engine generator set, induction	Caterpillar 300 kW turbo charged
Stencil Farm	electricity and heat	engine generator set, synchronous	Caterpillar 3306 140 kW, 123 kW net
Suring Community Dairy	electricity and heat	engine generator set, synchronous	Dreyer & Bosse 250 kW, 230 kW net, engine is dual fuel using 20% diesel
Vir-Clar Farm	electricity and heat	engine generator set, synchronous	Caterpillar/SEVA, 350 kW
Wild Rose Dairy	electricity and heat	engine generator set, synchronous, but not operated to stand alone*	Waukesha 775 kW, 750 kW net

\* The engine generator sets owned by Dairyland Power at Five Star, Norswiss, and Wild Rose dairies are synchronous systems which can be set up with a transfer switch so that they can continue to supply power to the farm during a system outage. These sets, however, are used primarily to provide voltage support in local distribution networks and are therefore configured to shut down in the event of a system outage.

Farm-scale biogas systems in Wisconsin have a total installed generation capacity of about 7.3 megawatts. In addition to the farms generating electricity, one farm is currently flaring the biogas and another is selling it to a third party. Owners of these two

operations are part of a group that has plans to install a gas pipeline linkage to allow them to upgrade their biogas and inject it into the natural gas distribution system as renewable natural gas. Additional information on these efforts is included in the case studies of Baldwin and Emerald dairies.

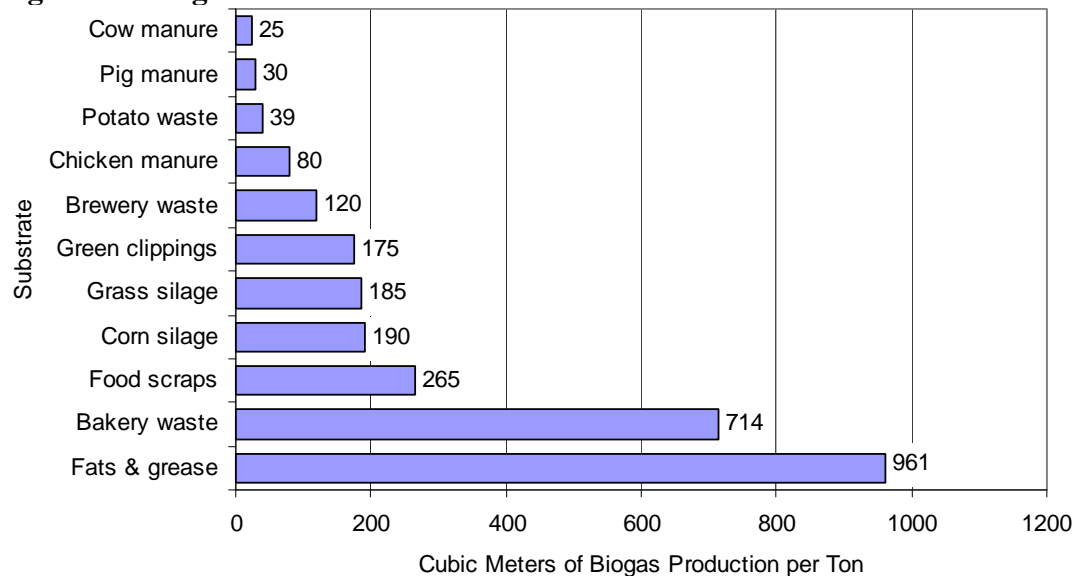
Eight digester owners are adding other substrates to their digesters in addition to the usual manure, bedding and wastewater. Some systems, such as those installed by Microgy, have inclusion of off-farm food wastes, and the resulting increase in biogas production is an integral part of their business models. Table 5 below lists farms that have reported addition of other feedstocks.

**Table 5 – Other Wastes Being Digested**

Farm name	Other Waste Added
Crave Brothers Farm	whey and other wastes added (some seasonal)
Five Star Dairy	industrial food-waste grease
Holsum Dairy (Elm Road)	waste substrates from 3 food processing industries
Holsum Dairy (Irish Road)	waste substrates from 3 food processing industries
Lake Breeze Dairy	corn syrup added as needed to supplement manure fuel value.
Norswiss Farms	industrial food-waste grease
Vir-Clar Farm	bunker waste, moldy feed, whatever not eaten by the cows (on-farm wastes)
Wild Rose Dairy	industrial food-waste grease

Figure 3 gives an estimate of the biogas production potential from various substrates. Manure is one of the lowest potential biogas producers.

**Figure 3 – Biogas Generation Potential of Substrates**



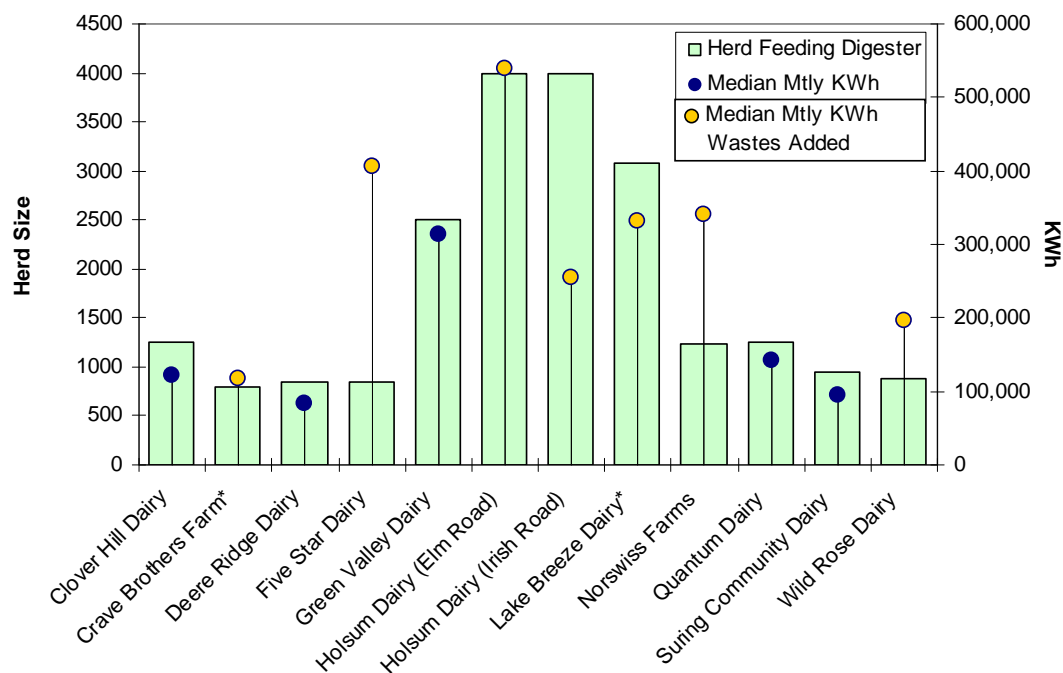
Source: Data derived from [www.biogas-energy.com](http://www.biogas-energy.com), © 2007 Biogas Energy, Inc., translated from: Basisdaten Biogas Deutschland, März 2005,; Fachagentur Nachwachsende Rohstoffe e.V.



Biogas generation information was not available for many of the systems in this report due to the lack of gas metering on older systems. Newer systems include biogas metering and this statistic is expected to be included in future editions of this casebook.

Each system that is generating electricity has a purchase agreement with their servicing utility and, therefore, with the owner's permission, a consistent measure of electricity generated was obtained from the utility. Figure 4 shows the average herd sizes and the median kWh of electricity generated from biogas over the 18 month period of January 2007 through June 2008. The median measure was chosen to give an indication of what "typical" monthly generation looks like. Medians were calculated based only on months in which the digester and energy generation equipment were operational (some systems only came on line recently and others had significant engine downtimes). Monthly generation profiles for individual systems are included in the case studies.

**Figure 4 – Herd Sizes and Median Monthly Electricity Generation**



\* Crave Brothers Farm has only one year of generation data. Lake Breeze Dairy has only 16 months of generation data.

Note : The yellow dots are for digesters that regularly or periodically add wastes other than manure and wastewater to their digesters.

In general, those farms that add additional substrates to be co-digested with the manure see proportionally higher energy generation; these are represented on the graph by the yellow dots. There are two exceptions for this data. Holsum Dairy Irish Road has undersized energy generation equipment (relative to their herd size) and is therefore not able to use all the biogas they produce for electricity production. Lake Breeze Dairy is adding off farm wastes to compensate for inconsistent manure addition due to construction projects on the farm. More details on these operations are included in the case studies.

Table 6 shows some details about the business models for the digester installations and utility contracts.

**Table 6 – Business Models and Utility Contract Types**

<b>Farm name</b>	<b>Business Model</b>	<b>Utility</b>	<b>Utility Contract Type</b>
Baldwin Dairy	farm owns digester, plans to sell biogas	St Croix Electric Cooperative	na
Clover Hill Dairy	farm owns all, sells electricity to utility	We Energies	sell all
Crave Brothers Farm	Clear Horizons owns digester and energy generation, farmer buys solids back from CH, We Energies buys electricity.	We Energies	buy excess
Deere Ridge Dairy	farm owns digester and sells biogas to utility, utility owns and operates generator on site	Alliant Energy	sell biogas
Double S Dairy	farm owns all, sells electricity to utility	Alliant Energy	sell all
Emerald Dairy	farm owns digester, sells biogas to third party	St Croix Electric Cooperative	none, contract sales of biogas to a third party
Five Star Dairy	Microgy built, operates and maintains digester, Dairyland buys biogas and owns/operates genset and scrubber, sells elec to member coops, gas sales and carbon credits buy down debt for farmer on digester	Dairyland Power Cooperative	biogas sales to Dairyland Power, output goes into Dairyland system and is made available to member coops
Green Valley Dairy	farm owns all, sells electricity to utility	We Energies	sell all
Holsum Dairy (Elm Road)	farm owns all, sells electricity to utility	Wisconsin Public Service	sell all
Holsum Dairy (Irish Road)	farm owns all, sells electricity to utility	Wisconsin Public Service	sell all
Lake Breeze Dairy	farm owns all, sells electricity to utility	We Energies	sell all
Norswiss Farms	Microgy built, operates and maintains digester, Dairyland buys biogas and owns/operates genset and scrubber, sells elec to member coops, gas sales and carbon credits buy down debt for farmer on digester	Dairyland Power Cooperative, Barron Electric Cooperative	biogas sales to Dairyland Power, output goes into Dairyland system and is made available to member coops
Quantum Dairy	farm owns all, sells electricity to utility	We Energies	sell all
Stencil Farm	farm owns all, sells electricity to utility	Wisconsin Public Service Corporation	sell all
Suring Community Dairy	farm owns all, sells electricity to utility	Wisconsin Public Service	sell all
Vir-Clar Farm	farm owns all, sells electricity to utility	Alliant Energy	sell all
Wild Rose Dairy	Microgy built, operates and maintains digester, Dairyland buys biogas and owns/operates genset and scrubber, sells elec to member coops, gas sales and carbon credits buy down debt for farmer on digester	Dairyland Power Cooperative	biogas sales to Dairyland Power, output goes into Dairyland system and is made available to member coops

## Case Studies

This section includes brief case studies of operational systems in Wisconsin. As of this writing, all farm-based anaerobic digester systems in Wisconsin were on dairy operations.

### ***Baldwin Dairy – Baldwin, Wisconsin***

<b>Farm Name:</b>	Baldwin Dairy	<b>Location:</b>	Baldwin
<b>Farm Type:</b>	dairy	<b>Herd Size:</b>	1,050 head (milking)
<b>Collection Method:</b>	scrape	<b>Bedding Type:</b>	digested solids
<b>Digester Type:</b>	modified mixed plug flow	<b>Design Temperature:</b>	100 deg F
<b>Digester Notes:</b>	not available		
<b>Design Capacity:</b>	1,200 head	<b>Date Operational:</b>	2006
<b>Design HRT:</b>	not available	<b>Current HRT:</b>	22 days
<b>Design Solids %:</b>	not available	<b>Current Solids %:</b>	8%
<b>Biogas Use:</b>	heat and flared, plans to upgrade and sell	<b>Utility Contract:</b>	none
<b>Installed Capacity:</b>	not applicable	<b>Prime Mover Brand:</b>	not applicable
<b>Solids Separation:</b>	yes, screw press	<b>Solids Use:</b>	bedding, sell about 20%
<b>Ownership:</b>	farm owns digester		
<b>Digester Designer:</b>	Komro International, LLC	<b>Utility:</b>	St. Croix Electric Coop.

Baldwin Dairy is located in Baldwin, Wisconsin, in central St. Croix County. It has a current milking herd size of about 1,050 Holsteins. This herd and milking operation produce about 30,000 gallons of manure and water per day at about eight percent solids, which is scrape collected four times per day and preheated prior entering the digester. They use a Fan screw press solids separator post digestion. Figure 5 below shows some of the barns at Baldwin Dairy. The former manure storage system for the farm was a covered anaerobic lagoon.

**Figure 5 – Baldwin Dairy**



Photo courtesy of Agri-Waste Energy, Inc.

Digester. A description of the digester from the designer was not available. The owner provided the following information. Manure is added to the digester four times per day. The digester is a modified mixed plug flow digester that operates in the mesophilic temperature range with liquid jet mixing. Liquid is sucked out on the bottom and re-injected on the sides. They are also returning activated sludge from the last stage to improve digestion efficiency by keeping more active bacteria in the system. The system is designed to use heat from the effluent to help pre-heat the manure going in. This is the first system of this type designed by Komro International. Influent (manure and wash-water) is pumped into the digester four times per day. The hydraulic residence time (HRT) is currently about 21 days, and the operating digester temperature is between 95 and 100 degrees F.

#### Outputs and Uses.

The owner reports that the system is putting out nearly 130,000 cubic feet per day (CFD) of biogas. They built their own biogas boiler to help heat the digester, and the rest is currently flared. The system produces 20-30 tons of digested solids per week at about 67 percent moisture. They are selling 20 percent of this to neighboring farms for use as bedding. The rest they use on farm for bedding. They are evaluating options for building a biogas pipeline from Baldwin and another local dairy to transport biogas to an upgrading facility near the natural gas pipeline injection point. The facility will use water column technology. This project is expected to move forward if financing is approved. During the summer of 2008 they began building a greenhouse complex to use biogas from the digester. They expect to use biogas for heat, and to eventually add absorption chilling and possibly electricity generation. Some possible uses for the greenhouses include aquaponics so they could grow algae for biodiesel production and tilapia (i.e., an edible fresh water fish capable of thriving in warm nutrient rich water).

#### History and Comments.

The owners were early adopters of anaerobic digestion technology when they installed covered lagoons at this and the Emerald Dairy in 1998 and 1999 respectively. When they did not get the digestion quality or biogas production they wanted, due to the cooling of the lagoons in cold months, the owners opted to replace them with heated systems. The owner had no additional comments on this system.

#### Information Sources.

John Vrieze – Baldwin Dairy

## Clover Hill Dairy – Campbellsport, Wisconsin

<b>Farm Name:</b>	Clover Hill Dairy	<b>Location:</b>	Campbellsport
<b>Farm Type:</b>	dairy	<b>Herd Feeding Digester:</b>	1,250 head (1,100 milking)
<b>Collection Method:</b>	scrape	<b>Bedding Type:</b>	digested solids
<b>Digester Type:</b>	mixed plug-flow	<b>Design Temperature:</b>	100 deg F
<b>Digester Notes:</b>	two-stage, below grade concrete tank, u-shaped, gas-induced mixing, RAS		
<b>Design Capacity:</b>	1,050 head	<b>Date Operational:</b>	2007
<b>Design HRT:</b>	20 days	<b>Current HRT:</b>	not available
<b>Design Solids %:</b>	8-9%	<b>Current Solids %:</b>	6%
<b>Biogas Use:</b>	electricity and heat	<b>Utility Contract:</b>	yes
<b>Installed Capacity:</b>	300 kW	<b>Prime Mover Brand:</b>	Guascor
<b>Solids Separation:</b>	yes, screw press	<b>Solids Use:</b>	bedding, sold, land applied
<b>Ownership:</b>	farm owns digester and energy generation		
<b>Digester Designer:</b>	GHD, Inc.	<b>Utility:</b>	We Energies, Inc.

Clover Hill Dairy is located in Campbellsport, Wisconsin, in southeastern Fond du Lac County. They have a herd size of 1,250 Holsteins, and use digested solids for bedding. Manure is scrape-collected continuously throughout the day. The volume of manure and liquids produced daily for treatment is not available, but has an average solids content of about six percent. The farm's former manure storage system was a lagoon and slurrystore.

### Digester.

The owner decided to install a mixed plug-flow digester designed by GHD, Inc. of Chilton, Wisconsin. The system is a U-shaped, below grade, concrete structure with a fixed concrete cover. Figure 6 below is a schematic of their standard design.

**Figure 6 – GHD Digester Design Schematic**

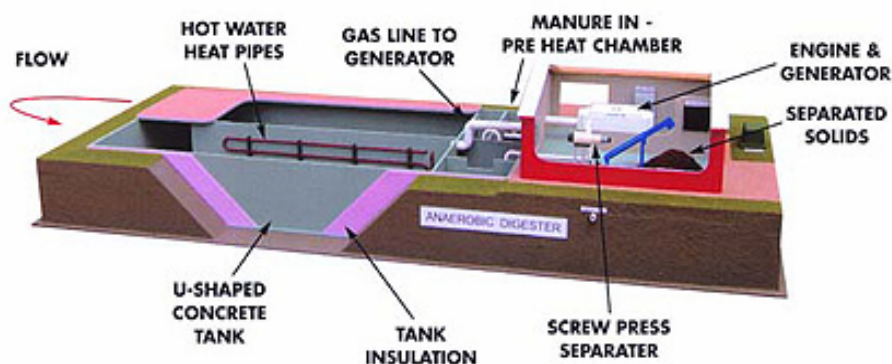


Image courtesy GHD Inc.

Manure and wastewater enter and exit on the same end of the digester (i.e., on the right end of the diagram), making a 180 degree turn at the enclosed end (i.e., left end). The design theoretically will allow expansion of the digester by extending the structure on the

enclosed end. The central shared wall holds hot water piping that heats the manure and helps conserve heat in the system by reducing outside surface area of the structure. The structure includes two distinct phases or digestion zones and is described as a two-phase system in which manure from the first phase flows directly into the second. The digester operates in the mesophilic range (design temperature of about 100 degrees F) and returns activated sludge. The design HRT is 20 days. The biogas is reintroduced into the digester along the bottom and the gas percolation through the manure provides passive mixing of the contents.

#### Outputs and Uses.

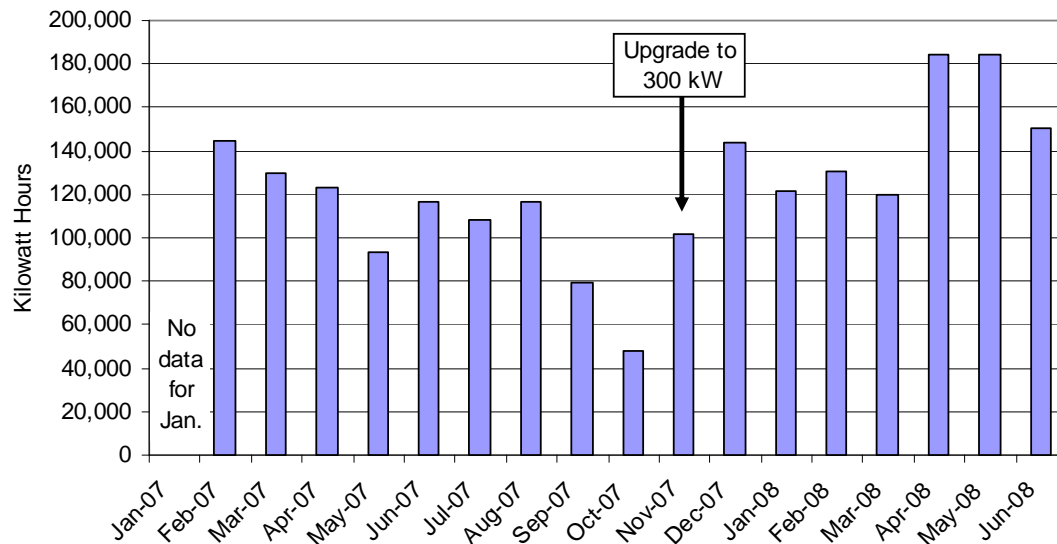
Biogas is treated with a passive hydrogen sulfide removal system and a chilling unit for condensate removal. It is then run through a 300 kW Guascor engine generator set (pictured in Figure 7 below) to produce electricity.

**Figure 7 – Guascor 300 kW Engine Generator Set**



Figure 8 on the following page shows the recent generation history for this system.

**Figure 8 – Clover Hill Electricity Generation History**



Waste heat from the water jacket and exhaust is captured and used for heating the digester, milk house, parlor and lanes. They are looking for other uses for heat as well. They do not have a boiler backup system to heat the digester when the engine is not operating.

They use a Bauer and Ireland brand screw press and produce about 100 tons of digested solids per week. The farm uses about 70 tons for both bedding and field application, and sells about 30-35 tons per week for \$20 per ton to a dairy farm for bedding. Their solids storage area is shown in Figure 9.

**Figure 9 – Digested Solids from Clover Hill Digester**



The farm retains ownership of the carbon credits and has signed on with the Pure Farm Energy® Producer Network of farm energy project owners.<sup>5</sup>

#### History.

The digester was installed in 2006 and was operational in early 2007. The owner reported that construction and contracting went “smoothly.” But the power purchase agreement with the utility was problematic and time-consuming. It took a while to get

<sup>5</sup> The Pure Farm Energy® Producer Network is an aggregator and certifier of carbon credits for farm energy project owners. <http://www.agrefresh.org/401.html>

the purchase and interconnect details worked out. They originally had a smaller engine generator set but after two to three months realized they were producing enough biogas to use a 300 kW system. They are also getting more usable heat from the energy generation than they expected and are still exploring ways to use it effectively. They are pleased with the large reduction in odor from the lagoon and land application of digested manure. The owner noted that they can also apply the effluent on to growing crops without burning or other adverse effects, which is not possible with raw manure.

Information Sources.

Joseph Bonlender – Clover Hill Dairy

Chris Bonlender – Clover Hill Dairy

Melissa VanOrnum – GHD, Inc.

Randy Jerome – We Energies, Inc.



## ***Crave Brothers Farm – Waterloo, Wisconsin***

<b>Farm Name:</b>	Crave Brothers Farm	<b>Location:</b>	Waterloo
<b>Farm Type:</b>	dairy	<b>Herd Size:</b>	800 head (milking)
<b>Collection Method:</b>	gravity flow to pit	<b>Bedding Type:</b>	digested solids
<b>Digester Type:</b>	complete mix	<b>Design Temperature:</b>	99 deg F
<b>Digester Notes:</b>	above ground steel tank, proprietary mixing tech, remotely managed via Web		
<b>Design Capacity:</b>	900 head (phase 1)	<b>Date Operational:</b>	2007
<b>Design HRT:</b>	25 days	<b>Current HRT:</b>	not available
<b>Design Solids %:</b>	12%	<b>Current Solids %:</b>	11-14%
<b>Biogas Use:</b>	electricity and heat	<b>Utility Contract:</b>	yes, buy excess
<b>Installed Capacity:</b>	230 kW	<b>Prime Mover Brand:</b>	Deutz
<b>Solids Separation:</b>	yes, screw press	<b>Solids Use:</b>	bedding, composted and sold as soil supplement
<b>Ownership:</b>	designer owns digester and energy generation		
<b>Digester Designer:</b>	Clear Horizons, LLC	<b>Utility:</b>	We Energies, Inc.

Crave brothers operate a dairy farm and specialty cheese production facility in Waterloo, Wisconsin, in southwestern Dodge County. They have 800 head of milking cows producing about 26,000 gallons of manure per day and use digested solids for bedding. Manure gravity-flows and drops through a slotted floor to a collection pit. They also add about 2,500 gallons of whey and other waste products from their cheese operations per day with some seasonal variation. Their former manure storage system was a pit.

### Digester.

The Crave Brothers Farm partnered with Clear Horizons, LLC to have a digester installed. This is the first system of its kind built by Clear Horizons for a livestock operation. It can be monitored and operated remotely by PC using a Web interface. The digester is an above ground mesophilic complete mix stainless steel tank system. As a complete mix digester it does not require return of activated sludge because, by design it retains bacteria. The target operating temperature is 99 degrees F, and it has an HRT of 25 days. Operating their own system, Clear Horizons has been able to reasonably maintain these target parameters. Figure 10 below shows a schematic of the Clear Horizons system.

**Figure 10 – Schematic of Clear Horizons System**

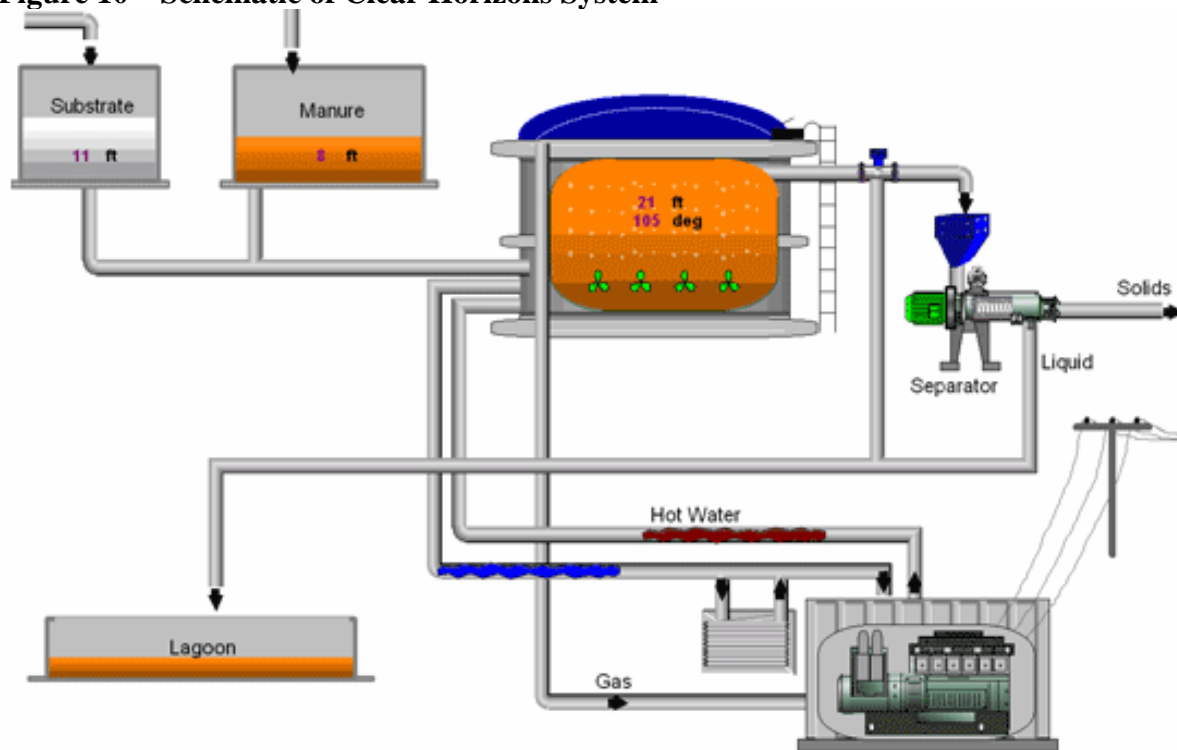


Image courtesy of Clear Horizons LLC.

The business model for this digester is Clear Horizons develops, owns, operates and maintains the digester, and generation equipment. It has rights to the products and credits associated with the digestion and energy generation. The farm buys solids back from Clear Horizons for bedding and retains the nutrient-rich liquid for field application. Figure 11 shows the digester.

**Figure 11 – Clear Horizons Digester at Crave Brothers Farm**



The Clear Horizons digester uses a patented mixing technology. The external mixer mounting apparatus is pictured in Figure 12.

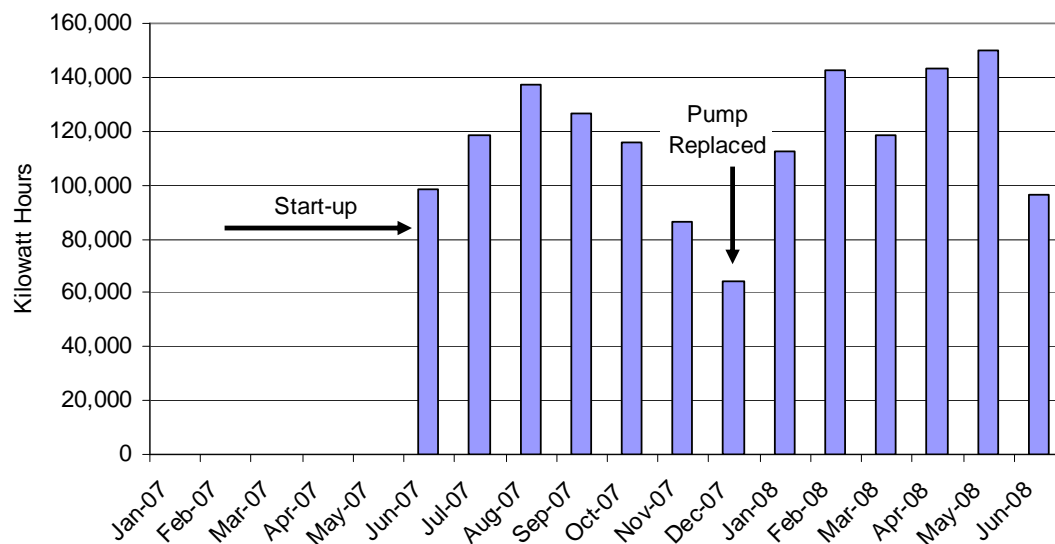
**Figure 12 – Clear Horizons Mixer**



#### Outputs and Uses.

The digester produces biogas which is treated with passive hydrogen sulfide removal and a chilling unit for condensate removal. It is then fed into a 230 kW Deutz synchronous spark-ignited engine generator set. Electricity is used to power the digester system with excess sold to We Energies. Heat captured from the engine generator set is used for digester heating, substrate tank heating, and heating of pumping and separation rooms at the site. Clear Horizons has a portable LP gas boiler that is designed mainly for startup of systems, but is also available for digester heating when engines are undergoing maintenance or repair. Figure 13 below shows the monthly gross energy generation for the Crave Brothers system.

**Figure 13 – Electricity Generation for Crave Brothers System**



Solids are separated using a Vincent KP-10 screw press solids separator. Clear Horizons produces a trademarked Energro potting mix using digested fiber, perlite and vermiculite, which it markets in bags. The sales of bedding to the farm and Energro amount to about two thirds of the income generated from the digester. Figure 14 on the following page shows the bagged commercial potting mix product.

### History and Comments.

This is the first system Clear Horizons has produced after researching other plants in Wisconsin and Germany. Their goal was to have a system that can be remotely operated (via an Internet-linked workstation) and to maximize the long term rate of return. Dan Nemke of Clear Horizons suggested that as a first of its kind system, they probably had a little longer learning curve than future systems will. They are doing extensive real-time monitoring of the systems to optimize operation.

Karl Crave (also representing Crave Brothers Farm) notes that Clear Horizons has done full-scale testing of multiple substrates to verify biogas production. They have also further developed composting methods and products to improve the quality of the digested fiber

Mr. Crave had a “great group” of local contractors and construction and start-up went smoothly. In five months, the project went from groundbreaking to consistently producing electricity. The farm is now able to focus more effort on their prime businesses: livestock and cheese operations. The option to pass on manure management duties to Clear Horizons was very welcome. As owners of the digester and the energy generation, Clear Horizons also handled utility power purchase and interconnect negotiations, as well as politics and permitting associated with the project.

### Sources.

Dan Nemke – Clear Horizons, LLC

Karl Crave – Clear Horizons, LLC

**Figure 14 – Digested Solids Potting Mix**



## ***Deere Ridge Dairy / Gordondale Farms – Nelsonville, Wisconsin***

<b>Farm Name:</b>	Deere Ridge Dairy / Gordondale Farms	<b>Location:</b>	Nelsonville
<b>Farm Type:</b>	dairy	<b>Herd Size:</b>	850 head (milking)
<b>Collection Method:</b>	scrape	<b>Bedding Type:</b>	digested solids
<b>Digester Type:</b>	mixed plug-flow	<b>Design Temperature:</b>	100 deg F
<b>Digester Notes:</b>	two-stage, below grade concrete tank, u-shaped, gas-induced mixing, RAS		
<b>Design Capacity:</b>	750 head	<b>Date Operational:</b>	2002
<b>Design HRT:</b>	20 days	<b>Current HRT:</b>	22 days
<b>Design Solids %:</b>	8-9%	<b>Current Solids %:</b>	not available
<b>Biogas Use:</b>	electricity and heat	<b>Utility Contract:</b>	yes
<b>Installed Capacity:</b>	140 kW	<b>Prime Mover Brand:</b>	Caterpillar
<b>Solids Separation:</b>	yes, screw press	<b>Solids Use:</b>	bedding and land applied
<b>Ownership:</b>	farm owns digester, utility owns energy generation		
<b>Digester Designer:</b>	GHD, Inc.	<b>Utility:</b>	Alliant Energy, Inc.

Deere Ridge Dairy or Gordondale Farms is an 850 Holstein dairy operation in Nelsonville, Wisconsin in eastern Portage County. Some 30,000 gallons of manure, bedding and milking parlor wastes are generated per day and scrape-collected at two hour intervals. They use digested solids for bedding and their former manure storage system was a pit.

### Digester.

Deere Ridge Dairy installed the first farm-scale digester designed by GHD, Inc. in 2001. It is a below-grade, U-shaped mixed plug-flow digester, with a fixed concrete cover. It uses biogas-induced mixing and return of activated sludge. The digester has two distinct digestion phases within the main chamber. Figure 15 below shows the digester and the adjacent equipment building.

**Figure 15 – Deere Ridge Dairy Digester**



Photo courtesy of GHD, Inc.

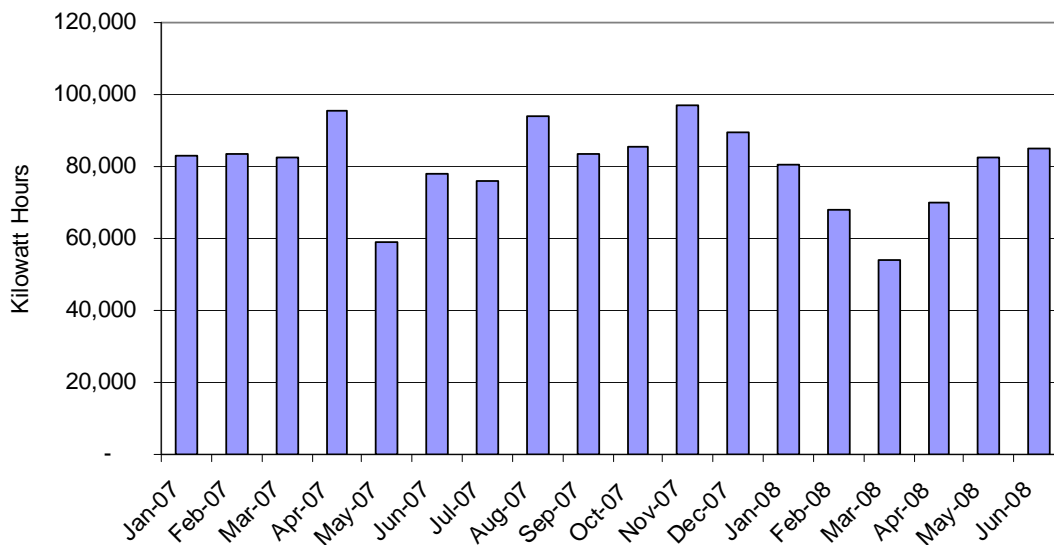
The digester has a design operating temperature of 100 degrees F, and a target influent solids content of eight to nine percent. The design hydraulic residence time is 22 days. They do solids separation after digestion with a Fan brand screw press.

#### Outputs and Uses.

Biogas from their digester is treated with a water trap. It is sold to Alliant Energy and run through their on-site Caterpillar 140 kW (net) engine generator set. Alliant Energy is responsible for the operation and maintenance of the energy generation equipment.

Figure 16 shows the monthly kW hours of electricity generated from January 2007 through June 2008.

**Figure 16 – Deere Ridge Dairy Electricity Generation**



Captured heat from the engine (via water jacket and exhaust) is used to heat the digester and milking parlor, and for facility water heating. They do not have a backup boiler for digester heat on site in the event the engine should be down for repairs or maintenance. However, they have the option of having GHD bring in a boiler if needed.

All digested solids are used for bedding on the farm. The owners were unsure of the quantity produced. Figure 17 on the following page shows the cows with digested solids bedding.



**Figure 17 – Cows and Digested Solids Bedding**



Photo courtesy of GHD, Inc.

History and Comments.

This installation originally came about because the farm owners were building a new dairy facility and were aware of the benefits of anaerobic digestion. Alliant Energy was also interested in a pilot project using biogas. The two parties talked with GHD, Inc. and agreed to have the first GHD digester installed on their farms. To reduce the financial risk for the farm, Alliant Energy agreed to supply, operate and maintain the engine generator set.

The digester has been operating as it is supposed to and they feel it is a good fit for the farm. Gale Gordon said he is surprised more digesters have not been built given the obvious advantages. For example, phosphorus (P) is concentrated mostly in the solids. After digestion, screw press solids separators take out about half the solids, and settling can remove most of the rest. The concentrated P in the lighter-weight solids can give the farm more flexibility in land application over greater distances and on fields that can use it. This added control helps farmers work within their nutrient management plans. He feels very strongly that digester designs should be as simple as possible.

Sources.

Gale Gordon – Deere Ridge Dairy / Gordondale Farms

Melissa VanOrnum – GHD, Inc.

Duane Hanusa – Alliant Energy, Inc.

## ***Double S Dairy – Markesan, Wisconsin***

<b>Farm Name:</b>	Double S Dairy	<b>Location:</b>	Markesan
<b>Farm Type:</b>	dairy	<b>Herd Size:</b>	1,100 head (milking)
<b>Collection Method:</b>	scrape	<b>Bedding Type:</b>	digested solids
<b>Digester Type:</b>	mixed plug-flow	<b>Design Temperature:</b>	100 deg F
<b>Digester Notes:</b>	two-stage, below grade concrete tank, u-shaped, gas-induced mixing, RAS		
<b>Design Capacity:</b>	1,200 head	<b>Date Operational:</b>	2004
<b>Design HRT:</b>	20 days	<b>Current HRT:</b>	not available
<b>Design Solids %:</b>	8-9%	<b>Current Solids %:</b>	not available
<b>Biogas Use:</b>	electricity and heat	<b>Utility Contract:</b>	yes
<b>Installed Capacity:</b>	200 kW	<b>Prime Mover Brand:</b>	Caterpillar
<b>Solids Separation:</b>	yes , screw press	<b>Solids Use:</b>	bedding and land applied
<b>Ownership:</b>	farm owns digester and energy generation		
<b>Digester Designer:</b>	GHD, Inc.	<b>Utility:</b>	Alliant Energy, Inc.

The Double S Dairy has 1,100 milking Holsteins and is located in Markesan, Wisconsin, in southern Green Lake County. The farm produces about 33,000 gallons of manure, wastewater and bedding for treatment every day. Manure is scrape-collected three times per day. They use digested solids for bedding and a Fan screw press for solids separation. Figure 18 is a photo of their solids separation operation. Their former manure storage system was a lagoon.

**Figure 18 – Double S Dairy Solids Separator**



### Digester.

In 2002, the owners installed a mixed plug-flow digester designed by GHD, Inc. The system is a standard GHD design, U-shaped, mesophilic, with gas-induced mixing and return of activated sludge. It is a concrete structure, built below grade, with a fixed concrete cover. The owners are unsure how frequently influent is added to the digester. The digester is operating near its designed temperature of 100 degrees F, and has an HRT of about 20 days.

### Outputs and Uses.

Biogas produced is dehumidified with a water trap, and run through a 200 kW Caterpillar engine generator set to produce electricity and heat. The system operates as an induction generator; it cannot operate in stand-alone mode. Figure 19 shows the engine generator set.



Electricity is sold to Alliant Energy through a sell-all purchase agreement that includes ownership of environmental attributes from generation.

Captured heat is used for digester, milking parlor, and shop heating. They also use this heat in the summer and into the fall to heat their swimming pool.

They produce about three to four semi-loads of digested solids per week and use about half for bedding. The rest are land spread on the farm.

**Figure 19 – Double S Dairy Engine Generator Set**



#### History and Comments.

Their system became operational in 2004. They switched from sand bedding to digested solids, and from flush collection to scrape so that farm operations would work more smoothly with the digester. Owner Dan Smits feels their digester has given them significant odor reduction, and that these systems are very “environmentally positive.” They have one of the earlier systems and it requires significant maintenance, and it “is not a money-making machine.” He adds that systems are getting more refined over the years and are constantly being improved. One thing they would do differently if starting over would be to spread out the buildings and structures more.

#### Sources.

Dan Smits – Double S Dairy

Melissa VanOrnum – GHD, Inc.

## ***Emerald Dairy – Emerald, Wisconsin***

<b>Farm Name:</b>	Emerald Dairy	<b>Location:</b>	Emerald
<b>Farm Type:</b>	dairy	<b>Herd Size:</b>	1,600 head
<b>Collection Method:</b>	scrape	<b>Bedding Type:</b>	digested solids
<b>Digester Type:</b>	mixed plug-flow	<b>Design Temperature:</b>	100 deg F
<b>Digester Notes:</b>	two-stage, below grade concrete tank, u-shaped, gas-induced mixing, RAS		
<b>Design Capacity:</b>	1,600 head	<b>Date Operational:</b>	2006
<b>Design HRT:</b>	20 days	<b>Current HRT:</b>	not available
<b>Design Solids %:</b>	8-9%	<b>Current Solids %:</b>	8%
<b>Biogas Use:</b>	upgrade, sell to 3M	<b>Utility Contract:</b>	no
<b>Installed Capacity:</b>	not applicable	<b>Prime Mover Brand:</b>	not applicable
<b>Solids Separation:</b>	yes, screw press	<b>Solids Use:</b>	bedding, some sold
<b>Ownership:</b>	farm owns digester and gas upgrade equipment		
<b>Digester Designer:</b>	GHD, Inc.	<b>Utility:</b>	St. Croix Electric Coop.

Emerald Dairy is a 1,600 head Holstein dairy in Emerald, Wisconsin, in eastern St Croix County. The dairy produces about 45,000 gallons of manure, bedding and wastewater per day. Manure is scrape-collected three times per day and averages about eight percent solids content. They use digested solids for bedding, and their former storage system was a anaerobic covered lagoon.

### Digester.

They replaced an older covered lagoon digester with a GHD, Inc. digester in 2005. The digester, which became operational in 2006, is a U-shaped mixed plug-flow system, with gas induced mixing and return of activated sludge. It is a below-grade concrete structure with a fixed concrete cover. Figure 20 shows the digester behind the adjacent gas processing facility.

**Figure 20 – Emerald Dairy Digester and Gas Cleanup Building**



Photo Courtesy of Agri-Waste Energy, Inc.

The digester has a design HRT of about 20 days and an operating temperature of 100 degrees F. Influent is pumped in to the digester four times per day. The farm also separates solids from the effluent stream using a Fan screw press to produce the digested solids used for bedding. Additional solids separation is achieved using an ISS system<sup>6</sup> that cleans up the water to a dischargeable level.

#### Outputs and Uses.

Biogas produced by the digester is run through a moisture trap and iron sponge to remove hydrogen sulfide. Then it is upgraded into compressed natural gas using water column technology. The CNG is then shipped using a tube tanker to a pipeline injection point. Figure 21 shows the equipment inside the on-farm gas processing facility at Emerald Dairy.

**Figure 21 – Biogas Processing Facility at Emerald Dairy**



The CNG is injected into a natural gas pipeline and sold to 3M, Inc. Some biogas is also used to heat the digester itself using a Bryan brand boiler. Figure 22 below shows a tube tanker used to haul the CNG, and the location where injection occurs.

**Figure 22 – Tube Tanker Truck at Injection Point**



Photo courtesy of Agri-Waste Energy, Inc.

<sup>6</sup> ISS stands for Integrated Separation Solutions of Madison, Wisconsin, which has provided an advanced filtration system for the dairy.

Effluent from the digester is stored in a lined lagoon before being land applied.

The farm produces about 38 tons of digested solids per week at about 67 percent moisture. They use these for bedding in higher proportions than at typical dairies because they use deep beds at Emerald. They sell 10-20 percent of the solids they produce to other farms.

#### History and Comments.

Both Emerald and Baldwin dairies had installed covered lagoon digesters in 1999 and 1998 respectively. When these systems did not provide an adequate level of digestion, they were replaced with heated systems. The digester at Emerald has allowed the owner to arrange an innovative sales contract with the company 3M, Inc. which was interested in using renewable fuel. They installed gas cleanup and upgrading equipment on the farm and are temporarily using tube tanker trucks to move the biogas to the injection point. Pending approval of financing, the owner plans to partner with another large dairy (Jon-De Dairy) to build a gas distribution pipeline to allow biogas to be piped from Baldwin, Emerald and the third dairy to the injection point. The plan is to move the gas upgrading equipment to the injection point so the biogas from all three farms can be processed with it.

The owner of Baldwin Dairy is also exploring other innovations for use of dairy operation byproducts. These include growing tilapia and algae in nutrient rich water, and making biodiesel from the algae.

#### Sources.

John Vrieze – Emerald Dairy

Melissa VanOrnum – GHD, Inc.

## ***Five Star Dairy – Elk Mound, Wisconsin***

<b>Farm Name:</b>	Five Star Dairy	<b>Location:</b>	Elk Mound
<b>Farm Type:</b>	dairy	<b>Herd Size:</b>	850 head (milking)
<b>Collection Method:</b>	scrape	<b>Bedding Type:</b>	digested solids
<b>Digester Type:</b>	complete mix	<b>Design Temperature:</b>	125 deg F
<b>Digester Notes:</b>	above ground cylindrical tank, carbon steel, thermophilic, fixed steel cover		
<b>Design Capacity:</b>	800-1,200 head	<b>Date Operational:</b>	2005
<b>Design HRT:</b>	20 days	<b>Current HRT:</b>	20 days
<b>Design Solids %:</b>	6-8%	<b>Current Solids %:</b>	not available
<b>Biogas Use:</b>	electricity and heat	<b>Utility Contract:</b>	yes
<b>Installed Capacity:</b>	750 kW	<b>Prime Mover Brand:</b>	Waukesha
<b>Solids Separation:</b>	yes, screw press	<b>Solids Use:</b>	bedding, give away for gardeners
<b>Ownership:</b>	farm owns digester (designer operates and maintains), utility owns energy generation		
<b>Digester Designer:</b>	Microgy, Inc.	<b>Utility:</b>	Dairyland Power Cooperative

Five Star Dairy, located in Elk Mound, Wisconsin in east-central Dunn County, has 850 milking cows. The owner planned to add anaerobic digestion when he was building this new dairy in 2000. The daily volume of manure and other liquids requiring treatment is not available. Manure is scrape-collected three times per day and they use a Fan screw press for solids separation after digestion. Their former manure storage system was a lagoon.

### Digester.

Five Star Dairy entered into an agreement with Microgy, Inc. and Dairyland power to have an anaerobic digester installed on the farm. Under this agreement they sell biogas to Dairyland Power for electricity generation. Figure 23 (on the following page) shows the digester installed at Five Star Dairy.

Under this agreement, Microgy installed the digester with no cash outlay from the farm owner. The farm owner pays off the debt on the digester through biogas sales to Dairyland Power. Microgy operates and maintains the digester. Dairyland Power has an engine generator set at the farm and generates green electricity for sale to its member cooperatives.

The Microgy system is a complete-mix above ground, carbon steel tank. It operates in the thermophilic range with a target temperature of 125 degrees F. The design HRT is 20 days, and as a complete mix system it has an inherent retention of activated sludge. The Microgy systems are designed to include addition of off-farm food wastes, preferably high fat wastes such as greases and oils. The systems and business model are designed around the co-digestion of such wastes and the resultant high level of biogas production. Five Star Dairy includes a storage tank for delivered food processing wastes (visible in Figure 23 as the smaller cylindrical tank on the lower right). A mixture of manure and about ten percent food wastes is batched into the digester every half hour. Solids are



separated out after digestion. Most of these are used for bedding and some are given away to local gardeners.

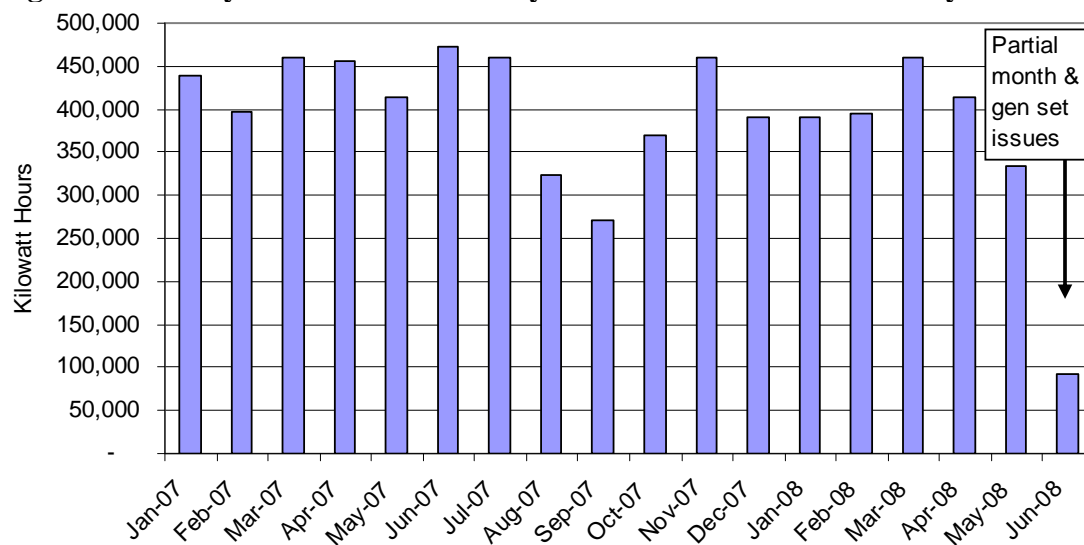
**Figure 23 – Microgy Digester at Five Star Dairy**



Photo courtesy of Microgy, Inc.

Figure 24 below shows the last 18 months of electricity produced from biogas in monthly kWh totals.

**Figure 24 – Dairyland Power Electricity Generation at Five Star Dairy**



History and Comments.

The digester at Five Star Dairy was the first establishment of the farm/Microgy/Dairyland Power business model in Wisconsin. Therefore, there was a large amount of negotiation and legal assistance needed to iron out the details. Once the contract was established, the

other two systems (Norswiss and Wild Rose) were able to copy the business model. The owner, Lee Jensen, is happy with the resulting arrangement and feels it is a good deal for all the parties involved. He also noted that biogas production has been close to normal throughout the energy monitoring period covered in Figure 24, and variation has been due to engine generator set issues.

Mr. Jensen feels having the digester has been a great thing for the farm, the image of his operation and for the community. They have a good product, low odor, and good fertilizer. They are getting growing interest from the community in the manure solids for gardening. They are currently giving these away and are building substantial goodwill with their neighbors.

Their manure has noticeably lower odor. As an additional control measure, they are installing a cover on their lagoon (where effluent from the digester is stored) and will monitor the gas coming off that to see if it is usable.

Mr. Jensen notes that the system is very well metered. Because of this, he noticed that his operation is using much more water than the other two farms, and he knows that if they pay more attention to controlling water use they can reduce costs. He has also learned that you can move liquids farther and more efficiently with slow hydraulic pumps. He says having many spots where you can open up the flow lines for cleanout is important and they must be cleared regularly. To help keep the lines clear, they have put in filters and also have the local septic truck come out and clear them out with suction and a pig. He stresses the key to making gas is consistent flow.

#### Sources.

Lee Jensen – Five Star Dairy

Mike Casper – Microgy, Inc.

John McWilliams – Dairyland Power Cooperative

## Green Valley Dairy – Green Valley, Wisconsin

<b>Farm Name:</b>	Green Valley Dairy	<b>Location:</b>	Green Valley
<b>Farm Type:</b>	dairy	<b>Herd Size:</b>	2,500 head
<b>Collection Method:</b>	scrape	<b>Bedding Type:</b>	digested solids
<b>Digester Type:</b>	complete mix (x2)	<b>Design Temperature:</b>	102 deg F
<b>Digester Notes:</b>	above ground cylindrical tank, flexible membrane cover		
<b>Design Capacity:</b>	2,500 head	<b>Date Operational:</b>	2007
<b>Design HRT:</b>	22 days	<b>Current HRT:</b>	not available
<b>Design Solids %:</b>	not available	<b>Current Solids %:</b>	8%
<b>Biogas Use:</b>	electricity and heat	<b>Utility Contract:</b>	yes
<b>Installed Capacity:</b>	600 kW	<b>Prime Mover Brand:</b>	Caterpillar
<b>Solids Separation:</b>	yes, screw press	<b>Solids Use:</b>	bedding, sold to farms
<b>Ownership:</b>	farm owns digester and energy generation		
<b>Digester Designer:</b>	Biogas Direct, LLC	<b>Utility:</b>	We Energies, Inc.

Green Valley Dairy is a 2,500 head (2,100 milking) dairy operation in Green Valley, in eastern Shawano County, Wisconsin. They scrape-collect manure three times per day, and produce about 83,000 to 105,000 gallons of manure per day. When milking parlor wash water is added the influent stream has about eight percent solid matter. The farm uses digested solids for bedding. The dairy is undergoing an expansion in summer 2008 (see History and Comments section for more details). Their former manure storage system was a lagoon.

### Digester.

The owners chose to install two Biogas Direct digesters for manure treatment. Figure 25 below shows the digesters.

**Figure 25 – Biogas Direct Digesters at Green Valley Dairy**





The digesters are complete mix above ground tanks with a flexible dual membrane cover that can expand to accommodate some limited biogas storage. Biogas is held in the inner membrane and there is a layer of air between the membranes. It is a mesophilic system with an operating temperature of 102 degrees F and an HRT of 22 days. As a complete mix system the digesters retain activated sludge during normal operation. The manure undergoes some pre-heating before entering the digesters, and is fed into the digester continuously. They do not add any off farm wastes to the digesters.

#### Outputs and Uses.

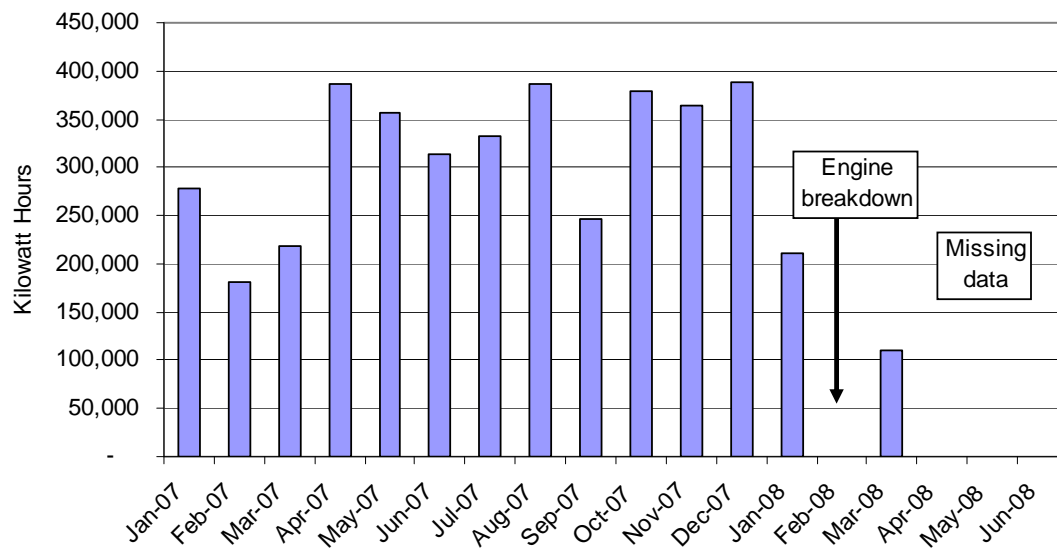
Biogas from the digesters is dehumidified using a condensate trap and chiller with oxygen addition. It is then used to generate electricity and heat. Electricity is sold to We Energies under a “sell all” contract. The farm owns a Caterpillar 600 kW engine generator set (see Figure 26) but plans to add generation capacity as part of their summer 2008 expansion.

**Figure 26 – Green Valley Dairy Engine Generator Set**



Their generator is synchronous and can run in stand-alone mode. Figure 27 on the following page shows the electricity production from January 2007 through June 2008.

**Figure 27 – Green Valley Dairy Generation History**



Heat is captured from the engine with a water jacket and from the exhaust. Currently all the recovered heat is used for heating the digester and bringing the manure up to temperature. They added a remote heat exchanger and they also have a cast iron Columbia boiler that can run on biogas for digester heat and pre-heating. Sometimes they supplement the heat with the boiler as well.

They use a Fan solids separator to separate digested solids for bedding. The farm generates about 120 tons per week of digested solids. They use half that on the farm and sell the other half to neighboring dairies. They are in the process of remodeling and will change from using mattresses (with which the cows end up kicking a lot of bedding into the aisles) to deep beds. They hope this switch will allow them to reduce their bedding use down to about 30 tons per week.

They have been producing more biogas than they could use and have ordered a second engine. After some fine tuning of engine settings, the current generator has been reportedly operating as high as 605 kW of gross output from biogas.

#### History and Comments.

Co-owner Guy Selsmeyer said they have experienced very good biogas production and have generally had more biogas than they could use – they flare the excess. They found that they got better digestion if they pre-heated the manure. They added a remote heat exchanger to be used for pre-heating and found that about 75 percent of the Btus they use for digester heat goes into that phase.

They are going through an expansion during the summer of 2008. They plan to add a new barn, 500 cows, a third digester and an additional 600 kW engine generator set. The owners are designing and building this third digester on their own and hope to have it running by the end of 2008.

Mr. Selsmeyer stressed that it is very important to have a backup boiler to provide heat to the digester, especially if the farm is using solids for bedding. During a recent engine breakdown (which they suspect was caused by a wiring issue) they were able to keep the digester up to temperature and continue production of good quality bedding until the engine was up and running again. Also, during below zero days, when ice crystals form in the manure, it can take significant extra heat to bring it up to digester temperature. Having additional boiler capacity is very useful at those times.

Sources.

Guy Selsmeyer – Green Valley Dairy

Michael Zander – Energies Direct, LLC (formerly with Biogas Direct, LLC)

Pat Keily – We Energies, Inc.

## ***Holsum Dairy, Elm Road – Hilbert, Wisconsin***

<b>Farm Name:</b>	Holsum Dairy, Elm Road	<b>Location:</b>	Hilbert
<b>Farm Type:</b>	dairy	<b>Herd Size:</b>	4,000 head
<b>Collection Method:</b>	scrape	<b>Bedding Type:</b>	digested solids
<b>Digester Type:</b>	mixed plug-flow (x2)	<b>Design Temperature:</b>	100 deg F
<b>Digester Notes:</b>	two-stage, below grade concrete tank, u-shaped, gas-induced mixing, RAS, fixed concrete covers		
<b>Design Capacity:</b>	4,000 head	<b>Date Operational:</b>	2007
<b>Design HRT:</b>	22 days	<b>Current HRT:</b>	20-22 days
<b>Design Solids %:</b>	8-9%	<b>Current Solids %:</b>	not available
<b>Biogas Use:</b>	electricity and heat	<b>Utility Contract:</b>	yes
<b>Installed Capacity:</b>	1200 kW (600 kW x2)	<b>Prime Mover Brand:</b>	Guascor
<b>Solids Separation:</b>	yes, screw presses	<b>Solids Use:</b>	bedding, sold to farms
<b>Ownership:</b>	farm owns digester and energy generation		
<b>Digester Designer:</b>	GHD, Inc.	<b>Utility:</b>	Wisconsin Public Service

Holsum Dairy has two separate farms both of which have digesters and are characterized in this casebook. The Elm Road dairy has about 4,000 head of Holsteins and is located in Hilbert, Wisconsin in Calumet County. Total volume of manure produced is not available. They use solids for bedding and scrape collect the manure three times per day. Their former manure storage method was in ponds.

### Digester.

Having worked with GHD digesters at their other dairy, the dairy owner decided to install two GHD, Inc. designed digesters at this facility as well. The systems were installed in 2006-2007 and became

operational in 2007. Figure 28 shows one end of a digester near the generator shed. These are U-shaped mixed plug-flow digesters with passive gas-induced mixing. The structures are concrete and below grade with fixed concrete covers. They operate in the mesophilic temperature range with a target operating temperature of 100 degrees F. The system has a design HRT of 22 days. In practice, they are seeing the temperature

range between 95 and 100 degrees, and estimate a 22 day HRT. The GHD system has return of activated sludge to help maintain the bacteria colonies. Frequency of the manure addition to the digester was unavailable. They also add about one to one and a

**Figure 28 – Holsum Digester and Equipment Shed**



half semi loads per day of non-farm food processing industry wastes from three industries to their influent stream and receive an undisclosed tipping fee.

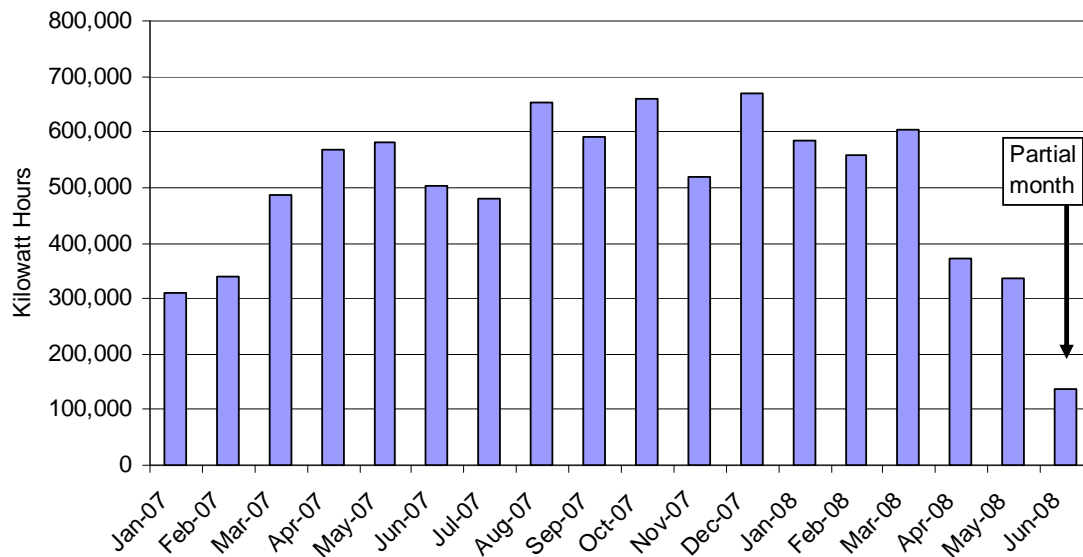
#### Outputs and Uses.

The produced biogas is dehydrated by running it through a condensate trap and chiller, then run through two engine generator sets to generate electricity. They have two 600 kW Guascor engine generator sets. Figure 29 shows Holsum's engine generator sets. They have a contract to sell all the electricity they generate to Wisconsin Public Service Corporation. Figure 30 shows the last 18 months of electricity generation for the Elm Road dairy.

**Figure 29 – Holsum Engine Generator Sets at Elm Road**



**Figure 30 – Elm Road Electricity Generation History**



Heat recovered from the engine generator sets is used for heating the digester, milking parlor, office, shop, and holding and transfer areas. They have a dual fuel boiler (brand unknown) for backup heat that can run on either diesel or biogas.

The farm uses two Fan screw presses to separate the solids from the digestate. The farm produces about 16 semi loads of solids per week and uses about one third on the farm. The other two thirds are sold to other dairies.

#### History and Comments.

The owner chose not to share any comments or history details other than to note that the layout for this system was somewhat different from their Irish Road dairy (see the following case study). They arranged the buildings differently, having an engine generator building further away from the radiators and heat exhaust.

#### Sources.

Kenn Buelow – Holsum Dairy

Melissa VanOrnum – GHD, Inc.

Joe Sinkula – Wisconsin Public Service Corporation



## ***Holsum Dairy, Irish Road – Hilbert, Wisconsin***

<b>Farm Name:</b>	Holsum Dairy, Irish Road	<b>Location:</b>	Hilbert
<b>Farm Type:</b>	dairy	<b>Herd Size:</b>	4,000 head
<b>Collection Method:</b>	scrape	<b>Bedding Type:</b>	digested solids
<b>Digester Type:</b>	mixed plug-flow (x2)	<b>Design Temperature:</b>	100 deg F
<b>Digester Notes:</b>	two-stage, below grade concrete tank, straight, gas-induced mixing, RAS, fixed concrete covers		
<b>Design Capacity:</b>	4,000 head	<b>Date Operational:</b>	2004
<b>Design HRT:</b>	22 days	<b>Current HRT:</b>	20-22 days
<b>Design Solids %:</b>	8-9%	<b>Current Solids %:</b>	not available
<b>Biogas Use:</b>	electricity and heat	<b>Utility Contract:</b>	yes
<b>Installed Capacity:</b>	700 kW (500 kW + 200 kW)	<b>Prime Mover Brand:</b>	Deutz and Caterpillar
<b>Solids Separation:</b>	yes, screw presses	<b>Solids Use:</b>	bedding and sold to farms
<b>Ownership:</b>	farm owns digester and energy generation		
<b>Digester Designer:</b>	GHD, Inc.	<b>Utility:</b>	Wisconsin Public Service

Holsum Dairy on Irish Road is one of two Holsum dairies with digesters in Hilbert, Wisconsin, in Calumet County. The Irish Road dairy, the older of the two, has 4,000 head of Holsteins (milking proportion unknown). The daily volume of manure produced is unknown. They use scrape collection three times per day and use digested solids for bedding. Their former manure storage method was in ponds.

### Digester.

Holsum Dairy was one of the early dairies in Wisconsin choosing anaerobic digestion for manure treatment. They installed two GHD designed digesters in 2001-2. Figure 31 shows the top of the digesters with flare. These systems are unlike the typical GHD digesters in that they are straight (laid out end to end) rather than U-shaped. The digesters are mixed plug-flow systems using biogas for mixing. They operate in the mesophilic range with a target temperature of 100 degrees F and have a design HRT of 22 days. They

use return of activated sludge. The structure is concrete below grade and has a fixed concrete cover. Manure mixed with food industry waste is added to the digesters three times a day. The one to one and a half semi-loads per day off farm wastes are byproducts

**Figure 31 – Holsum Dairy Irish Road Digesters**



from three area food processing industries for which the farm receives tipping fees. The manure and other wastes are not pre-treated in any way.

#### Outputs and Uses.

Biogas produced from the digester is fed through a condensate trap and chiller then used in two engine generator sets – a Deutz 500 kW and a Caterpillar 200 kW. Figure 32 shows the Cat engine generator set. Electricity produced from these is sold to Wisconsin Public Service Corporation under a “sell-all” agreement. The generators are not capable of operating in stand-alone mode (i.e., they are induction generators).

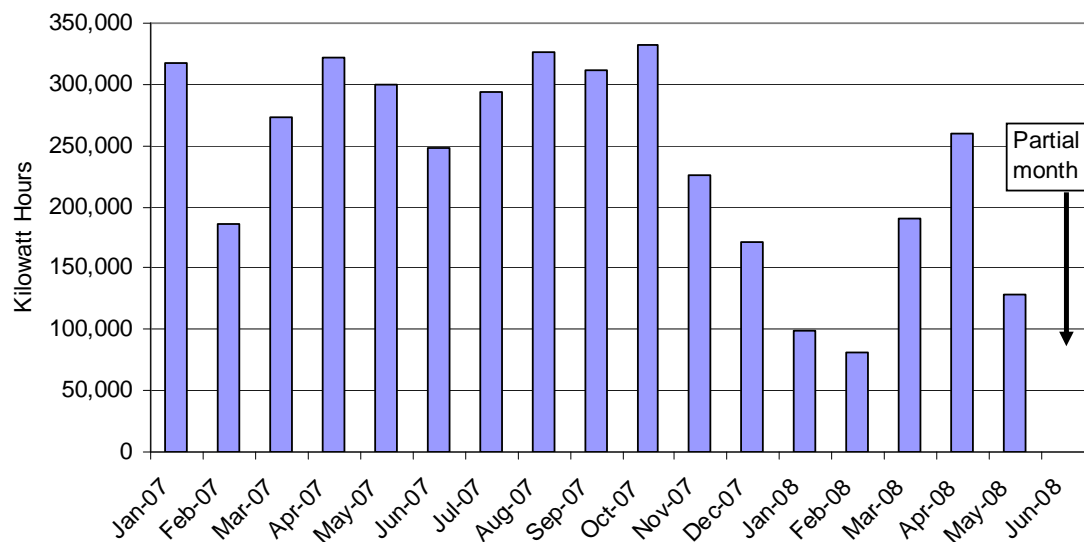
Waste heat from the engines and exhaust is captured and used for the digester, milking parlor, office, and holding and transfer areas. They also have a backup boiler (make unknown) that can use either diesel or biogas to provide supplemental heat to the system.

**Figure 32 – Holsum Dairy Irish Road Engine Generator Set**



Figure 33 shows the electricity production from Irish Road from January 2007 through June 2008

**Figure 33 – Holsum Dairy Irish Road Electricity Generation History**





The dairy produces about 16 semi-loads of digested solids per week. It uses one third on the farm and sells two thirds to other dairies.

History and Comments.

The owner stressed the importance of keeping the electronic equipment separate from the engine generator and solids separation areas. He said the systems were standard GHD digesters and installation was “pretty straightforward.”

Sources.

Kenn Buelow – Holsum Dairy

Melissa VanOrnum – GHD, Inc.

Joe Sinkula – Wisconsin Public Service Corporation

## Lake Breeze Dairy – Malone, Wisconsin

<b>Farm Name:</b>	Lake Breeze Dairy	<b>Location:</b>	Malone
<b>Farm Type:</b>	dairy	<b>Herd Size:</b>	3,072 head
<b>Collection Method:</b>	flush	<b>Bedding Type:</b>	sand
<b>Digester Type:</b>	mixed plug-flow (x2)	<b>Design Temperature:</b>	100 deg F
<b>Digester Notes:</b>	two-stage, below grade concrete tank, u-shaped, gas-induced mixing, RAS		
<b>Design Capacity:</b>	2,900 head	<b>Date Operational:</b>	2006
<b>Design HRT:</b>	22 days	<b>Current HRT:</b>	not available
<b>Design Solids %:</b>	8-9%	<b>Current Solids %:</b>	8-9%
<b>Biogas Use:</b>	electricity and heat	<b>Utility Contract:</b>	yes
<b>Installed Capacity:</b>	600 kW (300 kW x2)	<b>Prime Mover Brand:</b>	Caterpillar
<b>Solids Separation:</b>	yes, screw press	<b>Solids Use:</b>	stockpiling
<b>Ownership:</b>	farm owns digester and energy generation		
<b>Digester Designer:</b>	GHD, Inc.	<b>Utility:</b>	We Energies, Inc.

Lake Breeze Dairy is a 3,072 head (2,550 milking) Holstein dairy in Malone, Wisconsin, in northeastern Fond du Lac County. They use flush collection of their manure and use sand for bedding. Their farm processes produce about 120,000 gallons of material for treatment per day. Their former manure storage system was in ponds.

### Digester.

Because the farm uses sand bedding and flush collection, some additional treatments are required before the manure reaches the digesters. To remove the sand bedding the manure stream flows through one of two alternating sand settling lanes. The lane used is switched daily so the idle one can be scooped out. The sand is stored so bacteria cultures die off and it can be re-used. After the sand settling lanes, the manure stream goes into a mechanical rotary screen solids separation system. The liquid from this stage goes into a settling tank and the fine solids that settle out of this are re-mixed with the separated solids from the mechanical screen. This combination, approximating a solids composition of eight to nine percent, is fed into the digester while the clarified liquid is sent to a lagoon. The clarified undigested liquid is re-used for the flush collection system. The owners decided to install two GHD anaerobic digesters to treat their manure. The digesters are shown in Figure 34.

**Figure 34 – Digesters at Lake Breeze Dairy**



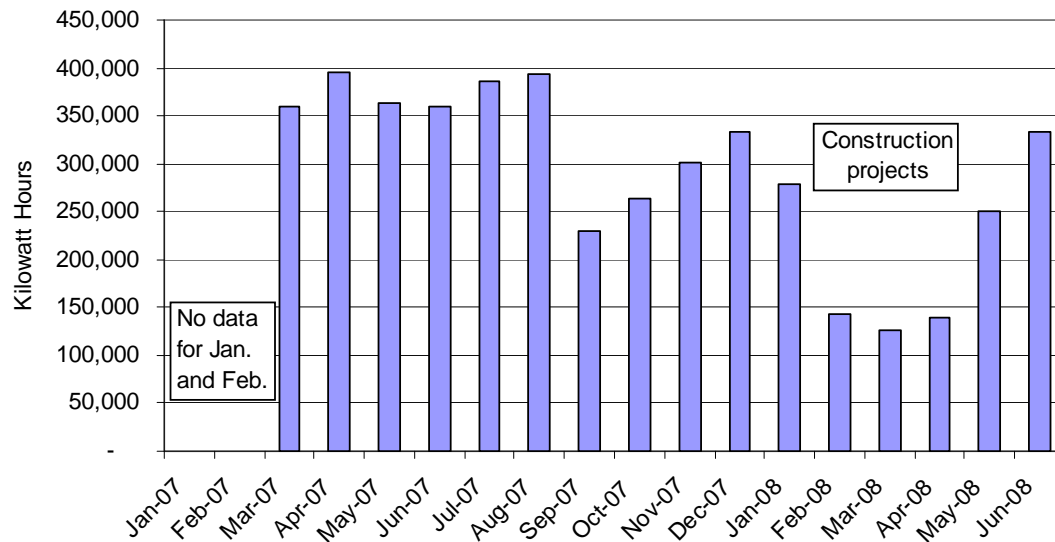
The digesters are side-by-side mixed plug-flow systems that are U-shaped. They operate in the mesophilic temperature range with a target of 100 degrees F. They use biogas for mixing and have return of activated sludge. They are below grade concrete structures with fixed concrete covers.

During the spring and summer of 2008 various construction projects (including installation of sand settling lanes) have interfered with the normal flow of manure to the digester making daily digester feeds smaller and variable. The owners have supplemented the input stream with varying amounts of purchased corn syrup from an Oshkosh ethanol plant to support biogas production.

#### Outputs and Uses.

Biogas produced by the digesters is conditioned using a condensate trap and chiller. Then it is fed into two Caterpillar 300 kW capacity engine generator sets that are capable of operating in stand-alone mode (i.e., synchronous generation). Electricity produced is sold to We Energies under a sell-all type of contract. Waste heat captured from engine water jackets and exhaust is used to heat the digester. Figure 35 shows the electricity production over the last 18 months.

**Figure 35 – Lake Breeze Dairy Electricity Generation History**



After digestion, solids are pulled out using Anderson brand screw presses. Figure 36 shows the solids separators used after digestion and the solids separation area. They tried using the solids for bedding but had some incidence of mastitis so switched to sand. These solids are currently being stockpiled because they do not have a ready market for them.

#### History and Comments.

The owners installed the anaerobic digesters to reduce odor from the farm (about which they had received some complaints). Brian Gerrits of Lake Breeze Dairy said that they

researched options and saw anaerobic digestion as fairly expensive one, but were encouraged by the benefits. Once the digesters were in they did not get the level of odor control they expected. Their water has a lot of sulfates in it which contribute to hydrogen sulfide (H<sub>2</sub>S) formation. They also noticed openings in the final section of the digester where manure is pumped to the screw press. They closed these and experienced a reduction in odor. They are now adding ferric chloride to the effluent when it goes from the screw presses to the lagoon for H<sub>2</sub>S control. They tried adding ferrous chloride to the influent but that did not work well.

Their sand removal lanes are reportedly working well, but they expect to periodically need to clean sand out of the digester as it builds up over time.

Maintenance of their system was more expensive than they thought. The feasibility study also did not give the amount of parasitic load (i.e., energy needed to run the manure handling and treatment system) for pumps and agitation equipment which was especially high due to the flush collection and associated systems. Still, they feel that power generation from their overall system is “pretty good.”

**Figure 36 – Digested Solids Separation Area**



Some anaerobic digester experts contend that the practices of flush collection and sand bedding are incompatible with most anaerobic digesters (or at a minimum, present a reduced chance for successful implementation).<sup>7</sup> The coordination of these systems clearly involved some fine-tuning and compromises, but both designer and farm owners feel the sand separation and digester system are working well. Mr. Gerrits pointed out that it is important to have farm reps and digester design reps work well together in order to work out these issues. In retrospect, he feels they could have spent more time on design and layout of the manure handling systems. This may have allowed them to avoid some pumps and use gravity more.

#### Contacts.

Brian Gerrits – Lake Breeze Dairy

Melissa VanOrnum – GHD, Inc.

Randy Jerome – We Energies, Inc.

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<sup>7</sup> For example, see the Agricultural Utilization and Research Institute “Self-Screening Checklist” at: <http://www.auri.org/research/digester/digchck.pdf>. This identifies each as “key issues.”

## Norswiss Farms – Rice Lake

<b>Farm Name:</b>	Norswiss Farms	<b>Location:</b>	Rice Lake
<b>Farm Type:</b>	dairy	<b>Herd Size:</b>	1,240 head (1,180 milking)
<b>Collection Method:</b>	scrape	<b>Bedding Type:</b>	digested solids
<b>Digester Type:</b>	complete mix	<b>Design Temperature:</b>	125 deg F
<b>Digester Notes:</b>	above ground cylindrical tank, carbon steel		
<b>Design Capacity:</b>	800-1,200 head	<b>Date Operational:</b>	2006
<b>Design HRT:</b>	20 days	<b>Current HRT:</b>	not available
<b>Design Solids %:</b>	6-8%	<b>Current Solids %:</b>	not available
<b>Biogas Use:</b>	electricity and heat	<b>Utility Contract:</b>	yes
<b>Installed Capacity:</b>	848 kW	<b>Prime Mover Brand:</b>	Jenbacher
<b>Solids Separation:</b>	yes,	<b>Solids Use:</b>	bedding
<b>Ownership:</b>	farm owns digester (designer operates and maintains), utility owns energy generation		
<b>Digester Designer:</b>	Microgy, Inc.	<b>Utility:</b>	Dairyland Power Cooperative, Barron Electric

Norswiss Farms is a 1,240 head dairy farm with mostly Holsteins and some Swiss cows. The dairy is located in Rice Lake, Wisconsin, in northern Barron County. The daily manure production amount is not available. Manure is scrape-collected three times per day to a center gravity-flow system from which it is pumped to the digester. The farm uses digested solids for bedding. Their former manure storage system was a lagoon.

### Digester.

The farm owner chose to work with Microgy and Dairyland Power to have a digester installed on his farm. Figure 37 shows the Norswiss digester and the surrounding structures.

**Figure 37 – Norswiss Farms Digester**



Photo courtesy of Microgy, Inc

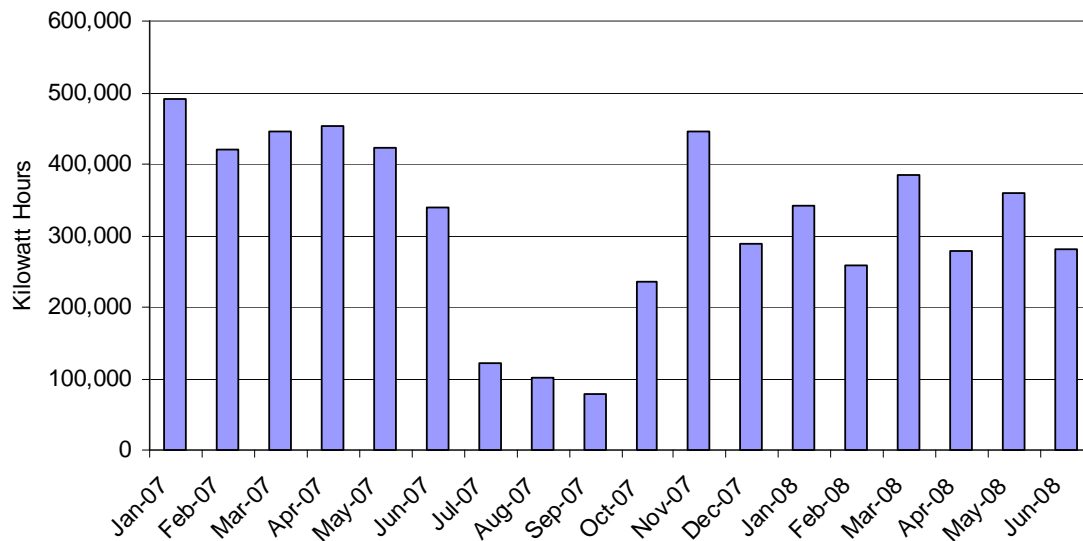
The Microgy digester is an above-ground carbon steel cylindrical complete mix tank. It operates in the thermophilic temperature range with a target of 125 degrees F. The digester has an HRT of 20 days. Next to the digester is a 50,000 gallon tank in which the off farm food wastes, primarily grease, are stored. These wastes are pumped into the digester every half hour and are limited to about 10 percent of the total volume in the digester. The farm puts all farm waste liquids into the digester including waste milk and footbath water.

Under this business model, Microgy installs the digester, which is owned by the farm, with no cost outlay from the farm. Dairyland Power installs an engine generator set on the farm as well. Microgy operates and maintains the digester and sells biogas to Dairyland Power. The proceeds from these sales pay down the farm's debt on the digester. Dairyland Power generates green electricity with the biogas and sells it to its member cooperatives. Important to the model is the co-digestion of off-farm food processing wastes – preferably high fat greases and oils. These boost biogas production and produce more income to pay down the debt.

#### Outputs and Uses.

The biogas produced by the digester is scrubbed with a Biothane brand scrubber. It then is used to run a Jenbacher 848 kW engine generator set owned, operated and maintained by Dairyland Power. The system is synchronous, but is set to shut down in the event of power failure. As a synchronous generator the utility relies on it to provide voltage support for their distribution system. Figure 38 shows the electricity production history for Norswiss.

**Figure 38 – Electricity Production History at Norswiss Farms**



Dairyland Power gets renewable energy credits for the electricity generated, and the farm gets carbon credits for methane emissions avoided by using an anaerobic digester. Sales of these carbon credits also go toward paying down the debt on the digester.

The farm also has a backup boiler that runs on biogas to provide heat to the digester in the event the engine is down. Recovered heat is used for digester heating only.

Effluent from the digester goes through a Fan brand screw press solids separator which runs constantly. The liquid fraction is pumped into the storage lagoon seen at the top of the photo. They produce about 55 yards of solids per day and use all of it on the farm as bedding on mattresses.

#### History and Comments.

Andreas Heer, the farm owner, said that once digested, the manure is more liquid with relatively lowered chemical oxygen demanding compounds (COD). They can use it on their hayfields which they cannot do with raw manure. They have been able to eliminate fertilizer purchases for hay, bean and alfalfa fields which the owner sees as a very good benefit.

The digester took a bit longer than predicted to build due to some permitting delays and some problems with out of state contractors. But, Mr. Heer said that this did not negatively affect the farm operation. He says the digester and business arrangement is working well for them – they had no cash outflow and are now saving money on bedding and fertilizer. The availability of these solids has allowed them to do heavy bedding (6-12 inches) on mattresses for much better cow comfort and performance, and they have had low somatic cell counts. They are avoiding the expense of using sawdust which would otherwise be costing them \$1,800 every 6 days, and is sometimes hard to find.

#### Sources.

Andreas Heer – Norswiss Farms

Mike Casper – Microgy, Inc.

John McWilliams – Dairyland Power Cooperative



## Quantum Dairy – Weyauwega, Wisconsin

<b>Farm Name:</b>	Quantum Dairy	<b>Location:</b>	Weyauwega
<b>Farm Type:</b>	dairy	<b>Herd Size:</b>	1,700 head
<b>Collection Method:</b>	scrape	<b>Bedding Type:</b>	digested solids
<b>Digester Type:</b>	mixed plug-flow	<b>Design Temperature:</b>	100 deg F
<b>Digester Notes:</b>	two-stage, below grade concrete tank, u-shaped, gas-induced mixing, RAS		
<b>Design Capacity:</b>	1,250 head	<b>Date Operational:</b>	2005
<b>Design HRT:</b>	22 days	<b>Current HRT:</b>	18 days
<b>Design Solids %:</b>	8-9%	<b>Current Solids %:</b>	11%
<b>Biogas Use:</b>	electricity and heat	<b>Utility Contract:</b>	yes
<b>Installed Capacity:</b>	300 kW	<b>Prime Mover Brand:</b>	Caterpillar
<b>Solids Separation:</b>	yes, screw press	<b>Solids Use:</b>	bedding, sold to farms or gardeners
<b>Ownership:</b>	farm owns digester and energy generation		
<b>Digester Designer:</b>	GHD, Inc.	<b>Utility:</b>	We Energies, Inc.

Quantum Dairy is a dairy in Weyauwega, in southern Waupaca County, Wisconsin. They have 1,700 head of milking Holsteins (their dry cows and replacements are kept off site) and are planning to expand to 2,100 head in the near future. The operation produces about 55,000 gallons per day of manure and liquids for treatment. This influent has a solids content of about 11 percent. They use scrape collection of manure three times per day, and use separated digested solids for bedding. Their former manure system was an open lagoon.

### Digester.

The owners researched digester designs and chose GHD, Inc. to design and install their digester and energy generation systems. The digester was built in 2004-5 and became operational in 2005. Figure 39 shows the digester at Quantum Dairy.

**Figure 39 – Quantum Dairy Digester**



The digester is a U-shaped mixed plug-flow system with biogas induced mixing. It operates in the mesophilic temperature range with a target of 100 degrees F. It uses return of activated sludge and has a design HRT of about 22 days. The structure is



below-grade concrete with a fixed concrete cover. The farm owns the digester and energy generation and sells electricity to We Energies.

Manure from the reception pit is pumped to the digester 12 times per day. Cows undergoing footbath treatment are at a separate barn so that liquid currently does not go through the digester (this will soon be included in the influent). After the digester, solids are separated out of the effluent stream with a Fan brand screw press solids separator pictured in Figure 40.

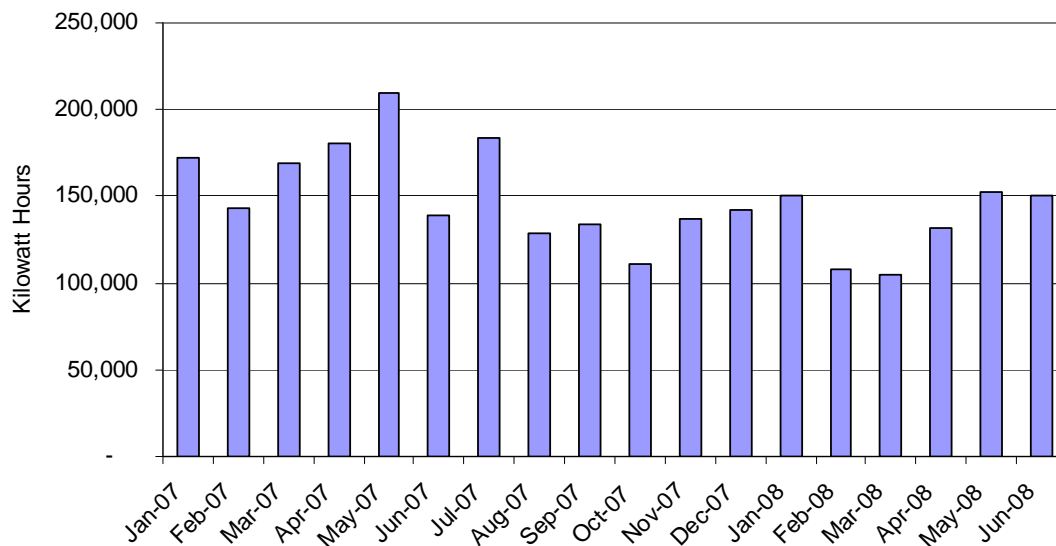
**Figure 40 – Screw Press Solids Separator**



#### Outputs and Uses.

Biogas produced by the digester is sent through a condensate trap and chiller to remove moisture. It is then sent to a Caterpillar 300 kW turbo-charged engine generator set. Electricity is sold to We Energies under a sell-all contract. The generation history for Quantum is shown in Figure 41.

**Figure 41 – Electricity Generation at Quantum**



Note: These generation numbers are net of parasitic load.

Heat is recovered and used to heat the digester, two parlors, the engine generator set building, the shop and the house.

The dairy creates about 133 tons (about 400 yards) of digested solids per week, about 75 percent of which they use on the farm. The remainder is sold to other dairies for bedding and occasionally to gardening businesses. They are selling the solids for \$15 ton or \$5 per yard take away.

#### History and Comments.

GHD designed the digester, integration with the engine generator set, and associated structures. Richard Wagner of Quantum Dairy said they did the project when they only had 600 cows, but had planned to expand, so the digester was built to handle 1,200 to 1,500 cows. They are currently over the design capacity (at 1,700) and plan to push manure from as many as 2,100 cows through the system. They are planning to upgrade the engine generator set again (they have been awarded funding from Focus on Energy). They have already upgraded from their original 200 kW to their current 300 kW set, but it only runs well up to 270 kW. They hope to expand to a generation capacity of 400-450 kW. They have experienced some pinhole leaks in the digester. Mr. Wagner says one way to avoid these leaks is to operate at zero pressure. They have noticed that manure exiting the digester still has gas bubbles coming out and odor is still an issue (probably due to overloading of the digester which causes manure to move through more quickly). They capture these gases which contain hydrogen sulfide ( $H_2S$ ), run them through a pipe and bubble them through water which converts the  $H_2S$  into liquid sulfuric acid. This is then sent to the lagoon.

Mr. Wagner noted that depending on staff, the job falls to someone to maximize the run-time of the engines. This can be demanding because they typically seem to shut down in the middle of the night.

#### Sources.

Richard Wagner – Quantum Dairy

Melissa VanOrnum – GHD, Inc.

Tom Young – We Energies, Inc.

## Stencil Farm – Denmark, Wisconsin

<b>Farm Name:</b>	Stencil Farm	<b>Location:</b>	Denmark
<b>Farm Type:</b>	dairy	<b>Herd Size:</b>	1,300 head, (700-1,000 feed digester)
<b>Collection Method:</b>	scrape	<b>Bedding Type:</b>	digested solids
<b>Digester Type:</b>	plug-flow	<b>Design Temperature:</b>	100 deg F
<b>Digester Notes:</b>	straight plug-flow, below grade, flexible cover		
<b>Design Capacity:</b>	1,200 head	<b>Date Operational:</b>	2002
<b>Design HRT:</b>	20 days	<b>Current HRT:</b>	22-23 days
<b>Design Solids %:</b>	9-12%	<b>Current Solids %:</b>	varies
<b>Biogas Use:</b>	electricity and heat	<b>Utility Contract:</b>	yes
<b>Installed Capacity:</b>	123 kW	<b>Prime Mover Brand:</b>	Caterpillar
<b>Solids Separation:</b>	yes, screw press	<b>Solids Use:</b>	bedding
<b>Ownership:</b>	farm owns digester and energy generation		
<b>Digester Designer:</b>	RCM Digesters, Inc.	<b>Utility:</b>	Wisconsin Public Service

Stencil Farm in Denmark, Wisconsin, in eastern Brown County, has a herd size of around 1,300 Holsteins. Manure from between 700 and 1,000 head is regularly sent to the digester. They use digested solids for bedding and scrape collect the manure hourly. The volume, as well as the solids content of the manure sent to the digester varies depending on which barns it is coming from. Their former manure storage system was a lagoon.

### Digester.

The Stencils installed a digester designed by RCM Digesters, Inc. in 2001-2, and the system became operational in 2002. The digester is a below grade, concrete, straight plug-flow system with a flexible cover. It operates in the mesophilic range with a target temperature of 100 degrees F. The system is designed to work best with manure solids concentrations of 9 to 12 percent.

### Outputs and Uses.

Biogas produced by the digester is used to generate electricity and heat with a Caterpillar 123 kW (biogas rated) engine generator set. The electricity is used entirely on the farm, but they have the capability of selling excess to Wisconsin Public Service. Because the farm is not selling electricity, there is no generation data available.

Heat recovered from the engine is used entirely for the digester. The shop adjacent to the engine room receives some radiant heat from the engine.

Digested solids are separated out from the effluent using a Fan screw press type separator. All solids produced at the farm are used on the farm. They are looking at a press and tumbler system to produce solids from raw manure, heat it to 150 degrees F, and have solids ready for use in a day.

### History and Comments.

The farm has had some trouble with the variability in solids content in their manure influent stream affecting digester performance. Dave Stencil said when their solids content is lower, they get some crusting, and it interferes with the heat exchangers making them less effective at bringing the manure up to temperature. He is checking into some modifications including some agitation that might make their system more tolerant of their variable manure input stream. Their primary goal is to generate bedding product.

He thinks the flexible cover on his digester offers insufficient insulation capability for cold Wisconsin winters, and that his digester's structural insulation may have been compromised over time. Their difficulties in maintaining the system temperature have affected digester performance.

As one of the earlier systems installed in Wisconsin, they were required to put in 16 inch thick concrete walls which made the system more expensive. They also had repeated problems with the engine and other safety features. Mr. Stencil stated that he has had a hard time getting local people to work on his system and at one point had a \$14,000 overhaul (of the engine) that could have been avoided with a \$600 repair. He pointed out that newer engines made for biogas are more efficient and can provide more energy output.

He says owning and maintaining a digester and energy generation equipment is challenging, and he knows farmers who have given up on their digesters. One reason he is considering redoing his system is that the modifications look pretty good on paper.

### Sources.

Dave Stencil – Stencil Farm

Mark Moser – RCM Digesters, Inc.

## ***Suring Community Dairy – Suring, Wisconsin***

<b>Farm Name:</b>	Suring Community Dairy	<b>Location:</b>	Suring
<b>Farm Type:</b>	dairy	<b>Herd Size:</b>	950 head (810 milking)
<b>Collection Method:</b>	scrape	<b>Bedding Type:</b>	digested solids
<b>Digester Type:</b>	complete mix	<b>Design Temperature:</b>	100 deg F
<b>Digester Notes:</b>	above ground bolted stainless steel tank with dual membrane, flexible cover on floating concrete pad		
<b>Design Capacity:</b>	1,000 head	<b>Date Operational:</b>	2005
<b>Design HRT:</b>	22 days	<b>Current HRT:</b>	28 days
<b>Design Solids %:</b>	not available	<b>Current Solids %:</b>	7-8%
<b>Biogas Use:</b>	electricity and heat	<b>Utility Contract:</b>	yes
<b>Installed Capacity:</b>	230 kW	<b>Prime Mover Brand:</b>	Dreyer & Bosse
<b>Solids Separation:</b>	yes, screw press	<b>Solids Use:</b>	bedding, composting, other farms
<b>Ownership:</b>	farm owns digester and energy generation		
<b>Digester Designer:</b>	American Biogas Company, Inc.	<b>Utility:</b>	Wisconsin Public Service

Suring Community Dairy is a 950 head Holstein operation in Suring, Wisconsin in Oconto County. They use scrape collection continuously throughout the day. The daily production volume of manure is about 25,000 gallons. The manure and wastewater influent stream requiring treatment has an estimated solids content of seven to eight percent. They use separated solids for bedding and their former manure storage method was a lagoon.

### Digester.

The farm owners chose to install a complete mix digester designed by American Biogas Company (AMBICO). The digester is an above ground, stainless steel complete mix tank with a dual membrane flexible cover, resting on a floating concrete pad. It operates in the mesophilic range with a target temperature of 100 degrees F, and an HRT of 22 days. Figure 42 shows the Suring Community Dairy digester.

**Figure 42 – Suring Community Dairy Digester**



The farm feeds manure in every two hours. They are planning to adjust the schedule to pump more in during off hours to take advantage of lower time-of-day electricity rates. They do not do any kind of pre-treating of the influent. Currently, only manure, wastewater and bedding are sent into the digester. Small amounts of footbath water are sent through the digester as well.

#### Outputs and Uses.

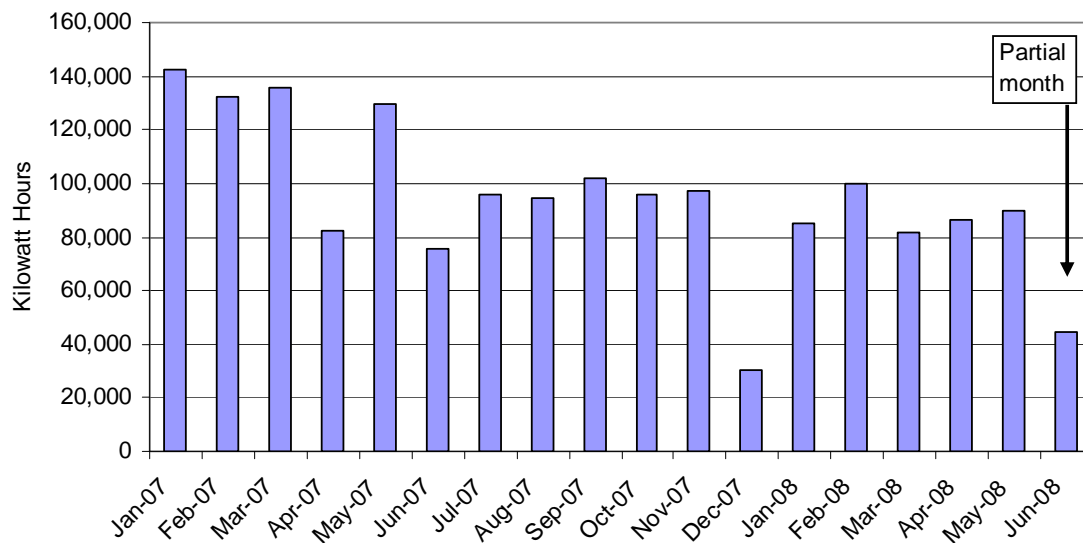
Biogas produced from the digester is sent through a passive hydrogen sulfide removal system and chilling unit for condensate removal. It is then fed into a 250 kW Dreyer and Bosse, dual fuel engine generator set. The engine uses 20 percent diesel and is synchronous (i.e., can run in stand-alone mode). Figure 43 shows the engine generator set.

**Figure 43 – Suring Engine Generator Set**



Electricity produced on the farm is sold to Wisconsin Public Service Corporation under a sell all agreement. Figure 44 shows the electricity generation history for the dairy.

**Figure 44 – Suring Community Dairy Electricity Generation History**



Heat captured from the engine and exhaust is used to heat the digester and the shop building.

They separate solids from the effluent stream with two separators: a WEDA brand screw press solids separator, and a PTI (Press Technologies, Inc.) model. They have replaced one of each model so far due to failures. They produce between 80 and 100 yards of digested solids per week. They use 40 to 45 yards per week on the farm. Of the rest, they compost some and have some neighbors who are trying them out for bedding. They are also considering doing some drying and bagging solids as possible horse bedding, a market that is developing due to a growing shortage of sawdust. They have recently supplied some solids for landscapers and gardeners who appreciate the lower cost manure. They are also considering an option to supply solids to a pelleting operation for fuel production.

#### History and Comments.

Ray Leicht of Suring Community Dairy said the utility, digester designer, Focus on Energy, and the USDA Rural Development all worked well together to bring this project to life. The biggest hang-up they had was working with equipment manufactured in different countries (e.g., German engine, Japanese controllers) caused some delays in getting things to fit together properly.

Had he been more familiar with the demands of having a digester as part of their manure management system he would have located equipment differently. They planned to have substrates from off-farm brought in for co-digestion, but discovered that arranging this was not as easy as they thought it would be. One food producer was talking with them about some grease trap wastes and he found out from the Department of Natural Resources that using it may cause some permit issues related to their nutrient management. They continue to explore options for co-digesting some off farm substrates such as food waste and septage.

One energy and cost-saving measure they are implementing is to reroute effluent from the screw press back into the reception pit for pre-heating. This helps lower the energy needed to heat the manure up to digester target temperature by capturing heat from the effluent that would otherwise be wasted. They also plan to pump more manure into the digester during off hours to take advantage of the lower time-of-day electricity rates.

#### Sources.

Ray Leicht – Suring Community Dairy

Carsten Weber – American Biogas Company

Joe Sinkula – Wisconsin Public Service Corporation

## Vir-Clar Farm – Fond du Lac, Wisconsin

<b>Farm Name:</b>	Vir-Clar Farm	<b>Location:</b>	Fond du Lac
<b>Farm Type:</b>	dairy	<b>Herd Size:</b>	1,350 head (1,200 milking)
<b>Collection Method:</b>	scrape	<b>Bedding Type:</b>	digested solids
<b>Digester Type:</b>	complete mix (x2)	<b>Design Temperature:</b>	100 deg F
<b>Digester Notes:</b>	above ground tanks, flexible membrane covers		
<b>Design Capacity:</b>	1,350 head	<b>Date Operational:</b>	2004
<b>Design HRT:</b>	33 days (oversized system)	<b>Current HRT:</b>	30 days
<b>Design Solids %:</b>	not available	<b>Current Solids %:</b>	not available
<b>Biogas Use:</b>	electricity and heat	<b>Utility Contract:</b>	yes
<b>Installed Capacity:</b>	350 kW	<b>Prime Mover Brand:</b>	Caterpillar/SEVA
<b>Solids Separation:</b>	yes, screw press	<b>Solids Use:</b>	bedding, farms and potting soil company
<b>Ownership:</b>	farm owns digester and energy generation		
<b>Digester Designer:</b>	Biogas Direct, LLC	<b>Utility:</b>	Alliant Energy

Vir-Clar Farm is a 1,350 head Holstein dairy, in Fond du Lac, Wisconsin, in eastern Fond du Lac County. They produce about 27,000 gallons of manure per day. They use digested solids for bedding and do continuous scrape collection. Their former system for manure storage was a storage tank.

### Digester.

Vir-Clar Farm installed two Biogas Direct, LLC, digesters to treat their manure. These are above ground complete mix tank systems, with flexible dual membrane covers. The inside membrane holds biogas, and there is a layer of air between the membranes. They operate in the mesophilic temperature range with a target operating temperature of 100 degrees F. The design HRT is 33 days and they are currently at about 30 days. Figure 45 shows the digesters at Vir-Clar.

**Figure 45 – Vir-Clar Farm Digesters**





Manure is added to the digesters twice a day. They also digest other organics from the farm including bunker wastes, moldy feed, and whatever is not eaten by the cows. They mix the manure going into the digester with liquid coming from the solids separators. They avoid having footbath water go into the digester.<sup>8</sup>

#### Outputs and Uses.

Biogas from the digester is passed through a passive hydrogen sulfide removal system and chilling unit for condensate removal. It is then fed into a Caterpillar engine generator set that has been modified by the German company SEVA and has a 350 kW generating capacity. The engine generator set is containerized. Figure 46 shows a view of the inside of the container. The generator is synchronous and can operate in stand-alone mode. Electricity generated is sold to Alliant Energy under a sell-all contract. Electricity generation information was not available for this system.

**Figure 46 – Engine Generator Set in Container**



They do not have a backup boiler. Heat from the engine and exhaust is captured and used for heating the digester, water for calves, the separator room, and to provide in-floor heating in the calf barn.

The farm produces about 150 tons of digested solids per week. They use between 70 and 80 tons on the farm each week, and sell the rest to a small farm and to a potting soil facility who will buy all they can. They compost it and put it into their potting soil mix. Liquid digestate is stored in a storage tank under the cows before being land applied.

#### History and Comments.

Gary Boyke, owner of Vir-Clar Farm says they had a great experience with construction. They started building the digesters in the beginning of June 2004 and by mid-October they were filling them with manure. In November 2004 they were making electricity.

He thinks the system has paid for itself and is making them money. They are often making more gas than the engine can use and are looking for ways to improve production

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<sup>8</sup> Copper sulfate, a common footbath treatment, is toxic to digester bacteria.

and get an even better return. One short-term option they are exploring is to use biogas to heat a new shop they are building.

One thing he would do differently is he would have arranged the structures differently to better use their 1.5 million gallon storage lagoon, and to more easily allow for growth of the farm.

Sources.

Gary Boyke – Vir-Clar Farm

Michael Zander – Energies Direct, LLC (formerly Biogas Direct, LLC)

## ***Wild Rose Dairy – La Farge, Wisconsin***

<b>Farm Name:</b>	Wild Rose Dairy	<b>Location:</b>	La Farge
<b>Farm Type:</b>	dairy	<b>Herd Size:</b>	1,050 head (880 milking)
<b>Collection Method:</b>	scrape	<b>Bedding Type:</b>	kiln-dried sawdust
<b>Digester Type:</b>	complete mix	<b>Design Temperature:</b>	125 deg F
<b>Digester Notes:</b>	above ground cylindrical tank, carbon steel		
<b>Design Capacity:</b>	800-1,200 head	<b>Date Operational:</b>	2005
<b>Design HRT:</b>	20 days	<b>Current HRT:</b>	20 days
<b>Design Solids %:</b>	6-8%	<b>Current Solids %:</b>	not available
<b>Biogas Use:</b>	electricity and heat	<b>Utility Contract:</b>	yes
<b>Installed Capacity:</b>	750 kW	<b>Prime Mover Brand:</b>	Waukesha
<b>Solids Separation:</b>	yes, screw press	<b>Solids Use:</b>	sold to dairies and organic farmers (export P)
<b>Ownership:</b>	farm owns digester (designer operates and maintains), utility owns energy generation		
<b>Digester Designer:</b>	Microgy, Inc.	<b>Utility:</b>	Dairyland Power Cooperative

Wild Rose Dairy is a 1,050 head dairy consisting of half Holsteins, and half Jersey/Holstein crossbreeds. The dairy is located in La Farge, Wisconsin, in southeastern Vernon County. They have 880 head milking from which about 33,000 gallons of manure per day is collected for treatment. They use scrape collection three times a day, and use kiln-dried sawdust for bedding. Their previous manure storage system is an earthen basin which now holds the liquid digestate.

### Digester.

Wild Rose Dairy chose to have a Microgy digester installed. Under this business model Microgy installed their digester system on the farm with no cost outlay to the farm. The farmer owns the digester and Microgy operates and maintains it. Dairyland Power Cooperative installed energy generation (using biogas) equipment on the site and buys biogas from the farm. These biogas payments go to Microgy to pay down the farm's debt owed on the digester.

The Microgy system is an above ground carbon steel tank complete-mix digester with a fixed cover. It operates in the thermophilic range with a target temperature of 125 degrees F and an HRT of 20 days. The system is designed to include co-digestion of off-farm high fat food wastes to boost biogas production. About 1,100 gallons of manure mixed with food wastes are batched into the digester hourly. Figure 47 on the following page shows the digester and surrounding structures.

**Figure 47 – Wild Rose Dairy Digester**

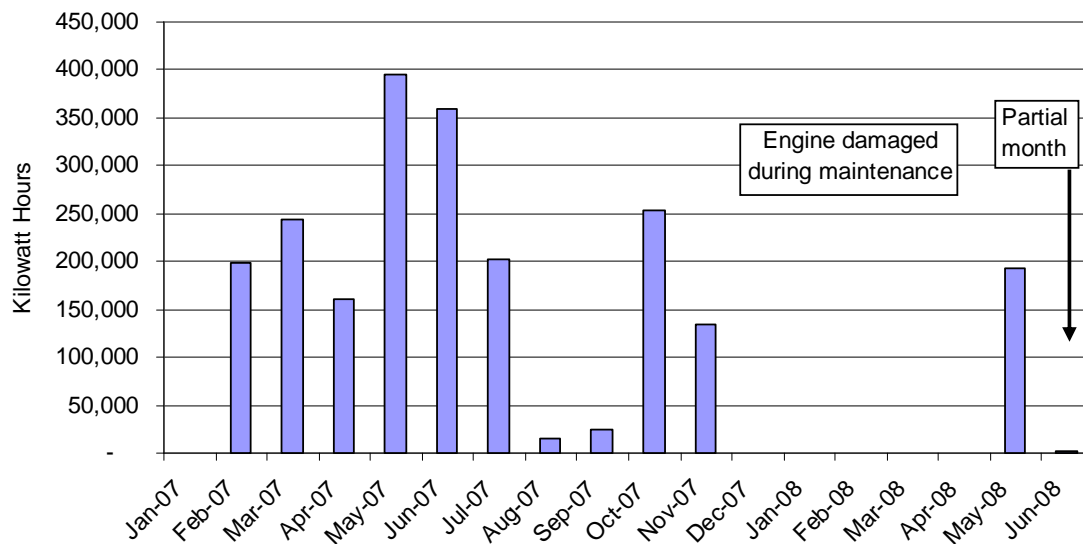


Photo courtesy of Microgy, Inc.

#### Outputs and Uses.

Biogas produced by the digester is treated with a Biothane brand scrubber, water trap and dehumidifier. It is then used to run a Waukesha 750 kW (net) synchronous engine generator set owned, operated and maintained by Dairyland Power Cooperative. Dairyland buys the biogas and owns renewable energy attributes from the electricity generation. Figure 48 shows the electricity generation history for this location.

**Figure 48 – Electricity Generation History for Wild Rose Dairy**



Heat captured from the engine is used for the digester only. They have extra they could use but have not yet made the investment to do so. All recovered heat is pulled off the water jacket. They have a backup furnace that runs on LP.

They separate out solids and sell them for use off the farm. Changes in nutrient management requirements meant they had to reduce P application to their soils and this is how the owners decided to address this. This helps with their nutrient management by giving them some control over P application that would not be there without digestion. They are selling separated solids to other dairies for bedding and to organic farmers for fertilizer at about \$20 per ton. They produce about five tons per day of these digested solids. In contrast, they use about 12.5 tons of sawdust for bedding every week (or nearly 2 tons per day).

#### History and Comments.

Mike Casper of Microgy (Dave Schroeder of Microgy is responsible for on-site maintenance and upkeep of the digester) says they experienced greater variability in biogas output from this system than the other two systems in Wisconsin, and they are still exploring why this occurred. One possible reason is that this system was not consistently being run at full load which may have affected the development and sustenance of bacteria cultures. When run at full loading, the system should have outputs similar to Five Star and Norswiss.

**Figure 49 – Structures and Piping at Wild Rose**

Art Thelen the owner of Wild Rose Dairy says he likes having the digester very much. Microgy did a great job during construction and the start-up went smoothly. They have many tours so people can see what they are doing and how well the animals are being treated. He said “it is only right that the gas be put to use.” He also noted that gas production has been more consistent than electricity generation.

One thing Mr. Thelen said he would do differently if starting over that is he would try to group functions into a smaller number of buildings to avoid having so many small buildings. For instance, he would put all pumps and sensors in one place to use the excess heat. Figure 49 shows some of the structures and piping. They have lots of extra heat year round.



#### Sources.

Art Thelen – Wild Rose Dairy

Mike Casper – Microgy, Inc.

John McWilliams – Dairyland Power Cooperative

### 1. According to Gas Storage

The design of biogas digester may vary accordingly to suit the requirements of the owner. This can be divided into three groups, namely: fixed-digester, floating gas holder and bag digester.

- **Fixed-Dome Digester**

Fixed-dome digester (Figure 9) is the most common type of design. The four major components of the digester which are gas storage, fermentation chambers, hydraulic tank and inlet tanks are integrated into one structure. Its distinct advantage over the other designs are:

1. All concrete construction, hence, durable and life long investment. Simple structure. Least cost.
2. No moving parts and metal components, thus, easy to maintain.
3. Capable of generating higher gas pressure (on the average 10 times higher than floating gas holder type) and does not use floating tank.
4. Completely constructed underground, thus save land space. Input materials flow easily into the digester by gravity, hence simplifying operation.

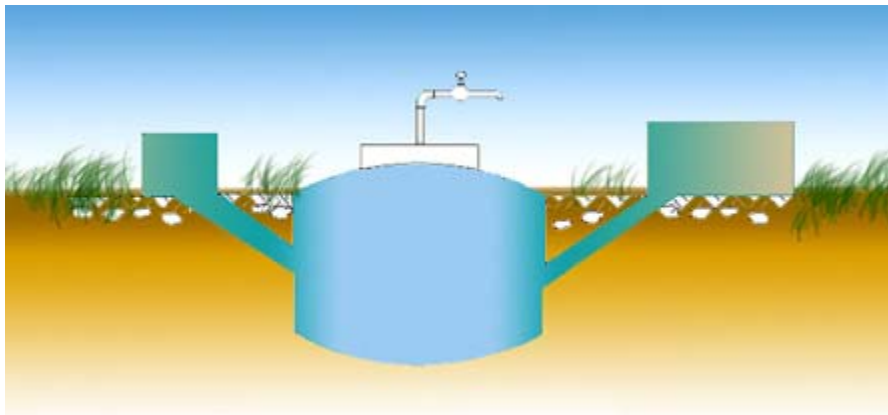


Figure 9. Fixed-Dome Type

- **Floating Gas Holder Digester**

The floating gas holder digester makes use of a floating tank for gas storage. This can be further subdivided into:

1. Top Floating Gas Holder Digester

The floating tank (Figure 10) for gas storage is directly installed on top of the digester. This is usually employed for small size digester.

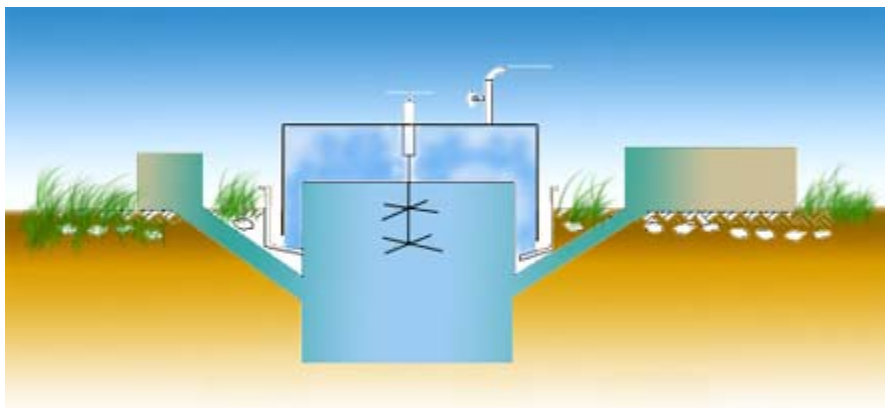


Figure 10. Floating Gas Holder Type Type

## 2. Separate Floating Gas Holder Digester

The application of this style is for medium to large size digester. There are two tanks involved: one is the fermentation tank and the other is the storage tanks.

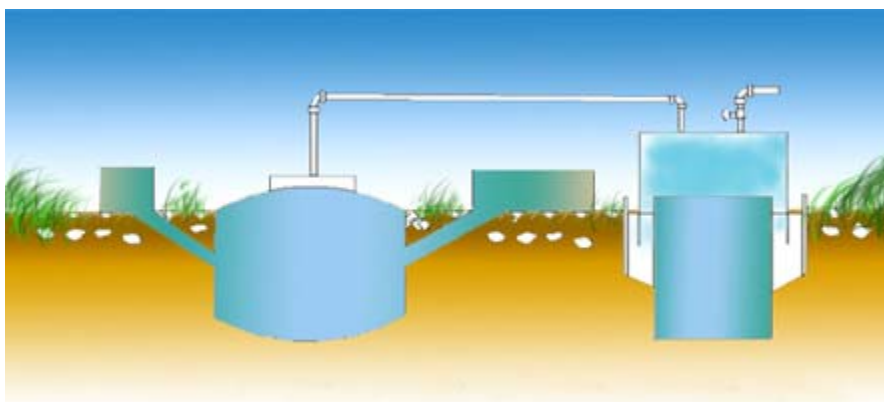


Figure 11. Separate Floating Gas Holder Type Type

- **Bag Digester**

The bag digester (Figure 12) is a type of digester with a separate bag for gas storage.



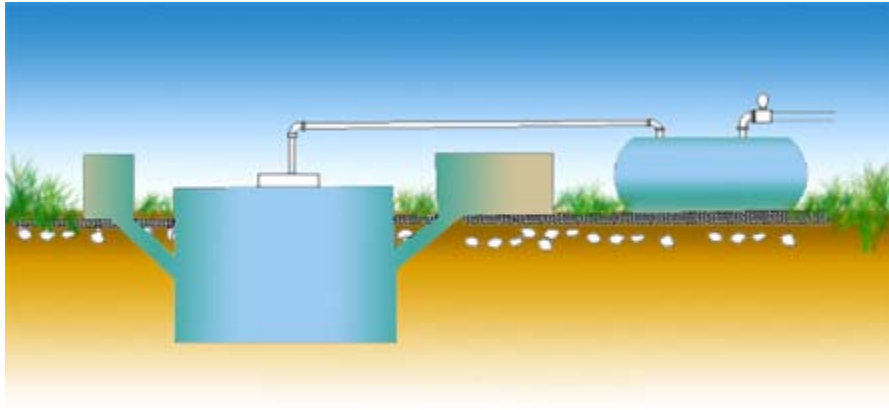


Figure 12. Bag Type Gas Holder

## 2. According to Geometrical Shapes

Biogas digester can be constructed in various geometrical shapes: vertical cylinder, spherical, rectangular, square, pipe-shaped, oval, spindle-shaped, elliptical, arch, oblate, etc.

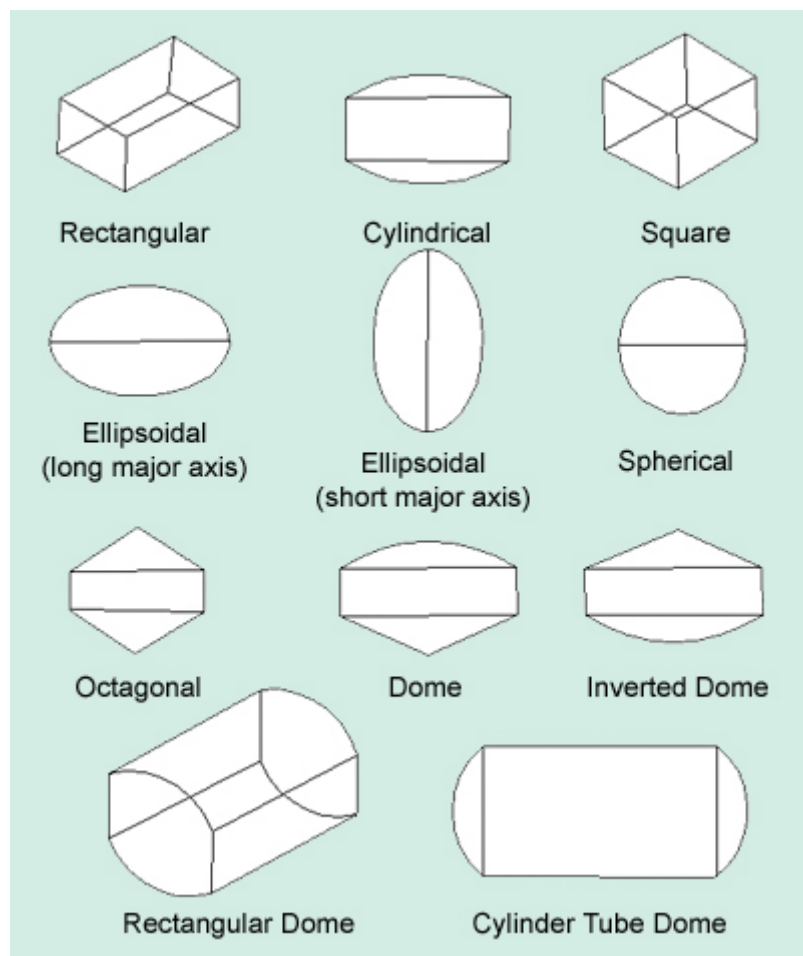
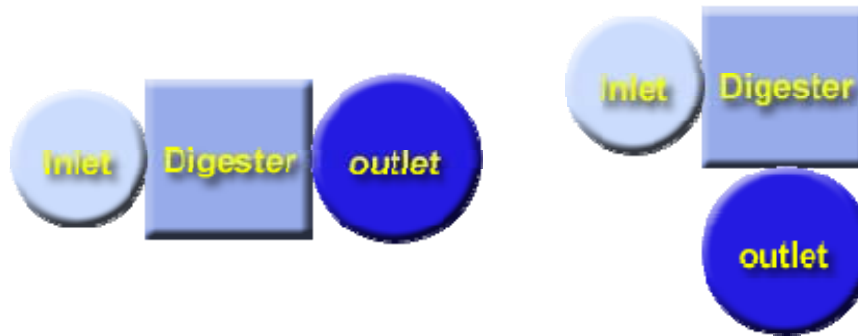


Figure 13. Design according to geometrical shape



### 3. According to Orientations of Inlet and Outlet

The arrangement of the different components of biogas system can be varied according to what is suitable to the condition of the area. The different orientations of inlet and outlet are shown in Figure 13 for design flexibility.



Option 1

Option 2

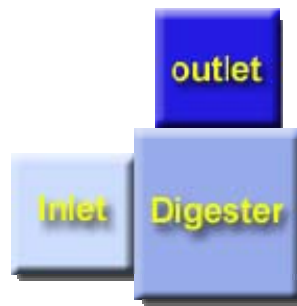


Option 3



Option 4

Option 5



#### Option 6

Figure 14. Design According to Orientations of Inlet and Outlet

#### 4. According to Buried Position

Biogas digesters can be erected either of the following ways:.

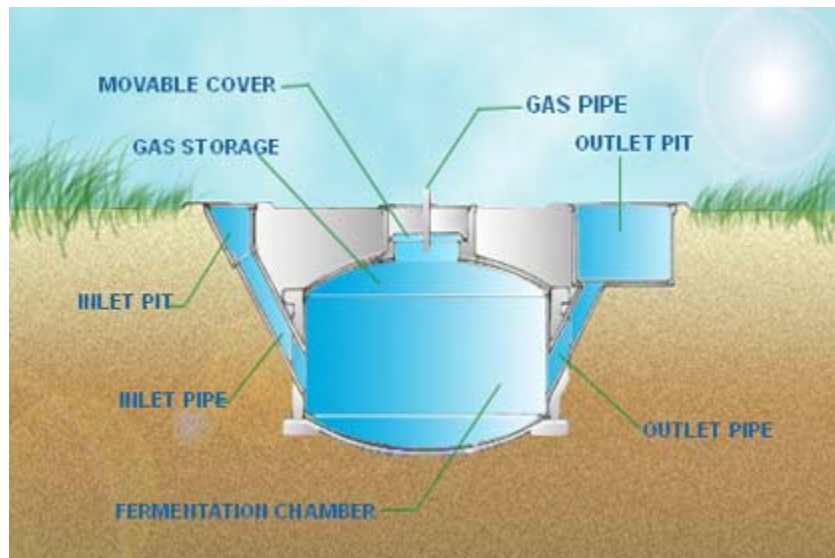


Figure 15. Under-ground digester

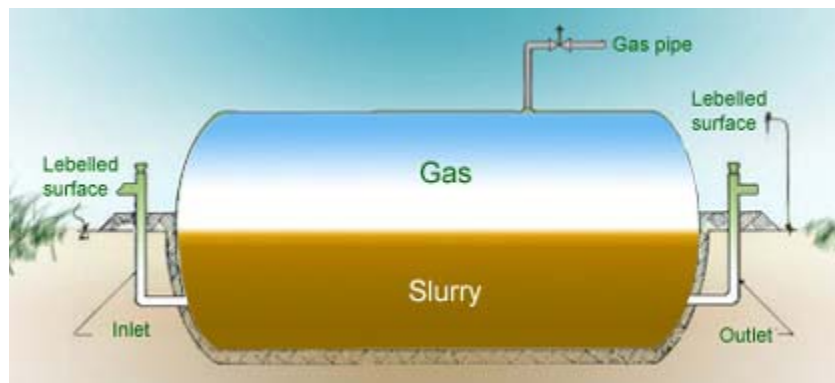


Figure 16. Semi-Buried digester

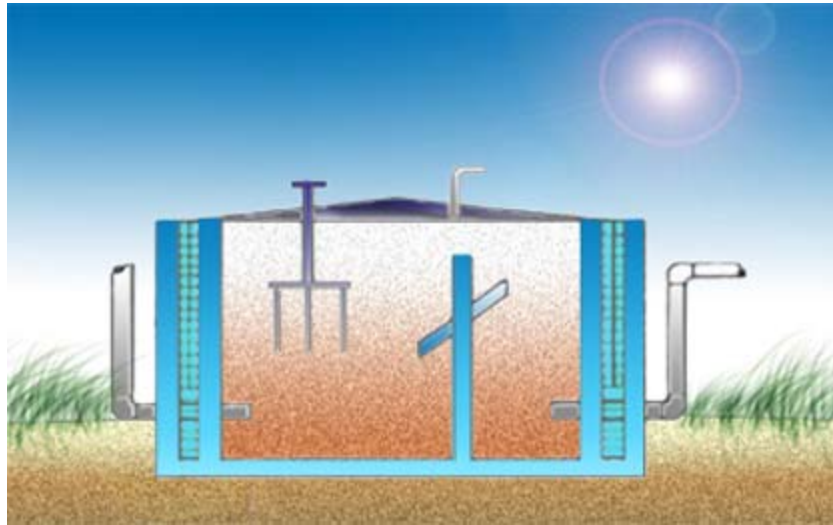


Figure 17. Ground digester

# Bio-gas:

## GP Option for Community Development

Prepared for  
Asian Productivity Organization

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## **Bio-gas: GP Option for Community Development**

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## **CHAPTER 1**

### **Green Productivity Concept and Practices**

#### **1.1 Introduction**

The increase in human need and the explosion of population within the last decade have resulted in severe environmental problems at present. During the last three decades, at least a seven-fold increase in manufacturing output has been estimated. By the middle of next century, an increase of ten folds will be expected. As a result many of the natural resources are depleting. Water resource is one of the major issues in many parts of the world. Scarcity of water and the deterioration of water quality from human use give rise to environmental problems throughout the world. Energy consumption has been increased rapidly through industrial development and increase of domestic demand. The wide spread use of chemicals such as pesticides and fertilizers in agriculture contaminates the environment and also threatens our eco-system. Greenhouse gases, such as carbon dioxides and methane, are produced from industries and burning of energy sources in rural area. Improper waste treatment also produces greenhouse gas through anaerobic process. This causes global warming. Up to early 1960, public awareness on environmental problems was rather low. The later half of the 1960s were a period that concerns on environmental issues became alive. Since 1970, responses and actions from many international agency and many individual countries were initiated to work more on the issues. The depletion in resources has become a major issue at present.

Green Productivity (GP) signifies a new paradigm of socio-economic development aimed at pursuing economic and productivity growth while protecting the environment. The concept of Green Productivity emerged in the early 1990s when people started to realize that emphasizing productivity and economic growth alone may lead to an adverse and irreversible effect on the environment. Solving environmental problems using end-of-pipe technology is not cost effective nor sustainable in the long run. There is a need for developing strategies which are simultaneously productivity enhancing and environmental friendly.

#### **1.2 Concept of Green Productivity**

Green Productivity is a concept of harmonizing the socio-economic development and mechanism of environmental protection. It is the key for enhancing the quality of life of people through sustainable development. Improvement of quality of life is often associated with an increase in demand for goods and services. The increase in productivity will normally deplete natural resources and generate wastes which cause environmental damage. Conventional productivity improvement techniques have not paid due attention to environmental aspects. The environmental cost has been intentionally neglected in the system. Wastes have been counted as valueless. Excessive use of resources or generation of pollution is indicative of low productivity as well as poor environmental performance. GP pursues a strategy based on the technical and managerial interventions to improve the situation.

The definition of Green Productivity is:

***Green Productivity is a strategy for enhancing productivity and environmental performance of overall socio-economic development. It is the application of appropriate techniques, technologies and management systems to produce environmentally compatible goods and services.***

Green Productivity (GP) is applicable not only to the manufacturing sector, but also to the agriculture and services sectors. GP also addresses the interaction between economic activities and community development. Another dimension of GP is the role of the public sector (government and education) in environmental protection and awareness. GP is a stepwise approach and also a process of continuing improvement.

- The first step in this process is to identify ways to prevent pollution or waste at its source, as well as reduce the level of resource inputs by the process of rationalization and optimization. Possibilities of reuse, recovery and recycle are looked into to salvage the wastes generated.
- Next, opportunities for substituting toxic or hazardous substances are explored to reduce the life-cycle impact of the product. At this stage, the product itself is examined, including packaging in the framework of design for environment.
- Finally, the wastes in its residual forms are treated adequately to meet the regulatory requirements both from the perspectives of the workspace and the receiving environment. In order to ensure a continuous improvement in the productivity as well as in the level of environmental protection, a management system is developed, much on the lines of Environmental Management System of ISO 14000 series.

### **1.3 Green Productivity Tool and Techniques**

The basic concept of GP is built around the prevention of wastes and emissions at the point of generation. What cannot be prevented needs to be treated and thus rendered environmentally benign before discharging it to the recipient environmental media. This applies to both materials as well as energy wastes. GP techniques are classified into four categories – waste prevention, energy conservation, pollution control and design of product.

#### **1.3.1 Waste Prevention Techniques**

Waste prevention techniques can be applied to any manufacturing process, agricultural and service sectors. Available techniques range from easy operational changes to state-of-the-art recovery equipment. Waste prevention techniques can be broken down into five major categories: good housekeeping, inventory management, production process modification, volume reduction and recovery. In actual application, waste prevention techniques generally are used in combination so as to achieve maximum effect at the lowest cost. It has been experienced that a careful application of these techniques and a sincere commitment for implementation can lead to reduction in waste generation from 30% to 50% in most cases.

### **a. Good Housekeeping**

Good housekeeping is not limited to keeping the work place clean and eliminating leakages and spillages. It also includes the operational practices involved, especially manual practices and making them more resource efficient. Preparation of recipes in right quantity to avoid surplus, efficient handling of materials, optimum storage procedures to avoid losses and material degradation during storage are illustrative examples of good housekeeping. It has been the experience that in small scale industries, good housekeeping alone could lead to a reduction in waste generation up to 20-25%.

### **b. Inventory Management**

Proper control over raw materials, intermediate products, final products, and the associated waste streams is now being recognized by the industry as an important waste reduction technique. In many cases waste is just out-of-date, off-specification, contaminated, or unnecessary raw material, spill residues, or damaged final products. The cost of disposing of these materials not only includes the actual disposal costs but also the cost of the lost raw materials or products.

There are two basic aspects to inventory management, inventory control and material control.

#### **(i) Inventory Control**

Methods for controlling inventory range from a simple change in ordering procedures to the implementation of just-in-time (JIT) manufacturing techniques. Most of these techniques are well known in the business community. Many companies can help reduce their waste generation by tightening up and expanding current inventory-control programs. This approach will significantly impact the three major sources of waste resulting from improper inventory control: excess, out-of-date, and no-longer-used raw materials. Purchasing only the amount of raw material needed for a production run or a set period of time is one of the keys to proper inventory control.

If surplus inventories do accumulate, steps should first be taken to use the excess material within the plant or company. If this is not successful, then the supplier should be approached to see if it will take the material back. If the supplier won't, the next step is to identify possible users or markets outside the company. Only if this fails should other management options be examined.

#### **(ii) Material Control**

Proper material control procedures will ensure that raw materials will reach the production process without loss through spills, leaks, or contamination. It will also ensure that the material is efficiently handled and used in the production process and does not become waste. Material loss can be greatly reduced through improved process operation, increased maintenance, and additional employee training. Many sources of material loss, such as leaks and spills, can be easily identified and corrected.



### **c. Production Process Modification**

Improving the efficiency of a production process can significantly reduce waste generation. Using this approach can help reduce waste at the source of generation, thus decreasing waste management liability and costs. Available techniques range from eliminating leaks from process equipment to installing state-of-the-art production equipment.

#### **(i) Operational and Maintenance Procedures**

Significant amounts of waste can be reduced through improvements in the way a production process is operated and maintained. Improvements in operation and maintenance usually are relatively simple and cost-effective. Most of the techniques are not new or unknown.

*Operational procedures.* A wide range of methods are available to operate a production process at peak efficiency. Improved operation procedures optimize the use of raw materials in the production process. Most production processes, no matter how long they have been in operation or how well they are running, can be operated more efficiently. Some process steps may in fact be unnecessary, and eliminating them will reduce waste generation. Once proper operating procedures have been established they must be fully documented and be part of the employee training program. A comprehensive training program is a key element of any effective waste reduction program.

*Maintenance program.* About one-fourth to one-half of the excess waste load is due to poor maintenance. A strict maintenance program which stresses corrective and preventive maintenance can reduce waste generation caused by equipment failure. Such a program can help spot potential sources of waste and correct a problem before any material is lost.

#### **(ii) Material Change**

The manufacturing sector usually use the most cost benefit input raw materials in the production process without considering environmental aspects. Thus, highly toxic and hazardous chemicals came into use. Hazardous material used in either a product formulation or in a production process may be replaced with a less hazardous or non-hazardous material. Reformulating a product to contain less hazardous material should reduce the amount of hazardous waste generated during both the product's formulation and its end use. Using a less hazardous material in a production process will generally reduce the amount of hazardous waste produced.

#### **(iii) Process Equipment Modification**

Waste generation may be reduced by installing more efficient process equipment or modifying existing equipment to take advantage of better production techniques. New or updated equipment can use process materials more efficiently, producing less waste. Higher-efficiency systems may also reduce the number of rejected or off-specification products, thereby reducing the amount of material which has to be reworked or disposed of.

Modifying existing process equipment can be a very cost-effective method for reducing waste generation. In many cases, the modifications can just be relatively simple and inexpensive changes in the way the materials are handled within the process to ensure that they are not

wasted or lost. Process modifications and improved operational procedures can be used together to reduce waste.

#### **d. Volume Reduction**

Volume reduction includes techniques to separate hazardous wastes and recoverable wastes from the total waste stream. These techniques are usually used to increase recoverability, reduce the volume and thus the disposal costs, or increase management options. These techniques can be divided into two general areas, source segregation and waste concentration.

##### **(i) Source Segregation**

Segregation of wastes is a simple and economical technique for waste reduction. By segregating wastes at the source of generation and handling the hazardous and non-hazardous wastes separately, waste volume and thus management costs can be reduced. The uncontaminated or undiluted wastes may be reusable in the production process or may be sent off site for recovery. The segregation technique is applicable to a wide variety of waste streams and industries and usually involves simple changes in operational procedures.

##### **(ii) Concentration**

Various techniques are available to reduce the volume of a waste through physical treatment. Such techniques usually remove a portion of a waste, such as water. Concentration techniques are commonly used to dewater wastewater treatment sludges and reduce the volume by as much as 90 percent. Unless a material can be recycled, just concentrating a waste so that more waste can fit into a drum is not waste reduction. In some cases, concentration of a waste stream may also increase the likelihood that the material can be reused or recycled.

#### **e. Recovery**

Recovering wastes can provide a very cost-effective waste management alternative. This technique can help eliminate waste disposal costs, reduce raw material costs, and possibly provide income from a salable waste. Recovery of wastes is a widely used practice in many manufacturing processes and can be done on site or at an off-site facility.

##### **(i) On-Site Recovery**

The best place to recover process wastes is within the production facility. Waste can be most efficiently recovered at the point of generation, because the possibility of contamination with other waste materials is reduced. Other waste streams can be reused directly in the original production process as raw material. Some waste may have to undergo certain type of purification before it can be reused. A number of physical and chemical techniques available on the market can be used to reclaim the waste material. These techniques range from simple filtration to state-of-the-art techniques such as distillation. The method of choice will depend on the physical and chemical characteristics of the waste stream recovery economics, as well as on operational requirements.

Most on-site recovery systems will generate some type of residue. This residue can either be processed for further recovery or properly disposed of.

### (ii) *Off-Site Recovery*

Wastes may be recovered at an off-site facility when (1) the equipment is not available to recover on site, (2) not enough waste is generated to make an in-plant system cost-effective, or (3) the recovered material cannot be reused in the production process. Off-site recovery usually entails recovering a valuable portion of the waste through chemical or physical processes or directly using the waste as a substitute for virgin material. Wastes directly used are usually chemically or physically specific for a selected purpose, and can range from concentrated acids to chemical by-product streams.

The cost of off-site recycling will depend on the purity of the waste and the market for the waste or recovered material. Some materials may be salable, while others may require a fee to be paid for disposal. The markets for some wastes are very volatile, and a waste material which has a value one day may have none the next.

## 1.3.2 Energy Conservation Techniques

Production facilities consume energy basically in two different forms: electricity and process heat. Combustion of fossil fuels in primary heat sources such as boilers or fired heaters provides a major source of heat input to industrial processes. Nearly all energy used in most manufacturing facilities is generated by processes that consume materials and generate pollutants (gaseous, liquid and solid) which pollute the environment if released directly. Any action that conserves energy would reduce the quantity of pollutants from energy-generating processes. On the other hand, actions that reduce pollutants would lower the expenditure of waste handling and treatment.

Combustion of fossil fuels in primary heat sources such as boilers or heaters provides a major source of heat input to industrial processes. Thermal energy can be conserved by taking care to prevent its loss during transport from the combustion site to the specific processes where it is used. Table 1.1 lists some measures that can be taken to conserve thermal energy as it is transported and used. It may also be possible to recover and use heat generated by production processes. Production facilities consume enormous amounts of electricity in both their production processes and the operation of their facilities. Table 1.1 lists several ways to conserve electricity.

Table 1.1. Example Approaches That Conserve Thermal and Electrical Energy

Thermal Energy Conservation	Electrical Energy Conservation
<ul style="list-style-type: none"> <li>• Adjust burners for optimal air/fuel ratio.</li> <li>• Improve or increase insulation on heating or cooling lines.</li> <li>• Institute regular maintenance to reduce leakage and stop steam trap bypass.</li> <li>• Improve the thermodynamic efficiency of the process using options such as:</li> </ul>	<ul style="list-style-type: none"> <li>• Implement housekeeping measures such as turning off equipment and lights when not in use.</li> <li>• Place cool air intakes and air-conditioning units in cool, shaded locations.</li> <li>• Use more efficient heating and refrigeration units.</li> </ul>

<ul style="list-style-type: none"> <li>* Using condensers or regenerative heat exchangers to recapture heat</li> <li>* Using heat pumps or similar equipment to recover heat at distillation column</li> <li>* Using more efficient heat exchangers</li> <li>• Co-generating heat and electricity.</li> </ul>	<ul style="list-style-type: none"> <li>• Eliminate leaks in compressed air supply lines.</li> <li>• Use more efficient motors.</li> <li>• Improve lubrication practices for motor driven equipment</li> <li>• Use efficient power transfer belts.</li> <li>• Use fluorescent lights and low wattage lamps or ballast.</li> <li>• Install timers and thermostats to better control heating and cooling.</li> </ul>
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Source: USEPA 1992

### 1.3.3 End-of-pipe Treatment Technology

Whether waste is land disposed, emitted into the air or discharged to surface waters, all waste generators can strive to reduce waste generation to the point where treatment and subsequent disposal in the environment is avoided. However, for some processes, waste generation is inevitable. These wastes which cannot be eliminated, reduced, recycled or reused must be treated and disposed of within all applicable environmental regulations. Appropriate treatment does not include the transfer pollutants to other environmental media, or dilution as a means for meeting environmental regulations.

### 1.3.4 Designing Environmental Compatible Product

Environmentally compatible products minimize the adverse effects on the environment resulting from their manufacture, use, and disposal. The environmental impact of a product is to a large extent determined during its design phase. By taking environmental considerations into account during product planning, design, and development, a company can minimize the negative impact of its products on the environment.

Design changes made to prevent pollution should be implemented in such a manner that the quality or function of the product is not affected adversely. Design for the environment can be achieved by the people directly involved, within the framework of company policy and with support from company management, whether or not in response to incentive external to the company.

*Product Conservation.* Product conservation refers to the way in which an end product is used. For example, better maintenance of process equipment and components by industry can decrease the frequency of equipment component replacement, which in turn reduces the waste generated by the used component.

*Product Design Changes.* Product design changes involve manufacturing a product with a lower composition of hazardous substances, or less toxic materials being formed, or changing the composition so that no hazardous substances are involved

The goals of new product design can be reformulation and a rearrangement of product requirements to incorporate environmental considerations. For example, the new product can be made out of renewable resources, have an energy-efficient manufacturing process, have a

long life, be non-toxic, and be easy to reuse or recycle. In the design of a new product, these environmental considerations can become an integral part of the program of requirements.

## 1.4 Green Productivity Methodology

For an effective Green Productivity Program, it is important to bring all stake holders together to ensure identification and implementation of maximum opportunities. A step by step procedure ensures exploitation of maximum Green Productivity opportunities. A typical Green Productivity Assessment Methodology is described as follows:

The methodology consists of 13 tasks divided into 6 steps. The main steps are:

<i>Step I</i>	<i>Get started</i>
<i>Step II</i>	<i>Planning</i>
<i>Step III</i>	<i>Generation and evaluation of GP options</i>
<i>Step IV</i>	<i>Implementation of Options</i>
<i>Step V</i>	<i>Monitoring and Review</i>
<i>Step VI</i>	<i>Sustaining Green Productivity</i>

Figure 1.1 shows the flow chart of GP methodology.

### Step I Get Started

This step consists of the following 2 tasks, namely team formation and walk through survey.

#### ***Task 1 - Green Productivity Team Formation***

The first task in a Green Productivity program is to form a GP team. The GP team would co-ordinate the entire program, be responsible for identification of various GP measures, get them implemented and bear the overall responsibility. The GP team should be made up of representatives of group that will have interest in the results of the program. To the extent as possible, all the stakeholders should be represented in the team. The composition of the team would ultimately depend on the organizational structure and the requirements of the program. Inclusion of external experts helps in creativity and looking at the possible opportunities from a different perspective. The GP team should be capable of identifying potential areas, developing solutions and facilitating their implementation. For continuity and sustainability of the GP program, an in-house team is more desirable than a fully external team.

#### ***Task 2 - Walk through Survey and Information Collection***

GP team should familiarize itself with the manufacturing process including utilities, waste treatment and disposal facilities. A walk through survey would allow the team to identify and list all process steps. *Process diagram*, initial layout (*for eco-mapping*), drainage system, vents and other material/energy loss area should be prepared and identified. Special attention must be paid to periodic and intermittent waste generating steps as these often tend to be overlooked. House keeping practices should be observed and take note of obvious lapses. The GP team should prepare a preliminary list of waste generating operations, including a gross estimation of waste generate from different process steps. The possibility of waste prevention and control should be noted. Special attention should be paid to steps that generate toxic and

hazardous wastes. If a facilitator, who is not familiar with the operations of the organization, is involved in the GP exercise, the facilitator should gather general information about the organization, such as the number of employees in the organization and physical size of the factory or farm.

The above 2 tasks would help in selecting the first focus area for Green Productivity. Normally in larger premises, it would be desirable to focus on a smaller area so that the assessment can be completed fast and the results can also be shown at an early date. This help in generating and sustaining interest in the organization. Too wide a focus complicates the assessment and is time consuming.

Following the walk through survey, the team would have to gather detailed information of the organization. Information necessary for further evaluation such as detail process, flowchart, physical plant information, management structure, cost of purchasing raw materials, amount of raw materials purchased including energy use, should be gathering from concerned departments/sections. Detailed flow chart need to be prepared for further investigation and material balance step.

Technical information needed for further evaluation such as water use, waste generated, energy use, raw material use including existing waste treatment facilities should be collected. In case where no information is available in the plant, a practical survey and measurement should be performed to obtain the data. All the inputs and outputs of waste stream and emission should be identified and quantified. Special care needs to be taken of the recycle streams. Free and low cost inputs like water and air should be highlighted as these often tend to be neglected in production cost accounting but end up being the major source and cause of waste. Existing waste treatment facilities should be evaluated whether they conformed to legislative discharge limits and are operated within the designed condition. The periodic/batch/intermittent steps should be carefully highlighted. The GP team should also specify the items that do not appear in the usual input/output streams such as catalysts and coolant oil.

*Material/Energy balance* is important for any GP assessment since it enables identification and quantification of wastes and emissions. It provides information for ascertaining the cost of waste streams and thereby helps in monetary quantification of the loss. The balance also serves as a baseline data for evaluating the GP options and monitoring/comparing the advances made in the course of implementation of a GP program. Typical components of a material balance are given below.

<b>Input</b>	<b>Output</b>
Raw materials	Products
Catalyst	Gaseous emissions
Water	By-products including wastes for recovery
Air	Waste water and other liquid waste
Recycled materials	Solid waste for storage and/or disposal

Typical components of the energy balance are given below.

<b>Input</b>	<b>Output</b>
Electrical energy	Radiation loss
Steam	Energy in vapors and gases
Energy in raw materials	Energy in hot products
Condensation	Energy in hot residue
Cooling water	Energy in cooling water

Several factors should be considered while constructing the material/energy balance. The precision of data and flow measurement is essential. Time span is also important. Material balance constructed over too long a time period does not show the short term variations. On the other hand, material balance made over shorter time span requires repetitive and more accurate monitoring data to make the balance representative. Consistency of measurement units is another factor that needs to be taken care of. Making an energy balance is tougher than a material balance due to the fact that it requires more complex measurement systems and also because of its invisible nature.

## **Step II      Planning**

### ***Task 3 - Identification of Problems and Their Causes***

Problems concerning process efficiency, waste generation, energy loss should be identified and characterized at this step. Process inefficiency should be determined in order to be improved (if any) for higher productivity. The problems in materials and energy loss could be identified through material/energy balance. The waste streams could be in all 3 media i.e. solid, liquid and gaseous. It is now important to characterize these streams in terms of their constituents. To the extent possible, generic characterization such as BOD for organic pollution load should be avoided, as it does not throw open the possibilities of reduction and recycle. Characterization in terms of actual constituents is always more useful. It would also be a good idea to assign some sort of priority to the waste streams in terms of quantity, toxicity, possibility of recovery/recycle etc. Energy balance should reflect the areas where energy loss takes places. Only energy loss areas which are discrete, measurable and workable need to be identified e.g. energy loss due to friction between bearing and shaft need not be worked upon as it is not possible to recover and reuse this energy. Typical energy loss areas are heat loss in solid/liquid/gaseous streams, electrical energy loss due to under loading, excessive lighting and heat loss by radiation.

The cause analysis of problems identified can now be carried out. This analysis involves locating and pinpointing the causes of waste generation and energy loss. There could be a wide range of causes for waste generation and energy loss ranging from simple lapses in housekeeping to complex technological reasons. Quite often, each identified problem would have more than one cause and similarly the same cause might be applicable to more than one problem. The generic causes such as poor process control, improper design etc. should be avoided, as it does not lead to specific GP option development. Cause analysis should be specific and to the point. The use of the *Cause and Effect (Fishbone) diagram* would assist in identifying root cause of problems. Here, problems can often be traced to 5 main categories of causes, namely, Man, Machine, Material, Method and Environment. Holding

*brainstorming* sessions often leads to excellent cause analysis. The brainstorming should not be limited to people belonging to the area of concern as the causes could have been extended beyond these areas. The principles of good brainstorming should be followed.

#### ***Task 4 – Set Objectives and Targets***

Once the concerns are identified and prioritized, it is necessary to set objectives and targets. Objectives should be based on concerns identified. One objective can have multiple targets, which could be phased over time. Targets should be developed based on the need. For example, if legal compliance is to be sought within one year, then the target for an objective which addresses a compliance parameter should be set for one year.

Targets should be decided with an anticipatory perspective. For example, if a certain objective is to be sought within 2 years, it should be investigated whether the objective will be completely achieved in that time frame. It is possible sometimes that the value of concerns also might have changed in the 2 years, which would necessitate setting of another target in the future.

Step II should end in a list of identified problems and their causes in the selected focus area and objectives and targets which the organization will be working towards.

### **Step III      Generation and Evaluation of GP Options**

This is the most creative step in the entire GP assessment process. The efforts put in so far would now be made use of for determining problems solving options. The step consists of 3 tasks namely, development of GP options, preliminary screening and evaluation of options, and formulation of an implementation plan for the selected options.

#### ***Task 5 – Generation of GP Options***

The most significant task in entire GP methodology relates to the development of GP options. These options emerge directly from the cause analysis carried out earlier. This is the most creative phase of the GP Assessment Process as the GP team ready with data should now look for possible methods of reducing waste. Finding waste prevention options depends on the knowledge and creativity of its members, their education, work experience and facilitating resources. Resources such as personnel from the same or similar plant elsewhere, trade associations, success cases tried elsewhere, specialist organizations including R & D institutions, equipment suppliers and consultants could be sought. The process of finding waste prevention options should take place in an environment which stimulates creativity and independent thinking. Use of techniques like brain storming and group discussions are very helpful in generating and better ideas. Members of the GP team may also source information on the internet, books or other published literature.

#### ***Task 6 - Preliminary Screening of Options***

Under the earlier task, a list is prepared for all possible GP options that emerge in the brain storming or group discussion system. The first shifting of the workable options is now available. The options are distributed under 3 categories namely “option, which are directly implemented”, “options requiring further analysis” and “rejected options”. This



categorization should be done based on very simple and quick assessment. In case of any doubt, the option should be put into the middle category. The weeding out process should be simple, fast and straightforward and may often be only qualitative.

The options, which are placed in the first category of directly implemented options, should be taken up for implementation immediately. Options falling into the third category would be shelved for the time being. The remaining options falling into the second category would now be subjected to a more detailed feasibility analysis.

*a. Assessment of technical feasibility*

The technical evaluation determines whether the proposed option is technically workable under the given conditions. A typical checklist for technical evaluation should consist of

- Availability of hardware/technology
- Availability of operating skills
- Availability of space
- Effect on production
- Effect on product quality
- Safety aspects
- Maintenance requirements
- Effect on operational flexibility
- Shut down requirements for implementation

*b. Assessment of economic viability*

Economic viability is often the key parameter for promoting or discussing implementation of waste prevention options. For a smooth take off and for sustaining interest in the entire GP program, it is essential that the first few options should be economically very attractive. Such a strategy generates more interest and commitment. Options requiring small investment but involving more procedural changes like housekeeping measures, operational improvements, and process control measures, do not require intensive economic analysis and simple methods like '*pay back period*' could be used. However, as the measures become more involved and capital intensive, methods like *internal rate of return (IRR)* or *Net Present Value (NPV)* need to be adopted to get a complete picture. While doing the economic assessment, the "cost" may include fixed capital cost i.e., cost of the hardware, shutdown cost and O&M cost. The "savings" may consist of savings of input material/energy, profit due to higher production levels, lower O&M cost, value of by-products, reduction in environmental cost such as waste treatment, transportation and disposal cost.

*c. Evaluation of environmental aspects*

The waste prevention options need to be analyzed with respect to their impacts on the environment. In many cases, the environment benefit is obvious - reduction in toxicity and/or quantity of waste. The other impacts be improved treatability of waste, changes in applicability of environmental regulations and applicability of simple End-of Pipe pollution control systems.

Initially the environmental aspects may not appear to be as important as technical and economical aspects. However, with increasing pressures from different customers, it is expected that, in due course, environmental evaluation may well become the most important criteria for selection of waste prevention solutions.

After technical, economic and environmental considerations, it is often difficult to decide which option should be taken up for implementation. A *rating matrix* helps in combining the results of three evaluations. Each aspect is given a weight as determined and agreed upon by the management. Each option is then assessed in the context of the given weight for each of the aspect. The sum of these marks would determine the ranking of options with regards to priority of implementation.

### ***Task 7 – Formulation of GP Implementation Plan***

The preparation for implementing waste prevention solutions requires arranging finances, technical preparation and establishing linkages with other departments. Support and cooperation of concerned persons has to be ensured. Checklists of tasks involved, agencies/departments to be approached provide good help. The implementation plan should cover a detailed activity plan, the inputs (including manpower and financial inputs), required time frame and the persons responsible for implementation. For implementation of any GP option, it is required to know the following :

Location / point of application of the option

Nature of the option

Resources necessary

Personnel necessary

Whether production or activity at or near the point of application of the option is to be stopped, altered or relocated.

Responsibility matrix and task allocation in teams

Details on cost requirements, when, how much sourcing of funds

Milestones to be set in the implementation sequence.

Step III should result in a prioritized list of GP options and its implementation plan.

### **Step IV                      Implementation of GP option**

#### ***Task 8 – Implementation of Selected Options***

The implementation of waste prevention solutions is similar to any other industrial modification. The task comprises preparation of drawings, ordering and procurement of equipment, transportation of the same to the site, installation and commissioning. Whenever required, simultaneous training of manpower should not be missed out as an excellent measure may fail miserably if not backed up by adequately trained people.

#### ***Task 9 – Training, Awareness Building and Develop Competence***

Depending on the nature of the GP options, the staff of the organizations will have to be trained for installation operation and maintenance of the GP option.

This step should result in a number of successfully implemented waste prevention solutions. Quite often, this step is the most time consuming step as the implementation is the single largest time consuming activity.

## **Step V            Monitoring and Review**

After implementation, it is important to continually monitor and evaluate the appropriateness of the options employed. The results have to be reviewed by the management.

### ***Task 10 - Monitoring and Evaluation of Results***

The performance of the options implemented should be monitored to compare the actual results with the expected ones. In case of any deviation, the cause needs to be determined and appropriate modifications, if required, should be carried out. The implementation job would be considered as completed only after sustained performance is recorded over a reasonable period of time.

### ***Task 11 – Management Review***

Post implementation review by management involves checking whether the overall GP program is proceeding in the right direction and whether targets are being achieved as per implementation plan.

## **Step VI            Sustaining Green Productivity**

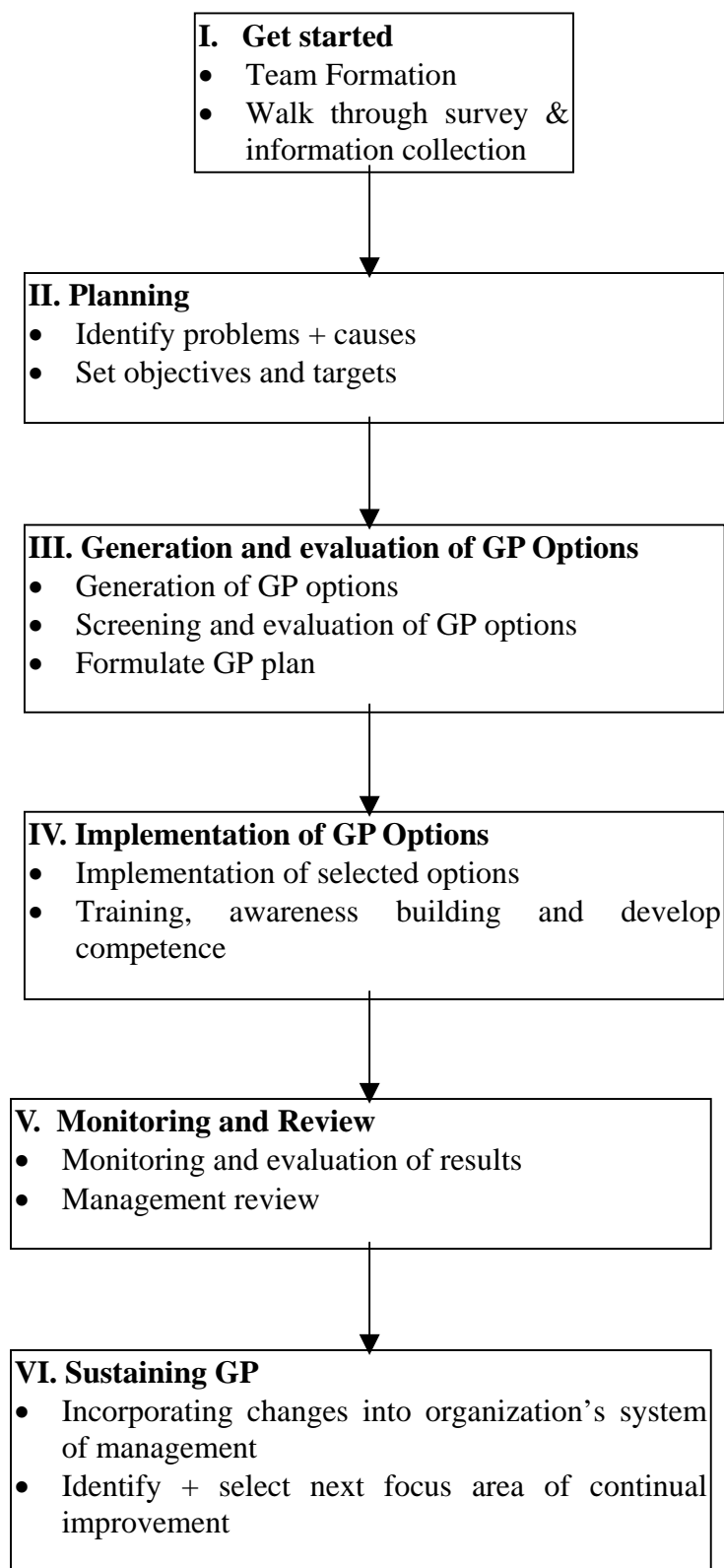
The biggest challenge in Green Productivity lies in its sustainability, otherwise, the euphoria of the program dies out very soon and the situation returns to where it started. The zeal and tempo of the GP Team will also wane off backing out from commitment. Absence of rewards and appreciation for performers, shifting priorities are some of the commonly encountered reasons for such a project end of a Green Productivity program.

### ***Task 12 – Incorporate Changes into the Organization's System of Management***

Green Productivity would not sustain in isolation. It should be integrated to become a part of day to day management practices. The GP team should establish a system for sustaining the implemented solutions, simultaneous development and implementation of ISO 14000 Environmental Management System would help in providing a structured system integrated with the basic management system.

### ***Task 13 - Identify and Select Next Focus Area***

The entire methodology can now be repeated for the second focus area. By the time one full cycle is completed, there would be fresh opportunities of waste prevention in the first focus area and the whole cycle could similarly be repeated. Green Productivity would, therefore, never end. It is a continuous process and would go on forever.



**Figure 1.1 Flow Chart of GP Methodology**

## CHAPTER 2

### An Overview of Green Productivity for Community Development

#### 2.1 Introduction

As mentioned in the previous chapter, GP is also applicable to non-industrial sectors. Community Development is one of the other sector which GP could be applied. At present, about 80% of the population in developing countries are living in rural area. In many developing countries, this group of people contributes to the major economic development of the countries. Agriculture, and small-scale agro-industry are the major activities in rural area. Apart from these income driven activities, other supporting activities such as small-scale animal farming, solid waste generation, farm residue and water supply are also major factors influencing the way of life of the people. The pressure of rapid population growth, and conventional farming methods are causing degradation of the environment and depletion of natural resources. Agricultural activities may produce wastes and generate hazardous residues in products and the environment. Farmers have been using all kinds of pesticides, herbicides, chemical fertilizers for total productivity enhancement without considering environmental and health impacts. Safe water supply and proper sanitation are not adequate in many developing countries. Human and animal waste creates health impacts in the rural area. Agricultural, water, forestry and environmental concerns have an impact on land use in rural communities.

In order to alleviate environmental problems, long term improvement of living conditions of the rural population should be planned. In many developing countries, the government has put a lot of efforts in assisting rural community development. The assistants are normally:

- To develop the ability of local officials to manage their own problems and find cost-effective solutions.
- To increase the visibility of rural community concerns in drinking water, wastewater and solid waste.
- To provide environmental education to rural public.
- To assist the communities in achieving compliance of their drinking water and wastewater systems

GP could be an useful strategy to improve living standard of the community.

#### 2.2 GP for Community Development

There are 5 important categories in community development especially in the rural area of developing countries.

*Increased use of the skills, knowledge and ability of local people:* Local people are the basis for community success. Ongoing improvements in skills and knowledge of a community's residents help build rural community progress.

*Strengthened relationships and communication:* Community efforts benefit when everyone has a voice, when all voices are encouraged and when residents understand the means to express their idea. Relationships with other communities and organizations are helpful for their own development.

*Improved community initiative, responsibility and adaptability.* A community that is responsible for its own future, makes change when conditions or assumptions change, monitors and documents the results of its action, learns from its experience, can become more resilient, more capable of adapting to change and can sustain itself over time.

*Sustainable, healthy ecosystems with multiple community benefits.* Human communities are part of natural ecosystems. They should plan and act in concert with nature.

*Appropriately diverse and healthy economies:* Vital economies deploy financial, natural and human resources to create, maintain and improve local livelihoods. In healthy economies, community residents move toward self-sufficient and prosperity.

Successful communities focus on outcome. Planning starts from where a community wants to go. Once that is clear (often in a vision or mission statement which states specific outcome), alternative ways of getting there can be considered (outputs). The actions (activities) necessary to achieve the various outputs can be considered. Finally, the inputs of time, skills, technical assistance, equipment, space and finance can be calculated. If the actions to get to an output that lead to an outcome are too costly, then another output that leads to the same outcome can be considered. This is a typical strategic planning activity, which builds on the Total Quality Management literature, which focuses on results.

GP could be a powerful strategy in community development.

### **2.3 GP Methodology in Community Development**

Green Productivity methodology for community development could be derived from the general GP methodology as shown in details in Chapter 1. There are 6 steps of GP methodology as follows:

<i>Step I</i>	<i>Get started</i>
<i>Step II</i>	<i>Planning</i>
<i>Step III</i>	<i>Generation and evaluation of GP options</i>
<i>Step IV</i>	<i>Implementation of Options</i>
<i>Step V</i>	<i>Monitoring and Review</i>
<i>Step VI</i>	<i>Sustaining Green Productivity</i>

#### **Step I      Getting started**

This step consists of the following 2 tasks, namely team formation and walk through survey.

### ***Task 1 - Green Productivity Team Formation***

GP team in community development will be responsible for coordinating the entire GP program. The team needs to be responsible for the implementation of GP options generated from their activities. The GP team should be made up of representatives of group that will have interest in the results of the program. To the extent as possible, all the stakeholders should be represented in the team. GP team should comprise the following parties:

- Community leaders
- Local government officers
- Federal or Central government officers
- NGOs' representatives
- Academia
- Private sectors
- Consultants (if needed)

### ***Task 2 - Walk through Survey and Information Collection***

A walk through survey would allow the team to prepare themselves in understanding the real situation of the community. Information on environmental situation, physical infrastructure, socio-economic status of the communities should be collected for further analysis. The walk through survey could be performed using video camera, photograph and hand note. Problems in water supply, waste, agricultural condition, sanitation, and household industries should be studied.

Following the walk through survey, information concerning the community should be collected. Useful information in the community such as socio-economic information (Population, income, health, occupations etc) should be collected. Infrastructure and services such as water supply, waste management, and agriculture within the community should be studied. Detailed studies in infrastructure, which will be useful for GP are:

#### **Water Supply**

- Water sources, quantity and quality
- Water demand
- Water use in the community
- Problems

#### **Waste**

- Generation of waste in the community
- Management of waste in the community
- Problems generated from waste

#### **Agriculture**

- Types and kinds of agricultural products
- Amount of pest control and fertilizer used
- Problems generated from agricultural sector

The following questions should be answered during information collection:

What kind of water sources do the community use?

- Surface water
- Groundwater
- Rainwater
- How much water is available for community uses.

How is the water quality of water sources?

- Chemical analysis
- Physical analysis
- Biological analysis

Is the water suitable for consumption?

How much do the community need water for their consumption?

- At present
- In the future

Compare their demand to other places?

What kind of waste generated in the community?

- Wastewater
- Solid waste
- Air pollution

Amount of waste generated?

- Wastewater, m<sup>3</sup>/d, m<sup>3</sup>/year, m<sup>3</sup>/person-d
- Solid waste, m<sup>3</sup>/d, ton/d, gram/person-d
- Air pollution, smoke, dust etc.

Characteristic of waste?

- BOD, COD
- Toxicity
- Type

What kind of agricultural products, amount produce in the community?

- Rice
- Vegetables
- Fruits
- Animal husbandry

Consumption, locally or regionally?

Marketing potential?

What kinds and amount of pesticides are being used?

What kinds and amount of fertilizers are being used?

Are other alternatives available?

Compare to other areas?



These data will be the background information for further analysis.

## **Step II            Planning**

### ***Task 3 - Identification of Problems and Their Causes***

Problems concerning water supply, wastes generated, and agricultural activities should be identified. Problems to be identified depend mainly on the community standard of living, cultural background, and to a certain extent physical condition of the community. Similar situation from different communities may identify different problems. However, the consensus of the GP team should be important. A brain storming session among GP team should be organized to identify problems within the community. In order to identify problems many questions among the environmental activities need to be addressed. They are as follows:

- Do the community use too much water in their daily live?
- Are there enough water sources in the area?
- Do they have any alternatives in obtaining water from some where else?
- Does water quality suitable for consumption?
- Does water quality in natural sources suitable for recreation?
- Is water pollution a problem in the community?
- Do water treatment facilities suitable in treating water from the sources?
- Is there enough financial available for operation and maintenance?
- Is too much waste generated compare to other communities?
- Do they have proper waste management in the community?
- Do community have enough personnel, financial availability and appropriate technology within its reach?
- Do agricultural products meet consumption need?
- Did we use too much pesticide, herbicide, fertilizer etc?

There may be a lot more questions to be asked to understand the problems in the community. After a period of brainstorming, a number of problems will be identified. The next step is to group these problems into a common cause of problem. Later, cause analysis could be done. The cause analysis could be performed using Ishikawa diagram or Fish Bone diagram. This technique will lead the GP team to root causes of the problems.

### ***Task 4 – Set Objectives and Targets***

Once the problems are identified and prioritized, it is necessary to set objectives and targets to solve the concerned problem. One objective can have multiple targets, which could be phased over time. Targets should be developed based on the need of the community. For example, if water supply is the major issue, the improvement of water work should be done in one year. The information gathered during task 2 will be background information for setting proper objectives and targets to alleviate the community's problems.

Targets should be decided with an anticipatory perspective. For example, if a certain objective is to be sought within 2 years, it should be investigated whether the objective will

be completely achieved in that time frame. It is possible sometimes that the value of concerns also might have changed in the 2 years, which would necessitate setting of another target in the future.

Step II should end in a list of identified problems and their causes in the selected focus area and objectives and targets which the community will be working towards.

### **Step III      Generation and Evaluation of GP Options**

This is the most creative step in the entire GP assessment process. The efforts put in so far would now be made use of for determining problems solving options. The step consists of 3 tasks namely, development of GP options, preliminary screening and evaluation of options, and formulation of an implementation plan for the selected options.

#### ***Task 5 – Generation of GP Options***

The most significant task in the entire GP methodology relates to the development of GP options. These options emerge directly from the cause analysis carried out earlier. This is the most creative phase of the GP Assessment Process as the GP team should now look for possible methods of problems solving with the available data. In this task, a brainstorming session within the GP must be organized. The options should be generated within each sectors namely, water supply, wastewater, solid waste, air pollution, and agriculture sector. Water supply options could refer to options of alternative water sources, options in water treatment, and options in water preservation. Alternative of water sources could be from surface water such as stream, river, dam and reservoir or from ground water such as shallow well and deep well. Water treatment alternatives could be chemical, physical and biological treatment suitable for raw water sources. Water preservation could be done by public awareness campaign, reuse and recycle of wastewater. Options in waste management such as waste reduction, using waste as resources and wastewater treatment should be considered. Waste generation rate of either wastewater or solid waste could be reduced through campaigns, waste segregation, recycle and reuse. Alternatives in waste treatment and disposal such as pond system, constructed wetland, composting and bio-gas are very good options for community development. Options in agriculture practices such as alternative uses of chemical and bio-fertilizer, alternate crops, and bio-control should be considered.

Finding options depends on the knowledge and creativity of its members, their education, work experience and facilitating resources. Resources such as personnel from the same or similar situation elsewhere, success cases tried elsewhere, specialist organizations including R & D institutions, consultants etc could be sought. The process of finding options should take place in an environment which stimulates creativity and independent thinking. Use of techniques like brain storming and group discussions are very helpful in generating ideas. Members of the GP team may also source information on the internet, books or other published literatures.

#### ***Task 6 – Evaluation of GP Options***

The first step is to make a preliminary screening of the options generated. The options are classified into 3 categories. The first group of options, which do not require a high budget can be directly implemented. The second group of options, which may be too expensive or too

complicated, will be rejected. The third group of options which require a certain amount of financial support and are rather complicated should be further evaluated. In case of any doubt, an option should be put into the third category. The weeding out process should be simple, fast and straightforward and may often be only qualitative.

The options, which are placed in the first category of directly implemented options, should be taken up for implementation immediately. Options falling into the second category would be shelved for the time being. The remaining options falling into the third category would now be subjected to a more detailed feasibility analysis.

**a.      *Assessment of technical feasibility***

The technical evaluation determines whether the proposed option is technically workable under the given conditions. A typical checklist for technical evaluation should consist of

- Availability of hardware/technology
- Availability of operating skills
- Availability of space
- Safety aspects
- Maintenance requirements
- Effect on operational flexibility
- Availability of training resources

**b.      *Assessment of economic viability***

Economic viability is often the key parameter for promoting and discussing implementation of GP options. Unlike the industrial sector, the most important part will be the affordability by the community, and the possibility of obtaining financial budget elsewhere. For a smooth take off and for sustaining interest in the entire GP program, it is essential that the first few options should be economically very attractive. Such a strategy generates more interest and commitment. Options requiring small investment but involving more procedural changes like recycle of household waste, segregation of waste, do not require intensive economic analysis and simple methods like '*pay back period*' could be used. However, as the measures become more involved and capital intensive, methods like *internal rate of return (IRR)* or *Net Present Value (NPV)* need to be adopted to get a complete picture. While doing the economic assessment, the "cost" may include fixed capital cost i.e., cost of the hardware and O&M cost. The "savings" may consist of savings of input material/energy, lower O&M cost, value of by-products, reduction in environmental cost i.e., waste treatment, transportation and disposal cost.

**c.      *Evaluation of environmental aspects***

The GP options need to be analyzed with respect to their impacts on the environment. In many cases, the environment benefit is obvious - reduction in toxicity and/or quantity of waste. The other impacts are improved treatability of waste, changes in applicability of environmental regulations, improving environmental situation in the community, reduce odor and improving of aesthetic environment etc.

After technical, economic and environmental considerations, it is often difficult to decide which option should be taken up for implementation. A *rating matrix* helps in combining the results of three evaluations. Each aspect is given a weight as determined and agreed upon by the management. Each option is then assessed in the context of the given weight for each of the aspect. The sum of these marks would determine the ranking of options with regards to priority of implementation.

### ***Task 7 – Formulation of GP Implementation Plan***

The preparation for implementing GP solutions requires arranging finances, technical preparation and establishing linkages with other organizations. Support and cooperation of concerned persons has to ensured. Checklists of tasks involved, agencies/departments to be approached provide good help. The implementation plan should cover a detailed activity plan, the inputs (including manpower and financial inputs), required time frame and the persons responsible for implementation. For implementation of any GP option, it is required to know the following :

- Location / point of application of the option
- Nature of the option
- Resources necessary
- Personnel necessary
- Responsibility matrix and task allocation in teams
- Details on cost requirements, when, how much sourcing of funds
- Milestones to be set in the implementation sequence.

Step III should result in a prioritized list of GP options and its implementation plan.

### **Step IV      Implementation of GP option**

### ***Task 8 – Implementation of Selected Options***

The implementation of GP solutions is similar to any other activities. The task comprises preparation of design and drawings, ordering and procurement of equipment, transportation of the equipment to the site, installation and commissioning. Training of manpower and all stakeholders should not be missed out as an excellent measure may fail miserably if not backed up and used by adequately trained people.

### ***Task 9 – Training, Awareness Building and Develop Competence***

Depending on the nature of the GP options, the community need to be educated for all of the applications of the GP options.

This step should result in a number of successfully implemented GP solutions. Quite often, this step is the most time consuming step as training, campaigning are certainly time consuming activities. And it requires continuous program to sustain the activities.

## **Step V            Monitoring and Review**

After implementation, it is important to continually monitor and evaluate the appropriateness of the options employed. The results have to be reviewed by the GP team.

### ***Task 10 - Monitoring and Evaluation of Results***

The performance of the options implemented should be monitored to compare the actual results with the expected ones. In case of any deviation, the cause needs to be determined and appropriate modifications, if required, should be carried out. The implementation job would be considered as completed only after sustained performance is recorded over a reasonable period of time.

### ***Task 11 – Management Review***

Post implementation review by GP team involves checking whether the overall GP program is proceeding in the right direction and whether targets are being achieved as per implementation plan.

## **Step VI            Sustaining Green Productivity**

The biggest challenge in Green Productivity lies in its sustainability, otherwise, the euphoria of the program dies out very soon and the situation returns to where it started. The zeal and tempo of the GP Team will also wane off backing out from commitment. Absence of rewards and appreciation for performers, shifting priorities are some of the commonly encountered reasons for such a project end of a Green Productivity program.

### ***Task 12 - Incorporate Changes into the Community's System of Management***

Green Productivity would not sustain in isolation. It should be integrated to become a part of day to day way of living. The GP team should establish a system for sustaining the implemented solutions.

### ***Task 13 - Identify and Select Next Focus Area***

The entire methodology can now be repeated for the second focus area. By the time one full cycle is completed, there would be fresh opportunities of GP in the first focus area and the whole cycle could similarly be repeated. Green Productivity would, therefore, never end. It is a continuous process and would go on forever.

## **2.4      Experience of GP for Community Development in Vietnam**

*(Extracted from the Green Productivity Demonstration Project by VPC Vietnam)*

A demonstration program on GP in community development has been carried out in Vietnam during the period of June 1998-June 1999. This project is the Green Productivity Demonstration Program (GPDP) sponsored by APO and implemented by Vietnam Productivity Center (VPC).

The main objective of the GPDP project was to demonstrate the application of GP approach for the environmental problems within the integrated community since GP is an appropriate approach to reduce environmental degradation of the community.

GPDP project has established a GP application model and experiences gained would be disseminated to other communities. Three communities are selected for the GPDP project – two in the North and the other in the South. Tinh Loc and Kha Ly Ha communities are located 70 km from Hanoi in the North and My Khanh B is located 45 km from Ho Chi Minh city in the South.

### **2.4.1 Objectives**

The objectives of the program were to change the attitudes of villagers about environmental protection, and to create a new habit to live through sustainable development. The detailed objectives were as follows:

- a) To improve the quality of life through improving standard of living, decreasing poverty, improving health condition and improving kids' education.
- b) To improve agricultural productivity through Integrated Pest Management (IPM).
- c) To improve environmental condition through improvement of drinking water supply, wastewater facilities, solid waste management, human and animal wastes management.

### **2.4.2 Methodology**

The methodology of the project closely followed the Green Productivity (GP) methodology developed by APO. The methodology consists of 13 tasks divided into 6 steps. The main steps are:

Step I	Get Started
Step II	Planning
Step III	Generation and Evaluation of GP Options
Step IV	Implementation of GP Options
Step V	Monitoring and Review
Step VI	Sustaining Green Productivity

The project were concentrated on a number of GP techniques in the community sector such as:

- Waste Prevention and Management
- Pollution Control
- Water Supply
- Integrated Pest Management

### **2.4.3 Results from the Vietnam GPDP**

#### **a. Institutional and Organization Structure**

In order to fulfill the objectives of the project and to ensure the efficiency of project management, 3 national-level committees and a community-level committee were established.

The national-level committees were Governing Council Committee, Executive Committee and Local Experts Committee. Nine members form the Governing Council. Governing Council's functions are to give direction and advisory to Executive Committee in implementation of the project. The Executive committee consisted of six members. These core members carry out most EC meetings and copies of minutes of meetings are sent to other members. The roles of this Committee are to coordinate and carry out the implementation works, and prepare the technical reports. The Local experts committee consisted of 8 members. These local experts were responsible for auditing, analysing, consulting and evaluating all the environment issues in the village. They also conducted several training courses for villagers in their concerns.

The community-level committees i.e., the GP team, consists of nine members from the management of community and representatives of local organisations within the community such as farmer union, woman union and youth union. Among this GP team, one member was appointed to be the team leader who took all the responsibilities of GP team's activities. In order to assist the team leader, one member was assigned to be the secretary of the team. He/she was responsible for writing and keeping all minutes of meetings. Each member was responsible for one environmental issue in the community.

Beside the GP team, several organizations were involved in this project in supporting and working along with the GP team. They were namely the People's Committees from Bac Giang Province, Viet Yen District, the veteran's union, youth union, farmer's union, women union and IPM club. The supports were either finance or labor works since members of the union were mostly the villagers in the community.

## **b. Initial Assessment of the Community**

Tinh Loc village is located in the Northeast of Bac Giang Province, about 70 km away from Hanoi. The community has a total land area of 167.6 hectares wherein cultivated area accounts for 56% (about 93.6 hectares), transportation 3.7 % and irrigation accounts for 2.7 ha. The population of Tinh Loc was 1375 persons with 301 households of which 19 % are considered poor. The villagers had an average income of 2,300,000 VND/capita/year in 1998 (equivalent to US\$ 170) which was rather low as compared to the GDP of the country (US\$325/capial/year in 1998).

The major incomes of the villagers are generated from agricultural production, including cultivating, breeding and fishing. In 1998, the income from cultivating accounted for 66% of the total income. Animal breeding contributed to 16.8 % and fishing accounted for 2%. In addition, other businesses such as trading, construction works and handicraft production have been grown up in the village to solve employment problem which contributed to 5.2% of the total income of the community. There are 4 crops per year including two rice crops and two vegetable harvesting. Highly profitable vegetables, like potatoes and soy bean had been introduced to the villagers.

## **c. Environmental Situation and Information Collection**

The environmental situation of the demonstration village were as follows:

### **(i) Water Sources**

The major source of water for agriculture was from the irrigation channel. The government authority controlled and ensured enough water use through out the region. Water from reservoirs flowed into the channel once or twice a week and the farmers will be charged according to their cultivating area. For domestic use, the villagers use rainwater or well water for consumption (shallow well or deep well).

Groundwater was the major source for human consumption in the village. The well water contains very high concentration of iron and manganese. Besides 90% of well water were contaminated by microorganisms. The villagers normally do not treat their water before consumption. Water quality of well water in the village is as shown in Table 2.1. As indicated in the Table, iron concentrations of wells with depth about or less than 30m are 10 to 17 times higher than that of Vietnamese standards (TCVN5944-1995). Manganese concentration was 2 to 3 times in excess of the allowable WHO's guidelines and Vietnamese standards. Coliform level was also higher than the allowable limits. At 70 meters depth, water will be considered to be suitable for drinking and cooking purpose since the iron concentration is low and no bacteria exists.

Table 2.1 Water analysis results of samples taken at different depth

No	Parameters	Samples					Vietnamese standards TCVN5944-1995	WHO's guidelines
		Shallow well	Deep well					
			7m depth	10m depth	30m depth	45m depth		
1	pH	6.2	6.67	6.71	6. 81	6.67	6.5 – 8.5	6.5 – 8.5
2	Color (Pt - Co)	2	1	1	1	1	5 – 50	15
3	Hardness (mg/L)	139.64	140	142.85	143.92	140	300 - 500	300
4	Cl <sup>-</sup> (mg/L)	7.5	7.1	7.1	7.1	7.1	200 - 600	250
5	SO <sub>4</sub> <sup>-</sup> (mg/L)	27	28.8	28.8	28.8	28.8	200 - 400	250
6	NO <sub>2</sub> <sup>-</sup> (mg/L)	0.5	0	0	0	0	-	3
7	NO <sub>3</sub> <sup>-</sup> (mg/L)	4.0	0	0	0	0	45	50
8	Fe (mg/L)	5.2	5.1	3.1	1.5	0.2	0.3	0.3
9	Mn (mg/L)	0.3	0.3	0.2	0.15	0.01	0.1	0.1
10	NH <sub>4</sub> <sup>+</sup> (mg/L)	10.0	0.4	0.2	0.2	0.01	0.1	1.5
11	Coliform (MNP/100mL)	25	10	2	0	0	0	0



## (ii) *Water Demand*

The daily water consumption for the villagers are as follows:

- Drinking water      2 L
- Cooking water      2.2 L
- Washing water      50 L

Beside human, animals also need water. Each cow or buffalo needs 30 L/day and each pig requires about 15 L/day.

Based on the preliminary audit, the community has total 300 cows and buffaloes, 1,100 pigs, and 7,800 chickens and ducks. The water demand of the whole community can be calculated and summarized in Table 2.2.

Table 2.2 Demand of potable water

	Population	Amount of necessary potable water		Total volume (liter)
		Volume	Unit	
<b>Human</b>	1,350	54.2	liter /person/day	73,170
<b>Pig</b>	1,100	15	liter /animal/day	16,500
<b>Cow and buffalo</b>	300	30	liter /animal/day	9,000
<b>Chickens and ducks</b>	7,800	20	liter /100 animals/day	1,560
<b>Total</b>				100,230

The results show that the average water demand for domestic purposes in Tinh Loc is about 100m<sup>3</sup> per day.

## (iii) *Solid Waste*

In the village, solid wastes were classified into three groups, domestic, agriculture, and construction wastes. Some of the agriculture wastes such as dried wood chips, leaves, grass and paper were used as fertilizers and fuel. Other wastes were littered in many places: community roads, gardens, backyards, paddy fields and at the surface of water sources such as ponds and drainage.

Information of physical analysis of solid wastes was shown in Tables 2.3 and 2.4. Waste generation rate in Tinh Loc was about 0.112 kg/person/day which is rather low as compared to the average generation rate of 0.45 kg/person/day in other developing countries. The majority of waste in Tinh Loc were ash and dust which contributed 26.4% of the total solid waste. Plastic and rubber were the second and third largest composition with 21.1% and 16.6% respectively. No metal were found in the waste stream as it was already recycled by the villagers. The other composition such as glass, paper, ceramics were in the range of 2 to 8%. Batteries were found in the waste stream and it contributed about 2.5% to total amount of solid waste. After measuring and analyzing the sample, data of the solid waste generation

and composition of the whole community was calculated based on the obtained results. This data is shown in Table 2.5.

Table 2.3 Results of solid waste generation rate

Date	Amount of solid wastes (kg)	Number of sampling (person)	Generation rate (kg/person/day)
April, 8, 1999	15.57	124	0.125
April, 9, 1999	16.26	124	0.131
April, 10, 1999	16.67	124	0.134
April, 11, 1999	16.05	124	0.129
April, 12, 1999	10.95	124	0.085
April, 13, 1999	8.94	124	0.072
		<b>Average</b>	<b>0.112</b>

Table 2.4 Composition of solid wastes

Composition	8	9	10	11	12	13	Average (%)
Plastic	23.1	19.2	16.8	22.4	22.7	22.4	21.1
Rubber	20.1	24.4	16.8	12.5	155.2	9.9	16.6
Glass	12.8	7.3	9.6	5.0	7.6	3.6	7.7
Paper	2.6	0.0	2.4	2.5	3.8	4.5	2.7
Ceramic	10.3	4.9	7.2	10.0	5.3	13.5	8.5
Ash and dust	17.9	19.5	31.2	27.4	27.5	35.9	26.4
Textile	3.84	12.2	12.0	7.5	3.8	4.5	7.3
Organic matter	5.1	9.8	2.4	10.2	11.4	4.5	7.2
Hazardous	3.8	2.4	1.7	2.5	3.8	1.4	2.5
						Total	100

Table 2.5 Solid waste generation rate and composition in Tinh Loc

	Calculation formula	Value	Unit
<b>Generation rate</b>		0.112	kg/capita/day
<b>Population</b>		1,375	people
<b>Amount of solid waste generated</b>	$1375 * 0.112$	154	kg/day
<b>Amount of composition of waste</b>			kg/day
• Plastic	$154 * 21.1\%$	32.90	
• Rubber	$154 * 16.6\%$	25.56	
• Glass	$154 * 7.7\%$	11.86	
• Paper	$154 * 2.7\%$	4.16	
• Ceramics	$154 * 8.5\%$	13.09	
• Ash and dust	$154 * 26.4\%$	40.66	
• Textile	$154 * 7.3\%$	11.24	
• Organic	$154 * 7.2\%$	11.09	
• Hazardous	$154 * 2.5\%$	3.85	

These data indicated that in Tinh Loc of a population of about 1375 people and with the obtained waste generation rate, there would be about 154 kg of solids waste generated daily. From this, about 32.9 kg would be plastic, 25.56 kg rubber, 11.86 kg glass, 4.14 kg paper, 13.09 kg ceramic, 40.4 kg ash and dust, 11.24 kg textiles, 11.9 kg organic waste and 3.85 kg hazardous waste. The majority of waste in term of volume would be plastic. The villagers have indicated that it is difficult to recycle plastic as the amount of daily recyclable waste is not enough to collect and sell back to the factory. However, it could be possible to collect the plastic over a long period of time and the amount may then be enough for transportation. Besides plastic, paper, textiles and glass also could be collected for sale.

**(iv) Human and Animal Waste**

The community has approximately 300 cows and buffaloes, 1,100 pigs, and 7,800 chickens and ducks. The wastes generated each day are as follows:

- Human                      0.5              kg /person/day
- Poultry                    0.2              kg /animal/day
- Pig                            4                kg /animal/day
- Cow or buffalo        8                kg /animal/day

The total human and animal waste generated each day can be calculated and shown in Table 2.6.

Table 2.6 Human and animal waste analysis

	Population	Amount of waste released		Total waste
		Amount	Unit	Kg/day
<b>Human</b>	1,350	0.5	kg /person/day	675
<b>Poultry</b>	7,800	0.2	kg /animal/day	1,560
<b>Pig</b>	1,100	4	kg /animal/day	4,400
<b>Cow and buffalo</b>	300	8	kg /animal/day	2,400
<b>Total</b>				9,035

**(v) Pesticides and Fertilizers**

Earlier the villagers used traditional agricultural practices without chemical fertilizers and pesticides. Since 1980, to improve their productivity, the farmers started to introduce chemical fertilizers and pesticides. The quantities of fertilizers and pesticides used are as shown in Table 2.7. Farmers usually applied 1 ton of chemical fertilizers per year for one ha of rice. This amount included 230 kg urea, 290 kg potassium and 450 kg phosphorus. For other crops, the amount of chemical fertilizers could be twice of these amount. On the average, this community applied 100 tons of chemical fertilizers in a year including 23 tons urea, 29 tons potassium and 45 tons phosphorus which could decrease agricultural productivity in the future. Besides applying chemical fertilizers, the villagers also used about 2,000 kg of chemical pesticides per year.

Table 2.7 Chemical fertilizers and pesticides used by Tinh Loc community

Names	Unit	Amount	Value (*1000VND)
<b>Chemical fertilizers</b>	ton	100	200,000
<b>Insecticides</b>	kg	1,560	23,400
<b>Fungicides</b>	kg	260	26,000
<b>Herbicides</b>	kg	180	36,000

#### d. Identify problems and their causes

After information collection, the GP team identified the problems and analyzed their root causes through a fish bone diagram. The results are as follows:

##### (i) *Water Sources*

Water for cultivation was supplied through irrigation canals. The quality of this source of water was good enough for agriculture activities. In the village, there are a couple of ponds which were highly polluted by organic substances, bacteria and other fecal micro-organism. The water was turbid and contains bad odor. Shallow wells were also polluted by coliform bacteria. The water in most deep wells contained high iron and bacteria and were not suitable for drinking. Through the brainstorming of GP team, causes of water pollution were identified and analyzed. The major cause of water pollution can be attributed to human activities including wastewater, persistence of chemical fertilizers and pesticides and rubbish from community. Only iron and other metals are resulting from a geological structure factor.

##### (ii) *Solid Waste*

Solid wastes generated in the community were not properly managed. Solid wastes were present in many places: community roads, gardens, backyards, paddy fields and at water surface such as ponds and drainage canals. The cause analysis showed that the villagers do not have enough knowledge in handling their wastes. There were not enough funds to work on waste disposal.

##### (iii) *Human and Animal Waste*

Primary audit revealed that the major cause of environment problems at this village is human and animal waste management. There was no regulation concerning human and animal waste management. Human waste in this community was usually applied directly to fields or gardens without proper treatment. Most of the cattle and poultry like buffaloes, cows, and chickens, and animals like dogs and cats were set free. Therefore, surface water was easily polluted. Each household built stables and barns within their housing territory. Most of them were simple and were not equipped with the proper drainage system. Wastes were discharged into the open ditch and later entered into the community ponds. Most of the ponds were highly polluted. One of the major causes of this problem is the lack of knowledge of waste

treatment such as composting and bio-gas. There was not enough training or information dissemination to the village.

**(iv) Pesticides and Fertilizers**

The problems identified by the GP team were the rapid degradation of soil in the village, resulting in the over use of chemical fertilizer and pesticides. The identified causes were the improper use of chemical fertilizer, no knowledge of integrated pest management, bad management and improper cultivation.

**e. Option Generation and Evaluation**

**(i) Water resource**

From brainstorming and the assistance of experts, the following options were obtained:

1. Education and training should be provided to the villagers concerning environmental awareness, importance of health and potable water system.
2. Promotion of use of rain water for domestic purpose.
3. Building up a common water supply plant, including treatment plant and distribution system.
4. Building up the drainage system.
5. Repair and reconstruct animal barns to prevent wastes from polluting surface and groundwater.

The options were evaluated and the following were implemented:

- Education and training program should be provided.
- Rainwater should be used.
- Common water supply system should be built.
- Drainage system should be constructed.

**(ii) Solid Waste**

From the current situation of solid waste management, the following options were generated by GP team members of the community under the assistance of experts.

1. Training course on solid wastes should be provided to the villagers.
2. Solid waste regulation should be implemented in the village
3. Public awareness in waste reduction should be promoted.
4. Collection should be provided.
5. Integrated solid waste management should be used.

After options were generated, they were evaluated. The results were:

- Options 1 and 3 were implemented immediately.
- Integrated solid waste management should be used within the community.

**(iii) Human and Animal Waste**

By brainstorming, the following options were generated:

1. Training course concerning human and animal waste including bio-gas and composting, should be provided.

2. Public awareness should be promoted
3. Implementing bio-gas technology using concrete construction, plastic bag or brick construction.
4. Implementing aerobic composting
5. Promote the use of Vietnamese toilet.

After the options were evaluated, the following were the outcome:

- Training and Public awareness should be implemented immediately.
- Aerobic composting of garden/farm waste should be promoted.
- Bio-gas using concrete compartment should be used.

#### **(iv) Pesticides and Fertilizers**

By using brainstorming, the following options were generated :

1. Training on IPM and proper cultivation method should be provided.
2. Public awareness on IPM should be promoted
3. Organize the IPM model households as demonstration project.
4. Introducing new seeds and new plants for more effective cultivation.
5. Introducing bio-fertilizer and bio-pesticides.

After the options were evaluated, the following were the options for implementation:

- Training and public awareness should be implemented immediately.
- Organization of IPM model households should be implemented
- Bio-fertilizer and bio-pesticides should be introduced.

### **f. Implementation and Results**

The implementation of each options were summarized as followed:

#### **(i) Drinking water**

Through training courses, the villagers were aware of the importance of using potable water for preventing water borne diseases. A common water supply plant was constructed which can supply 150 m<sup>3</sup>/day of sanitary water (without bacteria and low iron concentration). The villagers will also build a pipe network to every household in the future. Total investment of this center was about 300 millions VND (equivalent to about US\$ 21,000)

#### **(ii) Wastewater**

A 1.5 km long drainage system was constructed in the village to collect all wastewater to the existing ponds. The problem of stagnant water in the community was eliminated.

#### **(iii) Solid waste**

The training program on solid waste was very effective as most of the villagers knew how to analyze their waste. Integrated solid waste management system was started. The collection system in the village was established with waste segregation program. Hazardous and non-recyclable wastes were transported to a sanitary landfill 1 km away from the village. Litter

disappeared from the village. The image of the village was significantly improved since the wastes were rarely present on the streets and other public places.

**(iv) *Human and animal wastes***

Three concrete compartment bio-gas plants were constructed in the village. The farmers collected their animal and human waste and put them into the reactors. As a result, the ones who owned the reactor had bio-gas for cooking, and bio-fertilizer for agriculture use. One of the most important issues was that the environment of these households was protected. Nasty odor of the human and animal waste is almost eliminated from the environment. The cost of the concrete compartment reactor was about 2 millions VND (US\$140) per cubic meter. The cost of brick reactor was about 1 millions VND (US\$70) per cubic meter. The brick model seemed to be more suitable than the concrete compartment. The villagers decided to build more in the village.

Composting was introduced in the village. Two households implemented aerobic composting with the addition of microorganism. The results show that this method generated bio-fertilizer after 2 composting – weeks. By using the bio-fertilizer, these two households could decrease the use of chemical fertilizer and pesticide.

**(v) *Management of using agriculture chemical***

Even though IPM was not new to Vietnam, only 30% of households in this village were implementing IPM in their farms. After the promotion of IPM in the village, number of households implementing increased up to 95% of the total households in the village. Primary result showed that the amount of chemical fertilizers used by the villagers decreased by 33% in 1999.

## **2.4.4 Summary**

The result from this green productivity demonstration project in Vietnam demonstrated the effectiveness of GP methodology application in the community level. The community development could be enhanced and the management could be very effective through GP implementation.

## **2.5 The necessity of Bio-gas in Community Development**

Community in most developing countries depends on their agricultural products. In many countries, farmers use their farm animals such as buffaloes, oxen and cows in soil preparing work. Horses have been used in farm transportation for centuries. Apart from these farm animals, villagers in the community raise other animals such as chickens, hens, ducks, pigs, and sheep for their food supply and extra income. All these animals are normally raised in the vicinity of their boundaries and in barns within the housing area. Some animals are set free and roaming around the housing area. Therefore, animal wastes are litter around the area and it could become health hazard to human being.

Major energy consumption of community in developing countries are mainly lighting and energy for cooking. The luxury of hot water bathing, air conditioning is unheard of. If electricity is available in the community, villagers will use electricity for lighting. However,

most villagers will use charcoal or wooden fuel for cooking as they are considered more or less free of charge. Villagers normally will enter the near-by forest area and cut down tree for making charcoal or cut wood for cooking purpose. This activity certainly creates deforestation in many developing countries.

With these two factors in mind bio-gas should be a good alternative in both waste treatment and alternative energy source.

### 2.5.1 Waste Generation and Management in Community

In a small community, normally one village will raise animals for farming and for food. The normal trend is that a family of 4-6 members will have one ox or one horse or one buffalo for farming and transportation, 4-5 pigs for food and extra income, and 30-40 poultry for food. With this assumption, waste generated for a family will be as follows:

• From Human	0.5x6	=	3.0	kg/day
• From ox or horse or buffalo	8x1	=	8.0	kg/day
• From pigs	5x4	=	20.0	kg/day
• From poultry	0.2x40	=	8.0	kg/day
Total		=	39.0	kg/day

Normally, human waste will be put in septic tank or latrine so that soil can reduce the pollution level. However, risk for groundwater contamination is very high. Animal wastes are either used directly in farm, or turning to compost, or sometimes discharged directly into nearby stream. All these activities can create risk on human health.

### 2.5.2 Energy Consumption in Community

In most villages, a family of 5-6 will need energy for their living as follows:

- Energy for cooking for 3 meals
- Energy for lighting for approx. 3-4 hours per day
- Energy for appliances such as refrigerator, fan, TV, radio, etc

In the remote area, energy for cooking is mainly from wood or charcoal that the community may obtain it freely in the forest. Lighting and other appliances will need electricity power supply. The amount of energy needed depend on the quality of life in that community. However, no matter what, the energy consumption will mean expenses in the family. In many part of the world, deforestation due to energy consumption for cooking and house warming is a big issue.

### 2.5.3 Design of Bio-gas for Community

With the above reason, bio-gas could be a very good alternative for pollution control and energy sources. The use of anaerobic digestion of organic waste materials, such as farm manure, litter, garbage, and night-soil, accompanied by the recovery of methane for fuel, has been an important development in rural sanitation during the last few decades. This development is basically an extension of the anaerobic process for sludge digestion used in municipal sewage treatment to small digestion-tank installations on farms. These farm plants



comprise one or more small digesters and a gas-holder. Manure and other wastes are placed in a tank which is sealed from atmospheric oxygen, and are permitted to digest anaerobically. The methane gas, which is produced during the anaerobic decomposition of the carbonaceous materials, is collected in the gas-holder for use as fuel for cooking, lighting, refrigeration, and heating, and for other domestic or agricultural purposes, such as providing power for small engines.

With the amount of waste generation of 39 kg/day, the size of bio-gas reactor could be about 8 cubic meters. With this size, gas produced would be about 1.4-2.3 cubic meters per days. The amount of gas produced could be used for 3-5 hours of cooking or 8-13 hours of lighting. Apart from this, the family will obtain 15 kg/day of good compost which may be able to use in their farms. The family could save money for energy and fertilizer. Besides, with the bio-gas reactor in the vicinity of housing boundary, the environmental situation will be much better and the quality of life will be improved. Therefore, bio-gas could be a good alternative in community development.

## CHAPTER 3

### Review Of Bio-Gas Technology

#### 3.1 Bio-Gas Technology

Bio-gas technology is the transformation of solid waste through anaerobic digestion process to obtain bio-gas such as methane.

##### 3.1.1 Process Microbiology

The biological conversion of the organic fraction of municipal solid waste under anaerobic conditions is thought to occur in three steps. The first step involves the enzyme-mediated transformation (hydrolysis) of higher-molecular-mass compounds into compounds suitable for use as a source of energy and cell tissue. The second step involves the bacterial conversion of the compounds resulting from the first step into identifiable lower-molecular-mass intermediate compounds. The third step involves the bacterial conversion of these intermediate compounds into simpler end products, principally methane and carbon dioxide.

In the anaerobic decomposition of wastes, a number of anaerobic organisms work together to bring about the conversion of the organic portion of wastes into a stable end product. One group of organism is responsible for hydrolyzing organic polymers and lipids to basic structural building blocks such as fatty acids, monosaccharides, amino acids, and related compounds. A second group of anaerobic bacteria ferments the breakdown products from the first group to simple organic acids, the most common of which is acetic acid. This second group of microorganisms, described as nonmethanogenic, consists of facultative and obligate anaerobic bacteria that are often identified in the literature as “acidogens” or “acid formers”.

A third group of microorganisms converts the hydrogen and acetic acid formed by the acid formers to methane gas and carbon dioxide. The bacteria responsible for this conversion are strict anaerobes, called methanogenic, and are identified in the literature as “methanogens” or “methane formers”. Many methanogenic organisms identified in landfills and anaerobic digesters are similar to those found in the stomachs of ruminant animals and in organic sediments taken from lakes and river. The most important bacteria of the methanogenic group are the ones that utilize hydrogen and acetic acid. They have very slow growth rates; as a result, their metabolism is usually considered rate-limiting in the anaerobic treatment of an organic waste. Waste stabilization in anaerobic digestion is accomplished when methane and carbon dioxide are produced. Methane gas is highly insoluble, and its departure from a landfill or solution represents actual waste stabilization.

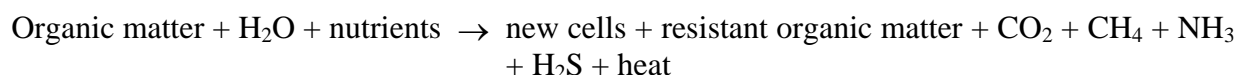
##### 3.1.2 Environmental Factors

To maintain an anaerobic treatment system that will stabilize an organic waste efficiently, the nonmethanogenic and methanogenic bacteria must be in a state of dynamic equilibrium. To establish and maintain such a state, the reactor contents should be void of dissolved oxygen and free of inhibitory concentrations of free ammonia and such constituents as heavy metals and sulfides. Also, the pH of the aqueous environment should range from 6.5 to 7.5. As the

methane bacteria cannot function below this point, sufficient alkalinity should be present to ensure that the pH will not drop below 6.2. When digestion is proceeding satisfactorily, the alkalinity will normally range from 1000 to 5000 mg/L and the volatile fatty acids will be less than 250 mg/L. Values for alkalinity and volatile fatty acids in the high-solids anaerobic digestion process can be as high as 12,000 and 700 mg/L, respectively. A sufficient amount of nutrients, such as nitrogen and phosphorus, must also be available to ensure the proper growth of the biological community. Depending on the nature of the sludges or waste to be digested, growth factors may also be required. Temperature is another important environmental parameter, with optimum temperature in the mesophilic, 30 to 38°C (85 to 100°F), and the thermophilic, 55 to 60°C (131 to 140°F) range.

### 3.1.3 Gas Production

The general anaerobic transformation of solid waste can be described by means of the following equation.



### 3.1.4 Bio-Gas

Bio-gas is a gas generated from the anaerobic digestion of organic waste. It consists of CH<sub>4</sub> (50-70%), CO<sub>2</sub> (30-50%) with the remaining gases being: H<sub>2</sub>, O<sub>2</sub>, H<sub>2</sub>S, N<sub>2</sub> and water vapor. To ensure optimal Bio-gas production, the three groups of micro-organisms must work together. In case of too much organic waste, the first and second groups of micro-organisms will produce a lot of organic acid which will decrease the pH of the reactor, making it unsuitable for the third group of micro-organisms. This will result in little or no gas production. On the other hand, if too little organic waste is present, the rate of digestion by micro-organisms will be minimal and production of Bio-gas will decrease significantly. Mixing could aid digestion in the reactor but, too much mixing should be avoided as this would reduce bio-gas generation. Table 3.1 shows the amount of bio-gas generated from animal waste and agriculture residue.

Table 3.1 Amount of bio-gas generated from animal waste and agriculture residue

animal	gas produced L/kg-solid
Pig	340-550
Cow	90-310
Chicken	310-620
Horse	200-300
Sheep	90-310
Straw	105
Grasses	280-550
Peanut shell	365
Water Hyacinth	375

### 3.1.5 Factor Affecting Gas Generation

To ensure a constant generation of gas, the following factors should be considered :

- Organic waste should be sufficient at all time.
- Daily input of waste should conform with reactor size. Too much input will reduce the gas generation rate.
- Digestion period (retention time) should be about 60-80 days

$$\text{Digestion period} = \frac{\text{Volume of reactor}}{\text{Daily input of waste}}$$

- pH within reactor should be about 7.0-8.5. Too low a pH will inhibit gas production.

### 3.1.6 Benefit of Bio-Gas Technology

The following benefits will be obtained from bio-gas technology:

- Energy

Bio-gas could be used as a fuel alternative to wood, oil, LPG and electricity.

- Agriculture use

Sludge from the bio-gas reactor could be used as compost. Organic nitrogen from waste will be transformed into ammonia nitrogen, a form of nitrogen which plants can uptake easily.

- Protect environment

Using bio-gas technology on animal waste treatment will reduce risk of infection from parasite and pathogenic bacteria inherent in the waste. Odor and flies will be significantly reduced in the area, and water pollution created by the dumping of waste can also be prevented.

### 3.2 Review of Bio-Gas Reactor

The anaerobic digestion of organic waste materials, such as farm manure, litter, garbage, and night-soil, accompanied by the recovery of methane for fuel, has been an important development in rural sanitation during the last few decades. This development is basically an extension of the anaerobic process for sludge digestion used in municipal sewage treatment to small digestion-tank installations on farms. These farm plants comprise of one or more small digesters and a gas-holder. Manure and other wastes are placed in a tank which is sealed from atmospheric oxygen, and are permitted to digest anaerobically. The methane gas, which is produced during the anaerobic decomposition of the carbonaceous materials, is collected in the gas-holder for use as fuel for cooking, lighting, refrigeration, and heating, and for other domestic or agricultural purposes, such as providing power for small engines.

This method provides for the sanitary treatment of organic wastes, satisfactory control of fly-breeding, efficient and economical recovery of some of the waste carbon as methane for fuel, and retention of the humus matter and nutrients for use as fertilizer.

Most of the farm installations have, so far, utilized only animal manure and organic litter; however, night-soil can be satisfactorily treated together with the other wastes in these digesters if adequate digestion time is allowed to permit the destruction of the pathogenic organisms and parasites. Such a practice has many advantages on farms and in villages where water-carried sewage disposal is not available. The use of the digestion tank can eliminate the dangerous insanitary practice of allowing night-soil to be deposited on fields, and in the immediate environment of homes, without proper treatment. Straw, weed trimmings, or any other type of cellulose materials may be digested together with the manure and night-soil for the production of methane.

Digester tanks with gas collection are particularly advantageous in areas which are short of fuel and where animal dung is burned for cooking. The burning of dung destroys, with digestion, the valuable nitrogen and other nutrients which could be used as fertilizer. The nitrogen, phosphorus, potash, and other nutrients are retained in the tank as humus and liquid while much of the carbon and hydrogen are evolved as methane, for collection and use as fuel. The quality of the humus is similar to that obtained from aerobic composting, and when the liquid is utilized together with the solids as fertilizer, practically all of the fertilizer nutrients are reclaimed.

The evolved gas, which consists approximately of two-thirds methane and one-third carbon-dioxide, will contain 4500 to 6000 calories per cubic metre, thus providing a convenient source of heat at low cost. One cubic metre of the gas at 6000 calories is equivalent to the following quantities of other fuels : 1,000 litres of alcohol; 0.800 litres of petrol; 0.600 litres of crude oil; 1.500 m<sup>3</sup> of commonly manufactured city gas; 1.400 kg of charcoal; and 2.2 kilowatt-hours of electrical energy.

The gas can be stored in the gas-holder and piped into the house to provide clean fuel for cooking and lighting. It has a slight barn-yard odour by which any leaks can be readily detected, and a very low toxicity since it contains very little carbon monoxide—the toxic constituent of most city gas. It burns with a violet flame without smoke. Since a considerable amount of CO<sub>2</sub> is mixed with the methane, the risk of fire or explosion is

somewhat less than in the case of city gas. However, every precaution should be taken to avoid obtaining a mixture of methane and air, except when the methane is burned as an open flame. Mixtures of 5% - 14% methane in air are explosive when large quantities are ignited.

There are several basic factors to be considered when constructing or purchasing a digester installation. These are : (1) climate; (2) single or multiple family installations; (3) amount of wastes available; (4) gas production; (5) location of digesters; (6) gas requirements and storage.

### **3.2.1 Climate**

Small digester plants can be used most effectively in temperate climates, where freezing temperatures are infrequent and of short duration. Decomposition and gas production are most rapid at about 35°C, but are satisfactory at temperatures between 15-20°C. Gas production practically ceases at temperatures below 10°C.

### **3.2.2 Single or Multiple Family Installations**

Either single or multiple family installations can be provided, depending on whether the family has sufficient manure and other wastes to operate a unit. A minimum single family installation would normally include a digester tank of about 4-5 m<sup>3</sup> capacity and a gas-holder of at least 2 m<sup>3</sup> capacity. Two or more digesters are desirable so that there will not be an interruption of gas production and so that one tank may be loaded while the other is digesting. A single gas-holder can serve more than one digester unit. If two or more families living in adjacent compounds do not have more than one farm animal each, it may be advantageous to combine their wastes into one digester installation from which the gas could be distributed to each dwelling.

### **3.2.3 Amount of Wastes Available**

As indicated, horses and cows produce between 10 to 16 metric tons of manure per year, depending on stabling conditions and amounts of organic litter used for bedding. To this amount, garbage, waste straw, cane stalks, or any other organic litter may be added. Where night-soil is used as a fertilizer, it should be digested with the other organic wastes before application to the land, in order to prevent the spread of fecal-borne diseases. While human excrement does not add much weight to the digester (15-30 kg per capita per year) it does provide appreciable quantities of the nitrogen and phosphorus necessary for the biological digestion and methane production of cellulose and other materials with a high carbon content.

### **3.2.4 Gas Production**

In practice, about 50% of the carbon theoretically available for gas production is converted into gas. A metric ton of waste will normally yield about 50-70 m<sup>3</sup> of gas per digestion cycle, depending upon the proportion of organic matter and the carbon content of the waste.

The digestion cycle will be shorter at high temperatures than at low temperatures, and the daily yield per ton of material will be greater. Considerably greater digester-capacity is required to produce a fixed amount of gas at a temperature of about 20°C than at a

temperature of 30-35°C. Mignotte<sup>54</sup> gives the following estimates for gas production per ton of manure for different digestion periods at different temperatures :

Temperature (°C)	Gas production (m <sup>3</sup> per day)	Digestion period (months)
15	0.150	12
20	0.300	6
25	0.600	3
30	1.000	2
35	2.000	1

### 3.2.5 Location of Digesters

The digesters should be located near the source of manure and waste material to avoid excessive handling and transportation. Also it is desirable to place them so as to minimize the amount of gas piping required.

### 3.2.6 Gas Requirements and Storage

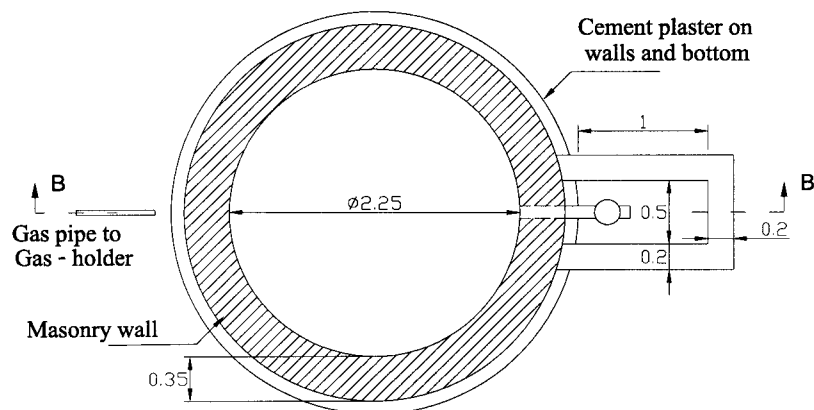
The gas may be used for domestic purposes, such as cooking, heating water, food refrigeration, and lighting. The following are some approximate quantities of gas for these different uses : domestic cooking, 2 m<sup>3</sup> per day for a family of five or six people; water heating, 3 m<sup>3</sup> per day for a 100-litre tank or 0.600 m<sup>3</sup> for a tub bath and 0.35 m<sup>3</sup> for a shower bath; domestic food refrigeration, 2.5-3 m<sup>3</sup> per day for a family of five or six people; lighting, 0.100-150 m<sup>3</sup> per hour per light.

Since the gas is produced continuously, day and night, but is used largely during the daytime, it is necessary to provide storage facilities so that the gas will not be wasted and will be available when needed. The storage capacity should be estimated to meet peak demands. For small installations, storage capacity of about one day's requirement of gas should be provided. The volume of the gas-holder should not be less than about 2 m<sup>3</sup>, even for very small installations.

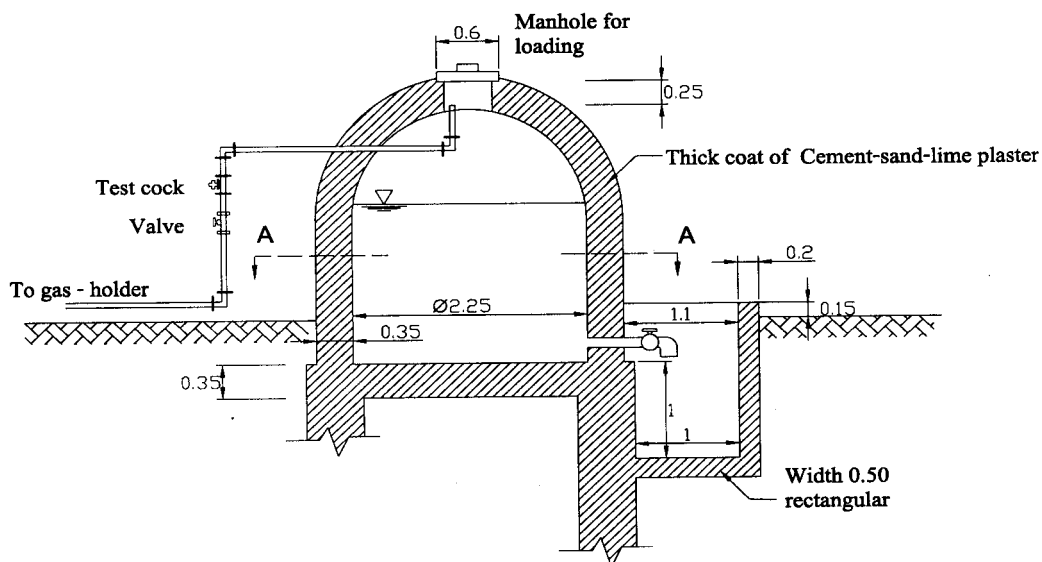
The gas-holder may be circular or square and should be provided with a water seal to prevent the escape of gas or admission of air. The weight of the floating cover of the gas-holder provides the gas pressure.

### 3.3 Example of Digesters

Some examples of digesters are shown in Figures 3.1-3.6. They are individual digester unit, manure gas plant with latrine, digester and latrine, gas holder for manure gas plant and manure digester with floating cover for gas holder.



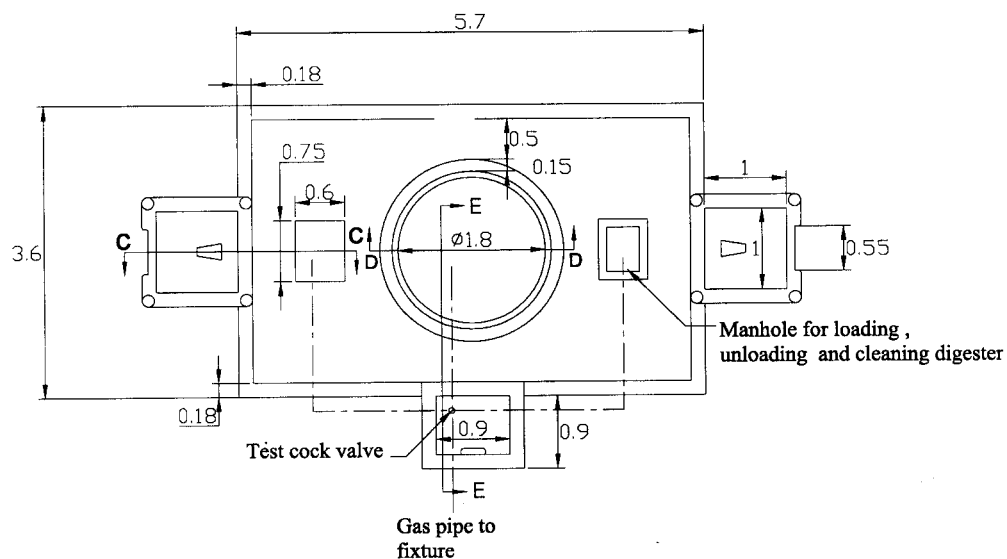
*All Measurements are in metres*  
**Figure 3.1 Plan of Individual Digester Unit**



*Maximum manure - storage capacity of digester : 7.860  $m^3$*

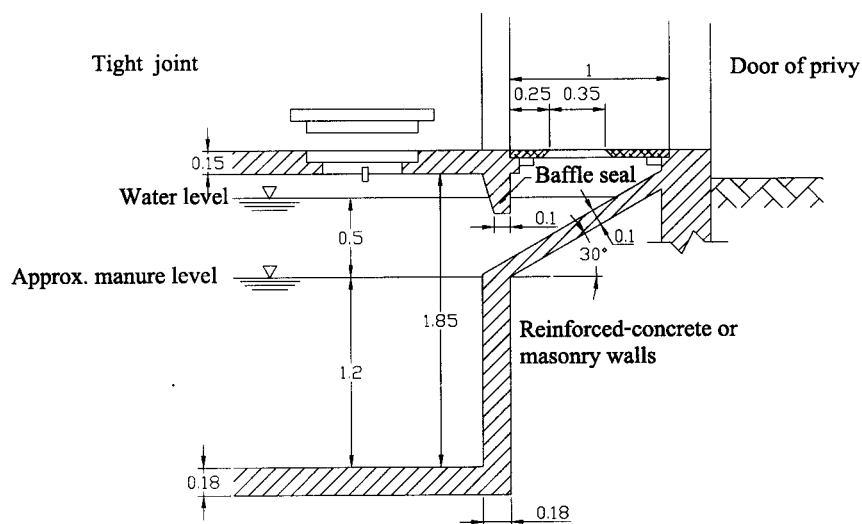
*All Measurements are in metres*  
**Figure 3.2 Cross Section of Individual Digester Unit**





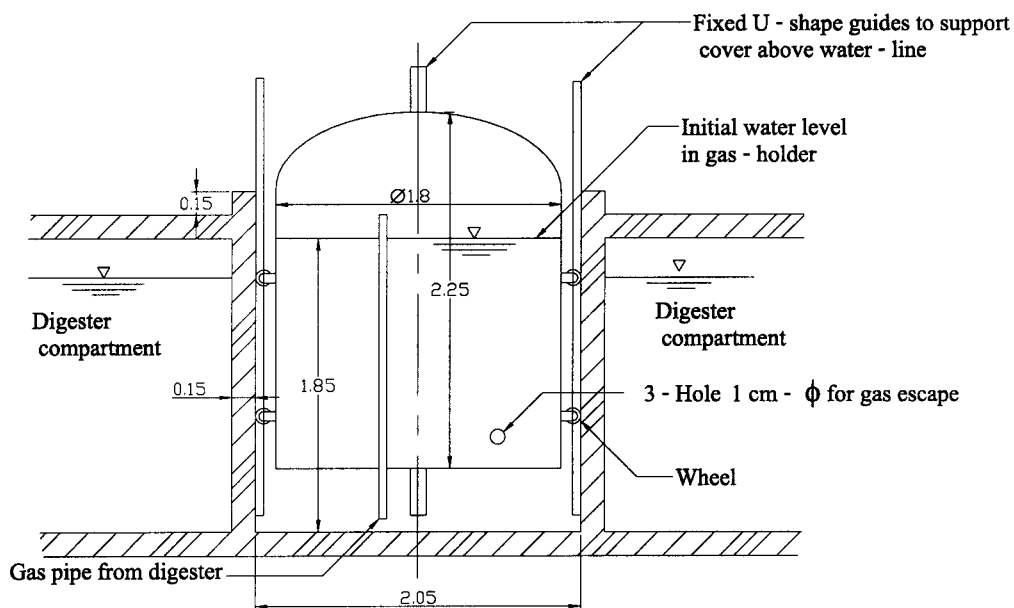
*All Measurements are in metres*

**Figure 3.3 Plan of Manual Gas Plant with Latrines**



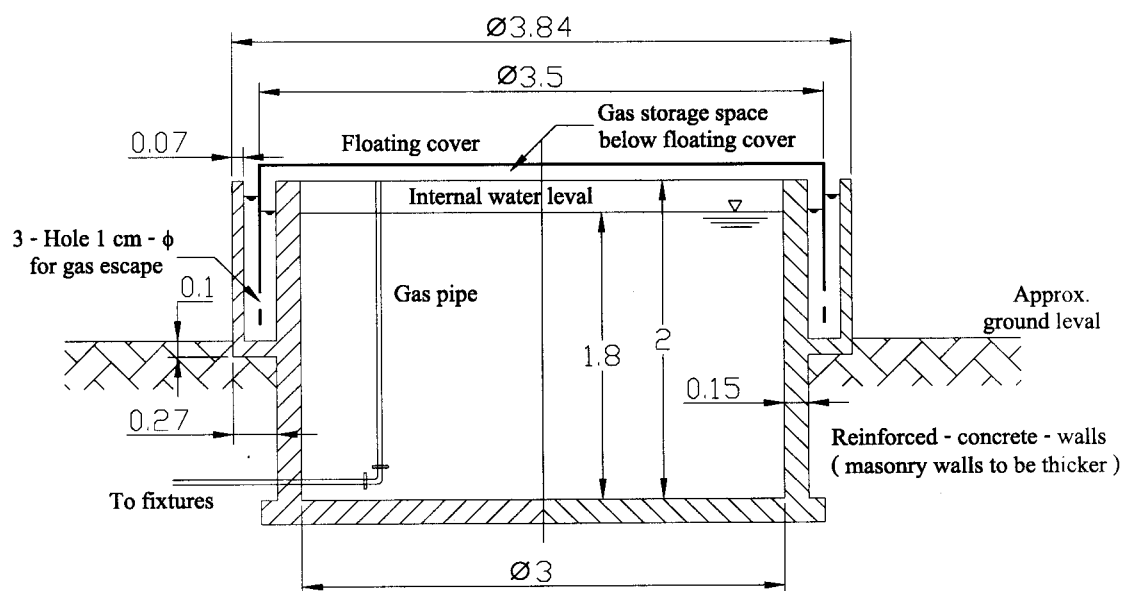
*All Measurements are in metres*

**Figure 3.4 Cross Section of Digester and Latrines**



*All Measurements are in metres*

**Figure 3.5 Cross Section of Gas - Holder for Manure Gas Plant**



*All Measurements are in metres*

**Figure 3.6 Cross Section of Manure Digester with Floating Cover for Gas - Holder**

## CHAPTER 5

### Steps of Bio-gas Reactor Construction

#### 5.1 Step 1

##### 5.1.1 The strength of the chamber depends on beams

After the excavation is completed, the ground soil must be well pressed. Piles are required at the foundation in places where the ground is soft or filled with water or liquid. The crack will appear if the chamber is sinking. Set the level of beams using level line and marked with peg. (Figure 5.1)

2.00meters	➤	4.6 m <sup>3</sup>	3.13 meters	➤	30 m <sup>3</sup>
2.34 meters	➤	8 m <sup>3</sup>	3.57 meters	➤	30 m <sup>3</sup>
2.37 meters	➤	12 m <sup>3</sup>	4.04 meters	➤	30 m <sup>3</sup>
2.62 meters	➤	16 m <sup>3</sup>			

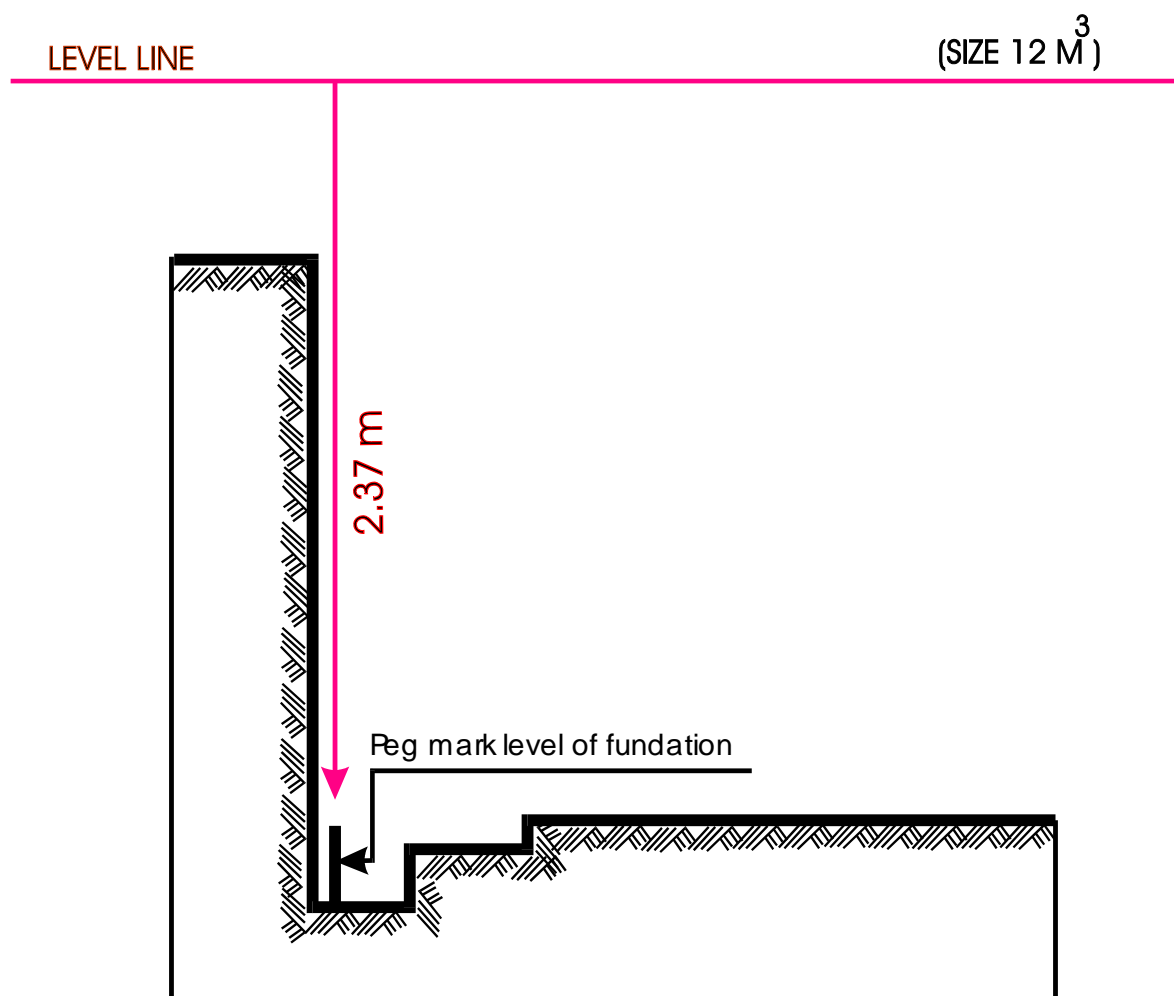
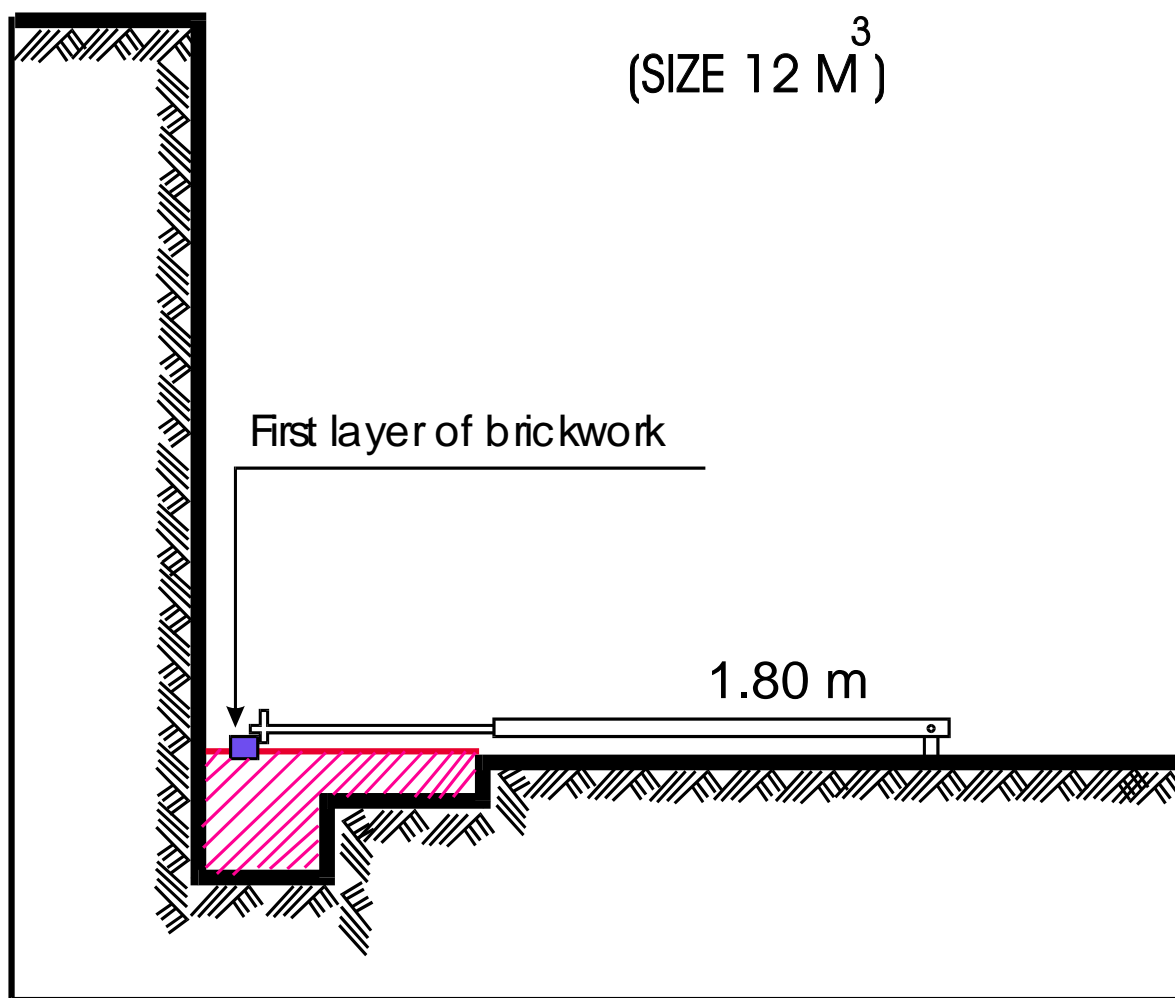


Figure 5.1 strength of the chamber depends on beams

Fill the foundation edge up to the same level as the ground with a mixture of cement 1 bucket : coarse sand 2 buckets : gravel 4 buckets (1 : 2 : 4 / volume). The mixture can be poured directly on the hard ground but fill the floor with coarse sand or gravel first if the ground is soft. While the cement is setting, cast the first layer of brickwork to allow the sufficient time for the bricks to attach to the cement base. The radius of brickwork is

1.30 meters	➤	4.6 m <sup>3</sup>	2.55 meters	➤	30 m <sup>3</sup>
1.57 meters	➤	8 m <sup>3</sup>	3.00 meters	➤	50 m <sup>3</sup>
1.80 meters	➤	12 m <sup>3</sup>	3.58 meters	➤	100 m <sup>3</sup>
2.05 meters	➤	16 m <sup>3</sup>			

Ram half of the brick into the cement base and scrape the surface of the outer beam.  
(Figure 5.2)



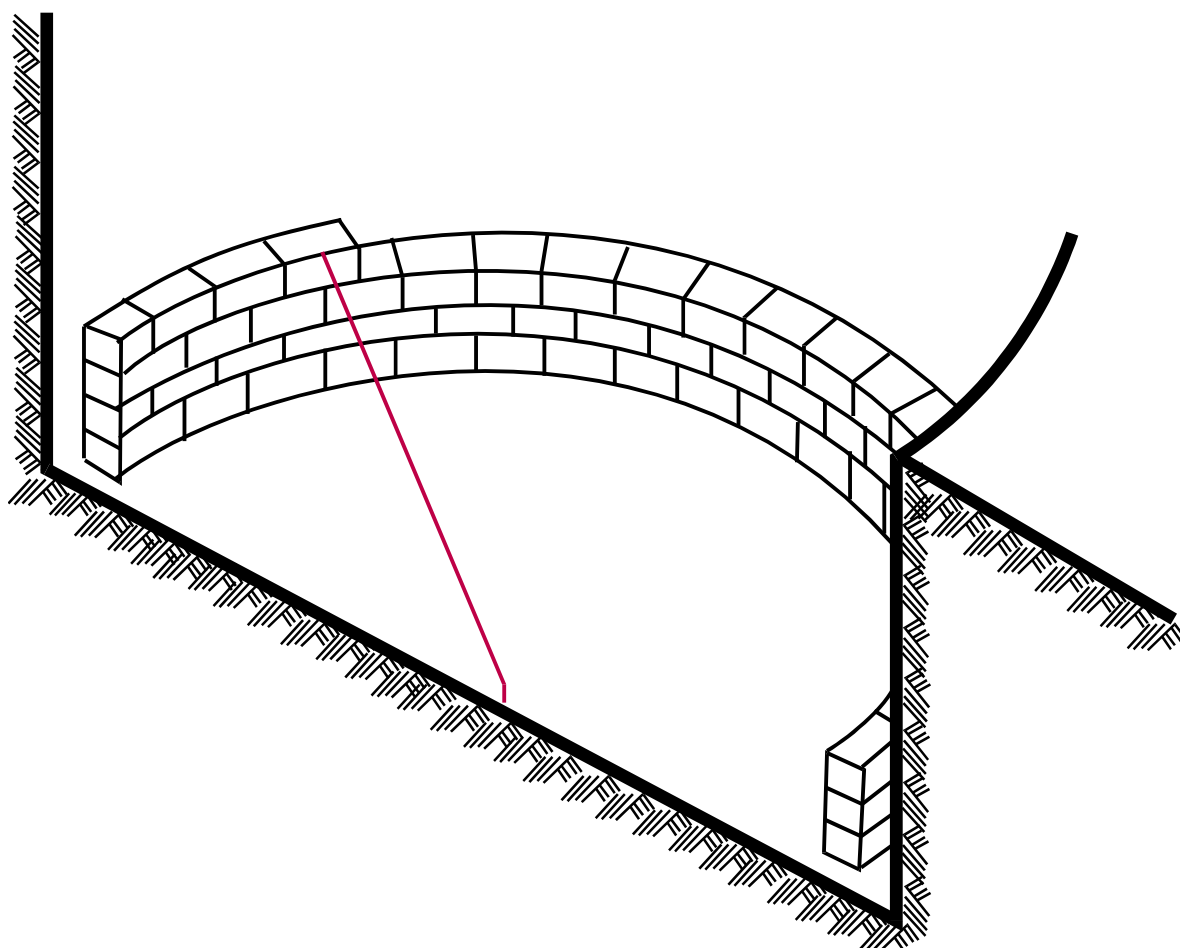
**Figure 5.2 First layer of brick work**

### 5.1.2 How to Line the Walls

When the first layer of brickwork was attached to the base, soak the bricks prepared for the next layer in water in order to wash out dust and to help the brick to settle better with cement. Concrete mixture is cement 1 bucket : lime 1/3 bucket : coarse sand 2.5 buckets (1 : 1/3 : 2.5 per volume). Set line for each brick using radius stick

1.30 meters	➤	4.6m <sup>3</sup>	2.55 meters	➤	30 m <sup>3</sup>
1.57 meters	➤	8 m <sup>3</sup>	3.00 meters	➤	50 m <sup>3</sup>
1.80 meters	➤	12 m <sup>3</sup>	3.58 meters	➤	100 m <sup>3</sup>
2.05 meters	➤	16 m <sup>3</sup>			

Radius stick must be used with each layer of brick to keep the radius constant.(Figure 5.3) Joints should be offset and finish consecutively one layer after the other until 4 layers has been completed. Stop working and wait for the cement to dry after casting the third layer of brickwork - 10cm above the ground, place the outlet pipe then continue casting.

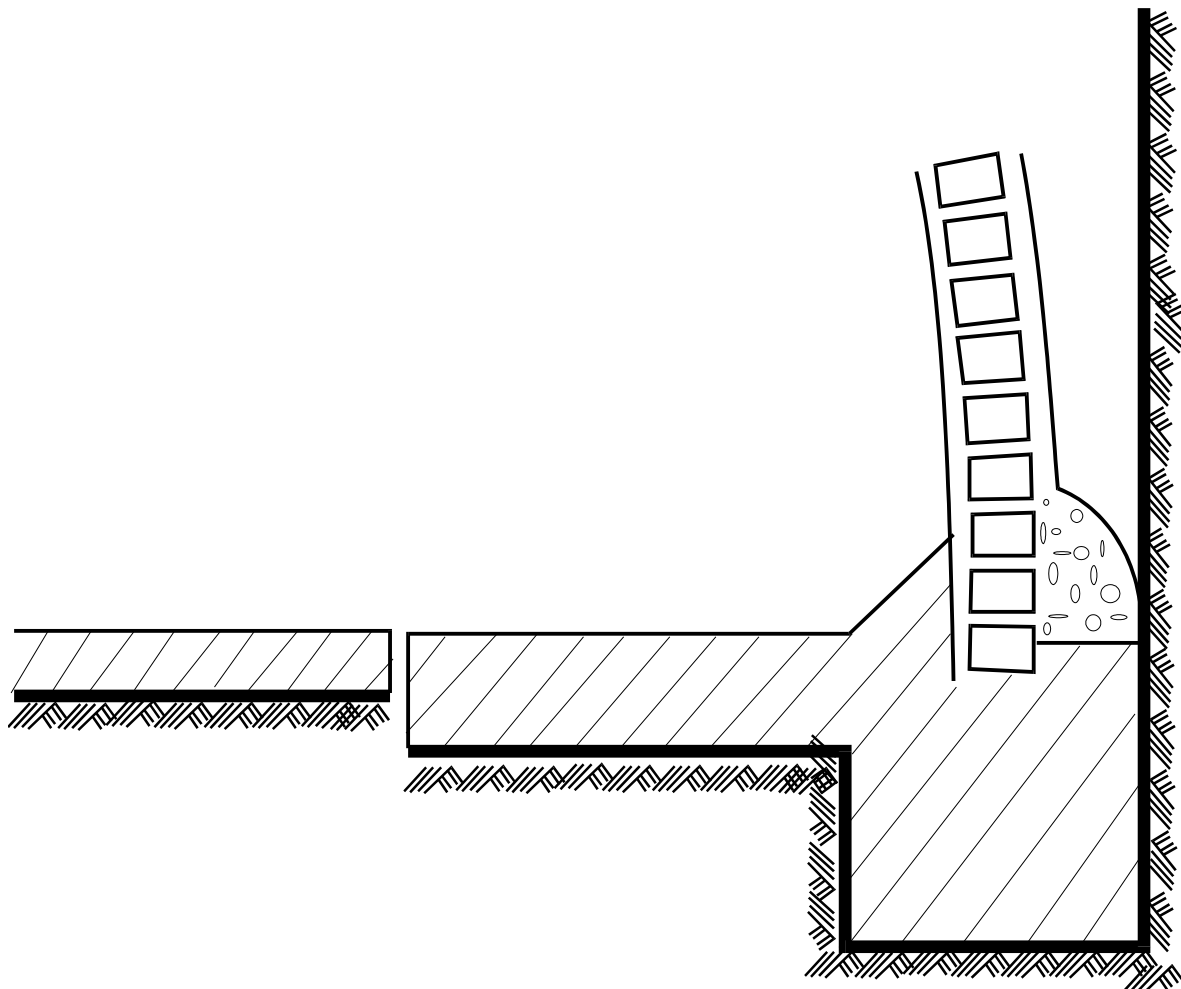


**Figure 5.3 layer of brick to keep the radius stick constant**

Seal the outside of the wall 3 layer high with cement mortar. Cement mixture is cement 1 bucket : coarse sand : 2 buckets : gravel 4 buckets (1 : 2 : 4 per volume). (Figure 5.4)  
When the layer is 1.60 meters measured from level line, leave a hole to place outlet pipe and inlet pipe (measure from the level line to the end of pipes). Continue casting until the level of brick work is

1.50 meters	➤	4.6 m <sup>3</sup>	1.44 meters	➤	30 m <sup>3</sup>
1.44 meters	➤	8 m <sup>3</sup>	1.78 meters	➤	30 m <sup>3</sup>
1.29 meters	➤	12 m <sup>3</sup>	2.04 meters	➤	30 m <sup>3</sup>
1.38 meters	➤	16 m <sup>3</sup>			

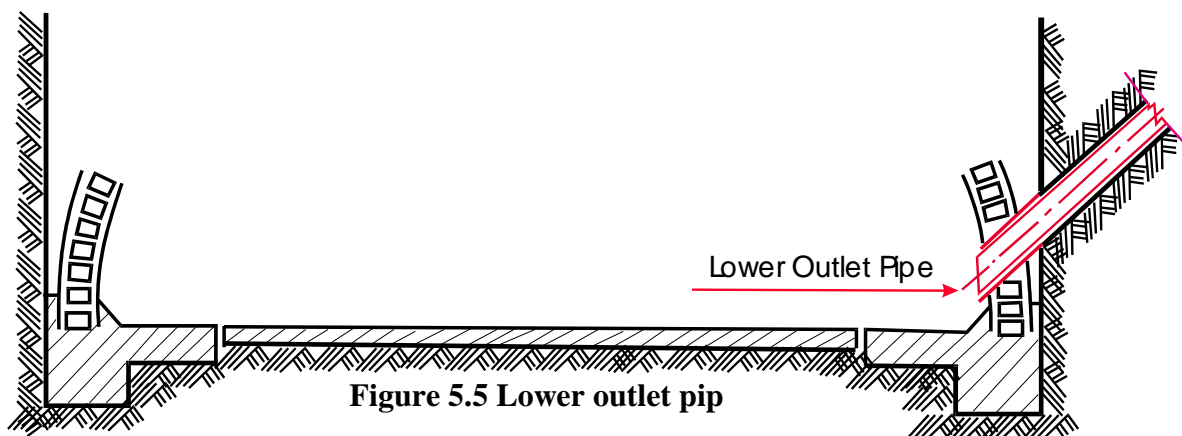
Stop casting and leave it to dry. Apply the outside wall with plaster 1 cm thick using the same mixture as for building wall.



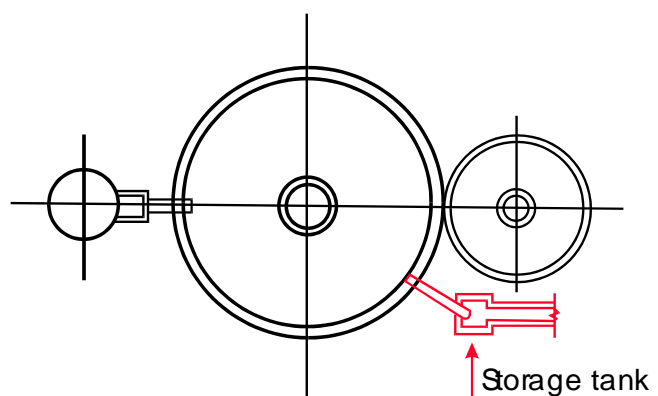
**Figure 5.4 Seal the outside of the wall 3 layer high**

### 5.1.3 Lower Outlet Pip and Storage Tank

This is for bio-gas plant that is filled with pig excrement. The residue of pig excrement is harder and sinks faster causing blockage. This 8 or 10 inch PVC diameter outlet pipe is rested at the bottom of the digester chamber wall. The bottom edge of the pipe is connected to the brickwork when it was constructed 10 cm or 3 layers above the floor ground (Figure 5.5). Before placing the pipe, use saw to scrape the outside of the pipe to let the cement settle better and to prevent seeping of water. At the upper end of the pipe build a square pit near the expansion chamber. The bottom floor of the storage tank is at the same level as the expansion chamber. The size of the storage tank is 25 cm (width) x 30 cm (length) x 60 cm (Height). There is an alley connected to outlet pipe of the expansion chamber or to storage tank to collect manure (Figure 5.6).



**Figure 14 Lower Outlet Pip**

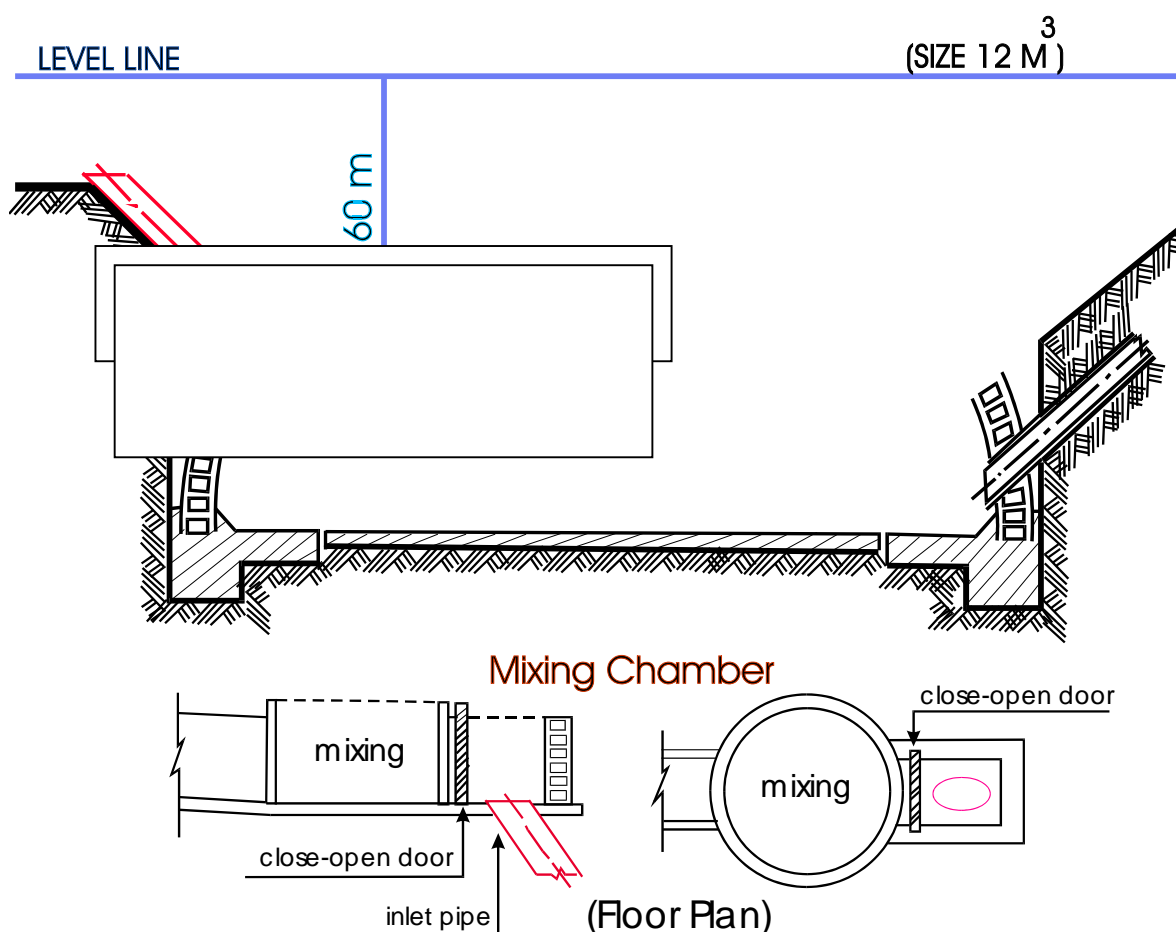


### 5.1.4 Inlet Pipe

The end of Inlet pipe is rests 1.60 meters from the level line. PVC pipe (or concrete pipe diameter 8 –10 inch) is required. Scrape the outside of PVC mixing pipe by saw to let the cement settle well and prevent seepage of water. Locate where the pipe should be placed and ram the pipe well into cement and keep the pipe in position with pegs.(Figure 5.7 )

1.60 meters	➤	4,6,8,12,16 m <sup>3</sup>
1.74 meters	➤	30 m <sup>3</sup>
2.08 meters	➤	50 m <sup>3</sup>
2.14 meters	➤	100 m <sup>3</sup>

□



**Figure 5.7 Inlet pipe**

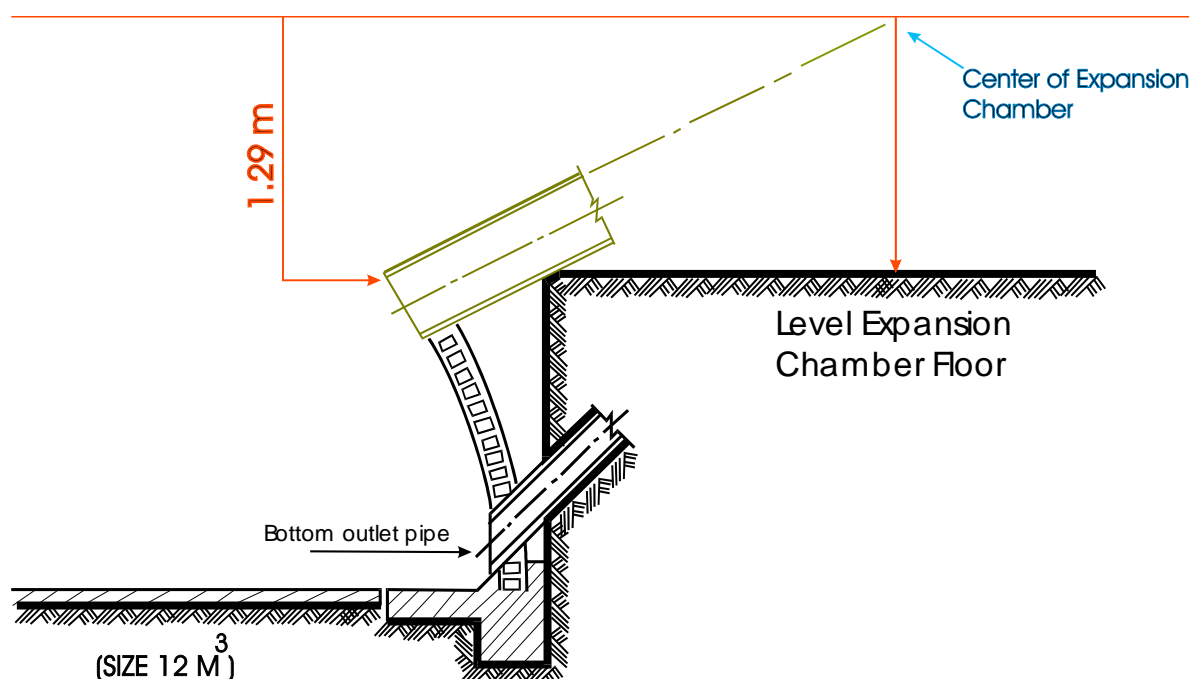


### 5.1.5 Outlet Pipe and Gas Control Pipe

**Outlet pipe** drains slurry and manure that had been broken down and stores them in expansion chamber. At the same time it controls gas pressure inside the chamber by releasing out exceeding gas or when gas is not being used. This prevents the wall of the chamber from exposing to high pressure. Increasing the life span of the gas chamber. The outlet pipe is made of concrete with diameter 10-12 inch. The bottom of the pipe is placed at the same level of weak ring, measured from reference line to the top edge of the pipe

1.35 meters	➤	4.6 m <sup>3</sup>	1.44 meters	➤	30 m <sup>3</sup>
1.44 meters	➤	8 m <sup>3</sup>	1.78 meters	➤	50 m <sup>3</sup>
1.29 meters	➤	12 m <sup>3</sup>	2.04 meters	➤	100 m <sup>3</sup>
1.38 meters	➤	16 m <sup>3</sup>			

The inside of the top of the pipe must be lined straight to a string that is tied to the level line at 90° to the center of the expansion chamber. Pour cement under the pipe for supporting and the pipes are kept in position by pegs. Continue the rest of the brickwork and face the concrete outside wall (Figure 5.8).



**Figure 5.8 Outlet pipe & Gas control**

### 5.1.6 Plaster the bottom to avoid leaking

When the wall is built at the height to start the weak ring, measure from the level line

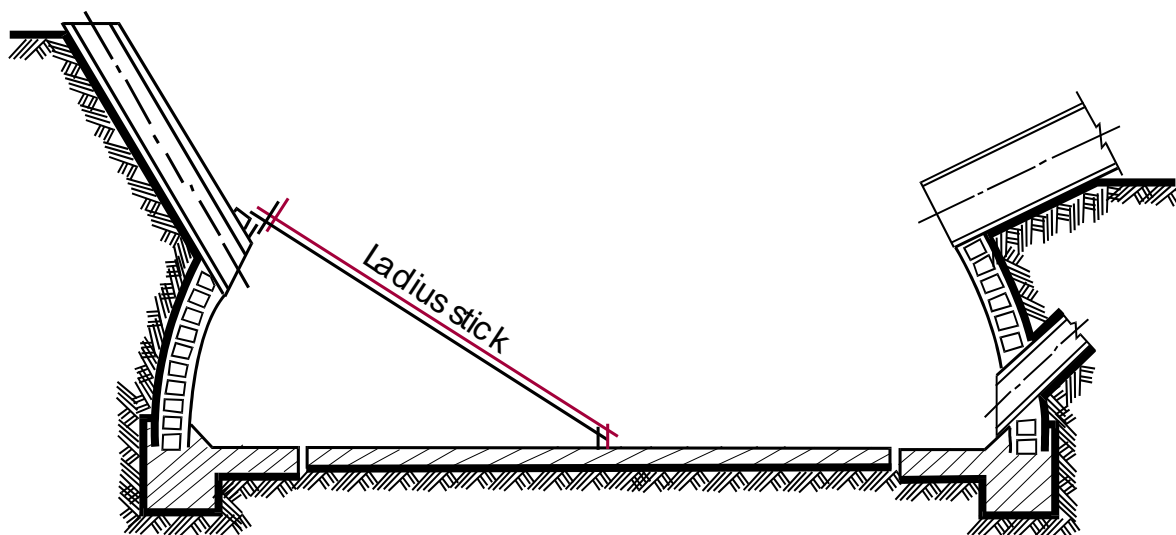
1.35 meters	➤	4.6 m <sup>3</sup>	1.44 meters	➤	30 m <sup>3</sup>
1.44 meters	➤	8 m <sup>3</sup>	1.78 meters	➤	50 m <sup>3</sup>
1.29 meters	➤	12 m <sup>3</sup>	2.04 meters	➤	100 m <sup>3</sup>
1.38 meters	➤	16 m <sup>3</sup>			

Clean the inside of the digester chamber and cover with lean mortar the mixture of cement 1 bucket : lime 1/3 bucket : fine sand 2.5 bucket (1 : 1/3 : 2.5 per Volume). Plaster the inside of the wall to 1 cm thick then plaster another layer at 1 cm thick. When cement is setting, use sponge to smooth the wall and to prevent leakage. When the plaster is finished, apply cement to cover the digester chamber floor 5 cm using the mixture cement 1 bucket : coarse sand 2 buckets : gravel 4 buckets (1 : 2 : 4 per Volume), do not cover the center. Leave to dry.

## 5.2 Step 2

### 5.2.1 Why does the soil have to be pressed firmly?

When the concrete face inside the wall is done, fill the outside dome 30 cm high with soil. Press firmly and fill more soil, press firmly again. It is not recommended to fill soil up to the top and press only once because the bottom soil would not pressed well enough. and the dome will crack. The outside back filling helps to support the high pressure of gas inside the dome. The back filling should be higher than the layers of brickwork and press the soil to the level of the radius stick (Figure 5.9).



**Figure 5.9 Outside back filling**

**Notice** Face concrete inside the wall before back filling to avoid the problem of having water outside dome.

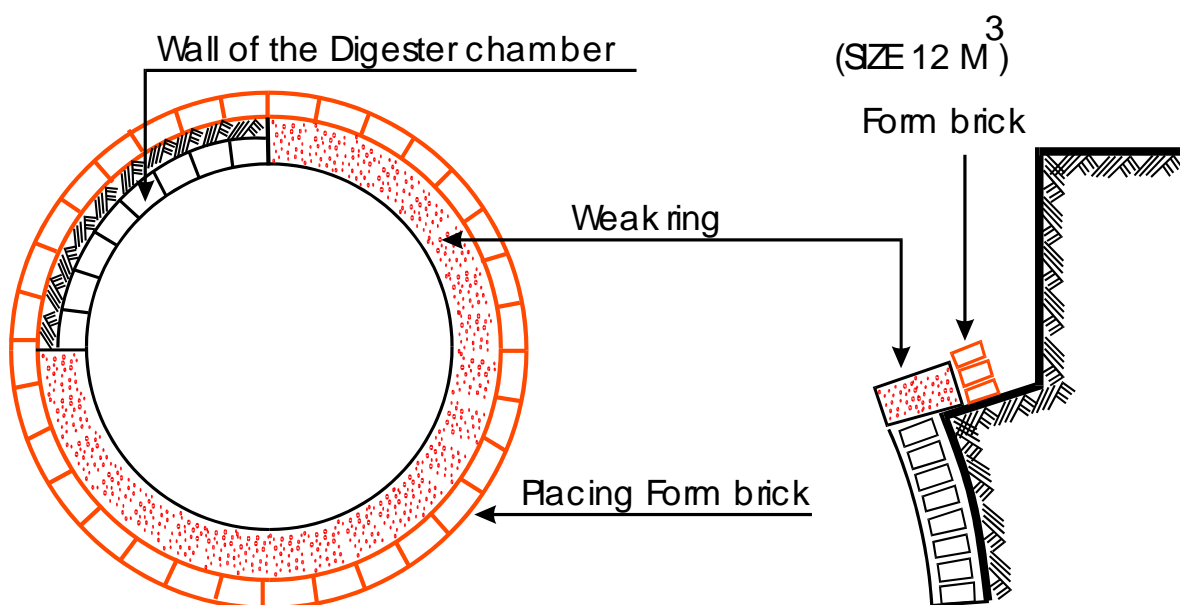
### 5.2.2 What is a Weak Ring?

A **weak ring** is constructed to separate the bottom wall and the upper part of dome. When the ground is sinking or the wall is cracked, the weak ring will prevent the vertical crack spreading up to the top of the dome. The weak ring is a soft mixture and flexible.

#### Mark a circle from the existing wall use radius

1.42 meters	➤ 4.6 m <sup>3</sup>	2.67 meters	➤ 30 m <sup>3</sup>
1.69 meters	➤ 8 m <sup>3</sup>	3.12 meters	➤ 50 m <sup>3</sup>
1.92 meters	➤ 12 m <sup>3</sup>	3.70 meters	➤ 100 m <sup>3</sup>
2.17 meters	➤ 16 m <sup>3</sup>		

The weak ring is built by placing bricks to form a wall outside the radius. The distance between the wall and weak ring is 1 brick wide. The mixture of cement 1 bucket : lime 3 buckets : fine sand 15 buckets ( 1 : 3 : 15 per Volume ) is required to form a circle over the top of the wall until the thickness is the same as the thickness of the formed brick. Use hard broom to scrape the cement while it is setting then start the next layer of cement until 3 layers are finished. With the same method applied in one day, the thickness of the cement will be approximately 10 cm. Smooth the last layer and leave it to be hardened for 24-48 hours (Figure 5.10).



**Figure 5.10 The weakring**

*Notice*

Do not use lime replacement

### 5.2.3 What is the Purpose of Expansion Chamber and How it is Built?

The expansion chamber controls the volume of gas in digester chamber and is involved in pushing gas up for usage when the valve is opened., it also drains out manure that has been digester.

To build an expansion chamber, fill the soil up and firmly press. Draw a circle to mark the size of the expansion chamber use radius

1.10 meters	➤	4.6 m <sup>3</sup>	1.50 meters	➤	30 m <sup>3</sup>
1.25 meters	➤	8 m <sup>3</sup>	1.88 meters	➤	50 m <sup>3</sup>
1.30 meters	➤	12 m <sup>3</sup>	2.07 meters	➤	100 m <sup>3</sup>
1.50 meters	➤	16 m <sup>3</sup>			

Mark out where the drainage alley will be excavated then dig a hole to build an expansion chamber according to the drawing. The depth of the chamber is measured from the level line approximately

1.10 meters	➤	4.6 m <sup>3</sup>	1.04 meters	➤	30 m <sup>3</sup>
1.16 meters	➤	8 m <sup>3</sup>	1.05 meters	➤	50 m <sup>3</sup>
1.05 meters	➤	12 m <sup>3</sup>	1.22 meters	➤	100 m <sup>3</sup>
1.10 meters	➤	16 m <sup>3</sup>			

Use plumb to find the center of expansion chamber floor and mark it. Mix the mixture of cement 1 bucket : coarse sand 2 buckets : gravel 4 buckets (1 : 2 : 4 per volume).and apply to built a 5 cm thick floor. The floor is at the same level of the upper edge of the outlet pipe. While the cement is setting, cast the first layer of brickwork use radius to control the line of brickwork (Figure 5.11).

0.90 meters	➤	4.6 m <sup>3</sup>	1.30 meters	➤	30 m <sup>3</sup>
0.95 meters	➤	8 m <sup>3</sup>	1.68 meters	➤	50 m <sup>3</sup>
1.10 meters	➤	12 m <sup>3</sup>	1.87 meters	➤	100 m <sup>3</sup>
1.30 meters	➤	16 m <sup>3</sup>			

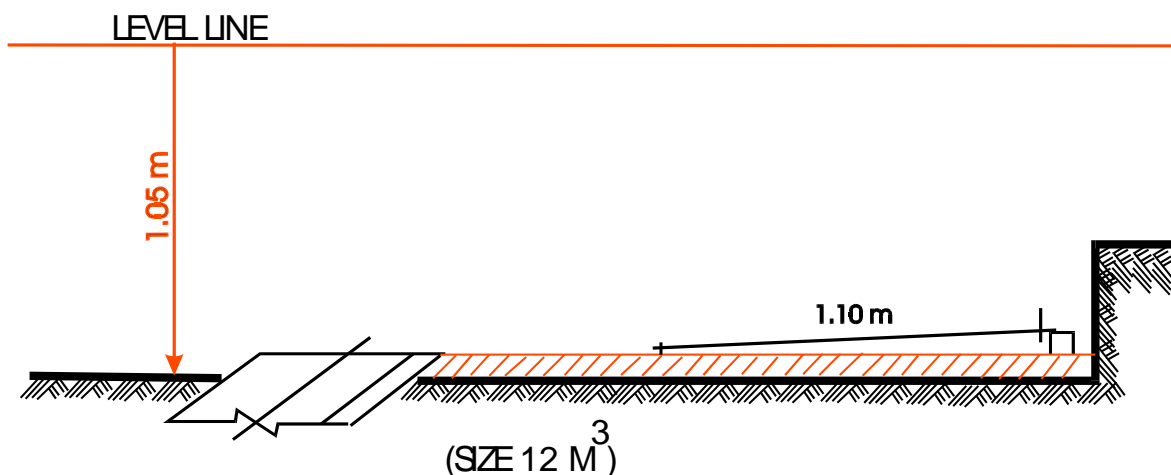
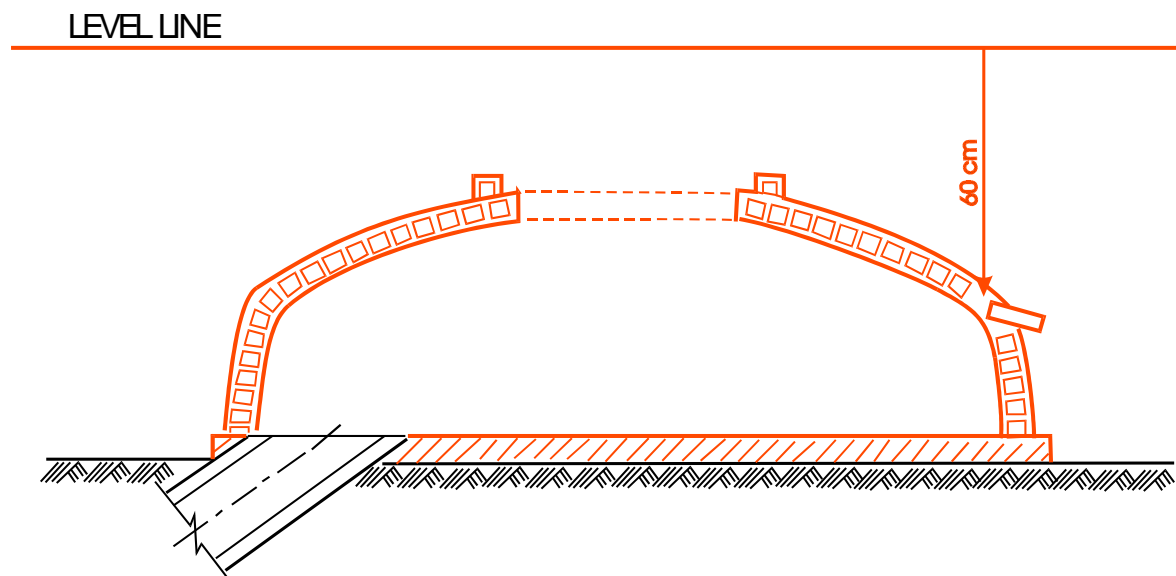


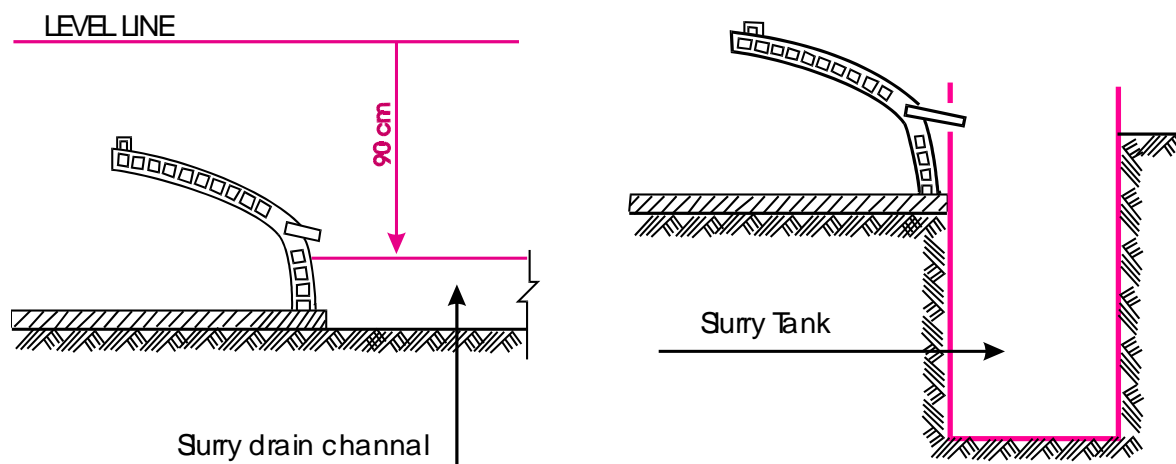
Figure 5.11 Expansion chamber floor

When the first layer is finished, leave it to dry. Soak the bricks prepared for other layers in water to let the cement set better. The mixture of cement 1 buckets : lime 1/3 bucket : coarse sand 2.5 buckets (1 : 1/3 : 2.5 per Volume) is applied to cast a brick wall and use radius stick to maintain the consistency (Figure 5.12).



**Figure 5.12 Cast a brick expansion chamber wall**

When the wall is approximately 60 cm high from the level line, place header bricks where the expansion outlet starts in order to support another layer of bricks. (This outlet width is twice a size of 2 bricks and as high as 3 layers of bricks.). Leave it to be hardened. Mix the mixture of cement 1 bucket : lime 1/3 bucket : fine sand 2.5 buckets (1 : 1/3 : 2.5 per Volume), face the concrete both sides of the wall 1 cm thick and smooth them. When it is dry, continue casting the wall and leave 80cm wide at the top as the outlet. Face the concrete both sides of the wall. Build an outlet channel on the vertical until reaches 90cm from level line. Leave it to be hardened. Face the concrete both sides 1cm thick and smooth the edge (Figure 5.13).



**Figure 5.13 Slurry drainage channel & Slurry tank**

### 5.3 Step 3

### 5.3.1 What is a Dome?

**The dome** collects gas and is located at the top of the digester chamber, separated from the lower wall by weak ring. Build the fixed dome by casting one layer of vertical bricks on top of the weak ring. On each layer, the lower part of brick sticks out 3-5 cm towards the inside of the dome. Build the next layer using the following radius.

1.30 meters	➤	4.6 m <sup>3</sup>	2.55 meters	➤	30 m <sup>3</sup>
1.57 meters	➤	8 m <sup>3</sup>	3.00 meters	➤	50 m <sup>3</sup>
1.80 meters	➤	12 m <sup>3</sup>	3.58 meters	➤	100 m <sup>3</sup>
2.05 meters	➤	16 m <sup>3</sup>			

Cast 5 layers and stop (to build strong ring). When finished continue building until the top of fixed dome is 42 cm wide. Leave it to harden. Pour cement to cover of the digester chamber that had been left earlier (Figure 5.14).

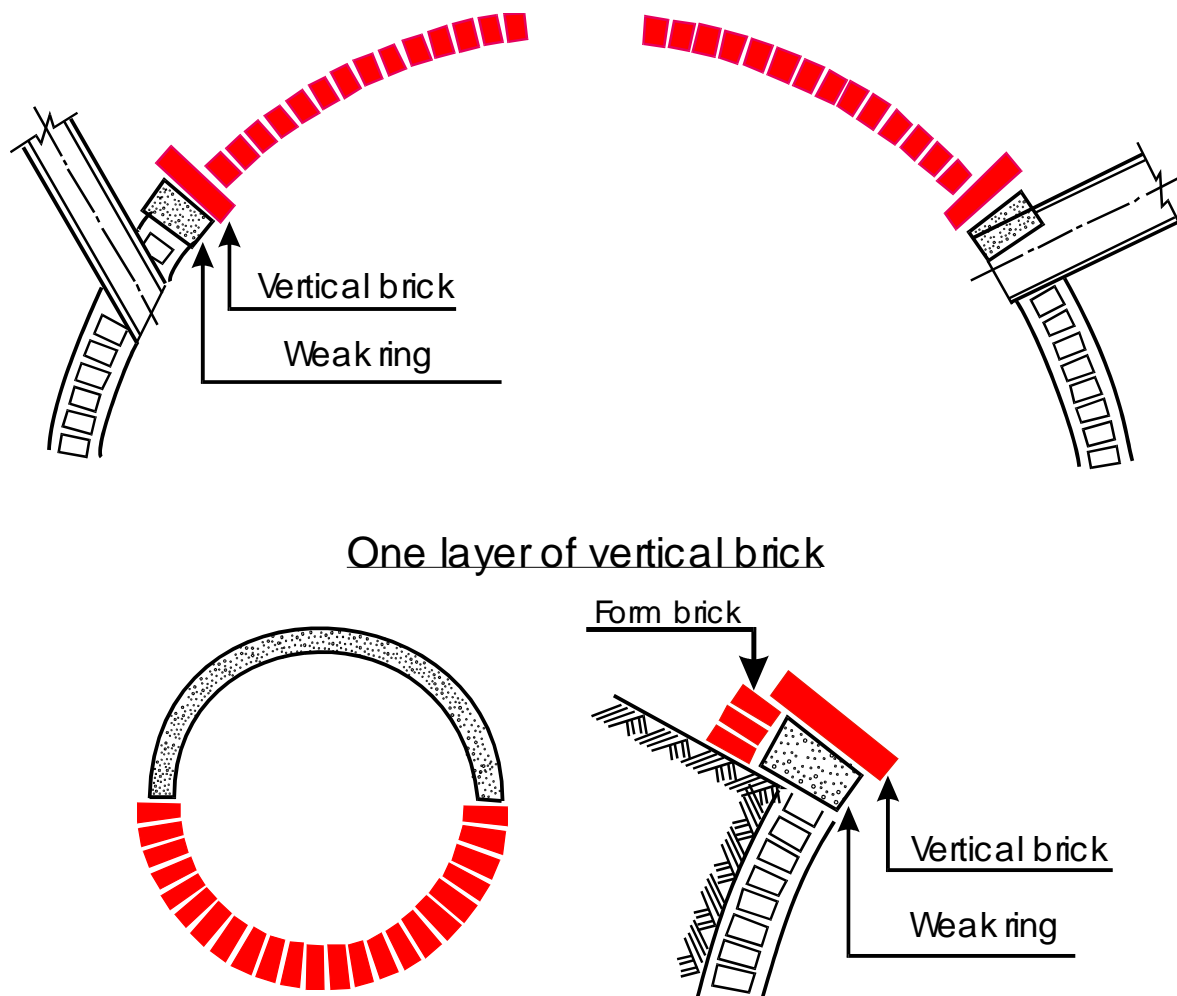


Figure 5.14 The Digester chamber dome

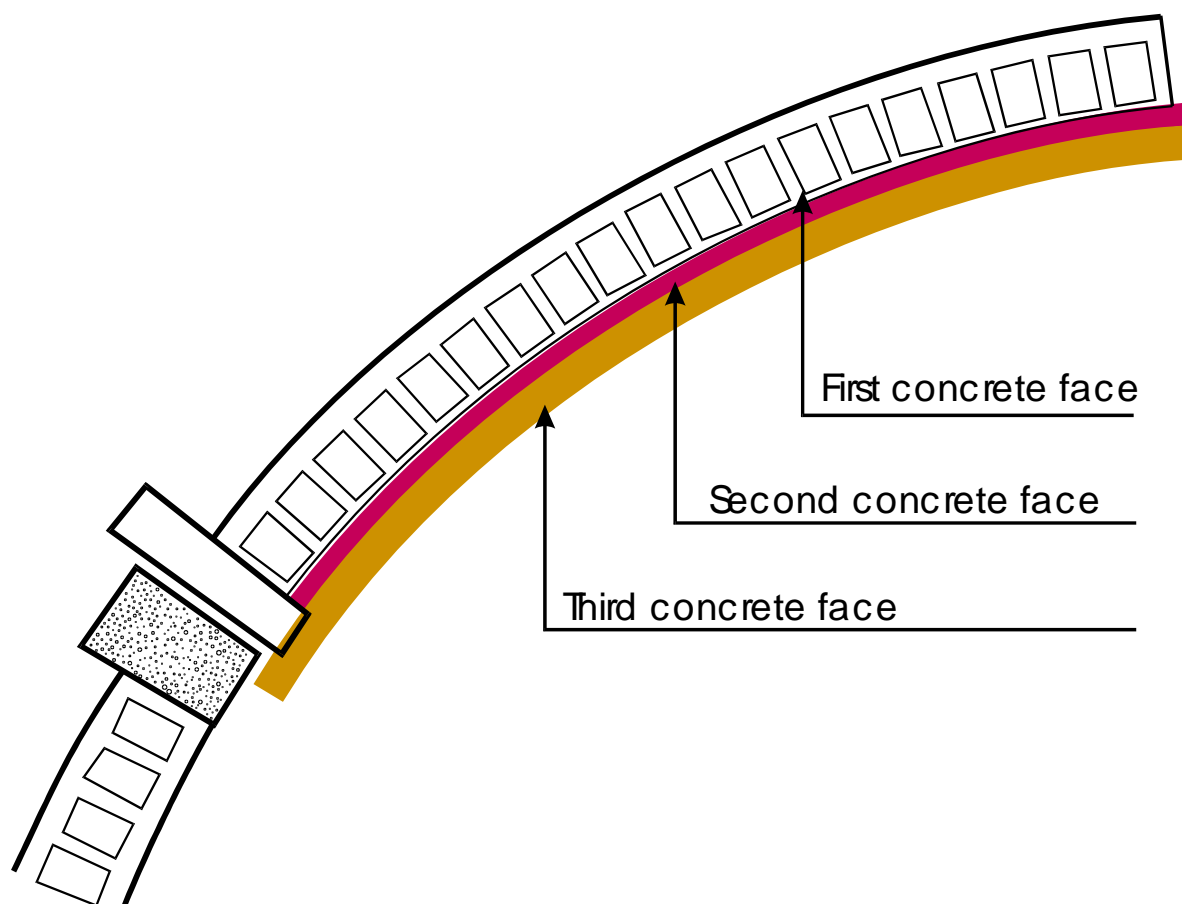
### 5.3.2 Non Crack Dome

Clear the loose cement and clean inside of the fixed dome. Spread lime water over the dome.

**First concrete face** Apply a mixture of cement 1 bucket : lime 1/3 bucket : coarse sand 2.5 buckets (1 : 1/3 : 2.5 per Volume ) to the inside dome to a thickness of 1 cm. Use hard broom to scrape the plaster and leave it for one day.

**Second concrete face** Apply a mixture of cement 1 bucket : lime 1/4 bucket : coarse sand 2.5 buckets (1 : 1/4 : 2.5 per Volume ) to the wall to a thickness of 1 cm thick after lime water is spread. Scrape the wall and leave it to be dry for 1 day.

**Third concrete face** Mix waterproofer with the same mixture of cement mortar. Plaster the dome 1 cm thick including the outlet (manhole). Polish well. Cover the neck of the chamber with sacks for retention (Figure 5.15).



**Figure 5.15 The dome concrete face**

**Notice** Fixed dome is where gas is collected. Workers must follow the instruction strictly. Do not rush to face the concrete in one day, it cannot prevent the crack.

### 5.3.3 Strong Ring is the Beam of Fixed Dome

The upper part of fixed dome is also very important. The strength of fixed dome is required by the mixture of cement 1 bucket : coarse sand 2 buckets : gravel 4 buckets (1 : 2 : 4 per Volume ). Before the cement is poured, remove the brick of the weak ring. Chip the soil under weak ring until reaches the first brick and strike the loosen cement out. Clean the outside wall, spread weak ring and 3 layers above with lime water. Pour cement to cover the vertical bricks in a shape of turtle back. Leave it to dry for one night (Figure 5.16).

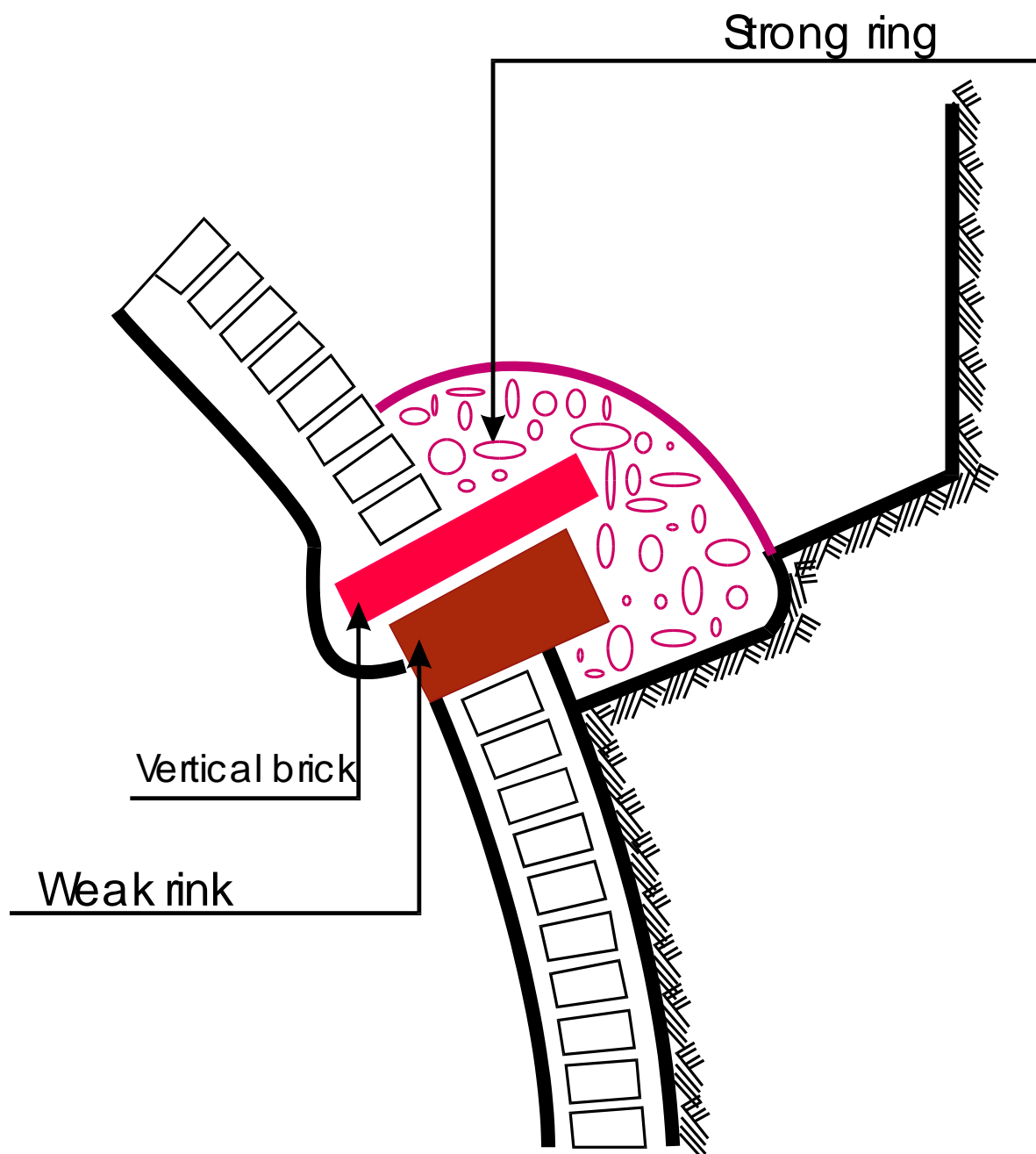


Figure 5.16 The strong ring



### 5.3.4 Why is the Neck of the Chamber Required?

**The neck** of the chamber is built to support the lid. Place a 70-80 cm diameter concrete ring on top of the open chamber. Adjust this 42cm hole until it is in the middle of the ring. Use water adjusting level to balance the vertical level. Use nail to mark the circle and remove the ring. Build up an edge with cement mortar and replace the ring exactly at the marked spot. Place steel mould to shape the inner wall. Put bricks inside the mould for ballast to stop the mould from moving. Coat oil to the outer mould to facilitate the removal of the mould (Figure 5.17). Clean the floor and spread the floor and the neck of the chamber with lime water. Use the mixture of cement 3 buckets : coarse sand 6 buckets : gravel 9 buckets (3 : 6 : 9 per Volume) to fill the gap until the height is 10 cm below the edge of the mould. Poke well to get rid of air bubbles. Place a wedge plugged with banana stem, (Figure 5.19) 4 cm measured from the top edge of the mould to the back of the wedge (Figure 5.18). Mark the position of wedges on the cement edged when the mould is removed, it will be easy to find the position later. There are 3 pieces of the wedges rested in triangle position with the end of each wedge 48 cm apart from each other (Figure 5.20). The gas pipe lies directly opposite one of the wedges. . Pour the rest of the cement to fill up to the top of the neck without poking because it may cause the wedges to move. Smooth the surface and leave it to dry for one day.

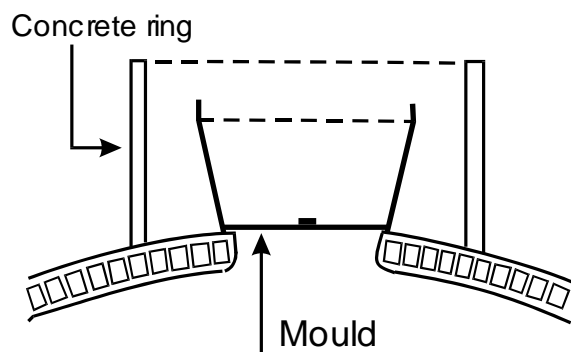


Figure 5.17 The neck

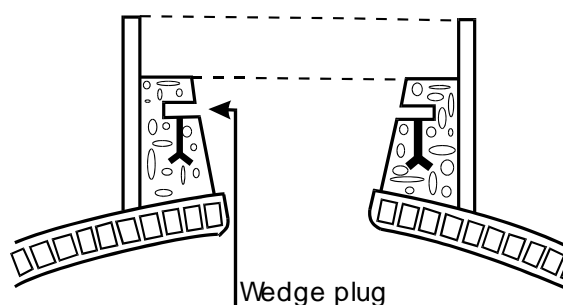


Figure 5.18 Position of the wedge plug

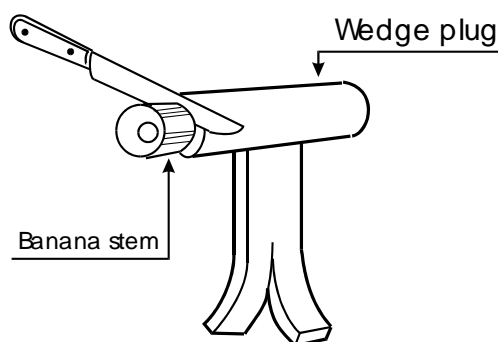


Figure 5.19 wedge plugged with banana stem

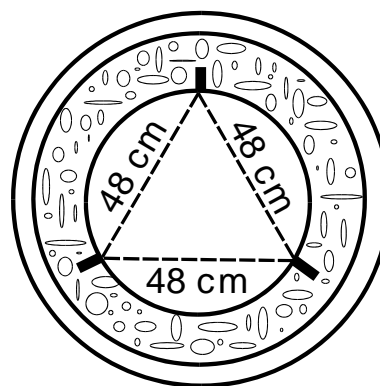
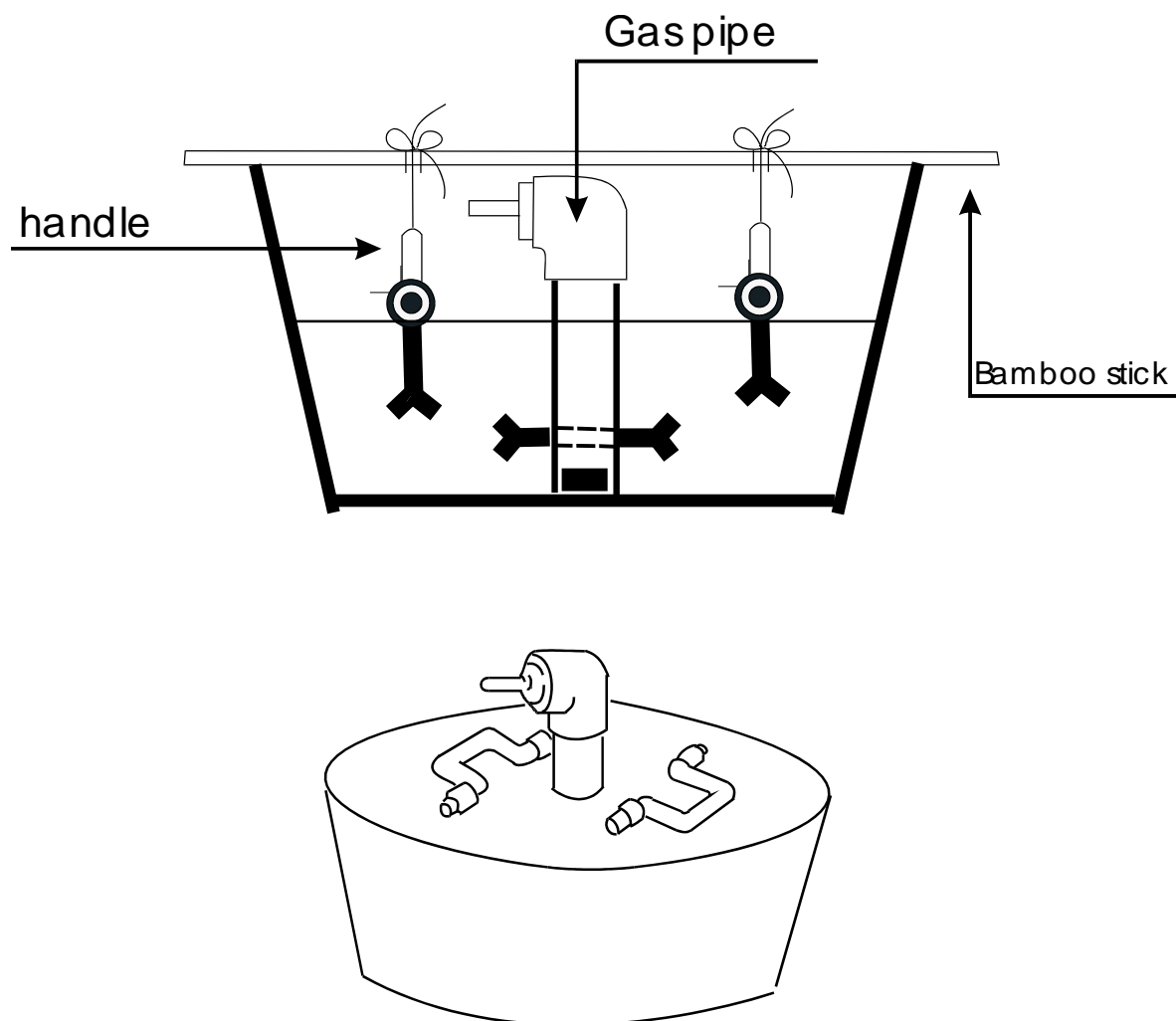


Figure 5.20 Triangle position

### 5.3.5 How to Mould the Lid?

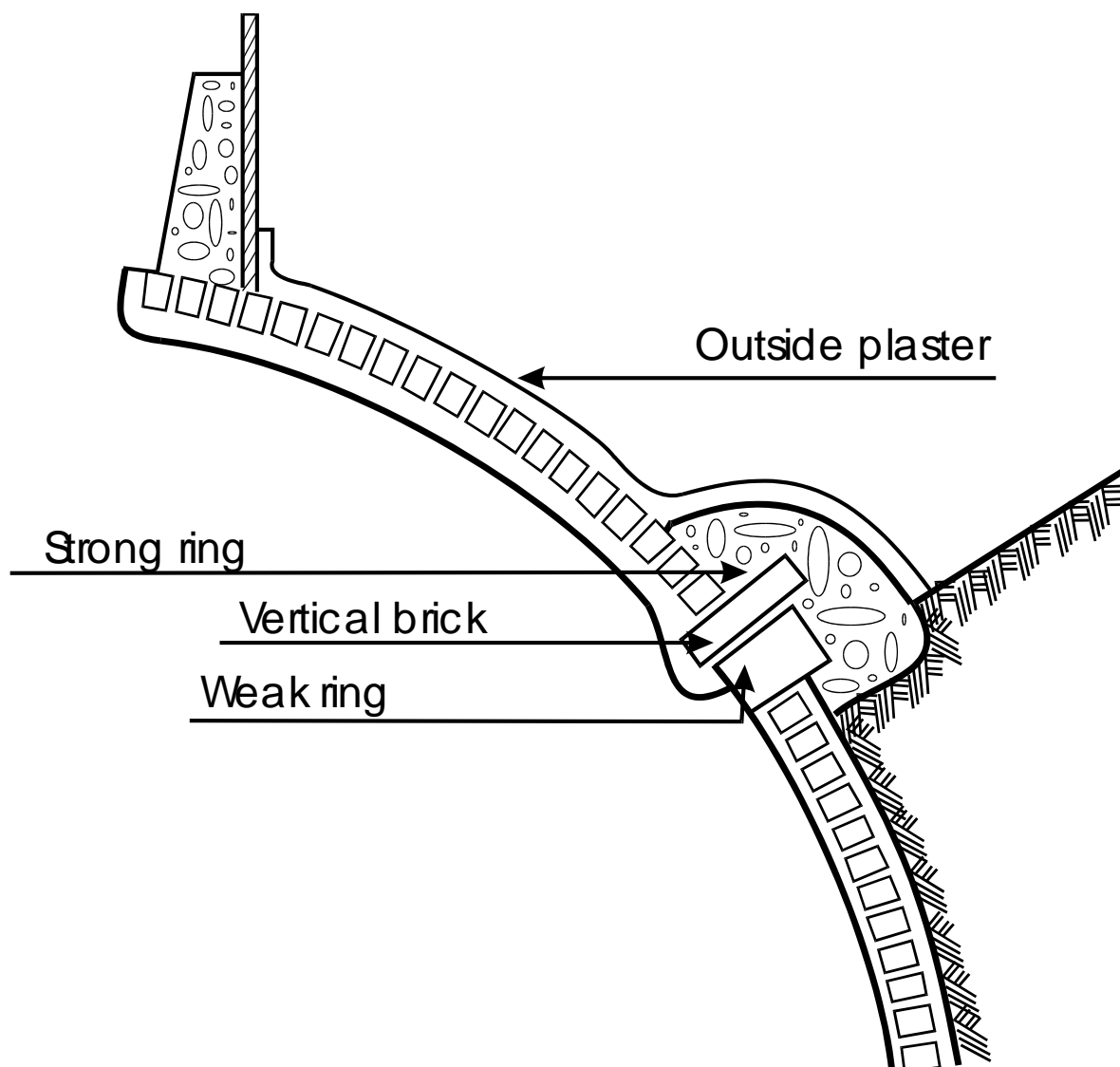
Before moulding the lid, the steel mould and gas pipe must be cleaned with wire brush. Coat the inside with oil and set the gas pipe together with 90° (1.5 inch) joint. Pour the mixture of cement 2 bucket : coarse sand 4 bucket (1 : 2 per Volume) into the mould until a depth of 15 cm is reached. Use a hammer strike the outside mould to get rid of air bubbles. Secure 2 handles by tying to a bamboo stick laid across top of the mould. Smooth the surface and leave it to harden. Use a sack to cover the mould to avoid any cracks. After 1-2 days remove the mould and leave the lid in water until it is being used (Figure 5.21).



**Figure 5.21 The lid**

### 5.3.6 The Outside Dome Plaster

Clean the outer wall including the strong ring and spread with lime water. The mixture of cement 1 bucket : lime 1/3 bucket : coarse sand 2.5 buckets : (1 : 1/3 : 2.5 per Volume) is required to plaster the outer wall until the thickness of 3 cm is reached. Polish and leave it to be hardened (Figure 5.22). When the cement is completely dry, cover it with sacks and apply water 3 times a day to maintain the retention. After that fill the back with soil. The expansion chamber and the digester chamber must be covered well under the soil and only the necks are left free to avoid any cracks and to let the weight of soil support against the dome. Vegetables or grass can be planted on the top to prevent eroding or provide a good sight.



**Figure 5.22 The outer plaster cement**

## 5.4 Step 4

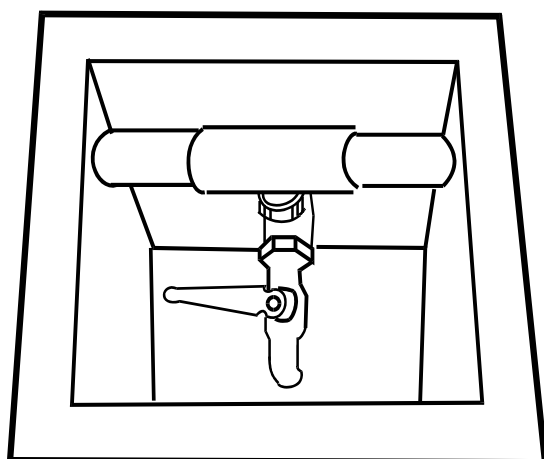
### 5.4.1 Gas Pipe Installation

It is one of the most important Steps of the construction. If the pipes are badly connected or if there is any leakage, the volume of gas will decrease. Some farmers will blame it on the construction of the chambers

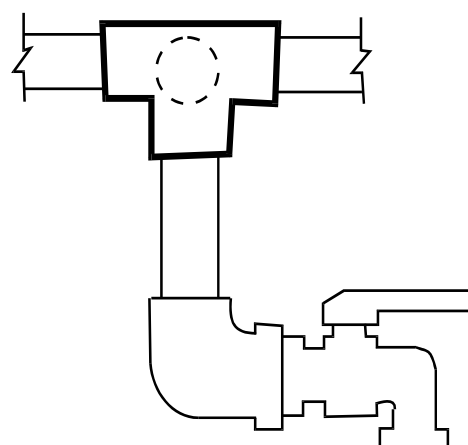
### 5.4.2 The Piping System

1. **Excavating the channel.** Set the level of the channel slight slope from the valve at the outlet to the lowest point at least 20 cm deep and 20 cm wide. From the lowest point dig a trap water pit sizes 30 cm x 50 cm x 50 cm. Form a brick wall, fill the floor with cement and face the concrete to the inner wall with cement added waterproofer.
2. **Gas pipe.** If the piping distance is within 20 meters use 6/8 inch PVC pipe. The 1 inch pipe is suitable for the distance further than 20 meters.
3. **Checking the pipe.** The pipe is checked by closing one end with a palm and letting a person blow through the other end of the pipe. Blow for 1 minute, if the pressure is still stable, it indicates the sufficiency. If the pressure is reducing, the pipe is leaking, change new pipe.
4. **Clean the pipe and joint.** Use sand paper No.100 to scrape the end of pipe and inside the joint then clean well.
5. **Gluing.** Apply glue onto the parts that will be connected both the end of the pipe and inside the joint. Put them together and press with palms for 30 seconds then release.
6. **Water trap.** Apply T-joint 15-20 cm downward into water trap pit and install the valve at the end of the joint (Figure 5.23).
7. **Piping system.** Line the pipe to an area where the gas will be used. Install a gas valve and steel plate collar over the PVC pipe to connect to gas equipment. The pipe must be well covered underground to avoid cracks caused by animal or vehicles.

Figure 5.23 Water trap



Water Tape Pond

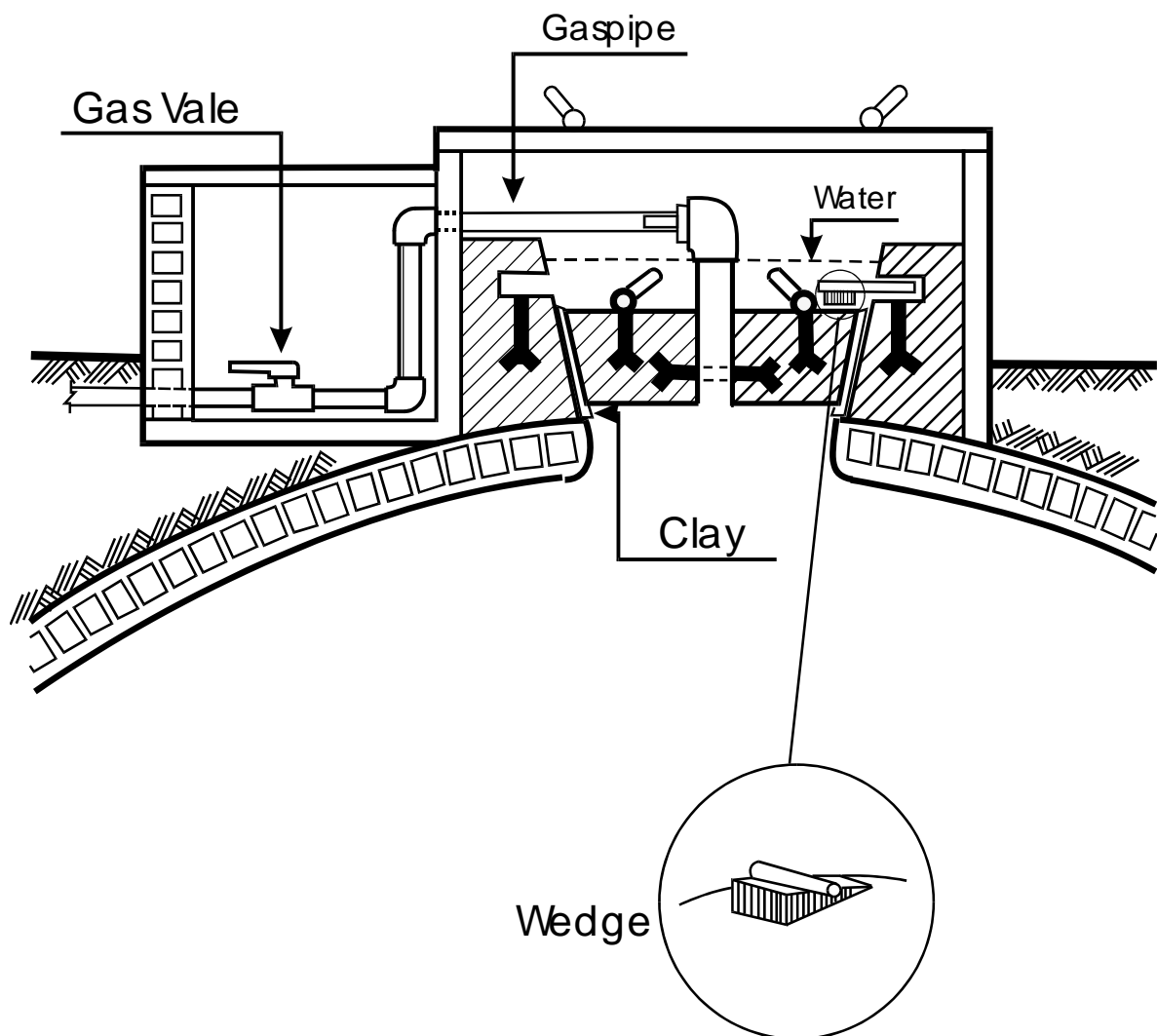


Water Tape

*Notice* To connect to screw pipe use tape to wind threads before connection. Do not wind too tight, the pipe may break. The locations where valve should be installed are the outlet of digester chamber, the place where gas the equipment will be installed and manometer.

### 5.4.3 Closing the Lid

Use well kneaded clay (without any stones) to plaster around the edge of the manhole or the outlet to a thickness of 1cm. Plaster the lid 0.5 thick. Remove the banana stems used to clog the wedge. Put the lid to cover the edge of the outlet slowly and check the level. Press hard using body weight. Insert pegs to secure under the wedges and fill with water until they are covered. Before closing the lid, plan where the gas pipe is to be connected (Figure 5.24).



**Figure 5.24 Closing the lid**

#### 5.4.4 Why the Chamber has to be Tested?

The most important process of constructing the bio-gas plant is to test the gas chamber and gas pipe. If there is any crack, gas can not be stored. Before filling animal excrement, the leakage must be tested.

##### Testing unit

*Mano-meter* is connected to the gas pipe at the outlet of the digester chamber. Fill water into either the inlet pipe or expansion chamber until the mono meter can be read 80 cm. (40 x 2) and leave it for 12 hours.

If the pressure reduces by less than 10 cm (5 x 2), the gas chamber is in good condition. If the pressure reduces more than 10 cm, check the possible sites where water is seeping, for example at the bottom of digester chamber, the bottom of the expansion chamber or leakage of air through fixed dome. Repair cracks and leaks and test again until air is not leaking (Figure 5.25).

*Testing gas pipe.* Close valves of the digester chamber and the water trap. Open kitchen valve and blow into gas pipe until the pressure is at 80 cm. Close valve in the kitchen leave it for 1 hour. If the pressure reduces, there is leakage. Check every joints and T joints by using soap water. The bubbles will indicate the leakage. Change a new joint. When the gas chamber is tested and there is no leakage, fill the animal excrement without release water in the chamber.

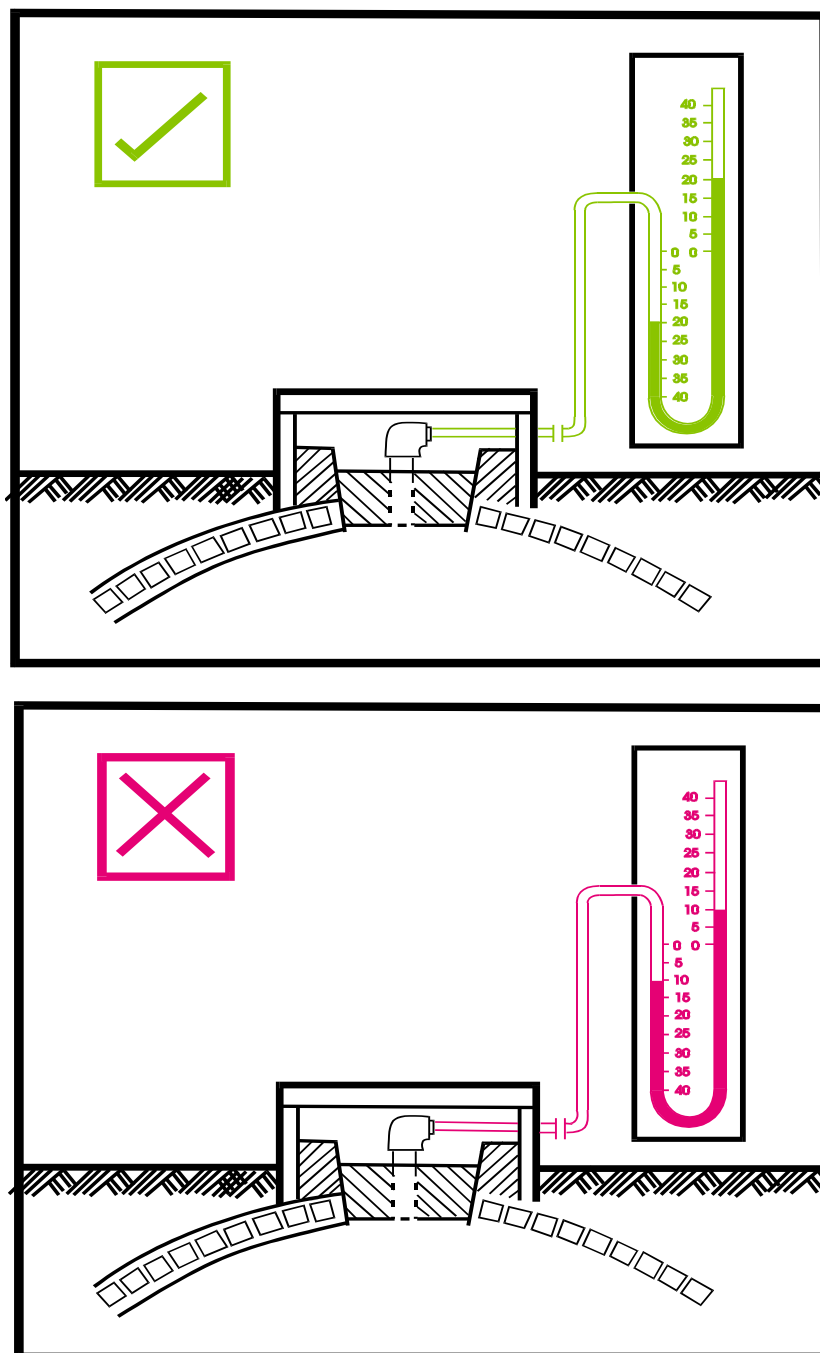


Figure 5.25 Manometer Testing

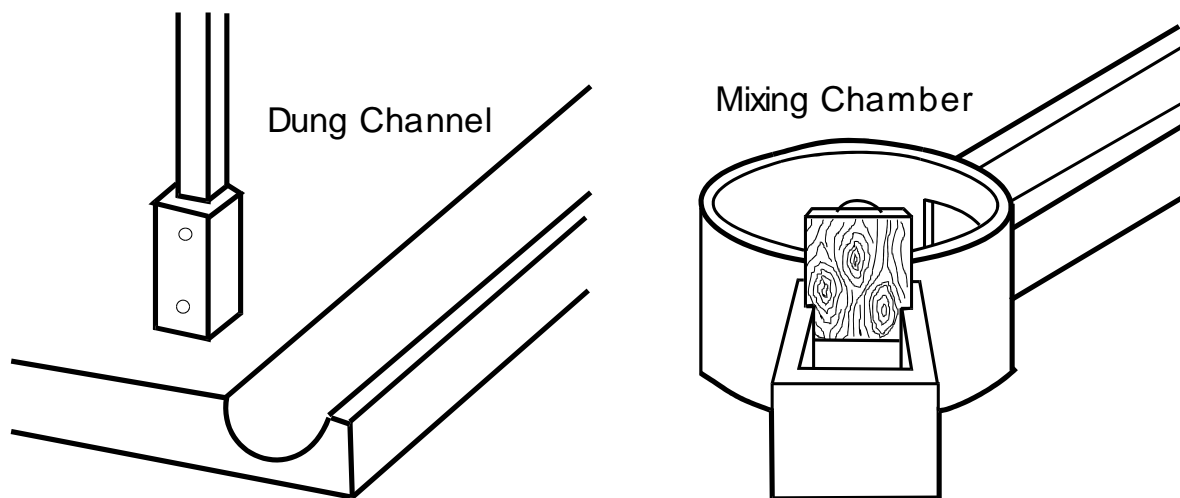
**Notice** If the gas pipe is already connected to the digester chamber, the chamber and pipe can be tested together by installing the mono meter. Close kitchen's valve and water trap valve then open valve at the digester chamber. Testing according to the above suggestion.

## Chapter 6

### Additional Information in Reactor Construction

#### 6.1 Where to Fill in Animal Excrement?

The drainage alley must be built connected to the enclosure. The floor should be slightly arched polished. The excrement will flow easily and no residue will be left. Connect the alley to the inlet of the mixing chamber. There is a gate built at the mixing chamber for mixing the excrement and let it flow into the chamber (Figure 6.1).



**Figure 6.1 Dung channel & mixing chamber**

#### 6.2 Lids

Lids are required to prevent animal and rain water to fall in and also to keep it tidy. The lids are for

- ✱ Digester chamber
- ✱ Pit where the valve is installed for the digester chamber.
- ✱ Expansion chamber
- ✱ Water trap pit
- ✱ Storage tank



### 6.3 Storage Tank

Storage tank collects overflow manure from the expansion chamber. Manure in the storage tank can be used as fertilizer to improve soil by pouring over agricultural fields, fruit plantations grass. It prevents the manure from overflowing to the outside ground (Figure 6.2).

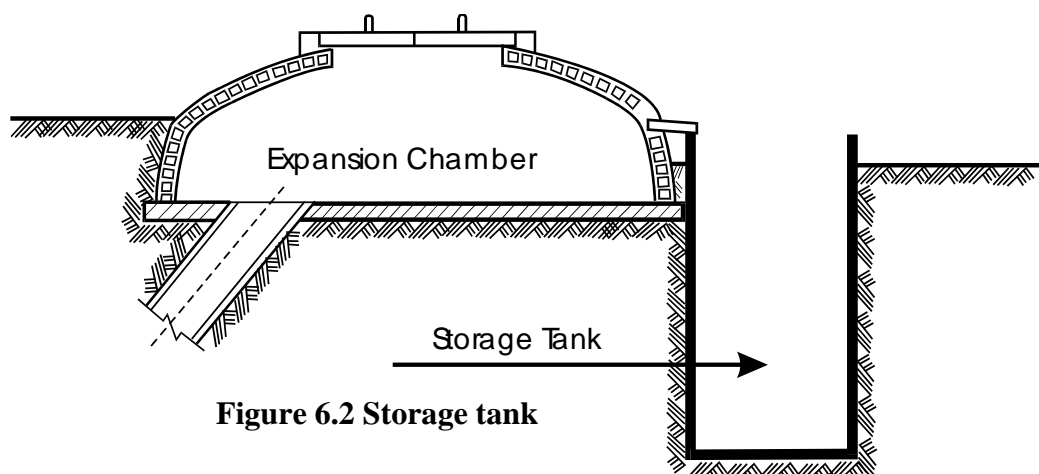


Figure 6.2 Storage tank

### 6.4 Addition of the First Animal Excrement

After the chamber is tested, animal excrement can be filled into the mixing chamber without releasing water. When the excrement is added, use the water from the expansion chamber to mix and stir until it become liquid slurry. Release the testing pressure by opening valve at the water trap. Let the air vent out until it is empty then close the valve. The manure will flow into the digester chamber. It is not recommended to fill up the top at one time so as to avoid the slow production of gas or decomposing. It should be added portion by portion until full. The first adding takes about 7 days as follows :

#### 6.4.1 The first filling (first 7 days), use cow or buffalo excrement

	4.6 m <sup>3</sup>	8 m <sup>3</sup>	12 m <sup>3</sup>	16 m <sup>3</sup>	100 m <sup>3</sup> pig
Cow or buffalo excrement	330 liters	600 liters	800 liters	1200 liters	4,000 liters
Water	330 liters	600 liters	800 liters	1200 liters	8,000 liters

**Notice** If cow or buffalo excrement is not available, pig excrement is accepted by using half of the suggested quantity. After 2 weeks, add normally according to the manual.

#### 6.4.2 Next filling, after the first 7 days, add excrement daily

	4.6 m <sup>3</sup>	8 m <sup>3</sup>	12 m <sup>3</sup>	16 m <sup>3</sup>	100m3
Cow or buffalo excrement	38 liters	70 liters	100 liters	140 liters	833 liters
Water	38 liters	70 liters	100 liters	140 liters	833 liters
Pig excrement	25 liters	50 liters	70 liters	90 liters	660 liters
Water	50 liters	100 liters	140 liters	180 liters	1,320 liters

Gas will be produced within 2-3 days.

**Notice** Do not fill more than suggested because gas will cease. If filling too little, gas will be slowly produced.

## 6.5 Summary of Levels and Sizes for Construction

Activities	4.6m <sup>3</sup> meter	8 m <sup>3</sup> meter	12 m <sup>3</sup> meter	16 m <sup>3</sup> meter
1. <b>The center of digester chamber</b> should be far from the enclosure at least	2.50	2.70	3.00	3.30
2. <b>Excrement outlet</b> is measured from the center of digester chamber radius	2.90	3.95	4.10	5.22
<b>3. Digester chamber sizes</b>				
3.1 Radius digging of digester chamber	1.55	2.01	2.24	2.30
3.2 Depth of the chamber measured from the level line do not dig deeper than criteria	2.10	2.39	2.42	2.67
3.3 Radius of wall and dome construction * place bricks outside the radius	1.30	1.57	1.80	2.05
<b>4. Beam of digester chamber</b>				
4.1 <i>Radius of outer beam</i> inner ring	1.15	1.46	1.70	1.94
Outer ring	1.41	1.76	1.99	2.24
* excavate the outer ring 30 cm				
4.2 <i>Radius of inner beam</i>	0.85	1.01	1.25	1.50
* excavate the inner ring 10 cm				
5. <b>The level of the lower outlet pipe</b> from the floor of digester chamber	0.10	0.10	0.10	0.10
6. <b>The level of the upper inlet pipe</b> measured from level line to end of pipe	1.50	1.60	1.60	1.60
7. <b>The level of outlet pipe</b> measured from level line to end of pipe	1.35	1.44	1.29	1.38
8. <b>The level of weak ring</b> measured from level line	1.35	1.44	1.29	1.38
9. <b>The center of expansion chamber</b> from the center of digester chamber	2.20	3.00	3.00	3.60
<b>10. Expansion chamber sizes</b>				
10.1 Radius to excavate the chamber	1.10	1.25	1.30	1.50
10.2 Radius of filling the floor	1.00	1.05	1.20	1.40
10.3 The depth of chamber measured from level line	1.10	1.11	1.05	1.10
10.4 Radius of wall construction	0.90	0.95	1.10	1.30



## 6.6 Equipment Used in Construction

Description	4.6m <sup>3</sup>	8 m <sup>3</sup>	12 m <sup>3</sup>	16 m <sup>3</sup>
Grounded rocks or gravel ½ inch	2 m <sup>3</sup>	2 m <sup>3</sup>	3 m <sup>3</sup>	4 m <sup>3</sup>
Coarse sand	2 m <sup>3</sup>	3 m <sup>3</sup>	3 m <sup>3</sup>	4 m <sup>3</sup>
Fine sand	1 m <sup>3</sup>	2 m <sup>3</sup>	3 m <sup>3</sup>	4 m <sup>3</sup>
Brick size 7x17 cm tin 4.5 cm.	2,500 pcs	3,000 pcs.	4,200 pcs.	5,000pcs
Cement	22 bags	25 bags	35 bags	40 bags
Waterproofer	1 tin	1 tin	1 tin	1 tin
Lime	6 bags	8 bags	10 bags	15 bags
Lime replace	1 tin	1 tin	1 tin	1 tin
Concrete pipe diameter 10-12 inch	1 piece	1 piece	1 piece	1 piece
Concrete ring diameter 70 cm	2 pieces	2 pieces	2 pieces	2 pieces
Concrete ring diameter 80 cm (Storage tank)	2 pieces	3 pieces	3 pieces	3 pieces
PVC pipe diameter 6”(inlet and lower outlet )	1piece	1 piece	1 piece	1 piece
Handle set		1 set	1 set	1 set
Mono-meter		1 set	1 set	1 set

## Equipment Used in Construction (continued)

Description	30m <sup>3</sup>	50m <sup>3</sup>	100m <sup>3</sup>
Grounded rocks or gravel ½ inch	6 m <sup>3</sup>	3m <sup>3</sup>	10 m <sup>3</sup>
Coarse sand	6 m <sup>3</sup>	12 m <sup>3</sup>	15 m <sup>3</sup>
Fine sand	6 m <sup>3</sup>	6 m <sup>3</sup>	10 m <sup>3</sup>
Brick size 7x17 cm tin 4.5 cm.	6,500 pcs	13,000pcs	18,000pcs
Cement	70 bags	120 bags	170 bags
Waterproofer	1 tin	1 tin	2 tin
Lime	15 bags	20 bags	30 bags
Lime replace	2 tin	3 tin	4 tin
PVC pipe diameter 10-12 inch	2 piece	3 piece	3 piece
Concrete ring diameter 70 cm	2 piece	2 piece	2 piece
Concrete ring diameter 80 cm (Storage tank)	3 piece	3 piece	3 piece
Handle set	1 set	1 set	1 set
Mono-meter	1 set	1 set	1 set

### 6.7 Summary of Ratio of Cement Mixture for Construction

Step of construction	Cement bucket	Water proofer	Lime bucket	Sand bucket	Gravel bucket
Base of digester and expansion chamber	1	-	-	2	4
Chamber walls	1	-	1/3	2.5	-
Back filling	1	-	-	2	4
Outer wall mortar	1	-	1/3	2.5	-
Weak ring	1	-	3	1.5	-
Strong ring	1	-	-	2	4
Mortar for Digester chamber bottom wall	1	-	1/3	2.5	-
Mortar for inner wall of digester dome – first layer	1	-	1/3	2.5	-
Mortar for inner wall of digester dome – second layer	1	-	1/4	2.5	-
Mortar for inner wall of digester dome – third layer	1	with	1/4	2.5	-
Polish mortar	1	with	-	-	-
Digester chamber neck	1	-	-	2	4
Digester chamber lid	2	-	-	4	-
Mortar for water trap pit	1	With	1/3	2.5	-

#### Notice

- Follow the instruction of lime replace on the label strictly
- 1/3 means in one bucket, divide the material into 3 parts and use only one part
- 1/4 means in one bucket, divide the material into 4 parts and use only one part

#### Caution

Do not use lime replacement when constructing the weak ring

### 6.8 Materials Used to Connect Gas Pipe per one Chamber

Description	Quantity	Remarks
1. 90° Iron joint	1 pc.	Use with lid
2. Iron joint diameter 1.5 “ reduce to 6/8 “	1 pc.	Use with lid
3. Hose holder 6/8“	2 pcs.	Use with lid
4. Water valve 6/8”	1 pc.	Use with outlet
5. Water valve 4/8 “	1 pc.	Use before connecting with stove
6. Water tap 4/8”	1 pc.	Use with water trap
7. Hose joint (brass)4/8” reduce to 3/8”	2 pcs.	Use with stove
8. Joint 6/8”	1 pc.	Use with tap
9. Joint 6/8”	2 pcs.	Use at the neck of the chamber
10. Joint 4/8” inner screw	2 pcs.	Use with tap
11. Joint 4/8” outer screw	2 pcs.	
12. T joint 6/8” reduce to 4/8”	1 pc.	To the kitchen
13. T joint 4/8 inner screw	1 pc.	Use with manometer pipe
14. Thick hose diameter 1”	1 ft	Use with the neck of the chamber
15. Gas hose	1 meter	Use with gas stove
16. Straight joint 6/8 reduce to 4/8	1 pc.	Use in the kitchen
17. Tape	2 roll	
18. Hose clamp 1”	2 pcs.	
19. Hose clamp 4/8”	3 pcs.	
20. PVC pip 4/8”	1 pc.	
21. PVC pipe 6/8”	Real quantity used	
22. Straight joint 6/8” and 4/8”	Real quantity used	
23. 90° joint 6/8” and 4/8”	Real quantity used	
24. Glue used with PVC pipe and clamp	Real quantity used	
25. Stove or equipment used with gas	Real quantity used	
26. Mono-meter	1 set	

**Notice** Use the same brand of PVC pipes, joints and glue.

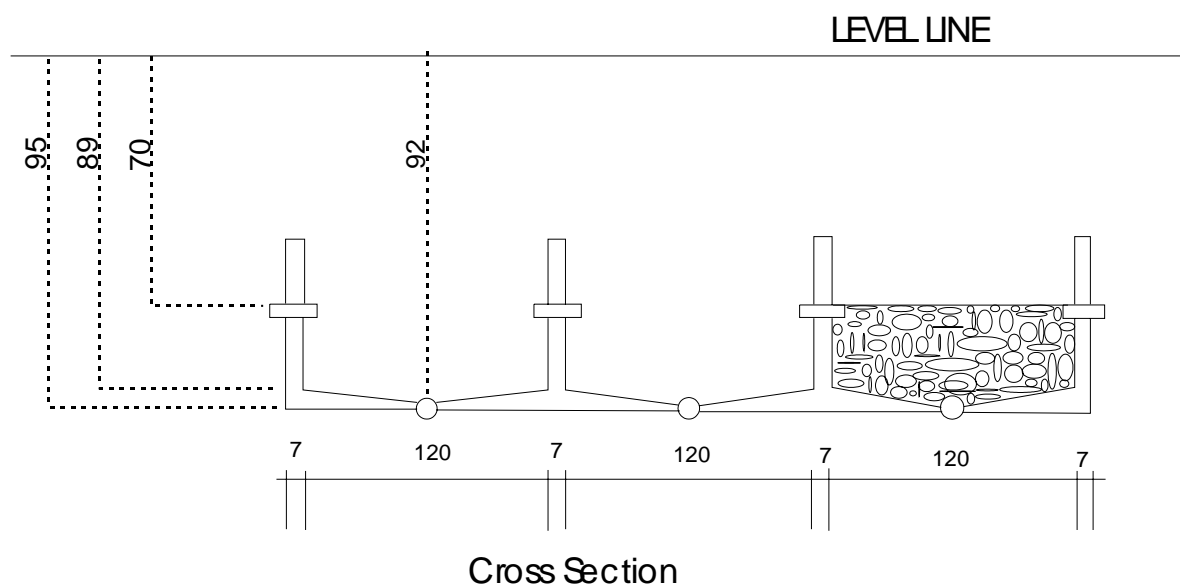
## 6.9 Sand Bed Filter

Excavated soil 4 x 2.40 m x 95 cm deep from reference line to build a sand bed filter of sizes 8-16 m<sup>3</sup>. Pour cement to form a 6 cm high beam. Lay a course of bricks divided into 3 beds of size 1.20 x 2.20 m. On the length sides of each wall lay one brick horizontal to form an edge to wipe the manure. On the back of each brick is 70 cm lower than the reference line. Lay another course of bricks. Build a drainage alley connected between the sand bed filter and the outlet of the expansion chamber. This alley is parallel to the filter. The width of the alley is 20 cm and 2 cm deep from the outlet of the expansion chamber.

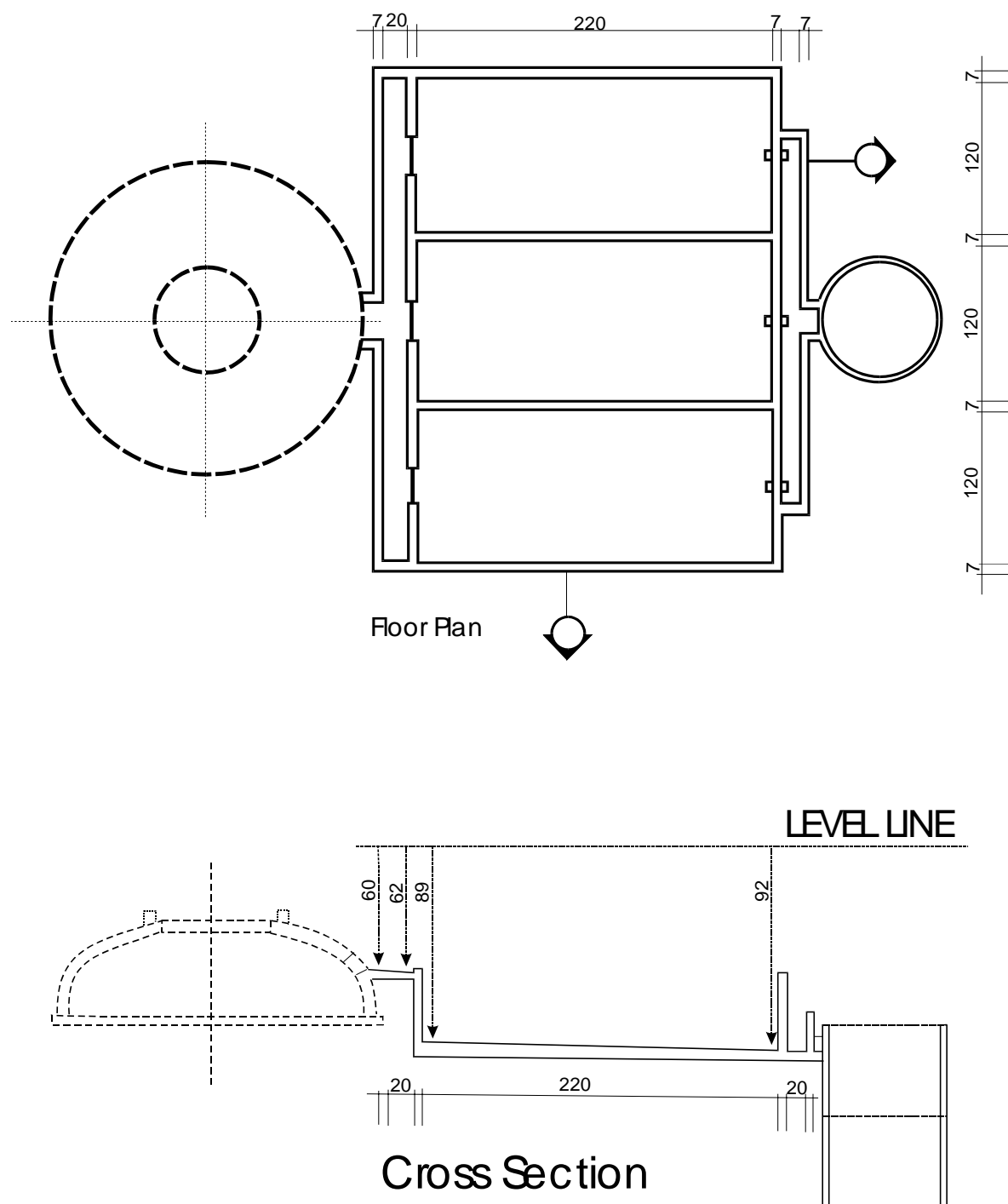
Make a small hole in the middle of each bed at the end of the sand bed filter. Insert a 2 inches PVC joint to let the filtered slurry flow out. Build an alley to connect to the end of the sand bed filter to let filtered water to drain out or to flow into the storage tank. When finished, face the concrete both inside and outside. Pour cement to cover each floor of the beds with 3 cm slope from the side into the middle and from the start of the sand bed filter to the end (Figure 6.3, 6.4).

Sand bed filter consists

*First layer* 10 cm thick of gravel or grounded rocks size ½ inch  
*Second layer* Nylon mesh



**Figure 6.3 Sand bed filter**



**Figure 6.4 Sand bed filter**





① HORIZONTAL REFERENCE LINE 0 CM.

② HIGHEST SLURRY LEVEL 60 CM.

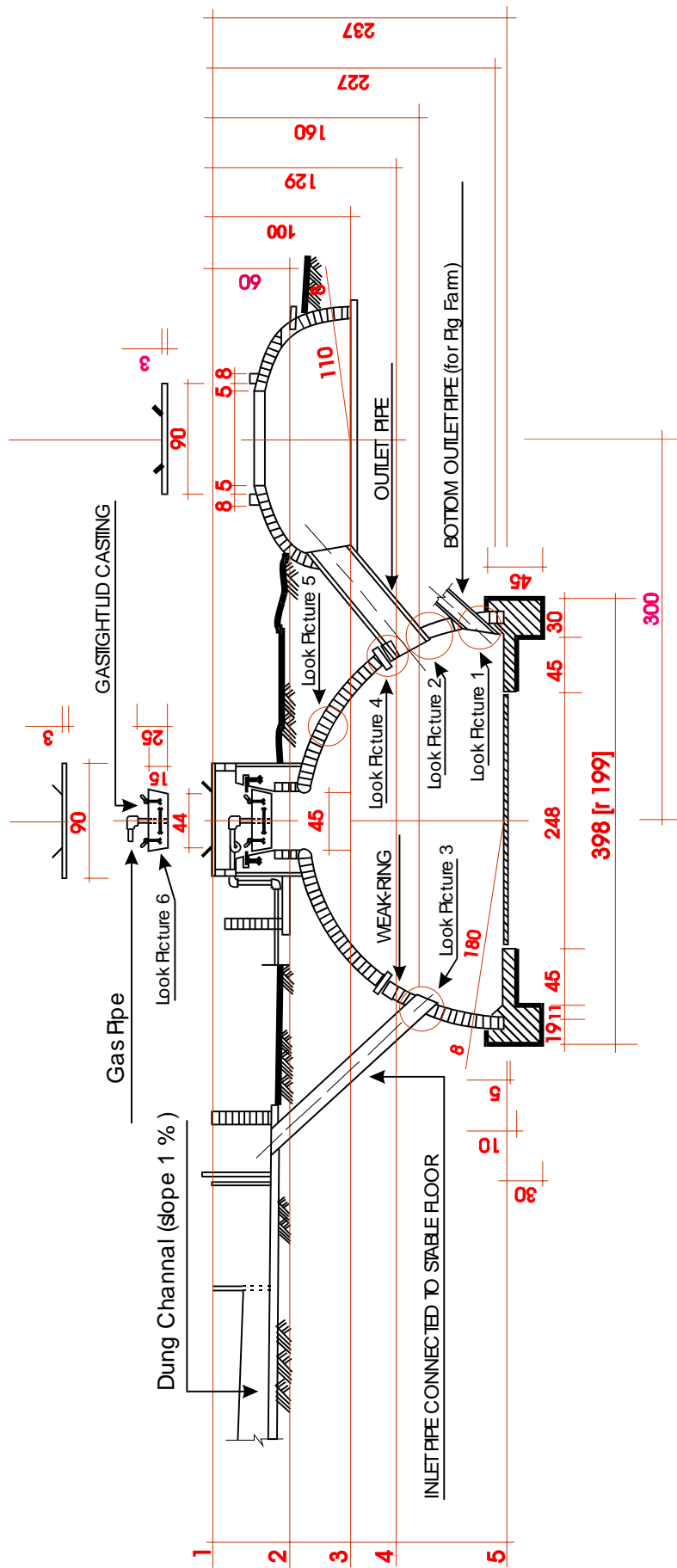
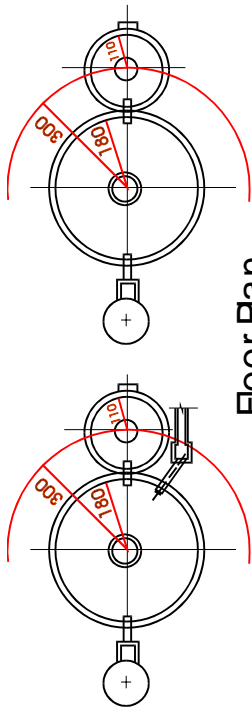
③ BOTTOM OF EXPANSION CHAMBER 111 CM.

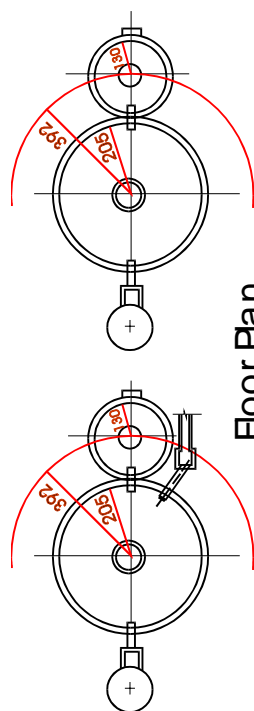
④ LOWEST SLURRY LEVEL, WEAK RING 144 CM.

⑤ BOTTOM LINE 234 CM.

ALL DIMENSION IN CENTIMETER

## Floor Plan

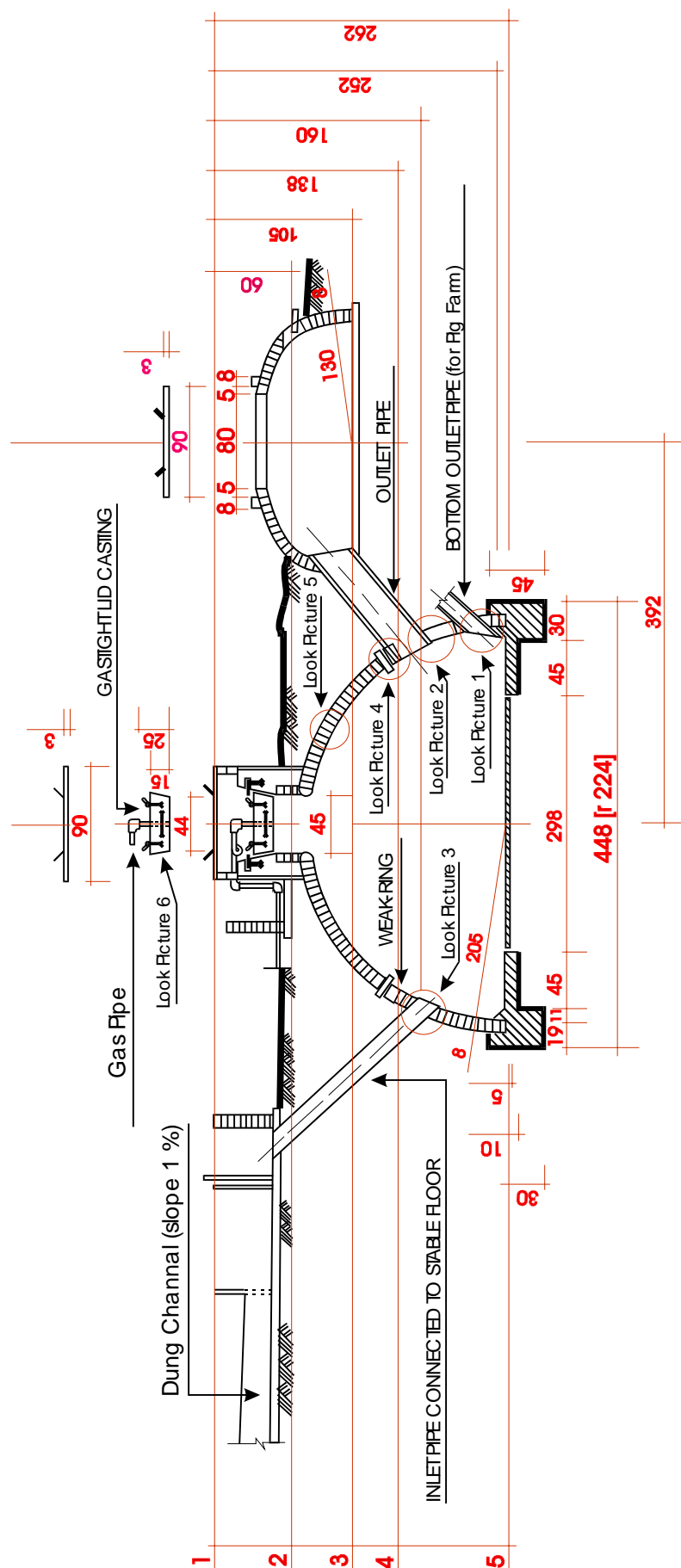




REMARK

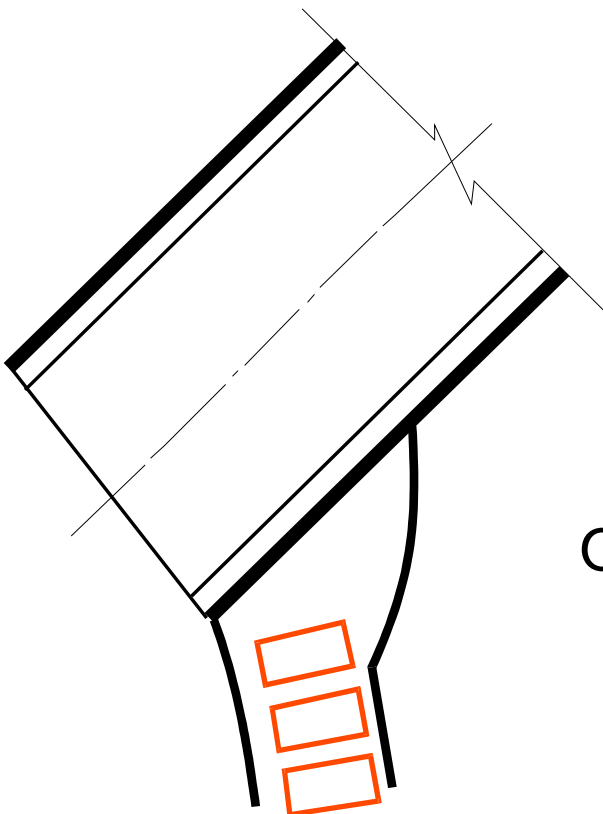
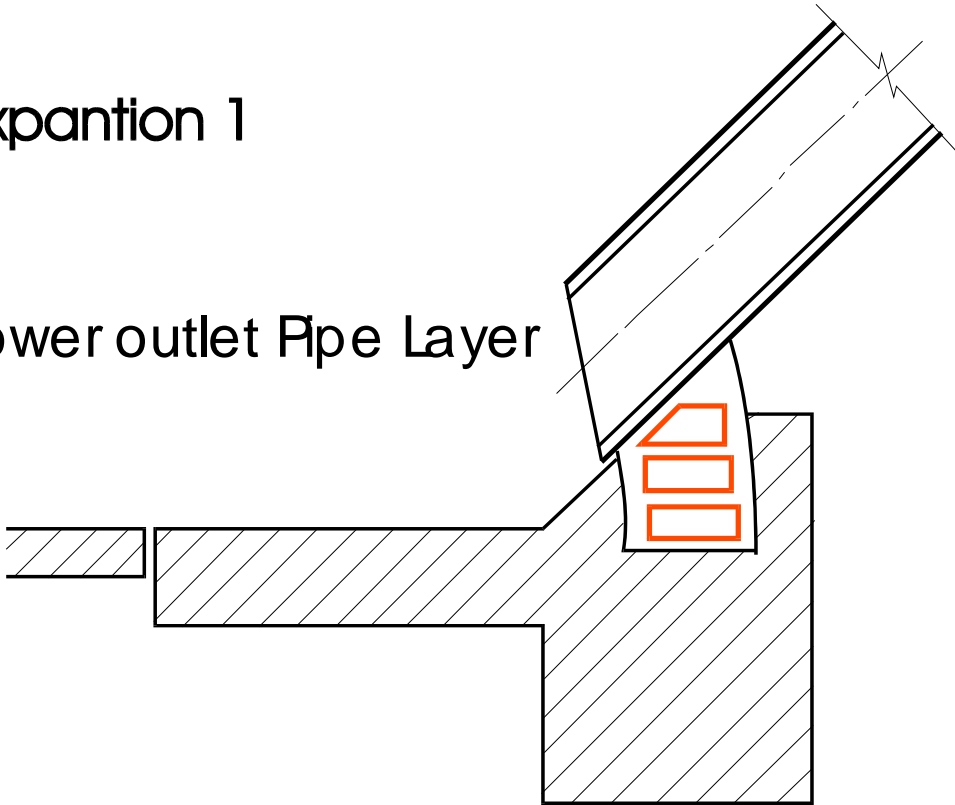
- ① HORIZONTAL REFERENCE LINE 0 CM.
- ② HIGHEST SLURRY LEVEL 60 CM.
- ③ BOTTOM OF EXPANSION CHAMBER 111 CM.
- ④ LOWEST SLURRY LEVEL, WEAK RING 144 CM.
- ⑤ BOTTOM LINE 234 CM.

ALL DIMENSION IN CENTIMETER



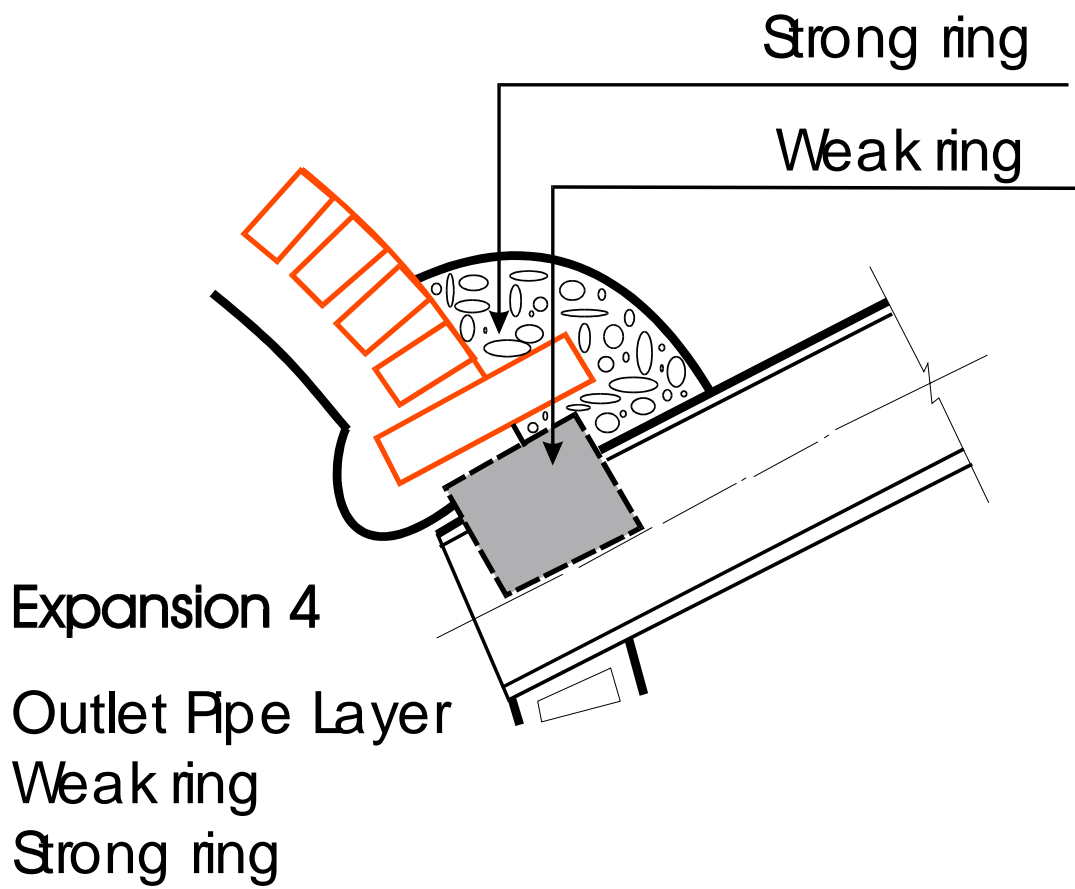
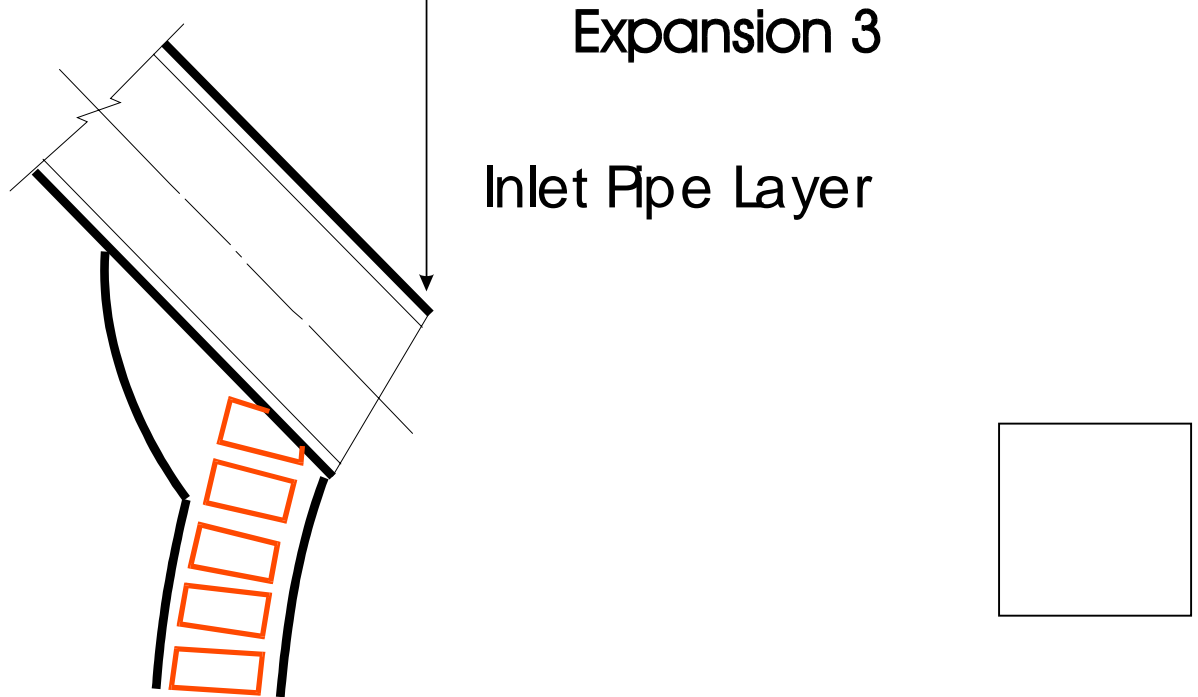
## Expansion 1

Lower outlet Pipe Layer

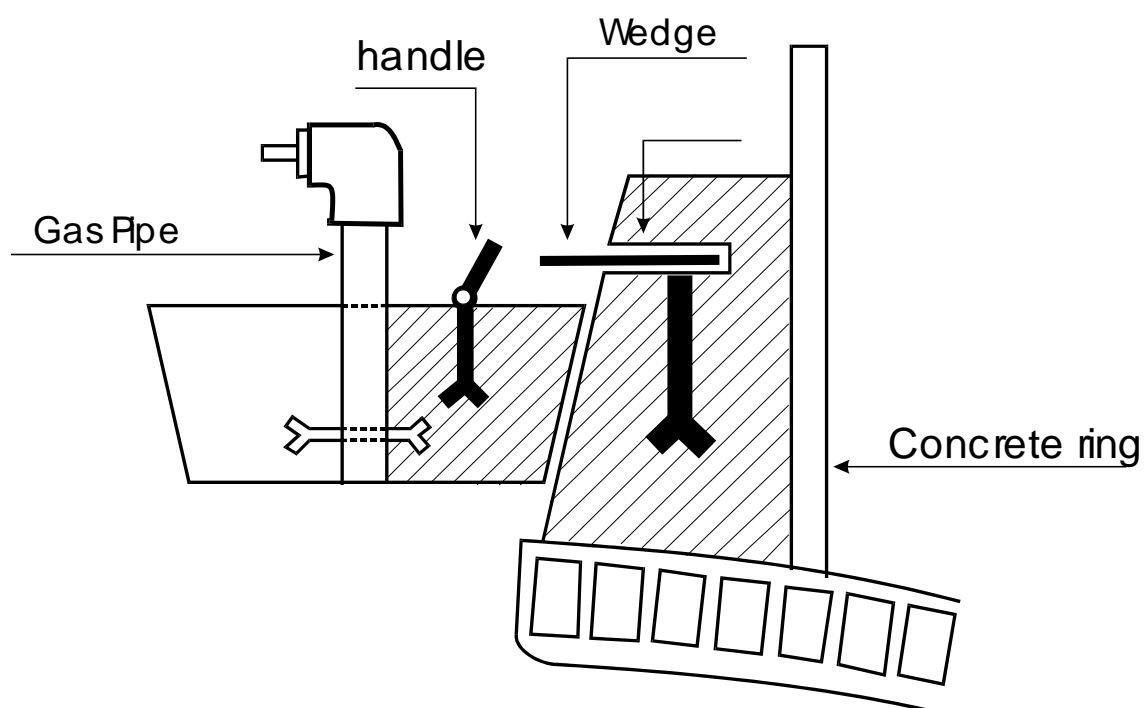
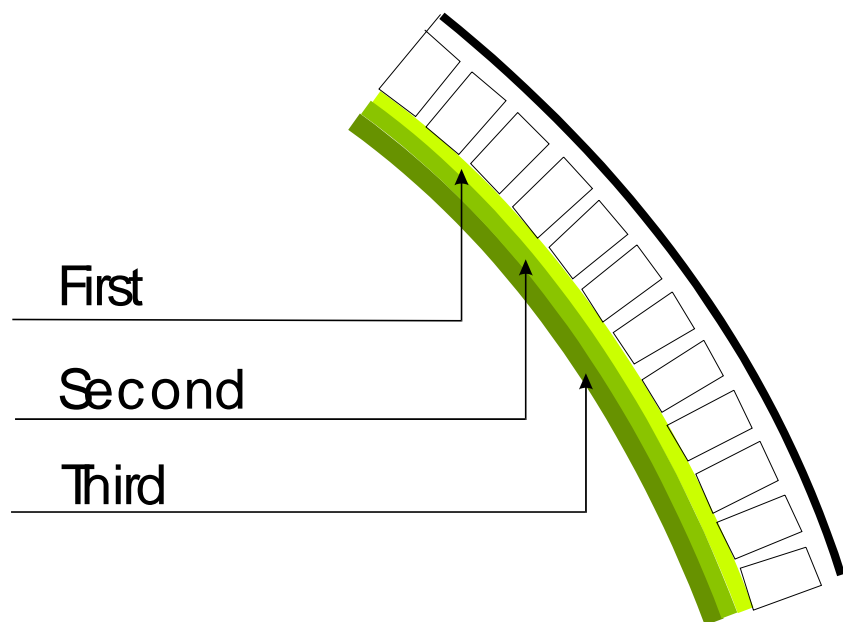


## Expansion 2

Outlet Pipe Layer



## Expansion 5 Inside Plastering



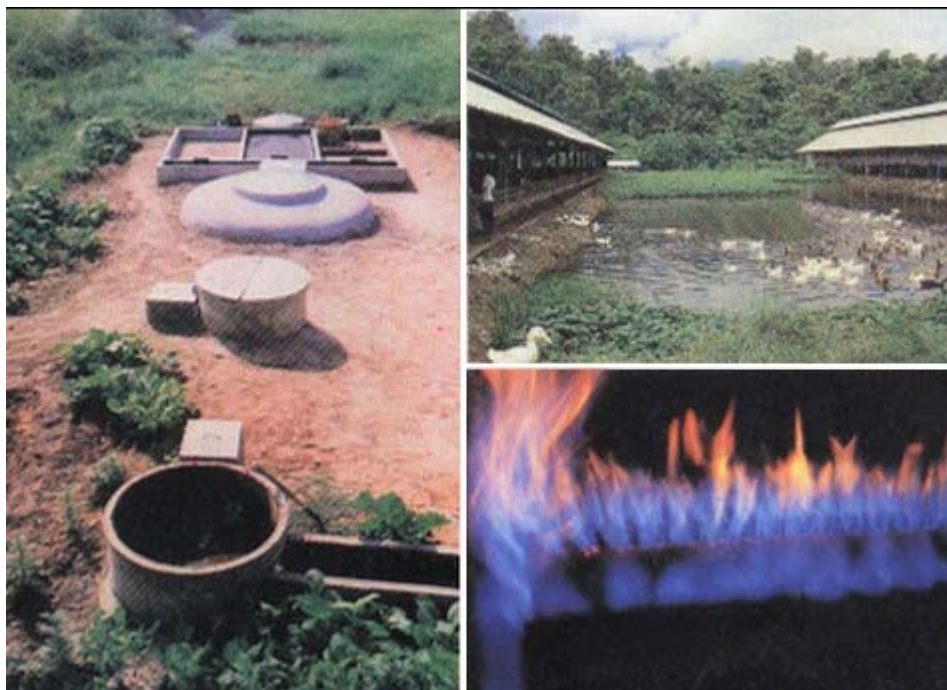
## CHAPTER 7

### Operation Manual of Bio-gas Reactor

#### 7.1 The Significance of the Bio-gas

Bio-gas is a form of energy produced when organic materials such as animal excrement or products that are left over from agriculture are fermented easily and at low cost. The advantage of bio-gas is that it replaces other energy sources for example charcoal, firewood, electricity, liquid petroleum gas and oil. After animal excrement had been fermented in the gas plant it becomes a good quality and odorless substrate, which is better than fresh manure in improving the soil for the agriculture. As an energy source, it prevents deforestation and animal excrement from causing pollution, smell, flies and water pollution in the community.

Nowadays the use of bio-gas has spread from small farms to big animal farms. It is expected that bio-gas will be a significant source of energy in the future to preserve the environment, solve the pollution problem and to promote better health to agriculture and community.



#### 7.2 Bio-gas Plant and Agriculture Cycle System

Three main cycle components as in full agriculture system are animal farming, bio-gas plant and animal products. Each provides direct economic benefit to agriculture.

*Provide energy to household uses*

*Provide organic fertilizer to improve the soil or for merchandise.*

### 7.3 Cycle System

1. Waste water and excrement from enclosure
2. Flow through the inlet pipe into mixing chamber
3. Then into digester chamber
4. Substrate overflow into expansion chamber
5. Into storage tank ready to be used in the agricultural fields or to be dried as fertilizer for merchandise.

### 7.4 Maintenance of Bio-gas System

Factors affecting bio-gas production

**7.4.1 Animal excrement:** daily quantity of excrement added must be sufficient, if too much or too little is added, very little or no gas will be produced as the bacteria dose not have sufficient time to break down the manure.

**7.4.2 Time:** suitable fermenting and breaking down time of manure is between 40-60 days.

**7.4.3 Mixing:** occasional stirring is required to help mixing the manure which will accumulate gas and prevent the forming of crust (cow dung) or scum (pig dung) in digester chamber.

**7.4.4 Chemicals:** such as antibiotic, pesticide, chemical fertilizer or other chemical products may damage bacteria that break down the organic materials in the chamber. The bacteria may stop working and gas will not be produced. Therefore chemical substances should not be released into bio-gas plants.

**7.4.5 Temperature:** the effective temperature for bacteria to grow is 37° C. If higher or lower than the suggested the bacteria will not develop, decreasing gas production. For example less gas will be produced in summer or winter.

**7.4.6 pH Balance:** A pH between 7-8.5 is optimal. If below the suggested pH, gas will not be produced.



## 7.5 Animal Excrement Adding

**First adding** (first 7 days) add cow or buffalo excrement daily.

- If cow or buffalo excrement is not available, pig excrement can be used at ratio of half the cow excrement suggested for a length of 2 weeks. After that add accordingly to the chart below.

Type of Materials	Sizes of Bio-gas plants						
	4.6M <sup>3</sup>	8M <sup>3</sup>	12M <sup>3</sup>	16M <sup>3</sup>	30M <sup>3</sup>	50M <sup>3</sup>	100 M <sup>3</sup>
Cow/buffalo excrement (litres)	300	600	800	1,200	2,200	3,600	7,200
Water (litres)	300	600	800	1,200	2,200	3,600	7,200

- After the plant is built and tested by filling with water, the water should be left inside. Open the valve to release the air until the mono-meter is at 0 and animal excrement can then be filled.
- The first adding of excrement should not be filled up to the top to avoid the slow production of gas or materials becoming decomposed. It should be separately added in small amount until fully filled.

**Next adding**, after 7 days of the first addition, add the materials regularly on daily basis as shown below:

Type of Materials	Sizes of Bio-gas plant						
	4.6M <sup>3</sup>	8M <sup>3</sup>	12M <sup>3</sup>	16M <sup>3</sup>	30m <sup>3</sup>	50m <sup>3</sup>	100M <sup>3</sup>
Cow/buffalo excrement (litres)	40	70	100	140	250	416	833
Water (litres)	40	70	100	140	250	416	833
Pig excrement (litres)	30	50	70	90	166	277	555
Water (litres)	60	100	140	180	332	555	1,110

- This addition will produce gas within 2-3 days.
- Release the gas from the tank 3 times before using it.
- Exceeded material will cease gas production.
- Use only fresh excrement, dry excrement is prohibited because it stops the process of producing gas and will block the pipes.

## 7.6 Animal Enclosure and Drainage Alley Maintenance



- ❑ Cleanliness of the enclosure is maintained daily by removing the excrement and putting it into the mixing chamber.



- ❑ Wash the enclosure with water and let it flow into drainage alley.
- \* Water that mixed with chemicals, antibiotics or antiseptics is not allowed to flow into the digester chamber as bacteria that activate the gas in the chamber will die.

## 7.7 Mixing Chamber Maintenance

- ❑ All rice hay, rice husk, gravel, soil, sand or non-organic materials must be removed from animal excrement when mixed with water, before releasing it into the mixing chamber. Those materials will shallow the level of the digester chamber and cause blockage in pipes.



- ❑ Mix or stir the mixture in the inlet pit until it becomes liquid, then open the gate of the mixing chamber to let the mixture flow into the digester chamber.



- ❑ Clean mixing chamber and gate at every addition of the excrement in the digester chamber.



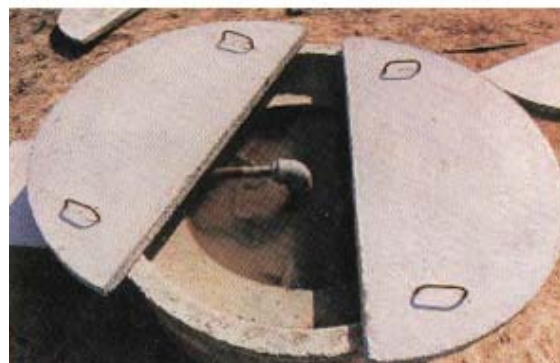
- ❑ Use wooden stick to stir the fermented liquid once a week to avoid the formation of crust or scum at the bottom of the chamber or blockage of the inlet pipe.
- \* Before adding of excrement gas should be partly released for usage to let manure flow easily in to the digester chamber, as high pressure in the digester chamber would slow down the flow of the manure.

### 7.8 Digester Chamber and Outlet Pipe Maintenance

- ❑ Pour clean water into the inlet of the digester chamber to prevent the clay covering the pipe from drying and gas from leaking.



- ❑ Water level at the top of the inlet cover should not be over the steel clamp which tightens the gas pipe. It can become rusty.







- ❑ The inlet should be covered to prevent domestic animals from drinking this water and also prevent the water from evaporating quickly.



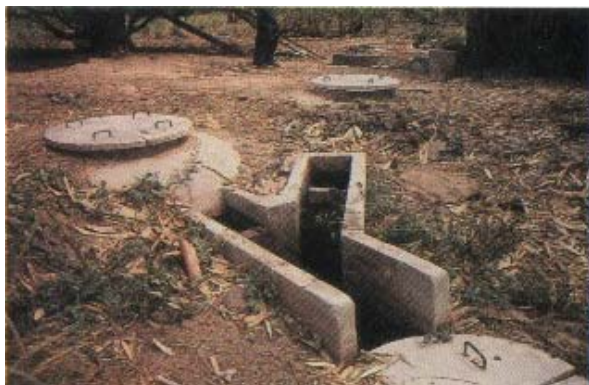
- ❑ The cover of the inlet pipe should be opened for maintenance once a year. The crust or scum formed by manure should be removed if possible.

*\*No excrement adding if gas is not produced for many days.*

### **7.9 Pig Excrement Chamber (Outlet Pipe Installed)**

Pig excrement forms more residue than cow or buffalo excrement and the removal residue from the floor base is more difficult. To prevent the blockage or the build up of residue on the floor, these instructions should be followed.

- ❑ Pull gate at the outlet pipe while the pressure is at the highest level, gas will help push out residue at the bottom.



Leave gate opened for a while and after one smells the gas or the overflow slurry is very liquid then close the gate.

- \* The substrate should be removed at least once a week. If the substrate does not flow out when the gate is pulled, use wooden stick to unclog the outlet pipe.
- \* Gate must be closed tightly. If there is water leaking, the pressure in the digester chamber will decrease.
- \* When the storage tank is full, the gas must be removed for usage.

### 7.10 Expansion Chamber Maintenance

- ❑ Keep the outlet pipe free from blockage by clearing the dry manure or residue around the edge of the outlet pipe to let the manure flow freely.



- ❑ Close the lid of the expansion chamber to prevent animals or rainwater to fall in.

- ❑ At least once a week the inside of the chamber should be pushed and stirred with wooden stick to prevent crust or scum formed to block the pipe and the residue from forming at the bottom floor.



### 7.11 Storage Tank and Sand Bed Filter Maintenance



- ❑ Do not leave the substrate overflow from storage tank as it is unsightly and dirty.

- ❑ The substrate should be removed from storage tank and sand bed filter regularly to prevent the over filling and the flow of substrate back into the digester chamber. Use the substrate in the agricultural fields or store it for merchandise.



- ❑ Substrate in the storage tank can be used as liquid slurry form or mixed with cutting weeds as fermented fertilizer or dried for usage or as dried fertilizer for sale.



## 7.12 Water Trap Maintenance

- ☐ Water trap should be opened every two weeks without opening the valve at the inlet of the chamber to let the risen water flow out. Close the trap tightly to avoid the water from stopping the flow of gas.



- ☐ Water trap pit should be covered to avoid trash, leaves and rain which will cause problem or rust at the valve.

- ☐ Valve has to be changed or repaired immediately if there is any damage.

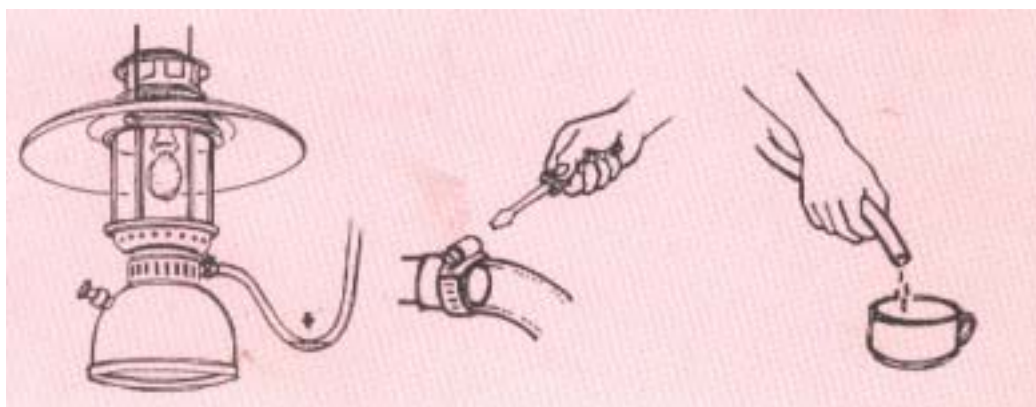


### 7.13 Gas Pipe Maintenance



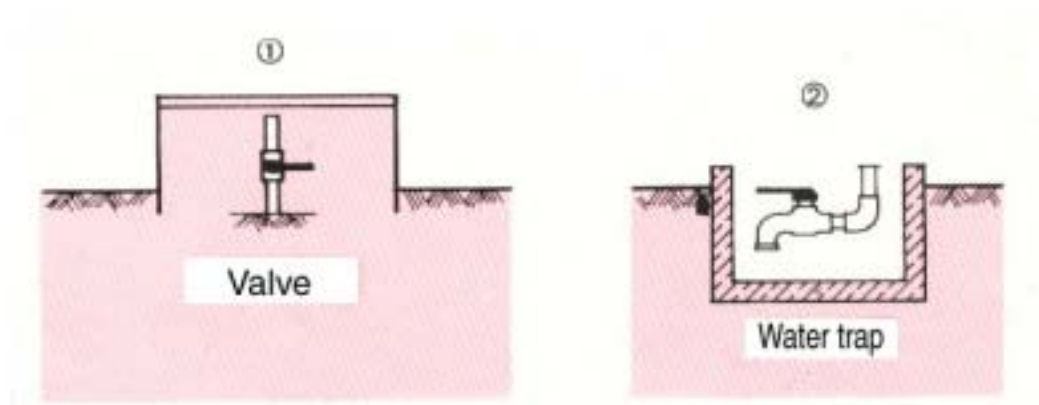
- ❑ Gas pipe should be installed against the wall or post and secure tightly. The pipe will be broken easily if installed independently or loosely.

- ❑ Underground gas pipe should be covered safely to prevent the damage caused by animals, humans or vehicles.

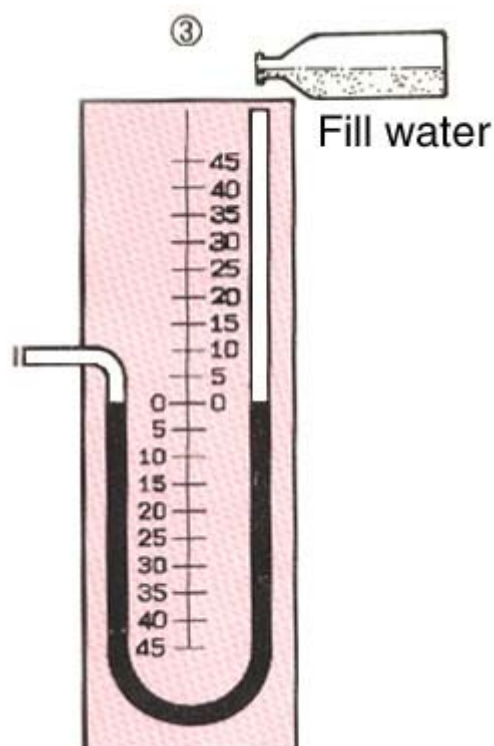


- ❑ Rubber hose should be checked every month for any water. Valve should be closed and hose emptied if there is water trapped inside. Hose clamp must be tightened after replacing the hose.

### 7.14 Manometer



- ❑ Manometer is an important instrument in bio-gas system. It indicates any malfunction in bio-gas system.



- ❑ Both water levels in mono-meter should be the same (when gas is emptied). To calculate the exact quantity of gas stored, adjust the level as follows :
1. Close the valve at the inlet of digester chamber.
  2. Open valve at water trap
  3. Fill water at the end of the pipe until both levels are at 0.

## 7.15 Bio-gas Equipment Maintenance

- ☐ Valve must be closed for safety before cleaning any gas equipment.

### 7.15.1 Burner



- ☐ Always clean the burner by removing the head burner and pushing through the holes with a sharp wooden stick, wire or nail so that gas will flow out easily. Use a wire brush to get rid of sediment. Later scrub the rust or dirtiness out.



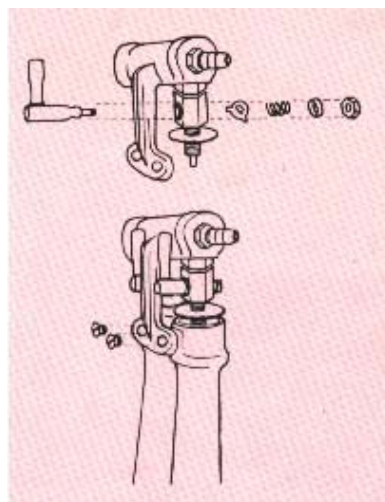
- ☐ For a stove with built-in cooking vessel built into the stove, remove the tray under the stove to clean.



- ☐ When stove is being used, open valve in the kitchen first and set fire prepared at burner then turn on the switch of stove last.



- ❑ Flame should come out from each hole of the burner head evenly, pale blue flame indicates clean burner but red flame indicates presence of sediment.
- ❑ After using stove, valve must be closed and switch on the stove must be turned off. If only valve is closed it may cause rust on the switch. Grease the switch occasionally, and do not let it dry. Change a new switch when damaged as stove has been long used.



### 7.15.2 Lamp



- ❑ To clean or change gauze mantle, detach gas hose, remove the shade and head of the lamp first. After cleaning put them back together and screw tightly. Attach the hose back to the joint and secure with clamp.



To get rid of sediment, dismantle the lamp and wash parts with sediment in water. When it will come out then dry it quickly.

- ❑ To clean lamp shade and glass cover, wash with water and dry with clean cloth. At the same time, remove dirt and dead insects from the head of the lamp. Change new gauze mantle if broken and secure tightly.



- ❑ Lamp should be lit by candle because match is too short and may cause damage.



- ❑ When the brightness is low and the gauze mantle is flaming, adjust the nozzle to the left with tongs or up and down until the light is bright again.



### 7.15.3 Piglet Heater



- ❑ To light piglet heater, open valve and press auto switch and hold it. Set fire at the heater plate and wait until the plate is heated thoroughly and become red then release the switch.



- ❑ To clean, leave the head of the heater in water for 2-3 minutes then dry with cloth or leave in the sun.

- ❑ Air filter should be looked after and cleaned with soft brush to avoid dust or insects.



### 7.15.4 Engine

Stationary engines such as water pump, milling machinery, generator, animal feed mixer and milking machine can use bio-gas by installing gas pipes to the intake pipe of the engines.

For using bio-gas in engine, one main valve must be installed to PVC gas pipe and one small valve to rubber hose before connecting to the engine.

### 7.15.5 Gasoline Engine

- ☐ Start the engine with gasoline as normal then adjust the accelerator at moderate speed. Turn gasoline valve to fully close position then turn main valve to fully open position. Slightly open small valve, adjust and listen. Proper position is when the engine runs smoothly without misfiring.



*\* Let gasoline flow to replace gas (close gas valve) and leave engine run for another 3 minutes then turn the engine off.*

### 7.15.6 Diesel Engine

- ☐ Start the engine and adjust accelerator at moderate position. Slightly open diesel fuel valve and at the same time turn main valve to fully open position then open the small valve to the position which the engine runs smoothly.

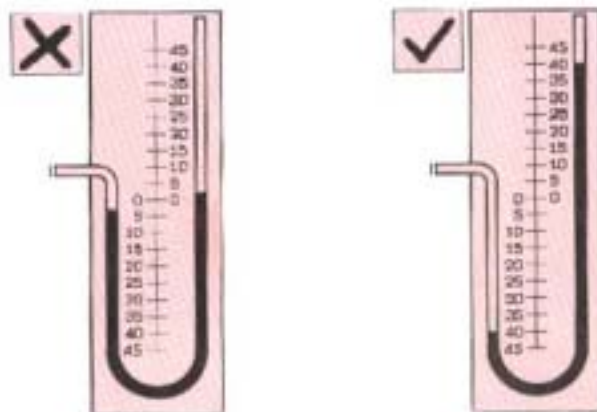


*\* Turn the engine and main valve off when not in use.*

- ☐ If higher RPM (accelerating) is required, small valve must be adjusted to let more gas enter. Engine will be accelerated without adjusting the accelerator.
- ☐ At the first installation after accelerator is properly adjusted, remove handle from the small valve for safety reason.
- ☐ The next starting  
*Benzene engine* is started by gasoline. When engine is started, gasoline valve must be closed and open the main valve to fully open position.  
*Diesel engine* will run normally after starting the engine and opening the main valve.

## 7.16 Practice Rules and Caution in Bio-gas Uses

- ☐ In a new chamber, gas produced after animal excrement has been first added must be vented as it cannot be used. It should be vented 2-3 times or until gas becomes flammable.



- ☐ Use manometer to check magnitude before using gas. Pressure should be at 10-80 cm.
- ☐ Do not leave valve opened when not in use. If pipe or hose is damaged, gas may leak and cause a fire.
- ☐ Light should be lit closely at the head of burner before opening the valve. If the valve is opened first, gas may come out exceedingly and is dangerous.
- ☐ Do not use igniter to lighten the stove because bio-gas is a slowly flammable passive gas.



- ☐ When valve is left open, excess gas will result in a bad smell. Close valve immediately and open windows and doors for ventilation. Do not fire until there is no more gas leaking.

### 7.16.1 Gas Saving



### 7.16.1 Gas Saving

- ❑ Food ingredients and condiments must be prepared before starting stove.



- ❑ Cooking container should be placed 1 inch above the head of the stove to save gas and avoid loss of heat energy while cooking.

Lid should be used regularly to cover cooking container when boiling, steaming or decocting to save energy and time for cooking.



- \* Stove should not be placed in windy area as the wind will blow the heat away.
- \* Stir frying should be in high heat while boiling or deep frying should be in medium heat.

daily will be changed and the component in this substrate can be used in agriculture as a better fertilizer than unfermented manure (unfermented fertilizer).

## 7.18 Methods of Using Substrate from Expansion Chamber

### 7.18.1 Liquid slurry

#### *1. Draining through drainage alley*

Substrate from expansion chamber will flow easily through the alley or drainage pipe with the aid of gravity if the ground is on slope area and bio-gas plant is located at higher elevation than agriculture areas. The loss of nutrients will be lower.



#### *2. Using pump*

Pump could be used in flat or remote area to pump substrate out directly from storage tank (which is filtered through sand bed) and sent along the alley or pipe to agriculture areas. (Density of substrate from expansion chamber is one of the limitation of using pump in remote area.)



#### *3. Using container*

Special implement is required to shift substrate from expansion chamber to remote area. Wheel barrows or carts are suitable for short distance. While animals or engines powered vehicles are very helpful for long distances.



## 7.19 Dry Manure

### 1. *Fermented fertilizer*

Substrate from expansion chamber can be kept in form of fertilizer when fermented together with cut weeds or grass. It is one of the easy ways of shifting. Scoop manure from expansion chamber and pour alternately over layers of cut grass. Stack of fermented grass should be turned over several times to speed up the process. Pile of fertilizer should be near the storage tank for easy access.



### 2. *Filtered in sand bed*

Filter component is gravel, coarse sand and fine sand. Water that has been filtered will flow into a pit to settle down, substrate will be left on top of sand bed surface. It will dry and be ready for removed within 3-4 days.



### 3. *Drying technique*

This technique is recommended when moving substrate from expansion chamber to remote area. Location for drying should be near the bio-gas plant. The ground should be a water proof concrete slab to avoid the liquid from seeping into ground water.

Farmers who do not use the substrate from expansion chamber in their field or there is a lack of implementation to help in shifting should use dry technique. Shifting dry manure is more practical than using slurry. Besides, dry manure can be packed and sold in small bags, sacks, bamboo baskets or loaded on to trucks.



## 7.20 Problems and Solutions

	Problems	Solutions
1. Pressure is low or decreasing even gas is not used	<ul style="list-style-type: none"> <li>★ Too little excrement adding when there is no consumption</li> <li>★ Lid of digester chamber is leaking</li> <li>★ Gas pipe or valve is leaking</li> <li>★ Blockage at the end of gas pipe of digester chamber inlet</li> <li>★ Fixed dome is cracked</li> </ul>	<ul style="list-style-type: none"> <li>➤ Add more excrement as related to size of chamber</li> <li>➤ Check for any bubbles on the surface of trap water. If there is any leak, open the lid and have clay changed then close the lid.</li> <li>➤ Use bubbles from soap liquid to check for leakage of valves and joints including all instruments involved with gas, pipes and hoses also check that water trap and/or gate of outlet pipe (pig chamber) is tightly closed.</li> <li>➤ Disconnect hose between joint of digester chamber inlet and gas pipe. Have them checked by using thin stick or soft wire to unclog any manure that may cause blockage.</li> <li>➤ Dig soil around the outside dome and check for leakage by using soap water.</li> <li>➤ Bubbles will indicate the leak. Pump or take out all manure until the chamber is empty. Clean the chamber and check for any crack inside fixed dome. Chip cement around the crack and fill it up with new cement, added with waterproofer.</li> </ul>
2. Pressure is normal but gas supply runs out quickly.	<ul style="list-style-type: none"> <li>★ Scum on surface of digester chamber</li> <li>★ Residue sinks to bottom / shallow level</li> <li>★ Scum on surface of expansion chamber</li> <li>★ Outlet pipe is blocked</li> </ul>	<ul style="list-style-type: none"> <li>➤ Open lid and add water. Use wooden stick to stir until scum is dissolved then close the lid.</li> <li>➤ Pull gate of the outlet pipe (pig chamber) up to release residue out.</li> <li>➤ Use stick to break scum then scoop out.</li> <li>➤ Use stick to unclog the pipe</li> </ul>
3. Pressure is too high	<ul style="list-style-type: none"> <li>★ Gas pipe is blocked</li> <li>★ The inlet of expansion chamber is on high level</li> </ul>	<ul style="list-style-type: none"> <li>➤ Use stick to unclog the pipe</li> </ul>
4. Bubbles at the entrance of the expansion chamber	<ul style="list-style-type: none"> <li>★ Add too much excrement</li> </ul>	<ul style="list-style-type: none"> <li>➤ Stop adding excrement for 7 days or add lime 5 bags a day for 4 days.</li> </ul>

5. Gas pressure is not consistent	★ Water is trapped in gas pipe	➤ Open water trap valve to empty water in the pipe then close valve tightly. Solutions
6. Enough pressure but gas have bad smell and is nonflammable	★ pH factor is too low indicates too much acid ★ Add too much excrement ★ Antiseptic or other toxin is mixing in animal excrement ★ First filling with pig excrement	➤ Add lime into gas plant to decrease acid.  ➤ Stop adding excrement temporary (follow No 4) ➤ Stop adding excrement 2-3 days, if the gas is still non flammable, remove old excrement and start new filling again ➤ Leave the gas valve on until gas is flammable or remove old manure and replace with cow or animal manure from operating gas plant
7. Enough pressure but gas is odorless and non flammable	★ Too much air	➤ Adjust air adjustment ring
8. Uneven flame	★ water is trapped in gas pipes or hoses	➤ Open water trap valve to empty the water and close tightly
9. Low flame	★ Low gas pressure ★ Nozzle hole is too small or head burner is blocked	➤ Check gas plant and gas pipe for leakage. ➤ Enlarge nozzle hole to diameter as follows ➤ <i>Cooking burner</i> ➤ Size of inner ring nozzle 1.2mm (3/64") ➤ Outer ring 1.6mm (1/16") ➤ <i>Double ringed burner</i> ➤ Size of inner ring nozzle 1.6mm (1/16") ➤ Outer ring 2.3mm (3/32")
10. High flame	★ Nozzle hole is too big	➤ Change nozzle to diameter as No.9 ➤ Control quantity of gas by adjusting the valve
11. Yellow flame instead of pale blue flame.	★ Nozzle hole is too wide	➤ Open air regulator until flame is pale blue
12. Flame return to switch instead of going up through burning holes	★ Gas return because head burner is blocked. Air inlet is not completely closed	➤ Clean burner using wire or nail unclog burning holes or use wire brush to scrub and remove sediment and dirt from burner. ➤ As for cooking stove adjust ring of air regulator at fully close position

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# **Biomethane from Dairy Waste**

## **A Sourcebook for the Production and Use of Renewable Natural Gas in California**

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# Glossary

## Acronyms and Abbreviations

AB	Assembly Bill
AFV	Alternate fuel vehicle
B100	Neat biodiesel, 100% biodiesel
B2	Diesel fuel containing 2% biodiesel
B20	Diesel fuel containing 20% biodiesel
BACT	Best available control technology
BDT	Bone dry tons
BOD	Biological oxygen demand
BRDA	Biomass Research and Development Act (2000)
Btu	British thermal units
CAFO	Confined animal feeding operation
CARB	California Air Resources Board
CBM	Compressed biomethane
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CH <sub>4</sub>	Methane
CHP	Combined heat and power
CNG	Compressed natural gas
CO	Carbon monoxide
CO <sub>2</sub>	Carbon dioxide
CPUC	California Public Utility Commission
CWC	California Water Code
DGE	Diesel gallon equivalent
DMV	Department of Motor Vehicles
DOE EIA	U.S. Department of Energy, Energy Information Administration
DOT	U.S. Department of Transportation
DTSC	Department of Toxic Substance Control
E10	Gasoline fuel containing 10% ethanol
E85	Gasoline fuel containing 85% ethanol

E100	Gasoline fuel substitute containing 100% ethanol.
EQIP	Environmental Quality Incentives Program
ERC	Emission Reduction Credits
ft <sup>3</sup> /d	Cubic feet per day
ft <sup>3</sup> /h	Cubic feet per hour
ft <sup>3</sup> /y	Cubic feet per year
FTP	Federal Test Procedure (US EPA)
FY	Fiscal year
GGE	Gasoline gallon equivalent
GHG	Greenhouse gas
gpd	Gallons per day
gpm	Gallons per minute
GVW	Gross vehicle weight
GW <sub>e</sub>	Gigawatts of electricity (10 <sup>9</sup> watts)
H <sub>2</sub>	Hydrogen
H <sub>2</sub> O	Water
H <sub>2</sub> S	Hydrogen sulfide
H <sub>2</sub> SO <sub>4</sub>	Sulfuric acid
HOV	High-occupancy vehicle
hp	Horsepower
HRT	Hydraulic retention time
IOU	Investor owned utility
kW	Kilowatt (10 <sup>3</sup> watts)
kWh	Kilowatt-hour
lb	Pound(s)
LBM	Liquefied biomethane
LCNG	Liquefied-to-compressed natural gas
LFG	Landfill gas
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MM	Millions
MTBE	Methyl tertiary-butyl ether
MW	Megawatt
MWh	Megawatt-hours

MW <sub>e</sub>	Megawatts of electricity (10 <sup>6</sup> watts)
NO <sub>x</sub>	Nitrogen oxides and dioxides, typically NO and NO <sub>2</sub>
N <sub>2</sub> O	Nitrous oxide
NPDES	National Pollution Discharge Elimination System
PG&E	Pacific Gas and Electric Company
PIER	California's Public Interest Energy Research Program
PING	California's Public Interest Natural Gas Energy Research Program
PM	Particulate matter
POTW	Publicly owned treatment works
ppm	Parts per million
psi	Pounds per square inch
psig	Pounds per square inch, gauge
PURPA	Public Utility Regulatory Policy Act
PZEV	Partial zero-emission vehicle
RCRA	Resources Conservation and Recovery Act
ROG	Reactive organic gases
RPS	Renewable Portfolio Standard
scf	Standard cubic feet
scfm	Standard cubic feet per minute
SB	Senate Bill
SCE	Southern California Edison
SoCalGas	Southern California Gas Company
SULEV	Super ultra low-emission vehicle
TS	Total solids
ULEV	Ultra low-emission vehicle
USDA	US Department of Agriculture
US DOE	US Department of Energy
US EPA	US Environmental Protection Agency
VOC	Volatile organic compounds
VS	Volatile solids
ZEV	Zero-emission vehicle

## Definitions

<i>Acetic acid</i>	A carboxylic acid, acetic acid is a relatively weak acid mainly used as a pH buffer (chemical formula $\text{CH}_3 \text{COOH}$ ).
<i>Acidogenic</i>	Acid-forming; used to describe microorganisms that break down organic matter to acids during the anaerobic digestion process
<i>Anaerobic digestion</i>	A naturally occurring biological process in which organic material is broken down by bacteria in a low-oxygen environment resulting in the generation of methane gas and carbon dioxide as its two primary products.
<i>Anaerobic digester</i>	A device for optimizing the anaerobic digestion of biomass and/or animal manure, often used to recover biogas for energy production. Commercial digester types include complete mix, continuous flow (horizontal or vertical plug-flow, multiple-tank, and single tank) and covered lagoon.
<i>Biodiesel</i>	Any liquid biofuel suitable as a diesel fuel substitute or diesel fuel additive or extender. Biodiesel fuels are typically made from oils such as soybeans, rapeseed, or sunflowers, restaurant waste greases, or from animal tallow using a transesterification process (though unprocessed oils are sometimes used). A bio-derived gasoline or diesel substitute can also be made from thermal gasification of biomass followed by a gas-to-liquids process (Fischer-Tropsch liquids).
<i>Biofuel</i>	Technically, any biomass derived substance used for energy (heat, power, or motive). The term 'biofuel' usually is used to describe liquid transportation fuels derived from biomass.
<i>Biogas</i>	A naturally occurring gas formed as a by-product of the breakdown of organic waste materials in a low-oxygen (e.g., anaerobic) environment. Biogas is composed primarily of methane (typically 55% – 70% by volume) and carbon dioxide (typically 30% – 45%). Biogas may also include smaller amounts of hydrogen sulfide (typically 50 – 2000 parts per million [ppm]), water vapor (saturated), oxygen, and various trace hydrocarbons. Due to its lower methane content (and therefore lower heating value) compared to natural gas, biogas use is generally limited to engine-generator sets and boilers

adapted to combust biogas as fuel. Biogas includes landfill gas, digester gas (from wastewater treatment plants) and biogas from the decomposition of animal waste or food processing waste. In this study the word biogas usually refers to biogas created by animal manure.

*Biogas upgrading*

A process whereby a significant portion of the carbon dioxide, water, hydrogen sulfide and other impurities are removed from raw biogas (digester gas) leaving primarily methane. Also referred to as “sweetening.” The major biogas upgrading technologies currently identified are water scrubbing, membrane separation, pressure swing adsorption, amine scrubbing (Selexol™ and COOAB™) and mixing with higher quality gases.

*Biological oxygen demand*

A measure of the amount of oxygen consumed in the biological processes that break down organic matter in water. Biological oxygen demand (BOD) is used as an indirect measure of the concentration of biologically degradable material present in liquid organic wastes. It usually reflects the amount of oxygen consumed in five days by biological processes breaking down organic waste. BOD can also be used as an indicator of water quality, where the greater the BOD, the greater the degree of pollution. Also referred to as “biochemical oxygen demand.”

*Biomass*

Biomass is any organic matter that is available on a renewable or recurring basis, including agricultural crops and trees, wood and wood wastes and residues, plants (including aquatic plants), grasses, residues, fibers, and animal wastes, municipal wastes, and other waste materials.

*Biomethane*

Biogas which has been upgraded or “sweetened” via a process to remove the bulk of the carbon dioxide, water, hydrogen sulfide and other impurities from raw biogas. The primary purpose of upgrading biogas to biomethane is to use the biomethane as an energy source in applications that require pipeline quality or vehicle-fuel quality gas, such as transportation. From a functional point of view, biomethane is extremely similar to natural gas except that it comes from renewable sources. (Note that the term “biomethane” has not yet come into popular usage;

thus the term “biogas” is often used when referring to both the raw and upgraded forms of biogas/biomethane.)

*Butyric acid*

A carboxylic acid with structural formula  $\text{CH}_3\text{CH}_2\text{CH}_2\text{-COOH}$ . It is notably found in rancid butter, parmesan cheese, or vomit and has an unpleasant odor and acrid taste, with a sweetish aftertaste (similar to ether).

*Cellulose*

A complex carbohydrate,  $(\text{C}_6\text{H}_{10}\text{O}_5)_n$ , that is composed of glucose units. Cellulose forms the main constituent of the cell wall in most plants.

*Chemical oxygen demand*

Chemical oxygen demand (COD) is used to indirectly measure the amount of all organic compounds in a water sample (whereas BOD indicates the amount of biodegradable compounds in solution). COD is widely used in municipal and industrial laboratories to measure the overall level of organic contamination in wastewater. COD is determined by measuring the amount of oxygen required to fully oxidize organic matter in the sample. A COD test requires approximately 3 hours to complete, while BOD requires 3-5 days.

*Co-digestion*

Co-digestion is the simultaneous digestion of a mixture of two or more feedstocks. The most common situation is when a major amount of a main basic feedstock (e.g., manure or sewage sludge) is mixed and digested together with minor amounts of a single or a variety of additional feedstocks. The expression co-digestion is applied independently to the ratio of the respective substrates used simultaneously.

*Compressed biomethane*

Compressed biomethane (CBM) is basically equivalent to compressed natural gas (CNG). The main difference is that CNG is made by compressing natural gas (a fossil fuel) whereas CBM is made by compressing biomethane (a renewable fuel).

*Compressed natural gas*

CNG is natural gas that has been compressed to 3,000 to 3,600 pounds per square inch, gauge (psig), usually for purposes of on-board fuel storage for natural gas vehicles.

*Conventional pollutants*

As specified under the Clean Water Act, conventional pollutants include suspended solids, coliform bacteria, biochemical oxygen demand, pH, and oil and grease.

<i>Criteria air pollutants</i>	As required by the Clean Air Act, the EPA identifies and sets standards to protect human health and welfare for six pollutants, called criteria pollutants: ozone (O <sub>3</sub> ), carbon monoxide (CO), particulate matter (PM <sub>10</sub> , PM <sub>2.5</sub> ), sulfur dioxide (SO <sub>2</sub> ), lead (Pb), and nitrogen oxides (NO <sub>x</sub> ). The term “criteria pollutants” derives from the requirement that the EPA must describe the characteristics and potential health and welfare effects of these pollutants. Periodic reviews of new scientific data may lead the EPA to propose revisions to the standards.
<i>Desulfurization</i>	Any process or process step that results in removal of sulfur from organic molecules.
<i>Dew point</i>	The temperature at which vapor in a gas-vapor mixture starts to condense when the mixture is cooled at constant pressure (most commonly used for water vapor in gas mixtures).
<i>Digester gas</i>	Biogas that originates from an anaerobic digester. The term is often used, and used in this report, to represent only biogas from a wastewater treatment plant.
<i>Economy of scale</i>	The principle that higher volume production operations have lower unit costs than smaller volume operations.
<i>Endothermic</i>	A process or reaction that absorbs heat. For example, ice melting is an example of an endothermic process because it absorbs heat from its surroundings.
<i>Enteric fermentation</i>	A digestive process by which carbohydrates are broken down by microorganisms in the rumen to simple molecules for absorption into the bloodstream of a ruminant animal, such as a cow.
<i>Ethanol</i>	A colorless, flammable liquid (CH <sub>3</sub> CH <sub>2</sub> OH) produced by fermentation of sugars. Can be produced chemically from ethylene or biochemically from the fermentation of sugars. Ethanol from starch, especially corn, and sugar crops is commercial. Ethanol from cellulosic feedstocks (woody material and agricultural residues) is still being developed. Used in the United States as a gasoline octane enhancer and oxygenate, it increases octane 2.5 to 3.0 numbers at 10% concentration. Ethanol also can be used in higher concentration in alternative-fuel vehicles optimized for its use.

<i>Exothermic</i>	A process or reaction that releases heat. For example, wood burning in the presence of oxygen is an example of an exothermic reaction.
<i>Global warming</i>	An increase in the near surface temperature of the Earth. Global warming has occurred in the distant past as the result of natural influences, but the term is most often used to refer to the warming that occurs as a result of increased emissions from human activity of greenhouse gases, such as carbon dioxide, methane, and nitrous oxide, which trap the sun's heat.
<i>Hemicellulose</i>	A carbohydrate polysaccharide that is similar to cellulose and is found in the cell walls of many plants
<i>Hydraulic retention time</i>	HRT is the average time a 'volume element' of fluid resides in a reactor. It is computed from liquid-filled volume of an anaerobic digester divided by the volumetric flow rate of liquid medium.
<i>Landfill gas</i>	Biogas produced as a result of natural, anaerobic decomposition of material in landfills. Landfill gas (LFG) is typically composed of approximately 55% methane and 45% CO <sub>2</sub> , with variable air content due to air introduced during the LFG collection process. Small amounts of H <sub>2</sub> S, siloxanes, other sulfur compounds, various trace hydrocarbons and other impurities can be present which provide a significant challenge in LFG handling and upgrading.
<i>Ligno-cellulosic</i>	Consisting of cellulose intimately associated with lignin, an amorphous polymer related to cellulose that has strength and rigidity. Wood is the most abundant ligno-cellulosic material, though almost all plant biomass contains lignin. Lignin does not degrade anaerobically (and is the most recalcitrant component of biomass for aerobic decomposition). Because of the structural nature of ligno-cellulosic material, much of the cellulose is difficult to access for anaerobic digestion.
<i>Liquefied biomethane</i>	Liquefied biomethane (LBM) is basically equivalent to LNG (liquid natural gas). The main difference is that LNG is made using natural gas (a fossil fuel) as a feedstock whereas liquefied biomethane is made using biomethane (a renewable fuel) as a feedstock.



<i>Liquefied natural gas</i>	A natural gas in its liquid phase. Liquefied natural gas (LNG) is a cryogenic liquid formed by cooling natural gas to approximately - 260° F at atmospheric pressure. In practice, LNG is typically stored at somewhat elevated pressures (e.g., 50 to 75 psig) to reduce cooling requirements and allow for pressure increases due to LNG vapor “boil off.” LNG is stored in double-insulated, vacuum-jacketed cryogenic tanks (pressure vessels) to minimize warming from the external environment. LNG is typically greater than 99% methane.
<i>Mesophilic</i>	Conditions in a biological reactor where temperatures are around 95° F (35° C).
<i>Methanogenic</i>	Methane-forming; In the anaerobic digestion process, methanogenic bacteria consume the hydrogen and acetate (from the hydrolysis and the acid forming stages) to produce methane and carbon dioxide
<i>Methane</i>	Methane is the main component of natural gas and biogas. It is a natural hydrocarbon consisting of one carbon atom and four hydrogen atoms (CH <sub>4</sub> ). The heat content of methane is approximately 1,000 Btu/scf (standard cubic feet). Methane is a greenhouse gas with 21 times the global warming potential of carbon dioxide on a weight basis.
<i>Nameplate rating</i>	The initial capacity of a piece of electrical equipment as stated on the attached nameplate in watts, kilowatts or megawatts. Actual capability can vary from the nameplate rating due to age, wear, maintenance, fuel type or ambient conditions.
<i>Natural gas</i>	Natural gas typically contains more than 90% methane; it may also contain traces of propane and butane. Natural gas is generally found either above crude oil deposits or in a relatively pure form in “stranded” natural gas fields. The methane content varies considerably in natural gas geologic reservoirs (deposits). Low-methane natural gas (sour gas) must be sweetened or upgraded before it can enter the natural gas grid. Sour gas or stranded gas often occurs in quantities too small to be economically processed and gathered into the pipeline network. Thus, it is often burned off near the well (i.e., flared) as a low-value by-product during the oil pumping process. Natural gas is a vital fossil fuel that is used in electricity generation, heating,

fertilizer production, the creation of plastics, and other industrial processes and products.

*Net metering*

A method of crediting customers for electricity that they generate on-site in excess of their own electricity consumption. Customers with their own generation offset the electricity they would have purchased from their utility. If such customers generate more than they use in a billing period, their electric meter turns backwards to indicate their net excess generation. Depending on individual state or utility rules, the net excess generation may be credited to their account (in some cases at the retail price), carried over to a future billing period, or ignored.

*Nitrogen or nitric oxides*

NO<sub>x</sub> is a regulated criteria air pollutant, primarily NO (nitric oxide) and NO<sub>2</sub> (nitrogen dioxide). Nitrogen oxides are precursors to photochemical smog and contribute to the formation of acid rain, haze and particulate matter.

*Nitrous oxide*

N<sub>2</sub>O, a greenhouse gas with 310 times the global warming potential of carbon dioxide.

*Nonconventional pollutants*

Pollutants not classified as conventional or toxic but which may require regulation. They include nutrients such as nitrogen and phosphorus.

*Nonpoint source*

Pollution source that is diffuse, without a single identifiable point of origin, including runoff from agriculture, forestry, and construction sites.

*Point source*

Contamination or impairment from a known specific point of origination, such as sewer outfalls or pipes.

*Priority (toxic) pollutants*

Pollutants that are particularly harmful to animal or plant life. They are grouped primarily into organics (including pesticides, solvents, polychlorinated biphenyls (PCBs and dioxins) and metals (including lead, silver, mercury, copper, chromium, zinc, nickel, and cadmium).

*Propionic acid*

The chemical compound propionic acid (systematically named propionic acid) is a naturally occurring carboxylic acid with chemical formula CH<sub>3</sub>CH<sub>2</sub>COOH. In the pure state, it is a

	colorless, corrosive liquid with a sharp, somewhat unpleasant odor. Found in milk, sweat, and fuel distillates
<i>Reactive organic gases</i>	A term used by the California Air Resources Board as interchangeable with <i>volatile organic compounds</i> .
<i>Rumen</i>	The large first compartment of a ruminant's stomach in which cellulose is broken down by the action of symbiotic microorganisms.
<i>Scrubbing</i>	Cleaning emission gases from a chemical reactor, generally with sprays of solutions that will absorb gases.
<i>Stoichiometric</i>	Pertaining to the proportion of chemical reactants in a specific reaction in which there is no excess of any reactant. For combustion, stoichiometric is the theoretical condition at which the proportion of the air-to-fuel is such that all combustible reactants will be completely burned with no oxygen or fuel remaining in the products.
<i>Thermal gasification</i>	Thermal gasification typically refers to conversion of solid or liquid carbon-based materials by direct internal heating provided by partial oxidation. The process uses substoichiometric air or oxygen to produce fuel gases (synthesis gas, producer gas), principally CO, H <sub>2</sub> , methane, and lighter hydrocarbons in association with CO <sub>2</sub> and N <sub>2</sub> depending on the process used. Thermal gasification can convert all of the organic components of the feedstock, whereas anaerobic digestion cannot convert lignin and some lignin/cellulose matrices. Generally lower moisture feedstocks are candidates for thermochemical conversion while high moisture feedstocks are best converted by biochemical means.
<i>Thermophilic</i>	Conditions in a biological reactor where temperatures are around 130° F (55° C) or higher.
<i>Total Solids</i>	Used to characterize digester systems input feedstock. Total solids (TS) means the dry matter content, usually expressed as % of total weight, of the prepared feedstock. By definition, TS = 100% – moisture content % of a sample. Also, TS = VS plus ash content.

<i>Volatile organic compounds</i>	VOCs are non-methane, non-ethane, photoreactive hydrocarbon gases that vaporize at room temperature (methane and ethane are not photoreactive). The quantity of VOC is sometimes determined by measuring non-methane non-ethane organic compounds. When combined with NO <sub>x</sub> and sunlight, VOCs produce ozone, a criteria air pollutant. Anthropogenic sources of VOCs include products of incomplete combustion, evaporation of hydrocarbon fuels, fugitive emissions from oil refineries and petro-chemical plants, fermented beverage manufacturing, large animal feeding operations and feed ensiling. However, natural VOC emissions account for the majority of VOC emissions (approximately 60% of the US VOC emission inventory). Vegetation, especially hardwood and pine trees account for most of the natural VOC emissions. They are also an intermediate product in the creation of methane during anaerobic digestion and are produced during enteric fermentation.
<i>Volatile Solids</i>	Used to characterize digester systems input feedstock Volatile Solids (VS) are the organic (carbon containing) portion of the prepared reactor feedstock. Usually expressed as a fraction of total solids, but sometimes expressed as a fraction of total sample (wet) weight. The amount of VS in a sample is determined by an analytical method called “loss on ignition.” It is the amount of matter that is volatilized and burned from a sample exposed to air at 550 °C for 2 hours. The inorganic (ash) component of total solids remains after the loss on ignition procedure. VS + ash = TS. Not all of the VS component of a feedstock is digestible.
<i>Wheeling</i>	The process whereby owners of electricity or natural gas pay to transport and distribute their commodity through another entity’s, distribution system (wire or pipeline grid).

## Executive Summary

This report examines the feasibility of producing biomethane from dairy manure. We investigated a number of possible technologies for producing renewable forms of energy and fuel from dairy wastes as well as applications and markets for these products. Although some of the applications proved to be technically or economically infeasible at this time, we believe that the information gathered could prove useful for other investigators or future studies. With this in mind, we designed this sourcebook for readers and investigators interested in exploring alternate uses of biogas created from dairy wastes.

## Summary of Findings

- Biomethane is renewable natural gas. It is made by upgrading biogas that is produced by the controlled decomposition of dairy manure or similar waste products. It can serve as a substitute for natural gas in transportation, heating, cooling, and power generation.
- Producing biomethane from dairy manure is not technically difficult, but it is challenging to produce it cost competitively with natural gas on the relatively small scale of a dairy.
- Dairies can produce more biomethane than they can use. A successful project must identify an off farm use, and provide a means to transport and store the fuel.
- There are institutional and regulatory barriers to transporting biomethane through the natural gas pipeline which will be difficult to overcome. Alternatively, it can be transported by dedicated pipeline or truck.
- Biomethane provides a number of societal and environmental benefits, especially improved energy security and reduced greenhouse gas emissions. Unlike raw biogas which has impurities that corrode exhaust systems, NO<sub>x</sub> emissions from biomethane combustion can be easily controlled.
- Current Federal and State programs provide little support for biomethane.
- The estimated cost of producing biogas and upgrading it to biomethane on farm can be competitive with the price the dairy would pay for natural gas. Added to the production cost is the cost of transportation and storage.
- Electrical generation from biogas is more cost effective than upgrading the biogas to biomethane, but current regulations make it difficult for the farmer to realize the economic value of the electricity he/she generates.
- Biomethane is a proven vehicle fuel. Sweden has 20 plants producing biomethane and runs 2,300 vehicles, mostly buses on it.
- Manure from about half the cows in California could provide enough biomethane to power all the natural gas vehicles currently operating in the state.

## Summary of Opportunities

- Central Valley cities such as Tulare, Visalia, Hanford or Modesto would be good sites for a biomethane vehicle fuel project because they are in a non-attainment area for ozone, and they each have many dairies in close proximity to existing compressed natural gas

filling stations. To make these projects feasible, the cities would need to enlarge their natural gas fleets (natural gas vehicles have lower air emissions than diesel vehicles) and expand or reconfigure their filling stations.

- There are many industrial customers in the Central Valley that could use large quantities of locally produced biomethane, though raw or partially cleaned biogas may suffice in many industrial applications.
- The output of Central Valley liquefied biomethane plants could replace the liquefied natural gas currently trucked in from other states.
- A biomethane industry along California's Highway 99 could serve as the infrastructure for a future "hydrogen highway," should it prove feasible, because it would provide a renewable fuel to replace natural gas as a feedstock for the on-site manufacture of hydrogen.

## Structure of Report

The report deals with five major areas of investigation:

- *Producing biogas from California dairy wastes.* We considered the theoretical maximum production potential, the technical and economic considerations, and the technologies and systems most suitable for producing biogas on dairy farms.
- *Upgrading biogas to biomethane.* We use the term "biomethane" to describe an upgraded form of biogas similar to natural gas in composition and energy capacity, and we investigated the various technologies that can be used to create biomethane by removing hydrogen sulfide, moisture, and carbon dioxide from biogas.
- *Using and distributing biogas and biomethane.* We investigated various traditional and non-traditional uses of biogas and considered potential on- and off-farm uses of biomethane. An important consideration is the means of storing and transporting the fuel to its final place of consumption. We considered the technical and economic implications of the various means of distribution.
- *Meeting regulatory requirements and obtaining access to government incentives.* Most existing government policies and incentives for renewable energy focus either on renewable electricity sources or two forms of alternative vehicle fuels: ethanol and biodiesel. We examined federal and state (California) policies and programs now in place to determine their current or potential applicability to the dairy biogas and biomethane industry. We also considered the various permits and regulatory requirements needed to build a dairy digester and/or biomethane upgrading plant, whether on an individual farm or at a centralized location.
- *Determining the financial, economic, and business environment for the development of a biomethane industry.* We estimated the costs of building a biomethane plant and considered these in the context of existing and potential markets for biomethane. Despite some favorable economic conditions, such as the currently high price of natural gas, we concluded that public (i.e., governmental) policy support of the industry is needed to help move it beyond the pioneering stage, and we concluded that the various environmental, social, and economic benefits associated with the development of such an industry justify this support. We also determined a logical process for analyzing and developing specific biomethane projects and provided some scenarios for five projects that we believe have the best chance for success.

## **Producing Biogas from California Dairy Wastes**

California is the largest dairy state in the USA, with approximately 1.7 million cows that produce over 20,000 pounds of milk per cow each year. These same cows also generate approximately 3.6 million bone dry tons of manure, which must be properly managed to minimize air emissions, prevent water pollution, and control odor, flies, and pathogens.

Biogas, a mixture consisting primarily of methane and carbon dioxide, is produced from dairy wastes through anaerobic digestion, a natural process that breaks down organic material in an oxygen-free environment. This process occurs unaided at dairies that store their wastes in covered piles or lagoons, with the resulting biogas and its greenhouse gases typically released into the atmosphere. Anaerobic digesters allow dairies to produce and capture biogas that can be used as a renewable source of energy. Most dairies currently using anaerobic digesters for energy production capture the biogas and burn it as a source of renewable electricity for on-farm operations. Anaerobic digesters also help control odors, flies, and pathogens.

### ***Methane Production Potential of Dairy Wastes and Other Biomass***

Nearly two-thirds of all cows in California are on dairies that use a flushed management system; the others use a scrape system. In practice, flush dairies are the best candidates for biogas production because manure that is scraped and stored typically decomposes aerobically, which inhibits the development of the bacteria that create biogas. Potentially, California dairies could generate nearly 14.6 billion ft<sup>3</sup> of methane each year (which corresponds to 140 megawatts of electrical capacity); however, this figure does not reflect the practicalities of manure collection and storage.

Dairy wastes can be co-digested with other biomass, such as agricultural residues or food-processing wastes, to augment methane production. Co-digestion of animal manures with food processing wastes in community digestion facilities is practiced in a number of European locations and could be applicable also in some dairy areas in California. The practical potential methane production from all biodegradable sources in California is about 23 billion ft<sup>3</sup> per year (220 megawatts); dairy wastes make up nearly two-thirds of this amount. If all theoretically available feedstocks were used and better technologies were developed, the potential is five or six times greater.

### ***Technical Considerations for Anaerobic Digestion***

Key considerations in the design of an anaerobic digester include the amount of water and inorganic solids that mix with manure during collection and handling. The anaerobic digester itself is an engineered containment vessel designed to exclude air and promote the growth of methanogenic bacteria. The three digester types most suitable for California dairies are ambient-temperature covered-lagoon, complete-mix, and plug-flow digesters.

## **Collection and Use of Biogas**

Biogas formed in the anaerobic digester bubbles to the surface where it is captured. Sometimes the biogas is scrubbed to reduce the hydrogen sulfide content. Depending on the application, biogas may be stored either before or after processing, at low pressures. More often recovered biogas is fed directly into an internal combustion engine to generate electricity and heat, or it can be used only for heating. If the biogas is upgraded to biomethane, additional uses are possible.

## **Upgrading Dairy Biogas to Biomethane and Other Fuels**

By removing hydrogen sulfide, moisture, and carbon dioxide, dairy biogas can be upgraded to biomethane, a product equivalent to natural gas, which typically contains more than 95% methane. The process can be controlled to produce biomethane that meets a pre-determined standard of quality. Biomethane can be used interchangeably with natural gas, whether for electrical generation, heating, cooling, pumping, or as a vehicle fuel. Biomethane can also be pumped into the natural gas supply pipeline. High pressures can be used to store and transport biomethane as compressed biomethane (CBM), which is analogous to compressed natural gas (CNG), or very low temperatures can be used to produce liquefied biomethane (LBM), which is analogous to liquefied natural gas (LNG).

### ***Technologies for Upgrading Biogas to Biomethane***

The technologies for upgrading biogas are well established. They are used in the natural gas industry to “sweeten” sour gas, i.e. natural gas that is low in methane content. They have also been used at a few US landfills, but in all cases the scale is much larger than the average dairy.

There are three steps to upgrading biogas to biomethane. They are: (1) removal of hydrogen sulfide, (2) removal of moisture, and (3) removal of carbon dioxide. The simplest way to remove moisture is through refrigeration.  $H_2S$  can be removed by a variety of processes:

- Air injected into the digester biogas holder
- Iron chloride added to the digester influent
- Reaction with iron oxide or hydroxide (iron sponge)
- Use of activated-carbon sieve
- Water scrubbing
- Sodium hydroxide or lime scrubbing
- Biological removal on a filter bed

The following processes can be considered for  $CO_2$  removal from dairy manure biogas. Some of them will also remove  $H_2S$ . The processes are presented roughly in the order of their current availability for and applicability to dairy biogas upgrading:

- Water scrubbing
- Pressure swing adsorption



- Chemical scrubbing with amines
- Chemical scrubbing with glycols (such as Selexol™)
- Membrane separation
- Cryogenic separation
- Other processes

Some technologies are more suitable for dairy farm operations than others, typically because of cost considerations, ease of operation, and other concerns such as possible environmental effects. A possible design for a small dairy biogas upgrading plant might consist of the following:

- Iron sponge unit to remove hydrogen sulfide
- Compressors and storage units
- Water scrubber with one or two columns to remove carbon dioxide
- Refrigeration unit to remove water
- Final compressor for producing CBM, if desired

Operation and maintenance of this system would be relatively simple, which is one reason it is recommended over other, possibly more efficient, processes. Electricity for the compressors could be produced from an on-site generator using biogas, which could also generate power for other on-site uses, or from purchased power. If purchased power were used, the major operating costs for this process would be for power for gas compression. Our research suggests that a farm of about 1,500 dairy cows is the lower limit of scale for this technology.

### ***Potential for Upgrading to Fuels other than Biomethane***

Other potential high-grade fuels that could possibly be produced from biogas include (1) liquid hydrocarbon replacements for gasoline and diesel fuels (created using the Fischer-Tropsch process), (2) methanol, and (3) hydrogen. At present, however, technological constraints, poor economies of scale for small operations, and—in the case of methanol—a lack of markets, make these processes impractical for dairy operations.

## **Storing, Distributing, and Using Biogas and Biomethane**

Dairy manure biogas is generally used in combined heat and power applications that combust the biogas to generate electricity and heat for on-farm use as it is created. Because of its highly corrosive nature (due to the presence of hydrogen sulfide and water) and its low energy density (as obtained from the digester, biogas contains only about 600 Btu/scf), the potential for off-farm use of raw biogas is extremely low.

Biomethane, which was upgraded from biogas by removing the hydrogen sulfide, moisture, and carbon dioxide, has a heating value of about 1,000 Btu/scf. Because of this high energy content, biomethane can be used as a vehicular fuel. It could also be sold for off-farm applications to industrial or commercial users or for injection into a natural gas pipeline.

### ***Storage of Biogas and Biomethane***

The least expensive and easiest to use storage systems for on-farm applications are low-pressure systems; these systems are commonly used for on-site, intermediate storage of biogas. Floating gas holders on the digester form a low-pressure storage option for biogas systems.

The energy, safety, and scrubbing requirements of medium- and high-pressure storage systems make them costly and high-maintenance options for biogas. They can be best justified for biomethane, which is a more valuable fuel than biogas.

Biomethane can be stored as CBM to save space or for transport to a CNG vehicle refueling station. High-pressure storage facilities must be adequately fitted with safety devices such as rupture disks and pressure relief valves. Typically, a low-pressure storage tank is used as a buffer for the output from the biogas upgrading equipment and would likely have sufficient storage capacity for around one to two days worth of biogas production. Since CNG refueling stations normally provide CNG at 3,000 to 3,600 psi, biomethane is compressed and transported at similar or higher pressures to minimize the need for additional compression at the refueling station.

Biomethane can also be liquefied to LBM. Two advantages of LBM are that it can be transported relatively easily and it can be dispensed to either LNG vehicles or CNG vehicles. However, if LBM is to be used off-farm, it must be transported by tanker trucks, which normally have a 10,000-gallon capacity. Since LBM is a cryogenic liquid, storage times should be minimized to avoid the loss of fuel by evaporation through tank release valves, which can occur if the LBM heats up during storage.

### ***Distribution of Biomethane***

Biogas is a low-grade, low-value fuel and therefore it is not economically feasible to transport it for any distance, although occasionally it is transported for short (1 or 2 mile) distances via a dedicated pipeline. In contrast, biomethane can be distributed to its ultimate point of consumption by dedicated biomethane pipelines, the natural gas pipeline grid, or in over-the-road transportation as CBM or LBM.

If the point of consumption is relatively close to the point of production, the biomethane could be distributed via dedicated pipelines (buried or aboveground). For short distances over property where easements are not required, this is usually the most cost-effective method. Costs for laying dedicated biomethane pipelines can vary greatly, and range from about \$100,000 to \$250,000 per mile.

The natural gas pipeline network offers a potentially unlimited storage and distribution infrastructure for biomethane. Once the biomethane is injected into the natural gas pipeline network, it becomes a direct substitute for natural gas. There is at least one location in the US (at the King County South Wastewater Treatment Plant in Renton, Washington) where this is done.

The gas can be sold to a utility, or wheeled to a contracted customer. However there are substantial regulatory and other barriers involved in using the natural gas pipeline.

If distribution of biomethane via dedicated pipelines or the natural gas grid is impractical or prohibitively expensive, over-the-road transportation of compressed biomethane may be a distribution option.

Over-the-road transportation of liquefied biomethane is a potential way of addressing many of the infrastructure issues associated with biomethane distribution. In California, where almost all LNG is currently imported from other states, in-state production of LBM would gain a competitive advantage over LNG with respect to transportation costs.

### ***Biogas as a Fuel for On-Farm Combined Heat and Power Applications***

At present, dairy manure biogas is used on-farm for direct electrical generation, and some of the waste heat is recovered for other uses. Because of its highly corrosive nature (due to the presence of hydrogen sulfide and water) and its low energy density, the potential for off-farm use of biogas is limited.

Electricity generation using biogas on dairy farms is a commercially viable, proven renewable energy technology. Typical installations use spark-ignited natural gas or propane engines that have been modified to operate on biogas. Gas treatment to prevent corrosion from hydrogen sulfide is usually not necessary if care is taken with engine selection and proper maintenance procedures are followed, though it may become necessary in the future to help control NO<sub>x</sub> from combustion.

Burners and boilers used to produce heat and steam can be fueled by biogas if the equipment is modified to ensure the proper fuel-to-air ratio during combustion and if operating temperatures are maintained at a high enough level to prevent condensation and the resultant corrosion from the hydrogen sulfide contained in the biogas.

For combined heat and power (CHP) applications, the key to energy savings is recovering heat generated by the engine jacket and exhaust gas. Nearly half of the engine fuel energy can be recovered through this waste heat by, for example, recovering hot water for process heat, preheating boiler feedwater, or space heating.

### ***Alternative On-Farm Uses of Biogas***

Theoretically, biogas can replace other fuels for on-farm non-CHP applications such as irrigation pumps and engine-driven refrigeration compressors, but this is unlikely. Raw biogas cannot be used as a vehicular fuel because of engine and performance maintenance concerns.

Spark-ignited gasoline engines may be converted to operate on biogas by changing the carburetor to one that operates on gaseous fuels (some gas treatment may be necessary). Diesel engines can also be modified to operate on biogas; the high compression ratio of a diesel engine lends itself to operation on biogas.

Irrigation pump use is intermittent and highly seasonal and therefore would not consume biogas on a steady basis throughout the year. Also, it would probably be more cost-efficient to switch remote diesel-powered irrigation pumps to electrical power (which could be provided by a generator set using “raw” biogas as fuel) than to upgrade the biogas and transport it via pipeline to feed the remote irrigation pumps.

Refrigeration accounts for about 15% to 30% of the energy used on dairy farms; most of this is for compressors used for chilling milk. Since dairy cows are milked daily, a steady source of energy is required for refrigeration needs. However, natural-gas driven motors are significantly more expensive than electrical motors with similar output power ranges and therefore have not been traditionally considered as economically desirable choices for this application. Thus, the use of biogas as a direct fuel for on-farm refrigeration compressors is not likely.

### ***Potential On-Farm Uses of Biomethane***

All the equipment described above that can run on biogas or natural gas can run on biomethane. In addition biomethane is suitable as a fuel in vehicles converted or designed to run on natural gas. Biomethane could be moved around a farm more easily than biogas because it is a cleaner fuel; however, it will likely still be more cost-effective to use biogas to generate electricity to run irrigation pumps than to convert the pumps to run on biomethane. The same is true of refrigeration equipment which could be run by electricity or driven by waste heat.

Although it is technically feasible to use biomethane as a fuel for on-farm alternative-fueled vehicles, there are currently no commercially available CNG- or LNG-fueled non-road agricultural vehicles. Commercial versions of some on-road agricultural vehicles such as pickup trucks are available, but the lack of convenient refueling infrastructure, makes it difficult to use CNG or LNG vehicles for on-farm applications.

### ***Off-Farm Uses of Biomethane***

There are two main potential off-farm uses of biomethane: to sell it to a nearby industrial user with heavy natural gas requirements or to sell it as a vehicular fuel. The major considerations for the first use is (1) to locate an industrial user willing to buy biomethane and (2) to transport the biomethane to the industrial user economically. There are many industrial users in the Central Valley that could use very large amounts of biomethane. Dairy cooperatives use large amounts of natural gas to dry milk into powder.

The medium- and heavy-duty CNG vehicle market is expected to be fueled by continued strong demand for CNG transit buses and to a lesser extent, school buses and refuse trucks. Given the potential variability in the medium- and heavy-duty market, a range of projections has been given based on a conservative annual growth rate of 15% to 20%.

The heavy-duty market accounts for the vast majority of the LNG vehicles in California. In general, the growth in this market is expected to be fueled by continued niche demand for LNG transit buses, refuse trucks, and Class 8 urban delivery trucks (regional heavy delivery). Growth is limited by the lack of a refueling infrastructure and of in-state LNG production facilities. The market is expected to grow from its small base by 5% to 10% a year.

The combined annual market for CNG and LNG vehicle fuel in California is approximately 80 million gasoline gallon equivalents. To put this in perspective, it would take methane from about 900,000 cows, about half the cows in the state, to provide this amount of fuel.

## **Meeting Regulatory Requirements and Gaining Access to Government Incentives**

The successful development of a California biomethane industry will require supportive government policies and financial incentives. The production and use of biomethane as a replacement for fossil fuels could potentially provide numerous benefits such as reduced greenhouse gas, reduction of odors and flies on the dairy, less dependence on fossil fuel supplies, better energy security, stimulation of rural economies, and could possibly improve water quality. These are benefits to society rather than financial benefits for the farmer who produces the biomethane. Consequently, it is appropriate for the government to provide support for the development of the biomethane industry.

Unfortunately biomethane does not get as much governmental support as other renewable energy sources. Most federal and state policies that support renewable energy and alternative fuels focus either on renewable electricity, often referred to as renewable energy, or on two specific liquid biofuels: ethanol and biodiesel. With a few exceptions, they do not provide specific support for biomethane production. If the biomethane industry is to prosper, it must help launch policy initiatives that will provide the same direct financial incentives or tax credits that are now earned by programs that focus on renewable electricity, ethanol, and biodiesel.

### ***Policy Responses to Environmental Issues***

Public policy is moving to address emissions from dairy biogas; it remains to be seen whether this takes shape as increased regulatory efforts, market incentives such as a carbon trading market or an emission reduction credit market, or the development and promotion of technologies that will help dairies or other sources voluntarily reduce their emissions.

### **Regulation to Control Dairy and Vehicle Emissions**

Federal and state policies are already in place to help regulate air quality. Although, the application of these policies to agricultural activities such as dairy farming has been minimal to date, recent changes in California law require California air districts to regulate dairies in accordance with the federal Clean Air Act. Since the San Joaquin Valley and the South Coast are extreme non-attainment areas for ozone, major sources of pollution in those air districts need to control their volatile organic compound emissions. As a result both districts have considered anaerobic digesters to control VOC as a possible requirement in some cases, or as a mitigation measure. However, anaerobic digesters should be viewed primarily as a renewable energy technology rather than as an air quality control technology.

### **Market Incentives to Reduce Pollution**

Two types of emission trading permits could impact the biogas/biomethane industry in the USA: carbon trading and emission reduction credits. Although carbon trading is unlikely in the near future unless the USA ratifies the Kyoto Treaty, California has a market in place for emission reduction credits. As currently structured, this market does not allow agricultural enterprises to participate effectively; however, if such participation were possible, dairies might be provided with an incentive to collect biogas, thus potentially reducing volatile organic compound (VOC) emissions and gaining emission reduction credits.

### **Promotion of New Energy Technologies and Fuels**

There are several approaches that can help encourage new technologies: tax credits or incentives, subsidies through direct funds, and long-term contracts that guarantee market and/or price. For example, in response to concerns about the contribution of methane to climate change, the US EPA set up the AgSTAR program to develop and disseminate information about anaerobic digesters for animal waste. The California Energy Commission has also funded research on anaerobic digestion for electrical production and has a new program natural gas research program that may fund biomethane research.

### **Financial Incentives**

Renewable electricity, ethanol, and biodiesel are supported by direct financial incentives and mandates that increase their usage, while biomethane does not.

California is committed to renewable electricity and has a variety of programs that provide direct benefits for electrical generation, but the dairy loses them when it chooses to use its biogas for biomethane instead of electricity.

Ethanol has direct cash incentives in excise tax exemptions that began in 1978. Both ethanol and biodiesel are also supported by producer incentive funds under the 2002 Farm Bill. The ethanol market is also supported by oxygenation mandates under the Clean Air Act amendments of 1990.

Traditional biofuels and biomethane receive some market support through the alternative fuel program created by the Energy Policy Act of 1992, which may be expended in the proposed Energy Policy Act of 2005. Vehicles that run on biomethane fulfill alternative vehicle fleet requirements as mandated in federal, state, and local law and should be able to earn various federal, state, and local incentives.

Biomethane receives no direct financial incentives, although it can qualify for some of the benefits available to alternative fuels. The federal government has programs to promote farm-based and rural renewable energy, and biomethane projects can compete for such awards. The federal government's efforts are concentrated in the Farm Bill of 2002. In addition, biomethane research and development funds are available through competitive grant programs.

### ***Government Permits and Regulations for Biogas Upgrading Plant***

A biogas upgrading facility is subject to federal, state, and local regulatory requirements. The dairy itself is subject to a number of air and water quality regulations, whether or not it produces biogas. Even if a dairy has a water permit, a new permit is required for the installation of an anaerobic digestion system. If a dairy has a digester that combusts biogas, or upgrades biogas to biomethane, an air permit will be required from the local air district. Depending on the county, a local administrative permit or conditional use permit may also be required.

No specific additional permits are needed by an upgrading facility to compress or liquefy biomethane to produce CBM or LBM. However, there may be emission or safety issues associated with the production of these fuels that will make it more difficult to meet permitting requirements.

Regulations pertaining to over-the-road transportation of CNG and LNG are assumed to be fully applicable to over-the-road transportation of CBM and LBM, respectively.

No known federal, state, or local regulations expressly prohibit the distribution of dairy based biomethane via the natural gas pipeline network, though there is a California regulation that blocks landfill generated biomethane from the natural gas pipeline. Yet only one US biomethane plant, the aforementioned wastewater treatment plant in Renton, Washington, puts biomethane into the natural gas pipeline. Regulatory barriers and utility resistance are likely to make this alternative very challenging.

It is unclear whether state and county regulations pertaining to local pipeline distribution of natural gas would be applicable to the local distribution of biomethane (or biogas) via dedicated pipelines. More than likely, the use of a dedicated pipeline to transport biogas or biomethane in a gas utility service area would be subject to the standard city and county regulations and permitting process for underground pipe installations. Some local regulations specify that permits for underground pipelines carrying gas can only be granted to public utilities. For this reason,

having a local utility company as a partner in a biogas/biomethane project could be an important asset during the permitting process.

Obtaining the necessary permits for siting, constructing, and operating dedicated biogas/biomethane pipelines could be a complex, time-consuming, and expensive process depending on the location of the proposed pipelines (i.e., what land they will cross). Permits from state, local, and possibly federal agencies may be required.

## **Determining the Financial, Economic, and Business Environment for the Development of a Biomethane Industry**

As sources of renewable energy, biogas and biomethane compete in one of two markets: electricity and natural gas (including natural gas vehicle fuels). To be viable energy sources, they must be able to compete in these markets from a financial and economic standpoint.

### ***California's Electricity and Natural Gas Markets***

Electricity is different from all other commodities in that it cannot be stored; it must be generated on demand, when it is needed. Thus the capacity of the system is as important as the quantity of electricity that is generated. Despite the 1996 restructuring of California's electricity market, it remains regulated and strapped by complex rules.

Electricity price analysis in California is complex because the retail price includes many components in addition to charges for electricity generation. In addition, dairies that use biogas from anaerobic digesters to generate electricity face market barriers. Under California's current market structure, most dairies cannot sell their electricity. Their best alternative is to use it on-farm availing themselves of opportunities presented under California's net metering legislation (AB 2228, proposed AB 728). Inasmuch as they use the electricity on-farm without sending it through the grid, they save the full retail price of electricity.

California consumes about 6 billion ft<sup>3</sup> of natural gas per day. This gas is burned directly as a fuel, used as a feedstock in manufacturing, or used to generate about one-third of California's electricity (the share used in electricity generation is increasing). Eighty-four percent of the natural gas used in California originates outside the state.

Most dairies are not on the natural gas grid. If they were most of them would be in PG&E territory and would be charged prices on the small commercial gas tariff. Those prices have varied considerably over the last several years, and are currently at a very high price historically.

In all likelihood, biomethane production will be cost effective only if it can be sold to an off-dairy customer, either by distributing it through a natural gas pipeline grid, or by transporting it by private pipeline or vehicle to a site where it can be used or sold. The most promising off-site



customers would be a nearby alternative vehicle fueling station (for CBM or LBM) or an industrial user of large amounts of natural gas.

### ***Estimated Costs for Building a Biogas Fueled Electric Plant or Biomethane Upgrading Plant***

A dairy anaerobic digester that will be used to create biogas for electrical generation has two major components. The first is the system to generate and collect the biogas. The second component is the system to generate the electricity.

A dairy anaerobic digester whose ultimate purpose is to produce biomethane uses the same sort of digester to generate and collect biogas. The biogas is then upgraded to biomethane by removing the hydrogen sulfide, moisture, and carbon dioxide. Finally, the biomethane is compressed or liquefied, stored, and/or transported to a location where it can be used.

### **Estimated Costs for Anaerobic Digesters for Electricity Generation**

We analyzed the published costs for 12 dairy digesters larger than 50 kW and found that the average cost for building the anaerobic digester systems for electrical generation was about \$4,500 per average kilowatt generated. In contrast, an analysis of four projects completed under California's Dairy Power Production Program showed average costs of \$6,100 per nameplate kilowatt. Based on these "high" and "low" averages, we calculated cost ranges for the various digesters, both with and without equipment to remove nitrogen oxide emissions. Of course costs for specific projects vary considerably from these averages based on local conditions.

At the lower average cost of \$4,500 per average kilowatt generated, the capital costs for a digester-generator with a capacity of about 100-kW would be about \$450,000 (without NO<sub>x</sub> controls). At 28% efficiency, with operating costs included and with the plant fully amortized over 20 years at 8%, this plant would have a levelized cost of electricity of \$0.067/kWh. If controls for NO<sub>x</sub> emissions were added (another \$90,000 in capital costs), the levelized cost of electricity would go up to about \$0.077/kWh. If waste heat is used for some on-farm uses, the estimated costs for both ranges will decrease. The most likely scenario for California is an anaerobic generator with NO<sub>x</sub> controls and co-generation, which gives a cost range of \$0.062 (for a \$4,500/kw digester) to \$0.077/kWh (for a \$6,100/kw digester). These costs compare favorably with the retail price the farmer is paying, currently \$0.09 to \$0.11/kWh, but they are not competitive in the wholesale market.

### **Estimated Costs to Upgrade Biogas to Biomethane**

Estimating the costs of a biogas to biomethane plant is more speculative than for a digester-generator. Although several large-scale upgrading plants have been built and operated at landfills, to date, no biogas upgrading facility has been built on a dairy in the USA. Sweden, however, has 20 plants that produce biomethane from various sources of biomass. Several of the authors of this

report visited Sweden in June 2004 to tour biomethane plants and were able to obtain cost data on four biomethane plants. All four plants were municipally run centralized plants that processed a variety of feedstocks.

The scale of the Swedish biomethane plants is smaller than the few landfill-gas upgrading plants in the USA, but larger than what would be required for most dairy facilities. For example, the largest plant we visited would require raw biogas from 27,000 cows to generate the amount of biomethane they produce, while the mid-sized plants would require 7,000 to 10,000 cows each, and the smallest plant could operate with manure from 1,500 to 2,000 cows. Each of these plants removes hydrogen sulfide, moisture, and carbon dioxide from the raw biogas and places the resultant biomethane into a pipeline, or compresses it for storage and/or transportation.

The capital costs of the smallest Swedish biogas upgrade plant were \$2.20 per thousand ft<sup>3</sup> of biomethane produced, while capital costs were for the largest plant were \$0.74 per thousand ft<sup>3</sup>. In contrast to electricity generation, where the capital costs exceed the operating costs, the operating and maintenance costs for the Swedish plants exceeded capital costs by a significant margin, ranging from \$5.48 to \$7.56 per thousand ft<sup>3</sup>. These costs did not include the anaerobic digester.

To estimate the cost of a US biomethane facility that includes an anaerobic digester and a biomethane plant, we combined US costs for anaerobic digestion with Swedish costs for biogas upgrade. The total costs of the combined digester and biomethane plant varied from \$8.44 to \$11.54 per thousand ft<sup>3</sup>.

We also estimated the cost of a digester combined with LBM plant that generated its own electricity from some of its biogas and liquefied biomethane from the remainder. We estimate that the plant could produce LBM for \$1.26 per gallon, or 2.10 per diesel gallon equivalent. To these costs must be added the costs of storage and transportation to a fueling station and taxes.

### **Estimated Costs for Storage and Transport of Biomethane**

In addition to the costs of generating biogas and upgrading it to biomethane, a biomethane producer must add the costs of storing and transporting the biomethane. If the biomethane could be put into a pipeline, there would be no storage expense. If the biomethane were purchased by the pipeline owner, there would be no transportation expense. Otherwise these expenses must be paid by the producer or the buyer.

Storage costs vary considerably with the length of time for which the gas must be stored. For example, enough storage capacity to store a day's worth of CBM produced from a plant that produces 45,000 ft<sup>3</sup> of biomethane per day would add \$100,000 to \$225,000 to the cost of the facility (\$0.60 to \$1.40 per thousand ft<sup>3</sup> of gas) to the cost of the biomethane production.

Estimates for U.S. piping costs vary from \$100,000 to \$250,000 per mile depending on the number of landowners involved, the need to cross public rights-of-way, the terrain, and similar factors. If an 8,000 cow dairy built a dedicated pipeline for \$150,000 per mile, that would add about \$.90 per thousand ft<sup>3</sup> of biomethane to the cost. Trucking requires more on-site storage than piping because enough biomethane must be accumulated to fill a tanker. Other than for LBM, transportation of biomethane by truck costs more per volume than pipeline transport and should be considered as an interim solution.

### ***Summary of Estimated Costs for Dairy Digester and Biomethane Plant***

Based on costs for similar, albeit larger, plants in Sweden, as well as discussions with equipment suppliers and other industry personnel, our best estimates for the various capital and operating costs associated with a dairy digester and biogas upgrading plant are as shown below:

<b>Component or Process</b>	<b>Cost (\$ per 1,000 ft<sup>3</sup>) Low Estimate</b>	<b>Cost (\$ per 1,000 ft<sup>3</sup>) High Estimate</b>
<i>Anaerobic digester</i>		
Capital cost	2.50	4.65
Operating cost	0.50	0.60
<i>Biomethane (Upgrading) Plant</i>		
Capital cost	1.55	3.10
Operating cost	3.70	6.80
<i>Biomethane storage</i>	0.00	2.80
<i>Biomethane transport</i>	0.00	0.90

Like other pioneering renewable energy technologies, the production and distribution of dairy biomethane is not currently cost effective for the private developer without a public subsidy. In time, after a number of small-scale plants are built, costs are likely to come down.

Our estimated costs for producing biogas and upgrading it to biomethane can compete only marginally with today's natural gas prices. Pioneering plants may have higher costs due to inexperience. At today's market prices, a large dairy could likely produce biomethane for a price lower than that paid by small retail commercial users (like dairies); while a smaller dairy's cost of production would be higher than the going market rate. Added to the cost of production is the cost of storage and transportation.

Costs of Digestion and Upgrade to Biomethane			Current Natural Gas Prices	
Cost Category	Cost (\$ per 1,000 ft <sup>3</sup> biomethane)		Price Category	Price (\$ per 1,000 ft <sup>3</sup> )
	Low Est.	High Est.		
Production cost	\$8.44	\$11.54	Wellhead	\$6.05
Storage	\$0.00	\$2.80	City gate	\$7.44
Transportation	\$0.00	\$0.90	Distribution	\$9.84

In contrast, generating electricity from biogas can offset retail electric purchases and can be simpler and more profitable than biomethane production. However, the farmer may produce more electricity than he can use; if this occurs, the farmer cannot be compensated for the excess dairy biogas electricity under California's current market structure, and the present net metering program in California is not as attractive for the small biogas electric generator as it is for the solar generator. Also, obtaining an interconnection agreement is time-consuming and expensive.

### ***Why Support the Development of the Biomethane Industry?***

Swedish experience demonstrates that a viable biomethane industry is possible. It is important to note, however, that the economics in Sweden are much more favorable for a biomethane industry than they are in the USA. The most important lesson we learned during our trip to Sweden was that no biomethane plant should be built until a market for the biomethane has been established and a distribution system designed that can move the biomethane to the market.

The current economics for development of the biomethane industry in the USA are challenging if there is no public subsidy. We feel, however, that there are a number of valid reasons to support the development of this industry through publicly funded subsidies, regulation, or tax incentives. Such subsidies and incentives are always necessary to develop a new source of renewable energy or an alternative transportation fuel.

A society that is heavily dependent on fossil fuel energy should be actively developing a wide variety of alternative energy resources. We cannot always predict which technologies will prove the most viable for our future needs. We need to invest in research and development and to build pilot plants for a variety of these technologies. Biomethane production addresses California's commitment to renewable energy and to reducing dependence on imported petroleum.

Development of a dairy biomethane industry would help to stimulate California's economy, particularly its rural economy. Biomethane production provides a series of environmental benefits both during the production process and because it can be substituted for fossil fuels. Development of biomethane production technologies and markets today will ensure future preparedness for the growth of this industry should conditions arise that make the production and use of biomethane a more financially viable and/or necessary option.

The biomethane industry, like the rest of the renewable energy sector, needs public subsidies, tax credits, or market rules that will help earn a premium for the product during its start-up phase. Regulators and lobbyists for the industry also need to be aware of the cost structure of the biomethane industry. In contrast to anaerobic digester systems that generate electricity, which have higher capital costs than operating costs, biogas upgrading plants that produce biomethane typically have higher operating costs than capital costs. Subsidies that cover even a large portion of the capital costs may be insufficient to stimulate industry growth. If biomethane facilities are to become viable, ongoing sources of renewable energy, they will likely need the support of ongoing production tax credits, a long-term fixed price contract, and/or market rules that provide a premium for its output.

### ***Considerations for Planning a Biomethane Project***

Although there is no magic formula for creating a successful biomethane project, our research indicates that a business plan for a successful biomethane enterprise should demonstrate that the following have been researched and, where possible, completed or obtained:

- Buyer for the biomethane
- Supply of organic waste
- Distribution system—pipeline or storage and subsequent over-the-road transport
- Location for biomethane plant
- Technology and operating plan
- Financial plan
- Permitting and regulatory analysis
- Construction plan

Our research also included a geographic analysis that highlighted the San Joaquin Valley as a focal point for future biomethane projects. By considering factors such as the proximity of dairies to market, existing infrastructure, and regional demand and need, this analysis indicated five promising scenarios that could be further investigated by those interested in developing a biomethane project:

- *Provide fuel to a community vehicle fleet.* A Central Valley community could make a significant environmental contribution by developing an integrated project involving CNG vehicles and a biomethane plant. At least four San Joaquin communities—Tulare, Visalia, Hanford, and Modesto—have both CNG fueling stations and a nearby dense population of dairies. However, the current CNG fleets in these communities are not large enough to support a biomethane plant. An integrated project that increased the number of CNG vehicles on the road and used locally produced CBM would capture a number of environmental and energy security benefits. The first community to do this would be a national showcase.
- *Sell biomethane directly to large industrial customer.* Several areas in the San Joaquin Valley have dairies concentrated near sizable industrial users of natural gas. One or more

of these industrial users could provide a substantial demand for locally produced biomethane, though raw or partially cleaned biogas may suffice in many applications.

- *Distribute biomethane through natural gas pipeline grid.* If the barriers to the use of the natural gas transmission system could be overcome, a biomethane plant could sell directly to the local gas utility, or pay to wheel the biomethane to an industrial or municipal customer on the natural gas grid. The biomethane plant would need to be located along or very close to the distribution line.
- *Build liquefied biomethane plant.* Liquefied biomethane can be used as a direct substitute for LNG. Except for a small pilot project, all LNG vehicle fuel is trucked into California from out-of-state LNG plants. While transportation costs limit a CBM plant to nearby markets, an LBM plant can cost-effectively transport LBM to fueling stations much further away. LBM could also be delivered to liquefied-to-compressed natural gas fueling stations or to customers off the natural gas grid that already receiving gas supplies deliveries in the form of LNG.
- *Use compressed biomethane to generate peak-load electricity.* Because CBM can be stored, a biomethane plant could use its fuel to generate peaking electrical power. Renewable energy that can be dispatched to serve peak demand can earn a substantial premium over non-dispatchable renewable energy resources such as wind and solar.

# **1. Potential Biogas Supply from California Dairies**

Biogas is a product of naturally occurring anaerobic fermentation of biodegradable material. Anaerobic bacteria occur naturally in the environment in anaerobic “niches” such as marshes, sediments, wetlands, and in the digestive tract of ruminants and certain species of insects. These bacteria also exist in landfills where anaerobic decomposition is the principal process degrading landfilled food wastes and other biomass.

When collected or captured, biogas can be used as a renewable energy source similar to natural gas, but with significantly lower methane content and thus a lower heating value. Biogas is derived from renewable biomass sources through a process called anaerobic digestion. Within the USA, the biogas industry is comprised primarily of landfills that collect and utilize landfill gas (LFG) and wastewater treatment plants utilizing anaerobic digesters. Digestion of animal manure from dairies and swine farms is gaining importance in the US both as an energy product and as a means for management of environmental impacts. Currently in the US, biogas is used primarily in engine-generators or boilers for generation of electricity and heat.

This report primarily addresses alternate (non-power and heat generation) uses of biogas produced on dairies, and more specifically, with the production and use of biomethane, an upgraded form of biogas that is equivalent to natural gas. This chapter explores the potential supply of biogas from dairies, including on-farm management factors that affect biogas production. In addition, it discusses the possibility of co-digesting dairy and other biomass wastes—that is, of augmenting dairy wastes with other biomass sources to improve overall biogas yield.

## **California Dairy Industry**

California is the largest dairy state in the nation, with approximately 1.7 million cows on about 2,100 dairies. The average California dairy has about 800 cows, and there is a clear trend toward concentration. According to Western United Dairymen, the number of California dairies decreased from more than 9,700 in 1960 to less than 2,200 in 2003 (Tiffany LaMendola, Western United Dairymen, personal communication, 29 June 2004). This represents a 78% reduction in the number of dairies. Despite the decreasing number of dairies, milk production grew from less than 10 billion pounds a year in 1963 to 35 billion pounds a year in 2003 (CDFA 2004, p. 44). The growth in milk production was generated by a significant increase in production per cow and, due to an increase in the average herd size, to an increase in the total number of cattle in the state.

The continuing trend toward an increased concentration of animals on fewer farms is illustrated in Table 1-1.

Table 1-1 Recent Trends in the California Dairy Industry: More Cows, Fewer Dairies

Year	Average Number of Cows per Dairy	Number of California Dairies
2001	721	2,157
2002	776	2,153
2003	806	2,125

Source: CDFA, 2003a

Table 1-2 Number of Cows in California's Dairies, 2003

County	Number of Cows	Number of Dairies	Average Number of Cows per Dairy
Butte	712	5	142
Del Norte	2,540	10	254
Fresno	90,345	109	829
Glenn	19,398	73	266
Humboldt	16,242	93	175
Kern	98,478	46	2,141
Kings	153,475	155	990
Madera	57,099	56	1,020
Marin	10,145	29	350
Merced	224,734	316	711
Monterey	1,632	4	408
Riverside	82,213	74	1,111
Sacramento	16,247	48	338
San Benito	774	3	258
San Bernardino	152,333	169	901
San Diego	5,500	8	688
San Joaquin	106,162	151	703
Santa Barbara	2,296	3	765
Siskiyou	1,677	5	335
Solano	3,643	5	729
Sonoma	31,192	81	385
Stanislaus	177,432	313	567
Tehama	5,103	23	222
Tulare	437,476	323	1,354
Yolo	2,048	3	683
Yuba	3,302	4	826
<i>Total</i>	1,702,198	2,109	807

Source: CDFA, 2004



Milk produced on California dairies is used in five major dairy product categories: fluid milk; soft products such as sour cream, cottage cheese, and yogurt; frozen products; butter and nonfat dry milk products; and cheese. Cheese is the largest category, using 45% of California's milk production compared to fluid milk, which represents 18% (CDFA 2003a).

Most of California's dairy farms are in the Central Valley. As shown in Table 1-2, Tulare County has the highest number of dairy cows, while Kern County has the largest dairies. Large dairies with 5,000 to 6,000 cows are becoming more commonplace as smaller dairies are consolidated or go out of business.

### ***On-Farm Manure Management and Biogas Supply***

California's dairy cows generated 3.6 million bone dry tons (BDT) of manure in 2003 (CBC, 2004). To assess the potential for biogas production from this manure, on-farm waste management techniques need to be considered. The methane-generation potential of the manure is directly affected by the methods used to collect and store manure.

Anaerobic digestion of animal manure, described more fully in Chapter 2, is a readily available technology that is limited by the type of feed a digester can receive. Common digesters use manure that is between 1% and 13% solids. Raw dairy manure contains about 15% total solids, of which about 83% is volatile solids. The percentage of total solids in stored manure depends on how much water the dairy uses to flush the manure. Manure collected fresh has greater methane-generation potential due to the retention of volatile solids. To ensure freshness, animal manure must be collected at least weekly, although daily collection is preferable.

### ***On-Farm Manure Management Systems***

In California, manure is collected as a semisolid or solid with a tractor scraper, or as a thin slurry formed by flushing water over a curbed concrete alley where manure is deposited. Typically, one of four prevailing manure management schemes is used on California dairies, depending on dairy housing patterns and manure deposition characteristics:

- Flushed freestall
- Scraped freestall
- Drylot with flushed feedlanes
- Scraped drylot

*A flushed freestall dairy* generally includes a milking barn, a separately roofed freestall barn that usually accommodates only the milk cow herd, and drylots for cow lounging. The milking parlor floor is cleaned by hose or flushed with fresh water. Flushed water containing manure is collected at the end of the flush lane and piped either to a separator or to the storage lagoon.

A *scraped freestall dairy* has the same configuration as a freestall flush dairy, except the freestall lanes are scraped using a skid steer tractor, rubber scraper, mechanical scraper, or vacuum scraper. The manure is typically deposited in a gutter that drains into a central pit. The milking parlor floor is cleaned by hose or flushed with fresh water.

A *flushed drylot dairy* has a milk barn that is flushed as well as drylots with flushed feedlanes. The parlor floor is cleaned by hosing or flushing with fresh water and flushed water containing manure is collected at the end of the flush lane and piped either to a separator or to the storage lagoon. However, a significant portion of the manure is deposited in drylots and scraped at random intervals as solid manure. The solids are often scraped into piles and left until there is an opportunity to haul them away.

Most *scraped drylot dairies* are older dairies. In this system, 85% to 90% of the manure is managed by dry scraping and truck removal. Manure is pushed by a tractor or pulled by a hydraulic scraper to a collection point. Drylot feedlanes usually do not have curbs and are not cleaned by flush water.

RCM Digesters (Berkeley, California; <<http://rcmdigesters.com/Default.htm>>) estimates that 35% of the cows in California are on flushed freestall dairies, 10% are on scraped freestall dairies, 30% are on flushed feedlane drylot dairies, and 25% are on drylot or scrape dairies (Mark Moser, personal communication, 27 May 2004). Many farms use a combination of these manure management systems, but in general most farms in northern California and the Central Valley use flush water and store manure in lagoons, while most Southern California dairies scrape their manure. The farmer chooses between these systems based on the price and availability of water as well as on local regulations and the amount of available land. In some jurisdictions the farmer is obligated to remove the dairy manure from the farm if there is inadequate acreage on which to spread it.

### ***Biogas Production Potential from California Dairies***

The quantity of biogas created from the digestion of dairy manure is determined by the dairy's manure management system. Key considerations for biogas production include the freshness and concentration of digestible materials in the manure. In theory, flushed manure collection systems produce less gas than regularly scraped manure systems because the digestible materials are dispersed and diluted. However, if collection of scraped manure is infrequent—which it typically is—the manure in scraped drylots may decompose and become unusable for anaerobic digestion. Dirt lot scraping incorporates dirt and stones into the scraped manure, and these may damage equipment and accumulate in a digester. Manure scraped from concrete surfaces on dirt lots will also include large quantities of inorganics, although manure scraped from freestall barns where cows remain inside is typically relatively clean, unless the bedding is sand or wood chips. Sand tends to collect within the digester and reduce the active volume of the digester over time; sawdust used as bedding passes through the digester untreated; and paper bedding increases gas

yield. In practical experience, therefore, because of the infrequency of collection and the incorporation of inorganics into the manure, scraped drylot dairies are usually not good candidates for biogas production.

Storage of manure also affects biogas production potential. Drylot storage techniques produce very little biogas because aerobic conditions inhibit the development of the methanogenic bacteria that create biogas. Manure stored in lagoons produces a substantial quantity of methane-rich biogas. If the lagoons are uncovered, this biogas is released into the atmosphere. When the waste is very dilute, solids tend to sink and create a layer of sludge in the bottom of lagoons or float and create a crust. For this reason, many dairies have solids separators to reduce solids loading in storage lagoons. Typical mechanical separators recover 15% to 20% of the solids from manure, while gravity separation may recover up to 40% of the solids. Separation of the solids results in the reduction of volatile solids in the lagoons and a roughly 25% lower methane yield.

Table 1-3 presents the potential daily methane (CH<sub>4</sub>) production from California dairies using existing technology and practices. The amount that is produced depends primarily on the quality of the feed for the cows and the manure collection system used. The use of screen separators, which is assumed in the table, tends to reduce methane production by 25%.

Table 1-3 Potential Daily Methane Production from California Dairies <sup>a</sup>

Type of Dairies	Number of Cows	Potential Daily Methane Production <sup>b</sup> (ft <sup>3</sup> /d)	
		Per Cow <sup>c</sup>	In California
Flushed freestall	595,769	32.2	19,183,771
Scraped freestall	170,220	32.2	5,481,084
Flushed drylot	510,659	23.8	12,153,691
Scraped drylot <sup>d</sup>	425,550	5.6	2,383,080
<i>Totals</i>	1,702,198		39,201,626

ft<sup>3</sup>/d = Cubic feet per day

<sup>a</sup> Updated from (CEC 1997).

<sup>b</sup> Assuming screen solids separators are used, which reduces methane production by 25%.

<sup>c</sup> Note that an average of 30 ft<sup>3</sup>/day/cow is used elsewhere in this report; this figure reflects the practical consideration that most of the biogas potential will come from freestall rather than drylot dairies because manure management on these dairies is more conducive to biogas generation.

<sup>d</sup> Although scraped drylot dairies have the potential to generate biogas, most are not good candidates because of infrequent manure collection and storage techniques.

Based on the information presented in Table 1-3, we estimate that California dairies have a methane production potential of about 40 million cubic feet per day (ft<sup>3</sup>/d) or 14.6 billion cubic feet per year (ft<sup>3</sup>/y). Using the early 2005 delivered price of natural gas (about \$10.00 per

thousand cubic feet), this is equivalent to over \$146 million per year in energy costs.<sup>1</sup> In terms of electricity output, this corresponds to over 1.2 million megawatt-hours (MWh) of energy or about 140 MW of electricity (MW<sub>e</sub>). As new technologies are tried and proven the methane yield and electrical production per cow is likely to increase.

## Co-Digestion of Dairy and Other Wastes

To augment methane production, manure from dairy cows can be co-digested with additional substrates such as agricultural residues and food-processing waste. Table 1-4 shows the potential methane-generation potential of various biomass sources available in California. The data used to estimate methane potential for these wastes was derived from an early study by Buswell and Hatfield of the Illinois Water Survey (1936); this study is still the most comprehensive information from a single study on the digestion of various waste resources.

Both gross and technical methane potentials are presented in Table 1-4. The gross potential represents the methane potential of all the waste generated within the stated categories in the state. The portion that is technically available is based on evaluations by the author and the various references cited.

The gross potential of swine and poultry layer manure in California is 30,000 and 274,000 BDT, respectively. Of this amount, about half is available for anaerobic digestion (technical potential). This amounts to about 160 million ft<sup>3</sup>/yr of CH<sub>4</sub> from swine operations (ASAE, 1990, p. 464), and about 850 million ft<sup>3</sup>/yr of CH<sub>4</sub> for poultry layer operations (RCM Digesters, 1985). Swine and poultry farms lend themselves to biogas generation due to the regular collection of manure, and were therefore included in Table 1-4. Manure from cattle feedlot and poultry broiler and turkey operations were not considered to be technically available due to the infrequent collection of manure at these facilities.

## Crop Residues

The 2003 California Biomass Resource Assessment (CBC, 2004) indicates that the gross potential of waste available from vegetable production in 2003 was 1.2 million BDT. Of this amount, only 100,000 BDT of biomass are estimated to be “technically” available on an annual basis. This waste would have the potential to generate about 1 billion ft<sup>3</sup> of CH<sub>4</sub> per year (Buswell and Hatfield, 1936, p. 170). The CBC assessment (2004) also states that the gross potential for biomass from field and seed production is about 5 million BDT. The main components are rice

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<sup>1</sup> This figure will vary according to the actual price of natural gas. At the time of final manuscript preparation (spring 2005), this price is historically high at around \$10 per therm; in the recent past, the price has been between \$6 and \$7 per therm.

straw (1.5 million BDT), cotton residue, wheat straw, and corn stover (leaves and stalks of corn). About 2.4 million BDT of this is potentially available for anaerobic digestion. As shown in Table 1-4, this 2.4 million BDT of biomass has the potential to generate 5.2 billion ft<sup>3</sup> of CH<sub>4</sub> per year (Buswell and Hatfield, 1936, p. 114) recoverable using existing collection methods. Though not considered in Table 1.4, recent research on rice straw indicates that the 1.5 million BDT of rice straw that is potentially available could produce as much as 6 billion ft<sup>3</sup> of CH<sub>4</sub> per year (Zhang, 1998).

Figures for orchard and vine production biomass wastes are also provided (CBC, 2004); however, these biomass sources were not included in Table 1-4 because the woody nature of the biomass generated in these farming operations does not lend itself to anaerobic digestion. It should be noted that all the crop residues mentioned are relatively undigestible without pretreatment such as screening (to remove dirt) and size reduction, and present significant handling issues for anaerobic digestion. Thus, although they represent a potentially large biomass resource, crop residues may not be a practical source of material for co-digestion with dairy wastes.

### ***Food Processing Waste***

The League of California Food Processors estimates that 14 to 16 million tons of fruits and vegetables are processed in California every year by canners, freezers, dryers, and dehydrators (Ed Yates, personal communication, 17 May 2004). These operations generate 1 million tons of waste annually from July through September. The waste material consists of peeled material, core material, culls and extraneous leaves and is 5% to 8% total solids. According to Yates, 49% of the waste is used as cattle feed and another 49% is used as soil amendment (personal communication, 17 May 2004). The 490,000 wet tons of waste material used annually as soil amendment could potentially be available for anaerobic digestion. The technical CH<sub>4</sub> generation potential from this waste would be 359 million ft<sup>3</sup>/yr (Buswell and Hatfield, 1936, p. 170). If the material fed to cattle was also used to generate gas, the gross potential is double this amount. However, using these food wastes as cattle feed is a higher value use than using them as a biomass source for gas generation. Also, the seasonal availability of food processing wastes could be problematic (e.g., grape and apple harvests occur over a 60-day period).

The California Milk Advisory Board indicates there are 60 cheese manufacturing plants that produced 1.8 billion pounds of cheese in 2003 (<[www.realcaliforniacheese.com](http://www.realcaliforniacheese.com)>, 17 May 2004). According to Carl Morris, general manager of Joseph Gallo Farms, for every pound of cheese produced, approximately 9 pounds of whey is generated (personal communication, 18 May 2004). The whey is typically converted into a powdered product and sold. However, 4.6% of the whey is in the form of lactose permeate, a waste product with a total solids content of 6%. Based on this, approximately 23,700 tons of lactose-permeate solids waste was generated in 2003 by California's cheese industry. This waste stream is both continuous and highly digestible, and

could easily be combined with dairy wastes. Using Buswell and Hatfield's data (1936, p. 170), lactose permeate waste has the potential to generate 250 million ft<sup>3</sup> of CH<sub>4</sub> per year.

### ***Slaughterhouse Waste and Rendering Plant Wastewater***

The 2003 California Biomass Resource Assessment conducted by the California Biomass Collaborative indicates that there are 79,000 BDT of slaughterhouse waste produced annually in the state, of which approximately 63,600 BDT would be technically available for anaerobic digestion. This waste, which includes digestible solids as well as liquids, is continuous and highly digestible and could generate approximately 660 million ft<sup>3</sup> of CH<sub>4</sub> per year (Buswell and Hatfield, 1936, p.155).

Table 1-4 Potential Methane Generation from Biomass Sources, California

Biomass Waste Material	Annual Methane Production <sup>a</sup> (million ft <sup>3</sup> /y)	
	Gross Methane Potential	Technical Methane Potential
Swine manure <sup>b</sup>	320	160
Poultry layer manure <sup>c</sup>	1,700	850
Poultry broiler manure <sup>d</sup>	1,800	0
Turkey manure <sup>d</sup>	1,300	0
Dairy manure	21,100	14,300
Cattle feedlot manure <sup>d</sup>	4,100	0
Crop residues	10,700	5,220
Vegetable residue	11,300	940
Meat processing	660	530
Rendering (wastewater) <sup>e</sup>	120	120
Cheese whey (lactose permeate)	250	250
Food processing waste	720	360
Processed green waste <sup>f</sup>	18,000	0
Landfilled manure <sup>f</sup>	220	0
Landfilled composite organic waste	15,200	0
Landfilled food waste <sup>f</sup>	19,900	0
Landfilled green waste <sup>f</sup>	16,500	0
<i>Total</i>	123,890	22,730

ft<sup>3</sup>/y = Cubic feet per year

<sup>a</sup> Unless otherwise indicated, these figures calculated based on Buswell and Hatfield data (1936).

<sup>b</sup> ASAE, 1990, p. 464.

<sup>c</sup> RCM Digesters, 1985.

<sup>d</sup> CBC, 2004 amended by personal communication from R. Williams, June 29, 2005.

<sup>e</sup> Metcalf & Eddy, 1979, p. 614; US EPA, 1975, p. 61.

<sup>f</sup> Al Seadi, Undated.

According to the California Integrated Waste Management Board (<<http://www.ciwmb.ca.gov/FoodWaste/Render.htm>>, 26 May 2004), there are 21 rendering operations in California. Waste from these plants amounts to approximately 2.45 million gallons per day (gpd) of high-strength organic wastewater (Fred Wellen, Baker Commodities, Inc., personal communication, 26 May 2004). The waste is typically treated in open lagoons to reduce the biological oxygen demand (BOD) prior to release to sewage treatment facilities or land application. This wastewater is highly digestible and could potentially be digested at the plant or co-digested with manure, especially if the rendering operations are in close proximity to the dairy. Rendering plant waste has the potential to generate 120 million ft<sup>3</sup> of CH<sub>4</sub> per year (US EPA, 1975, pp. 61, 87).

### ***Green Waste from Municipal/Commercial Collection Programs***

According to a June 2001 report entitled *Assessment of California's Compost and Mulch Producing Infrastructure*, composters and processors in California process over 6 million tons of organic materials per year (CIWMB, 2001). From this raw material, about 15 million cubic yards of organic material products are produced, including compost, boiler fuel, mulch and various blends (CIWMB, 2001). Although this material, unprocessed, is generally not suitable for anaerobic digestion because of its high lignin and low digestibles content, Sweden and other European countries digest significant portions of this waste stream. The presence of pesticides, fertilizer, wood chips, and other debris in domestic greenwaste adds further complexity. If these problems can be surmounted greenwaste could substantially augment the production of dairy biogas. The Inland Empire Utilities Agency is now in the planning stages for building such a system using dairy waste and local greenwaste. The California Energy Commission has provided funding to build a research digester designed by Dr. Ruihong Zhang of University of California Davis that will utilize greenwaste.

### ***Conclusions Regarding Co-Digestion***

The gross and technical potential for methane generation from biodegradable wastes in California, including dairy wastes and landfilled wastes, is summarized in Table 1-4. The total gross potential is about 124 billion ft<sup>3</sup> CH<sub>4</sub>/year, enough gas to produce about 10.4 million megawatt-hours (MWh) of electricity or about 1,200 MW of electrical capacity (at a heat rate of 12,000 Btu/kWh, assuming an energy conversion factor of 28%). However, most of this waste is not technically available due to inefficiencies in collection, contamination with other waste products, and other uses. Therefore the technical potential is estimated at only 23 billion ft<sup>3</sup> of CH<sub>4</sub>/year, or about 220 MW<sub>e</sub>, with dairy manures representing about two thirds of this amount. To put these figures in perspective, the total statewide demand for natural gas is about 6 billion ft<sup>3</sup>/day, or 2,200 billion ft<sup>3</sup>/year.

For co-digestion with dairy manures, only a relatively small fraction of potential or even technically available wastes would actually be usable, due to the many constraints on co-digestion, which range from location to seasonal availability to process constraints. Most

importantly, only a few waste resources (whey, meat processing, rendering, fruit and vegetable processing) lend themselves to co-digestion without introducing major difficulties (e.g., pretreatment). Although co-digestion may be important on a site-specific basis, on a statewide basis we do not expect that co-digestion of other biomass wastes would augment the dairy waste methane potential shown in Table 1-2 by more than 10% to 20%.



## 2. Production of Biogas by Anaerobic Digestion

Anaerobic digestion is a natural process in which bacteria convert organic materials into biogas. It occurs in marshes and wetlands, and in the digestive tract of ruminants. The bacteria are also active in landfills where they are the principal process degrading landfilled food wastes and other biomass. Biogas can be collected and used as a potential energy resource. The process occurs in an anaerobic (oxygen-free) environment through the activities of acid- and methane-forming bacteria that break down the organic material and produce methane ( $\text{CH}_4$ ) and carbon dioxide ( $\text{CO}_2$ ) in a gaseous form known as biogas.

Dairy manure waste consists of feed and water that has already passed through the anaerobic digestion process in the stomach of a cow, mixed with some waste feed and, possibly, flush water. The environmental advantages of using anaerobic digestion for dairy farm wastes include the reduction of odors, flies, and pathogens as well as decreasing greenhouse gas (GHG) and other undesirable air emissions. It also stabilizes the manure and reduces BOD. As large dairies become more common, the pollution potential of these operations, if not properly managed, also increases. The potential for the leaching of nitrates into groundwater, the potential release of nitrates and pathogens into surface waters, and the emission of odors from storage lagoons is significantly reduced with the use of anaerobic digestion. There may also be a reduction in the level of VOC emissions.

### Elements of Anaerobic Digestion Systems

Anaerobic digester systems have been used for decades at municipal wastewater facilities, and more recently, have been used to process industrial and agricultural wastes (Burke, 2001). These systems are designed to optimize the growth of the methane-forming (*methanogenic*) bacteria that generate  $\text{CH}_4$ . Typically, using organic wastes as the major input, the systems produce biogas that contains 55% to 70%  $\text{CH}_4$  and 30% to 45%  $\text{CO}_2$ . On dairy farms, the overall process includes the following:

- *Manure collection and handling.* Key considerations in the system design include the amount of water and inorganic solids that mix with manure during collection and handling, as described in Chapter 1.
- *Pretreatment.* Collected manure may undergo pretreatment prior to introduction in an anaerobic digester. Pretreatment—which may include screening, grit removal, mixing, and/or flow equalization—is used to adjust the manure or slurry water content to meet process requirements of the selected digestion technology. A concrete or metal collection/mix tank may be used to accumulate manure, process water and/or flush water. Proper design of a mix tank prior to the digester can limit the introduction of sand and rocks into the anaerobic digester itself. If the digestion processes requires a thick manure slurry, a mix tank serves a control point where water can be added to dry manure or dry manure can be added to dilute manure. If the digester is designed to handle manures

mixed with flush and process water, the contents of the collection/mix tank can be pumped directly to a solids separator. A variety of solids separators, including static and shaking screens are available and currently used on farms.

- *Anaerobic digestion.* An anaerobic digester is an engineered containment vessel designed to exclude air and promote the growth of methane bacteria. The digester may be a tank, a covered lagoon (Figure 2-1), or a more complex design, such as a tank provided with internal baffles or with surfaces for attached bacterial growth. It may be designed to heat or mix the organic material. Manure characteristics and collection technique determine the type of anaerobic digestion technology used. Some technologies may include the removal of impurities such as hydrogen sulfide ( $H_2S$ ), which is highly corrosive.
- *By-product recovery and effluent use.* It is possible to recover digested fiber from the effluent of some dairy manure digesters. This material can then be used for cattle bedding or sold as a soil amendment. Most of the *ruminant* and hog manure solids that pass through a separator will digest in a covered lagoon, leaving no valuable recoverable by-product.
- *Biogas recovery.* Biogas formed in the anaerobic digester bubbles to the surface and may accumulate beneath a fixed rigid top, a flexible inflatable top, or a floating cover, depending on the type of digester. (Digesters can also include integral low-pressure gas storage capability, as described in Chapter 4.) The collection system, typically plastic piping, then directs the biogas to gas handling subsystems.
- *Biogas handling.* Biogas is usually pumped or compressed to the operating pressure required by specific applications and then metered to the gas use equipment. Prior to this, biogas may be processed to remove moisture,  $H_2S$ , and  $CO_2$ , the main contaminants in dairy biogas, in which case the biogas becomes *biomethane* (see Chapter 3). (Partial removal of contaminants, particularly  $H_2S$ , will yield an intermediate product that we refer to in this report as *partially upgraded* biogas). Depending on applications, biogas may be stored either before or after processing, at low or high pressures (see Chapter 4).
- *Biogas use.* Recovered biogas can be used directly as fuel for heating or it can be combusted in an engine to generate electricity or flared. If the biogas is upgraded to biomethane, additional uses may be possible (see Chapter 5).

Anaerobic digestion is a complex process that involves two stages, as shown in the simplified schematic in Figure 2-2. In the first stage, decomposition is performed by fast-growing, acid-forming (*acidogenic*) bacteria. Protein, carbohydrate, cellulose, and hemicellulose in the manure are hydrolyzed and metabolized into mainly short-chain fatty acids—acetic, propionic, and butyric—along with  $CO_2$  and hydrogen ( $H_2$ ) gases. At this stage the decomposition products have noticeable, disagreeable, effusive odors from the organic acids,  $H_2S$ , and other metabolic products.



Figure 2-1 A dairy farm anaerobic digestion system (RCM, Inc., Berkeley, California)

In the second stage, most of the organic acids and all of the  $H_2$  are metabolized by methanogenic bacteria, with the end result being production of a mixture of approximately 55% to 70%  $CH_4$  and 30% to 45%  $CO_2$ , called biogas. The methanogenic bacteria are slower growing and more environmentally sensitive (to pH, air, and temperatures) than the acidogenic bacteria. Typically, the methanogenic bacteria require a narrow pH range (above 6), adequate time (typically more than 15 days), and temperatures at or above 70° F, to most effectively convert organic acids into biogas. The average amount of time manure remains in a digester is called the *hydraulic retention time*, defined as the digester volume divided by daily influent volume and expressed in days.

A more complete discussion of the anaerobic digestion process can be found in Appendix A.

## Anaerobic Digestion Technologies Suitable for Dairy Manure

Numerous configurations of anaerobic digesters have been developed, but many are not likely to be commercially applicable for California dairy farms. This section briefly describes the three digester types most suitable for California dairies: ambient-temperature covered-lagoon, complete-mix, and plug-flow digesters. Table 2-1 provides the operating characteristics of these manure digester technologies. More detail about these technologies is provided in Appendix B.

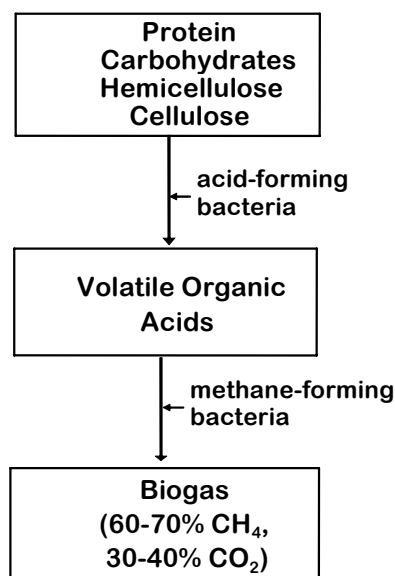


Figure 2-2 Simplified process of biogas production

Table 2-1 Characteristics of Anaerobic Digesters Suitable for On-Farm Use

Digester Type	Technology Level	Concentration of Influent Solids (%)	Allowable Solids Size	Supplemental Heat Needed?	HRT <sup>a</sup> (days)
Ambient-temperature covered lagoon	low	0.1 – 2	fine	no	40+
Complete mix	medium	2.0 – 10	coarse	yes	15+
Plug flow	low	11.0 – 13	coarse	yes	15+

<sup>a</sup> HRT = Hydraulic Retention Time = digester volume/daily influent volume

### **Ambient-Temperature Covered Lagoon**

Properly designed anaerobic lagoons are used to produce biogas from dilute wastes with less than 2% total solids (98% moisture) such as flushed dairy manure, dairy parlor wash water, and flushed hog manure. The lagoons are not heated and the lagoon temperature and biogas production varies with ambient temperatures. Coarse solids such as hay and silage fibers in cow manure must be separated in a pretreatment step and kept out of the lagoon. If dairy solids are not separated, they float to the top and form a crust. The crust will thicken, which will result in reduced biogas production and, eventually, infilling of the lagoon with solids.

Unheated, unmixed anaerobic lagoons have been successfully fitted with floating covers for biogas recovery for dairy and hog waste in California. Other industrial and dairy covered lagoons are located across the southern USA in warm climates. Ambient temperature lagoons are not suitable for colder climates such as those encountered in New York or Wisconsin.

### **Complete-Mix Digester**

Complete-mix digesters are the most flexible of all digesters as far as the variety of wastes that can be accommodated. Wastes with 2% to 10% solids are pumped into the digester and the digester contents are continuously or intermittently mixed to prevent separation. Complete-mix digesters are usually aboveground, heated, insulated round tanks. Mixing can be accomplished by gas recirculation, mechanical propellers, or circulation of liquid.

### **Plug-Flow Digester**

Plug-flow digesters are used to digest thick wastes (11% to 13% solids) from ruminant animals. Coarse solids in ruminant manure form a viscous material and limit solids separation. If the waste is less than 10% solids, a plug-flow digester is not suitable. If the collected manure is too dry, water or a liquid organic waste such as cheese whey can be added.

Plug-flow digesters consist of unmixed, heated rectangular tanks that function by horizontally displacing old material with new material. The new material is usually pumped in, displacing an equal portion of old material, which is pushed out the other end of the digester.

## Factors Influencing Anaerobic Digestion Efficiency

Digesters can function at ambient temperatures in warmer climates such as California, but with a lower biogas output than heated digesters. In some applications and in colder environments, digesters are heated. The optimal ranges for anaerobic digestion are between 125 to 135° F (*thermophilic* conditions) and between 95 to 105° F (*mesophilic* conditions). Anaerobic digestion under thermophilic conditions generates gas in a shorter amount of time than anaerobic digestion under mesophilic conditions. However, a higher percentage of the gross energy generated is required to maintain thermophilic conditions within the reactor. The extra heat is either extracted from the gross waste heat recovery in an engine or recovered from effluent.

Covered lagoons have seasonal variation in gas production due to the variation in ambient temperature. Gas production from complete-mix and plug-flow digesters are impacted less by ambient temperature variation since they are usually heated. On an annual basis, gas production from complete-mix and plug-flow digesters tends to be higher than for ambient-temperature covered lagoons because a higher percentage of solids entering complete-mix and plug-flow digesters is converted to biogas and the higher operating temperatures favor greater microbial activity. Gas production in all these digesters is dependent on hydraulic retention time.

Table 2-2 Modeled Comparison of Biogas Generation Potential of Three Different Anaerobic Digestion Processes on Typical 1,000-Cow Dairy Merced, CA Dairy <sup>a</sup>

Month	Biogas Generation (1,000 ft <sup>3</sup> )		
	Covered Lagoon	Plug Flow	Complete Mix
January	949	1,713	1,713
February	1,096	1,547	1,547
March	1,358	1,713	1,713
April	1,383	1,658	1,658
May	1,488	1,713	1,713
June	1,544	1,658	1,658
July	1,648	1,713	1,713
August	1,634	1,713	1,713
September	1,532	1,658	1,658
October	1,475	1,713	1,713
November	1,323	1,658	1,658
December	1,003	1,713	1,713
<i>Total Annual</i>	16,430	20,172	20,172

<sup>a</sup> Modeled using US EPA AgStar Farmware program

A comparison of the biogas potential of the three main types of digesters for use on dairy farms was made by the US EPA (see AgStar website <<http://www.epa.gov/agstar/>>). The US EPA's Farmware program was run for a 1,000-milking-cow freestall dairy operated in Merced, California. The program was run under three different digester configurations: covered lagoon,

plug flow, and complete mix. For the covered lagoon configuration, US EPA chose a manure management scheme in which all areas of the dairy were flushed and all dairy wastes ended up in the lagoon. To meet the higher total solids requirement of the plug-flow and the complete-mix designs, the chosen manure management option involved flushing the parlor area and scraping all other areas of the dairy. The results of biogas production in a typical year are shown in Table 2-2.

The results indicated that the plug-flow and the complete-mix digesters have the same gas production; however, the cost of a complete-mix digester is higher than a plug-flow system. A complete-mix digester must be larger than a plug-flow to accommodate the additional water added to reduce the total solids concentration of the influent. The gas output from the covered lagoon was significantly less than from the plug-flow and complete-mix digesters (especially in the winter months) because it was not heated and therefore had suboptimal conditions for gas production.

## Environmental Impacts of Anaerobic Digestion

The environmental impacts of on-farm anaerobic digestion depend on the manure management system that the digester amends or replaces as well as the actual use of the biogas produced.

Typically, the anaerobic digestion of dairy manure followed by flaring of biogas, combustion of biogas for electricity, or production and use of biomethane as fuel can provide a number of direct environmental benefits. These include:

- Reduced GHG emissions
- Potential reduction of VOC emissions
- Odor control
- Pathogen and weed seed control
- Improved water quality

One potentially negative environmental impact of anaerobic digesters that combust the biogas is the creation of nitrogen oxides ( $\text{NO}_x$ ), which are regulated air pollutants and an ozone precursor. Nitrogen oxides are created by combustion of fuel with air. Combustion of dairy biogas or any other methane containing gas (whether in a flare, reciprocating or gas turbine engine, or a boiler) will emit  $\text{NO}_x$ . The emission rate varies but is generally lowest for properly engineered flares and highest for rich burn reciprocating (piston) engines.  $\text{NO}_x$  emissions are controlled by using lean burn engines, catalytic controls or microturbines. The latter two methods are fouled by the high sulfur content of biogas, and the  $\text{H}_2\text{S}$  must be scrubbed to prevent the swift corrosion of these devices.

### **Reduced Greenhouse Gas Emissions**

The use of anaerobic digestion to create biogas from dairy manure can reduce GHG emissions in two distinct ways. First, when used in combination with a manure management system that stores manure under anaerobic conditions, it can prevent the release of  $\text{CH}_4$ , a greenhouse gas, into the

atmosphere. Second, the biogas or biomethane generated by the anaerobic digestion process can replace the use of fossil fuels that generate GHGs.

The biogas generated from anaerobic digestion contains about 60% CH<sub>4</sub>. It is this component, methane (which is also the main component of natural gas), that can produce energy. In addition to being an energy resource, however, CH<sub>4</sub> is also a GHG with 21 times the global warming potential, by weight, of CO<sub>2</sub>. Globally, CH<sub>4</sub> constitutes 22% of anthropogenic GHG emissions in terms of carbon equivalents. In the USA, CH<sub>4</sub> contributes 10% of anthropogenic GHG emissions and 10% of the CH<sub>4</sub> is derived from animal manure (US DOE, 1999b, pp. 6, 13-14). Thus animal manure produces approximately 1% of all anthropogenic GHG emissions in the USA.

Most of the Central Valley dairies store manure in large lagoons under anaerobic conditions. Manure stored in anaerobic conditions produces the bulk of the GHG emissions from animal waste. The methanogenic bacteria that thrive in this environment produce CH<sub>4</sub>, which is released into the atmosphere. If the lagoon is covered or the manure is digested in another type of digester, the CH<sub>4</sub> can be captured and combusted. This destroys the CH<sub>4</sub> and releases CO<sub>2</sub>. Since each unit of CH<sub>4</sub> has 21 times the global warming potential of CO<sub>2</sub>, 21 units of GHG are eliminated and 1 unit is created for each unit of CH<sub>4</sub> that is captured and combusted, creating an overall net gain of 20 units. This benefit will occur as long as the methane is combusted—whether the biogas is flared, used to generate electricity, or upgraded to biomethane and then combusted to produce energy. This benefit is in addition to the benefit when energy created by this renewable fuel replaces energy created by combusting a fossil fuel.

A good proportion of dairy manure in Southern California is stored aerobically. Methanogenic bacteria do not thrive in aerobic conditions and thus manure that is stored in corrals or piles where it is exposed to the air produces very little CH<sub>4</sub> (US EPA, 1999, p 7.4-15). Since manure stored in this manner releases little CH<sub>4</sub>, putting it into an anaerobic digester produces no significant reduction in CH<sub>4</sub> emissions, although there may be some nitrous oxide (N<sub>2</sub>O) reductions. Also, if the anaerobic digester has any significant leakage, emissions of CH<sub>4</sub> may actually be higher than they would be using aerobic (dry) storage alone.

### ***Reduced Volatile Organic Compound Emissions***

Volatile organic compounds, in combination with NO<sub>x</sub> and sunlight, produce ozone, the primary element in smog and a criteria air pollutant. Thus VOCs are an ozone precursor and are regulated by State and federal law. In California, VOCs are often called reactive organic gases (ROG).

VOCs are an intermediate product generated by methanogenic bacteria during the transformation of manure into biogas. It is expected that the total volume of VOCs generated is related to the total volume of CH<sub>4</sub> produced, but the more effective the methanogenic decomposition, the lower the VOCs as a percentage of the biogas. VOCs are created by enteric fermentation (the digestion process of the cow) and released primarily through the breath of the cow. They are also produced

by the anaerobic decomposition of manure. A well designed and managed anaerobic digester may reduce VOCs by more completely transforming them into CH<sub>4</sub>. Some fraction of the remaining VOCs in the biogas should be eliminated through the combustion of the biogas.

For its emission inventory, the California Air Resources Board (CARB) uses an emission factor for dairy cows of 12.8 lb of VOCs per cow per year. (This emission factor is based on a single 1938 study, which measured CH<sub>4</sub> emissions from a cow but did not measure VOC emissions.) Based on this emission factor, dairies are a significant source of VOC emissions and a major contributor to ozone in the San Joaquin Valley. The CARB has not determined the portion of VOC emissions that is generated by manure-holding lagoons.

Current law, notably Senate Bill 700 (SB 700), requires California air districts to regulate dairies in accordance with the federal Clean Air Act. Since the San Joaquin Valley and the South Coast are extreme non-attainment areas for ozone (see <[http://www.valleyair.org/General\\_info/faq\\_frame.htm](http://www.valleyair.org/General_info/faq_frame.htm)>), major sources of pollution in those air districts need to control their VOC emissions. The San Joaquin Valley Air Pollution Control District has proposed that anaerobic digesters be required for new dairies that have more than 1,984 cows as a “best available control technology” (BACT) for ROGs (SJVAPCD, 2004). The South Coast Air Quality Management District (which covers the Los Angeles Basin) is reviewing the anaerobic digestion technology under its Proposed Rule 1127 (see <<http://www.aqmd.gov/rules/reg/reg11/r1127.pdf>>).

Now that dairies are being regulated for VOC emissions, air districts and other regulators recognize the importance of providing a better VOC emission factor. The CARB, the San Joaquin Air Pollution Control District, the US EPA Region IX, the US Department of Agriculture (USDA), and the State Water Board have initiated and funded several studies, mostly led by researchers from University of California Davis and California State University Fresno. The research is aimed at determining an emission factor for VOCs from California cows. Preliminary results indicate that most of the VOCs on the dairy come from enteric fermentation and from feed, with a smaller proportion from lagoons.

### ***Increased Nitrogen Oxide Emissions***

When biogas or any fuel is combusted in an internal combustion engine it produces NO<sub>x</sub>, a criteria air pollutant as well as a precursor to ozone and smog.

For reciprocating engines the main NO<sub>x</sub> production route is thermal, and is strongly temperature dependent. Internal combustion engines can produce a significant amount of NO<sub>x</sub>. Maximum NO<sub>x</sub> formation occurs when the fuel mixture is slightly lean, i.e. when there is not quite enough oxygen to burn all the fuel. Lean-burn engines typically have lower NO<sub>x</sub> formation than stoichiometric or rich-burn engines because more air dilutes the combustion gases, keeping peak flame temperature lower. Gas turbines and microturbines also produce a very low level of NO<sub>x</sub> because peak flame temperatures are low compared to reciprocating engines. A system to flare



gas, if properly engineered, will generate a substantially lower level of NO<sub>x</sub> than an uncontrolled reciprocating engine.

Dairy anaerobic digesters that burn biogas for electricity typically use reciprocating internal combustion engines; microturbines have not been used successfully because impurities in the biogas corrode the engines. When there is enough biogas to support a lean-burn engine, NO<sub>x</sub> can be kept relatively low. The Inland Empire Utility Agency in Chino, California uses 700 to 1,400 kilowatt (kW) engines to combust biogas and has kept NO<sub>x</sub> production below 50 ppm (Clifton, 2004), which meets BACT for waste gas as proposed by CARB in its guidance document to California air districts as required under SB 1298 (CARB, 2002, p.4). For smaller applications (capacity of less than 350 kW), there are no lean-burn waste-gas reciprocating engines available in the USA; consequently, NO<sub>x</sub> formation at these facilities can be expected to be much higher.

There are several catalytic conversion technologies for reducing NO<sub>x</sub> emissions which can be used on rich- and lean-burn engines that use natural gas, but the impurities in dairy biogas will substantially shorten the life of the catalytic NO<sub>x</sub> controls. If the H<sub>2</sub>S content of the biogas is reduced to a very low level before introduction to the engine, the emissions from the scrubbed dairy biogas will not degrade catalytic controls or microturbines as quickly. One California dairy has installed a H<sub>2</sub>S scrubbing system and a catalytic emission control device on its engine. Initial tests are promising, but it is too soon to know if this will be a reliable solution. The current status of air district regulation of NO<sub>x</sub> emissions will be discussed in Chapter 6.

If biogas is upgraded to biomethane, the selective catalytic reduction technologies used for natural gas engines can be used to keep NO<sub>x</sub> formation at acceptable levels. Biomethane will not corrode microturbines and electricity generated in microturbines from biomethane has a very low accompanying NO<sub>x</sub> formation.

### ***Control of Unpleasant Odors***

According to anecdotal reports, most of the approximately 100 anaerobic digesters processing animal manure in the USA were built to address odor complaints from neighbors. As more housing is built in formerly rural areas of California's Central Valley, complaints about odors from dairies increase. Most of the odor problem comes from H<sub>2</sub>S, VOC, and ammonia (NH<sub>3</sub>-N) emissions from dairy manure. While hard to measure objectively, these odors are perceived as a serious environmental problem by residents in proximity to dairy farms. Fortunately, anaerobic digestion is a good method for controlling these odors, particularly if used in conjunction with a system that will scrub the H<sub>2</sub>S from the biogas.

### ***Control of Pathogens and Weed Seeds***

Digesters that are heated to mesophilic and thermophilic levels are very effective in denaturing weed seeds and reducing pathogens. Pathogen reduction is greater than 99% in a 20-day

hydraulic retention time, mesophilic digester. Thermophilic temperatures essentially result in the complete elimination of pathogens. Covered-lagoon digesters, which operate at ambient temperatures, have a more modest effect on weed seeds and pathogens.

### ***Improved Water Quality***

An anaerobic digester will have minimal effect on the total nutrient content of the digested manure. However, the chemical form of some of the nutrients will be changed. A digester decomposes organic materials, converting approximately half or more of the organic nitrogen (org-N) into  $\text{NH}_3\text{-N}$ . Some phosphorus (P) and potassium (K) are released into solution by decomposing material. A minimal amount of the P and K will settle as sludge in plug flow and complete mix digesters. However 30% to 40% of the P and K are retained in covered-lagoon digesters in the accumulated sludge. Dissolved and suspended nutrients are of lesser concern as they will flow through the digester.

The anaerobic digestion process is an effective way to reduce high BOD in the effluent. Biological oxygen demand is a measure of the amount of oxygen used by microorganisms in the biochemical oxidation of organic matter; BOD concentrations in dairy wastewater are often 25 to 40 times greater than those in domestic wastewater. Anaerobic processes can remove 70% to 90% of the BOD in high-strength wastewater at a lower cost, in terms of both land and energy inputs, than aerated systems.

### ***Motivation for Realizing Environmental Benefits on Dairy Farms***

Many of the environmental benefits discussed above also can be realized by capturing the biogas produced at a dairy and flaring it. In fact, flaring typically produces less  $\text{NO}_x$  than combustion of the biogas for generating electricity. Federal and state law require large landfills to flare their *landfill gas* (similar in composition to dairy biogas) to reduce VOC emissions and the danger of explosions. As a result of SB 700, the San Joaquin Air Pollution Control District proposed to require digesters as BACT for new or modified dairies with more than 1,954 head of cattle, although the proposal has since been withdrawn as a result of a lawsuit. At this time, the major motivations for smaller dairies to combust or capture/flare the  $\text{CH}_4$  produced on-site are likely to be economic or as a means of odor control.

Whether used to generate electricity, or upgraded to biomethane and used for vehicular or engine fuel, biogas is a renewable energy product. Like other renewable energy sources, such as solar and wind-generated power, biogas can be substituted for greenhouse-gas-emitting fossil fuels, producing a net decrease in GHG emissions. On those dairy farms where manure is stored under anaerobic conditions (i.e., where it is not stored in piles that decompose aerobically over time), there is an added benefit. Using biogas as a fuel results in the reduction of  $\text{CH}_4$  emissions that would otherwise be released into the atmosphere (e.g., through storage in uncovered lagoons).

However, without financial or regulatory motivations, farmers will have little motivation to capture and use dairy biogas.

## **Increasing the Methane Content of Biogas**

There are several technologies that have been used to increase methane generation and extraction at landfills and wastewater treatment plants; conceivably, these techniques could also be applied to dairy wastes. Possible techniques include pretreatment of the feedstock with heat, ultrasonic devices, or impact grinding (all to increase the degree of hydrolysis of the feedstock); microbial stimulants; or co-digestion with other wastes.

### ***Pretreatment Techniques***

Thermal pretreatment can increase the CH<sub>4</sub> yield of certain substrates. However, it is not an effective pretreatment technique for the anaerobic digestion of all substrates. For example, Ferrer et al. found that thermal pretreatment at 80° C (176° F) did not enhance the anaerobic digestion of water hyacinth because water hyacinth's solubility increased only slightly under the tested conditions (2004, pp 2107-2109). In contrast, the pasteurization of slaughterhouse waste at the Upsalla biogas plant in Sweden resulted in a reported fourfold increase in CH<sub>4</sub> yields after thermal treatment at 70° C (158° F) for 1 hour (Norberg, 2004). However, the effects of this treatment method on high-lipid and protein waste have not been adequately studied to determine the reasons behind the increased methane production.

Ultrasonic pretreatment has been shown to be effective in disintegrating sewage sludge, resulting in greatly improved fermentation rates (Vera et al., 2004, pp 2127-2128). This method uses low-frequency ultrasound to induce cavitation with high shear forces, which promotes sludge disintegration. Short ultrasound bursts disperse sludge floc agglomerates without causing accompanying cell destruction. Longer ultrasound applications break down microorganism cell walls, causing intra-cellular material to be released to the liquid phase. The destruction of volatile solids increases according to the degree of cell disintegration. Increased biogas production was also observed. However, the application of this technology to manure solids is untried and its success uncertain due to the ligno-cellulosic character of manure.

Peltola et al. (2004, pp. 2,129 – 2,132) showed that impact grinding can increase the soluble *chemical oxygen demand* (COD) content of the organic fraction of municipal solid waste by approximately 2.5 times. This increased COD indicates partial disintegration of plant cells and microbial floc of the organic fraction of municipal solid waste. Though no increase in biogas production was observed, the onset of methane production began sooner as a result of impact grinding, and the digestion process was more stable than when the organic fraction of municipal solid waste was simply crushed. The breakdown of cell walls as a result of impact grinding could also improve the anaerobic digestion of dairy manure. However, any benefits that might be gained, such as an increased rate of biogas production and consequent reduction in hydraulic

retention time and digester size, would need to be weighed against the increased energy (and resultant costs) required to grind the manure.

### **Microbial Stimulants**

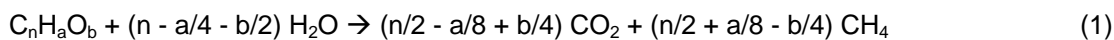
Aquasan® and Teresan® are *saponified* steroid products (available from Amit Chemicals in New Dehli, India) that are used to activate microbes. Both products are derived from plant extracts and work directly on the microbial population, restricting odor emissions by enzyme interference and accelerating digestion by stimulating the bacterial metabolism. In bench-scale experiments using Aquasan, a dosage level of 15 ppm was optimum for gas production, and resulted in production that was 55% higher than that from untreated cattle manure. In another bench-scale study, the addition of Teresan to the mixed residues of cattle manure and kitchen wastes at a concentration of 10 ppm produced 34.8% more gas than the uninoculated mixture (Singh et al., 2001, pp. 313-316). The efficacy of these microbial stimulants has not been demonstrated at the commercial scale.

### **Co-Digestion with Other Waste Sources**

Co-digestion of manure with other substrates such as industrial wastes, grass clippings, food industry wastes, animal by-products (slaughterhouse waste), or sewage sludge can result in multiple benefits. This includes an improved nutrient balance of total organic carbon, nitrogen, and phosphorous, which results in a stable and maintainable digestion process and good fertilizer quality (Braun and Wellinger, 2003). Co-digestion also improves the flow qualities of the co-digested substrates. In addition, the economics of digester projects benefit from the increased gas production due to co-digestion and also from the income generated from tipping fees (i.e., waste disposal fees that are generally based on a per volume or weight basis).

Increased biogas production from the co-digestion of dairy manure and grease-trap waste has been documented at the Amersfoort wastewater treatment plant in the Netherlands (Mulder et al., 2004, pp. 2,064-2,068). The results at Amersfoort showed that the grease-trap waste was converted with an efficiency of 70% at a hydraulic retention time of 20 days. The biogas production rate was doubled from approximately 180,000 ft<sup>3</sup>/d using sewage sludge alone to approximately 353,000 to 424,000 ft<sup>3</sup>/d when co-digested with grease-trap waste.

As previously noted, the typical dairy farm biogas contains approximately 55% to 70% CH<sub>4</sub> and approximately 30% to 45% CO<sub>2</sub>. The theoretical CH<sub>4</sub> to CO<sub>2</sub> ratios of various substrates were determined by Jewel et al. (1978) using the following equation, developed by McCarty (1964):



The theoretical CH<sub>4</sub> content of biogas for various substrates, based on this equation, are presented in Table 2-2. More detail about the stoichiometry of the anaerobic digestion process of various substrates can be found in Appendix A.

**Table 2-3 Theoretical Methane Content of Biogas**

<b>Substrate</b>	<b>Chemical Composition</b>	<b>Methane, % of Total Gas</b>
Fat	C <sub>15</sub> H <sub>31</sub> COOH	72
Protein	C <sub>4</sub> H <sub>6</sub> ON	63
Carbohydrate	C <sub>6</sub> H <sub>12</sub> O <sub>6</sub>	50

Readily degradable substrates (urea, fats, and proteins) yield the highest percentages of CH<sub>4</sub>. However, the fats and proteins available from industrial wastes such as slaughterhouse and rendering operations may, in high concentrations, inhibit the anaerobic digestion process through the accumulation of volatile fatty acids and long chain fatty acids (Salminen et al., 2003; Broughton et al., 1998). When manure is added to the anaerobic digestion process, it acts as a buffer and provides the essential nutrients necessary for digestion, overcoming some of the operational problems associated with the anaerobic digestion of lipids and proteins. A tour of Swedish biogas plants taken by the authors of this report tends to support these conclusions (WestStart/CalStart, 2004). Table 2-3 presents the operational parameters for three of the Swedish biogas plants that were visited during this tour.

As seen in Table 2-3, large quantities of biogas with high CH<sub>4</sub> content can be produced from manure mixed with slaughterhouse and food processing waste; however, this level of production comes with certain operational restrictions. For example, at the Laholm plant, no more than 40% slaughterhouse waste is used in the process. When a higher percentage of slaughterhouse waste is included, yeasts are produced and the reactor must be evacuated for the process to be recovered. The Linköping plant uses the highest percentage of slaughterhouse waste of the three plants. This plant monitors incoming loads for volatile fatty acids, alkalinity, and dry matter content and also monitors the reactor for these same parameters two to three times a week. If the digesters begin to foam as result of high volatile fatty acid content, manure is added to stabilize the process. The plant uses bench-scale fermenters to test new wastes. Thus, the Linköping plant successfully uses a high percentage of slaughterhouse waste to produce high-methane biogas, as long as it maintains a high degree of process monitoring and control.

Table 2-4 Operational Parameters for Three Swedish Biogas Plants

Operational Parameter	Laholm Plant	Boras Plant	Linköping Plant
Waste mass processed (tons/day)	14	82	148
Total solids content (%)	10	30	10 – 14
Waste composition	33% pig manure 27% dairy manure 40% slaughterhouse & potato peels	restaurant food & grease trap household food food processing slaughterhouse	75% slaughterhouse 15% food processing & pharmaceutical 10% manure
Biogas production (ft <sup>3</sup> /hour)	~18,000	~14,000	~48,000
Biogas quality (% methane)	75	No data	70-74
Feedstock processing	slaughterhouse waste minced to ~0.5 inch	Muffin Monster® <sup>a</sup> (30% to 8% total solids)	slaughterhouse waste minced to ~0.5 inch
Reactors <sup>b</sup>	2	1	2
Operating temperature	95° F (mesophilic)	~130° F (thermophilic)	100° F (mesophilic)
HRT	21 days	16 – 17 days	30 days
Pasteurization	~160° F for 1 hour	~160° F for 1 hour	~160° F for 1 hour
Process heat	10% of the biogas	10% – 15% of the biogas	-

<sup>a</sup> Muffin Monster is the registered trademark of JWC Environmental for grinding machines that reduce particle size of feedstock.

<sup>b</sup> Continuously-stirred tank reactors

Because of the limited degree of monitoring and process control available at dairy farms, the percentage of slaughterhouse waste would likely need to be limited to less than 33% by volume of the incoming waste stream to prevent yeasting or foaming problems. In addition, it would be appropriate to digest slaughterhouse and other food processing waste in a complete-mix digester, which gives a higher degree of control over the digestion process than do plug-flow and covered-lagoon digesters.

### **Effluent Absorption of Carbon Dioxide**

The chemistry of the anaerobic digestion process indicates that the CH<sub>4</sub> content of anaerobic digesters is typically 55% to 65% and cannot be much higher than 70%, even if the substrate is all fats and vegetable oils (see Appendix A for a detailed analysis). However, some standard anaerobic digesters have produced biogas with a CH<sub>4</sub> content higher than would be expected based on the anaerobic digestion process alone.

Biogas methane contents of 65% to 80% appear to be the result of absorption of excess CO<sub>2</sub> in the digester effluent. Higher CH<sub>4</sub> content than this is not likely, as it is not possible for digester effluents to absorb the additional CO<sub>2</sub> that would be needed to produce higher methane biogas. In a few cases, such as when biogas has been collected from partially covered ponds, CH<sub>4</sub> contents as high as 90% have been observed, the result of absorption of CO<sub>2</sub> by the effluent, which is of limited capacity. Other anaerobic digestion processes, such as “two-phase” digestion, might produce marginal increases in CH<sub>4</sub> content, but these processes are not suitable for dairy wastes (and have limited success in other applications, as explained in Appendix A).

## **Centralized Digestion of Dairy Wastes for Biogas Production**

Although many California dairies are following the trend towards increased animal numbers per dairy, about half of the state’s dairy animals remain in smaller herds. The smaller dairies, mostly unable to afford individual manure digestion systems, may be able to cooperate with similar local enterprises to build and operate “community manure digestion facilities.” Tanker trucks could be used to transport manure from various farms to a central treatment facility. Facility output could be returned to contributing farms or otherwise distributed in a controlled, regulated fashion. Such centralized treatment facilities are conceptually the same as large on-farm production facilities, with the addition of load-out points for tank truck pickup and discharge. Also, centralized facilities are likely to be larger than most on-farm digestion facilities.

Another option, especially when the local number of dairy cows is not sufficient to make centralized processing economically viable, is to seek other organic wastes for inclusion in the centralized system. Co-digestion of animal manures with food processing wastes in community digestion facilities is practiced in Denmark (University of Southern Denmark, 2000) and other European locations, and could be applicable also in some dairy areas in California. In particular, the addition of food processing wastes to manure could improve system economics, by providing waste-tipping fee revenues while generating more biogas.

Food-processing industries typically dispose of their waste streams through on-site aerobic treatment, discharge into sewer systems, sending solids to landfills, or regulated land application, all of which are relatively expensive. Recipients of these waste streams are required to meet local, state, and federal standards. Because food wastes are typically high in volatile solids concentration, they may produce significant odor when treated through land application. Food waste requires high energy inputs to process at a sewage treatment plant, where it can cause substantial sludge production, as well as requiring increased sewage treatment plant capacity.

### **Centralized Digesters and Gas Production**

Centralized digesters have no intrinsic advantage with regard to gas production per unit volume as compared to on-farm digesters, but they will realize some *economies of scale* as the cost of anaerobic digestion per animal unit will decrease with herd size. However, trucking costs will

reduce any economies realized. The main criterion with regard to gas production for both centralized and decentralized digesters is the age of the manure that reaches the digester. Ideally, collection should occur frequently enough that the manure used in digestion is no more than 3 days old. As manure ages it loses volatile solids, reducing the gas production potential. After about 30 days, manure biogas yield is very low.

### ***Transport of Manure and Digested Effluent to Centralized Digesters***

A major consideration for centralized digestion is the practicality of transportation. Manure must be transported from the various farms to the community or regional digester. After digestion, the digested liquid is transported back for field application, while the digested solids are typically composted and sold at the central digester location.

To understand how the transportation process might affect the viability of a centralized digester, we contacted Zwald Transport. They perform “two-way” hauling for the Port of Tillamook Bay regional digester. Mr. Zwald reported that the speed of loading and unloading is the key to success, and the best equipment to ensure this speed is a vacuum tanker. The process is also tightly controlled by the transporter: all of Zwald’s pick-up and delivery operations are under control of the driver and the farmer provides only the hose to the truck and pipe to the storage lagoon. The farmer is not required to buy a pump or valves or to modify any existing pumping system (Zwald, personal communication, November 2003).

Zwald’s truck is a 5,500-gallon vacuum tanker in a semi-trailer (combination) configuration. Larger units are possible, but the trade-off is maneuverability. A full load of digested liquid is taken on in 3 minutes, 30 seconds. Farm manure takes longer to load. There is some time variation due to the different loading situations, but the average time to load manure is around 7 minutes. The farm hoses (purchased by the farmers) are always ready to hook up to the truck. A suction hose is carried on the truck, but is used in emergencies only. Total turnaround time for a farm that is 2 miles from the digester site is about 55 minutes. One farm, 9 miles from the digester, has a total turnaround time of an hour and 35 minutes.

Another example of transportation services for an ongoing centralized digester is DeJaeger Trucking, which collects and hauls manure to the Inland Empire Utility Agency digester in Chino, California. DeJaeger uses a Honey Vac (a vacuum tanker truck) to collect the manure from the feed aprons, which have concrete floors. The manure contains 12% to 16% solids and the truck holds 25 tons. DeJaeger’s hauling rate is \$45 per hour, and the furthest effective haul is about 5 miles. The cost of hauling is about \$4/ton (DeJaeger, 2004).



These two examples illustrate the importance of distance, time, and other details that affect the viability of a centralized digester. Two general principles that should be adhered to when considering the start-up of a community digester include the following:

- Maximum haul distance to a centralized digester should be no more than 5 miles. A general rule of thumb is that manure from the equivalent of 6,000 mature Holstein cows must be available in a 5-mile radius of the centralized facility.
- Operational details such as collection, hauling, distribution, and costs must be carefully negotiated through contracts and maintained through active cooperation and management among participants.

Pumping manure through a pipeline is an alternative to trucking. However, this requires a higher moisture content in the manure, a suitable piping infrastructure, and pumping facilities. It is equivalent to building a sewage system for the manure.



### 3. Upgrading Dairy Biogas to Biomethane and Other Fuels

Dairy biogas can be combusted to generate electricity and/or heat. This report, however, focuses on alternate uses of biogas including the upgrading of biogas to biomethane, a product equivalent to natural gas or other higher-grade fuels. Biomethane, which typically contains more than 95% CH<sub>4</sub> (with the remainder as CO<sub>2</sub>), has no technical barrier to being used interchangeably with natural gas, whether for electrical generation, heating, cooling, pumping, or as a vehicle fuel. The process can be controlled to produce biomethane that meets a pre-determined standard of quality. Biomethane can also be put into the natural gas supply pipeline, though there are major institutional barriers to this alternative.

As discussed in Chapter 2, raw dairy biogas typically contains 55% to 70% CH<sub>4</sub> and 30% to 45% CO<sub>2</sub> along with other impurities such as H<sub>2</sub>S and water vapor. To produce biomethane from biogas, the H<sub>2</sub>S, moisture, and CO<sub>2</sub> must be removed. This chapter provides an overview of the types of processes that can be used to remove these components, reviews the associated environmental impacts, and suggests the most practical processes for small facilities typical of dairy farm applications. In addition, this chapter explores the possibility of upgrading biogas to produce various higher-grade fuels:

- Compressed biomethane (CBM), which is equivalent to compressed natural gas (CNG)
- Liquid-hydrocarbon replacements for gasoline and diesel fuels (created using the Fischer-Tropsch process)
- Methanol
- Hydrogen
- Liquefied biomethane (LBM), which is equivalent to liquefied natural gas (LNG)

#### Upgrading Biogas to Biomethane

Biogas upgrading, or “sweetening,” is a process whereby most of the CO<sub>2</sub>, water, H<sub>2</sub>S, and other impurities are removed from raw biogas. Because of its highly corrosive nature and unpleasant odor, H<sub>2</sub>S is typically removed first, even though some technologies allow for concurrent removal of H<sub>2</sub>S and CO<sub>2</sub>. The following sections discuss various removal technologies with specific emphasis on those technologies most suitable for on-farm use.

#### *Technologies for Removal of Hydrogen Sulfide from Biogas*

The concentration of H<sub>2</sub>S in biogas generated from animal manure typically ranges between 1,000 to 2,400 ppm, depending in large part on the sulfate content of the local water. Minor quantities of mercaptans (organic sulfides) are also produced, but are removed along with H<sub>2</sub>S and need not be addressed separately. Even in low concentrations, H<sub>2</sub>S can cause serious

corrosion in gas pipelines and biogas conversion and utilization equipment as well as result in unpleasant odors and damage to the metal siding and roofing of buildings (Mears, 2001).

H<sub>2</sub>S can be removed by a variety of processes, each of which is described below:

- Air injected into the digester biogas holder
- Iron chloride added to the digester influent
- Reaction with iron oxide or hydroxide (iron sponge)
- Use of activated-carbon sieve
- Water scrubbing
- Sodium hydroxide or lime scrubbing
- Biological removal on a filter bed

### **Air/Oxygen Injection**

When air is injected into the biogas that collects on the surface of the digester, thiobacilli bacteria oxidize sulfides contained in the biogas, reducing H<sub>2</sub>S concentrations by as much as 95% (to less than 50 ppm). The injection ratio is typically a 2% to 6% air to biogas ratio (a slight excess of O<sub>2</sub> over the stoichiometric requirement). Thiobacilli bacteria naturally grow on the surface of the digestate, and do not require inoculation. The by-product of this process is hydrogen and yellow clusters of elemental sulfur on the surface of the digestate.

Air injection directly into the digester's gas holder, or, alternatively, into a secondary tank or biofilter is likely the least expensive and most easily maintainable form of scrubbing for on-farm use where no further upgrading of biogas is required (i.e., when the biogas is being cleaned solely to prevent corrosion and odor problems, not to increase its methane content). However, the addition of the proper proportion of air presents significant control problems. Without careful control over the amount of air injected, this process can result in the accidental formation of explosive gas mixtures. Furthermore, such process results in some dilution with nitrogen (N<sub>2</sub>), which is undesirable if CO<sub>2</sub> is to be subsequently removed and the resulting biomethane compressed for use as a vehicular fuel. Residual oxygen (O<sub>2</sub>) would also be a concern for a pressurized gas.

### **Iron Chloride Injection**

Iron chloride reacts with H<sub>2</sub>S to form iron sulfide salt particles. Iron chloride can be injected directly into the digester or into the influent mixing tank. This technique is effective in reducing high H<sub>2</sub>S levels, but less effective in maintaining the low and stable H<sub>2</sub>S levels needed for vehicular fuel applications.

### **Iron Oxide or Hydroxide Bed**

Hydrogen sulfide reacts endothermically with iron hydroxides or oxides to form iron sulfide. A process often referred to as “iron sponge” makes use of this reaction to remove  $H_2S$  from gas. The name comes from the fact that rust-covered steel wool may be used to form the reaction bed. Steel wool, however, has a relatively small surface area, which results in low binding capacity for the sulfide. Because of this, wood chips impregnated with iron oxide have been used as preferred reaction bed material. The iron-oxide impregnated chips have a larger surface-to-volume ratio than steel wool and a lower surface-to-weight ratio due to the low density of wood. Roughly 20 grams of  $H_2S$  can be bound per 100 grams of iron-oxide impregnated chips.

Iron oxide or hydroxide can also be bound to the surface of pellets made from red mud (a waste product from aluminum production). These pellets have a higher surface-to-volume ratio than steel wool or impregnated wood chips, though their density is much higher than that of wood chips. At high  $H_2S$  concentrations (1,000 to 4,000 ppm), 100 grams of pellets can bind 50 grams of sulfide. However, the pellets are likely to be somewhat more expensive than wood chips.

The optimal temperature range for this reaction is between 77° F and 122° F. The reaction requires water; therefore, the biogas should not be dried prior to this stage. Condensation in the iron sponge bed should be avoided since water can coat or “bind” iron oxide material, somewhat reducing the reactive surface area.

The iron oxide can be regenerated by flowing oxygen (air) over the bed material. Typically, two reaction beds are installed, with one bed undergoing regeneration while the other is operating to remove  $H_2S$  from the biogas. One problem with this technology is that the regenerative reaction is highly *exothermic* and can, if air flow and temperature are not carefully controlled, result in self-ignition of the wood chips. Thus some operations, in particular those performed on a small scale or that have low levels of  $H_2S$ , elect not to regenerate the iron sponge on-site.

For on-farm applications requiring both  $H_2S$  and  $CO_2$  removal and compression of the biomethane gas, the iron sponge technology using iron-impregnated wood chips appears to be the most suitable. One farm digester reported that an iron sponge reduced  $H_2S$  to below 1 ppm, quite sufficient for all purposes (Zicari, 2003, page 18).

### **Activated Carbon Sieve**

In pressure-swing adsorption systems,  $H_2S$  is removed by activated carbon impregnated with potassium iodide. The  $H_2S$  molecule is loosely adsorbed in the carbon sieve; selective adsorption is achieved by applying pressure to the carbon sieve. Typically, four filters are used in tandem, enabling transfer of pressure from one vessel to another as each carbon bed becomes saturated. (The release of pressure allows the contaminants to desorb and release from the carbon sieve.) This process typically adsorbs  $CO_2$  and water vapor in addition to  $H_2S$ . To assist in the adsorption of  $H_2S$ , air is added to the biogas, which causes the  $H_2S$  to convert to elementary sulfur and water.

The sulfur is then adsorbed by the activated carbon. The reaction typically takes place at a pressure of around 100 to 115 pounds per square inch (psi) and a temperature of 122 to 158° F. The carbon bed has an operating life of 4,000 to 8,000 hours, or longer at low H<sub>2</sub>S levels. A regenerative process is typically used at H<sub>2</sub>S concentrations above 3,000 ppm.

### **Water Scrubbing**

Water scrubbing is a well-established and simple technology that can be used to remove both H<sub>2</sub>S and CO<sub>2</sub> from biogas, because both of these gases are more soluble in water than methane is. Likewise, H<sub>2</sub>S can be selectively removed by this process because it is more soluble in water than carbon dioxide. However, the H<sub>2</sub>S desorbed after contacting can result in fugitive emissions and odor problems. Pre-removal of H<sub>2</sub>S (e.g., using iron sponge technology) is a more practical and environmentally friendly approach.

Water scrubbing is described below in more detail as a method to remove carbon dioxide.

### **Selexol Scrubbing**

Selexol™ is a solution of polyethylene glycol that can be used for the simultaneous scrubbing of biogas for CO<sub>2</sub>, H<sub>2</sub>S and water vapor. However, because elementary sulfur can be formed when Selexol is stripped with air (during regeneration), prior removal of H<sub>2</sub>S is preferred. The Selexol technology is described in more detail below as a method to remove CO<sub>2</sub>.

### **Sodium Hydroxide Scrubbing**

A solution of sodium hydroxide (NaOH) and water has enhanced scrubbing capabilities for both H<sub>2</sub>S and CO<sub>2</sub> removal because the physical absorption capacity of the water is increased by the chemical reaction of the NaOH and the H<sub>2</sub>S. The enhanced absorption capacity results in lower volumes of process water and reduced pumping demands. This reaction results in the formation of sodium sulfide and sodium hydrogen sulfide, which are insoluble and non-regenerative. (The NaOH also absorbs CO<sub>2</sub>, which could, in principle, be partially regenerated by air stripping; however in practice, the process is not regenerative and is thus prohibitively expensive.)

### **Biological Filter**

A biological filter combines water scrubbing and biological desulfurization. As with water scrubbing, the biogas and the separated digestate meet in a counter-current flow in a filter bed. The biogas is mixed with 4% to 6% air before entry into the filter bed. The filter media offer the required surface area for scrubbing, as well as for the attachment of the desulfurizing (H<sub>2</sub>S oxidizing) microorganisms. Although biofiltration is used successfully to remove odors from exiting air at wastewater treatment plants, and suitable media (e.g., straw, etc.) is available on farms, some oxygen would need to be added to the biogas. We are unaware of any instance where biofiltration has been usefully applied to remove H<sub>2</sub>S from streams of oxygen-free biogas.

### ***Technologies for Removal of Water Vapor***

Because biogas from digesters is normally collected from headspace above a liquid surface or very moist substrate, the gas is usually saturated with water vapor. The amount of saturated water vapor in a gas depends on temperature and pressure. Biogas typically contains 10% water vapor by volume at 110° F, 5% by volume at 90° F, and 1% by volume at 40° F (Weast, 1958). The removal of water vapor (moisture) from biogas reduces corrosion that results when the water vapor condenses within the system. Moisture removal is especially important if the  $H_2S$  has not been removed from the biogas because the  $H_2S$  and water vapor react to form sulfuric acid ( $H_2SO_4$ ), which can result in severe corrosion in pipes and other equipment that comes into contact with the biogas. Even if the  $H_2S$  has been removed, water vapor can react with  $CO_2$  to form carbonic acid ( $H_2CO_3$ ), which is also corrosive (pH near 5). When water vapor condenses within a system due to pressure or temperature changes, it can result in clogging of the pipes and other problems as well as corrosion.

A number of techniques can be used to remove condensation from a pipe, including tees, U-pipes, or siphons. The simplest method to remove condensation water is to install horizontal pipe runs with a slope of 1:100. A drip trap or condensate drain can then be located at all low points in the piping to remove condensation. However, this will only remove water vapor that condenses in the piping. The simplest means of removing excess water vapor to dew points that preclude downstream condensate in biogas is through refrigeration. In a refrigerator unit, water vapor condenses on the cooling coils and is then captured in a trap.

The dew point of biogas is close to 35° F. As mentioned, at 90° F the biogas contains 5% water vapor, which has a density of about 0.002 lb/ft<sup>3</sup>. At 105° F, the water vapor content doubles to 0.004 lb/ft<sup>3</sup>. At this temperature, for example, a thousand cow dairy that produces 2,000 ft<sup>3</sup>/h of biogas would yield about 4 lb of condensation water per hour (when all the water vapor is condensed). The latent heat of vaporization of water is 1,000 Btu/lb of water. Therefore, condensation of 5 lb of water will require 5,000 Btu/hour, which is a little less than 0.5 ton of refrigeration.

Refrigerators with capacities of 0.5 to 1 ton are commercially available and easily used on a dairy. Scrubbing of the biogas to remove  $H_2S$  prior to refrigeration would significantly lengthen the life of the refrigeration unit. The power needed for this type of refrigeration unit would be modest, less than 2% of the biogas energy content.

### ***Technologies for Removal of Carbon Dioxide***

The technologies available for removal of  $CO_2$  from dairy manure biogas are typically used for larger scale applications such as upgrading natural gas from “sour” gas wells, sewage treatment plants, and landfills. Because of the different contaminants, scales, and applications, removal of

CO<sub>2</sub> from dairy manure biogas will differ significantly from these applications and requires a case-by-case analysis.

The following processes can be considered for CO<sub>2</sub> removal from dairy manure biogas. The processes are presented roughly in the order of their current availability for and applicability to dairy biogas upgrading:

- Water scrubbing
- Pressure swing adsorption
- Chemical scrubbing with amines
- Chemical scrubbing with glycols (such as Selexol™)
- Membrane separation
- Cryogenic separation
- Other processes

### **Water Scrubbing**

When water scrubbing is used for CO<sub>2</sub> removal, biogas is pressurized, typically to 150 to 300 pounds per square inch, gauge (psig) with a two-stage compressor, and then introduced into the bottom of a tall vertical column. The raw biogas is introduced at the bottom of the column and flows upward, while fresh water is introduced at the top of the column, flowing downward over a packed bed. The packed bed (typically a high-surface-area plastic media) allows for efficient contact between the water and gas phases in a countercurrent absorption regime. Water often pools at the bottom of the contact column and the biogas first passes through this water layer in the form of bubbles. The CO<sub>2</sub>-saturated water is continuously withdrawn from the bottom of the column and the cleaned gas exits from the top.

A purity of about 95% methane can be readily achieved with minimal operator supervision in a single pass column. After scrubbing, the water can be regenerated (i.e., stripped of CO<sub>2</sub> by contacting with air at atmospheric pressures, either in a packed bed column similar to the one used for absorption, or in a passive system such as a stock pond).



This type of system was apparently first used in the USA for stripping  $\text{CO}_2$  from biogas at a wastewater treatment plant in Modesto, California and is currently used at the King County South Wastewater Treatment Plant in Renton, Washington (Figure 3-1). It is also the most commonly used biogas clean-up process in Europe. The Modesto plant, operated in the 1970s and early 1980s, was rather simple and crude, and had no separate  $\text{H}_2\text{S}$  removal system. It produced a renewable methane stream that was compressed to fuel vehicles at the sewage treatment plant. The system was discontinued due to corrosion problems as well as lack of interest when the energy crisis abated.

At the Renton plant near Seattle, approximately 150,000  $\text{ft}^3$  of biomethane (95%+  $\text{CH}_4$ ) are produced daily and injected into a medium-pressure pipeline. Because a large amount of treated water is available at Renton (and other wastewater treatment plants), a single-pass process with no water regeneration stage can be used, which saves the cost of regenerating  $\text{CO}_2$ -laden water. Dairy operations could similarly avoid the regeneration stage by using available on-farm stock water.

In addition to being a simple, well-established, and relatively inexpensive technology, water scrubbing typically loses relatively little  $\text{CH}_4$  (less than 2%) because of the large difference in solubility of  $\text{CO}_2$  and  $\text{CH}_4$ . Methane losses can be larger, however, if the process is not optimized.

A water scrubbing system preceded by  $\text{H}_2\text{S}$  removal would be a practical, low-cost process for upgrading dairy biogas to biomethane. It is important that the  $\text{H}_2\text{S}$  be removed prior to the removal of the  $\text{CO}_2$ , as  $\text{H}_2\text{S}$  is highly corrosive and would result in decreased life and higher maintenance of the subsequent compressors required in the  $\text{CO}_2$ -removal step.



**Figure 3-1** Carbon dioxide absorption towers at the King County South Wastewater Treatment Plant

Our research indicates that all but one or two of the dozen municipal wastewater treatment plants where sewage biogas is upgraded use water scrubbing. The other main processes used for CO<sub>2</sub> removal at wastewater treatment facilities are pressure swing adsorption (used mainly by Kompogas in Switzerland) and membrane technology, both of which are discussed below. Solvents other than water (e.g., glycols or amines) have not been used except at a few landfill sites and at the Gasslosa plant in Sweden, where the Cirmac process is used (see discussion, below).

One reason for the prevalence of water scrubbing at wastewater treatment plants is that these plants have an abundance of water, and thus can use a single-pass system, with no need for water regeneration. This greatly simplifies operations. Some dairy operations also have water in sufficient quantities for a single-pass system, and could use the wastewater from a water-scrubbing system for certain dairy operations such as washing stalls. If the wastewater were stored in stock ponds, the CO<sub>2</sub> would be released on its own over a period of a few days (faster with some aeration).

The disadvantage of water scrubbing is that it is less efficient than other processes, both in terms of CH<sub>4</sub> loss and energy. However, some of the energy inefficiency of the process may be offset by the use of a single-pass water scrubbing system, since other processes require a regeneration stage.

Water scrubbing is the most applicable CO<sub>2</sub> scrubbing process for use in an agricultural setting because of its simplicity and low cost. On a dairy farm, these factors would be more important than efficiency, reduced footprint, and redundancy. Another advantage of water scrubbing over some other processes is that water is fairly easy to dispose of whereas the chemicals used in some of the other processes may require special handling and disposal when spent.

### **Pressure Swing Adsorption**

This approach uses a column filled with a molecular sieve (typically an activated carbon) for differential sorption of the gases, such that CO<sub>2</sub> and H<sub>2</sub>O adsorb preferentially, letting CH<sub>4</sub> pass through. The process is operated under moderate pressures. Several columns, typically four, are operated sequentially to reduce the energy consumption for gas compression (Figure 3-2) and the gas pressure released from one vessel is subsequently used by the others. The first column cleans the raw gas at about 90 psi to an upgraded biogas with a vapor pressure of less than 10 ppm H<sub>2</sub>O and a CH<sub>4</sub> content of 96% or more. In the second column, the pressure of 90 psi is first released to approximately 45 psi by pressure communication with the fourth column, which was previously degassed by a slight vacuum. The pressure in the second column is then reduced to atmospheric pressure and the released gas flows back to the digester so that the CH<sub>4</sub> can be recovered. The third column is evacuated from about 15 to about 1 psi. The desorbed gas consists predominantly of CO<sub>2</sub> and is normally vented to the environment even though it contains some

residual CH<sub>4</sub>. To reduce CH<sub>4</sub> losses, the system can be designed so that desorbed gases recirculate to the pressure swing adsorption system or even the digester.

This process produces a water-free gas that is cleaner than gas produced by other techniques such as water scrubbing; however, it requires considerably more sophistication and increased process controls, including careful recycling of a fraction of the gas to avoid excessive CH<sub>4</sub> losses. Another drawback is its susceptibility to fouling by contaminants in the biogas stream.

Automated cycling of multiple columns is used by Air Products, Inc. at the Olinda Landfill in California. Smaller automated systems would be more applicable to dairy farm use.

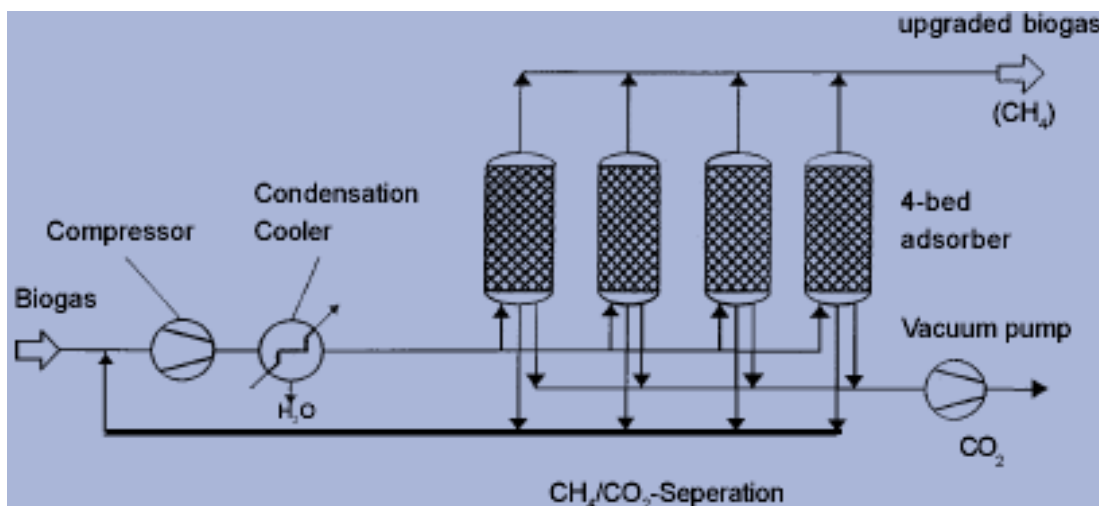
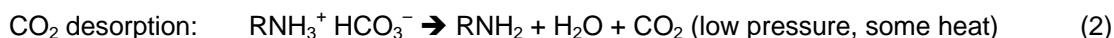


Figure 3-2 Schematic of a pressure swing absorption system with carbon molecular sieves for upgrading biogas

### Chemical Scrubbing With Amine Solvents

Amine scrubbing is widely used in food-grade CO<sub>2</sub> production and has also become the preferred technology for large-scale systems that recover CO<sub>2</sub> from natural gas wells. More recently, amine scrubbing technologies have played a key role in CO<sub>2</sub> removal from power plant flue gases as part of GHG abatement programs. The process uses organic amines (monoethanolamine [MEA], diethanolamines [DEA], and diglycolamines [DGA]) as absorbers for CO<sub>2</sub> at only slightly elevated pressures (typically less than 150 psi). The amines are regenerated by heating and pressure reduction to drive off the CO<sub>2</sub>, which can be recovered as an essentially pure by-product of the process.

The principle of amine scrubbing is represented by the following general chemical equations:



(R represents the remaining organic component of the molecule that is not relevant to this equation.)

One advantage of the amine approach is the extremely high selectivity for CO<sub>2</sub> and the greatly reduced volume of the process; one to two orders of magnitude more of CO<sub>2</sub> can be dissolved per unit volume using this process than with water scrubbing. If waste heat is available for the amine-scrubbing stage, the overall energy use is lower than for other processes such as Selexol™ or water scrubbing. The process has been scaled-down for landfill applications and works relatively well.

The main problems are corrosion, amine breakdown, and contaminant buildup, which make it problematic to apply this process to small-scale systems such as dairy farms. However, dairy manure biogas typically has fewer contaminants of concern than biogas sources such as landfills, and steel pipes can be used to minimize corrosion.

Cirmac, a Dutch company, has developed a proprietary amine (COOAB™) scrubbing process that is used at the Gasslosa biogas plant in Borås, Sweden (Figure 3-3). One advantage of this process is its very low CH<sub>4</sub> loss; one disadvantage is that it is a more complex technology. However, most of the system complexities are not visible to the operator of the COOAB packaged unit and Cirmac is actively promoting its technology for small-scale biogas upgrading (see <<http://www.cirmac.com/>>).

### Chemical Scrubbing with Polyethylene Glycols

Polyethylene glycol scrubbing, like water scrubbing, is a physical absorption process. Selexol™ is the main commercial process using this solvent, and it is used extensively in the natural gas industry as well as other applications. Carbon dioxide and H<sub>2</sub>S have even greater solubility

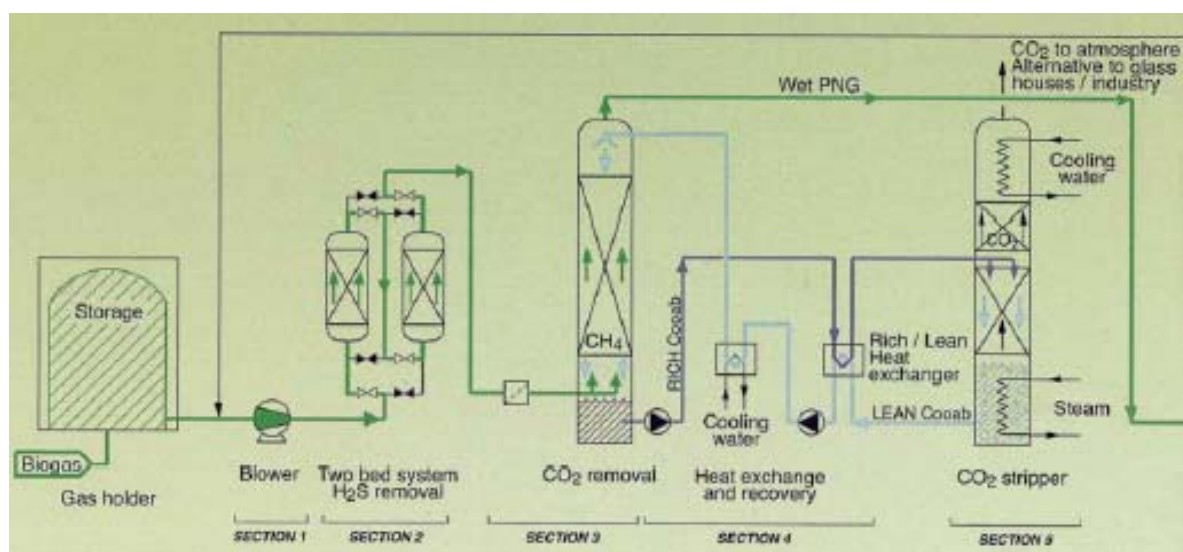


Figure 3-3 Cirmac amine carbon dioxide absorption process (LP Cooab™) for upgrading biogas (Source: Cirmac, Undated)

relative to methane in Selexol fluid than in water, which results in a lower solvent demand and reduced pumping. Selexol is typically kept under pressure, which improves its capability to absorb these contaminants. In addition, water and halogenated hydrocarbons (contaminants in landfill gas) are removed when scrubbing biogas with Selexol.

Selexol scrubbing systems are always designed with recirculation. The Selexol solvent is stripped with steam; stripping the Selexol solvent with air is possible but not recommended because of the formation of elementary sulfur. (Prior removal of  $H_2S$  is preferred for this reason.) The Selexol process has been used successfully to upgrade landfill gas at several landfill sites in the USA. The major drawback is that the process is more expensive for small-scale applications than water scrubbing or pressure swing adsorption.

### Membrane Separation

The most common membrane separation process uses pressure and a selective membrane, which allows preferential passage of one of the gases. Due to imperfect separation, several stages are generally used. During the 1990s Clean Fuels Corporation designed and operated a landfill gas purification system that produced vehicular fuel at the Puente Hills Landfill in Los Angeles County (Roe, et al., 1998). This small system, which treated only about 1% of the total landfill gas flow, had a capacity of about 90 standard cubic feet per minute (scfm) and produced the natural gas equivalent of about 1,000 gallons of gasoline daily.

The Puente Hills process (shown schematically in Figure 3-4) used a water knockout tank to remove condensate from the raw landfill gas, followed by a three-stage compression system that

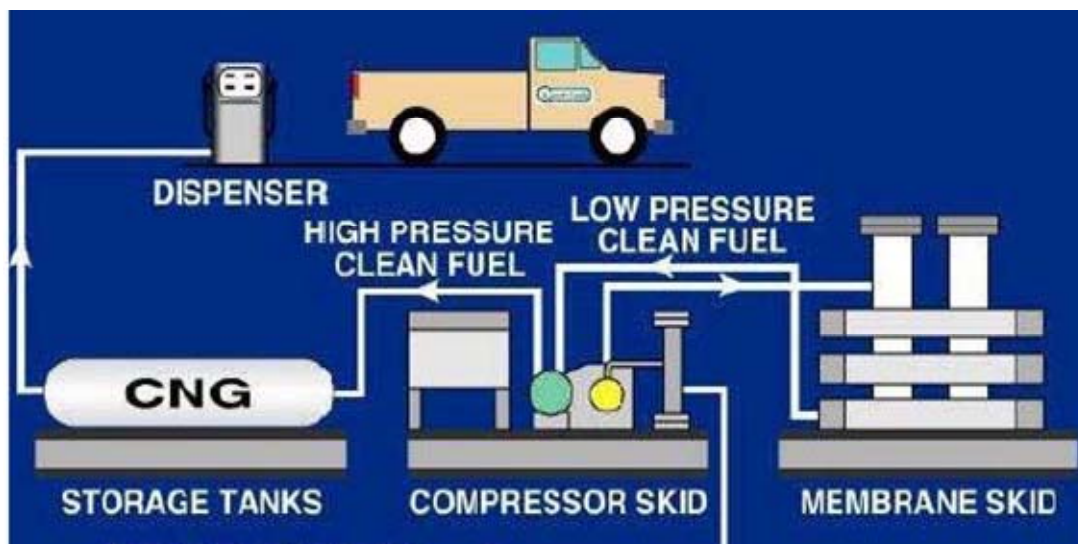


Figure 3-4 Schematic of Puente Hills landfill gas carbon dioxide – methane separation process (Source: Sanitation Districts of Los Angeles County, <http://www.lacsd.org/swaste/Facilities/LFGas/CNGFacility.htm>)

increased pressure from 41 to 150 to 525 psi. Next, an activated carbon absorption system removed impurities and a heater increased the gas temperature to 140° F before the gas entered a three-stage acetate membrane separation unit. About 15% of the gas, which contained about 80% CH<sub>4</sub>, was recycled to the head of the system. The remaining 85% of the gas, which contained about 96% CH<sub>4</sub>, was compressed and stored at 3,600 psi. Some tanks were kept at medium and others at higher pressure, allowing for sequential fast filling by the fuel dispenser.

Major problems with compressor oil carryover, corrosion, and other operational issues were encountered at the Puente Hills Landfill. Membrane life was not as long as expected, with a 30% loss in permeability after 1.5 years. The process had to be carefully monitored, in part due to the variable nature of landfill gas, which often contains large amounts of nitrogen gas from air intrusion, in addition to other contaminants. Methane losses were significant, but not documented.

Membrane processes are also used at several plants in Europe, but less detail is available on these operations. New low-pressure membranes are being developed that could be more effective for CO<sub>2</sub> removal.

### **Cryogenic Separation**

Because CO<sub>2</sub>, CH<sub>4</sub>, and contaminants all liquefy at very different temperature-pressure domains, it is possible to produce CH<sub>4</sub> from biogas by cooling and compressing the biogas to liquefy CO<sub>2</sub> which is then easily separated from the remaining gas. The extracted CO<sub>2</sub> also can be used as a solvent to remove impurities from the gas. A cryogenic separation has been proposed by Acirion Technologies (Cleveland, Ohio) to purify landfill gas, which contains halocarbons, siloxanes and VOCs and is thus more challenging to clean-up than dairy manure biogas. In the Acirion scheme, considerable CO<sub>2</sub> is still present in the biomethane after processing. Removal of this CO<sub>2</sub> requires a follow-up membrane separation step, or CO<sub>2</sub> wash process, mainly to remove impurities and produce some liquid CO<sub>2</sub> (Figure 3-5). This wash process has been demonstrated at a landfill in Columbus, New Jersey.

The economics of cryogenic separation still need to be assessed and further development is needed before cryo-separation can be considered ready for applications. A potential problem with cryo-separation is that its costs of separation tend to drop sharply with increasing scale and its cost-effectiveness at small scales has not been established. No information is available on using cryogenic separation solely for CH<sub>4</sub> purification (i.e., not in conjunction with other cleanup technologies).

This process might be worth considering if the end objective is to produce liquefied biomethane (LBM), a product equivalent to liquefied natural gas (LNG). In this case, the refrigeration process needed for cryo-separation would likely be synergistic with the further cooling required for LBM production. Determining the actual technical and economic feasibility of combining these processes, however, is beyond the scope of this study.



### Other Technologies for Carbon Dioxide Removal

There are literally dozens of vendors of alternative technologies for CO<sub>2</sub> removal from gases. Many of these have been spurred by recent interest in separation of CO<sub>2</sub> from power plant flue gases for purposes of CO<sub>2</sub> sequestration. Commercial CO<sub>2</sub> removal technologies have been in use for several decades to produce CO<sub>2</sub> for processed foods (e.g., soft drinks, etc.), for tertiary oil recovery, and for natural gas purification. It is not apparent, however, that the present increase in research in this field has produced any new or superior technologies applicable to biogas upgrading. The main commercial processes for power plant flue gas clean-up are the amine processes (described above), which have proved to have superior economic performance. Organic solvents—in particular methanol—have also been used for CO<sub>2</sub> removal, but have also fallen out of favor due to high costs. The use of hot potassium carbonate solutions, which are often mixed with various other chemicals to facilitate the process, are similarly considered obsolete technology. A recently proposed process uses refrigeration to produce CO<sub>2</sub> clathrates (water complexes) that can be easily recovered; however, this process is still at a very early exploratory stage. In conclusion, despite the worldwide search for “game-changing” technologies for CO<sub>2</sub> removal from power plant emissions, none have yet been identified.

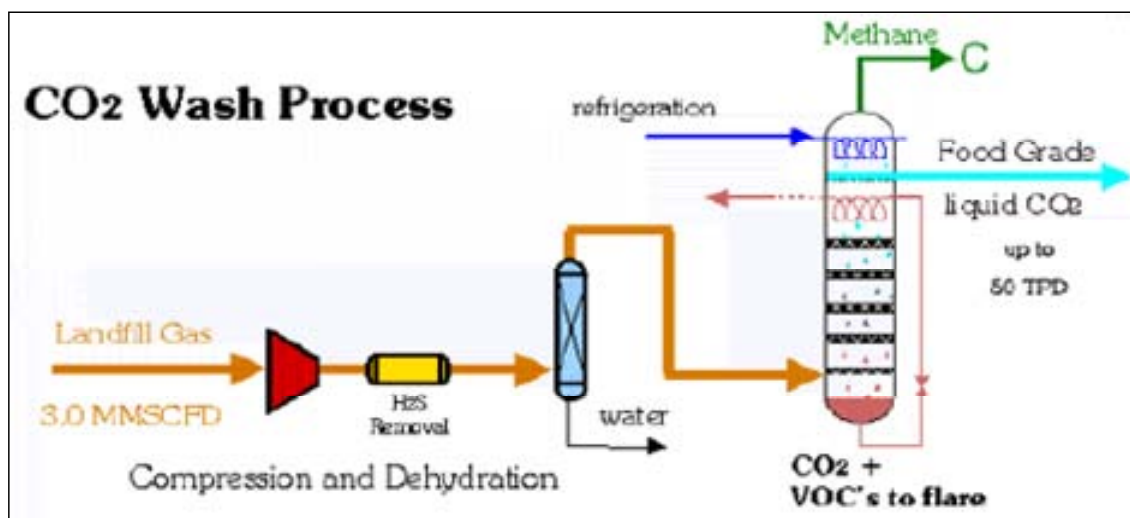


Figure 3-5 Carbon dioxide scrubbing process developed by Acion Technologies (source: Acion Co. <[www.acion.com](http://www.acion.com)>)

### Environmental Effects of Gas Cleanup Technologies

Materials used in adsorption gas cleanup technologies such as iron sponge, activated carbon sieve, and other molecular sieves can be regenerated. The iron sponge bed can be recovered by oxidizing it with air, forming iron oxide and elemental sulfur. Activated carbon is typically regenerated with steam, and other molecular sieves (such as zeolites) are regenerated by passing a heated gas (400° to 600° F) over the bed. The sulfur remains attached to the surface of the iron

sponge bed material after regeneration, requiring replacement of the bed media after a number of cycles. Elemental sulfur is not hazardous, and the bed material can be disposed of through composting or at a landfill (F.Varani, Honeywell PAI, personal communication, September 2004). Thus, these technologies are considered environmentally friendly.

Liquid based (aqueous) absorption processes such as scrubbing with water, sodium hydroxide, amines, or glycols present disposal challenges. The most benign of these solvents is water. However,  $H_2S$  should be removed by a method other than water scrubbing to prevent fugitive  $H_2S$  emissions

Chemical removal processes have significant potential for chemical pollution from the accidental release of chemicals or from their final disposal. Chemicals may degrade during use because of contamination with pollutants in the biogas (although this should be less of a problem with dairy biogas than with sewage or landfill gas), corrosion, and other problems. The disposal of spent and degraded chemicals may pose a hazardous waste disposal issue for both  $CO_2$  and  $H_2S$  scrubbing. The use of sodium hydroxide for  $H_2S$  scrubbing results in large volumes of wastewater contaminated with sodium sulfide and sodium hydrogen sulfide, insoluble salts whose disposal is environmentally sensitive. Polyethylene glycol (Selexol process) and amines are not as problematic as these solvents are recirculated and stripped of elemental sulfur using an inert gas or steam.

Biological gas clean-up technologies for  $H_2S$ , such as a biological filter bed or injection of air into the digester gas holder, result in the sulfur particles flowing out with the digestate. Due to the low concentrations of  $H_2S$  in the dairy biogas and the large volumes of digestate involved this does not result in a disposal problem.

## Possible Design for Small Dairy Biomethane Plant

A small dairy biogas upgrading plant might consist of the following:

- Iron sponge unit to remove  $H_2S$
- Compressors and storage units
- Water scrubber with two columns to remove  $CO_2$
- Refrigeration unit to remove water
- Final compressor for producing CBM, if desired



Table 3-1 provides basic system parameters for such a system, which is scaled to a dairy farm with 1,500 cows with an assumed CH<sub>4</sub> production of 30 ft<sup>3</sup>/cow/day.<sup>1</sup>

**Table 3-1 Components for Typical Small Biogas Upgrading Plant**

<b>Component</b>	<b>Size/Capacity</b>
Iron sponge H <sub>2</sub> S scrubber	<ul style="list-style-type: none"> <li>• 70,000 ft<sup>3</sup>/day</li> <li>• 6 ft. dia x 8 ft. high</li> </ul>
First-stage compressor (centrifugal blower)	<ul style="list-style-type: none"> <li>• intake capacity = 100 ft<sup>3</sup>/m compression to 8 psig</li> </ul>
Modified piston compressor	<ul style="list-style-type: none"> <li>• 1<sup>st</sup> stage compression from 8 to 40 psig</li> <li>• 2<sup>nd</sup> stage compression from 40 to 200 psig</li> </ul>
Pressurized storage tanks	2 x 5,000 gal. propane tanks
Water CO <sub>2</sub> scrubber	<ul style="list-style-type: none"> <li>• Two 12-inch diameter x 12-ft columns with Jaeger packing</li> <li>• water pump, piping, pressure valves, regulators</li> <li>• operates at pressures between 200 and 300 psig</li> </ul>
Flash tank, gas recycler, chiller to reduce moisture	
High-pressure compressor	compression from 200 to 3,000 psig (small unit)
Additional components that may be needed	<ul style="list-style-type: none"> <li>• refrigeration</li> <li>• contingencies</li> <li>• engineering hook-ups</li> <li>• infrastructure</li> </ul>

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<sup>1</sup> Various sources provide different average methane yields per cow. For example, Mehta (2002) cites Parsons (1984) as suggesting a biogas yield of 54 ft<sup>3</sup> per cow per day; since biogas has an estimated heat value of 600 Btu/ft<sup>3</sup>, this means one cow would generate about 32.4 ft<sup>3</sup>/day of CH<sub>4</sub>. Other gas yields cited by Mehta (2002) include 139 ft<sup>3</sup>/cow/day at Haubenschild Farm (as cited by Nelson and Lamb, 2000) and a design estimate of 65 ft<sup>3</sup>/cow/day (Craven Farms, as cited by Oregon Office of Energy). Barker (2001) states that a 1,400 lb cow will yield about 30 ft<sup>3</sup> of CH<sub>4</sub> day. This is also the figure we use in this report based on the following:

1. An average cow weighs 1,400 lb and produces 120 lb/day of manure containing 11.33 lb of volatile solids.
2. Manure is collected within 2 days of deposition.
3. 1 lb of 2-day-old volatile solids from a dairy cow anaerobically digests to produce 3 ft<sup>3</sup> of methane.
4. The percent of manure collected in California, by farm type, is: 90% on flush free stall dairies, 90% of scrape freestall dairies, 60% on flushed feedlane drylot dairies, and 15% on dry lot dairies.
5. Solids separation reduces biogas production potential by 25%.
6. Using flushed and scraped freestall dairies as our standard and multiplying this out:  $1.4 \times 11.3 \times 3 \times 0.9 \times 0.75 = 32 \text{ ft}^3$  of methane per cow, which we have chosen to round conservatively to 30 ft<sup>3</sup>/cow for most of our calculations.

The iron sponge  $\text{H}_2\text{S}$  scrubber would be an insulated fiberglass with a removable top cover for spent sponge removal. The iron oxide bed would last about one year. After  $\text{H}_2\text{S}$  removal, compressors would pressurize the gas and two packed columns would be used for the  $\text{CO}_2$  water scrubbing process. The total system would be mounted on a small skid including water pump, piping, pressure valves and regulators. Other equipment needed in process would include a flash tank and gas recycler, as well as a chiller to reduce moisture content prior to final compression.

Process water could be re-used on the farm (for dairy barn cleaning, irrigation, or a stock pond). If stored in a stock pond, it could be recycled after a day or two of open air storage.

Figure 3-6 is a schematic of an on-farm water scrubbing process for  $\text{CO}_2$  (but does not include iron sponge removal of  $\text{H}_2\text{S}$ ). The final stage in the system (also not shown in Figure 3-6) would be a compressor to produce compressed biomethane, assuming this type of vehicle fuel is desired.

Operation and maintenance of this system would be relatively simple, which is one reason it is recommended over other, possibly more efficient, processes. Electricity for the compressors could be produced from an on-site generator using biogas (biogas could also be used to generate power for other on-site uses) or from purchased power. If purchased power were used, the major operating costs for this process would be for power for gas compression.

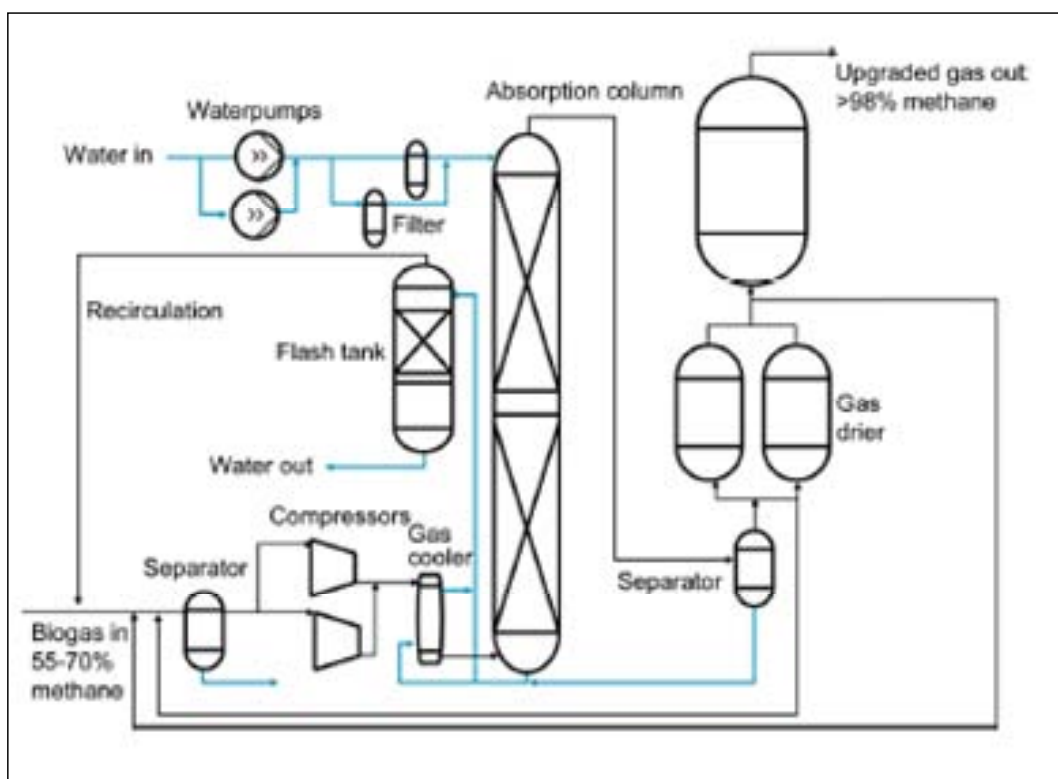


Figure 3-6 Water scrubbing process to remove carbon dioxide from biogas without regeneration (source: Hagen et al., 2001, Figure 7)

Capital and operating costs for a relatively small-scale plant with the capacity to upgrade biogas from 1,500 cows are discussed in more detail in Chapter 8. Our research suggests that a farm of about 1,500 dairy cows is the lower limit of scale for this technology.

## **Blending Biogas with More Valuable Fuels**

The addition of propane or liquefied petroleum gas (LPG), which is gaseous at ambient pressure, is sometimes used to increase the heating value of natural gas in order to meet pipeline quality specifications and could do the same for biomethane. The percentage of propane or LPG mixed in with natural gas tends to be low (i.e., less than 8%) for cost reasons. Since this method does not increase the overall CH<sub>4</sub> content of the gas, it is not by itself sufficient for upgrading biogas to biomethane.

Hypothetically, a small amount of raw or partially purified biogas could be mixed with a larger amount of natural gas from the natural gas pipeline to create a blended feedstock for a town gas system. Although this has been done in Europe, we have no such systems in the USA and blending biogas and natural gas would be inappropriate for producing pipeline quality gas (there would still be too much H<sub>2</sub>S and CO<sub>2</sub> present. The basic effect of the addition of the biogas would be to reduce the average CH<sub>4</sub> content of the blended gas feedstock and increase its level of contaminants. As an example, assuming natural gas with 92% CH<sub>4</sub> and raw biogas with 65% CH<sub>4</sub>, a blending ratio of 6:1 or greater would yield a blended gas with the required 88% methane or better. Pre-blending of raw or partially purified biogas with natural gas or other fuels offers no advantages in the production of either LNG or CNG.

## **Compressing Biomethane**

Biomethane compressed to about 3,600 psi is referred to in this report as compressed biomethane (CBM). Compositionally, it is equivalent to compressed natural gas (CNG), an alternate vehicular fuel, which contains about 24,000 Btu/gallon compared to approximately 120,000 for gasoline and 140,000 for diesel fuel. Consequently, CNG (or CBM) vehicles have both larger fuel tanks and a more limited driving range than traditionally fueled vehicles. Bi-fueled vehicles that could switch from CNG (or CBM) to gasoline would allow for longer driving ranges and less dependence on CNG refueling stations. However, infrastructure costs for distribution and fueling stations present a major hurdle for off-farm use of dairy biomethane (see Chapter 4).

## **Converting Biomethane to Non-Cryogenic Liquid Fuels**

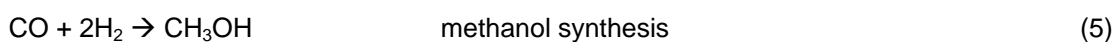
There is considerable interest in the production of renewable liquid fuels that could be used more directly in the existing transportation fleet and could overcome the volume, range, and weight limitations imposed by CBM (or CNG). For example, the energy contents of methanol and liquefied biomethane (LBM, equivalent to LNG) are about 65,000 and 84,000 Btu/gallon,

respectively, much closer to the energy density of gasoline or diesel fuel than CNG (or CBM) and thus better suited for existing passenger vehicle applications.

In addition to liquefied biomethane (LBM), which is discussed at the end of this chapter, two main technologies exist for converting biogas to liquid fuels: catalytic conversion to methanol, and Fischer Tropsch synthesis for hydrocarbon fuels production. The initial steps to produce these liquid fuels from biomethane—the methane-reforming and catalytic conversion processes—are described below.

### ***Methane-Reforming and Catalytic Conversion Processes***

The conversion of methane (from natural gas) to liquid fuels can be accomplished through a methane-reforming process along with steam to produce synthesis gas (consisting of CO, H<sub>2</sub>, and CO<sub>2</sub>). This synthesis gas can then be catalytically converted to methanol or hydrocarbon fuels. The key to these processes is the nature and specificity of the catalysts, as well as the methane to CO-H<sub>2</sub> conversion reaction. The two basic processes used for methane conversion are steam reforming (Equation 3) or dry reforming (Equation 4):



A range of iron or copper catalysts are typically used for the catalytic conversion process to liquid fuels; different catalysts will selectively produce one product or the other. Furthermore, these catalysts are very sensitive to impurities, specifically H<sub>2</sub>S. This requires careful scrubbing of the H<sub>2</sub>S, but also of mercaptans (organic sulfur compounds) and other impurities.

The main drawbacks of both methane-reforming and catalytic conversion processes are the high temperatures and pressures at which they must be operated, as well as their complexity. Complexity comes from, among other causes, the requirement for efficient heat (energy) exchange and recovery among process components. Process control is a significant issue. An additional major factor for the poor economies of scale (both capital and operating) of such systems is the requirement for high-pressure compressors. Both processes require a relatively large scale for economic performance as smaller systems are not much cheaper than larger ones.

### ***Biomethane to Gasoline Using the Fischer-Tropsch Process***

The Fischer-Tropsch method has been in use since the 1920s to convert coal, natural gas, and other “low-value” fossil fuel products into a high-quality, clean-burning fuel. The performance of Fischer-Tropsch fuels is similar to other fuels such as gasoline and diesel. The drawback of these

fuels is that they are very expensive to produce, even at very large scales. For example, the Fischer-Tropsch process is presently being developed commercially in Qatar, where a 34,000-barrels-per-day plant is being built to convert natural gas to gasoline using the Fischer-Tropsch process, at an investment of about \$100/barrel output-year. Two-thirds of this cost is said to be tied to the methane-reforming process, with only one-third tied to the Fischer-Tropsch reaction itself. This cost does not reflect the cost of the infrastructure for getting the gas to the plant, cleaning it up, or getting the product to market.

One major problem is that the Fischer-Tropsch catalysts are far from perfect (the reaction is not sufficiently selective) and the by-products formed—in particular heavier oils and waxes—require further refining to generate a clean, high-value liquid fuel equivalent to gasoline. The by-product fuel would be best used for small-scale applications such as heating or bunker oil, as upgrading of this fuel for other uses would be costly (Dale Simbeck, SFA Pacific, personal communication, 8 November 2004).

Overall, the large economies of scale required for these processes makes them inapplicable to dairy biogas. Another problem is that parasitic energy requirements cause thermal efficiency (fuel energy out/biogas energy fed) to be lower than for other products such as liquefied natural gas.

More fundamentally, for the Fischer-Tropsch process as well as for methanol production, the optimal process is to react the natural gas with both pure O<sub>2</sub> and steam to get a H<sub>2</sub>:CO ratio of 1:2.1 (this is slightly higher than the stoichiometry shown above, to account for hydrocarbon molecule and extra hydrogen). Again, such a process is not applicable for dairy-scale operations due to the high cost of O<sub>2</sub> at such scales. Also the high purity of gas required is an issue for small-scale operations.

The project in Qatar demonstrates that the technology is indeed commercial (even with the almost 50% lower oil prices that prevailed at the time of this investment), but it also points to the need for very large investments to achieve economics of scale. If Fischer-Tropsch technologies were economically viable at a small scale, it is likely they would be marshaled for greater use under the current market conditions of nearly \$50/barrel of oil. For example, there is considerable interest in capturing the enormous potential of natural gas that is now being flared worldwide, but the Fischer-Tropsch process has not been attempted for this, to our knowledge. The lack of application of Fischer-Tropsch technologies to these natural gas wells suggests that this technology is not yet suitable for small biogas applications.

### ***Biomethane to Methanol***

The conversion of methane to methanol is very similar to, but somewhat easier than, the Fischer-Tropsch process, both in terms of engineering and economic principles and application. An advantage of methanol production is that unwanted by-products are minor compared to Fischer-Tropsch, and the fuel obtained is uniform and more easily recovered and produced. The drawback

is that this fuel has very limited demand, particularly now with the phaseout of methyl-tertiary butyl ether (MTBE), a fuel additive introduced in the late 1970s. There are industrial uses for methanol. A potentially expanding market for renewable methanol (biomethanol) is in the production of biodiesel.

A large potential source of biomethanol is from biomass gasification followed by catalytic conversion. Biomass gasification to produce methanol was proposed in the USA during the 1980s and again in the 1990s, when MTBE became an important oxygenated fuel additive. At that time, methanol, an important input to the production of MTBE, sharply increased in price. This economic incentive led several groups to explore the potential of methanol from biogas (see Appendix C for more in-depth discussion of past and present proposed biomethanol projects). Nevertheless, during the past 20 years, no market has developed for methanol as a neat fuel or fuel additive. Methanol has only half the energy content of gasoline; it has a lower vapor pressure than gasoline, it can attack fuel and engine components; and it is toxic. Although these obstacles could be overcome, together with the lack of a methanol vehicle fueling infrastructure, they severely limit the potential of this fuel.

### ***Biogas or Biomethane to Hydrogen Fuel***

Perhaps no single fuel has as much promise and presents as many challenging problems as hydrogen. Not surprisingly, there is great interest in the conversion of biogas to hydrogen. However, the only avenue to hydrogen from methane is through the previously discussed gasification/reform and shift reactions, in which CO and H<sub>2</sub> are produced from CH<sub>4</sub>, and the CO along with H<sub>2</sub>O is converted to H<sub>2</sub> and CO<sub>2</sub>. Converting CH<sub>4</sub> to H<sub>2</sub> is not a major challenge, technically, and might even be feasible on somewhat modest scales. Several companies claim to have small-scale methane reformers that can accomplish this, but nothing has yet materialized. (However, Exxon-Mobil is expected to announce a new reformer for on-board conversion of fuels to H<sub>2</sub> in the near future.)

Once H<sub>2</sub> is produced, it could be used for fuel cells in cars or for stationary applications. The latter, however, are of limited interest for small-scale conversion facilities (and electricity can be produced from biogas without the highly expensive and overall inefficient routing through H<sub>2</sub> and then fuel cells).

One critical issue is the high degree of clean-up required before H<sub>2</sub> can be used in fuel cells. The very high purity of H<sub>2</sub> required makes applications to small-scale biogas operations problematic. Although iron sponge and other H<sub>2</sub>S removal systems can be highly effective, even occasional breakthroughs or accidents would be catastrophic for fuel cell applications.

Carbon monoxide (CO) is another contaminant that has to be reduced to very low levels. The shift reaction using pressure swing absorption to remove CO can produce high purity H<sub>2</sub>; however, the blow-down stream loses 10% or more of the fuel input. In large plants this can be

used for process heat; in smaller plants such use is more limited. Thus, the net efficiency of a reformer-shift reactor train is estimated at 75% for large installations and 60% for smaller ones. In this context, small refers to plants that produce at least 1 million scf of methane per day, which is equivalent to over 30,000 cows.<sup>2</sup> For a dairy manure facility with 5,000 cows, the best likely net efficiency would be around 50%. This does not consider parasitic energy requirements, which, again, can be high at small scales.

At present and for the foreseeable future, the real limitation of biogas-to-CH<sub>4</sub>-to-H<sub>2</sub> conversion systems is the undeveloped nature of the technology, from production to storage to use. This is illustrated from the recent opening in Washington D.C. of the first H<sub>2</sub> fueling station, which uses liquid H<sub>2</sub>, not on-site reformed H<sub>2</sub>. Based on efficiency alone, conversion of biogas to biomethane to H<sub>2</sub> is perhaps the least favorable option for upgrading biogas.

## **Converting Biomethane to Liquefied Biomethane**

Theoretically, biomethane from biogas can be liquefied to a fuel similar to LNG, which we call liquefied biomethane (LBM) in this report. This requires a combination of high pressures and low temperatures, and is a rather energy intensive and expensive process. However, emerging technologies developed in the last five years have highlighted better opportunities for LBM technologies. The advantages of LBM over CBM is a much higher energy content per volume, about 84,000 Btu/gallon or about 70% that of gasoline. If the energy required for liquefaction is ignored, 1,000 scf of CH<sub>4</sub> will yield about 12 gallons of LBM (if included, the yield is about 10 gallons/1,000 scf). Thus, assuming 10% losses and a separate source for electricity, a 1,500-cow dairy farm, producing about 70,000 ft<sup>3</sup> per day of biogas (45,000 ft<sup>3</sup>/day of CH<sub>4</sub>) could generate roughly 500 gallons of LBM/day.

However, as with other biogas upgrading options, there are a number of constraints on the conversion of biogas to LBM. First, the biogas needs to be meticulously purified, as even slight impurities (H<sub>2</sub>O or CO<sub>2</sub>) can cause significant problems during the liquefaction process (e.g., deposits on heat exchange surfaces, clogging of piping, etc.). Inclusion of air must be carefully avoided, as entrained O<sub>2</sub> would create danger of explosions (which is perhaps more of a problem with landfill gas, where air entrainment is common). Until quite recently, the capital and operating costs of the compression and liquefaction technology have been quite scale sensitive, with trade-offs between efficiency and costs.

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<sup>2</sup> There are actually quite a number of small plants that convert methane (natural gas) to H<sub>2</sub> for industrial applications, primarily for use in refineries to remove H<sub>2</sub>S and to clean up gasoline and diesel fuel. Typically, these systems have high available pressure and high purity natural gas and the product, H<sub>2</sub>, has higher value as a chemical than it does as fuel.

Although large, centrally located LNG facilities are more economical in most respects than small dispersed production, small facilities do not have the added costs of distribution, storage, and associated losses, which can be significant for LNG. Many “stranded” natural gas wells and fields that are not serviced by pipelines would seem to be appropriate for the use of small-scale LNG production, which would allow the recovery natural gas that is currently flared. However, at the present time in California, only a single experimental Pacific Gas and Electric Company (PG&E) plant produces LNG, and this plant uses non-biomass sources for LNG production. All other LNG is imported from out-of-state, particularly from Arizona. This would seem to argue against the viability of small-scale production of LBM (or LNG) at present.

Several small-scale methane liquefaction technologies have been developed over the years. These include the following:

- *Anker-Gram liquefier.* More than 30 years ago, a Vancouver, Canada, company developed a 500-gpd system called the Anker-Gram liquefier for small-scale production of LNG for fueling vehicles. Although it is no longer in use, the technology (and, apparently the prototype liquefier unit itself) passed through many companies and traveled to many continents (North America, Australia, South America) over the years, demonstrating the feasibility of the technology along the way. It failed in the hands of Ecogas in Houston, Texas, because the “feedgas pressure was lower and CO<sub>2</sub> content higher than the liquefier was designed for.” Powers and Pope (2002) state that this liquefier was “noteworthy because it is the only small liquefier that we know that has ever operated routinely to provide fuel for an LNG fleet.”
- *Other relatively small units* (1,500 to 5,000 gpd from natural gas) have also been developed and tested in California. Liberty Fuels, Inc. had a liquefier proposed for use in the 250-to-2,000 gpd range, with a projected cost of \$420,000 for operations of 1,000 gpd. However, only a 50-gpd pilot-scale unit was built. Powers and Pope (2002) state that “The liquefier is no longer in operation and it is unclear if Liberty fuels is still actively promoting onsite liquefiers and fueling stations at this time.” More recently, the California Energy Commission (CEC) has supported development and demonstration of small-scale liquefaction units that could be used at stranded gas wells and landfill gas and could also be considered for dairy manure biogas.
- *A process developed by the Gas Technology Institute (GTI)* to produce 1,000 gpd of LNG from biogas or digester gas uses off-the-shelf components and has a purchase price of \$150,000. Two important reservations are that the equipment purchase cost does not include gas cleanup cost and is only suitable for pipeline gas. If installation and cleanup are included, it is estimated by the project team that a system producing 1,000 gpd LNG would probably cost in the range of \$500,000 to \$1 million (Wegryzn, 2004)
- *A process attempted by Cryofuels, Incorporated* (Monroe, Washington) was supported at the Hartland Landfill in British Columbia. Problems were encountered with CO<sub>2</sub> freezeout, and the unit, despite later participation by Applied LNG technology, Inc. was ultimately shut down for lack of funding (Powers and Pope, 2002).

Despite its problems, the most apparently relevant project is that of CryoFuel Systems, Inc., of Monroe, Washington. In partnership with Applied LNG Technologies (ALT) a natural gas company, CryoFuel demonstrated a skid-mounted, 225-gpd liquefaction system at the Hartland



Road Landfill in Victoria, BC (Canada). The unit, shown in Figure 3-7, was reported to include a gas purification system (condenser and activated carbon unit) and CO<sub>2</sub> removal in dual-freezing heat exchangers followed by a temperature-swing absorber bed. The company has announced several projects for applying this process, including one in Kern County and one near Stockton, for both landfill gas and stranded gas wells. The Stockton project is said to have produced over 5,000 gallons of LNG per day beginning in 2003, but verification of actual long-term performance is lacking (Powers and Pope, 2002).

This recent activity indicates that technology for liquefaction is becoming more cost-effective. Also, much of the lack of progress or success has been due to oil prices that were, until recently, low even in comparison to earlier inflation-adjusted prices. Now that oil prices have reached new



Figure 3-7 Skid-mounted 225-gpd landfill gas liquefaction Hartland Unit, located in Victoria, B.C. developed by CryoFuels Systems, Inc. (source: CryoFuels Systems, undated)

heights, continued improvements in this technology are likely. Carefully engineered demonstration projects can help achieve such advances.

Even so, the economics of the entire package (digester, LBM production unit, storage-fueling system, and vehicular modifications) would need to be investigated in some detail. From this initial review, however, liquefaction appears to be the most promising use for biogas. One of the advantages of LBM is that it is more easily distributed (via cryogenic tankers) than CBM, as discussed in Chapter 4. Although liquefaction is more challenging and expensive from a technological perspective than compression, it results in a more usable and more transportable product.



## **4. Storage and Transportation of Biogas and Biomethane**

Dairy manure biogas is generally used in combined heat and power applications (CHP) that combust the biogas to generate electricity and heat for on-farm use. The electricity is typically produced directly from the biogas as it is created, although the biogas may be stored for later use when applications require variable power or when production is greater than consumption.

Biogas that has been upgraded to biomethane by removing the  $H_2S$ , moisture, and  $CO_2$  can be used as a vehicular fuel. Since production of such fuel typically exceeds immediate on-site demand, the biomethane must be stored for future use, usually either as compressed biomethane (CBM) or liquefied biomethane (LBM). Because most farms will produce more biomethane than they can use on-site, the excess biomethane must be transported to a location where it can be used or further distributed.

This chapter discusses the types of systems available for the storage of biogas and/or biomethane as well as modes of biomethane transportation.

### **Storage Systems and Costs**

There are two basic reasons for storing biogas or biomethane: storage for later on-site usage and storage before and/or after transportation to off-site distribution points or systems. The least expensive and easiest to use storage systems for on-farm applications are low-pressure systems; these systems are commonly used for on-site, intermediate storage of biogas. The energy, safety, and scrubbing requirements of medium- and high-pressure storage systems make them costly and high-maintenance options for on-farm use. Such extra costs can be best justified for biomethane, which has a higher heat content and is therefore a more valuable fuel than biogas.

Table 4-1 summarizes on-farm storage options for biogas and biomethane. These options are discussed in more detail below.

Table 4-1 On-Farm Storage Options for Biogas and Biomethane

Purpose of Storage	Pressure (psi)	Storage Device	Material	Size (ft <sup>3</sup> )
Short and intermediate storage for on-farm use (currently used on farms for biogas storage)	< 0.1	Floating Cover	Reinforced and non-reinforced plastics, rubbers	Variable volume usually less than one day's production
	<2	Gas bag	Reinforced and non-reinforced plastics, rubbers	150 – 11,000
	2 – 6	Water sealed gas holder	Steel	3,500
		Weighted gas bag	Reinforced and non-reinforced plastics, rubbers	880 – 28,000
		Floating roof	Plastic, reinforced plastic	Variable volume, usually less than one day's production
Possible means of storage for later on- or off-farm use (could be used for biomethane)	10 – 2,900	Propane or butane tanks	Steel	2,000
	>2,900	Commercial gas cylinders	Alloy steel	350

Source: Ross et al., 1996.

psi = Pounds per square inch, ambient conditions

ft<sup>3</sup> = Cubic feet

### Biogas Storage

Both biogas and biomethane can be stored for on-farm uses. In practice, however, most biogas is used as it is produced. Thus, the need for biogas storage is usually of a temporary nature, at times when production exceeds consumption or during maintenance of digester equipment. Important considerations for on-farm storage of biogas include (1) the needed volume (typically, only small amounts of biogas need to be stored at any one time), (2) possible corrosion from H<sub>2</sub>S or water vapor that may be present, even if the gas has been partially cleaned, and (3) cost (since biogas is a relatively low-value fuel).

#### Low-Pressure Storage of Biogas

Floating gas holders on the digester form a low-pressure storage option for biogas systems. These systems typically operate at pressures up to 10-inch water column (less than 2 psi). Floating gas holders can be made of steel, fiberglass, or a flexible fabric. A separate tank may be used with a floating gas holder for the storage of the digestate and also storage of the raw biogas.

One advantage of a digester with an integral gas storage component is the reduced capital cost of the system. The least expensive and most trouble-free gas holder is the flexible inflatable fabric top, as it does not react with the H<sub>2</sub>S in the biogas and is integral to the digester. These types of

covers are often used with plug-flow and complete-mix digesters (see Chapter 2). Flexible membrane materials commonly used for these gas holders include high-density polyethylene (HDPE), low-density polyethylene (LDPE), linear low density polyethylene (LLDPE), and chlorosulfonated polyethylene covered polyester (such as Hypalon<sup>®</sup>, a registered product of DuPont Dow Elastomers L.L.C.). Thicknesses for cover materials typically vary from 18 to 100 mils (0.5 to 2.5 millimeters) (Ross, et al., 1996, p. 5-15). In addition, gas bags of varying sizes are available and can be added to the system. These bags are manufactured from the same materials mentioned above and may be protected from puncture damage by installing them as liners for steel or concrete tanks.

### **Medium-Pressure Storage of Cleaned Biogas**

Biogas can also be stored at medium pressure between 2 and 200 psi, although this is rarely, if ever done, in the USA. To prevent corrosion of the tank components and to ensure safe operation, the biogas must first be cleaned by removing H<sub>2</sub>S. Next, the cleaned biogas must be slightly compressed prior to storage in tanks. Typical propane gas tanks are rated to 250 psi. Compressing biogas to this pressure range uses about 5 kWh per 1,000 ft<sup>3</sup> (Ross, et al., 1996, p. 5-18). Assuming the biogas is 60% methane and a heat rate of 13,600 Btu/kWh, the energy needed for compression is approximately 10% of the energy content of the stored biogas.

### ***Biomethane Storage***

Biomethane is less corrosive than biogas and also is potentially more valuable as a fuel. For these reasons, it may be both possible and desirable to store biomethane for on- or off-farm uses.

### **High-Pressure Storage of Compressed Biomethane**

Biomethane can be stored as CBM to save space. Gas scrubbing is even more important at high pressures because impurities such as H<sub>2</sub>S and water are very likely to condense and cause corrosion. The gas is stored in steel cylinders such as those typically used for storage of other commercial gases. Storage facilities must be adequately fitted with safety devices such as rupture disks and pressure relief valves. The cost of compressing gas to high pressures between 2,000 and 5,000 psi is much greater than the cost of compressing gas for medium-pressure storage. Because of these high costs, the biogas is typically upgraded to biomethane, a more valuable product, prior to compression. Compression to 2,000 psi requires nearly 14 kWh per 1,000 ft of biomethane (Ross et al., 1996, pp 5-19). If the biogas is upgraded to 97% methane and the assumed heat rate is 12,000 Btu/kWh, the energy needed for compression amounts to 17% of the energy content of the gas.

The main components of an example on-farm CBM storage system are shown in Figure 4-1.

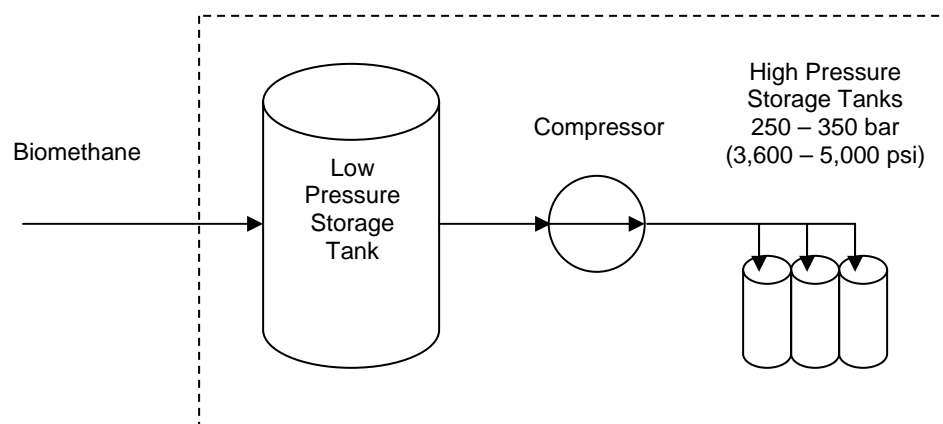


Figure 4-1 Schematic of on-farm storage system for compressed biomethane

The low-pressure storage tank is a buffer for the output from the biogas upgrading equipment. The tank would most likely consist of one or two large, air-tight vessels with sufficient storage capacity for around one to two days worth of biogas production. For example, a dairy with 1,000 cows would yield approximately 30,000 ft<sup>3</sup> biomethane/day. Note that by compressing the biomethane slightly, the amount of gas stored in the low-pressure storage tank can be increased proportionately<sup>1</sup>. Large, stationary low-pressure storage tanks suitable for this application are typically custom designed and are available from many manufacturers.

Because it is highly unlikely that there would be sufficient on-farm vehicle demand for all of the biomethane that a farm could produce, most or all of the biomethane must eventually be transported to a refueling station. Biomethane has an inherently low energy density at atmospheric pressure; therefore, the most economical and efficient way to transport upgraded biogas over the road is in compressed form. (Pipeline distribution of biomethane is discussed in a later section.) Since CNG refueling stations normally provide CNG at 3,000 to 3,600 psi, CBM would be transported at similar or higher pressures to minimize the need for additional compression at the refueling station.

The compressor receives the low-pressure biomethane from the storage tank and compresses it to 3,600 to 5,000 psi. The compressor should be specified to handle the output flow rate from the

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<sup>1</sup> According to Boyle's Law, pressure (P) is inversely proportional to volume (V) for an ideal gas assuming temperature and the amount of gas are held constant, i.e.,  $P \times V = \text{constant}$ .

biogas upgrading equipment. For example, a dairy with 1,000 cows would yield a flow rate of approximately 2,000 ft<sup>3</sup> raw biogas/hour. There are several manufacturers of commercially available compressors in this range (e.g., Bauer Compressors and GreenField Compression).

The CBM output of the compressor is fed to a number of individual high-pressure storage tanks connected in parallel and housed in a portable trailer. (In the case of on-farm CBM refueling, the high-pressure storage tanks could be stationary and potentially much larger.) Portable high-pressure storage tanks rated for this type of application are commercially available from a variety of manufacturers (e.g., Dynetek Industries and General Dynamics).

### **Storage of Liquefied Biomethane**

Biomethane can also be liquefied, creating a product known as liquefied biomethane (LBM). Two of the main advantages of LBM are that it can be transported relatively easily and it can be dispensed to either LNG vehicles or CNG vehicles (the latter is made possible through a liquid-to-compressed natural gas (LCNG) refueling station equipment which creates CNG from LNG feedstock). However, if LBM is to be used off-farm, it must be transported by tanker trucks, which normally have a 10,000-gallon capacity. For obvious economic reasons, the LBM must be stored on-farm until 10,000 gallons have accumulated.

Figure 4-2 shows the generalized process of storing LBM prior to use or transport. The low-pressure storage tank is a buffer for LBM after it exits the biomethane liquefaction equipment. Typical LNG storage tanks are double-walled, thermally insulated vessels with storage capacities of 15,000 gallons for stationary, aboveground applications. (Smaller LNG storage tanks with 6,000-gallon storage capacities are also available, but would only be useful for on-farm applications, and the on-farm demand for LBM is likely to be relatively low.) For a dairy with 1,000 cows, 15,000 gallons is equivalent to approximately six weeks' worth of LBM production. The LBM output of the biogas liquefaction equipment is nominally at 50 psi, which is also the nominal pressure of the LBM in the low-pressure storage tank. LNG storage tanks are available from several companies specializing in LNG equipment (e.g., NexGen Fueling). The typical cost for a 15,000-gallon tank is \$170,000.

Since it is highly unlikely that on-farm vehicle demand will consume all of the LBM produced (see Chapter 5), most or all of the LBM must be transported to a refueling station where it can be dispensed to natural-gas fueled vehicles. Liquid biomethane is transported in the same manner as LNG, that is, via insulated tanker trucks designed for transportation of cryogenic liquids. Standard tanker trucks hold 10,000 gallons of LNG or LBM at approximately 50 psi.

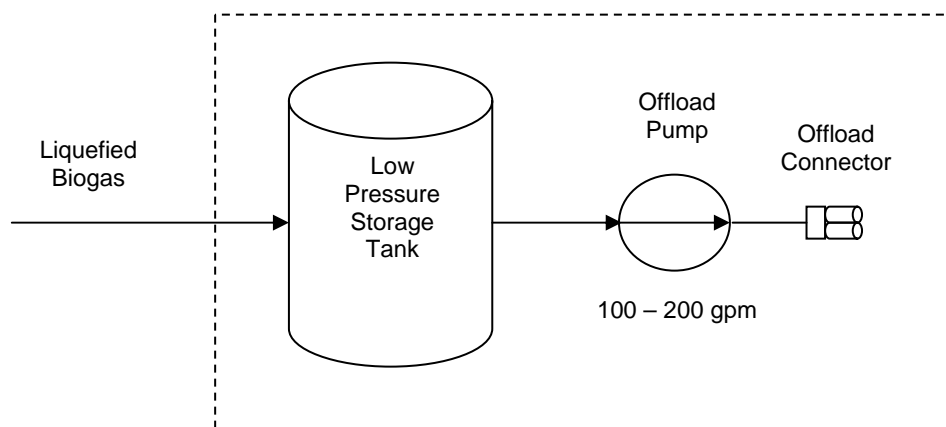


Figure 4-2 Schematic of storage system for liquefied biomethane

An offload pump is needed to pump the LBM from the low-pressure storage tank to the tanker truck (Figure 4-2). Typical flow rates for these types of pumps are 100 to 200 gallons per minute (gpm). Cryogenic pumps for this type of application are available from a variety of manufacturers and typically cost between \$15,000 to 25,000. The offload connector is a standard LNG interface connector and is normally included as part of the offload pump.

One of the main disadvantages of LNG and thus LBM is that the cryogenic liquid will heat up during storage, which will result in loss of LBM to evaporation through a release valve on the tank. To minimize these losses, LBM should be used fairly quickly after production. It is generally recommended that LBM be stored for no more than a week before it is either used or transported to a fueling station. Storage for a longer period will result in an economically unacceptable level of evaporative loss. Since standard LNG tankers carry about 10,000 gallons, a small-scale liquefaction facility should produce at least 3,000 gallons of LBM per day. However, the production of this much LBM requires approximately 8,000 cows—which could only be found at an extremely large dairy or a central digester facility.

## Distribution of Biomethane

Biogas is a low-grade, low-value fuel and therefore it is not economically feasible to transport it for any distance (although there are two locations in California where it is sent through a 1- or 2-mile pipeline to a generator). Likewise, biogas cannot be economically trucked.

In contrast, biomethane can be distributed to its ultimate point of consumption by one of several options, depending on its point of origin:

- Distribution via dedicated biomethane pipelines
- Distribution via the natural gas pipeline
- Over-the road transport of CBM
- Over-the-road transport of LBM



### ***Distribution via Dedicated Biomethane Pipelines***

If the point of consumption is relatively close to the point of production (e.g., less than 1 mile), the biomethane would typically be distributed via dedicated biogas pipelines (buried or aboveground). For example, biomethane intended for use as CNG vehicle fuel could be transported via dedicated pipelines to a CNG refueling station. For short distances over privately owned property where easements are not required, this is usually the most cost-effective method. Costs for laying dedicated biomethane pipelines can vary greatly, and may range from about \$100,000 to \$250,000 or more per mile. Note that biomethane distributed via dedicated biomethane pipelines must compete with natural gas prices in the marketplace.

### ***Distribution via the Natural Gas Pipeline Network***

The natural gas pipeline network offers a potentially unlimited storage and distribution system for biomethane. Since the natural gas pipelines are typically owned by either private or municipal gas utilities, the biomethane producer must negotiate an agreement with the pipeline owner (i.e., the local gas utility) to supply biomethane into the natural gas pipelines. One prerequisite for such an agreement would be to ensure that biomethane injected into the natural gas pipeline network meets the local gas utility's pipeline gas quality (e.g., gas composition) standards. Once the biomethane is injected into the natural gas pipeline network, it can be used as a direct substitute for natural gas by any piece of equipment connected to the natural gas grid, including domestic gas appliances, commercial/industrial gas equipment, and CNG refueling stations.

As mentioned, any gas (including biomethane) transported via the natural gas pipeline network is required to meet the local gas company gas quality standards set by the owner of the natural gas pipeline network. In California, the two major private natural gas pipeline distribution networks are owned by PG&E and Southern California Gas Company (SoCalGas); these networks provide natural gas for most of northern and southern California, respectively. In addition to PG&E and SoCalGas, there are a number of municipal gas utilities throughout the state which own and operate their own natural gas pipeline distribution networks. Default gas quality and interchangeability requirements for the two networks are set forth in PG&E's Rule 21 and SoCalGas's Rule 30 (although these requirements may be superseded by specific agreements).

In reality, there is likely to be significant resistance by the local gas utility toward attempts to distribute biomethane via the natural gas pipeline network. One reason for this resistance is the justifiable concern that poor gas quality might have potentially devastating effects on gas equipment. As a result, there are likely to be severe requirements for gas quality monitoring and fail-safe disconnection of the biomethane supply from the natural gas pipeline network, which may lead to prohibitively high costs for biomethane producers. In addition, biomethane distributed via the natural gas pipeline network would probably be sold to the local gas utility and therefore must compete with the wholesale price of natural gas offered by other natural gas suppliers, though it might be possible to wheel the gas to an industrial user at a negotiated price.

As of 2005, the only location in the USA where biomethane is sold to a gas utility as a supplemental equivalent for natural gas is the King County South Wastewater Treatment Plant in Renton, Washington. This plant includes an anaerobic digester and water scrubbing unit that produce pipeline quality biomethane. The biomethane is sold to the local gas utility, Puget Sound Energy, which in turn resells the biomethane to its natural gas customers. Local circumstances support this scenario: electric power is extremely cheap in the Seattle area (\$0.025 to \$0.03/kWh), and thus the biomethane produced by the Renton plant is more valuable than the electric power that could have been produced by the biogas. In California, where electric power costs are currently much higher (e.g., 0.08 to \$0.10/kWh), it would be more economical to generate electric power from the biogas rather than upgrade it to biomethane.

### ***Over-the-Road Transportation of Compressed Biomethane***

If distribution of biomethane via dedicated pipelines or the natural gas grid is impractical or prohibitively expensive, over-the-road transportation of compressed biomethane may be a distribution option. The energy density of biomethane is extremely low at ambient pressure and as a result it must be compressed to relatively high pressures (e.g., 3,000 to 3,600 psi) to transport economically in over-the-road vehicles.

Compressed natural gas bulk transport vehicles, often referred to as “tube trailers,” are used when over-the-road transportation of CNG or compressed biomethane is required. U.S. Department of Transportation (DOT) regulations classify CNG as a Class 2 (gas), Division 2.1 (flammable) hazardous material; it is assumed that over-the-road transportation of compressed biomethane would be held to the same requirements. Major requirements include the following:

- Transportation in DOT-approved tanks (e.g., DOT-3AAX seamless steel cylinders) that do not exceed the rated tank pressure
- Water vapor content of less than 0.5 lbs/million scf (i.e., less than 10 ppm H<sub>2</sub>O)
- Minimum methane content of 98%
- Appropriate hazardous materials markings

Given the transportation and capital equipment costs associated with over-the-road transportation of compressed biomethane as well as the probable need for additional compression at the point of consumption, this method of biomethane distribution is generally not considered a long-term, cost-effective solution. Rather it is used as a temporary solution in certain situations, for example, as a means of expanding the use of compressed biomethane vehicle fuel into a new market prior to the installation of permanent refueling infrastructure.

### ***Over-the-Road Transportation of Liquefied Biomethane***

Over-the-road transportation of liquefied biomethane is a potential way of addressing many of the infrastructure issues associated with biomethane distribution; however, this distribution method presents additional technical challenges. Bulk LNG is transported in LNG tankers. These are

typically class 8 vehicles consisting of a tractor towing a 10,000-gallon LNG tanker. Liquid natural gas is transported at relatively low pressures (e.g., 20 to 150 psi), but because it is a cryogenic liquid (i.e., its nominal temperature is -260° F), it requires special handling. U.S. DOT regulations classify LNG as a Class 2 (gas), Division 2.1 (flammable) hazardous material; it is assumed that over-the-road transportation of liquefied biomethane will be held to the same requirements:

- Transportation in DOT-approved tanks (e.g., double-walled insulated steel tanks)
- Presence of two independent pressure relief systems
- Maximum one-way-travel-time marking
- Appropriate hazardous materials markings

One of the most attractive features of over-the-road transportation of liquefied biomethane is that an infrastructure and market already exist. (In addition to acting as a fuel for LNG vehicles, liquefied biomethane can also be used to provide fuel for CNG vehicles via LCNG refueling stations which turn LNG into CNG.) In California, where almost all LNG is currently imported from other states, in-state production of LBM would gain a competitive advantage over LNG with respect to transportation costs. While liquefaction of landfill gas has been demonstrated at a number of locations throughout the USA, this technology has never been applied to biomethane produced from dairy manure or similar feedstocks.

As noted, a significant disadvantage of LBM is that it must be used fairly quickly after it is produced (typically within one week) to avoid significant fuel losses from thermal evaporation. Since standard LNG tankers carry about 10,000 gallons of LNG, a small-scale LNG liquefaction facility should produce about 3,000 gallons of liquefied biomethane/day. This would allow a full LNG tanker to be loaded approximately every four days for cost-effective distribution to the ultimate point of consumption.



## 5. Potential Uses of Biogas and Biomethane

This chapter discusses the potential uses of biogas and biomethane. At present, dairy manure biogas is used on-farm for direct electricity generation and some of the waste heat is recovered for other uses. One of our goals was to explore alternative direct on-farm uses of raw and slightly cleaned biogas. Because of its highly corrosive nature (due to the presence of  $\text{H}_2\text{S}$  and water) and its low energy density (as obtained from the digester, biogas contains only about 80 Btu/gallon or 600 Btu/scf, the potential for off-farm use of biogas is extremely low. As a result, this chapter focuses on possible alternate on-farm uses of biogas.

This chapter also explores potential on- and off-farm uses of biomethane—dairy biogas that has been upgraded through the removal of  $\text{CO}_2$ ,  $\text{H}_2\text{S}$ , and water. Biomethane contains a heat capacity of about 130 Btu/gallon, which is equivalent to about 1,000 Btu/scf. Because of this high energy content, biomethane could be sold for off-farm applications to industrial or commercial users, for injection into a natural gas pipeline, or as vehicular fuel.

### Potential On-Farm Uses of Biogas

The most common and popular on-farm use of biogas is to fuel an engine-generator (generator-set or genset) to produce electricity for on-farm use, or, less commonly, for off-farm sale or under a net-metered arrangement with the utility. Heat recovered from combustion of the biogas (whether in boilers or internal combustion engines) can be used to maintain the operating temperature of the anaerobic digester or for other on-farm uses. Because of relatively low energy prices in the past, other on-farm uses of biogas have been minimal and the associated experience base is quite small. Recent increases in energy prices and the likelihood of continued high prices may increase the attractiveness of other on-farm uses. More development work and analysis is needed, however, particularly with regard to USA-specific issues (as opposed to somewhat more favorable i.e., subsidized situations in Europe).

Biogas could be used for the same applications off-farm; however, as discussed in Chapter 4, off-farm distribution of biogas is constrained by factors such as economics and corrosion of transporting equipment.

In the following sections, we discuss some of the general considerations related to the use of biogas as a direct on-farm fuel. Although many of these considerations pertain to combined heat and power (CHP) applications, they provide important background information for possible alternative uses of biogas.

We also consider specific alternative on-farm uses, including as fuel for irrigation pumps and refrigeration systems. Finally, we discuss practical (non-technical) factors that affect the viability

of biogas as a fuel for alternate on-farm use such as how well production capacity is matched to on-farm demand.

### ***Biogas as a Fuel for Combined Heat and Power Applications***

Burners and boilers used to produce heat and steam can be fueled by biogas. The direct substitution of biogas for natural gas or LPG, however, will not work for most standard commercially available burners. At given fuel gas feed pressures, gas must flow into combustion in the right stoichiometric ratio with air. Because of its high CO<sub>2</sub> content, if biogas flows through the burner orifice at the pressure intended for feeding methane or propane, the fuel-to-air ratio is insufficient to ensure flame stability.

A relatively simple option is to provide the combustion equipment with a second “as is” biogas burner that operates in parallel with the first. In this case, regardless of the fuel used, air flow is kept constant. Burner orifices for the respective burners can be set such that each burner meters the proper amount of gas to meet combustion stoichiometry. This could require other control measures such as (for simplest control) complete switchovers from pure biogas fuel to the fossil alternative, and modest (a few hours’ worth) backup biogas storage, but is otherwise straightforward.

Some operations that use landfill gas have adapted standard equipment to allow easy switchover from different fuel sources, whether landfill biogas, natural gas, or oil. An example of such equipment is the Cleaver-Brooks boiler at the Ajinomoto Pharmaceutical plant in Raleigh North Carolina, which has operated successfully using landfill gas for more than 10 years (Augenstein and Pacey, 1992; US EPA, 2001).

Conversion of a boiler system to operate on biogas typically involves the enlargement of the fuel orifice and a restriction of the air intake. Important considerations include the capability of the combustor to handle the increased volumetric throughput of the lower-Btu biogas, flame stability, and the corrosive impact of raw biogas on the burner equipment.

To prevent corrosion from H<sub>2</sub>S and water vapor, operating temperatures should be maintained above the dew point temperature (250° F) to prevent condensation. It may also be advisable to use propane or natural gas for start up and shut down of the system, since higher operating temperatures cannot be maintained at these times.

If the biogas has an energy content lower than 400 Btu/scf, the combustion system may be limited by the volumetric throughput of the fuel, which may result in de-rating of the equipment. In addition, the burner orifice should be enlarged to prevent a higher pressure drop across the burner orifice due to the decreased heating value and specific gravity of the biogas results. However, orifice enlargement will degrade the performance of the burner if it is ever operated on natural gas or propane. To resolve this problem, the propane or natural gas can be mixed with air to

create an input fuel with an equivalent pressure drop and heat input as the biogas. It is also possible to achieve fuel flexibility by using a dual burner system, as mentioned above. This allows optimum performance of the burners since they maintain the pressure drop for each fuel independently.

### **Direct Use of Biogas for On-Farm Heating**

The need for on-farm heating applications varies both seasonally and from farm to farm. All farms require hot water on a year-round basis, although for most, the amount needed is likely to be far less than what could be generated from the biogas production of an average farm. In California, the need to heat buildings is seasonal, with the exception of nursery and hog farrowing rooms, which may require some year-round heat. Depending on the type of anaerobic digester used, some heat may be needed to keep the digester system at the proper operating temperature. There are three common technologies that can be used to supply heat for these types of applications: hot water boilers, forced-air heat, and direct-fired heat.

**Hot water boilers.** A modified commercial cast-iron natural-gas boiler can be used to produce hot water for most on-farm applications. Modifications include adjustments to the air-fuel mixture and enlargement of the burner jets. All metal surfaces of the housing should be painted. Flame-tube boilers may be used if the exhaust temperature is maintained above 300° F to minimize condensation. The high concentration of H<sub>2</sub>S in the gas may result in clogging of the flame tubes.

The typical capacities, efficiencies, controls, and operating schemes for on-farm hot water boilers are provided below:

- *Available capacities:* Cast-iron pot boilers are available in sizes from 45,000 Btu/hr and larger.
- *Thermal efficiencies:* Conversion efficiencies are 75% to 85%.
- *Control systems:* Typical commercial control systems supplied with boilers.
- *Operating schemes:* The boiler could be used to produce all the heat required for an anaerobic digester (if a heated digester is used) as well as the maximum on-farm demand for heat.

**Forced-air furnaces.** Hot-air furnaces can be fueled by surplus biogas from a covered lagoon; however, California farms generally do not have a year-round need for heat. Forced air furnaces are manufactured from thin metal and depend on metal-to-air heat exchange. Corrosion-resistant models are not available; therefore, the gas should be pretreated to remove H<sub>2</sub>S and water.

The typical capacities, efficiencies, controls, and operating schemes for on-farm forced-air furnaces are provided below:

*Available capacities:* Forced air furnaces are made with capacities from 40,000 Btu/hr and up.

*Thermal efficiencies:* Conversion efficiencies are 75% to 85%.

*Control systems:* Typical commercial control systems supplied with furnaces are used for control.

*Operating schemes:* It is difficult to recover heat for digester heating from a hot air furnace, and because of the seasonal need for other types of heating, it would be unusual in California to find a use for forced hot air on a farm that could consume all of the available biogas production potential. On the positive side, this type of heat would produce few environmental impacts if a California-approved low-NO<sub>x</sub>-emission furnace were used. Gas treatment to remove H<sub>2</sub>S would also reduce potential SO<sub>2</sub> emissions.

**Direct-fired room heaters.** Direct-fired heating is commonly used in hog farrowing and nursery rooms. A farm will typically have multiple units and some heat is required virtually every day of the year. Commercial models of this equipment can be operated using treated biogas. Burner orifices should be enlarged for low Btu gas.

A direct-fired heater can be fueled by surplus biogas or by biogas from a covered lagoon. Biogas would be burned directly in the room for heat; therefore, the biogas would need to be treated to remove H<sub>2</sub>S and water.

The typical capacities, efficiencies, controls, and operating schemes for on-farm direct-fired heat are provided below:

- *Available capacities:* Direct-fired room heaters are available in a wide range of sizes, ranging from 40,000 Btu/h and upward.
- *Thermal efficiencies:* Conversion efficiencies are generally 85% to 90%, as all gas is burned in the room.
- *Control systems:* Typical commercial control systems supplied with these units can be used.
- *Operating schemes:* It is difficult to recover heat for digester heating from a direct-fired room heater. The operating scheme would depend upon the balance of biogas supply and maximum demand of installed heaters. Biogas could be supplied to as many heaters as the winter gas production could support. However, seasonal daily heat demand would likely be less than the production potential and, therefore, a portion of the collected gas would likely be wasted. Most direct-fired room heaters are of too small a capacity to be covered by air pollution regulations, but treatment of the gas to eliminate H<sub>2</sub>S would eliminate potential SO<sub>2</sub> emissions.

### **Biogas as an Engine Fuel**

Electricity generation using biogas on dairy farms is a commercially available, proven technology. Typical installations use spark-ignited natural gas or propane engines that have been modified to operate on biogas. Biogas-fueled engines could also be used for other on-farm applications.

As discussed below, diesel or gasoline engines can be modified to use biogas. Potentially, the more efficient Stirling engines could also be operated on biogas. Although waste heat from



engine operations is used frequently in CHP applications, it is probably not practical to recover the small amounts of heat generated by engines used directly for specific uses such as irrigation or refrigeration.

**Internal combustion engines.** Natural gas or propane engines (typically used for electricity generation) can be converted to burn treated biogas by (1) modifying carburetion to accommodate the lower volumetric heating value of the biogas (400-600 Btu/scf) compared to natural gas (1,000 Btu/scf) and (2) adjusting the timing on the spark to accommodate the slower flame velocity of biogas ignition systems. Gas treatment to prevent corrosion from  $H_2S$  is usually not necessary if care is taken with engine selection and proper maintenance procedures are followed. According to RCM Digesters, natural gas or propane engines operating on raw biogas should have an accelerated oil change schedule. Typically, oil changes are recommended every 600 hours for a natural gas engine. When operating on raw biogas, oil changes should be conducted every 300 hours.

Biogas can fuel engine-driven refrigeration compressor and irrigation pumps. Spark ignited gasoline engines may be converted to operate on biogas by changing the carburetor to one that operates on gaseous fuels. However, gas treatment may be necessary depending on the type of engine used. The inherent variable speed operation of a gasoline engine optimizes energy use by closely following the load profile of the compressor. Diesel engines can also be modified to operate on biogas in two ways: (1) by replacing the fuel injectors with spark plugs and replacing the fuel pump with a gas carburetor, and (2) by using diesel fuel for ignition and adding a carburetor for the biogas as well as advancing the ignition timing. The high compression ratio of a diesel engine (16:1) lends itself to operation on biogas. Spark-ignited gas engines tend to operate in the lower 7:1 to 11:1 range of compression ratios, whereas biogas engines ideally operate in the 11:1 to 16:1 range.

The metallurgy of the engine is a critical consideration if raw (digester) biogas is used. The presence of  $H_2S$  in the raw biogas may lead to the formation of sulfuric acids, which can result in bearing failures and damage to the piston heads and cylinder sleeves. Copper alloy wrist pins and bearings make engines particularly susceptible to corrosion damage. RCM Digesters has had positive experiences with both Waukesha and Caterpillar engines with regard to their metallurgical resistance to corrosion. To minimize condensation of acid fumes in the crank case, engine manufacturers recommend maintaining engine coolant temperatures above 190° F (Ross, et al., 1996).

Engine manufacturers also use positive crankcase ventilation filters to purge moisture and contaminant-laden gas from the crankcase.

Although biogas is not commonly used as a fuel for gasoline-fuel or diesel-fuel engines, this may change. Below is a synopsis of the typical capacities, controls, and maintenance schedules for on-

farm natural gas or propane engines suitable for biogas use... More detail about gasoline and diesel engines for non-electrical generation is given in later sections of this chapter.

*Available capacities:* Natural gas engines suitable for on-farm biogas utilization range in capacity from 40 to 250 kW.

- *Thermal and electrical efficiencies:* A biogas-fueled engine-generator will normally convert 18% to 25% of the biogas thermal capacity (Btu) to electricity. Because of the lower energy content per unit volume of biogas as compared to diesel or natural gas, engines converted to biogas will be de-rated with respect to their rated power output for other fuels. This de-rating may be as much as 20% of the output rating when the engine is fueled by natural gas.
- *Control systems:* Commercial control systems for engine-generators are well-developed. In the harsh on-farm operating environment, excess automation often fails where simple manual and mechanical controls succeed.
- *Operation and maintenance:* The engine manufacturer should supply an operation and maintenance schedule. A biogas engine should be inspected daily for adequate coolant and lubricant. Oil should be changed regularly to protect the engine. RCM Digesters recommends an accelerated oil change schedule (once every 300 operating hours) for engines that operate using raw biogas. This enables capture and removal of the H<sub>2</sub>S in the spent oil, and has resulted in successful operation of a Caterpillar 3306 engine at Langerwerf Dairy for 45,000 hours between major overhauls.

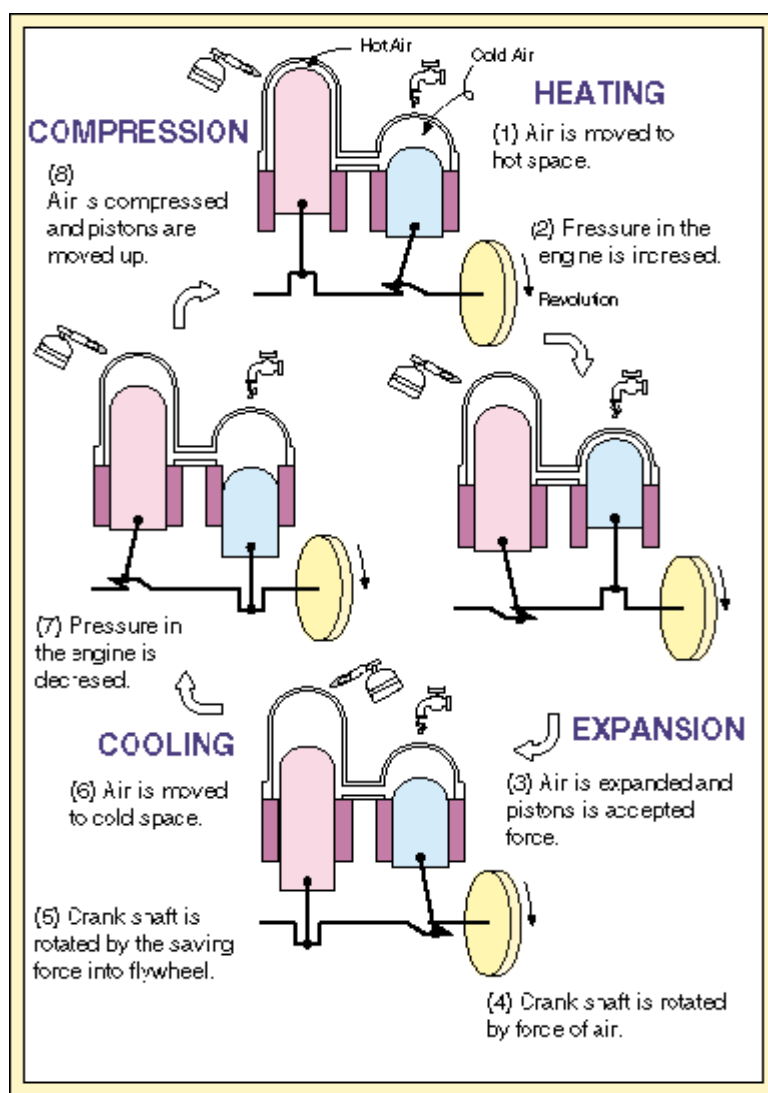
All engine mechanical safety devices should be checked monthly for proper function. Other engine components such as spark plugs require maintenance on a monthly to yearly basis. Normal engine wear requires valve jobs every 6 to 24 months and engine rebuilding or replacement every 2 to 4 years. Engine controls require periodic repair or replacement. Generator bearings may require lubrication annually. The industry-accepted standard for engine operation and maintenance is \$0.015/kWh with a professional maintenance staff. As farms do most of their routine engine maintenance, their costs are a bit lower.

**Stirling engines.** The Stirling engine is a closed-cycle external-heat engine that uses the same working gas repeatedly without any valve. Modern Stirling engines produce high power and efficiency levels by using high pressure helium or hydrogen as the working gas. However, these engines have not achieved widespread use because of their heavy weight and high production costs.

A popular type of Stirling engine has two pistons that create a 90-degree phase angle and two different areas of the engine that are kept at different temperatures (Figure 5-1). The working gas is perfectly sealed within the engine. Gas expands when heated, and contracts when cooled. Stirling engines move the gas from the hot side of the engine, where it expands, through a regenerator, to the cold side, where it contracts.

The combustion of biogas can be used as an external source of heat for a Stirling engine. The advantage of this configuration is that the biogas does not enter the engine cylinder or come in contact with the working fluid, which results in fewer corrosion problems for the engine. In addition, better emissions controls can be achieved in an external combustion process that is geared toward heat exchange as opposed to power production.

The California Energy Commission conducted the Stirling Engine Generator Biogas Demonstration Project in November 1995. The project was conducted at Sharp Ranch in Tulare, California, by SAIC Corporation. The engine was a Stirling Power Systems V160 engine that



used helium as the working fluid. However, the project was beset with a number of operational problems including difficulty operating in parallel with the existing Waukesha internal combustion engine (SAIC, 1995, p. 4-3). The poor performance of this particular demonstration engine is not indicative of the operation of Stirling engines in general, but demonstrates that support by the manufacturer is extremely important for the successful operation of such engines in an on-farm environment. There are currently two Stirling engine manufacturers in the USA: Stirling Thermal Motors of Ann Arbor, Michigan and Stirling Energy Systems of Phoenix, Arizona.

Figure 5-1 Principles of two-piston Stirling engine. (source: <[http://www.bekkoame.ne.jp/~khirata/english/still\\_a.htm](http://www.bekkoame.ne.jp/~khirata/english/still_a.htm), accessed October 22, 2004>)

**Recovering heat from biogas engines.** For CHP applications, the key to energy savings is recovering heat generated by the engine jacket and exhaust gas. Nearly half of the engine fuel energy can be recovered through this waste heat by, for example, recovering hot water for process heat, preheating boiler feedwater, or space heating. One drawback of gas-driven systems is that the engines are said to require much more maintenance than an electric motor. It is also important to note that irrigation pumping is generally intermittent and refrigeration represents a relatively small component of the biogas use potential of a dairy.

Heat recovery from biogas engines is achieved by jacket-water and exhaust-gas heat-exchange devices. When biogas is produced by plug-flow or complete-mix digesters, the majority of the “waste” heat is used to maintain a digester temperature of around 100° F. When a heat recovery process is used, a balance must be struck between maximizing the amount of heat recovered and maintaining optimal engine operating temperatures. The engine operating temperatures must be high enough to minimize the condensation of carbonic and sulfuric acids in the oil, but low enough to avoid damage to engine components.

Heat recovery from the engine jacket is achieved through a liquid-to-liquid heat exchanger. The maximum temperature that can be supplied to the hot water load is 190° F. Heat recovery from exhaust is carried out through a gas-to-liquid heat exchanger. Exhaust temperatures can reach as high as 1,200° F coming from the engine. The heat recovery system should maintain temperatures no lower than 400° F to prevent acidic vapors from condensing and corroding the exhaust-heat recovery package.

In addition to meeting process heat loads, an engine must have a redundant means of shedding excess heat, whether it is used for CHP or other purposes. This is typically accomplished by an air-cooled radiator that is capable of meeting the engine’s maximum cooling requirements. The radiator, which is plumbed in parallel to the heat load, has a fan that is thermostatically controlled and powered by a variable frequency drive in order to modulate heat rejection.

### ***Alternative Uses of Biogas***

There are other potential uses of biogas on a farm besides combined heat and power, such as in agricultural pumps, refrigeration, and vehicles. The section below discusses these alternatives and concludes that these uses would be economically challenging and would use only a limited percentage of a dairy’s biogas production.

#### **Biogas as a Fuel for Agricultural Pumps**

The use of agricultural pumps varies widely from dairy to dairy depending on both on-site conditions and pumping needs. Where agricultural pumps are required (e.g., for irrigation or effluent pumping), dairy farmers have the option of using electric motors, diesel engines, or natural gas engines to drive them. Often the location of the pump and the price of electricity

determine this choice. Recent estimates indicate that approximately 82% of the agricultural pumps in California are driven by electrical motors and 18% are driven by diesel engines (the number of agricultural pumps driven by natural gas engines is currently considered negligible) (CEC, 2003a).

Most stationary diesel engines on dairy farms are used for remotely located irrigation pumps (L. Schwankl, UC Davis Agricultural Extension, personal communication, 5 August 2004). Local conditions such as water source (well water vs. irrigation canals), well depth, waste management requirements, acres devoted to feed crops, etc., vary significantly and have a major impact on the pumping requirements. To meet differing requirements, irrigation pump power ratings vary considerably, ranging from about 10 horsepower (hp) to beyond 100 hp (J. Melo, Melo Pumps, personal communication, 30 August 2004).

**Converting agricultural pumps to run on biogas.** Diesel-driven irrigation pumps can potentially be converted to operate directly on raw biogas, although in practice, the biogas would probably need some amount of cleaning after it is collected from the digester to reduce particulates. The effects of H<sub>2</sub>S can be mitigated by an accelerated oil change schedule. The diesel engine modifications required include replacing the fuel injectors with spark plugs, installing a natural gas ignition and carburetor system, installing different pistons to lower the compression ratio, and replacing some of the valve and valve seats. In addition, the diesel gas tank and fuel delivery system would be replaced by low-pressure biogas distribution pipes, valves, and regulators to supply biogas from the on-farm biogas storage tank to the remote irrigation pumps.

**Hypothetical demand for biogas as a fuel for irrigation applications.** Irrigation pump use is intermittent and highly seasonal and therefore would not consume biogas on a steady basis throughout the year. Also, it would probably be more cost-efficient to switch remote diesel-powered irrigation pumps to electrical power (which could be provided by a generator set using “raw” biogas as fuel) than to upgrade the biogas and transport it via pipeline to feed the remote irrigation pumps.

Despite these barriers to the direct use of biogas for agricultural pumps, we can estimate the hypothetical annual potential demand for irrigation pump fuel use on a 1,000-cow dairy based on the following requirements (J. Melo, Melo Pumps, personal communication, 30 August 2004) and using a conversion factor of 14.7 kWh/gallon of diesel (20 hp-hr/gallon of diesel) (SCAQMD, 2001):

- Number of pumps: 5
- Pump capacity: 40 hp
- Fuel usage per hour: 2 diesel gallon equivalents (DGE)

- Hours operated per year: 1,800 (this assumes an 8-month growing season with 3 months of partial irrigation and 5 months of full-time irrigation)<sup>1</sup>
- Fuel usage per year: 9,000 DGEs

Assuming that a 1,000-cow dairy will produce approximately 50,000 ft<sup>3</sup> of biogas (a cubic foot of biogas contains 600 Btu) there is 30 MM Btu of energy available daily. Since a diesel gallon contains about 140,000 Btu, the biogas from the dairy would be just over 215 DGE/day or about 78,000 DGE/year. Thus, the 9,000 DGEs required to power the average number of irrigation pumps that could be converted to direct use of upgraded biogas corresponds about 12% of the total upgraded biogas output for a 1,000-cow dairy.

### Using Biogas to Run Refrigeration Equipment

In general, refrigeration accounts for about 15% to 30% of the energy used on dairy farms (U.S. EPA, 2004). Compressors used for milk chilling are the main sources of energy consumption in the refrigeration system. Since dairy cows are milked daily, a steady source of energy is required for refrigeration needs, unlike seasonal applications such as irrigation pumps.

**Hypothetical demand for biogas as a direct fuel for refrigeration systems.** Dairies cool milk every day of the year, and compressors for refrigeration run continuously during milking operations, often 20 hours or more each day. For a 1,000-cow dairy farm, the energy requirements for these compressors are typically in the range of 30 to 40 hp (22.5 – 30 kW). However, the implementation of the chilling process (and consequently energy usage) varies greatly according to the local conditions at each farm. In particular, milk prechilling (see below) can result in a significant reduction of the power required for refrigeration compressors.

Virtually all existing refrigeration compressors on dairy farms are driven by electrical motors. While natural-gas driven motors are commercially available for the low-hp ranges associated with dairy refrigeration equipment, they are significantly more expensive than electrical motors with similar output power ranges and therefore have not been traditionally considered as economically desirable choices for this application. Thus, the use of biogas as a direct fuel for refrigeration compressors is not likely.

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<sup>1</sup> A typical irrigation cycle consists of 7 days on and 10 days off. Partial irrigation has an average duty cycle of 30% during the on portion and full irrigation has a 100% duty cycle during the on portion. This equates to approximately 100 hours/month on time during partial irrigation and 300 hours/month on time during full irrigation. Use of irrigation pumps outside the growing season is assumed to be negligible.

If we consider momentarily that such an application were feasible, we could use the following information to estimate the hypothetical annual potential demand for refrigeration compressor fuel use on a 1,000-cow dairy:

- Number of refrigeration compressors: Variable
- Compressor capacity: 40 hp
- Fuel usage per hour: 2 DGEs
- Hours operated per year: 7,300 (assuming an average duty cycle of 20 hours per day during milking cycles)
- Fuel usage per year: 14,600 DGEs

Using a conversion factor of 14.7 kWh/gallon of diesel (20 hp-hr/gallon of diesel) (Southern California Air Quality Management District, 2001), and assuming that a 1,000-cow dairy produces about 78,000 DGE/year, the potential annual fuel demand for on-farm refrigeration corresponds to less than 20% of the total annual biogas output of a 1,000-cow dairy.

**Hypothetical demand for biogas as a fuel for prechilling milk.** The temperature of dairy milk directly out of the cow is about 98° F; the milk is typically cooled to 38° F for on-farm storage. Although many dairies use well water for prechilling, chilled water or glycol can be produced from biogas-fired absorption or adsorption chillers and used in milk precoolers (these chillers could also be used for air conditioning, but the amount of use on dairy farms would be negligible). Milk cooling using absorption and adsorption chillers also presents a potential opportunity to use waste heat captured from a biogas-driven generator set. Use of this waste heat could significantly reduce the on-farm electrical refrigeration load.

Double-effect chillers, producing hot and cold water simultaneously, are available for applications over 30 tons and could be coupled with a heated digester (1 ton cooling = 12,000 Btu/h). Corrosion-resistant models are not available; therefore, biogas must be treated for water and H<sub>2</sub>S removal before it can be used to fuel absorption or adsorption chillers. Absorption chillers can be used to prechill milk, but are typically not capable of providing chilling water below 44° F, which is not sufficient for most dairy needs. Adsorption chillers can generate chilled water temperatures of 37° F and therefore are marginally capable of handling the entire cooling load without additional refrigeration equipment.

Below is a summary of the capacities, efficiencies, controls, and operating schemes for adsorption chillers that could run on upgraded biogas.

- *Available capacities:* Adsorption chillers are available at various capacities, from 1 ton of cooling per hour and up.
- *Thermal efficiencies:* Adsorption chillers deliver 50% of the biogas Btu as cooling.
- *Control systems:* Adsorption chillers come with commercial control systems.
- *Operating schemes:* Milk cooling requirements do not vary widely over the year. Neither absorption nor adsorption chillers have been widely used in dairy applications, due in part to their relatively higher costs compared to conventional cooling systems (C. Moeller, HIJC USA, personal communication, 3 September 2004).

Most chillers are smaller in capacity than the minimum output covered by air pollution regulations, although larger-scale applications would use California-approved low-NO<sub>x</sub> units. Treatment of biogas to remove H<sub>2</sub>S would eliminate potential SO<sub>2</sub> emissions.

### **Biogas as a Vehicular Fuel**

There is neither an existing demand nor a projected future demand for raw biogas as a vehicle fuel in California.

The California Air Resources Board (CARB) alternative fuels regulations include specifications for natural gas used as a vehicle fuel (ref. California Code of Regulations, title 13, section 2292.5). While the text of the regulations specifically refers to CNG fuel specifications, it can be argued that biogas should meet the same specifications as CNG for use as a vehicle fuel. The purpose of having minimum CNG fuel specifications is to ensure the compatibility of engines designed to operate on natural gas.

Table 5-1 shows that the typical composition of raw (i.e., unprocessed) biogas does not meet the minimum CNG fuel specifications. In particular, the CO<sub>2</sub> and sulfur (as contained in H<sub>2</sub>S) content in raw biogas is far too high for it to be used as vehicle fuel without additional processing. Therefore, according to current regulations, raw biogas is not an acceptable vehicle fuel in the state of California. In addition, no known vehicle engine manufacturers currently offer products rated to operate on raw biogas as a fuel.



**Table 5-1 Compressed Natural Gas Fuel Specifications vs. Typical Raw Biogas Composition**

<b>Component</b>	<b>CNG Fuel Specification <sup>a</sup></b>	<b>Raw Biogas Composition <sup>a</sup></b>
Methane (CH <sub>4</sub> )	≥ 88	65
Ethane (C <sub>2</sub> H <sub>6</sub> )	≤ 6	≤ 0.1
C <sub>3+</sub> (Propane, etc.)	≤ 3	≤ 0.1
C <sub>6+</sub> (Hexane, etc.)	≤ 0.2	≤ 0.1
Hydrogen (H <sub>2</sub> )	≤ 0.1	≤ 0.1
Carbon monoxide (CO)	≤ 0.1	≤ 0.1
Oxygen (O <sub>2</sub> )	≤ 1.0	≤ 0.1
Inert gases (CO <sub>2</sub> + N <sub>2</sub> )	1.5 – 4.5 (range)	35
Sulfur	16 ppm	50 – 2000 ppm
Dew point	≥ 10° F below 99% winter design temp <sup>b</sup>	Saturated (non-compliant)
Particulate matter	Non-damaging to engines, etc.	Variable
Odorant	Easily detectable	Detectable

<sup>a</sup> Expressed as % unless otherwise noted.

<sup>b</sup> ASHRAE, 1989 (Chapter 24, Table 1).

Beyond the regulatory impediments to using raw biogas as a vehicle fuel in California, the low methane content of raw biogas (typically 55% to 70%) combined with its inherent trace contaminants (especially H<sub>2</sub>S) can have significant negative impacts on engine performance, durability, and emissions. While the degree of impact depends on both engine control and vehicle technology (e.g., open loop vs. closed loop, heavy duty vs. light duty), raw biogas is generally considered technically unsuitable as a vehicle fuel. For these reasons, there are no known vehicle engine manufacturers planning to offer products rated to operate on raw biogas as a fuel.

### ***Summary of On-Farm Demand for Biogas***

Table 5-2 summarizes the potential annual demand for raw and upgraded biogas on a typical 1,000-cow dairy. This table includes the most common current on-farm uses for biogas—heat, and electrical power generation as well as the potential alternate uses discussed above.

Table 5-2 Potential Annual Demand for Raw and Cleaned Biogas, Typical 1,000-Cow Dairy Farm

Source/Use	Potential Annual Production		Potential Annual Consumption			
	kWh <sup>a</sup>	DGE <sup>b</sup>	kWh	Fuel (DGEs)	% of Total kWh	% of Total Fuel
1,000-cow dairy farm	912,000	78,000	---	---		---
<i>Electricity</i>						
Older 1,000-cow dairy farm <sup>c</sup>	---	---	365,000	---	40	
Modern 1,000-cow dairy farm <sup>c</sup>	---	---	803,000	---	88	
Modern 1,000-cow dairy farm with fans <sup>c</sup>	---	---	1,095,000	---	120	
<i>Irrigation pumps</i>	---	---	---	9,000		12
<i>Refrigeration</i> <sup>d</sup>	---	---	---	14,600		19
<i>Total</i>	912,000	78,000	---	23,600		31

kWh = Kilowatt hour

DGE = Diesel gallon equivalent

--- = Not applicable

<sup>a</sup> Assumes that 1,000 cows each produce 50 ft<sup>3</sup> of biogas per day which is 60% methane, and that the biogas is combusted for electrical generation at 28% efficiency.

<sup>b</sup> Assumes that 140 ft<sup>3</sup> of biomethane is equivalent to 1 gallon of diesel, which yields a fuel production capacity of approximately 215 DGEs/day.

<sup>c</sup> Derived from information from energy audits conducted for the California Energy Commission by RCM Digester, which found that older dairies typically use less energy and operate in the 1 kWh per cow per day range, modern dairies operate at 2.2 kWh per cow per day, and modern dairies with fans for cow cooling operate at 3 kWh per cow per day.

<sup>d</sup> In actuality, the likelihood of converting refrigeration units to run on biogas is extremely small (see text discussion, above). However, biogas could be used for prechilling milk. The potential annual consumption for on-farm milk prechilling was not quantified for this study.

As shown in Table 5-2, a modern 1,000-cow dairy would have an annual energy usage ranging from around 800,000 to nearly 1,100,000 kWh per year. This matches well with the potential for electrical power generation of just over 900,000 kWh per year.

Based on the assumptions given, the total potential annual fuel demand for agricultural pumps and refrigeration equipment corresponds to less than a third of the total biogas output for a 1,000-cow dairy. As stated previously, however, irrigation pumps and refrigeration equipment are not necessarily cost-effective applications for biogas. For example, irrigation loads are seasonal. Refrigeration loads are both significant and consistent however electrically-driven refrigeration compressors are less expensive than refrigeration compressors driven by natural gas engines. There may be applications for waste heat to drive adsorption chillers for milk prechilling but the technology is not likely to be cost-effective at the scale of a typical dairy farm.

As shown in Table 5-2, the greatest demand for on-farm use of biogas is for electricity generation. This need matches well with the biogas production capacity and thus, at the present time, we conclude that the most practical use of raw/slightly upgraded biogas is its continued use for on-farm electrical generation.

## **Potential On-Farm and Off-Farm Uses of Biomethane**

Biomethane is equivalent in chemical composition, and therefore in energy content, to natural gas. Equipment that can run on natural gas can run on biomethane; other equipment will have to be converted to accommodate biomethane fuel, as was explained earlier in the discussion about on-farm biogas use. Vehicles are the major category of equipment that can run on biomethane, but not on biogas.

### ***Non-Vehicular Uses of Biomethane***

Biomethane is higher quality (i.e., has a greater heating value) fuel than biogas and therefore could be substituted for biogas in all of the applications discussed above as potential or current uses of biogas.

### **Converting Agricultural Pumps to Run on Biomethane**

Natural gas engines will run directly on biomethane. Diesel fueled agricultural pumps that could be converted to run on biogas (see above) would run more efficiently on biomethane using a similar conversion process. Biomethane could be moved around a farm more easily than biogas because it is a cleaner fuel; however, it will likely still be more cost-effective to use biogas to generate electricity to run pumps than to convert the pumps to run on biomethane.

A 1,000-cow dairy that produces 50,000 ft<sup>3</sup> of biogas per year will produce about 30,000 ft<sup>3</sup> of biomethane (assuming that the biogas contains approximately 60% methane), which is equivalent to about 78,000 DGE/year. Assuming the same conditions as described above under the biogas example, biomethane-fueled agricultural pumps would, on average, consume about 12% of a 1,000-cow dairy's biomethane output.

### **Converting Refrigeration Equipment to Run on Biomethane**

The motors in electrically driven refrigeration compressors could be replaced by natural gas engines and fueled by biomethane; however, this is highly unlikely for several reasons. For example, while natural gas engines can be coupled to refrigeration compressors, they are significantly more expensive than their electric counterparts and have much higher maintenance costs. Furthermore, electricity generated from “raw” biogas via a genset is a cheaper fuel than upgraded biogas. In addition, virtually all installed refrigeration compressors today are electrically driven.

Absorption and adsorption chillers driven by waste heat can potentially be used for milk prechilling and cooling on dairy farms but such applications do not appear to be well-suited at present due to higher costs compared to conventional equipment and technical issues relating to process stability. Also, it would be just as easy to operate these prechillers using waste heat from a biogas-fueled genset as it would be to upgrade the biogas and then use it as a fuel.

In summary, there are currently no obvious economic incentives for dairy farmers to either convert electrical refrigeration equipment to operate on biomethane or to replace electrical refrigeration equipment with absorption or adsorption chillers driven by waste heat. For new farms, there may be opportunities to use the waste heat from a biogas-driven genset to drive an absorption or adsorption chiller for milk prechilling, although the overall cost-effectiveness of such a system would be highly dependent on the particular conditions for each farm. Given the current state of technology, using biogas-generated electricity to drive refrigeration compressors may be the most realistic option for using biogas to supply refrigeration loads on dairy farms in the near-term.

### ***Vehicular Uses of Biomethane***

Both CNG and LNG vehicles will run on biomethane (i.e., on methane that has been compressed to CBM or liquefied to LBM as described in Chapter 3). Although it is technically feasible to use biomethane as a fuel for alternative-fueled vehicles, there are other important considerations in determining the viability of using biomethane as a vehicular fuel (or a source for other vehicular fuels such as methane). These include current and projected markets for these vehicles, the on-farm demand for vehicle fuel, the potential for on-farm use of alternate fuels, the requirements for converting on-farm vehicles to alternate fuels, and the infrastructure required to support alternative fuel vehicles (AFVs).

### **California's Market for Compressed Natural Gas Vehicles**

The current and projected CNG vehicle markets in California are summarized in Table 5-3. (See Appendix D for information about specific CNG vehicle models on the market as of late 2004.)

Table 5-3 California Market for Compressed-Natural-Gas-Fueled Vehicles

Vehicle Type	Estimated/Projected Number of CNG Vehicles <sup>a</sup>		
	2004	2007	2010
Light duty <sup>b</sup>	15,500	17,400	19,600
Medium and heavy duty <sup>c</sup>	4,850	7,400 – 8,400	11,200 – 14,500
<i>Total</i>	20,350	24,800 – 25,800	30,800 – 34,100

<sup>a</sup> While exact figures are not available, estimates of the current CNG vehicle market size are based on information provided by the California Natural Gas Vehicle Coalition (CNGVC). These figures have been corroborated with similar estimates in the U.S. Department of Energy Energy Information Administration (DOE EIA) database and supplemented by conversations and reports from various industry sources.

<sup>b</sup> Shuttles, taxis, and municipal fleet vehicles.

<sup>c</sup> Transit buses, school buses, and refuse trucks.

According to the US Department of Energy Energy Information Administration (DOE EIA), the average annual growth rate of the CNG vehicle market in the U.S. has been 12.4% during the last decade and 9.7% during the last three years, with a relatively consistent volume of 8,000 to 12,000 new vehicles per year. (In the western region of the USA, the annual growth rate for the CNG vehicle market was 8.9% in 2002 and 10.8% in 2003.) A breakdown of the statistics for 2001 to 2003 by weight category reveals that the light-duty CNG vehicle market experienced only minor growth (3.9% in 2002 and 4.4% in 2003); however there was significant growth in the combined medium- and heavy-duty markets (20.6% in 2002 and 24.6% in 2003).

Projections for the light-duty CNG vehicle market have been based on recent historical growth rates of approximately 4%. The growth in this market is expected to be fueled primarily by increased demand for CNG shuttles and taxis, which have been successfully demonstrated as ideal applications for this technology, as well as by AFV requirements for government fleets, which are primarily light-duty. Furthermore, many California airports now have regulations and/or incentive programs (for example, SCAQMD Rule 1194, Commercial Airport Ground Access Vehicles) that either require shuttles and taxis serving the airport to use low-emissions AFVs or make it economically attractive for them to do so.

Projections for the medium- and heavy-duty CNG vehicle market are more difficult to make. This is largely because the market tends to be more dependent on the current regulatory environment, which in turn is subject to variability in the political climate (see Chapter 6 for more about the regulatory environment). New, more stringent US EPA heavy-duty truck and bus emissions standards, scheduled to be phased in between 2007 and 2010, may increase demand for medium- and heavy-duty CNG vehicles, as they are expected to result in a price increase for compliant heavy-duty diesel engines and exhaust after-treatment systems. Conversely, the emerging hybrid heavy-duty truck and bus market may have a negative impact on the corresponding segments of the CNG vehicle market.

In general, the growth in this market is expected to be fueled by continued strong demand for CNG transit buses and to a lesser extent, school buses and refuse trucks. There are several regulatory incentives for growth of these market segments:

- CARB Fleet Rule for Transit Agencies
- CARB Clean School Bus Program
- SCAQMD rules for clean transit buses, school buses, refuse trucks, and other public heavy-duty fleet vehicles.

Given the potential variability in the medium- and heavy-duty market, a range of projections has been given based on a conservative annual growth rate of 15% to 20%.

### California's Market for Liquefied Natural Gas Vehicles

The current and projected LNG vehicle markets in California are summarized in Table 5-4 below. See Appendix D for information about specific LNG vehicle models on the market as of late 2004.

Table 5-4 California Market for Liquefied-Natural-Gas-Fueled Vehicles

Vehicle Type	Estimated/Projected Number of CNG Vehicles <sup>a</sup>		
	2004	2007	2010
Light duty	Negligible	Negligible	Negligible
Medium duty	0	0	0
Heavy duty <sup>b</sup>	1,200	1,400 – 1,600	1,600 – 2,100
<i>Total</i>	1,200	1,400 – 1,600	1,600 – 2,100

<sup>a</sup> Estimates of the current LNG vehicle market size are based on information obtained from the California Natural Gas Vehicle Coalition, the South Coast Air Quality Management District, INFORM, the DOE EIA database and various additional industry sources.

<sup>b</sup> Transit buses, refuse trucks, Class 8 urban delivery.

According to the DOE EIA, the average annual growth rate of the LNG vehicle market in the U.S. has been 20.1% during the last decade and 8.4% during the last three years; however, volumes have generally been low (typically 100 to 500 vehicles per year) and there has been little consistency from year to year. (In the western region of the USA, the annual growth rate for the LNG vehicle market was 4.1% in 2002 and 12.7% in 2003.) The heavy-duty market accounts for the vast majority of the LNG vehicles in California.

Projections for the heavy-duty LNG vehicle market are subject to the same regulatory and competitive factors as the medium- and heavy-duty CNG vehicle market (see Chapters 6 and 7). In general, the growth in this market is expected to be fueled by continued niche demand for LNG transit buses, refuse trucks, and Class 8 urban delivery trucks (regional heavy delivery). One of the key factors limiting wider acceptance of LNG vehicles is the much lower availability of LNG refueling infrastructure compared to diesel and even to CNG refueling infrastructure. In addition,

all of the LNG sold in California is currently imported from LNG production facilities located in other states. Given the current limited emphasis on expanding LNG refueling infrastructure, a range of projections for the heavy-duty market has been given based on a conservative annual growth rate of 5% to 10% assuming that there continues to be a sufficient supply of LNG available in California.

### **Current and Projected Market for Methanol Vehicles**

Methanol ( $\text{CH}_3\text{OH}$ ), which is typically manufactured from natural gas feedstock, has been used as an alternative vehicle fuel. The manufacture of methanol from landfill biogas has been demonstrated and manufacturing of methanol from dairy biogas feedstock is theoretically possible (see Chapter 3).

Estimates based on DOE EIA figures show that there are still approximately 3,700 methanol-fueled vehicles in California today, more than 99% of which are light-duty vehicles. In reality, however, virtually all of these vehicles are flexible-fuel vehicles that can operate on either M85 fuel (85% methanol, 15% gasoline) or gasoline. Since there are no longer any M85 refueling facilities operating in California, it is assumed that all methanol-fueled vehicles in the state now use gasoline as their only source of vehicle fuel.

There have been no M85 fuel vehicles offered for sale by vehicle manufacturers since 1998. Naturally this has been a key contributor to the rapid decline in the availability of M85 refueling infrastructure. In addition, other alternative fuel technology such as E85 (85% ethanol, 15% gasoline) has become increasingly well established in this market. As a result, there are no M85 vehicles being planned for future production.

In summary, while there may still be an opportunity to provide methanol to a small number of vehicles in California, there is currently no methanol refueling infrastructure available. The few methanol vehicles on the road are being retired without being replaced. As a result the small potential for methanol as a vehicle fuel in California will disappear.

### **Summary of Alternative Fuel Vehicles in California**

As discussed above, CNG- and LNG-fueled vehicles are the only types of vehicles which are either currently operating or projected to be operating on methane-based vehicle fuels by 2010. This section reviews the present and forecasted markets for CNG- and LNG-fueled vehicles in California, by vehicle type, and provides estimates of the annual fuel consumption represented by these markets.

**Current and projected markets.** The current and projected natural gas vehicle markets in California are summarized in Table 5-5.

Table 5-5 Summary of California Market for Natural-Gas-Fueled Vehicles

Vehicle Fuel	2004	2007	2010
Raw Biogas <sup>a</sup>	0	0	0
CNG <sup>b</sup>	20,350	24,800 – 25,800	30,800 – 34,100
LNG <sup>c</sup>	1,200	1,400 – 1,600	1,600 – 2,100
Methanol <sup>d</sup>	0	0	0
<i>Total</i>	21,550	26,200 – 27,400	32,400 – 36,200

<sup>a</sup> Biogas does not meet California's vehicle fuel specifications (see Table 5-1).

<sup>b</sup> See Table 5-3.

<sup>c</sup> See Table 5-4.

<sup>d</sup> No M85 refueling infrastructure.

**Annual fuel consumption.** Certain types of vehicles are normally associated with high annual fuel consumption. Key factors affecting annual fuel consumption include vehicle weight, fuel efficiency, duty cycle, annual hours of operation, and annual mileage. High-fuel-usage vehicles (HFUVs) have an average annual fuel consumption of 5,000 gasoline gallon equivalents (GGEs) or more. By comparison, the remaining vehicles, referred to here as low-fuel-usage vehicles (LFUVs), typically have an average annual fuel consumption of approximately 600 GGEs. School buses, with an average annual fuel consumption of 1,000 to 2,000 GGEs, fall between these two classifications.

The combined annual market for CNG and LNG vehicle fuel in California is approximately 80 million GGEs. Table 5-6 provides estimates of the key contributors to annual CNG and LNG vehicle fuel consumption in California by vehicle type.



Table 5-6 Estimated Annual CNG and LNG Vehicle Consumption in California, 2004

Vehicle Type <sup>a</sup>	Category	No. of Vehicles <sup>b</sup>	Fuel Consumption (GGEs)	
			Vehicle <sup>c</sup>	Total
Compressed Natural Gas Vehicles				
Taxis	Light duty	2,000	6,500	13,000,000
Shuttles	Light & medium duty	2,000	6,500	13,000,000
Transit Buses	Heavy duty	3,600	10,800	39,000,000
School Buses		900	1,500	1,000,000
Refuse Trucks		350	8,600	3,000,000
<i>CNG Subtotal</i>	NA	8,850	NA	69,000,000
Liquefied Natural Gas Vehicles				
Refuse Trucks	Heavy duty	700	8,600	6,000,000
Transit Buses		400	10,800	4,000,000
Class 8 Urban Delivery		100	11,500	1,000,000
<i>LNG Subtotal</i>	NA	1,200	NA	11,000,000
<i>Total</i>				80,000,000

GGEs = Gasoline gallon equivalents (1 GGE contains 120,000 Btu and uses 120 ft<sup>3</sup> of methane gas)

CNG= Compressed natural gas

LNG = Liquefied natural gas

<sup>a</sup> Vehicle types include school buses and heavy fuel use vehicles with significant representation in the California CNG vehicle market.

<sup>b</sup> Estimated number of vehicles in California.

<sup>c</sup> Typical values

### Demand for On-Farm Alternate-Fuel Agricultural Vehicles

Agricultural vehicles include both non-road and on-road vehicles used primarily for farming operations. Examples of non-road agricultural vehicles include tractors, combines, threshers, etc. Examples of on-road agricultural vehicles include pickup trucks and medium- and heavy-duty trucks.

There are currently no commercially available CNG- or LNG-fueled non-road agricultural vehicles. There are, however, commercially available versions of some on-road agricultural vehicles such as pickup trucks. In practice, however, CNG and LNG vehicles are rarely used in on-farm applications due to the lack of convenient refueling infrastructure.

At least one demonstration project has converted several agricultural tractors to CNG fuel and measured the performance of these tractors using CNG versus traditional fuels. The results of this study indicate that CNG tractor conversions are technically feasible and that CNG tractors can meet the expected functional and performance requirements (Davies and Sulatisky, 1989). The economics of farm-tractor conversions to CNG, however, were shown to be very poor due to fuel rebates to farmers, expensive CNG conversion equipment, and the low-annual, high-peak fuel use

pattern common for farm tractors (Sulatisky and Gebhardt, 1989). On-farm pickup truck conversions to CNG, performed as part of the same demonstration project, were shown to have much more reasonable payback periods when slow-fill home compressors were used (Sulatisky and Gebhardt, 1989). Another disadvantage noted with respect to CNG-fueled tractors is that tractors are often required to operate for extended periods of time (e.g., 12 hours) during peak seasons such as harvest time; at such times, the need to stop during the workday and return to a central refueling station could be economically undesirable (M.T. Kaminski, Saskatchewan Research Council, personal communication with Brad Rutledge, 5 August 2004).

Liquefied petroleum gas is currently the most widely used type of alternative fuel for agricultural vehicles. Some of the disadvantages of CNG relative to LPG include a lack of CNG refueling infrastructure, higher CNG conversion costs and larger, heavier CNG fuel tanks (National Propane Gas Association website <<http://www.npga.org>>). As a result, there is little incentive for farmers to choose CNG over LPG.

Table 5-7 shows an estimate of the potential annual fuel demand for a typical 1,000-cow dairy broken down by vehicle type (Nathan DeBoom, Milk Producers Council, personal communication with Brad Rutledge, 30 August 2004). Based on the assumptions provided in the table, total fuel production of a 1,000-cow dairy is about 78,000 DGEs/year. For this case, the potential annual fuel demand corresponds to less than 46% of the total upgraded biogas output for a 1,000 cow dairy. However the lack of factory produced CNG or LNG farm vehicles, the cost of vehicle conversion (discussed below), the cost of storing and pumping the fuel, and the uneven pattern of usage create substantial barriers to the use of CNG (and consequently, CBG) for on-farm vehicles.

Table 5-7 Potential Annual Vehicle Fuel Demand for Typical 1,000-Cow Dairy <sup>a</sup>

Vehicle Type	No. of Vehicles	Hours Operation/Day	Fuel Usage (DGEs)	
			Per Hour	Per Year
Large Tractor	1	4	6	8,760
Med. Tractor	1	5	4	7,300
Small Tractor	1	4	2	2,920
Feeder Truck	1	6	7	15,330
Pickup Trucks <sup>b</sup>	2	2	1	1,460
<i>Total</i>				35,770

DGE = Diesel gallon equivalent

<sup>a</sup> A 1,000-cow dairy is assumed to produce 30,000 cubic feet (ft<sup>3</sup>) of biomethane or 215 DGEs per day (1 DGE = 140 ft<sup>3</sup> methane).

<sup>b</sup> Difference between gasoline gallon equivalents (GGEs) and DGEs ignored for pickup trucks.

As a check on the above estimates, in 2003 the average monthly cost for vehicle fuel and oil expenses on California dairy farms was about \$3.00 per cow (CDFA, 2003b). Based on an average non-road price of approximately \$1.00/gallon in 2003 (California Farm Bureau Federation, 2004), this implies a fuel usage of around 3 gallons/cow/month. For a 1,000-cow dairy, this translates to an annual vehicle fuel consumption of approximately 36,000 gallons.

### **Requirements for Converting Agricultural Vehicles to Run on Biomethane**

The basic technologies and equipment necessary to convert agricultural vehicles to use upgraded biogas are the same technologies and types of equipment used to convert vehicles to use compressed natural gas (CNG). The main vehicle components and subsystems requiring modification are the engine, fuel storage tanks and fuel delivery system. Conversion of vehicles to use liquefied natural gas (LNG) involves similar modifications to the same vehicle components and subsystems. Note that while retuning natural gas vehicle engines to operate on partially cleaned low-methane biogas may be theoretically possible, such engines are not commercially available and therefore the topic of converting vehicles to use low-methane biogas as fuel has not been investigated further.

Engine modifications are dependent on whether the original engine is diesel- or gasoline-driven. With respect to the types of vehicles normally found on dairy farms, tractors and trucks typically have diesel engines while pickup trucks may have diesel or gasoline engines. Diesel engines employ compression ignition to ignite fuel injected into the cylinders whereas gasoline engines employ spark-ignition. Single-fuel natural gas engines which operate purely on natural gas (the most common type) employ a spark-ignition system. In addition, there is a combination type system called a dual-fuel system where a small amount of diesel fuel is injected into the cylinder with the natural gas and acts as a pilot to ignite the natural gas via compression ignition.

Conversion of diesel engines to run on 100% natural gas (i.e., single-fuel systems) normally requires replacing the fuel injectors with spark plugs, installing a natural gas ignition and carburetor system, installing different pistons to lower the compression ratio, and replacing some of the valve and valve seats. Dual-fuel conversion systems are currently marketed by Clean Air Power in conjunction with Caterpillar diesel engines. This system requires the addition of an electronic control unit to control the relative amount and timing of natural gas vs. diesel fuel injected into a standard, Caterpillar diesel engine. The system also requires a natural gas carburetor and dual-fuel injectors. Dual-fuel conversion systems are normally associated with medium and heavy duty vehicles where performance requirements are more severe. Conversion of gasoline engines to operate on CNG is somewhat simpler since gasoline engines already employ a spark-ignition system. A natural gas mixer to control the ratio of low-pressure natural gas vs. air is the main element of the engine modification.

For single-fuel systems, the diesel tank(s) is replaced by several high pressure CNG storage cylinders. These cylinders hold biogas in compressed form at 3,000 or 3,600 psi in order to provide sufficient fuel to attain a reasonable vehicle range without refueling. The primary drawbacks associated with CNG storage cylinders are their weight, volume and cost. Dual-fuel systems require both a diesel tank and CNG storage cylinders; however, a given vehicle range can be attained with a much smaller diesel tank and somewhat reduced CNG storage requirements compared to a single-fuel system.

LNG has 3.5 times the energy density of CNG and is stored at relatively low pressure (50 to 150 psi). It therefore takes considerably less LNG storage on a vehicle to achieve the same range, resulting in lower weight, volume and cost for LNG storage systems compared to CNG. The primary drawbacks associated with LNG storage cylinders are that the LNG must be stored at very low temperatures (e.g., -260° F) and will evaporate over time due to thermal losses.

For single-fuel systems, the diesel fuel delivery system is replaced by a high pressure gas delivery system including high pressure hoses, a high pressure regulator, a low pressure regulator and miscellaneous monitoring and control devices. In dual-fuel systems, the high pressure gas delivery system is in addition to the existing diesel fuel delivery system. LNG fuel delivery systems are similar to single-fuel gas delivery systems except that the hoses and devices must be insulated for very low temperatures and, in comparison to CNG, will have to handle only relatively low pressures.

### **Infrastructure for Converting Agricultural Vehicles**

Agricultural vehicles on dairy farms usually consist of three basic types of vehicles: tractors, feeder trucks, and pickup trucks. There are currently no companies performing CNG or LNG tractor conversions in the USA. (There is, however, an existing infrastructure to perform LPG tractor conversions, which could provide a framework for the development of a CNG infrastructure.) There are also currently no (original equipment manufacturers) offering new CNG or LNG tractors for sale in the USA.

A feeder truck is usually a class 8 straight truck (a class 8 truck has a gross vehicle weight rating of between 33,000 and 150,000 lbs and a straight truck has a combined body and trailer—i.e., it is not a tractor-trailer combination) upfitted with a feeder box and a mixer. There is no existing infrastructure to convert feeder trucks to CNG or LNG; however, some of the feeder truck chassis manufacturers (e.g., Mack and Peterbilt) offer alternative fuel engine options for their class 8 truck chassis. In addition, there are similar class 8 vehicles (e.g., yard hostlers) that are available from the manufacturer fitted with LNG engines. Thus, it is theoretically possible to procure a CNG or LNG feeder truck through the feeder truck upfitter, although no dairy farmers are known to have ordered such equipment to date.

As of 2005, General Motors (GM) is the only original equipment manufacturer offering CNG-fueled pickup trucks (e.g., the Chevrolet Silverado and the GMC Sierra) in the USA. Ford previously offered CNG- and bi-fueled versions of the F-150 pickup truck, but discontinued production of all CNG vehicles at the end of 2004.

The past decade has shown a marked decrease in the demand for light-duty CNG vehicle conversions and a general trend among CNG component suppliers to align themselves with vehicle original equipment manufacturers. As shown in Table 5-8, a small number of companies in the western USA still convert vehicles to CNG; these companies could help satisfy any demand for CNG conversions of pickup trucks for dairy farms.

**Table 5-8 Companies Performing Vehicle Conversions to Compressed Natural Gas Fuel, Western USA**

<b>Company</b>	<b>Location</b>	<b>Comments</b>
Baytech Corporation	Los Altos, CA	GM vehicles only
Clean-Tech LLC	Los Angeles, CA	Primarily GM vehicles
DRV Energy, Inc.	Oklahoma City, OK	CNG & dual-fuel conversion kits

LNG pickup trucks are not available from either vehicle original equipment manufacturers or vehicle converters.

### ***Summary of On-Farm Demand for Biomethane***

Though the costs of converting all the listed farm equipment to run on biomethane would be very high, Table 5-9 summarizes the potential annual demand for biomethane on a typical 1,000-cow dairy. This table includes heat and electrical power generation as well as uses such as vehicles, agricultural pumps, and refrigeration equipment. As with biogas, however, irrigation pumps and refrigeration equipment are not likely to be cost-effective applications for biomethane. Vehicles cannot run on biogas but they can run on biomethane. However the lack of factory produced CNG or LNG farm vehicles, the cost of vehicle conversion (discussed below), the cost of storing and pumping the fuel, and the uneven pattern of usage create substantial barriers to the use of CNG (and consequently, CBG) for on-farm vehicles.

While the table shows that a typical dairy could theoretically use 76% of the biomethane it produced, the substantial barriers involved make it much more likely that the dairy would seek an external user of the fuel.

Table 5-9 Potential Annual Demand for Biomethane, Typical 1,000-Cow Dairy Farm

Source/Use	Potential Annual Production		Potential Annual Consumption			
	kWh <sup>a</sup>	DGE <sup>b</sup>	kWh	Fuel (DGEs)	% of Total kWh	% of Total Fuel
1,000-cow dairy farm	912,000	78,000	---	---		---
<i>Electricity</i>						
Older 1,000-cow dairy farm <sup>c</sup>	---	---	365,000	---	44	
Modern 1,000-cow dairy farm <sup>c</sup>	---	---	803,000	---	88	
Modern 1,000-cow dairy farm with fans <sup>c</sup>	---	---	1,095,000	---	120	
<i>Vehicles</i> <sup>d</sup>				35,770		46
<i>Irrigation pumps</i>	---	---	---	9,000		12
<i>Refrigeration</i> <sup>e</sup>	---	---	---	14,600		19
<i>Total</i>	912,000	78,000	---	59,370		76

kWh = Kilowatt hour

DGE = Diesel gallon equivalent

--- = Not applicable

<sup>a</sup> Assumes that 1,000 cows each produce 50 ft<sup>3</sup> of biogas per day which is 60% methane, and that the biogas is combusted for electrical generation at 28% efficiency.

<sup>b</sup> Assumes that 140 ft<sup>3</sup> of biomethane is equivalent to 1 gallon of diesel, which yields a fuel production capacity of approximately 215 DGEs/day.

<sup>c</sup> Derived from information from energy audits conducted for the California Energy Commission by RCM Digester, which found that older dairies typically use less energy and operate in the 1 kWh per cow per day range, modern dairies operate at 2.2 kWh per cow per day, and modern dairies with fans for cow cooling operate at 3 kWh per cow per day.

<sup>d</sup> The lack of factory produced CNG or LNG farm vehicles, the cost of vehicle conversion, the cost of storing and pumping the fuel, and the uneven pattern of usage create substantial barriers to the use of CBG for on-farm vehicles.

<sup>e</sup> In actuality, the likelihood of converting refrigeration units to run on biogas is extremely small (see text discussion, above). However, biogas could be used for prechilling milk. The potential annual consumption for on-farm milk prechilling was not quantified for this study.

## 6. Government Policies and Incentives

The successful development of a California biomethane industry will require supportive government policies and financial incentives. New renewable energy technologies are generally more costly than fossil fuels, although some—such as wind energy—have become cost competitive over time. However, renewable energy resources also provide a variety of uncompensated public benefits. For example, the use of biomethane as a replacement for fossil fuels could provide numerous benefits:

- Reduced GHG emissions
- Potential reduction in criteria air pollutant emissions
- Improved water quality through better manure management
- Less dependence on declining fossil fuel supplies
- Better energy security (through a reduced dependence on imported energy)
- Stimulation of rural economies

These are benefits to society rather than financial benefits for the farmer who produces the biomethane. Consequently, it is appropriate for the government to provide support for the development of the biomethane industry.

This chapter discusses various environmental policy drivers, some of which could be used to promote the biomethane industry. It then focuses on specific government policies and incentives in three areas related to the use of biogas and biomethane: renewable energy (electricity), alternative vehicle fuels, and alternative-fuel vehicles and examines programs that could be tapped for financial support. Finally, it discusses why public support of this industry is not only necessary, but justified.

Unfortunately biomethane does not get as much governmental support as other renewable energy sources. Most federal and state policies that support renewable energy and alternative fuels focus either on renewable electricity, often referred to as renewable energy, or on two specific liquid biofuels: ethanol and biodiesel. With a few exceptions, they do not provide specific support for biomethane production. However, vehicles that can run on biomethane fulfill alternative fuel vehicle mandates and earn alternative fuel vehicle incentives.

If the biomethane industry is to prosper, it must help launch policy initiatives that will provide the same direct financial incentives or tax credits that are now earned by programs that focus on renewable electricity, ethanol, and biodiesel.

## Policy Responses to Environmental Issues

Environmental policy has a significant effect on the design of dairy manure management systems and biogas production. The release of biogas to the atmosphere contributes to several environmental problems, notably global warming (from methane), ozone (from volatile organic compounds), and unpleasant odors. Ammonia, which is a particulate matter (PM) precursor, may also be released from undigested dairy wastes. Public policy is moving to address emissions from dairy biogas. Public agencies can respond to concerns over dairy gas emissions in the same manner that they respond to other emissions of environmental concern:

- Regulate criteria air pollutants and GHG emissions.
- Control and reduce emissions through market incentives such as a carbon trading market or an emission reduction credit (ERC) market.
- Develop and promote technologies that will help dairies or other sources voluntarily reduce their emissions. This might include subsidies to dairies to help them reduce the creation of biogas or its release into the environment.

Dairies can reduce their biogas production by changing their manure management systems to eliminate flushing and anaerobic storage (aerobically stored manure creates very little biogas). Alternatively, they can capture the naturally occurring biogas or engineer the system to enhance its production and then capture it. Once captured the biogas can be flared, combusted to generate heat or electricity, or upgraded into pipeline-quality gas (biomethane) for use in vehicles or other applications.

### **Environmental Regulation**

Federal and state policies are already in place to help regulate air quality, however, the application of these policies to agricultural activities such as dairy farming has been minimal to date. Control of vehicle emissions has become more stringent in the past decade or more, and has moved in the direction of using biofuels such as ethanol to help control emissions. The existing federal and state regulatory framework for dairy farm emissions is presented below, followed by a discussion of several proposals that are currently pending that could affect dairy emissions (and thus, indirectly, the biogas/biomethane industry). This is followed by a review of regulatory requirements related to vehicle emissions that could impact the alternative fuel industry.

#### **Regulation of Dairy Farm Emissions**

The federal Clean Air Act, codified as 42 U.S.C. 7401 *et seq.*, aims to reduce criteria air pollutants (common air pollutants that can injure human health, harm the environment, and cause property damage) (US EPA, 2002). Criteria air pollutants include NO<sub>x</sub>, PM, ozone, and other emissions. Neither VOC nor GHGs are defined as criteria air pollutants under the Act; however, VOCs are often included in lists of criteria air pollutants because efforts to control smog focus on reducing VOCs (US EPA, 2002).



Beginning in 1974, California agriculture was exempted from the Clean Air Act under state law. Several years ago, two environmental organizations sued the US EPA to pressure them into ending this exemption. The lawsuit was settled when the US EPA agreed that the exemption should end. As a result of this settlement, Governor Davis signed SB 700 on September 22, 2003. Among other things, this bill requires that dairies that meet size thresholds set by the various local air districts obtain air quality permits. Although there are 35 local air districts in California, most dairies fall within two air districts: the San Joaquin Valley Air Pollution Control District (San Joaquin Air District) and the South Coast Air Quality Management District (South Coast Air District).

Both the San Joaquin and South Coast Districts are developing suitable regulations to comply with SB 700. The San Joaquin District originally proposed that anaerobic digesters be required as a BACT for VOCs (which are also called ROG in California) for new dairies that have more than 1,954 cows (SJVAPCD, 2004). This draft BACT was withdrawn in settlement of litigation brought against the San Joaquin District by dairy producers. The South Coast District is currently reviewing the technology under its Proposed Rule 1127 (see <<http://www.aqmd.gov/rules/reg/reg11/r1127.pdf>>).

If these districts require dairies to install anaerobic digesters to control emissions, the commercial production of biogas in anaerobic digesters could receive a needed boost. However, another recent California law, SB 1298, recommends that local air districts require distributed electrical generators to meet central station power plant standards for criteria air emissions by 2007 (CARB, 2002, p. 4). Using current technology, dairy operations that use biogas to generate electricity in internal combustion engines will not be able to meet the 2007 recommended central station power plant standard for NO<sub>x</sub>, which is 0.07 lb/MWh or about 1 ppm NO<sub>x</sub>.

To deal with this, the South Coast and San Joaquin Districts have proposed a more lenient standard for agricultural engines and waste gas engines. For example, in recently adopted Rule 4702 <[http://www.valleyair.org/rules/currentrules/Rule\\_4702\\_0605.pdf](http://www.valleyair.org/rules/currentrules/Rule_4702_0605.pdf)>, the San Joaquin District established an emission standard of 90 ppm NO<sub>x</sub> for rich-burn spark-ignited agricultural engines such as dairy generators; current dairy digester engines are to be retrofitted by 2008. Waste gas engines are limited to 50 ppm NO<sub>x</sub>. Although these standards are much more lenient than the central station standard, even this level of emissions will be costly to meet.

Technical solutions that will enable dairies with anaerobic digesters to meet the 90 ppm NO<sub>x</sub> standard likely exist, though none has yet been demonstrated to run successfully over time at an actual dairy digester site. If air districts adopt the SB 1298 recommendations, dairies may find themselves forced to collect biogas but unable to combust it to produce electricity, as combustion would produce NO<sub>x</sub> in excess of the new standard. In this situation, it may be more advantageous for dairies to collect the biogas and flare it using a low NO<sub>x</sub> flare or upgrade it to biomethane and use it as a substitute for natural gas. Flaring produces less NO<sub>x</sub> than combustion in an IC engine

because it occurs at a lower temperature, but it may still produce more than the 5 ppm NO<sub>x</sub> recommended in the CARB 2007 standard. Biomethane could also be combusted in a microturbine to generate electricity.

Currently there is no regulation of GHG emissions that would affect a dairy anaerobic digester. If such regulation came into force, however, it could provide an additional incentive for the commercial production of dairy biogas or biomethane as an energy source. Greenhouse gas regulations could force dairies to collect and combust their methane emissions. If those costs were already required, the additional cost to generate electricity or create biomethane might be low enough to make energy production worthwhile.

### **Regulation of Vehicle Fuel Emissions**

The Clean Air Act Amendments of 1990 requires gasoline in areas with unhealthy levels of air pollution to contain fuel oxygenates, cleaner burning additives that reduce carbon monoxide emissions. Both ethanol and MTBE are acceptable oxygenates. The oxygenated fuels program began in 1992 and required oxygenates during cold months (winter) in cities that had high levels of carbon monoxide (a criteria pollutant). Most cities that needed to address carbon monoxide in winter used ethanol. In 1995, cities with the worst ozone problems were required to add oxygenates; most chose MTBE. California adopted more stringent gasoline requirements.

Soon, MTBE emerged as a water quality problem. The phase-out of MTBE began in California in 1999 and was pursued by the federal government in 2000. Ethanol has replaced it. While CARB contends that California's reformulated gasoline (RFG3) provides all the air quality benefits of oxygenated gasoline, the US EPA still requires oxygenation of California gasoline in non-attainment regions such as the Central Valley and the South Coast: gasoline in these regions is required to contain at least 2% oxygen by weight. California completed its phase-out of MTBE in 2003 and is now adding ethanol to fuel to meet the oxygenation requirement. Typically, an ethanol content of about 6% is needed (CEC, 2003b, p. 27-28). About 80% of California's gasoline now contains ethanol.

### **Market-Based Incentives for Emission Control**

The regulatory approach, often called the "command-and-control approach," to pollution reduction has been criticized in recent years for various reasons. According to Robert Crandall of the Brookings Institution (2002), one problem is that regulatory agencies may not always get it right—they may decide to control the wrong substances or control some discharges too strictly and others not enough. Also, pollution regulation can make the cost of goods more expensive and, because controls are typically stricter for new sources than for older existing ones, can discourage the building of new, more efficient facilities. Finally, regulations can be difficult to enforce and do not encourage compliance beyond what is mandated. As a result of these problems,

policymakers have begun to include market-based incentives as a means to reduce pollution (Crandall, 2002).

There are two basic types of market incentives: pollution fees and emissions trading. Pollution fees, commonly used in Europe but not in the USA, are taxes that penalize polluters in proportion to the amount they pollute. Emissions permits, allowed by the 1990 Clean Air Act, enable polluters to trade “permits to pollute” so that they can meet the overall control levels set by regulatory authorities. Two types of emission trading permits could impact the biogas/biomethane industry in the USA: carbon trading and ERCs.

Regulatory initiatives affect both carbon trading and emission reduction markets. If ERCs are required under SB 1298 and by local air district regulations, as described above, those reduced emissions would not be tradable on the carbon or emission reduction credit markets.

### **Carbon Trading**

As of early April 2005, the proposed Kyoto Treaty was ratified, accepted, or acceded by 148 nations; the USA is one of six signatory nations that have not ratified the treaty ([http://unfccc.int/files/essential\\_background/kyoto\\_protocol/application/pdf/kpstats.pdf](http://unfccc.int/files/essential_background/kyoto_protocol/application/pdf/kpstats.pdf)). The Kyoto Treaty requires signatory countries that ratify the treaty to reduce GHG emissions. In response to the treaty, a market for reduced carbon emissions, commonly called the Carbon Market, has emerged. Under this cap and trade system, firms that are required to reduce their GHG emissions can either control their own emissions or buy reductions from other firms that have been able to reduce emissions at a lower cost.

If the USA were to ratify the Kyoto Treaty, dairy digesters within the country would be well-suited to trade carbon credits. As explained in Chapter 2, the collection and combustion of pre-existing methane destroys the methane while producing a similar amount of carbon dioxide as by-product. Since methane has 21 times the global warming potential, by weight, of carbon dioxide, dairies that combust methane which would otherwise be released into the atmosphere would gain a substantial number of carbon credits.

Because the Carbon Market is undeveloped in the United States, each trade is largely a pioneering effort, and transaction costs are very high. At present, even if a dairy could arrange a carbon trade, it could not begin to recover the transaction costs involved. However, if the USA signs the Kyoto Treaty, or if the Carbon Market develops for other reasons, dairies might be provided with an incentive to collect and use more biogas.

### **Emission Reduction Markets**

California has a market in place for ERCs. New sources of criteria air emissions are required to mitigate emissions by purchasing ERCs from other pollution sources that have already managed to reduce emissions. As currently structured, this market does not allow agricultural enterprises to

participate effectively; however, if such participation were possible, dairies might be provided with an incentive to collect biogas, thus reducing VOC emissions and gaining ERCs. However, the problem of NO<sub>x</sub> emissions from biogas combustion might prove to be an expense on the ERC market. Depending on the relative volume and prices of these two pollutants (VOC vs. NO<sub>x</sub>) a dairy might show net credits or debits on the ERC market. This, in turn, would affect the dairy's interest in pursuing biogas production for electricity or biogas production for non-electrical energy.

### ***Promotion of Environmentally Beneficial Technologies***

In addition to regulation and the promotion of market-based incentives, governments can encourage the development and use of new technologies that provide environmental benefits while meeting demand. There are several approaches that can help encourage new technologies: tax credits or incentives, subsidies through direct funds, and long-term contracts that guarantee market and/or price. For example, in response to concerns about the contribution of methane to climate change, the US EPA set up the AgSTAR program (see <<http://www.epa.gov/agstar/>>) to develop and disseminate information about anaerobic digesters for animal waste. AgSTAR funds research and has sponsored at least one national conference. The California Energy Commission (CEC) has also funded research, through its Public Interest Energy Research (PIER) program on anaerobic digestion for electrical production. The CEC views anaerobic digesters on dairies as a potential source of relatively clean renewable energy. The continued expansion and success of these federal and state efforts will promote the production of commercial dairy biogas.

## **Government Policies and Incentives for Renewable Energy**

The interest in renewable energy in the USA dates from the Arab oil embargo of 1973 and the oil price shock of 1979 that was triggered by the fall of the Shah of Iran. By the late 1970s energy conservation, renewable electricity and alternative fuels were focal points for public policy. The Public Utility Regulatory Policy Act (PURPA) of 1978 began Federal support for renewable electricity and distributed electrical generation. In the same year, the Energy Tax Act initiated support for alternative vehicle fuels (see discussion later in this chapter).

Much federal policy and most renewable energy policy at the state level is directed toward the development of renewable electricity generation from wind, solar, geothermal, and small hydropower sources, as well as from biomass. The following discussion focuses on support for the latter, as it is most pertinent to biogas and biomethane production.

### ***Federal Support for Biomass Energy Sources***

Federal support for the production of energy (primarily electricity) from biomass comes primarily from two pieces of legislation: the Biomass Research and Development Act (BRDA) of 2000 and the Farm Security and Rural Investment Act (Farm Bill) of 2002.

## **Biomass Research and Development Act**

The Biomass Research and Development Act of 2000 (BRDA) (Public Law 106-224, as amended through Public Law 108-199 of 2004) committed the federal government to the development of biobased industrial products including fuel, electricity, and heat from biomass. In addition, it established a Biomass Research and Development Board, a Technical Advisory Committee, and a Biomass Research and Development Initiative.

In 2002, the Technical Advisory Committee published a “vision” that calls for biobased transportation fuels. Currently, biobased fuels make up 0.5% of U.S. transportation fuel consumption; BRDA requires this to increase to 4% in 2010, 10% in 2020, and 20% in 2030 (BTAC, 2002, p. 9). Although this vision calls for biobased transportation fuels to increase much more dramatically than biopower (electricity and heat), the accompanying “roadmap” references anaerobic digestion as a source of biopower (electricity and heat). The roadmap does not mention anaerobic digestion as a source of transportation fuel, which it could be if the produced biogas were upgraded to biomethane.

Section 307 of BRDA launched a Biomass Research and Development Initiative. The research is aimed at understanding the conversion of biomass into biobased industrial products such as fuel and electricity, developing new cost-effective technologies to promote commercial production, ensuring that economic viability and environmental benefits of biobased products, and promoting the development and use of agricultural energy crops. Eligible grantees include universities, national laboratories, federal or state research agencies, and private or nonprofit organizations. Grants are awarded competitively. The Farm Bill of 2002 (Title IX, Section 9010), discussed below, appropriated funds for the program and extended its term from 2005 to 2007.

## **Farm Security and Rural Investment Act Of 2002**

The Farm Security and Rural Investment Act of 2002 (Farm Bill) contains a variety of loan and grant programs that support the development of a renewable methane industry from dairy biogas (see USDA Farm Bill website at <<http://www.usda.gov/farmbill/>>). These programs are discussed in three sections of the bill: Title II, Conservation; Title VI, Rural Development; and Title IX, Energy. Some of the most promising sections in Title IX are either unfunded or have been defined in such a way as to exclude renewable methane.

**Programs Authorized Under Farm Bill Title II, Conservation.** The following programs have been authorized under Title II of the Farm Bill.

*Environmental Quality Incentives Program.* The Farm Act of 1996 established the Environmental Quality Incentives Program (EQIP) and Title II, Subtitle D of the 2002 Farm Bill extends this program. The objective of EQIP is to encourage farmers and ranchers to adopt on-farm environmental conservation improvements through the use of five- to ten-year contracts. Eligible improvements include those related to improved soil, water, and air quality, and the program

provides education, technical assistance, cost-share payments, and incentive payments. Because anaerobic digesters that produce biogas (and lead to its subsequent capture and combustion or flaring) provide air and water quality improvements, they are eligible for this program, and have been funded.

Contracts signed under EQIP must be effective for no less than one and no more than ten years. Applications are accepted on a continuous basis. Generally, EQIP payments are limited to 75% of the cost of a project, though in some cases they may cover up to 90%. Payments for an individual farm are limited to a total of \$450,000 in the fiscal year (FY) 2002-to-2007 period. Sixty percent of the funds under the EQIP program target livestock production; there is no cap per animal unit. Livestock operations are required to develop a comprehensive nutrient management plan.

The program is funded through the Commodity Credit Corporation and is mandated at \$1.0 billion in FY 2004, \$1.2 billion each in FY 2005 and 2006, and \$1.3 billion in FY 2007. Since EQIP began in 1997, the USDA has entered into over 100,000 contracts with farmers, covering more than 50 million acres.

*Conservation Innovation Grants.* The Conservation Innovation Grants program (Section 1240H) provides support to government and nonprofit activities that aim to stimulate innovative approaches to environmental enhancement. Funds can be used to carry out projects that involve EQIP-eligible farmers, but CIG funds are limited to 50% of the total cost of the project. In FY 2003, \$15 million was made available under this program (USDA, 2004b).

**Programs Authorized Under Farm Bill Title VI, Rural Development.** Section 6013 expanded eligible loan programs under Title VI to specifically include anaerobic digesters as a renewable energy source. No specific funds were earmarked for this technology.

Section 6401 provides funds that can be used for planning grants or for working capital through Value Added Agricultural Product Market Development Grants. The language in this section specifically includes farm- or ranch-based renewable energy as an eligible product. In FY 2003, \$28 million in grants were awarded under this section (USDA, 2004b). In FY 2004, \$13 million has been appropriated. This report was funded by a VAPG grant.

**Programs Authorized Under Farm Bill Title IX, Energy.** A number of programs related to biobased energy production are funded under this title, but few include biomethane as a fuel source. Nevertheless, some of the programs discussed below could be expanded to include funding for biogas/biomethane production.

*Federal Procurement of Biobased Products.* Section 9002 of Title IX provides for a federal procurement preference for biobased products; a proposed rule for this program was published in December 2003 (Federal Register Vol. 68, No. 244, December 19, 2003, page 70730). The proposed rule is geared to support new markets for biobased products—both the legislation and

the proposed rule exclude motor vehicle fuels and electricity. There is, however, a category for fuel additives that could be used for vehicles, heating (of buildings), and other similar uses. This category includes both liquid biobased fuels, specifically ethanol and biodiesel, and solid fuels (Federal Register Vol. 68, No. 244, December 19, 2003, page 70738). During a public meeting about the proposed rule held on January 29, 2004, a USDA spokesperson stated that alternative fuels such as ethanol (E100), ethanol 85% (E85), biodiesel (B100) and biodiesel 20% (B20) are ineligible for funding through this program, but mentioned that fuel additives such as ethanol 10% (E10) or biodiesel 2% (B2) are eligible. The spokesperson did not characterize the intermediate cases (USDA, 2004a, p. 41).

Even though compressed biomethane is gaseous and the proposed rules do not mention gaseous fuels, it is unlikely that biomethane, when added to CNG, would be considered a “fuel additive.”

*Biorefinery Development Grants.* Section 9003 of Title IX assists in the development of new and emerging biomass technologies, and specifically includes transportation fuels. A biorefinery is defined as a process that converts biomass into fuels and chemicals. The Biorefinery Development Grants pay for the development and construction of biorefineries that demonstrate commercial feasibility of a process. Grants cannot exceed 30% of the cost of the project. No federal funds have been appropriated for this section.

*Biodiesel Fuel Education Program.* Nearly \$1 million in grants were issued in 2003 for the Section 9004 biodiesel fuel education program; this program, however, is not relevant to biomethane.

*Energy Audit and Renewable Energy Development Program.* Section 9005 of Title IX authorizes a competitive grant program for entities to administer energy audits and renewable energy development assessments for farmers, ranchers, and rural small businesses. No federal funds have been appropriated for this section.

*Renewable Energy Systems and Energy Efficiency Improvements.* A loan, loan guarantee, and grant program to assist eligible farmers, ranchers, and rural small businesses in purchasing renewable energy systems and making energy efficiency improvements is authorized under Section 9006 of Title IX. In FY 2003, \$22 million in grants was awarded under this program, and \$23 million is appropriated for FY 2004 grants. Grants alone cannot exceed 25% of the cost of the project and grants and loans made or guaranteed are not to exceed 50% of the cost. Renewable energy grants are limited to \$500,000. Financial need must be demonstrated.

*Hydrogen and Fuel Cell Technologies.* Section 9007 of Title IX instructed the USDA and the US DOE to develop a memorandum of understanding on cooperation among rural communities and agricultural interests relative to hydrogen and fuel cells. Biomethane is a potential feedstock for fuel cell hydrogen (see Chapter 3).

*Biomass Research and Development.* Section 9008 of Title IX extends the termination date of BRDA to September 30, 2007 and funds the BRDA Section 307 research and development initiative with \$75 million for the period FY 2002 to 2007. In FY 2003, \$16 million of USDA funds under this provision were combined with \$5 million from US DOE to fund a joint solicitation; actual awards totaled \$22 million. In FY 2004, \$25 million was awarded to 22 projects, with \$13 million contributed by USDA and \$12 million from the US DOE. Recipients of funds must share 20% of the costs under this program.

*Cooperative Research and Development.* Although Title IX, Section 9009 provides discretionary authority for competitive grants to research carbon fluxes and GHG issues, it is not relevant to biomethane.

*Continuation of Bioenergy Program.* Section 9010 of Title IX provides producer payments for increased production of bioenergy. This provision was funded in the legislation at \$150 million annually from FY 2002 to FY 2006; nearly \$150 million was awarded in 2003. However, as stated in this section of the Farm Bill, “‘bioenergy’ means biodiesel and fuel grade ethanol.” Thus, producers of biomethane are not eligible for payments under this program.

### **Energy Policy Act Of 2005**

Many provisions of the Energy Policy Act of 2005 support biomass energy. At the time of final editing, the bill has just been signed; an analysis of its provisions will not be undertaken in this study. The energy bill should be carefully reviewed to determine its possible impact on biogas and biomethane production.

### **California Renewable Energy Programs**

California has a major commitment to renewable energy, including renewable electricity from biomass. The Public Interest Energy Research (PIER) program, which focuses on electricity, has been funded by ratepayers for nearly ten years. The new California Natural Gas Research and Development Program, described below, provides funds for research and development of natural gas, including renewable natural gas. A number of state programs specifically target renewable energy (primarily electricity); these include the Renewable Portfolio Standard, the Self Generation Incentive Program, and the New Renewables Program. If biogas production is used to generate electricity it could qualify for several of these programs, as discussed below. When biogas or biomethane is used as a gaseous fuel for transportation, heat, or similar uses, however, it is ineligible for these funds.

### **Natural Gas Research and Development Program**

In 2000, California’s Governor signed Assembly Bill (AB) 1002, which created a surcharge on natural gas consumption to fund public-purpose activities. These activities included public interest research and development as authorized by California Public Utility Code Section 740,



which describes electrical and gas research and development and specifically lists “environmental improvement” and “development of new resources and processes, particularly renewable resources” as project objectives. AB 1002 did not propose a specific funding amount.

On August 19, 2004 the California Public Utility Commission (CPUC) released Decision 04-08-010, which established the CEC as the administrator of the research and development program and allowed the CEC to make funding decisions. The funding cap was \$12 million annually, starting on January 1, 2005; this will increase by \$3 million each year through 2009. The maximum cap approved is \$24 million, at which time the CPUC will reexamine the funding cap (CPUC, Rulemaking 02-10-001, Decision D0408010, p. 38. See <[http://www.cpuc.ca.gov/word\\_pdf/FINAL\\_DECISION/39314.pdf](http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/39314.pdf)>). Prior to this decision, research was administered by the investor-owned utilities at a statewide level of \$4.5 million per year.

Natural gas generally refers to a fossil fuel, but biogas is also a gas, and is also natural. For example, Pacific Gas and Electric’s Gas Rule 1, a document approved by the CPUC, specifically defines natural gas to include “gas obtained from biomass or landfill” (Pacific Gas and Electric, Gas Rule 1 Definitions).

The CEC has submitted a report to the CPUC that outlines a research plan to be funded through this program, which will be called the Public Interest Natural Gas Energy Research Program (PING); the report specifically mentions “renewable natural gas” as one component of the plan. The inclusion of this language was the result of information submitted by one of the authors of this report. In the same way, supporters of biomethane should work to expand programs intended to promote or research natural gas or alternative vehicles fuels to include biomethane.

### **Financial Incentives for Anaerobic Digesters**

The development of new energy resources, particularly renewable energy resources, typically is supported by federal and state grant programs or tax policies because the environmental benefits from these technologies serve the public good. Anaerobic digesters for electrical generation have received both federal and state subsidies, but these funds are usually not available if the biogas is not used to generate electricity. For example, a program authorized under California’s SB 5X provided \$15 million to support the building of manure digesters for electrical generation, of which \$10 million was directed to on-farm dairy digesters. The program covered up to 50% of the capital costs of the dairy digester, but is now closed to new applicants.

### **Financial Incentives for Renewable Electricity**

The Self Generation Incentive Program, authorized by California AB 970, provides incentives to customers who generate their own clean grid-connected electricity. The program has recently changed. Electrical generators that run on renewable fuel such as biogas can earn a capital grant of \$1.00/watt of installed capacity with no limit as to what proportion of the engine cost is covered. These funds will cover the engine-generator and related items, but not the anaerobic digester itself.

The Renewable Resources Trust Fund provides more than \$1 billion per year for the Existing Renewable Program, the New Renewables Program, and the Emerging Renewables Program. The Existing Renewables and the New Renewables Programs provide incentive payments per kWh for renewable generation, including biomass and biogas. The Emerging Renewables Program does not fund biomass to electricity unless the produced biogas is used in a fuel cell.

California is committed to increasing its use of renewable electricity generation. The Renewable Portfolio Standard, established by SB 1078, mandates the three California investor-owned utilities to increase their use of renewable energy to 20% by 2017 (see <[http://info.sen.ca.gov/pub/01-02/bill/sen/sb\\_1051-1100/sb\\_1078\\_bill\\_20020912\\_chaptered.pdf](http://info.sen.ca.gov/pub/01-02/bill/sen/sb_1051-1100/sb_1078_bill_20020912_chaptered.pdf)>). The Sacramento Municipal Utility District has made a similar commitment, and Los Angeles Department of Water and Power may do the same.

### **Net Metering For Solar, Wind, and Dairy Biogas Sources of Electricity**

*Net metering* is available for wind and solar electrical generation under AB 58, which allows a self-generator to credit electricity exports against imports. Thus, solar or wind self-generators can eliminate their electrical bills. Dairy biogas has net metering for self-generated electricity under AB 2228, but credits can be applied only to the generation charge, which is only one component of the electricity bill. Net metering for dairies will sunset in January 2006, if proposed new legislation (AB 728) is not approved.

### **Renewable Electricity Research and Development**

California's electricity ratepayers provide \$62 million per year to fund the Public Interest Energy Research (PIER) program, which is administered by the CEC. The PIER program focuses on electricity. Two of the six PIER research and development areas are renewable electricity and the environmental effects of electrical generation. The PIER renewable energy program has funded research on anaerobic digester technology for electricity generation as well as other biomass-to-electricity technologies.

## **Government Policies and Incentives for Alternative Fuels**

Many government policies and incentives that promote the use of natural gas fuels such as CNG and LNG will also serve to promote the adoption and use of biomethane as a vehicle fuel. A number of programs, both at the state and federal levels, are currently in place for this purpose.

Still, the incentives for biomethane use in vehicles are weak overall. A number of California provisions that provided financial incentives for natural gas vehicle usage have recently expired and show no signs of being revived. Other incentives and programs focus on small portions of the automotive market and/or do not contain significant amounts of funding.

### **Federal Policies and Incentives for Alternative Fuels**

Today, much of the focus of federal renewable energy policies and incentives is on two liquid biomass transportation fuels that have large farm state constituencies: ethanol and biodiesel. For example, the Bioenergy Program outlined in the 2002 Farm Bill (Section 9010) provides \$150 million annually to producers of “bioenergy,” which is defined as ethanol and biodiesel. Biomethane is not included in the definition of bioenergy.

Ethanol is predominantly derived from corn, and biodiesel predominantly from soybeans. Both are major crops in the Midwest and have received substantial political support from farm state senators from both parties. There has been a 25-year history of federal support to the ethanol industry, while support for biodiesel is more recent.

Federal support for ethanol dates from 1978 when the Energy Tax Act (P.L. 95-618) provided an exemption to the federal fuel excise tax on gasoline for fuel blended with at least 10 percent ethanol (E10). In 1980, domestic fuel development was promoted in the Energy Security Act of 1980 (P.L. 96-294). The Surface Transportation Assistance Act of 1982 (P.L. 97-424) raised the federal excise tax to \$0.09/gallon and also raised the ethanol exemption to \$0.05/gallon for gasoline fuel that contains E10. The ethanol exemption was raised to \$0.06/gallon in 1984, but then lowered to \$0.054 in 1990 and extended to 2000 (CEC, 2004, p. 6). The Transportation Equity Act for the Twenty First Century of 1998 (TEA-21) (P.L. 105-78) extended the ethanol exemption to 2007, and lowered it to \$0.053 in calendar years 2001 and 2002, to \$0.052 in calendar years 2003 and 2004, and to \$0.051 in calendar years 2005, 2006, and 2007 (Surface Transportation Revenue Act of 1998, Section 9003). Since the incentive is for a gallon of fuel that is 10% ethanol, the current exemption (\$0.051) is effectively \$0.51 per gallon of ethanol used. In addition, an exemption of \$0.04 is allowed for fuel that contains 7.7% ethanol, and \$0.0296 for fuel that contains 5.7% ethanol (CFDC, 2003, p. 24).

The Omnibus Reconciliation Tax Act of 1980 (P.L. 96-499) placed a tariff on imported ethanol; the tariff is currently \$0.54/gallon. The Omnibus Budget Reconciliation Act of 1990 (P.L. 101-508) enacted a small ethanol producer tax credit of \$0.10/gallon

As summed up by the CEC, “The federal ethanol fuel incentives...are generally acknowledged as the driving force for ethanol production and use in the U.S.....This incentive (or subsidy) has made ethanol competitive with gasoline....Without this long-standing federal energy policy it is highly unlikely that ethanol production and use in the U.S. would have reached its current level....And the tariff on most imported ethanol protects domestic producers against a large share of the U.S. ethanol fuel market being captured by lower-cost foreign producers” (CEC, 2004, p.7). Since 1979, U.S. ethanol production has grown from 10 million to 3,000 million gallons per year.

Table 6-1 summarizes existing federal government policies and incentives that could help spur the use of biomethane use in vehicles and shows their relative ranking in this regard. In addition to the policies established by the Farm Bill, there are two major programs, discussed below.

**Table 6-1 Federal Policies and Programs that Encourage Alternative Fuels, Ranked According to Presumed Impact on Growth of Biomethane Industry**

<b>Policy/Program</b>	<b>Value for Biomethane Industry</b>	<b>Explanation</b>
Energy Policy Act of 2005 (proposed)	High Potential Value	Includes incentives for renewable vehicular fuels including a requirement to increase the use of renewable fuels, including those produced from biomass, in the U.S. motor fuel supply and another that promotes renewable electricity generated from bovine and swine waste.
2002 Farm Bill: Biorefinery Development Grants	High Potential Value	Grants specifically targeting the development of new and emerging biomass transportation fuels.
State Energy Program (SEP)	Medium	Provides direct funding for renewable energy, including biogas, but funding level is low.
Pollution Prevention Grants Program	Low	Supports innovative pollution prevention programs. Wide range of technologies and fuels qualify. No specific incentive for renewable methane.

High = Provides substantial incentives for both natural gas vehicle use and biomethane production.

Medium = Provides adequate incentives for natural gas vehicle use or biomethane production, but not for both.

Low = Provides inadequate incentives for natural gas vehicle use or biomethane production.

### **State Energy Program**

The State Energy Program (SEP) provides US DOE funding for renewable energy and energy-efficient technologies. About \$5,000,000 is available for alternative fuels: nearly \$300,000 for bioenergy and biobased projects and fuels, and over \$525,000 for biomass power.

### **Pollution Prevention Grants Program**

This federal program supports the establishment and expansion of state pollution prevention programs and addresses various topics of concern such as energy, transportation, industrial toxins, and agriculture. Funds available under this grant/cooperative agreement are awarded to support innovative pollution prevention programs that address the transfer of potentially harmful pollutants across all media: air, land, and water. State agencies are required to contribute at least 50% of the total cost of their projects.

## **California Alternative Fuel Programs**

In the early 1980s, California created incentives for ethanol fuel including a state excise tax reduction of \$0.03/gallon for 10% ethanol blends (the excise tax was \$0.07/gallon). This incentive was in place from 1981 to 1984. In 1988, SB 2637 established a \$0.40/gallon incentive for liquid fuels fermented in state from biomass, but this initiative was never funded (California Public Resources Code, Section 25678). In contrast to 22 other states that have ethanol incentive programs, California does not currently have tax incentives in place for ethanol (CEC, 2004, p. 3-4), nor does it have any financial incentives or tax credits for the use of biodiesel, unlike a number of other states (US DOE, 2004).

Table 6-2 ranks California policies and programs that provide incentives for using alternative fuels. Details of the various programs are discussed below.

### **Excise Tax Options**

The excise tax imposed upon CNG, LNG, and LPG as vehicle fuels can be paid through an annual flat-fee rate sticker tax based on vehicle weight. Conversely, owners and operators may pay excise tax on CNG of \$0.07 per 100 ft<sup>3</sup>, on LNG of \$0.06 per LNG gallon (California Revenue and Taxation Code Section 8651.6), and on LPG of \$0.06 per LPG gallon (California Revenue and Taxation Code Section 8651.5). Excise taxes on ethanol and methanol containing not more than 15% gasoline or diesel fuel are \$0.09 per gallon (California Revenue and Taxation Code Section 8651, and Section 8651.8).

### **California Natural Gas Research and Development Program**

As discussed earlier in this chapter, on August 19, 2004 the CPUC released Decision 04-08-010, its final rule under Rulemaking 02-10-001 implementing AB 1002. This bill uses a surcharge to significantly increase natural gas research and development, including “development of new resources and processes, particularly renewable resources,” in California. Beginning on January 1, 2005, the program funding increased from \$4.5 million to \$12 million; by the fourth year, funding will be ramped up to \$24 million.

**Table 6-2 California Policies and Programs that Encourage Alternative Fuels, Ranked According to Presumed Impact on Growth of Biomethane Industry**

<b>Policy/Program</b>	<b>Value for Biomethane Industry</b>	<b>Explanation</b>
Excise Tax Options	Low	Flexibility for payment (flat fee or per quantity of fuel) of natural gas excise tax. Very low natural gas vehicle incentive. No specific incentive for renewable methane.
California Natural Gas Research and Development Program	Medium	Significantly increases funding for natural gas R&D. Renewable sources are mentioned, but are not allocated a specified portion of the funding.
Public Transit Bus Rule	Medium	Fleets can choose alternative fuels or clean diesel technologies to satisfy these requirements. No specific incentive for biomethane.
California Assembly Bill 2076	Medium Potential Value	Focus on GTL, natural gas, and increasing alternative fuel use could marginally stimulate biomethane industry.
State Fleet Energy Consumption Reduction Goal	Low	Natural gas vehicles can qualify towards the goal of reduced energy consumption, but so can efficient and low-polluting gasoline vehicles. No specific incentive for biomethane.

GHG = Greenhouse gases.

GTL = Gas-to-liquid, such as the Fischer Tropsch process.

High = Provides substantial incentives for both natural gas vehicle use and biomethane production.

Medium = Provides adequate incentives for natural gas vehicle use or biomethane production, but not for both.

Low = Provides inadequate incentives for natural gas vehicle use or biomethane production.

### **New Emission Standards for Public Transit Buses**

A public transit bus rule adopted by CARB in February 2000 regulates public transit fleets and sets emission reduction standards for new urban transit buses (California Code of Regulations [CCR], Section 1956.1, Title 13). The rule allows transit fleets to choose one of two options in order to reduce their emissions to the required levels: using low-sulfur diesel or using alternative fuels, such as natural gas. As enforcement of the 2007 and 2010 urban bus emission standards approaches, diesel systems become more complicated, and thus more expensive. Consequently, the cost differential between alternative fuel natural gas systems and diesel systems will decrease and alternative fuel may become an increasingly attractive option. To date, however, approximately two-thirds of California transit agencies have chosen to use low-sulfur diesel to meet the required emission levels.

### **Reduced Automotive Greenhouse Gas Emissions**

Assembly Bill 1493, which was passed in 2002, was the first piece of legislation in the world to mandate reductions in automotive GHG emissions. The bill focuses exclusively on the vehicle side of the equation (i.e., tailpipe emissions of GHG). The bill required the CARB to study the cost effectiveness of various technologies to reduce GHG emissions from autos, including the use

of alternative fuels. While natural gas is a lower GHG-emitting fuel the CARB concluded that changes in gasoline engine technologies were more cost effective than alternative use vehicles (see <<http://www.arb.ca.gov/cc/042004workshop/final-draft-4-17-04.pdf>>).

### **Reduced Petroleum Dependence**

Passed in 2000, AB 2076 instructs CARB and the CEC to develop and adopt recommendations for the governor and the legislature about a California strategy to reduce petroleum dependence. In response, CARB and the CEC produced a report that proposed and recommended a strategy to reduce California's demand for on-road gasoline and diesel to 15 percent below the 2003 demand level by 2020, and to maintain that level for the foreseeable future. As part of this strategy, the report identified mid-term options, which could be fully implemented in the 2010 to 2020 timeframe that highlighted natural gas in two ways. First, the report prominently suggested the use of natural gas-derived Fischer-Tropsch fuel as a 33 percent blending agent in diesel to reduce petroleum usage by 6 to 7 percent. Second, although not as prominently, it mentions that the expanded use of LNG and CNG in heavy-duty vehicles appears attractive and could provide reductions in petroleum usage at a net societal benefit.

In addition to recommending a reduction in the state's demand for petroleum, the CARB and CEC report also recommended that, regardless of how petroleum reduction is achieved, a minimum percentage of the fuel used in California should come from non-petroleum sources. It recommends that the governor and legislature establish a goal to increase the use of non-petroleum fuels to 20 percent of on-road fuel consumption by 2020 and to 30 percent by 2030, thereby helping achieve the overall petroleum demand reduction goal.

The California Legislature has yet to take action on the CARB and CEC recommendations. If, however, the recommendations are pursued, there may be a slight incentive for dairy farmers to produce biomethane that could be used as a fuel to help meet the bill's non-petroleum fuel targets.

### **State Fleet Energy Consumption Reduction Goal**

State Bill 1170 (2001) established a policy goal to reduce energy consumption of state fleets. California state fleets are directed to develop and adopt (1) fuel efficiency specifications for the use of state vehicles that will reduce energy consumption of the state fleet at least 10% by 2005 and (2) air pollution emission specifications requiring light-duty vehicles acquired by state fleets to meet or exceed the state's ultra-low-emission vehicle (ULEV) standards, a requirement that can be accomplished through the use of natural gas vehicles.

## **Government Policies and Incentives for Alternative Fuel Vehicles**

As discussed above, there are a number of policies and programs that encourage the use of alternative vehicular fuels, though few of them provide specific incentives for biomethane use and production. In addition, there are both federal and state policies and incentives that mandate or encourage the use of alternate fuel vehicles. These programs could indirectly enhance biomethane production and use as a vehicle fuel, although few would provide direct incentives.

### ***Federal Policies and Incentives for Alternative Fuel Vehicles***

The Energy Policy Act (EPAct) of 1992 set a national goal of 30 percent alternative fuel use in vehicles by 2010. It required various public fleets to purchase alternative fuel vehicles, although it does not directly require the purchase of alternative fuel. For example, the State and Alternative Fuel Provider Fleets Program requires fleets covered by the program to purchase alternative fuel vehicles as part of their annual light-duty-vehicle acquisitions.

The EPAct of 1992 provided tax deductions of as much as \$50,000 for a clean-fuel heavy-duty vehicle, \$2,000 for a passenger vehicle, and \$100,000 for a clean-fuel refueling property. Clean fuels are defined as natural gas, liquefied natural gas, liquefied petroleum gas, hydrogen, electricity, and any fuel that is at least 85% alcohol (i.e., ethanol) or ester (i.e., biodiesel) (IRS, 2004, p. 48). These deductions and credits ended December 31, 2004.

There are a variety of other federal programs that require or support the purchase of alternative fuel vehicles, including vehicles that will run on natural gas and biomethane. These include the Federal Transit Administration's Clean Fuels Grant Program to accelerate the use of low-emission buses and the US EPA's Clean Fuel Fleet Program that requires fleets in cities with air quality problems to incorporate vehicles that meet clean emission standards (see <[http://www.eere.energy.gov/cleancities/progs/afdc/search\\_state.cgi?afdc/US](http://www.eere.energy.gov/cleancities/progs/afdc/search_state.cgi?afdc/US)>). Alternative fuels include ethanol, E85, natural gas, and "fuels (other than alcohol) derived from biological materials (including neat biodiesel)" and electricity (Federal Register, Vol. 61, No. 51, March 14, 1996, page 10653). After passage of EPAct, the American Soybean Association wanted to add mixtures that include biodiesel to the program. In 1998, the EPAct was amended to allow entities that are required to have alternative fuel vehicles in their fleet get credit for vehicles that use B20. The final rule was issued in 2001. This has been the major factor in the growth of the U.S. biodiesel market, which increased from 500,000 gallons in 1999 to 2,000,000 gallons in 2001 to an estimated 25,000,000 gallons in 2003 (see National Biodiesel Board website <<http://www.biodiesel.org/resources/faqs/default.shtm>>).

Farm legislation during 1996 to 2001 provided for producer payments for increased bioenergy production in the form of ethanol and biodiesel but did not include biodiesel derived from animal by-products and fats, oils, and greases. The 2002 Farm Bill expanded the definition to include biodiesel from these sources.



Table 6-3 summarizes the existing federal policies and incentives for increased use of alternative fuel vehicles and ranks them according to their estimated value for stimulating growth of the biomethane industry. Each of these policies or programs is described in more detail below.

**Table 6-3 Federal Policies and Programs that Encourage Use of Alternative Fuel Vehicles, Ranked According to Presumed Impact on Growth of Biomethane Industry**

<b>Policy/Program</b>	<b>Value</b>	<b>Explanation</b>
EPAct: State and Alternative Fuel Provider Rule	Low	Requires states and alternative fuel providers to make AFVs a minimum percentage of vehicle fleet acquisitions. This rule does not provide specific incentives for natural gas vehicle purchases, much less renewable methane use. The majority of vehicles purchased under this program are E85 “flexible fuel” vehicles (65 percent of the state and alternative fuel provider fleets). CNG vehicles make up 24% of the state and alternative fuel provider fleets.
EPAct: Federal Fleet Rule	Low	Requires the federal government to make AFVs a minimum percentage of vehicle fleet acquisitions. It also requires these fleets to reduce their petroleum consumption. This rule does not provide specific incentives for natural gas vehicle purchases or renewable methane use. The majority of vehicles purchased under this program are E85 “flexible fuel” vehicles (78 percent of the federal fleet). CNG vehicles make up 21% of the federal fleet.
Federal Income Tax Deduction	Medium	Tax deduction for clean fuel vehicles. Includes natural gas, but no specific incentive for renewable methane. Expired January 1, 2005.
The Congestion Mitigation and Air Quality Improvement Program	Low	Funding for projects and programs that reduce transportation related emissions. Various fuels and technologies can qualify. No specific incentive for renewable methane.
EPA “Clean School Bus USA” Program	Low	Only 20 buses. Various fuels and technologies can qualify. No specific incentive for renewable methane.

High = Provides substantial incentives for both natural gas vehicle use and biomethane production.

Medium = Gives adequate incentives for either increased natural gas vehicle use or increased biomethane production, but not for both.

Low = Inadequate incentives for increased natural gas vehicle use or increased biomethane production.

### **Energy Policy Act of 1992**

As discussed above, the EPAct was passed by Congress to reduce the nation’s dependence on imported petroleum by requiring state, government, and alternative fuel provider fleets to acquire alternative fuel vehicles, which are capable of operating on non-petroleum fuels. Several rules regarding alternative fuel vehicles have been promulgated under this act.

### **State and Alternative Fuel Provider Rule**

As of 2001, the State and Alternative Fuel Provider Rule requires that 75% of new light-duty vehicles for state fleets and 90% for alternative fuel providers must be alternative fuel vehicles. Compliance with this rule is required of state government and alternative fuel provider fleets that operate, lease, or control 50 or more light-duty vehicles within the USA. Of those 50 vehicles, at least 20 must be used primarily within a single metropolitan statistical area or consolidated metropolitan statistical area. In California, the affected metropolitan areas are Bakersfield, Fresno, Los Angeles/Riverside/Orange County, Modesto, Sacramento, Salinas, San Diego, San Francisco/Oakland/San Jose, Santa Barbara/Santa Maria/Lompoc, and Stockton/Lodi.

### **Federal Fleet Rule**

According to the Federal Fleet Rule, from 1999 forward 75% of a federal fleet's light-duty vehicle acquisitions (in fleets covered by the program) must be alternative fuel vehicles. Furthermore, through a combination of AFV acquisitions, increased alternative fuel use in AFVs, improved efficiency in non-AFV acquisitions, and improvements in overall fleet operating efficiencies, agencies were required to decrease the annual petroleum consumption of federal fleets by 20% from 1999 to 2005.

### **Federal Income Tax Deduction**

A \$2,000 to \$50,000 federal income tax deduction from gross income is available for the incremental cost to purchase or convert qualified clean fuel vehicles. This full federal deduction is allowed for vehicles placed into service after June 30, 1993 and before January 1, 2006. The maximum allowable deductions are as follows, based on vehicle class:

- Truck or van, gross vehicle weight (GVW) 10,000 to 26,000 lb: \$5,000
- Truck or van, GVW more than 26,000 lb: \$50,000
- Bus with seating capacity of 20+ adults: \$50,000
- All other on-road vehicles: \$2,000

Additionally, a tax deduction of up to \$100,000 can be claimed for clean fuel refueling sites (including electricity). This deduction is allowed for sites placed into service after June 30, 1993 and before January 1, 2006.

Vehicles and sites placed in service in 2006 will receive 25% of the amounts indicated above. No clean fuel vehicle or sites deduction is available for vehicles or sites placed in service after December 31, 2006.

### **Clean School Bus USA Program**

In 2004, Congress allocated \$5,000,000 for school bus retrofit and replacement grants through this program, and in June of the same year, the US EPA announced the selection of 20 projects eligible for funding. The program advocates clean diesel technologies and fuels as well as buses that run on CNG.

### **The Congestion Mitigation and Air Quality Improvement Program**

The Congestion Mitigation and Air Quality program funds projects and programs that will reduce transportation-related emissions in non-attainment and maintenance areas. Along with natural gas vehicle projects, funding opportunities exist for diesel engine retrofit projects.

### **California Programs Alternative Fuel Vehicles**

California also has an alternative fuel vehicle program, related to the federal program that encourages the purchase of alternative fuel vehicles. This program focuses on methanol and methanol blends, ethanol and ethanol blends, compressed natural gas, liquefied petroleum gas, and hydrogen. Specifically, the CARB's alternative fuel regulations state that, ". . . 'alternative fuel' means any fuel which is commonly or commercially known or sold as one of the following: M-100 fuel methanol, M-85 fuel methanol, E-100 fuel ethanol, E-85 fuel ethanol, compressed natural gas, liquefied petroleum gas, or hydrogen." (CCR, Title 13, Section 2290 (a) (1)).

Compressed natural gas is defined by its chemical specifications (CCR, Title 13, Section 2292.5). As long as it meets those specifications, compressed biomethane should qualify as compressed natural gas. It is not clear if LNG or LBM qualify. If not, advocates of biomethane that want biomethane to qualify as a clean alternative fuel can petition CARB to get it added to the list (CCR, Title 13, Section 2317).

California has a variety of incentives for super-ultra-low-emission vehicles (SULEV) that run on alternative fuels.<sup>1</sup> For example, single occupants driving SULEV vehicles that use alternative fuels (including, it is assumed, biomethane) are allowed to use car pool lanes. Some localities allow free metered parking (see <<http://www.driveclean.ca.gov/en/gv/incentives/index.asp>>). Public agencies in the San Francisco Bay Area may get as much as \$5,000 from the Air District's Vehicle Incentive Program for the purchase of a SULEV, PZEV (partial zero-emission vehicle) or ZEV (zero-emission vehicle) that runs on natural gas, propane, hydrogen, electricity, or hybrid electricity (see Bay Area Air Quality Management District, Vehicle Incentive Program <[http://www.baaqmd.gov/pln/grants\\_and\\_incentives/vip/index.asp](http://www.baaqmd.gov/pln/grants_and_incentives/vip/index.asp)>). The San Joaquin District

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<sup>1</sup> For a general discussion of California incentives see US DOE, Clean Cities Program Review of California Incentives at <[http://www.eere.energy.gov/afdc/progs/state\\_summary.cgi?afdc/CA](http://www.eere.energy.gov/afdc/progs/state_summary.cgi?afdc/CA)>.

will provide as much as \$40,000 per vehicle for the purchase of new on-road heavy-duty vehicles such as transit buses that run on compressed natural gas or liquefied petroleum gas (SJAPCD, 2003). Vehicles running on ethanol or biodiesel do not qualify for either the Bay Area or San Joaquin District programs.

Table 6-4 summarizes existing California programs for encouraging alternative fuel vehicles and indicates their probable impact on the development and use of biomethane as an alternative fuel. Individual programs are discussed below.

Table 6-4 California Programs that Promote the Use of Alternative Fuel Vehicles

Program	Value	Reason
Tax Deductions	Medium	Exempts AFVs, including natural gas vehicles, from vehicle license fee. No specific incentive for renewable methane.
Bay Area Programs	Medium	Financial incentives for AFVs. No specific incentive for renewable methane.
Carl Moyer Memorial Air Standards Attainment Program	Low	Natural gas vehicles can qualify towards this program, but so can clean diesel technologies. No specific incentive for renewable methane.
California Alternative Fuel Programs	Low	Encourages the purchase of various alternative fuel vehicles, including compressed natural gas vehicles. No specific incentive for biomethane.
The Lower Emission School Bus Program	Low	Only 36 buses. Various fuels and technologies can qualify. No specific incentive for renewable methane.
HOV Lane Privileges	Medium	Allow single occupant SULEV AFVs to drive in HOV lane. No specific incentive for renewable methane.
San Joaquin Valley District Heavy Duty Engine Incentive Program	Low	Natural gas vehicles can qualify towards this program, but so can clean diesel technologies. No specific incentive for renewable methane.
Sacramento Metro District Heavy Duty Vehicle Incentive Program	Low	Natural gas vehicles can qualify towards this program, but so can clean diesel technologies. No specific incentive for renewable methane.
South Coast District Fleet Rules	Medium	Mandates the purchase of natural gas vehicles. No specific incentive for renewable methane.

HOV = High occupancy vehicle.

SULEV = Super ultra low-emission vehicle.

AFV = Alternative fuel vehicle.

High = Provides substantial incentives for both natural gas vehicle use and biomethane production.

Medium = Gives adequate incentives for either natural gas vehicle use or biomethane production, but not for both.

Low = Inadequate incentives for natural gas vehicle use or biomethane production.

### **Tax Deductions**

To help equalize the vehicle license fee for AFVs and conventional fuel vehicles, the incremental cost of the purchase of an alternative fuel vehicle is exempt from the vehicle license fee (of 2%). This reduction applies towards new, light-duty AFVs that are certified to meet or exceed ULEV standards. This program runs from January 1, 1999 to January 1, 2009 (California Revenue and Taxation Code, Section 10759.5).

### **Bay Area Air Quality Management District Programs**

The Bay Area Air Quality Management District (Bay Area District) offers several programs to provide incentives for clean-fuel vehicles, with an emphasis on public agency fleets. The Vehicle Incentive Program offers incentives to public agencies that purchase alternative fuel vehicles with a GVW of 10,000 lb or less. Qualifying vehicles must be certified as ULEV, SULEV II, or ZEV. Incentives range from \$1,000 to \$5,000 per vehicle. A total of \$500,000 is available in FY 2004/05. Another Bay Area District initiative, the Transportation Fund for Clean Air program, offers incentives to cover the incremental cost of alternative fuel heavy-duty vehicles.

### **Carl Moyer Memorial Air Standards Attainment Program**

By focusing on NO<sub>x</sub> and PM emissions, the Carl Moyer program, administered by CARB, provides funds on an incentive basis for the incremental cost of engines that are cleaner than required and certified to meet low NO<sub>x</sub> emission standards (this includes natural gas engines). Eligible projects include cleaner on-road, off-road, marine, locomotive, and stationary agricultural pump engines, as well as forklifts, airport ground support equipment, and auxiliary power units. About \$33.1 million in funding was available for FY 2004 through participating air pollution control and air quality management districts. No maximum grant amount per vehicle is specified, but in the first three years of the program's operation, which was established in 1999 by Chapter 923, around 48% of funding was focused on alternative fuels.

### **Lower-Emission School Bus Program**

Assembly Bill 425 (Statutes of 2002, Chapter 379) mandates that 20% of the Proposition 40 funds made available to CARB are allocated for the acquisition of "clean, safe, school buses for use in California's public schools that serve pupils in kindergarten and grades 1 to 12, inclusive." For FY 2003-2004, \$4.6 million was available for the purchase of new school buses, which was enough to purchase about 36 buses statewide.

### **High-Occupancy Vehicle Lane Privileges**

Starting July 1, 2000, certain alternative fuel vehicles were allowed to use high-occupancy vehicle (HOV) lanes, regardless of the number of occupants in the vehicle (California Vehicle Code Sections 5205.5 and 21655.9). To claim this privilege, an identification sticker must first be obtained from the California Department of Motor Vehicles (DMV).

### **San Joaquin Valley Unified Air Pollution Control District**

The San Joaquin District administers the Heavy-Duty Engine Emission-Reduction Incentive Program, which provides incentive funds for the differential cost (up to \$40,000 per vehicle) associated with reduced emission technology (as compared to the cost of conventional technology) for heavy-duty vehicles with a GVW over 14,000 lbs. Eligible funding categories include heavy-duty on-road vehicles, off-road vehicles, locomotives, marine vessels, electric forklifts, electric airport ground support equipment, and stationary agricultural irrigation pump engines. Eligible fuel types include natural gas, among others.

### **Sacramento Metropolitan Air Quality Management District**

The Sacramento Metropolitan Air Quality Management District also has a Heavy-Duty Low-Emission Vehicle Incentive program that offers a variety of financial incentives to entities that lower NO<sub>x</sub> emissions from heavy-duty vehicles (both on- and off-road). The incentives include the purchase of new natural-gas and other alternative fuel vehicles. Private businesses and public agencies in the six-county Sacramento federal ozone non-attainment area are eligible to apply for this program

### **South Coast Air Quality Management District**

The South Coast District has many rules that mandate the purchase of cleaner, natural gas vehicles (SCAQMD Fleet Rules 1191-1196, 1186.1). The vehicles covered include on-road light- and medium-duty public fleet vehicles, on-road heavy-duty public fleet vehicles, on-road transit buses, residential and commercial refuse collection vehicles, airport ground access vehicles, school buses, and sweepers. In 2004, however, the U.S. Supreme Court disallowed the portion of the South Coast District fleet rules regarding private fleet purchases of certain kinds of heavy-duty vehicles due to a legal jurisdictional issue. While there is a strong effort underway to effectively reinstate the rules via a state mechanism, the Supreme Court action has at least temporarily removed one of the primary drivers for sales of certain kinds of heavy-duty natural gas fuel vehicles in California. Given the potential instability of the current situation, it is difficult to predict the overall effect on the California natural gas vehicle market.

## **Summary and Conclusions**

Renewable electricity, ethanol, and biodiesel are supported by direct financial incentives and mandates that increase their usage. Biomethane receives no direct financial incentives, however, as an alternative fuel, biomethane can qualify for some of the benefits available to alternative fuels. The federal government has programs to promote farm-based and rural renewable energy, and biomethane projects can compete for such awards. In addition, biomethane research and development funds are available through competitive grant programs.

California is committed to renewable electricity and has a variety of programs that provide direct benefits including the California Self Generation Incentive Program, the Renewable Resources Trust Fund, net metering, and requirements under the Renewable Portfolio Standard to purchase renewable electricity. Both the federal and California governments are committed to research and development programs that support renewable electricity from biomass and renewable fuels from biomass. The federal government's efforts are concentrated in the Farm Bill of 2002. California efforts for biomass electricity are funded through the Public Energy Research Program. California has a new Public Interest Natural Gas Energy Research Program that can fund biogas and biomethane research.

When biogas created by an anaerobic digester system is combusted to generate electricity, the generator can earn incentives under federal, and especially, California renewable electricity programs. When biogas is used to create biomethane that will be used in vehicles or other applications, it is ineligible for this funding. It is also ineligible for alternative fuel incentives that are provided for ethanol and biodiesel. At present, the best opportunities for biomethane projects from dairy manure are found in the federal Farm Bill of 2002. Farm-based biomethane projects can compete for federal support under various provisions of this bill such as Title II (EQIP), and especially Title IX (Energy), Section 9006 and Section 9008.

Ethanol has direct cash incentives in excise tax exemptions that began in 1978 and have been consistently extended, currently running to 2007. Both ethanol and biodiesel are also supported by producer incentive funds under Farm Bill Section 9010. Most of those funds go to ethanol, which is produced in substantially larger volume than biodiesel. Federal taxpayers provide \$250 to \$300 million per year of support under these two programs. The ethanol market is also supported by oxygenation mandates under the Clean Air Act amendments of 1990. Ethanol, biodiesel, and in theory, biomethane receive some market support through the alternative fuel program created by the Energy Policy Act of 1992. These opportunities may be expanded if the Energy Policy Act of 2005 is passed.

Vehicles that run on biomethane fulfill alternative vehicle fleet requirements as mandated in federal, state, and local law and should be able to earn various federal, state, and local incentives.





## **7. Permits and Regulations for a Dairy Biomethane Plant**

A facility to upgrade dairy biogas to biomethane has several components that involve permitting and regulations. The dairy itself is subject to a number of air and water quality regulations, which are described in this chapter, whether or not it produces biogas. Some dairies, both new and existing, may be exempt from certain permit requirements based on dairy size, design, and location. In certain situations, dairies may also be subject to regulations other than those discussed in this chapter.

Most California dairies capture their wastewater in on-site lagoons and thus avoid discharging wastewater to water bodies except during severe storms. Until 2003, California dairies were not required to have water permits, but by April 2006 most California dairies will require water permits (CRWQC, 2003). Even if a dairy has a water permit, a new permit is required for the installation of an anaerobic digestion system. If a dairy has a digester that combusts biogas, or upgrades biogas to biomethane, an air permit will be required. Depending on the county, a local administrative permit or conditional use permit may also be required. New dairies or digesters will need to have a building permit prior to construction activities.

Because the focus of this report is on alternate uses of biogas, particularly through upgrading to biomethane, we will not review the permits and regulations required for dairies or anaerobic digesters. Instead our emphasis will be on permits and regulations applicable for installing a biogas upgrading facility and for storing and using biomethane produced by such a facility.

### **Permits for a Biogas Upgrading Plant**

A biogas upgrading facility is subject to federal, state, and local regulatory requirements. Any required water permits are issued by the regional water board. Unless exempted by local regulations, a biogas upgrading plant must obtain an air pollution permit from the local air district. If an upgrading facility uses or disposes of chemicals that are characterized as hazardous wastes, a permit must be obtained from the California Department of Toxic Substance Control (DTSC). Likewise, if the upgrading plant is off-dairy in an industrial area that is not already permitted, the facility must go through the same permitting process as any other stationary industrial facilities.

No specific additional permits are needed by an upgrading facility to compress or liquefy biomethane to produce CBM or LBM. However, there may be emission or safety issues associated with the production of these fuels that require other permitting or approvals.

At the local level, an upgrading facility should verify that it complies with city or county planning ordinances and meets zoning requirements. Facilities must also meet building code requirements and any new construction must be authorized through a building permit. The regional air district, water board, or other local authority must be contacted to determine if an environmental review is necessary under the California Environmental Quality Act (CEQA).

Table 7-1 provides an overview of the permits that may be required for a biogas upgrading (biomethane) plant and the parties responsible for permit issuance. Each type of permit is discussed in more detail below.

Table 7-1 Permitting Information for Biogas Upgrading Plant

Permit or Requirement	Issuer	Needed?
Water permit	Regional water board	
<i>If facility is located on previously permitted site</i>		Not likely
<i>If there is no discharge to water body</i>		No
<i>If there is discharge to receiving body and site is not previously permitted</i>		Yes
Stormwater permit	Regional water board	No
Stormwater construction permit	Regional water board	Maybe
Air permit	Local air district	Yes
Hazardous waste permit	California Department of Toxic Substance Control	Maybe
CEQA process	Lead agency	Maybe
Solid waste permit	Local enforcement agency	No
Use permit based on zoning	County or city	Yes
Building and related permits	County or city	Yes

### Water Permits

According to regulations, most dairies in California are confined animal feeding operations (CAFOs) and will be required to apply for NPDES water permits by April 13, 2006 (CRWQCB, 2003). More specifically, the regulations state that dairies with CAFOs that have more than 700 cows, or that have more than 300 cows and discharge wastewater to a water body or have surface water running across the dairy, will need permits, unless they prove that wastewater from their operations never, under any circumstances, enters a water body (US EPA, 2003). In some cases, smaller CAFOs may also require permits.

However these regulations were successfully challenged in a lawsuit, *Waterkeeper Alliance, et al., v. US EPA*, which was decided in the U.S. Court of Appeals, Second Circuit, on February 28, 2005. Among other aspects the Court ruled that CAFOs do not have a duty to apply for NPDES permits or otherwise demonstrate that they have no potential to discharge. It also eliminated the

700 cow threshold. A full analysis of the implications of this decision is beyond the scope of this report.

If a CAFO dairy (or other dairy without an existing water permit) plans to build a biogas upgrading facility, it will typically need a water permit from the regional water board. Even if the dairy has a water permit, the installation of an anaerobic digestion system requires a new water permit for the plant. If the plant will be off-dairy at a centralized site such as a publicly owned treatment works (POTW) that already has a water permit, a separate permit is probably not required. However, if the biogas upgrading facility will discharge to a water body or a POTW, and is at a location that is not otherwise permitted, then it must obtain the appropriate permit from the local regional water board as discussed below.

The statutory basis for federal water permits are the amendments to Federal Water Pollution Control Act of 1972 (P.L. 92-500), also referred to as the Clean Water Act. This act created the National Pollution Discharge Elimination System (NPDES) permit program, which is the basic regulatory structure for *point sources* that discharge pollutants. The NPDES requires all facilities that discharge pollutants into surface water from a point source to obtain a permit. It categorizes pollutants into *conventional pollutants* such as fecal coliform, toxic or *priority pollutants* such as metals or anthropogenic organic chemicals, and *nonconventional pollutants* such as ammonia, nitrogen, and phosphorus.

Publicly owned treatment works, including water or wastewater treatment plants, and industrial facilities are considered point sources. Most agricultural activities are considered *nonpoint sources* of pollution and are thus exempt from NPDES permitting; however, CAFOs (including large dairies) are defined as point sources. Point sources can discharge to bodies of water directly or indirectly. Direct sources discharge wastewater directly into the receiving water body. Indirect sources discharge to a POTW, which in turn discharges into the body of water. If an industrial facility discharge is a direct source, a general NPDES permit is required, but if the facility discharges to a POTW, it is regulated under the National Pretreatment Program (US EPA, 1999a). Stormwater that runs off a facility or construction site into a water body requires an NPDES stormwater permit (US EPA website <<http://www.epa.gov/npdes/pubs/101pape.pdf>>).

The Clean Water Act allows the US EPA to authorize state governments to permit, administer, and enforce the NPDES program. The US EPA has delegated NPDES permitting to regional boards, thus allowing regional regulation of water discharges. In California, the Porter-Cologne Water Quality Control Act, also known as the California Water Code (CWC), is the principal law governing water quality regulations. The CWC set up the State Water Resources Control Board and the nine regional water quality control boards.

A Water Discharge Requirement Permit, also issued by the regional board, is required for discharges that are not subject to NPDES, such as those affecting groundwater or those from nonpoint sources (e.g., erosion from soil disturbance or waste discharges to land).

Most upgrading plants will not need these water permits because they will be on a CAFO dairy site that already has a water permit. If there is no permit in place and the upgrading plant discharges water to a water body, it will require a general NPDES permit. If the plant connects to a sewer or other system that discharges to a POTW, it will require a permit under the National Pretreatment Program. The Code of Federal Regulations (CFR) lists specific categories of industrial facilities that require stormwater permits (40 CFR 122.26(b)(14)(i)-(ix)). A biomethane plant does not fit into any of the defined categories; therefore, such a plant should not require a stormwater discharge permit. It may, however, require a stormwater construction permit while it is being built.

### **Air Emission Permits**

The Clean Air Acts of 1970 (P.L. 91-604) and 1990 (P.L. 101-549) are the major federal laws that regulate air emissions. This legislation sets standards for air emission regulation and enforcement, and authorizes states to administer the rules.

The criteria air pollutants regulated under the Clean Air Act are ozone (O<sub>3</sub>), nitrogen oxide and dioxide (NO<sub>x</sub>), carbon monoxide (CO), particulate matter (PM-10 and PM-2.5), sulfur dioxide (SO<sub>x</sub>), and lead (Pb). Volatile organic compounds are defined by the Clean Air Act as precursors of ozone, a respiratory toxicant. The 1990 Clean Air Act also regulates the emission of air toxics, currently a list of 188 pollutants (see US EPA air toxics website at <<http://www.epa.gov/ttn/atw/188polls.html>>).

The Clean Air Act regulations are enforced in California by the local air districts. Most California dairies are located within the San Joaquin Valley Air Pollution Control District (San Joaquin District). In this district, an industrial plant, such as a biogas upgrading facility, that “emits or may emit air contaminants” is required to obtain an air permit, unless it is a facility that is specifically exempted (SJVAPCD, District Rule 2020, Sections 2, 6 and 7; see <<http://www.valleyair.org/rules/currnrules/r2020.pdf>>). The extensive list of exemptions does not include any descriptions of a biogas upgrading plant or take into consideration similar facilities in this type of agricultural location.

Since a biogas upgrading facility does not actually combust any gases, it is unlikely to release any of the criteria air pollutants other than VOCs. Depending, however, on the type of upgrade technologies used (see Chapter 3), the facility may release air toxics. If the facility will exceed the legal threshold for one or more air toxics, it will be subject to a “New Source Review,” a preconstruction permitting program established by the 1977 Clean Air Act Amendments. Thresholds for air toxics vary depending on the particular pollutant and the air basin in which the facility is located. Thresholds are lower in air basins with the worst air quality.

If the dairy combusts biogas for electricity instead of upgrading it to biomethane, it is still required to obtain an air permit because engine combustion of biogas (to generate electricity) produces criteria air pollutants, notably NO<sub>x</sub>.

As mentioned, most dairy-based upgrading facilities are likely to be located in the Central Valley (San Joaquin District); the second most likely location would be along California's South Coast (South Coast District). Both of these districts have been classified as nonattainment areas for ozone and particulate matter. Best available control technologies, as defined by the local air district, must be used in nonattainment areas to control criteria air pollutant emissions if total emissions exceed the designated threshold for that pollutant. For an upgrading plant located on-farm, total emissions include those generated from dairy operations, anaerobic digestion, and upgrading processes. In some districts, dairies with upgrading plants may also be required to purchase emission reduction credits.

### ***Hazardous Waste Regulations***

The Resources Conservation and Recovery Act (RCRA) of 1976 and its amendments govern the generation, transport, disposal and recycling of hazardous waste. The US EPA has authorized the California DTSC to carry out the RCRA program in California including permitting, inspection, and compliance. If a biogas upgrading plant will handle or produce any hazardous waste products, it must obtain a Hazardous Waste Facilities Permit from the local office of the DTSC. Hazardous chemicals that might be used at biogas upgrading plants, depending on the technology employed, include ethylene glycol.

### ***California Environmental Quality Act Requirements***

The construction of a biogas upgrading plant in California will require an approval by one or more public agencies, who in turn will decide if a CEQA review is required. A CEQA review requires the lead public agency on a project to consider and document any environmental impacts, including means of avoiding or mitigating these impacts where feasible. The first step is to perform an "Initial Study" to determine if there will be significant impacts. If none are anticipated, or if they can be avoided or mitigated, the agency can file a Negative Declaration or a Mitigated Negative Declaration. If, however, the impacts will be significant and cannot be avoided or substantially mitigated, an Environmental Impact Report (EIR) will be required (CRA, 2001).

### ***Local Land Use Regulations***

Before beginning construction of a biogas upgrading facility, the builder should check with the local city or county planning department to determine any zoning restrictions on the building site. Most dairies are located outside of city boundaries, on properties zoned for agriculture by the

local county. Each county has its own zoning regulations that identify the kind of uses allowed in agriculture zonings and the permits required for these uses.

Merced County, for example, specifically allows “Energy Generation Facilities, Wind Farms, Biomass Fuel Manufacturing” in areas zoned for agriculture (County of Merced, 2004, p. 30). If the energy is to be used on-farm the plant requires an administrative permit; if it is to be used off-farm a conditional use permit is needed (County of Merced, 2004). In addition, construction of a biogas upgrading plant will require a building permit. This permit will ensure that the facility meets the local building code and is built to all appropriate safety standards, including seismic and fire standards. Other counties may require additional permits such as grading permits.

### ***Permits for a Centralized Upgrading Facility***

A biogas upgrading plant may be a centralized facility. In this case, the manure is hauled or piped to the digester and the digested sludge and effluent may be disposed of off-site or, in the case of liquid effluent, in a water body. Because the facility is considered a point source, an NPDES permit will be required. A permit from the local air district will also be needed, but a solid waste permit will not be necessary unless the facility stores sludge on-site for more than a year or makes compost from the sludge or effluent (Jeff Paalsgard, County of Merced, personal communication, 24 September 2004). If hazardous wastes may be released during the upgrade process, a hazardous waste permit from the California DTSC is required. At the local level, an administrative or conditional use permit will be required and the local agency responsible for these permits will probably require an EIR that identifies issues involved with transport of the dairy manure or digester wastes on public rights-of-way. A building permit will also be required.

## **Permitting and Regulation of Biomethane Storage and Transport**

Biomethane vehicle fuels such as CBM and LBM are subject to the same federal, state, and local standards as their fossil-fuel counterparts, CNG and LNG. The remainder of this chapter discusses the standards and regulations that apply to biomethane when it is kept in on-vehicle storage tanks, transported over-the-road or distributed through a pipeline.

### ***On-Vehicle Storage Systems***

On-vehicle fuel delivery and storage systems for compressed and liquefied natural gas (and biomethane) are subject to federal and state motor vehicle safety standards. In addition, there are a number of industry safety standards and codes associated specifically with the design of CNG- and LNG-fueled vehicles. In general, determining which standards are applied is dependent on whether the biomethane fuel is in compressed or liquefied form as well as the type and GVW rating of the vehicle.

Multiple organizations specify safety standards for CNG- and LNG-fueled vehicles. Manufacturers are legally required to comply with federal and state standards as well as those adopted at the municipal level. Some of the major organizations involved with CNG and LNG component/system/vehicle standards are listed below:

- The National Highway Traffic Safety Administration, under the Department of Transportation (DOT), specifies Federal Motor Vehicle Safety Standards. This organization focuses primarily on light-duty passenger vehicles, pickup trucks, school buses, and other non-commercial vehicles.
- The Federal Motor Carrier Safety Administration, also under DOT, specifies Federal Motor Carrier Safety Regulations for commercial vehicles, primarily large trucks and buses.
- State motor vehicle regulations may include requirements for CNG and LNG vehicles, either explicitly or by reference to existing standards.
- The Society of Automotive Engineers specifies U.S. automotive industry design and safety standards including standards for CNG and LNG vehicles.
- The National Fire Protection Association specifies fire safety codes, including CNG and LNG vehicular fuel systems.
- The American National Standards Institute specifies voluntary standards across a range of industries and products including CNG tanks and CNG/LNG fuel system components.

Table 7-2 summarizes the major safety standards pertaining to CNG and LNG vehicles.

Although there are no specific permits required for retrofitting a CNG or LNG fuel system on a vehicle, retrofitters are responsible (e.g., from a liability perspective) for using certified components and systems, installing these components and systems according to manufacturer instructions, and doing so in a way that does not compromise the safety of the original vehicle.

In addition to complying with applicable safety standards, all new and retrofitted vehicles (including CNG- and LNG-fueled vehicles) must be certified to meet exhaust emissions standards. At the federal level, vehicle emissions requirements are specified by the US EPA. The EPA's Federal Test Procedure (FTP) is used to determine compliance with federal emissions requirements:

- *Light-duty vehicles.* Emissions certification involves chassis testing of the entire vehicle. Manufacturers are responsible for complying with exhaust emissions standards.
- *Medium- and heavy-duty vehicles.* Testing is required of the engine only. Manufacturers are responsible for complying with exhaust emissions standards.

The California Air Resources Board is responsible for setting exhaust emissions standards and overseeing emissions certification of vehicles and engines sold in California. California follows the EPA FTP testing procedure but requires chassis-based testing for medium-duty as well as light-duty vehicles.

There are no specific permits associated with emissions certification testing of CNG and LNG vehicles (including retrofits); however, companies performing such tests in California must be approved by the US EPA and CARB.

Table 7-2 Summary of Major Safety Standards for Compressed and Liquefied Natural Gas Vehicles

Standard or Code	Applicability	Comments
FMVSS 303 – Fuel system integrity of compressed natural gas vehicles	CNG vehicles ≤ 10,000 lb GVW School buses	DOT FMVSS for crash test of light-duty vehicle and school bus CNG fuel systems
FMVSS 304 – Compressed natural gas fuel container integrity	CNG vehicles	DOT FMVSS for CNG tanks (light-, medium- and heavy-duty vehicles)
FMCSR, Part 393.65 – All fuel systems	Medium- and heavy-duty commercial trucks and buses including CNG and LNG vehicles	General requirements for fuel systems including CNG and LNG fuel systems
13 CCR 2, Chapter 4, Article 2	CNG fuel systems in 13 CCR 934; LNG fuel systems in 13 CCR 935	California state requirements for CNG and LNG vehicles
SAE J2343 – Recommended practices for LNG-powered heavy-duty trucks	Heavy-duty LNG vehicles	Adopted by reference in CA state requirements for LNG vehicles.
SAE J2406 – CNG-powered medium- and heavy-duty trucks	CNG vehicles > 14,000 lb GVW	---
NFPA 52 – Compressed natural gas (CNG) vehicular fuel system code, 2002	CNG vehicles	---
NFPA 57 – Liquefied natural gas (LNG) vehicular fuel system code, 2002	LNG vehicles	---
ANSI/CSA NGV2-2000 – Basic requirements for compressed natural gas vehicle fuel containers	CNG vehicles	CNG tank requirements in addition to FMVSS 304
ANSI/AGA NGV3I.1-95 – Fuel system components for natural gas powered vehicles	Fuel system components for natural gas vehicles excluding LNG components upstream of vaporizer	Primarily for converted vehicles

FMVSS = Federal Motor Vehicle Safety Standards

LNG = Liquefied natural gas

CNG = Compressed natural gas

CCR = California Code of Regulations

DOT = Department of Transportation

SAE = Society of Automotive Engineers

FMCSR = Federal Motor Carrier Safety Administration

NFPA = National Fire Protection Association

ANSI = American National Standards Institute



## **Transportation of Biomethane**

In Chapter 5, we estimated that the theoretical maximum potential on-farm demand for biomethane would be about 75% of the potential supply from a typical dairy farm, but concluded that this level would not be achieved in practice. The expense to convert all farm equipment and vehicles to run on biomethane is substantial, and even so at least some of the biomethane would have to be used off-farm. Therefore, it would probably not be economically feasible to build on-farm fueling stations (because of the significant capital equipment costs for such stations). To be an economically viable commodity, biomethane produced on dairy farms should be transported to an off-farm fueling station where there is sufficient demand for biomethane fuel.

As discussed in Chapter 4, biomethane can be transported from a dairy farm to an off-farm fueling station in one of four ways:

- Over-the-road transportation, as compressed biomethane
- Over-the-road transportation, as liquefied biomethane
- Distribution via the natural gas pipeline network
- Distribution via dedicated biomethane pipelines (“raw” or partially upgraded biogas may also be transported via dedicated pipelines to a remote biogas upgrading facility)

The regulations pertaining to each of the above transportation/distribution methods are discussed below, along with applicable permitting requirements.

### **Over-the-Road Transportation of Compressed Biomethane**

Regulations pertaining to over-the-road transportation of CNG are assumed to be fully applicable to over-the-road transportation of CBM. These regulations are enforced by the DOT (49 CFR 171 – 180, Hazardous Materials (HAZMAT)). The DOT HAZMAT tables classify CNG as a flammable gas hazardous material (Class 2, Division 2.1).

Vehicles that transport CNG in bulk, often referred to as “tube trailers,” are used when over-the-road transportation of CNG (or CBM) is required. Tube trailers are typically class 8 vehicles consisting of a tractor and a trailer that has multiple CNG storage cylinders connected in parallel, often within an enclosed body or metal cage. Since natural gas has a low energy density at standard pressure, practical and economic considerations require that it be compressed to very high pressures (e.g., 3,000 to 3,600 psi) for over-the-road transportation in these storage cylinders.

Some of the critical HAZMAT vehicle requirements for over-the-road transportation of CNG/CBM include:

- Use of DOT-approved tanks (e.g., DOT-3AAX seamless steel cylinders) that do not exceed rated tank pressure
- Less than 0.5 lb water vapor/million scf
- Minimum methane content of 98%
- Appropriate HAZMAT markings, (i.e., markings for Class 2, Division 2.1 flammable gas).

In addition to these requirements, California DMV regulations require that drivers operating CNG bulk transportation vehicles possess a Class A commercial driver's license with endorsements for driving tank vehicles that contain hazardous materials.

### **Over-the-Road Transportation of Liquefied Biomethane**

The regulations pertaining to over-the-road transportation of LNG are assumed to be fully applicable to over-the-road transportation of LBM (49 CFR 171 – 180, Hazardous Materials). Since LNG is a liquefied version of natural gas, DOT HAZMAT tables classify it as a flammable gas hazardous material (Class 2, Division 2.1).

Bulk LNG is transported in LNG tankers, typically class 8 vehicles consisting of a tractor towing a 10,000 gallon tanker. Because it is liquid, and therefore denser than CNG, LNG is transported at lower pressures (e.g., 20 to 150 psi); however it is a cryogenic liquid and must be kept at extremely low temperatures (e.g., around -260° F). This requires the use of insulated, double-walled tankers and special equipment capable of operating under extremely low temperature conditions. Some of the critical HAZMAT vehicle requirements for over-the-road transportation of LNG (and therefore, LBG) include:

- DOT-approved tanks (e.g., double-walled, insulated steel tank)
- Two, independent pressure-relief systems
- Appropriate HAZMAT markings (i.e., markings for Class 2, Division 2.1 flammable gas)
- Maximum one-way travel time marking

In addition to these requirements, California DMV regulations require that drivers operating LNG bulk transportation vehicles must possess a Class A California driver's license with endorsements for driving tank vehicles that contain hazardous materials.

### **Distribution via Natural Gas Pipeline Network**

We are currently unaware of any federal, state, or local regulations expressly prohibiting the distribution of biomethane via the natural gas pipeline network; however in practice, this has been attempted only once in the USA (at the King County South Wastewater Treatment Plant in Renton, Washington). California law requires the CPUC to regulate the use of biomethane from

landfills (landfill gas) because of its vinyl chloride content. These regulations set extremely stringent standards for use of biomethane from landfill gas in a natural gas pipeline.

Local natural gas distribution networks (i.e., mains and service pipelines) are owned by local gas utilities (regulated/investor-owned or municipal), which distribute the gas to customers but do not own the gas production facilities. These utilities require that any gas transported through their systems conform to specific gas quality and interchangeability requirements at the point of receipt.

The two major regulated gas utilities in California are PG&E and SoCalGas; these utilities provide natural gas for most of northern and southern California, respectively. Default gas quality and interchangeability requirements are set forth in PG&E's Rule 21 and SoCalGas's Rule 30 (although these requirements may be superseded by specific agreements). Key default requirements are summarized in Table 7-3.

**Table 7-3 Basic Pipeline Quality Standards for Major California Distributors**

<b>Gas Component or Characteristic</b>	<b>Pacific Gas and Electric Company</b>	<b>Southern California Gas Company</b>
Carbon dioxide (CO <sub>2</sub> )	≤1%	≤3%
Oxygen (O <sub>2</sub> )	≤0.1%	≤0.2%
Hydrogen sulfide (H <sub>2</sub> S)	≤0.25 grains/100 scf	≤0.25 grains/100 scf
Mercaptan sulfur	≤0.5 grains/100 scf	≤0.3 grains/100 scf
Total sulfur	≤1 grain/100 scf	≤0.75 grains/100 scf
Water (H <sub>2</sub> O)	≤7 lb/million scf	≤7 lb/million scf
Total inerts	No requirement	≤4%
Heating value	Specific to receipt point	970 – 1,150 Btu/scf
Landfill gas	Not allowed	No requirement
Temperature	60 – 100° F	50 – 105° F
<i>Gas Interchangeability<sup>a</sup></i>		
Wobbe number	Specific to receipt point	Specific to receipt point
Lifting index	Specific to receipt point	Specific to receipt point
Flashback index	Specific to receipt point	Specific to receipt point
Yellow tip index	Specific to receipt point	Specific to receipt point

scf = Standard cubic feet

Btu = British thermal units

<sup>a</sup> The various indices— Wobbe number, Lifting index, Flashback index, and Yellow tip index—are all means of determining the gas interchangeability (AGA, 1946)

Additional contractual requirements between a gas utility and a biogas producer would cover quality control, flow metering, and safety items. In all likelihood, a gas utility would resist accepting biomethane from a dairy biogas producer because of gas quality and production reliability concerns. Detailed permitting requirements would be dependent on the contractual

arrangement between the biogas producer and the gas utility and would include, for example, the ownership and physical location of the pipeline connection equipment.

### **Distribution via Dedicated Pipelines**

It is unclear whether state and county regulations pertaining to local pipeline distribution of natural gas would be applicable to local distribution of biomethane (or biogas) via dedicated pipelines. Because these dedicated pipelines would be used for relatively short transport distances, regulations governing interstate transmission of natural gas would not apply.

The California Public Utilities Commission regulates distribution of natural gas through regulated gas utilities such as PG&E and SoCalGas. Establishment of an alternate natural gas pipeline network within an established service territory for a regulated utility is normally prohibited (Richard Myers, California Public Utilities Commission, personal communication, 14 December 2004). It is not clear if biogas or biomethane would be considered natural gas if an attempt were made to distribute it via a dedicated pipeline. If the issue arises, a CPUC ruling might be required.

If we assume that biogas and biomethane are not considered to be natural gas from a local distribution perspective, transporting “raw” or pipeline-quality biogas via a dedicated pipeline within a regulated or unregulated service area (e.g., a municipal gas utility service area) would be subject to the standard city and county regulations and permitting process for underground pipe installations. There is another potential obstacle, however; some local regulations specify that permits for underground pipelines carrying gas can only be granted to public utilities. For this reason, having a local utility company as a partner in a biogas/biomethane project could be an important asset during the permitting process.

Obtaining the necessary permits for siting, constructing, and operating dedicated biogas/biomethane pipelines could be an extremely complex, time-consuming, and expensive process depending on the location of the proposed pipelines (i.e., what land they will cross). Permits from state, local, and possibly federal agencies may be required. Some of the key agencies, regulatory bodies, and other parties that may become involved are listed below:

- Bureau of Land Management — responsible for granting natural gas pipeline rights-of-way on federal lands
- Municipal governments — responsible for granting local land-use permits, approval of pipeline siting plans, granting of encroachments on public lands, granting of construction permits, and granting of operating permits
- California state or municipal government agencies — must comply with CEQA, which may require an EIR
- U.S. Army Corp of Engineers — responsible for granting Section 404 permit for pipeline excavation projects that discharge dredged or fill material into public waters (per the Clean Water Act)

- Private property owners — negotiate easements for underground pipelines on their property

Additional federal agencies that may be involved in the permitting and review process include the US EPA, US Fish and Wildlife Service, and the Bureau of Reclamation. State agencies that may be involved include the California Coastal Commission, California Regional Water Quality Review Board, and California Department of Fish and Game.

In the simplest case, where biogas pipelines are to be buried along public rights-of-way (e.g., public roads), the pipeline operator would contact the local department of public works and file for an encroachment permit. If the pipeline crosses private property, the pipeline operator will need to negotiate an easement with the property owners. If the land that the pipeline crosses is not zoned to allow underground biogas pipelines (e.g., agricultural land), the pipeline operator will need to contact local planning commission and apply for a conditional use permit. In addition, any modifications to property owned by the pipeline operator will require a building permit from the city or county planning commission. Finally, the pipeline operator will need to subscribe to the appropriate local “dig alert service” and register the locations of all underground pipelines that it operates.



## 8. Financial Analysis of Biomethane Production

As sources of renewable energy, biogas and biomethane compete in one of two markets: electricity and natural gas (including natural gas vehicle fuels). This chapter provides an overview of these two markets, paying particular attention to how their current structure and pricing might affect the biomethane industry. Factors related to the commercial production and distribution of biomethane are also discussed. The chapter concludes with an evaluation of the estimated costs for building and operating a biogas/biomethane facility and a comparison of these costs to the potential revenue from the sale of the gas.

### **Biogas and Biomethane as Commercial Products**

Dairy biogas has been treated as an unregulated waste product with very little value. As this study has shown, biogas can be used to create at least two renewable energy products, electricity and biomethane, both of which have an economic value. To understand the revenue opportunities that they present, however, we need to understand the existing markets for electricity and natural gas: what do these items cost and what barriers might exist to selling electricity generated from biogas or biomethane into these markets?

#### ***Electricity Markets***

Electricity is different from all other commodities in that it cannot be stored. Electricity is generated on demand, when it is needed. Thus the capacity of the system is as important as the quantity of electricity that is generated. The electrical load is the flow of electricity required at a specific point in time. Kilowatts are used to measure the system's capacity, while kilowatt-hours indicate the amount of electricity that a system will generate or use in one hour. For example, a 1-kW generator that is running 100% of the time will generate 8,760 kWh in a year.

Baseload electricity is electricity that is generated all the time, such as electricity from a nuclear plant which is very hard to turn on and off. Peaking electricity is generated upon demand during periods when the load is highest. An electricity source whose production matches the demand is a load-following resource. For example, a solar photovoltaic system is a load-following resource because its output increases at the same time that demand for air conditioning is highest. California's peak demand for electricity is driven by summer air conditioning usage.

Despite the restructuring of California's electricity market in 1996 as a result of the passage of AB 1890 (Electric Utility Industry Restructuring Act), California's electricity market remains regulated and strapped by complex rules. California's peak demand for electricity is around 60,000 MW. Even if every dairy in the state generated electricity with biogas from anaerobic digesters, they could produce about 120 MW.

### Cost of Electricity

Electricity is priced in kWh or MWh (1 MWh equals 1,000 kWh). Electricity price analysis in California is complex because the retail price includes many components in addition to charges for electricity generation: demand charges, standby charges, transmission and distribution charges, public purpose charges, nuclear decommissioning charges, Department of Water Resources bond servicing, etc. To further complicate matters, a dairy may have many meters, with different tariffs applying to each meter. Often, these are time-of-use tariffs that reflect different charges for different times. For example, the winter base load tariff may be \$0.03/kWh, while summer peak may be \$0.20/kWh. On average, a dairy spends \$0.09 to \$0.11/kWh retail for electricity, but this varies depending on the specific utility, the tariff structure that applies to the dairy, and the dairy's time-of-use pattern.

### Opportunities and Obstacles for Selling Biogas-Generated Electricity

Dairies that use biogas from anaerobic digesters to generate electricity face market barriers. Under California's current market structure, most dairies cannot sell their electricity. Only if a dairy is large enough to dispatch 1,000 kW, which is very unlikely, can it contract with California's Independent System Operator to sell its electricity.

California's Renewable Portfolio Standard (RPS) provides a potential opportunity for dairies (California SB 1038 of 2002; CEC, 2005) to sell electricity generated from biogas combustion, although there are several problems that must be surmounted. One problem is that bidders must be able to dispatch 1,000 kW, a large amount for one dairy. PG&E has agreed to accept an aggregated bid from more than one dairy if the total meets the 1,000-kW requirement. Pricing is another problem. To meet their target, the California investor-owned utilities (PG&E, Southern California Edison [SCE], and San Diego Gas and Electric [SDG&E]) accept bids and buy the "least cost, best fit" product. Utilities are required only to purchase renewable electricity that is at or below a market price referent that CPUC has determined to be \$0.0605/kWh. A small state fund is available to subsidize purchases that are bid at a higher price, but overall, it is uncertain how much benefit, if any, dairy digesters will receive from the RPS in its current form.

Alternatively under PURPA, if a dairy's generator has a *nameplate rating* of less than 100 kW and the local utility is cooperative, the dairy could contract to sell its electricity to the utility. The price it receives will be the utility's *avoided cost*, currently about \$0.06/kWh.

A pilot program, legislated under AB 2228, created a limited net metering benefit that could provide some benefits to dairies that generate electricity (see <[http://www.energy.ca.gov/-distgen/notices/2002-11-18\\_forum/AB\\_2228.PDF](http://www.energy.ca.gov/-distgen/notices/2002-11-18_forum/AB_2228.PDF)>). Although charges for electricity generation can be avoided through this program, most other components of the rate structure such as



transmission and distribution, demand charges, public purpose funds, etc. must still be paid. For a typical dairy, these “extra” costs average \$0.055 per kWh.<sup>1</sup> Even so, net metering can offer a dairy some financial benefit for those periods when electricity generation exceeds usage. Another useful provision of AB 2228 allows a dairy to aggregate all its meters when crediting exports against imports. (Dairies may have as many as 20 electrical meters.) The net metering legislation does not apply to municipal electrical utilities and the law will expire, under its sunset provision, in January 2006. The dairy industry is supporting AB 728 which will have the law extended and improved.

Besides the limited financial opportunities, dairy digesters face barriers to interconnection. For safety reasons, utilities require distributed generators to obtain an interconnection contract as described under each utility’s CPUC-approved Rule 21. First, the dairy must pay a fee for the utility to process the application. If deemed necessary, the utility will undertake an interconnection study and costs for this study must be borne by the applicant. Finally, the utility may require changes to the design of the project; there is no appeal from the utility’s decision. Some dairies believe that the utilities are making the interconnection process unnecessarily expensive and difficult.

Changes in the electrical market structure or in any of the provisions discussed above will affect the viability of dairy biogas electrical generation. If net metering currently available under AB 2228 is not renewed by the approval of AB 728, it will have an adverse affect on dairy biogas generators. If someone offers a price for electricity generated from dairy biogas that is above the cost of production (currently about \$0.07 to \$0.10/kWh), it will encourage more biogas production. In the current market structure, a dairy that can use the electricity it generates on-farm obtains the best financial return because it avoids purchasing electricity at retail cost.

When the retail price of electricity is high, dairies will have more incentive to generate electricity—even if only for their own on-farm use. Rather than reducing commercial biogas production, problems in the electricity market may encourage dairies to use biogas as a feedstock to produce biomethane.

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<sup>1</sup> For specific tariffs see Pacific Gas and Electric Tariff E-BIO, Southern California Edison Tariff BG-NEM, and San Diego Gas and Electric Tariff NEM-BIO.

## Natural Gas Markets

California consumes about 6 billion ft<sup>3</sup> of natural gas per day. This gas is burned directly as a fuel, used as a feedstock in manufacturing, or used to generate about one-third of California's electricity (the share used in electricity generation is increasing). Eighty-four percent of the natural gas used in California originates outside the state.

## Natural Gas Prices

There are three natural gas prices relevant to this report. The wellhead price is the price at the point of origin of the gas. In the West, this is also called the Henry Hub price. The city-gate price is the price when it is delivered to the distributing gas utility from the natural gas pipeline or transmission facility. It incorporates the wellhead price and transportation to the city gate. The commercial price is the price a commercial customer pays. In this discussion we will reference the small commercial price, because that is the price a dairy would pay for its use.

Most dairies are not on the natural gas grid. If they were most of them would be in PG&E territory and would be charged prices on the small commercial gas tariff. Those prices have varied considerably over the last several years, and are currently at a high price historically, as shown in Table 8-1. The prices shown are for small commercial users; prices for large commercial users are slightly lower.

Table 8-1 Average Price of Natural Gas for PG&E Small Commercial Users, 2000 – 2005

Year	Average Price per 1,000 ft <sup>3</sup> <sup>a</sup> (dollars)
2000	7.62
2001	9.52
2002	6.06
2003	8.49
2004	8.38
2005 <sup>b</sup>	9.84

<sup>a</sup> Price is yearly average based on first 4,000 therms of usage.

<sup>b</sup> Price for 2005 reflects first five months of year only.

Natural gas prices change every month. Summer rates are slightly lower than winter rates, and the rate for the first 4,000 therms of usage is higher than the rate for usage in excess of 4,000 therms. (One therm is 100,000 Btu or approximately 100 ft<sup>3</sup> methane.). Table 8-1 indicates average prices (summer and winter) charged for the first 4,000 therms of usage over the past five years.

Table 8-2 shows current wellhead, city-gate, and small commercial retail distribution prices as well as the six-year high and low price for each category. In May 2005, PG&E's price of natural

gas to a small commercial user (such as a dairy), averaged \$9.84 per 1,000 ft<sup>3</sup>, down from \$10.90 in December 2004. As recently as April 2004, the price was \$6.94. As shown in Table 8-2, the range of small commercial retail prices in the last five years went from a low of \$4.03 in October 2001 to a high of \$17.30 in January 2001.

**Table 8-2 Natural Gas Wellhead, City-Gate, and Distribution Prices (Current Price and Historical Highs and Lows from 2000 through 2005)**

<i>Natural Gas</i>	Dollars per 1,000 ft <sup>3</sup>		
	Current Price <sup>a</sup>	Price Range 2000 – 2005	
		Low	High
Wellhead price <sup>b</sup>	\$6.05	\$2.19	\$6.82
City-gate price <sup>b</sup>	\$7.44	\$3.27	\$8.91
Distribution price (small commercial retail) <sup>c</sup>	\$9.84	\$4.03	\$17.30

<sup>a</sup> May 2005

<sup>b</sup> Source: US DOE Energy Information Administration website  
<[http://tonto.eia.doe.gov/dnav/ng/ng\\_pri\\_sum\\_dcu\\_nus\\_m.htm](http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm)>

<sup>c</sup> Source: Pacific Gas and Electric Rate Information website <<http://www.pge.com/rates/tariffs/GRF.SHTML#GNR1>>

The wellhead price of natural gas is significantly less than the retail price, typically in the range of \$5 to \$6 per 1,000 ft<sup>3</sup>. In December 2004, the wellhead price was \$6.25/1,000 ft<sup>3</sup>, its highest level since January 2001. In 2004, the average wellhead price was \$5.49/1,000 ft<sup>3</sup> (see U.S. Energy Information Administration website <[http://tonto.eia.doe.gov/dnav/ng/ng\\_pri\\_top.asp](http://tonto.eia.doe.gov/dnav/ng/ng_pri_top.asp)>).

### Opportunities and Obstacles for Selling Biomethane on the Natural Gas Market

Electrical usage is ubiquitous, but much of California's rural areas are not on the natural gas grid. Whether or not a dairy produces biomethane will depend on its ability to get the biomethane to a profitable market. As discussed in Chapter 5, biomethane can be used for on-farm purposes such as a load-following electrical resource or as a fuel for chillers, heating, pumps, or vehicles. However, converting these items to run on biomethane would be expensive and, on a typical dairy it would not be practical to use more than a fraction of the biomethane generated (if all biogas were upgraded). Thus, in all likelihood, biomethane production will be cost effective only if the biomethane can be sold to an off-dairy customer, either by distributing it through a natural gas pipeline grid, or by transporting it by private pipeline or vehicle to a site where it can be used or sold.

One obstacle to using a utility grid pipeline to transport biomethane is that the biomethane must meet the generally stringent quality standards of the utility (see Chapters 5 and 7). Also, the dairy must secure a contract with the utility. If the biomethane cannot be put into the grid, either because a natural gas pipeline is not accessible to the dairy, or because of quality or regulatory barriers, then it must be transported over the road or through a dedicated pipeline to a site where it can be used or sold (see Chapters 4 and 7).

### Comparison of Natural Gas and Electricity Prices

Natural gas prices are an important component of electrical prices because a third of California's electricity comes from combusting natural gas. At the wholesale level, prices for natural gas and electricity are correlative. At the retail level there is less correlation because of price regulation, hedging, market power, environmental permitting, and a variety of other issues (Bushnell, 2004). Electricity cannot be stored, so prices are very responsive to even small changes in demand, making retail electricity prices far more volatile than natural gas prices.

Electricity and natural gas prices can be compared by evaluating their relative energy content and the amount of natural gas (in ft<sup>3</sup>) it takes to produce 1 kWh of electricity. In its raw state (i.e., when it comes out of the ground), natural gas can vary tremendously in methane content, typically ranging from 70 to 90% methane (see Natural Gas Supply Association website at <<http://www.naturalgas.org/overview/background.asp>>). Before it can be transported and used commercially, natural gas must meet pipeline standards. These standards vary by utility and pipeline (see Table 7-3 in Chapter 7), but commercial or pipeline-quality natural gas is typically 97% methane with small amounts of other light hydrocarbons such as propane and butane. .

Pure methane contains 1 million Btu/1,000 ft<sup>3</sup>. To simplify our discussion, we will consider commercial natural gas to have the same Btu content as pure methane. 1 kWh of electricity contains 3,412 Btu (see Appendix E for more information regarding the Btu content and equivalencies of various fuels). Thus, the energy content of 3.4 ft<sup>3</sup> of natural gas is the same as 1 kWh of electricity. Of course there is a major efficiency loss whenever one form of energy is converted into another. In the case of converting natural gas to electricity, gas-fired peaking turbines are 33% efficient, and modern central station base load combined cycle gas turbines are about 50% efficient. Dairy generators are typically 28% efficient. Table 8-3 shows the approximate amount of natural gas (or biomethane) it would take to generate 1 kWh of electricity at these various conversion efficiencies.

Table 8-3 Natural Gas to Electricity Conversion at Various Efficiency Rates

Conversion Efficiency Rate (%)	Btu	Volume of Natural Gas (ft <sup>3</sup> ) Needed for 1 kWh Electricity
28	12,000	12.0
33	10,400	10.4
50	6,800	6.8
100	3,400	3.4

A utility generator with a conversion efficiency of 50% will require about \$0.041 worth of natural gas to produce 1 kWh of electricity. This is, historically, fairly expensive. During the 1990s, for example, when the price of natural gas averaged below \$2/1,000 ft<sup>3</sup>, the same utility would have spent less than \$0.015 on natural gas to generate 1 kWh (see U.S. Energy Information

Administration website at <[http://tonto.eia.doe.gov/dnav/ng/ng\\_pri\\_top.asp](http://tonto.eia.doe.gov/dnav/ng/ng_pri_top.asp)> for historical gas prices).

## **Estimated Costs for a Dairy Anaerobic Digester Facility**

This section presents estimated costs to build an anaerobic digester for electrical generation as well as an anaerobic digester to create biomethane. The estimated cost ranges are meant to be general guidelines, not costs for a specific project.

### ***Basic System Components***

A dairy anaerobic digester that will be used to create biogas for electrical generation has two major components. The first is the system to generate and collect the biogas. This can be a covered lagoon, plug-flow, or complete-mix digester system, as described in Chapter 2 (and Appendix B). The second component is the system to generate the electricity. In its simplest form, this may consist only of a generator and control system; more sophisticated systems may include H<sub>2</sub>S reduction and NO<sub>x</sub> (catalytic) control. Waste heat is usually captured and used to replace natural gas or propane in heating.

A dairy anaerobic digester whose ultimate purpose is to produce biomethane uses the same sort of digester to generate and collect the biogas. The biogas is then upgraded to biomethane by removing the H<sub>2</sub>S, moisture, and CO<sub>2</sub> (see Chapter 3). Finally, the biomethane is compressed or liquefied, stored, and/or transported to a location where it can be used.

### ***Cost Range for Dairy Anaerobic Digester and Electrical Generation Facility***

For this study, we analyzed the costs for 18 dairy digesters that were reported in the Lusk Casebook (Lusk, 1998) and several other sources (Moser and Mattocks, 2000; Mattocks, 2000; Nelson and Lamb, 2000). For details see Appendix G. The average cost for building the 12 anaerobic digester systems cited in these sources that generated on average more than 50 kilowatts was about \$4,500 per average kilowatt generated. In contrast, an analysis of four projects completed under California's Dairy Power Production Program showed average costs of \$6,100 per nameplate kilowatt. Based on these "high" and "low" averages, Table 8-4 provides cost ranges for the various digesters, both with and without equipment to control NO<sub>x</sub> emissions. The dairies that applied to the Dairy Power Production Program also indicated on average that the value of the heat they expected to produce was about 20% of the value of the electricity. If co-generation of heat and power were used to offset the cost of electrical generation, the costs per kWh would come down by 20%, as shown in Table 8-4. These costs compare favorably to the dairy's retail price of electricity, currently \$0.09 to \$0.11/kWh.

**Table 8-4 Estimated Costs of Generating Electricity from Biogas Produced on a Typical 1,000-Cow Dairy <sup>a</sup>**

	Cost per Kilowatt (\$)		Cost per Kilowatt-Hour (\$)			
			With Co-Generation		Without Co-Generation	
Cost Range	NO <sub>x</sub> Control	No NO <sub>x</sub> Control	NO <sub>x</sub> Control	No NO <sub>x</sub> Control	NO <sub>x</sub> Control	No NO <sub>x</sub> Control
High average <sup>b</sup>	7,000	6,100	0.077	0.069	0.096	0.086
Low average <sup>c</sup>	5,400	4,500	0.062	0.054	0.077	0.067

a A typical 1,000-cow dairy is assumed to have biogas production of 50 ft<sup>3</sup>/cow/day, with 60% methane content; thus, the dairy will produce 30 ft<sup>3</sup>/cow/day or 30,000 ft<sup>3</sup>/day methane (equivalent to 1,250 ft<sup>3</sup>/hour). At an approximate Btu content of 1,000 Btu/ft<sup>3</sup> methane, this is equivalent to about 100 kW of electrical capacity (1 kW equals approximately 3,415 Btu/hour). To convert this to kWh, we must consider the efficiency of the conversion process, which is estimated at 28% for a dairy operation. To produce 1 kWh of electricity at 28% conversion efficiency takes approximately 12.0 ft<sup>3</sup> methane (1 kWh is equivalent to approximately 3.4 ft<sup>3</sup> of methane). Thus, in one day (at a production level of 30,000 ft<sup>3</sup>/day), the dairy can produce 2,450 kWh or 2.45 kWh/cow/day.

b Source: Applications submitted to California Dairy Power Production Program

c Source: Lusk, 1998; Moser and Mattocks, 2000; Mattocks, 2000; Nelson and Lamb, 2000; see Appendix G.

Based on the lower costs, the capital costs for a digester-generator with a capacity of about 100-kW would be about \$450,000 (without NO<sub>x</sub> controls), exclusive of land costs. At a production level of 2,450 kWh/day and operations and maintenance costs of about \$0.015/kWh, a facility with a 20-year life and an 8% cost of capital would have a levelized cost of electricity (over 20 years) of \$0.067/kWh. If controls for NO<sub>x</sub> emissions are added (another \$90,000 in capital costs), the levelized cost of electricity goes up to about \$0.077 per kWh. The most likely scenario for California is an anaerobic generator with NO<sub>x</sub> controls and co-generation, which gives a cost range of \$0.062 to \$0.077/kWh. For purposes of further analysis in this report, if only one capital cost is given for anaerobic digestion electricity it is a capital cost of \$4,500 per average kilowatt for 1,000 and 1,500 cow dairies, and a cost 20% lower (based on an assumption reflecting anticipated economies of scale) is used for 8,000 cow and larger dairies.

### **Cost Range for Dairy Digester and Biogas Upgrading Facility**

Estimating the costs of a digester system for biomethane production is more speculative than for a digester-generator. Although a few biomethane facilities have been built on landfills in the USA, the scale for these is far larger than would be needed for a dairy or even a centralized facility serving a group of dairies. To date, no biogas upgrading facility has been built on a dairy, at least not in the USA.

Several biomethane facilities using animal manure and other types of organic waste as a feedstock have been built in Europe. Sweden is the leader in this type of facility, with 20 plants that produce biomethane. The biogas used for these facilities is generated from organic waste such as manure, slaughterhouse waste, and food processing waste. Other biomethane plants exist in Switzerland, Denmark, and the Netherlands.

### **Actual Costs of Plants to Upgrade Biogas to Biomethane in Sweden**

As part of this project, several of the authors of this report visited Sweden in June 2004 to tour biomethane plants (WestStart-CALSTART, 2004). During our tour, we were able to obtain cost data on four biomethane plants.

The scale of the Swedish biomethane facilities is smaller than the landfill-gas upgrading plants in the USA, but larger than what would be required for most dairy facilities. The Linköping facility would need 27,000 cows, while the Laholm and Borås facilities would need 7,000 to 10,000 cows each. The smallest plant, at Kalmar, could operate with manure from 1,500 to 2,000 cows. Each of these four plants removes  $\text{H}_2\text{S}$ , moisture, and  $\text{CO}_2$  from the raw biogas. The resultant biomethane is put into a pipeline, or compressed for storage and/or transportation.

Table 8-5 summarizes the costs from the four Swedish plants. These costs reflect Swedish experience; no doubt U.S. costs would be different, for a variety of reasons. The costs in Table 8-5 also reflect a range of costs; for example, capital costs per 1,000  $\text{ft}^3$  of produced biomethane decline steadily with volume. The lowest volume plant, Kalmar, cost \$2.20/1,000  $\text{ft}^3$  to build. The Linköping plant was the largest plant; its capital costs were \$0.74/1,000  $\text{ft}^3$ .

In each case, operating and maintenance costs exceed capital costs by a significant margin. This contrasts with electricity generation, where the capital costs exceed the operating costs. Table 8-5 shows that operating costs per  $\text{ft}^3$  increase with volume, based on the three Swedish examples for which we have data on operating cost or total cost. This is counterintuitive and, more than likely, a random result. Analysis of operating costs at landfill gas plants in the USA revealed a wide range of operating costs that were not correlated with size (Augenstein and Pacey, 1992, p. 17).

Based on the three Swedish examples, for which operating cost data was either available or derived, the cost to produce and compress biomethane from biogas ranged from \$5.48 to \$7.56 per 1,000  $\text{ft}^3$ . All three of these plants are larger in scale than a normal dairy upgrading plant would be—approximately 8,000 cows would be required to produce as much biogas as is processed in the smallest of the three (Borås). Neither total costs nor operating costs were available for the Kalmar facility, which is the only one of the four plants comparable in size to any but the largest California dairies.

### **Extrapolation of Actual Costs to Estimated Costs for a Dairy Biogas to Biomethane Plant**

To try to project reasonable costs for a small dairy biogas upgrading plant, we used the capital cost of the smallest Swedish plant, Kalmar, which was estimated to be \$500,000. This cost was also cross-checked: QuestAir Technologies, Inc. (<[http://www.bctia.org/members/QuestAir\\_Technologies\\_Inc.asp](http://www.bctia.org/members/QuestAir_Technologies_Inc.asp)>) claims to have a small skid-mounted pressure-swing absorption plant that can remove  $\text{CO}_2$  in the needed quantities. This plant retails for about \$300,000. After adding \$50,000 for an  $\text{H}_2\text{S}$  scrubber and \$150,000 for storage, the total cost would be about \$500,000.

Table 8-6 shows the estimated costs for three hypothetical plants: a small dairy biogas upgrading plant and two large dairy biogas upgrading plants which differ in operating costs. The estimated operating cost for the small dairy plant was taken from the average of the three Swedish plants discussed above. Operating costs for “large dairy A” are based on the Boras plant, and “large plant B’s” operating costs are based on the Linkoping plant.

The operating and maintenance cost exceeds the capital costs in all three hypothetical plants. The actual building and operating of a plant in the USA will likely have a different cost than the Swedish plant. It will probably cost more since U.S. contractors will not be as far along the learning curve as Swedish contractors. It may be more expensive to operate and maintain than Swedish plants because of the lack of experience in the USA, though labor rates may be lower. Another difference is that the Swedish plants are centralized facilities that process several different feedstocks.

#### **Estimated Cost of Anaerobic Digester and Biogas to Biomethane Plant**

The full cost of producing biomethane at a dairy includes an anaerobic digester that generates and collects the biogas as well as the upgrading facility. Earlier in this chapter we reviewed costs for an anaerobic digester in the context of electrical generation. Table 8-7 shows combined costs for an anaerobic digester and upgrading plant for the same hypothetical plants shown in Table 8-6: a small dairy with a low-cost digester and two large dairies (or centralized facilities), whose operating costs are based on the Boras and Linkoping plants in Sweden.

#### **Estimated Cost of Liquefied Biomethane Plant**

A final alternative to consider from a financial aspect is an upgrading plant that produces liquefied biomethane (instead of compressed biomethane) as its final product. As discussed below, the scale of this plant needs to be at least twice as large as the examples shown in Tables 8-6 and 8-7.

We saw in Chapter 4 that LBM cannot be stored economically for more than a few days because the product will begin to evaporate as temperatures rise. If LBM production is sufficient to fill a 10,000-gallon cryogenic tanker truck every few days cost effectively, LBM may prove to have a better market than CBM in California (currently almost all of the LNG used in California is trucked in from out of state).



**Table 8-5 Operating Parameters and Associated Costs for Four Swedish Biogas-to-Biomethane Plants**

Facility Name	Methane Output <sup>a</sup>		Capital Costs (\$) <sup>b</sup>			Operation & Maintenance (\$ per 1,000 ft <sup>3</sup> )	Total Costs (\$ per 1,000 ft <sup>3</sup> )
	ft <sup>3</sup> /hr	ft <sup>3</sup> /d	Total	Annual Amortization (8% for 20 years)	Costs per 1,000 ft <sup>3</sup>		
Linköping <sup>c</sup>	33,606	807,000	2,133,333	217,285	0.74	6.82	7.56
Laholm <sup>d</sup>	12,355	297,000	1,200,000	122,223	1.13	4.53	5.66
Boras <sup>e</sup>	9,884	237,000	1,500,000	152,778	1.77	3.71	5.48
Kalmar <sup>f</sup>	2,648	64,000	500,000	50,296	2.20	---	---

<sup>a</sup> Methane production for all plants given in cubic meters (m<sup>3</sup>) and converted to cubic feet (ft<sup>3</sup>) (35.3 ft<sup>3</sup> / m<sup>3</sup>).

<sup>b</sup> Costs for all plants given in Swedish Kroners and converted to US dollars (7.5 SK /\$).

<sup>c</sup> Figures provided for Linköping included biogas input (1,360 m<sup>3</sup>/hr), total costs (2 SEK/m<sup>3</sup>) and capital costs (16,000,000 SEK); all other figures derived.

<sup>d</sup> Figures provided for Laholm included methane output (350 m<sup>3</sup>/hr), capital costs (9,000,000 SEK), and operating costs (1.2 SEK/m<sup>3</sup>); all other figures derived.

<sup>e</sup> Figures provided for Borås included methane output (280 m<sup>3</sup>/hr) and capital costs as shown (\$1,500,000), and total costs (1.45 SEK/m<sup>3</sup>); all other figures derived.

<sup>f</sup> Figures provided for Kalmar included methane output (75 m<sup>3</sup>/hr) and capital costs as shown (\$500,000); all other figures derived, where possible.

**Table 8-6 Estimated Costs for Three Hypothetical Dairy Biogas-to-Biomethane Plants**

Facility	No. Cows or Cow-Equivalents <sup>a</sup>	Methane ft <sup>3</sup> /d	Estimated Capital Costs (\$)			Estimated Operation & Maintenance (\$ per 1,000 ft <sup>3</sup> )	Estimated Total Costs (\$/1,000 ft <sup>3</sup> )
			Total	Annual Amortization (8% for 20 years)	per 1,000 ft <sup>3</sup> Biomethane		
Small dairy plant <sup>b</sup>	1,500	45,000	500,000	50,926	3.10	5.02	8.12
Large dairy A <sup>c</sup>	8,000	240,000	1,500,000	152,778	1.74	3.71	5.46
Large dairy B <sup>d</sup>	8,000	240,000	1,500,000	152,778	1.74	6.82	8.56

<sup>a</sup> Based on an approximate figure of 30 ft<sup>3</sup>/cow/day of methane.

<sup>b</sup> Operating costs based on average of three Swedish plants; capital costs based on Kalmar plant.

<sup>c</sup> Operating and capital costs based on Borås plant in Sweden.

<sup>d</sup> Operating cost based on Linköping plant in Sweden; capital costs based on Borås plant.

**Table 8-7 Estimated Costs for Three Hypothetical Dairy Anaerobic Digester and Biogas to Biomethane Plant**

Facility	Number of Cows or Cow-Equivalents	Methane <sup>a</sup> ft <sup>3</sup> /d	Dollars per 1,000 ft <sup>3</sup> Biomethane				
			Estimated Cost for Anaerobic Digester (\$ per 1,000 ft <sup>3</sup> )		Estimated Cost for Biogas Upgrading (\$ per 1,000 ft <sup>3</sup> )		Estimated Total Cost (\$/1,000 ft <sup>3</sup> )
			Capital	Operation & Maintenance	Capital	Operation & Maintenance	
Small dairy plant <sup>b</sup>	1,500	45,000	3.10	0.60	3.10	5.02	11.82
Large dairy A <sup>c</sup>	8,000	240,000	2.48	0.50	1.74	3.71	8.44
Large dairy B <sup>d</sup>	8,000	240,000	2.48	0.50	1.74	6.82	11.54

<sup>a</sup> Based on an approximate figure of 30 ft<sup>3</sup>/cow/day of methane.

<sup>b</sup> Operating costs based on average of three Swedish plants; capital costs based on Kalmar plant.

<sup>c</sup> Operating costs and capital based on Boras plant in Sweden.

<sup>d</sup> Operating cost based on Linköping plant in Sweden; capital costs based on Boras plant.

According to Acion Systems, for \$1 million it is possible to build a LBM plant capable of processing 200,000 ft<sup>3</sup> of biogas daily to generate 860 diesel gallon equivalents (DGE) of LBM. The plant would need 300 kW of electrical generation. To operate, it will also need all three components discussed above: an anaerobic digester, a generator to create electricity from a bit less than half of the biogas, and a plant to upgrade and liquefy the remaining biogas to produce LBM. However, a facility of this size would only produce enough LBM to fill a 10,000-gallon LNG tanker truck every seven days. To minimize thermal losses and keep the operation economical, the LBM should not be stored for this length of time. Therefore, we chose to examine costs for a plant twice this size (i.e., one that can produce about 1,714 DGE of LBM each day). As a comparison to the earlier plants we considered, this facility would need to digest waste from 13,760 cows.

Input requirements, expected output, and costs for such a facility are shown in Table 8-8. The facility would use part of the biogas produced in its digester to generate electricity to run the LBM plant; the remainder of the biogas would be feedstock for the biogas upgrading plant. The entire cost of the anaerobic digester is applied to the cubic feet of biomethane incorporated into the LBM produced, since the remainder of the biogas is an intermediate product used to generate electricity needed in liquefaction. Thus, the operating cost of the anaerobic digester per 1,000 cubic feet of methane is higher than the costs shown in Tables 8-6 and 8-7. The operating costs of electrical generation are also applied only to the LBM produced.

An 8,000-cow dairy could produce the same amount of liquefied biomethane, but would have to purchase 300 kW of electricity. Since costs for generating electricity from anaerobic digestion

should be less than costs for purchased electricity, the smaller (8,000-cow) dairy would have higher production costs.

For comparison, the current fleet pump price for LNG as a vehicle fuel is about \$1.00 per LNG gallon or \$1.67 per DGE (NexGen Fueling, personal communication, 28 March 2005). Fleets with long-term contracts may pay much less. Of that \$1.00, Federal excise tax is about 12 cents, state excise tax is 6 cents, and state and local sales tax is about 8 cents. Thus, the price of LNG before tax is about \$0.74 per gallon, or about \$1.23 per DGE. This price reflects the cost of transporting the fuel to the fueling station as well as built-in cost recovery and profit for the fueling station; but neither these costs nor taxes are shown in Table 8-8.

Table 8-8 Estimated Inputs, Outputs and Associated Costs for Large Dairy Digester, Generator, and Liquefied Biomethane Facility

<b>Input Requirements</b>		<b>Estimated Component Costs (\$)</b>	
Number of Cows	13,760	Anaerobic digester	5,160,000
Cows for electricity	5,760	Generator	540,000
Cows for LBM	8,000	Upgrading plant to LBM	2,000,000
Biogas production (ft <sup>3</sup> /day)	688,000	Total capital cost	7,700,000
Biogas for electricity	288,000		
Biogas used for biomethane feedstock	400,000		
Electrical capacity (kW)	600		
<b>Facility Output</b>		<b>Estimated Costs to Produce LBM (\$)</b>	
Biomethane ft <sup>3</sup> /day (feedstock for LBM)	240,000	Capital cost per yr, amortized at 8% over 20 years	785,262.00
LBM output gal/day <sup>a</sup>	2,857	Capital cost / 1,000 ft <sup>3</sup> biomethane	8.595
LBM output in DGE/day <sup>b</sup>	1,714	Digester O&M / 1,000 ft <sup>3</sup> biomethane	1.43
<sup>a</sup> 1 gal of LBM = 84 ft <sup>3</sup> methane <sup>b</sup> 1 DGE of LBM = 140 ft <sup>3</sup> methane		Generator O&M / 1,000 ft <sup>3</sup> biomethane	0.90
		LBM upgrade plant O&M / 1,000 ft <sup>3</sup> biomethane	3.71
		Total cost for producing LBM (per 1,000 ft <sup>3</sup> biomethane)	15.00
		Total cost per DGE of LBM	2.10
		Total cost per gallon of LBM	1.26

### **Estimated Cost to Store and Transport Biomethane**

The cost of producing biogas and upgrading it to biomethane reflect only a part, albeit a substantial one, of the actual costs incurred by the producer. In addition, the producer needs to consider the costs of storing and transporting the biomethane, in whatever format required by the end market. Even if a dairy converted all of its on-farm equipment to run on biomethane (an unlikely scenario), and used only part of its digester biogas as a feedstock for producing biomethane, it could prove necessary to store more than one day's production of biomethane.

Small scale storage can be expensive. For example, a Volvo Bus roof-mounted 1,025-liter, 200-bar CNG storage tank costs \$25,000. When translated to normal gas processing units this is approximately equivalent to \$3.50/scf of stored gas. Storage tanks for CNG, which can also be used to store biomethane, have a typical capacity of 1,000 ft<sup>3</sup> and cost \$2,250 to \$5,000 each. Capital costs for storage vary considerably with the length of time for which the gas must be stored. Each day's storage will add to the capital cost. For example, enough storage capacity to store a day's worth of CBM produced from a 45,000-ft<sup>3</sup>/day plant would add \$100,000 to \$225,000 to the cost of the facility or \$0.60 to \$1.40 per 1,000 ft<sup>3</sup> to the cost of the biomethane production. Two days' worth of storage would double those numbers.

Transportation of biomethane incurs additional costs. Typically, biomethane produced on-farm would need to be transported to a location where it could be used or further distributed, such as an industrial plant or a CNG fueling station. Thus, the costs of trucking the biomethane or pumping it through a dedicated pipeline would need to be added to its production price.

The only way a dairy biomethane producer could avoid incurring the costs of storage and transportation for off-farm use of the biomethane would be to place the biomethane directly into a distribution line connected to the natural gas pipeline grid. Access to a natural gas pipeline is subject to the same kind of regulation and interconnection issues that face distributed electricity generators (see discussion earlier in this chapter). Obtaining contracts to place biomethane in the natural gas grid would take a pioneering effort. In addition, most dairies are not serviced by a natural gas pipeline, which means they have no immediate physical access. However, if obstacles such as these could be overcome, direct placement of biomethane into the natural gas pipeline grid would be the most cost-effective way of getting the gas to market. The down side is that the biomethane would have to compete with city gate or industrial prices for natural gas rather than small commercial retail prices.

The only other option for distribution of biomethane to off-farm markets is to privately pipe or truck the gas to an industrial user or a CNG or LNG fueling station. Both of these alternatives are expensive. A dedicated pipeline system that served the Boras plant in Sweden was just over 4 miles long and cost \$213,000 per mile. Costs could be reduced by using horizontal trenching. In Sweden horizontally trenched pipelines were built for 500 SEK per meter, or about \$100,000 per mile. Estimates for U.S. piping costs vary from \$100,000 to \$250,000 per mile depending on the

number of landowners involved, the need to cross public rights-of-way, the terrain, and similar factors (Rachel Goldstein, US EPA Landfill Gas Program, personal communication with Ken Krich, 1 March 2005). Piping eliminates the need for on-site storage, though there is still a need for storage at the point of usage.

As with the storage costs, transportation adds to the capital cost of the plant. Transportation costs will depend on the distance that the gas needs to be moved. Trucking requires more on-site storage than piping because enough biomethane must be accumulated to fill a tanker. Typically, trucking would occur on a cyclical basis; alternatively enough additional trucks could be purchased or made available so that one truck is always available on-site for filling, thus eliminating the need for other on-site storage. However, trucks also have associated capital costs, as well as operating costs such as fuel and maintenance for the truck, and labor costs for the driver. Other than for LBM, transportation of biomethane by truck costs more per volume than pipeline transport and should only be considered as an interim solution.

#### **Cost Summary: Range of Estimated Costs for Digester and Biomethane Plant**

Based on costs for similar (albeit larger) plants in Sweden, as well as on discussions with equipment suppliers and others, our best estimates for the various capital and operating costs associated with a dairy digester and biogas upgrading plant are shown in Table 8-9.

**Table 8-9 Estimated Range of Costs for Dairy Digester and Biogas to Biomethane Plant**

Component or Process	Dollars per 1,000 ft <sup>3</sup>	
	Low Estimate Large Dairy	High Estimate Small Dairy
<i>Anaerobic digester</i>		
Capital cost	2.50	4.65
Operating cost	0.50	0.60
<i>Biomethane (Upgrading) Plant</i>		
Capital cost	1.55	3.10
Operating cost	3.70	6.80
<i>Biomethane storage</i>	0.00	2.80
<i>Biomethane transport</i>	0.00	0.90

One day's storage cost is included in the biomethane plant capital cost shown in Table 8-9. The extra storage costs depend on the number of days of additional storage required. If the biomethane were sold to a gas utility and entered the natural gas pipeline grid, or if it were transported off the dairy every day, the storage cost would be zero. The high range shown assumes that the plant's total storage is three days' production.

Transportation costs depend on the distance the biomethane needs to be transported. If the biomethane is sold to a gas utility and enters the natural gas pipeline grid, transportation costs are zero. The high number assumes an 8,000-cow dairy that will transport biomethane 5 miles by a dedicated pipeline, which was built at a cost of \$150,000 per mile.

## Summary of Financial Challenges to Building a Biomethane Plant

Like other pioneering renewable energy technologies, the production and distribution of dairy biomethane is not currently cost effective for the private developer without a public subsidy. In time, after a number of small-scale plants are built, costs are likely to come down.

Earlier in this chapter, we discussed the range of possible costs associated with the production of biomethane (Table 8-7). In general, costs for a biomethane plant on a dairy with 1,500 cows would be in the range of \$11.54 per 1,000 ft<sup>3</sup>. Based on the operating costs of several of the Swedish biogas upgrading plants, we projected that, at a very large dairy (8,000 cows) or centralized facility, the cost might be as low as \$8.44 per 1,000 ft<sup>3</sup>.

Table 8-10 compares our estimated costs for producing biomethane to current prices for natural gas. This comparison shows that on today's market, a large dairy could likely produce biomethane for a price lower than that paid by small retail commercial users (like dairies); while a smaller dairy's cost of production would be higher than the going market rate. As discussed earlier, current natural gas prices are at an historic high; wellhead prices in the 1990s, for example, averaged below \$2.00 per 1,000 ft<sup>3</sup>. Also, pioneering biomethane plants will be likely to incur higher costs due to inexperience, lack of qualified designers and contractors, and the need to educate public entities and regulators.

Table 8-10 Estimated Biomethane Production and Distribution Costs on Large (8,000 Cow) Dairy Compared to Current Natural Gas Prices

Biomethane			Natural Gas	
Cost Category	Cost (\$per 1,000 ft <sup>3</sup> )		Price Category	Price <sup>a</sup> (\$per 1,000 ft <sup>3</sup> )
	Low	High		
Production cost	\$8.44	\$11.54	Wellhead <sup>b</sup>	\$6.05
Storage	\$0.00	\$2.80	City gate <sup>b</sup>	\$7.44
Transportation	\$0.00	\$0.90	Distribution <sup>c</sup>	\$9.84

<sup>a</sup> May 2005

<sup>b</sup> Source: US DOE Energy Information Administration website  
<[http://tonto.eia.doe.gov/dnav/ng/ng\\_pri\\_sum\\_dcu\\_nus\\_m.htm](http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm)>

<sup>c</sup> Source: Pacific Gas and Electric Rate Information website <<http://www.pge.com/rates/tariffs/GRF.SHTML#GNR1>>

Unfortunately, production is only part of the story. Since it is unlikely that a farm could cost effectively use as much as half of the biomethane produced by an on-farm upgrading plant, most of the biomethane would need to be stored and transported to market. This adds significant costs

to the enterprise. Private pipelines cost from \$100,000 to \$250,000 per mile, although they eliminate the need for storage. If the biomethane is trucked to market, it must first be stored until enough is accumulated to fill the tanker. Trucking itself is also expensive. The least costly means of biomethane distribution would be access to the natural gas pipeline grid, if a nearby pipeline were available. First, however, the farmer would have to overcome regulatory barriers and resistance from the gas utility; also, the gas utility would not pay the commercial price for the biomethane, but a price based on the wellhead or city gate price. Another possibility is that the dairy could *wheel* the gas via the natural gas grid, that is, pay a transportation fee to use the natural gas grid to convey the biomethane to a nearby industrial user. Producing and distributing LBM may be more economically favorable than other options.

In contrast, generating electricity from biogas can offset retail electric purchases and can be simpler and more profitable than biomethane production. However, there are problems with electrical generation. The farmer may produce more electricity than he can use, if this occurs, the farmer cannot be compensated for the excess electricity under California's current market structure, and the present net metering program in California is not as attractive for the small biogas electric generator as it is for the solar generator. Also, obtaining an interconnection agreement is time-consuming and expensive.

The biomethane industry, like the rest of the renewable energy sector, needs public subsidies, tax credits, or market rules that will help earn a premium for the product during its start-up phase. Regulators and lobbyists for the industry also need to be aware of the cost structure of the biomethane industry. In contrast to anaerobic digester systems that generate electricity, which have higher capital costs than operating costs, biogas upgrading plants that produce biomethane typically have higher operating costs than capital costs. Subsidies that cover even a large portion of the capital costs may be insufficient to stimulate industry growth. If biomethane facilities are to become viable, ongoing sources of renewable energy, they will likely need the support of ongoing production tax credits, a long-term fixed price contract, and/or market rules that provide a premium for its output.





## 9. Developing a Biomethane Industry

To be successful a biomethane enterprise must address two main issues, the production of biomethane from organic waste, and the distribution system that will deliver that biomethane to a user. This chapter discusses some of the broad issues related to development of the biomethane industry in the USA. It also reviews the eight steps needed to develop a successful business plan for a biomethane enterprise, and describes five scenarios for potential biomethane projects.

When this study was designed, we believed that the key barrier to producing biomethane from dairy biogas was the lack of economies of scale in a dairy-sized upgrading plant. As our research—including firsthand observation of operations in Sweden—progressed, however, we learned that the small size of dairy operations is only half of the problem. The other half is the need for a distribution system and a market for the fuel.

Thus, to be a viable economic venture, a dairy plant that produces biomethane must be part of an integrated industry that includes all of these activities:

- Gathering the feedstock
- Producing biogas by anaerobic digestion
- Upgrading of biogas to biomethane
- Storing biomethane
- Transporting biomethane
- Using biomethane

### Lessons from Sweden

In June 2004, several of the authors of this report joined a small California delegation on an educational tour of the Swedish biogas industry. Sweden is the world leader in the use of biomethane as a transportation fuel. During our week long tour we visited five biomethane facilities and met with many organizations (WestStart-CALSTART, 2004). They have 2,300 vehicles, mostly buses, running on biomethane. Biomethane has proven more reliable than natural gas because it is upgraded to a higher standard (Ichiro Sugioka, personal communication, June 10, 2005).

Swedish experience demonstrates that a viable biomethane industry is possible. The Swedes have about 20 biomethane plants of various sizes. In general, these are centralized plants, run by public agencies, which use a variety of biogas upgrade technologies and use different organic feedstocks, not just manure, in their digesters. This co-digestion of wastes improves production yields.

It is important to note, however, that the economics in Sweden are much more favorable for a biomethane industry than they are in the USA. Sweden has no fossil fuel industry of its own and all natural gas is imported. Automotive fuel is more expensive. Greenhouse gas emissions are highly taxed. Public policy is very committed to energy efficiency, reduced dependence on imported fossil fuel, and reduction of greenhouse gas emissions. Swedes are committed to recycling and to reducing or eliminating the use of landfills. The country also has a very high level of cross-industry cooperation and government support for alternative fuels.

The most important lesson we learned during our trip to Sweden was that no biomethane plant should be built until a market for the biomethane has been established and a distribution system designed that can move the biomethane to the market. Drivers of alternative fuel vehicles are not going to detour long distances for fuel; the biomethane must be transported to a location that is convenient for refueling. The Swedish operations depend largely on dedicated pipelines to move biomethane to fueling stations; trucks are typically used only as an interim measure until production volume is sufficient to support a pipeline.

## **Why Should the Public Support the Biomethane Industry?**

As Chapter 8 revealed, the current economics for development of the biomethane industry in the USA are challenging if there is no public subsidy. We feel, however, that there are a number of valid reasons to support the development of this industry through publicly funded subsidies, regulation, or tax incentives. Such subsidies and incentives are always necessary to develop a new source of renewable energy or an alternative transportation fuel.

A society such as ours that is heavily dependent on fossil fuel energy should be actively developing a wide variety of alternative energy resources. We cannot always predict which technologies will prove the most viable for our future needs. To preserve our ability to respond to changing future conditions, however, we need to invest in research and development and to build pilot plants for a variety of these technologies.

Biomethane production addresses California's commitment to renewable energy and to reducing dependence on petroleum. Development of a dairy biomethane industry would help to stimulate California's economy, particularly its rural economy. Biomethane production provides a series of environmental benefits both during the production process and because it can be substituted for fossil fuels. Development of biomethane production technologies and markets today will ensure future preparedness for the growth of this industry should conditions arise that make the production and use of biomethane a more financially viable and/or necessary option.

## ***Energy Independence and Renewable Fuel***

The development of a biomethane industry supports state and federal policy by reducing dependence on imported oil and, more generally, on a finite global supply of fossil fuel. Reduced

dependence on imported energy increases our national security. Replacing imported energy with domestically produced biomethane develops and supports our economy, especially our rural economy. Even if biomethane costs more than imported oil, the use of locally produced energy keeps our money at home and helps to support our rural communities instead of transferring wealth to Saudi Arabia and other oil producers.

California's Renewable Portfolio Standard and similar programs in other states demonstrate a commitment to increasing renewable electrical generation as a proportion of the total electrical mix. Renewable electricity promotes improved air quality, reduces GHG emissions, reduces dependence on imported energy, and preserves finite supplies of fossil fuels.

California's dependence on foreign energy sources for electrical generation (other than Canada) is modest. However, California, as well as the nation, is highly dependent on imported oil from relatively unstable countries for vehicle fuel. California legislators have begun to address this issue. Assembly Bill 2076, which became law in 2000, directed the California Energy Commission and the California Air Resources Board to develop a California Strategy to Reduce Petroleum Dependence. This will include statewide strategies to reduce the growth rate of gasoline and diesel fuel usage, and to increase the use of "nonpetroleum based fuels." Biomethane is one such fuel.

A number of existing federal laws aim to reduce petroleum dependency by supporting the use of ethanol and biodiesel; more laws with this goal are currently being developed. Biomethane serves the same purpose as ethanol and biodiesel and its use should be supported in new legislation. The proposed Energy Policy Act of 2005 would establish a national renewable fuel mandate and includes biomethane (although described in different terms).

### ***Future Fuel Shortages and Increased Prices for Fossil Fuels***

The economics of biomethane production will improve in the face of rising fossil fuel prices. Fossil fuels are a limited resource that will only become more expensive over time. Recent predictions by respected petroleum geologists indicate a decline in world peak oil production, which could occur before 2010 (see <<http://www.peakoil.net/>>). This could have staggering implications for world energy prices. Because of their uneven distribution and use worldwide, there is also an associated risk of supply interruption due to political upheaval (such as happened in 1979 from the overthrow of the Shah of Iran).

When supply is interrupted or threatened, higher prices are a certainty. We can better prepare for shortages if we develop renewable domestic alternatives. As prices rise, domestic sources of renewable automotive fuel will become more valuable and more cost competitive. Biomethane needs to be developed as an additional alternative fuel, alongside ethanol and biodiesel.

## **Environmental Benefits**

There are a number of environmental benefits associated with a biogas upgrading plant that produces biomethane. Methane generated by dairy waste and enteric fermentation makes up about 1% of California's total anthropogenic GHG emissions. On dairies that use flush systems to manage manure, an anaerobic digester collects methane that would otherwise be released to the environment. Whether the methane is used for electricity generation or for biomethane, its combustion reduces GHG emissions (even though CH<sub>4</sub> combustion releases CO<sub>2</sub>, another GHG, the harmful effects of methane are 21 times greater than those of CO<sub>2</sub>, thus the overall net effect is a 21:1 improvement in GHG emissions).

VOCs are an ozone precursor. Research is underway to determine the quantity of VOCs in the biogas generated from dairy manure. Whatever the quantity, the VOCs in the biogas are largely destroyed when biogas is collected and combusted, or when it is upgraded to biomethane and combusted in engines. Biogas combustion creates NO<sub>x</sub>, another ozone precursor, and is expensive to control because of the impurities in biogas. Biomethane, however, can be burned in very low NO<sub>x</sub> microturbines, or in internal combustion engines that, if properly equipped with catalytic controls, will generate very low levels of NO<sub>x</sub>.

Many dairy digesters are built because neighbors complain about dairy odors; digesters reduce these odors substantially. Because they break down manure and other organic material, they also reduce the number of flies. Plug-flow and complete-mix digesters reduce pathogens and weed seeds in the effluent. The whole system improves manure management and wastewater handling on the dairy.

These benefits have an economic value, even though current market conditions in the USA make it hard to quantify that value. In countries that have approved the Kyoto Treaty, reductions in GHG emissions can be bought and sold or traded at an established market value. In the USA, VOC reductions can be traded as ERCs, although it is currently difficult for dairies to participate in ERC markets. The economic benefit of odor reduction is difficult to value, but is nonetheless real. In some cases, odor reduction allows dairies at the urban rural interface to continue operating when political pressure from unhappy neighbors might otherwise be used to close down the dairy.

Further environmental benefits are achieved by the substitution of biomethane in engines for petroleum or natural gas. Biomethane produces no net GHG emissions; the CO<sub>2</sub> released by its combustion represents the product of recent biological processes. In contrast, petroleum and natural gas release GHGs that were captured eons ago, thus introducing an imbalance in the current system.

Greenhouse gases are not currently regulated in the USA, although some states are beginning to address these emissions. California, for example, passed AB 1493, which aims to reduce GHG

emissions from vehicle tailpipe emissions. Under federal law, large landfills are required to capture and combust their landfill gas. A state initiative for dairies to reduce GHG emissions by capturing and combusting biogas is under consideration; it would be a very costly proposition for California dairies. Similarly, the San Joaquin and South Coast Air Districts may require dairies to capture and combust biogas to reduce VOC emissions. A viable biomethane industry would allow dairies to recoup some of the costs associated with methane collection and would mitigate their opposition to these requirements.

## **Eight Steps to a Successful Biomethane Enterprise**

A business plan for a successful biomethane enterprise should demonstrate that the following have been researched and, where possible, completed or obtained:

- Buyer for the biomethane
- Supply of organic waste
- Distribution system—pipeline or storage and subsequent over-the-road transport
- Location for biomethane plant
- Technology and operating plan
- Financial plan
- Permitting and regulatory analysis
- Construction plan

### ***Step 1: Find a Buyer for the Biomethane***

The Swedish tour made it clear to us that a biomethane developer must have a firm buyer before building a plant. As discussed in Chapter 5 of this report, a dairy cannot use all the biomethane it can produce for on-farm purposes. Converting agricultural pumps, refrigeration, and vehicles to run on biomethane is costly in terms of both time and money. At a typical dairy, even if all of equipment was converted to run on biomethane, facility production would still outstrip demand.

Thus, a dairy upgrading plant needs to find an off-farm market for its biomethane. As part of this project, a special study focused on finding specific locations in the San Joaquin Valley where dairies were concentrated in proximity to CNG fueling stations and other potential biomethane markets. The resulting report is attached as Appendix G; some of the details are summarized below.

### **Potential Biomethane Markets in the San Joaquin Valley**

There are 20 CNG fueling stations in the San Joaquin Valley. Those stations located closest to clusters of dairy farms, however, have a very small demand. For example, the CNG fueling station in Tulare, which is in the midst of what may be the largest concentration of cows in the world, pumps only 84,000 GGE a year of CNG (10 million ft<sup>3</sup>/year or about 27,600 ft<sup>3</sup>/day). A

1,000-cow dairy could meet this need, but a biomethane plant that small would not be economically feasible.

This demand could be increased if the community committed itself to increasing its CNG fleet. Since the Central Valley has serious air pollution problems, a community might find it worthwhile, and might find public funding, to replace its diesel bus fleet with CNG buses. In this case, it could contract with local dairies to provide the CBM for the buses.

In addition to fueling stations, there are a number of industrial users in the Valley, including cheese plants, which use a significant quantity of natural gas. For example, the CP International plant in Tulare uses 140,000 ft<sup>3</sup>/day of natural gas. It would take more than 4,500 cows to produce this much biomethane. Appendix G identifies a number of other such plants in the area.

### **Other Potential Markets**

If a biomethane plant were located on the distribution arm of a public natural gas pipeline, and if it could overcome any regulatory issues and meet utility requirements, it could pay to *wheel* the gas through the pipeline and sell it to an industrial user or perhaps to a local power utility.

Biomethane could be converted to LBM and used as a substitute for LNG. This product can be trucked more competitively than CNG, since it does not compete with gas delivered via a pipeline. (Almost no LNG is produced in California; instead it is trucked into California from out of state.)

Biomethane could also be used, instead of biogas, to generate electricity. Using biomethane to generate electricity has two advantages over using biogas. First, it can be used in engines that do not produce NO<sub>x</sub>; this is important because future regulations to control NO<sub>x</sub> emissions in California may make biogas-generated electricity very expensive. Second, it can be stored to provide valuable peaking power, although this opportunity is limited by the high cost of storage.

Finally, biomethane could be a feedstock for other liquid fuel products such as methanol or fuels produced through the Fischer Tropsch process. Potentially, dairy biomethane could substitute for natural gas as a feedstock for hydrogen, although the technical problems associated with this use are greater than for most of the other uses. With the current administration's focus on the hydrogen highway, this source of renewable hydrogen may attract a lot of interest. Highway 99, which runs down the San Joaquin Valley, could become California's Hydrogen Highway.

### **Step 2: Obtain Feedstock for the Anaerobic Digester**

This report focuses on dairy manure as a feedstock for on-farm or centralized anaerobic digesters. The biomethane plants we visited in Sweden use a variety of feedstocks, based on what is available in the area. As Chapter 1 demonstrates, there are other feedstocks available in California, such as poultry and swine manure, field and seed residue, vegetable residue,

slaughterhouse waste, food processing waste, and slaughterhouse waste. Multiple feedstocks can increase biogas volume and yield, but may require careful monitoring to keep the process healthy. Also, the transport of off-farm wastes to an on-farm anaerobic digester may be subject to additional regulations.

### **Step 3: Determine Means of Transport**

Conceivably, there are several steps in the biomethane production process that may require the transport of feedstocks, wastes, or products to or from the facility. The need for transport depends on a number of factors including location of the facility (on-farm vs. centralized), the use of off-farm feedstock, and the final market.

Organic wastes from dairies, food plants, or similar industries make up the feedstock for the anaerobic digester. On California dairies that use flush systems to manage manure, the feedstock will normally be used on-site since it is mostly water, and therefore is too expensive to move. However, most dairies in the Chino basin in Southern California manage their manure wastes with a scrape system. Because of its lower moisture content, this manure is less expensive to transport than liquid wastes and is trucked to a centralized anaerobic digester at the Inland Empire Utility Agency in Chino. Trucking is only economically feasible for wastes generated a short distance from the processing site, typically less than 5 miles. The facilities in Sweden were all centralized and all trucked in the organic waste product that fed the anaerobic digester.

After biogas is produced from a digester, it must be conveyed to the upgrading plant for biomethane production. In Sweden, the upgrading plants were located next to the anaerobic digester. However, it would be possible to transport the biogas to a centralized location using private pipelines. A centralized upgrading plant that accepted biogas from multiple digesters would allow for greater economies of scale in the biomethane production process. As an example, the Inland Empire Utility Agency in Chino pipes biogas from the digester to the electrical generator (less than 2 miles), and one large dairy in California pipes biogas across its farm almost 1 mile to its electrical generator.

Finally, the biomethane must be transported to market. If the biomethane plant is located on the natural gas grid, using the existing public natural gas pipeline would be the most efficient and cost-effective way to move the biomethane. Distribution via the natural gas grid would eliminate the need to have the biomethane plant in proximity to end users and would also eliminate any need to store the biomethane. In Seattle, the King County wastewater treatment plant transports biomethane produced from digester gas in the local gas utility's pipeline. Since biomethane is chemically equivalent to natural gas this does not cause any problems. However, in California regulation and resistance from the utilities will make this access more difficult and expensive.

A second alternative is to build a private pipeline to transport the biomethane. Pipelines cost \$100,000 to \$250,000 per mile, and are less expensive when they do not cross public rights-of-

way. Private pipelines eliminate the need for storage at the point of production, although storage would probably be required at the delivery site, especially if it is a fueling station.

The third alternative is to truck the biomethane. This requires compressing or liquefying the biomethane and storing it at the point of production. Stand-alone storage can be avoided if there is enough trucking capacity to always have a truck available for filling. Trucking is more cost competitive if the product is liquefied (i.e., LBM).

#### ***Step 4: Locate the Upgrading Plant***

The first three steps all revolve around location issues: Where is the buyer? Where is the feedstock? How will the end product be transported to the buyer? The answers to these questions will determine where the upgrading (biomethane) plant should be located. If access to a public gas pipeline is not available, cost considerations require the feedstock, the buyer, the digester, and the biomethane plant to be within a few miles of each other. However, in the case of liquefied biomethane the buyer and the plant can be at a considerable distance.

The most promising locations will have a number of large dairies located in proximity to a CNG fueling station and/or to industrial users of natural gas. Proximity to landfills or to wastewater treatment plants can also be useful, because these facilities can produce large volumes of biogas and could be a good location for a centralized biomethane plant. Also, if the upgrading facility is in a non-attainment area for ozone and particulate matter, public subsidies might be available if it can be shown that the facility will help reduce these emissions.

Appendix G focuses on possible locations in the San Joaquin Valley, a non-attainment area for ozone and particulate matter. Seven counties in the Valley produce 72% of the state's milk. Various items were considered in the preparation of this appendix: databases on dairies, and the locations of CNG fueling stations, industrial gas users, landfills and wastewater treatment plants, were examined to determine optimal locations for upgrading facilities.

Four promising locations were identified in the San Joaquin Valley, the cities of Tulare, Visalia, Modesto, and Hanford (Appendix G). These four areas all have a high concentration of dairies and markets. Potential biomethane developers should review this document for its conclusions as well as for the methodology used. For example, if a developer wishes to locate a facility outside the San Joaquin Valley, he/she could use a similar methodology to review other regions of the State such as the Inland Empire or the Sacramento Valley.

#### ***Step 5: Select a Technology and Prepare an Operating Plan***

Chapters 2 and 3 of this report (and Appendices A and B) review the various technology alternatives for anaerobic digesting and biogas upgrading. There are three main technologies for dairy anaerobic digestion, several technologies for removing the hydrogen sulfide, and a number



of technologies for removing the carbon dioxide. A business plan for a biomethane facility needs to review these technologies in more detail to determine which are most suitable for the planned application. In this process the developer should consider European experiences, especially that of Sweden, which has the largest number of upgrading plants in the world. A review of products and package plants is also needed; for example, several firms are marketing small-scale, skid-mounted biogas upgrading plants.

A technology plan should consider operational requirements as well as performance and capital costs. Some very efficient technologies may require more sophisticated operational management; others may be less efficient but more robust. A large on-farm or a centralized plant may be a better venue for more sophisticated solutions, while smaller farm-based plants should probably choose robustness and ease of maintenance/operation over yields. Whatever technology the developer selects, the technology and operating plan should consider staffing needs.

### ***Step 6: Develop a Financial Model and Locate Potential Financing***

As discussed, the first dairy upgrading plants, like other pioneering renewable energy technologies, are not likely to be cost effective without public subsidies. A pro forma financial model needs to be developed that considers account revenues and expenses including operating, maintenance, transportation, and storage costs. Current natural gas prices are at an historical high, but natural gas and electricity prices are highly volatile. Without a long-term fixed price contract, discount rates must consider future price volatility. A capital plan should include permitting and other transaction costs involved in building the plant. To gain public support, the developer should try to quantify and value environmental and other societal benefits. The financial model will help determine the size of the needed public subsidy, while establishing the value of the societal benefits will demonstrate the contribution that the plant can make to the community and help convince decision-makers that a subsidy is warranted.

The developer also needs to identify potential funding sources. Unfortunately, as discussed in Chapter 6, most subsidies and tax benefits are designed either for renewable electricity or for two specific alternate fuels, ethanol and biodiesel. Nevertheless, some potential funding sources for biomethane projects do exist. Also, if community support can be developed, other funding sources, such as local economic development funds, may be tapped.

### ***Step 7: Identify Permitting Requirements and Develop a Permitting Plan***

A biomethane plant will require permits, as discussed in Chapter 7. Since the first such plants in California will be pioneering enterprises, the developers will face a great deal of regulatory scrutiny. A CEQA review is likely to be required. Some counties will be more cooperative than others. The developer will need to communicate the societal benefits from the plant. Acquiring the necessary permits will be a substantial effort, and money and time must be designated for this

task. If the process proves to be especially difficult, it will add direct costs and cause expensive delays, which would increase the cost estimates provided in Chapter 8.

### ***Step 8: Select a Designer and Contractor and Build the Facility***

A competent plant designer and contractor are critical to a successful facility. The anaerobic digester and the biomethane plant may be built by different designers and contractors, but it needs to be a coordinated effort. Many designers claim that they can build good anaerobic digesters because they have built digesters at publicly owned treatment works, however, in the USA few of these have dairy digester experience. Because the feedstock is a critical component of system design, it is best to find a designer who has experience with the proposed feedstock(s).

References for both designers and contractors should be obtained and checked. Experience designing small-scale biomethane plants will be very rare in the USA, so it might be useful to consider European designers as well.

## **Five Possible Biomethane Plant Projects**

Below are short descriptions of five biomethane projects that we consider to have the greatest chance for success from a business perspective.

### ***Project 1: Support Community Vehicle Fleet that Uses Compressed Biomethane***

The San Joaquin Valley is a non-attainment area for ozone and particulate matter. A community in the Valley could make a significant environmental contribution by developing an integrated project involving CNG vehicles and a biomethane plant. The community could reduce emissions from diesel buses by substituting CNG buses, and could fuel those buses with CBM produced from manure on a nearby dairy or group of dairies.

At least four San Joaquin communities—Tulare, Visalia, Hanford, and Modesto— have both CNG fueling stations and a nearby dense population of dairies. However, the current CNG fleets in these communities are not large enough to support a biomethane plant. To make such a plant viable, demand for CBM needs to be increased beyond the current level. An integrated project that increased the number of CNG vehicles on the road and used locally produced CBM would capture a number of environmental and energy security benefits. The first community to do this would be a national showcase.

With a fueling station already in place, part of the CBM distribution problem would be solved; however, the existing station(s) would need to be substantially expanded, at a significant cost. Increased demand would come from a new fleet of CNG-fueled municipal vehicles.

A single large dairy could generate the biogas and biomethane on-site and then pump it through a dedicated pipeline or truck it to the fueling station. Trucking (of CBM) is expensive and it should

probably be considered only as an interim solution until the volume is sufficient to support a pipeline. Alternatively, several dairies could pool their partially cleaned (i.e., H<sub>2</sub>S removal would be done on-farm) biogas and pump it through a dedicated pipeline to a centralized biomethane plant. If the dairies were near a landfill, the biomethane plant could be built at the landfill and could use biogas from the dairies as well as from the landfill gas to produce biomethane. Ideally, the biogas upgrading plant would be very close to the filling station.

If such a facility processed waste from around 8,000 cows, it would cost \$3,000,000 to \$5,000,000 for anaerobic digestion, the upgrade plant, storage, and piping. Additional costs would be incurred for the purchase of the fleet and for the fueling station at the bus barn. The financing of the biomethane plant would be facilitated if the community committed to purchasing CBM on a long-term contract. Finding an appropriate subsidy for the biomethane plant would take some ingenuity, but could be done.

The societal benefits would include cleaner air from cleaner vehicles, energy security and GHG emission reductions by substituting domestically produced renewable fuel for imported oil, reduced GHG and VOC emissions by capturing and eventually combusting dairy biomethane, odor and fly reduction at the dairy, and pathogen and weed seed reduction from the anaerobic digester.

### ***Project 2: Sell Biomethane Directly to Large Industrial Customer***

A number of areas in the San Joaquin Valley have dairies concentrated near sizable industrial users of natural gas. One or more of these industrial users could provide a substantial demand for locally produced biomethane.

As with the previous example, a single large dairy could generate biogas and upgrade it to biomethane on-site and then pump it through a dedicated pipeline or truck it to the industrial user (again, trucking should be considered an interim solution). Several dairies could pool partially cleaned biogas and pump it through a dedicated pipeline to a centralized biomethane plant. Ideally that plant would be very close to the industrial buyer.

This project would be especially useful for industrial users that are located off of the natural gas transmission grid. Because industrial users need a reliable supply of gas, the biomethane plant needs to be robust and storage would be needed at the industrial site to ensure fuel supply when the biomethane plant is not operating.

For many industrial users of natural gas, their main need is for heat. In some applications, heat could be supplied by raw or partially cleaned biogas, without the need to upgrade to biomethane. Even if heat is the only application, concerns about transportation, storage, corrosion, fuel blending, or air emissions may make the biogas unsuitable for an industrial user.

Project costs and benefits would be similar to the first proposed project, except there would be no costs for a vehicle fleet or upgraded fueling station. The financing of the biomethane plant would be facilitated if the industrial user committed to purchasing its output on a long term contract. As with any other pioneering renewable energy project, public subsidies would be needed to make this project feasible.

The societal benefits would include GHG emission reductions by substituting domestically produced renewable fuel for fossil fuel, reduced GHG and VOC emissions by capturing and eventually combusting dairy biomethane, odor and fly reduction at the dairy, and pathogen and weed seed reduction from the anaerobic digester.

### ***Project 3: Distribute Biomethane through Natural Gas Pipeline Grid***

If barriers to the use of the natural gas transmission system could be overcome, an on-farm or centralized biomethane plant could sell directly to the local gas utility, or pay to wheel the biomethane to an industrial or municipal customer on the natural gas grid. Of course, the biomethane plant would need to be located along or very close to the distribution line. Since the Central Valley is not well served by natural gas distribution, this option is not practical in some areas, despite the presence of abundant dairies.

The environmental and societal benefits would be similar to the direct sale of biomethane to an industrial customer.

### ***Project 4: Build Liquefied Biomethane Plant***

Liquefied biomethane can be used as a direct substitute for LNG. Except for a small PG&E pilot project, all LNG vehicle fuel is trucked into California from out-of-state LNG plants.

A California biomethane plant built to serve the CNG vehicle market has a competitive disadvantage. It has to transport its biomethane, or CBM, to a fueling station and still compete in price with the natural gas delivered via pipeline that already serves the fueling station. A California LBM plant does not have this handicap. In fact, it may have a competitive advantage because it will likely be closer than the out-of-state LNG plants that currently serve the customer.

A dairy LBM plant could be built anywhere in the state where there is a sufficient supply of dairy waste. It could be built at a single large dairy, or it could be operated at a central location by transporting partially cleaned biogas from several nearby dairies through dedicated pipelines to a biomethane plant. If a group of dairies were near a landfill, the LBM plant could be built at the landfill and could use biogas from the dairies as well as landfill gas to produce LBM.

While transportation costs limit a CBM plant to nearby markets, an LBM plant can cost-effectively transport LBM to fueling stations much further away. LBM could also be delivered to

liquefied-to-compressed natural gas (LCNG) fueling stations or to customers off the natural gas grid that already receive gas deliveries in the form of LNG.

Most LNG is used in heavy-duty vehicles; California currently has fewer than 1,500 such vehicles. Before an LBM plant is built, the developers must ensure a sufficient demand for its product by contracting with any of a number of fleet fueling stations in the state that could consume the LBM.

The societal benefits from such a plant would be the same as those from the community CBM vehicle fleet project described above.

### ***Project 5: Use Compressed Biomethane to Generate Peak-Load Electricity***

Because CBM can be stored (unlike biogas, which cannot be stored at high pressures due to associated corrosion problems and high cost) a biomethane plant could use its fuel to generate peaking electrical power.

The Renewable Portfolio Standard commits California to a substantial increase in renewable electricity. Bids for program funds are evaluated based on “least cost, best fit.” There is a Market Referent Price for electricity, and a higher price for peaking power. Renewable energy that can be dispatched to serve peak demand can earn a substantial premium over non-dispatchable renewable energy resources like wind and solar. If this premium were sufficient, storing compressed biomethane to generate peaking power could be cost effective. While the IOUs have not been eager to buy dairy electricity other than through the upcoming RPS process, the municipal utilities, particularly the Sacramento Municipal Utility District, may be more responsive.

To take advantage of the RPS program, the plant would have to be able to dispatch at least 1,000 kW, which would require biogas from about 10,000 cows. A very large single dairy or group of dairies could produce the needed biomethane on-farm or at a location central to several farms. The biomethane could be used to fuel a microturbine, but substantial storage capacity would be needed to ensure fuel availability for peak times.

True peak-load plants can make a profit running as little as 10 percent of the time. The high cost of biomethane storage, however, will require the biomethane plant to operate on a more regular basis, and will thus reduce the proportion of output that can capture the highest wholesale prices (during highest peak loads). The balance between the opportunity to capture peak-load prices and the cost of storing biomethane would need to be carefully evaluated, but it is unlikely that storage capacity of more than one or two weeks would be feasible.

The environmental and societal benefits would be similar to the direct sale to an industrial customer.



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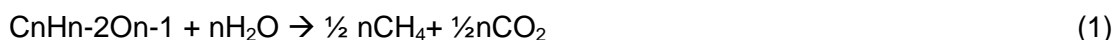


## Appendix A

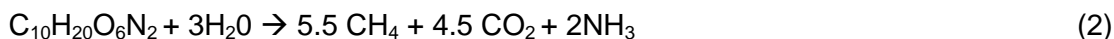
### Stoichiometry of the Anaerobic Digestion Process

Biogas from anaerobic digestion of sewage, food processing, animal and other wastes typically contains about 55% to 70% CH<sub>4</sub> and 30% to 45% CO<sub>2</sub>. In some cases, much higher CH<sub>4</sub> content are reported, over 70% (see Chapter 2 of main report) and even up to 90% CH<sub>4</sub> in some cases. High methane content in biogas would be desirable, as it would reduce, in some cases even avoid, the need for CO<sub>2</sub> removal from the biogas, and direct utilization (after H<sub>2</sub>S and moisture removal) as a vehicular fuels and other applications requiring compression. This Appendix briefly examines the potential for achieving high (>70%) methane content in the biogas as part of the anaerobic digestion process of dairy manures, to reduce or even avoid the need for a separate CO<sub>2</sub> removal operation.

Biogas production from organic substrates involves an internal redox reaction that converts organic molecules to CH<sub>4</sub> and CO<sub>2</sub>, the proportion of these gases being dictated by the composition and biodegradability of the substrates, as already briefly discussed above. For the simplest case, the conversion of carbohydrates, such as sugars (e.g., glucose, C<sub>6</sub>H<sub>12</sub>O<sub>6</sub>) and starch or cellulose (C<sub>n</sub>H<sub>n-2</sub>O<sub>n-1</sub>), an equal amount of CH<sub>4</sub> and CO<sub>4</sub> is produced (50:50 ratio):



In the case wastes containing proteins or fats, a larger amount of methane is produced, stoichiometrically from the complete degradation of the substrate. For proteins, the process is as follows:



This yields a CH<sub>4</sub>:CO<sub>2</sub> ratio of 55:45; the exact biogas composition will depend on the individual substrate protein.

For fats and vegetable oil (triglycerides), a typical CH<sub>4</sub>:CO<sub>2</sub> ratio is 70:30:



These simplified examples can change according to effects from several factors:

- Reactions are often incomplete (typically up to half of the cellulose is refractory to microbial anaerobic degradation, and lignin is completely inert, for example).
- By-products are produced and voided in the digester effluent (e.g., acetic, propionic and other fatty acids and metabolites).
- Bacteria use these reactions to make more bacteria; thus, there is also some biomass produced as part of these metabolic processes.

The last two factors will reduce  $\text{CH}_4$  somewhat more compared to  $\text{CO}_2$  production, as the by-products and bacterial cells are generally more reduced than the substrates. However, these corrections are relatively minor, as most of the substrate degraded is indeed converted to  $\text{CH}_4$  and  $\text{CO}_2$  because bacterial biomass yields in anaerobic fermentations are quite low, typically less than 5% of the C in the substrate being converted to bacterial biomass (composition approximately  $\text{C}_5\text{H}_8\text{NO}_2$ ). Incomplete digestion also does not affect gas composition significantly. For a first approximation, therefore, the three above factors can be disregarded for adjusting for expected  $\text{CH}_4:\text{CO}_2$  ratios.

Thus, the maximum content of  $\text{CH}_4$  in biogas produced from anaerobic digestion can only be about 70% when digestion of oils is included; for typical dairy wastes, a methane content of between 55% and 60% is most likely.

Despite this, it is frequently observed that  $\text{CH}_4$  concentrations in biogas from dairy manures are typically somewhat above 60%. There are two mechanisms that can explain such an increase in  $\text{CH}_4$  content in the biogas, and these could possibly be used to achieve the goal of increasing methane gas production: two phase digestion and  $\text{CO}_2$  dissolution in the process water. These are discussed below.

## Two-Phase Anaerobic Digestion

Two-phase anaerobic digestion processes have been extensively studied and in a few cases also applied in practice. In such processes, two bioreactors are operated in series, with the initial reactor operated at a much shorter hydraulic retention time (HRT), as little as one tenth or less of the HRT used in a typical single-stage reactor. The second reactor is operated at typical anaerobic digestion HRT, generally over 15 days. Thus, the first reactor is much smaller than the second reactor, in which nearly all conversion to methane occurs.

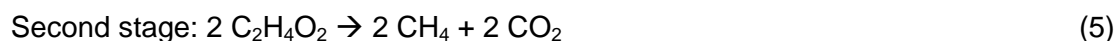
The essential concept of two-phase digestion is to separate the two main microbiological processes of anaerobic digestion, acidogenesis (production of volatile fatty acids,  $\text{H}_2$  and  $\text{CO}_2$ ) and methanogenesis (production of methane from the fatty acids,  $\text{H}_2$  and  $\text{CO}_2$ ). These two reactions are carried out by distinct bacterial species and populations, and the two-phase anaerobic digestion process is based on the concept that the operational characteristics of each stage can be adjusted to favor the bacteria: very short HRTs and solids retention times (SRTs), with resulting organic-acid formation and low pH in the first stage; longer HRTs and conversion of the acids to methane (and  $\text{CO}_2$ ) at neutral pH in the second. Thus the aim is to provide an optimal environment for each of these distinct microbial populations, thus allowing an overall faster reaction (e.g., reducing the reactor size of the combined first and second stage compared to conventional systems). Two-phase digestion is also claimed to result in a greater overall yield of methane, as a larger fraction of the substrates will be metabolized and converted to biogas, presumably by action of the more vigorous acidogenic bacteria.



Unfortunately, this concept suffers from a fundamental flaw: the two types of populations work commensally, that is they depend on each other for optimal metabolism. Simply put, the  $H_2$  and acetate (as well as the higher fatty acids) produced by the acid-forming bacteria are strong inhibitors of the metabolism by these bacteria. The methanogens, by removing these “waste” products and converting them to  $CH_4$ , perform a most useful and necessary role in the overall process. Indeed, although acidogenic bacteria (at least some populations) tolerate the low pH that develops in the first, short hydraulic retention time, acid-forming reactor of a two-phase process, a low pH does not actually help the process of acidogenesis. In brief, after several decades of research, the advantages of two-phase anaerobic digestion are still to be demonstrated. Indeed, the main advantage claimed for two-phase digestion, the reduction in overall tank sizes, has not been demonstrated, and the operation of two, rather than one, digesters is not an advantage.

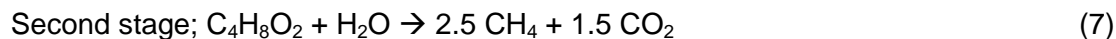
It should be noted in this context that many, and in practice perhaps most, of so-called two-phase processes, are in actuality, two-stage processes, where the first stage also produces methane. In these cases the volume ratio of the first and second stages is greater than the approximately 1:10 (or even 1:20) of the second stage, typical of two-phase digestion. Essentially in two-stage processes the first stage acts mainly as a surge tank, sometimes with a liquid recycle loop from the second to the first stage, which would actually defeat the objective of two-phase digestion. Two-stage digestion does, however, reduce short-circuiting, a significant issue with single-stage mixed tank reactors.

For a two-phase digestion, the ideal stoichiometry, for the simple case of carbohydrate breakdown, can theoretically be written as:



Overall this does not improve the biogas methane content and reduces methane yields by one third, though it produces an equivalent amount of  $H_2$  fuel.

A great deal of research is ongoing to achieve such a yield of  $H_2$  in the first stage, due to the current popularity of  $H_2$  as a fuel. However, in practice, such high yields would be achievable only under extreme laboratory conditions (e.g., with a large amount of purge gas, to strip  $H_2$  from the first stage, and the use of very high temperature strains, at 180° F). The best  $H_2$  yield that is actually obtained and obtainable is about half this, with the remainder of the sugar substrate being converted into more reduced products (e.g., propionic acid, butyric acid, ethanol, etc.):



This raises the content of the methane in the biogas from the second stage to a little over 60% (for this illustrative case), but at a decreased yield of methane (e.g., 2.5 vs. 3 in a single-phase process). Depending on the operating conditions of the first phase, virtually no  $H_2$  is produced in the first stage, resulting in a production of only  $CO_2$  in the first stage and more methane in the second stage. However, in this case the actual amount of net  $CO_2$  produced in the first stage is also reduced, and, thus, no further increase in biogas  $CH_4$  content is likely (although theoretically an increase of up to 75% could be possible).

In principle it would be possible to increase the  $CH_4$  content of biogas by feeding the  $H_2$  produced by the first-phase reactor to the second-phase reactor. Methanogenic bacteria, which dominate the second phase, use  $H_2$  preferentially and at very high rates, converting  $CO_2$  into  $CH_4$ . However, this process would only be effective in raising  $CH_4$  content if the  $H_2$  and  $CO_2$  produced in the first stage were separated, which would defeat the purpose of avoiding such separation processes.

In any event, a two-phase process is not applicable to dairy wastes. A two-phase process, and the stoichiometric relationships discussed above, are applicable only to soluble and readily metabolized sugars and starches, possibly some fats and protein, but not to the more difficult to digest particulate, fibrous and other insoluble matter that comprise most of the substrates available for bacterial decomposition in dairy wastes. For dairy wastes there would be essentially no  $H_2$  produced in the first phase of a two-phase process. The advantages of two-phase digestion, though a much promoted process, are modest even when applied to more suitable wastes such as food processing wastes, which are high in sugars or starches. The process should not be considered for dairy wastes.

## Removal of Carbon Dioxide During the Digestion Process

The second mechanism that can account for the relatively higher  $CH_4$  content in biogas than would be expected from simple stoichiometry is the dissolution of  $CO_2$  in the digester water.  $CO_2$  is much more soluble than  $CH_4$  in water. At 1 atmosphere pressure (about 14 psi) and ambient temperature (e.g., 21° C, or 70° F) about 1.8 grams per liter (g/l) of  $CO_2$  are dissolved in water compared to about 4 mg/l of  $CH_4$ . Gas solubility is proportional to partial pressure, thus, at a 50/50  $CH_4$ : $CO_2$  ratio, these concentrations would be halved but the relative ratios of the two gases dissolved in water would be the same. This ratio of 400 to 1 between  $CO_2$  to  $CH_4$  dissolution in water is the basis for the water scrubbing process for  $CO_2$  removal (see Chapter 3 of main report). It also accounts for the rather significant amount of  $CO_2$  that exits the digesters dissolved in water and, thus, the enrichment in  $CH_4$  observed in the biogas, compared to what is expected from the above stoichiometric equations.

This can be exemplified by a simple calculation: Assume that a dairy waste with 4 g/l of degradable VS (volatile solids), of which 50% is C, is stoichiometrically (molar basis) converted to equal amounts of  $CO_2$  and  $CH_4$ . This would produce 3.7 g/l of  $CO_2$  and 1.25 g/l of  $CH_4$ . As

more of the  $\text{CO}_2$  would remain dissolved in the water, the actual ratio of  $\text{CO}_2$ :  $\text{CH}_4$  in the liquid phase would, at equilibrium, be only about 2 mg of  $\text{CH}_4$ , a negligible amount, but 0.7 g/l of  $\text{CO}_2$ , which reduces the amount of  $\text{CO}_2$  in the gas phase, from 50/50 to about 55/45  $\text{CH}_4$ : $\text{CO}_2$ .

In practice, the effluent from a digester is not at equilibrium with the atmosphere above it (e.g., the biogas); more  $\text{CO}_2$  and  $\text{CH}_4$  are dissolved in the liquid than expected at equilibrium. Although disequilibrium would affect dissolved  $\text{CO}_2$  and  $\text{CH}_4$  about equally, because of the much higher solubility of  $\text{CO}_2$  than  $\text{CH}_4$  in the liquid, the recovered biogas would be more enriched in  $\text{CO}_2$  than calculated above for the equilibrium case. The “extra”  $\text{CO}_2$  (and  $\text{CH}_4$ ) dissolved in the liquid effluent from the digesters would be released to the atmosphere after the liquid effluent leaves the digester. This could more than double the amount of  $\text{CO}_2$  produced during the anaerobic digestion process that does not actually enter the biogas phase. In the above example, if the amount of  $\text{CO}_2$  dissolved in the water phase were three times higher than at equilibrium, this would give a 2:1 ratio of  $\text{CH}_4$ : $\text{CO}_2$  in the gas phase, with half the  $\text{CO}_2$  produced remaining in the liquid phase. At the same relative disequilibrium,  $\text{CH}_4$  losses in the liquid effluent would still be less than 1% of the total produced. A three-fold excess (above that equilibrium with the gas phase) in dissolved gases is well within what is possible for full-scale anaerobic digestion processes. It should, however, be noted that the very long retention times typical of anaerobic digestion processes, in particular dairy manures, means that there is more time for the gas and liquid phase to reach equilibrium. Thus, although the maximum ratio of  $\text{CH}_4$ : $\text{CO}_2$  that could be achieved just from  $\text{CO}_2$  being dissolved in the liquid effluent from the AD process is not clear, it is not likely that it would be much higher than the above projected 2:1 ratio. As this ratio increases the disequilibrium between liquid and gaseous phases increases sharply.

This issue of  $\text{CO}_2$  dissolution and disequilibrium has been somewhat neglected in most anaerobic digestion studies, but it can readily account for the frequent observations of relatively high  $\text{CH}_4$ : $\text{CO}_2$  ratios in biogas in many systems, including from dairy manures, compared to predictions from stoichiometry and equilibrium calculations. Although it does not appear likely that a much higher than 2:1 ratio would actually be achievable, this issue deserves further study.

It should be noted that for laboratory-scale and even small pilot plants, the amount of mixing (agitation) that the bioreactors are normally subjected to is many times greater per unit volume than for large-scale processes. Thus, small, well-mixed systems are typically run much more closely near the gas exchange equilibrium than would be the case for full-scale systems. Consequently, in respect to the ratio of gases in the biogas produced, it is not possible to directly extrapolate laboratory results to full-scale systems.

In a few cases, very high  $\text{CH}_4$ : $\text{CO}_2$  ratios, about 9:1, have been reported from anaerobic digester processes. These did not involve standard anaerobic digester reactor designs but, rather gas collected from anaerobic lagoons. In these situations, the gas, collected either at the surface or below, was exposed to large amounts of liquid. In particular these reports originate from algal

wastewater treatment systems, where algae deplete the water of  $\text{CO}_2$ , providing a sink for  $\text{CO}_2$  produced by the anaerobic digestion process. Thus, in reality, such systems combine anaerobic digester with a water scrubbing process. Although algal ponds can be used for treating anaerobic digester effluents (BOD removal and nutrient capture) and can be of interest in dairy manure management, this technology is still in the development stage. Also, it is not likely that this technology would be as closely integrated with an anaerobic digester process as suggested by proponents of using an in-pond digester process and submerged gas catchers. The most plausible system configuration separates these processes of anaerobic digester and effluent treatment, if required. In any event, this topic is beyond the scope of the present report.

## **Conclusions**

Biogas produced by dairy wastes in typical AD processes is somewhat enriched in  $\text{CH}_4$ , compared to what would be expected from the metabolic processes of organics degradation. However, the observed and expected enrichment is rather modest, from about 50% to 55% or 60%. There is also a near-doubling of  $\text{CH}_4$  to  $\text{CO}_2$  ratios, from 1:1 closer to 2:1 (e.g., 66% methane), which is about the maximum that would likely be achievable.

For applications where  $\text{CO}_2$  removal is required (e.g., for upgrading to vehicular fuels),  $\text{CH}_4$  to  $\text{CO}_2$  ratios of over 10:1, typically even above 20:1, would be required. This suggests that there is little point in trying to improve on the anaerobic digester process in this regards, as a  $\text{CO}_2$  removal process would not be avoided if the goal is for a higher purity  $\text{CH}_4$  fuel. Also, it does not appear that the additional effort that would be required to increase  $\text{CH}_4$ : $\text{CO}_2$  ratios during the anaerobic digester process could be justified by any savings in the final purification step. Thus, producing a high  $\text{CH}_4$  content biogas from dairy manures directly from the anaerobic digestion process is not practical and would not significantly decrease the costs of  $\text{CO}_2$  removal required for applications requiring biomethane quality fuel. Thus, post-digestion processes for upgrading biogas to renewable methane should be the main focus.

## **Appendix B**

### **Detailed Description of the Three Main Dairy Digester Technologies**

This appendix reviews and compares covered-lagoon, plug-flow, and complete-mix anaerobic digestion technologies for the quantity and quality of renewable biogas produced. It also presents detailed information and design considerations of these three anaerobic digester technologies available for dairy farms in California.

#### **Description of Covered Lagoon Digester**

A cover can be floated on the surface of a properly sized anaerobic lagoon receiving flush manure to recover methane. The most successful arrangement includes two lagoons connected in series to separate biological treatment for biogas production and storage for land application. A variable volume one-cell lagoon designed for both treatment and storage may be covered for biogas recovery. However, a single-cell lagoon cover presents design challenges not found in constant-volume lagoons and will require assistance of professionals familiar with the design, construction and operation of these systems. Figure B-1 shows the components of a covered lagoon digester; Figure B-2 shows an actual system operating in California.

The primary lagoon is anaerobic and operated at a constant volume to maximize biological treatment, methane production, and odor control. The biogas recovery cover is floated on the primary lagoon. Ideally, manure contaminated runoff is bypassed to the secondary lagoon. The secondary lagoon is planned as variable volume storage to receive effluent from the primary lagoon and contaminated runoff to be stored and used for irrigation, recycle flushing, or other purposes.

Temperature is a key factor in planning a covered lagoon. Warm climates require smaller lagoons and have less variation in seasonal gas production. Colder temperatures in northern California will reduce winter methane production. To compensate for reduced temperatures, loading rates are decreased and hydraulic retention time (HRT) is increased. A larger lagoon requires a larger, more costly cover than a smaller lagoon in a warmer climate. Reduced methane yield may decrease the return on investment.

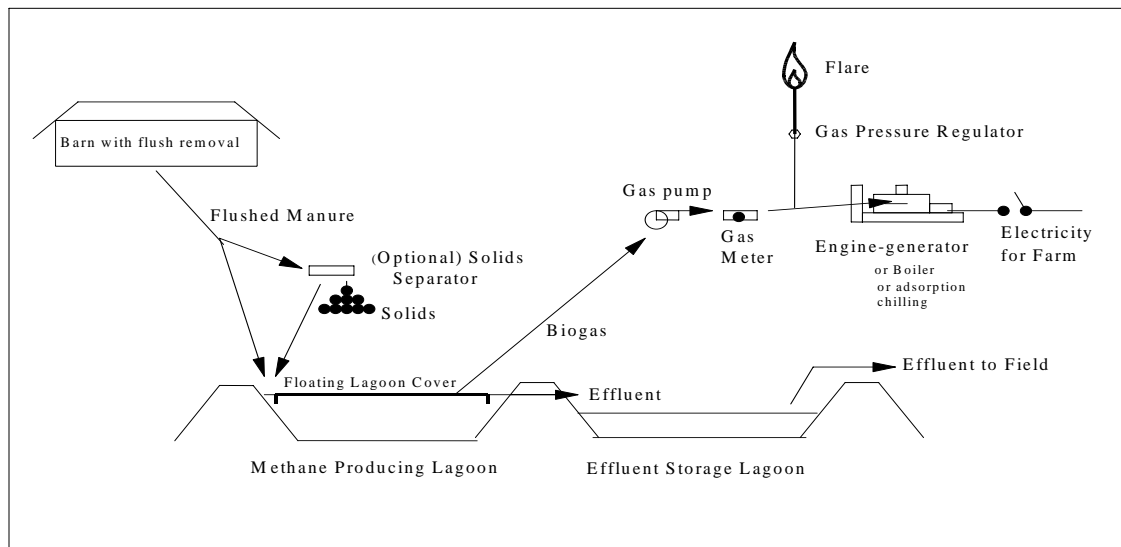


Figure B-1 Covered lagoon system components



Figure B-2 Photograph of Castelanelli Bros. Dairy covered lagoon digester located in Lodi, CA. (source: RCM Digesters, Inc.)

### **Components of Covered-Lagoon Digester**

*Solids separator.* A gravity solids trap or mechanical separator should be provided between the manure sources and the lagoon.

*Lagoons.* Two lagoons are preferred; a primary anaerobic waste treatment lagoon and a secondary waste storage lagoon.

*Floating lagoon cover.* The most effective methane recovery system is a floating cover over all or part of the primary lagoon.

*Biogas utilization system.* The recovered biogas can be used to produce space heat, hot water, cooling, or electricity.

### **Covered-Lagoon Design Variables**

*Soil and foundation.* Locate the lagoons on soils of slow-to-moderate permeability or on soils that can seal through sedimentation and biological action. Avoid gravelly soils and shallow soils over fractured or cavernous rock.

*Depth.* The primary lagoon should be dug where soil and geological conditions allow it to be as deep as possible. Depth is important in proper operation of the primary lagoon and of lesser importance in the secondary lagoon. Deep lagoons help maintain temperatures that promote bacterial growth. Increased depth allows a smaller surface area to minimize rainfall and to cover size, which reduces floating cover costs. The minimum depth of liquid in the primary lagoon should be 12 ft.

*Loading rate, hydraulic retention time and sizing of primary lagoon.* The primary anaerobic lagoon is sized as the larger of volatile solids loading rate (VSLR) or a minimum HRT. The VSLR is a design number, based primarily on climate, used to size the lagoon to allow adequate time for bacteria in the lagoon to decompose manure.

*Volatile solids loading rate.* Figure B-3 below shows isopleths for the appropriate loading rates for a constant volume primary lagoon in a two-cell lagoon system.

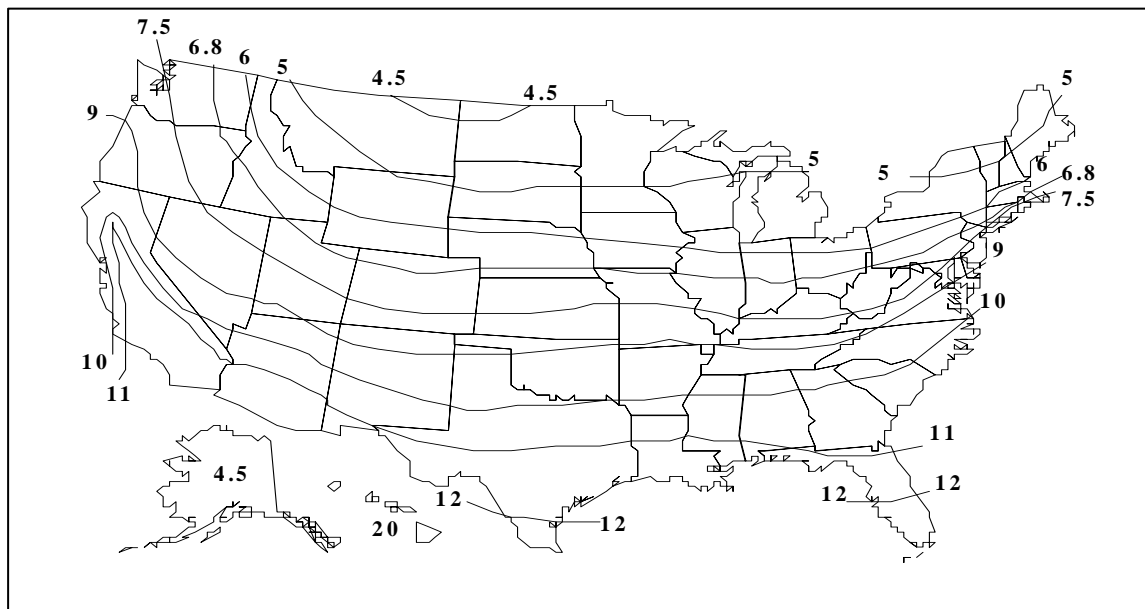


Figure B-3 Covered Anaerobic Lagoon Maximum Loading Rate (lb VS/1,000 ft<sup>3</sup>/day) (NRCS, 1996, Code 360, Reference 3)

*Minimum hydraulic retention time.* The VSLR procedure is appropriate in most cases, however modern farms using large volumes of process water may circulate liquids through a primary lagoon faster than bacteria can decompose it. To avoid this washout, a minimum hydraulic retention time (MINHRT) is used to size the lagoon. Figure B-4 shows MINHRT isopleths.

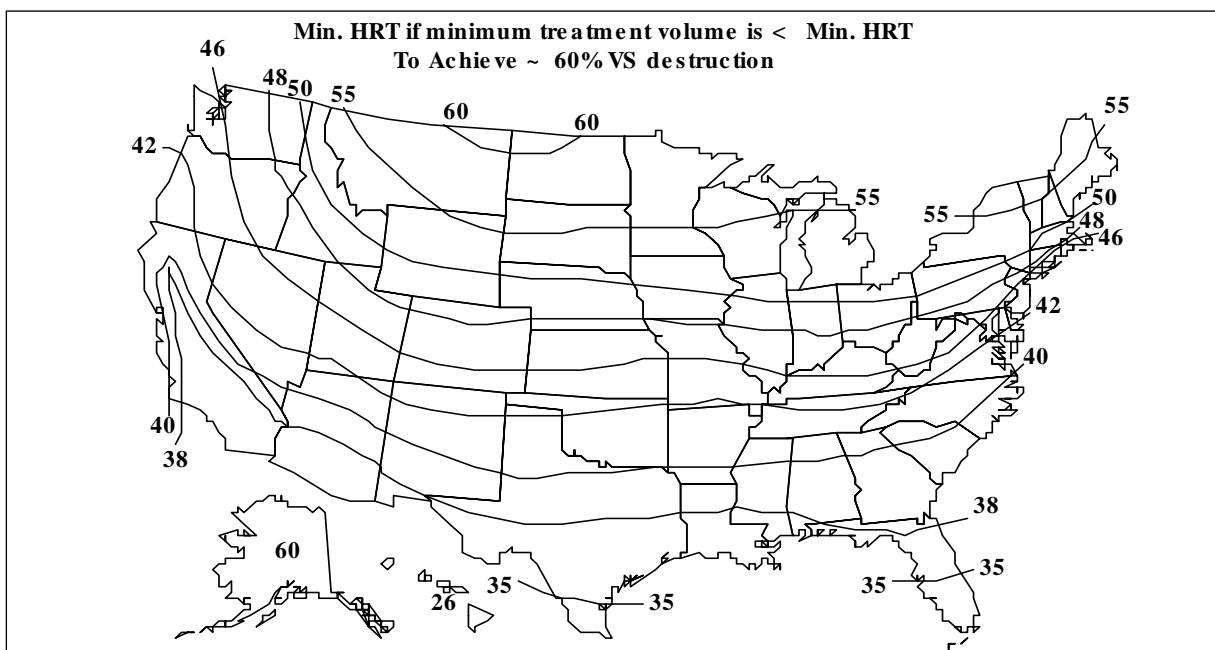


Figure B-4 Covered anaerobic lagoon minimum hydraulic retention times (NRCS, 1996, Code 360, Reference 3)



*Primary lagoon inlet and outlet.* The primary lagoon inlet and outlet should be located to maximize the distance across the lagoon between them.

*Rainfall.* Rainfall is not a major factor in determining the potential success of a covered lagoon. In areas of high rainfall, a lagoon cover can be used to collect clean rain falling on the cover and pump it off to a field. In areas of low rainfall, a lagoon cover will limit evaporation and loss of potentially valuable nutrient rich water.

*Cover materials.* Many types of materials have been used to cover agricultural and industrial lagoons. Floating covers are generally not limited in dimension. A floating cover allows for some gas storage. Cover materials must be: ultraviolet resistant; hydrophobic; tear and puncture resistant; non-toxic to bacteria; and have a bulk density near that of water. Availability of material, serviceability and cost are factors to be considered when choosing a cover material. Thin materials are generally less expensive but may not have the demonstrated or guaranteed life of thicker materials. Fabric reinforced materials may be stronger than unreinforced materials, but material thickness, serviceability, cost and expected life may offset lack of reinforcement.

*Cover installation techniques.* A lagoon cover can be installed in a variety of ways depending upon site conditions. Table B.1 lists features found in floating methane recovery lagoon covers. Figure B-5 shows typical features of lagoon covers.

Table B-1 Features of a Floating Methane Recovery Lagoon Cover

Feature	Description
Bank Attachment Options	See text and Figure B-5.
Rainfall Management	Rainfall may be pumped off the cover or drained into the lagoon.
Securing Edges of a Floating Cover	The edges of the cover can be buried in a perimeter trench on the lagoon embankment or attached to a concrete wall. Floating edges not secured directly on the embankment need support in place. A corrosion resistant rope or cable is attached to the cover as a tie-down and tied to an anchor point.
Skirting	Portions of the cover floating in the lagoon require a perimeter skirt hanging into the lagoon from the cover.
Anchor Points	Anchor points for cable or rope may be driven metal stakes or treated wood posts.
Float Logs	A grid of flotation logs is attached to the underside of the cover. The float logs may be necessary as gas collection channels, to minimize gas pockets and bubbles under the cover.
Weight Pipes	A grid of weight pipes may be laid on the cover surface to help hold the cover down.
Gas Collection	Biogas bubbles to the surface of the lagoon and migrates across the underside of the cover. A gas pump maintains a vacuum under the cover. A gas collection manifold is attached to the cover. A gastight through-the-cover, through-the-attachment wall or under the buried cover gas pipe carries biogas to a biogas utilization system.

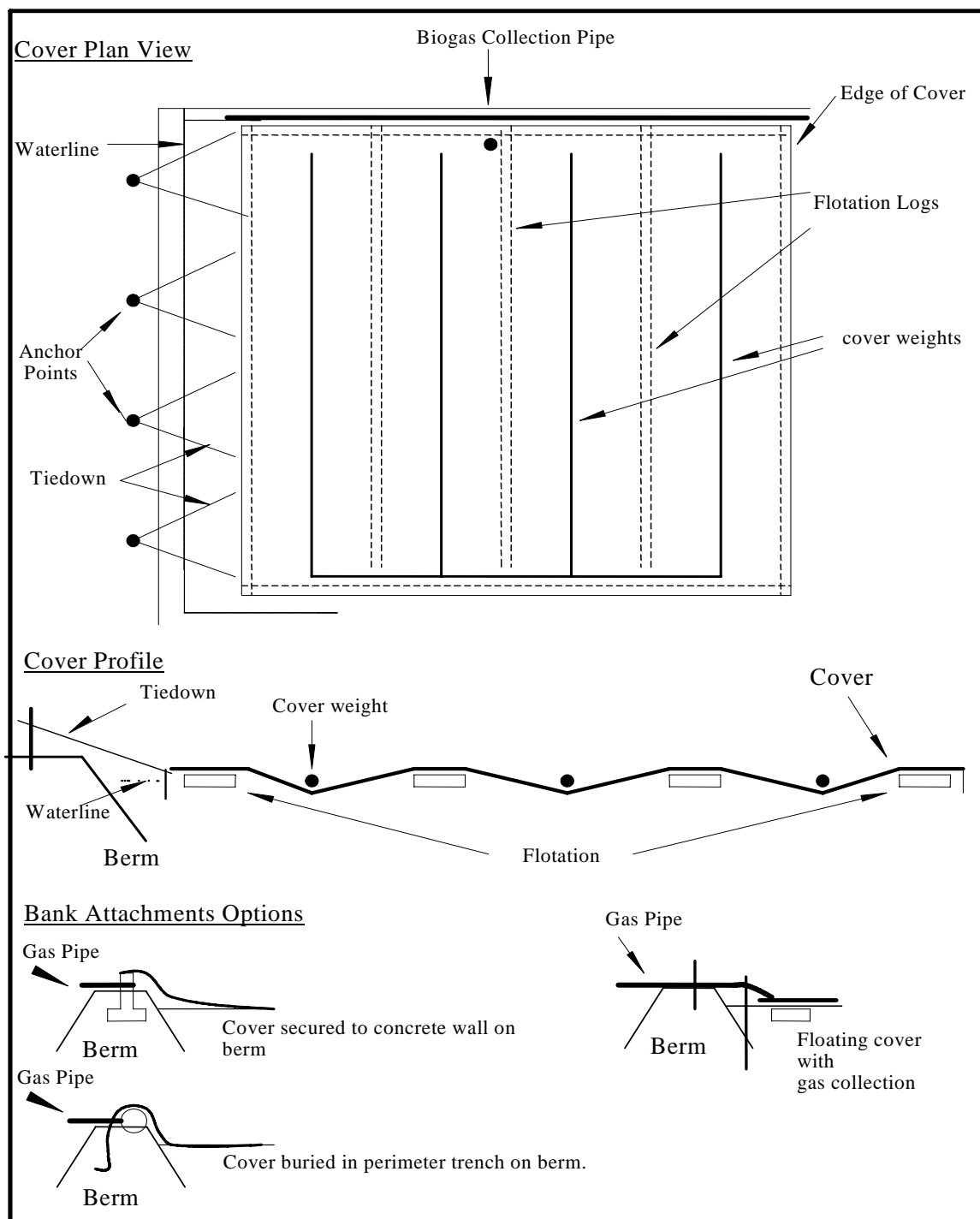


Figure B-5 Typical features of lagoon covers

*Full perimeter attachment.* The entire lagoon surface is covered and the edges of the material are all attached to the embankment.

*Completely floating or partially attached cover.* The cover may be secured on the embankment on one to three sides or the whole cover can float within the lagoon. All or some of the sides may stop on the lagoon surface rather than continuing up the embankment.

### **Operation and Maintenance of Covered-Lagoon Digester**

The operation and maintenance of a covered lagoon should be relatively simple.

*Primary lagoon — operation.* The proper design and construction of a primary lagoon leads to a biologically active lagoon that should perform year round for decades. Any change in operation will most likely be due to a change in farm operation resulting in an altered volatile solids loading or hydraulic load to the lagoon. The owner should make a visual inspection of lagoon level weekly.

*Primary lagoon — maintenance.* Minimal maintenance of the primary lagoon is expected if the design volatile solids and hydraulic loading rates are not changed. Lagoon banks should be kept free of trees and rodents that may cause embankment failure. Weeds and cover crops should be cut to reduce habitat for insects and rodents. Occasional plugging of inlet and outlets can be expected. Sludge accumulation may require sludge removal every 8 to 15 years. Sludge can be removed by agitating and pumping the lagoon or by draining and scraping the lagoon bottom.

*Cover operation.* Operating a lagoon cover requires removing the collected biogas from below the cover regularly or continuously. Large bubbles should not be allowed to collect. If the cover is designed to accumulate rainfall for pumpoff, accumulated rainwater should be pumped off.

*Cover maintenance.* The cover should be visually inspected weekly for rainwater accumulation, tearing, wear, and proper tensioning of attachment ropes. The rainwater pumpoff system should be checked after rainfall and maintained as needed.

### **Description of Plug-Flow Digester**

A plug-flow digester is used to digest manure from ruminant animals (dairy, beef, sheep) that can be collected as a semisolid (10% to 60% solids) daily to weekly with minimal contamination (dirt, gravel, stones, straw) and delivered to a collection point.

### **Components of Plug-Flow Digester**

A plug-flow digester system generally includes a mix tank, a digester tank with heat exchanger and biogas recovery system, an effluent storage structure, and a biogas utilization system. Post digester solids separation is optional. Figure B-6 shows the features of a plug-flow digester system.

*Collection/mix tank.* A mix tank as described above for a complete digester is used to achieve a solids concentration between 11% and 14% solids.

*Plug-flow digester.* A plug-flow digester is a heated, in-ground concrete, concrete block or lined rectangular tank. The digester can be covered by a fixed rigid top, a flexible inflatable top or a floating cover to collect and direct biogas to the gas utilization system.

*Biogas utilization system.* The recovered biogas can be used to produce space heat, hot water, cooling, or electricity.

*Solids separator (optional).* A mechanical separator may be installed between the plug-flow digester outflow and the effluent storage structure.

### **Design Criteria and Sizing the Plug-Flow Digester**

*Location.* If a manure pump is installed to pump the 12% solids manure, the digester can be located within a 300 ft radius of the mix tank at a convenient location with good access.

*Mix tank.* The mix tank can be round, square, or rectangular. A pump may be required to move manure to the plug flow digester.

*Hydraulic retention time and sizing of plug-flow digester.* A plug-flow digester will function with an HRT from 12 to 80 days. However, an HRT between 15 and 20 days is most commonly used to economically produce 70% to 80% of the ultimate methane yield.

*Dimensions.* The depth of a plug-flow digester can be between 8 feet and 16 feet depending upon soil conditions and the required tank volume. The width:depth ratio is usually greater than 1 and less than 2.5. The length:width ratio should be between 3.5 and 5.

*Heat exchanger:* An external heat exchanger or an internal heat exchanger is required to maintain the digesting mixture at the design temperature. Hot water circulated through the heat exchanger is heated using biogas as a fuel for a boiler or waste heat from a biogas fueled engine-generator.

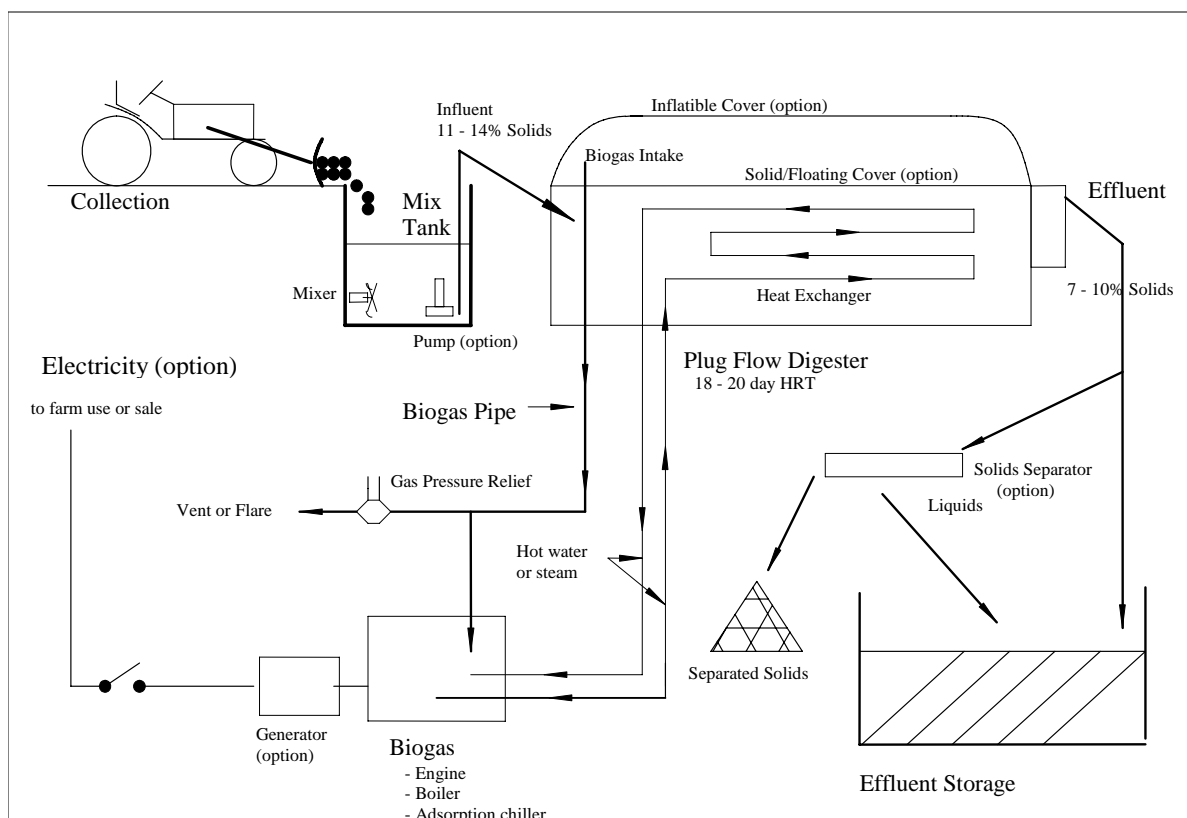


Figure B-6 Features of plug-flow digester system

*Operating temperature.* The daily temperature fluctuation should be less than 1° F. Most plug flow digesters operate in mesophilic range between 95° to 105° F with an optimum of 100° F. It is possible to operate in the thermophilic range between 135 to 145° F, but the digestion process is subject to upset if not closely monitored.

*Insulation.* A plug flow digester surface may be insulated to control heat loss.

*Construction materials.* The digester can be constructed as a lined trench or as a reinforced concrete or block tank.

*Methane recovery system and covers.* See discussion of methane recovery system above under complete mix digesters.

## Description of Complete-Mix Digester

A complete-mix digester is a controlled temperature, constant volume, mechanically mixed, biological treatment unit that anaerobically decomposes medium concentration (3% to 10% solids) animal manures and produces biogas (60% methane and 40% carbon dioxide) and biologically stabilized effluent. Figure B-7 includes general features of a complete-mix digester system.

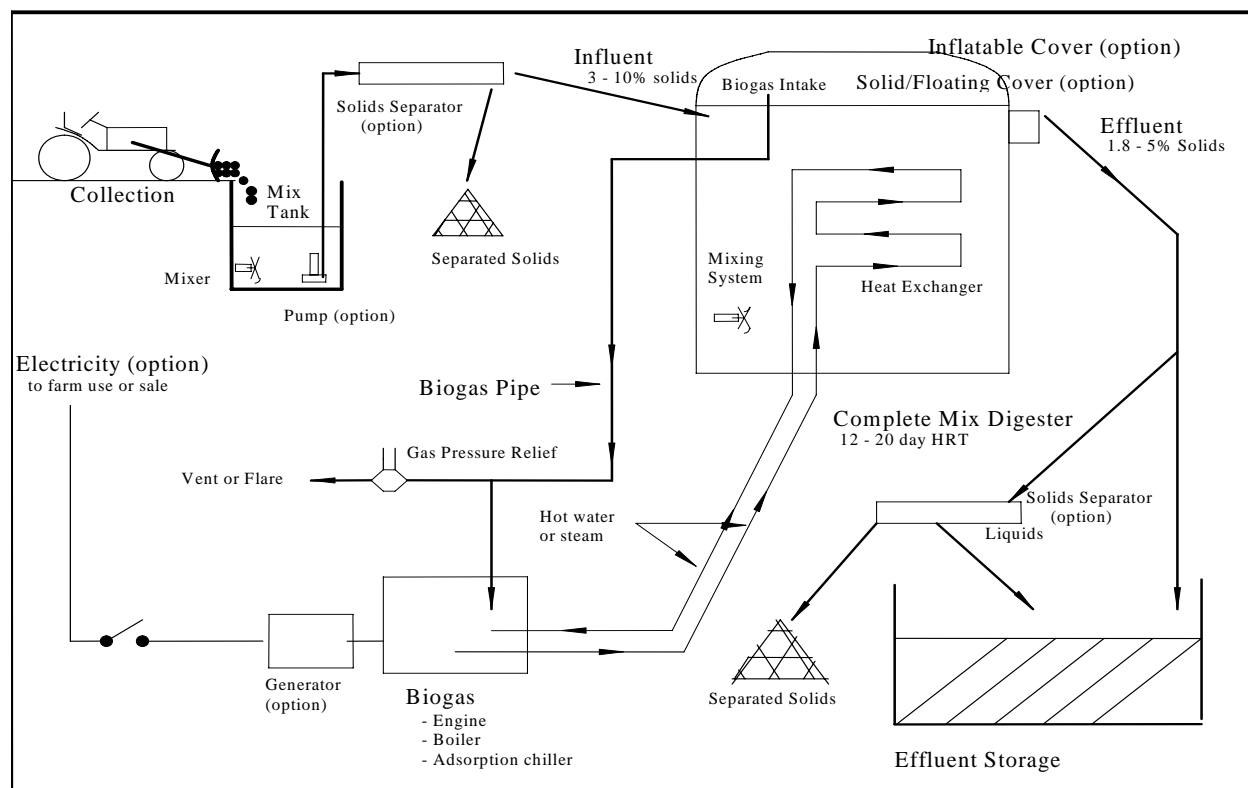


Figure B-7 Components of complete-mix digester

A complete-mix digester is designed to maximize biogas production as an energy source. The optimized anaerobic process results in biological stabilization of the effluent and odor control. The process is part of manure management system and supplemental effluent storage is usually required. Manure contaminated rainfall runoff or excess process water should not be introduced into the complete-mix digester.

### Components of Complete-Mix Digester

The components of a complete-mix digester system generally include a mix tank, a digester tank with mixing, heating and biogas recovery systems, an effluent storage structure, and a biogas utilization system. Pre- or post-digester solids separation is optional.

**Mix tank.** The mix tank is a concrete or metal structure where manure is deposited by a manure collection system. It serves as a control point where water can be added to dry manure or dry manure can be added to dilute manure. Manure is mixed to 3% to 10% solids content prior to introduction into the complete-mix digesters.

**Pretreatment.** A solids separator may be used to separate solids from influent manure to reduce solids buildup in the digester.

*Complete-mix digester.* A complete-mix digester is a heated, insulated above ground or in-ground circular, square or rectangular tank with a mixing system. The tank is covered by a fixed solid top, a flexible inflatable top, or a floating cover to collect and direct biogas to the gas utilization system. All covers are gas tight.

*Biogas use.* The recovered biogas can be used to produce space heat, hot water, cooling, or electricity.

*Solids separator (optional):* A mechanical separator may be installed after a complete-mix digester to capture fibrous materials fed as roughage to ruminants.

### ***Complete-Mix Digester Design Criteria***

*Location:* A complete-mix digester can be located within a 600 ft radius of the mix tank at a convenient location with good access.

*Optimum solids concentration.* The operating range for influent solids concentration in a complete-mix digester is 3% to 10% solids. However, 6% to 8% solids is the preferred concentration.

*Mix tank.* The mix tank can be round, square, or rectangular. A pump may be required to move manure to the digester.

*Hydraulic retention time and sizing of complete-mix digester.* A complete-mix digester will function with an HRT from 10 to 80 days. However, an HRT between 12 and 20 days is most commonly used to economically produce 60% to 75% of the ultimate methane yield.

*Operating temperature.* A heat exchange system should maintain the daily temperature fluctuation at less than 0.55° C (1° F). Most complete-mix digesters operate in the mesophilic range between 35° to 41° C (95° to 105° F). It is possible for this type of digester to operate in the thermophilic range between (135° to 145° F) but the digestion process is subject to upset if not closely monitored.

*Insulation.* A complete-mix digester tank may require insulation to control heat loss.

*Heat exchanger.* An external heat exchanger or an internal heat exchanger is used to heat and maintain the digesting mixture at the design temperature. Hot water or steam circulated through the heat exchanger is heated using a biogas-fueled boiler or waste heat from a biogas fueled engine-generator.

*Construction materials.* The digester tanks can be concrete or metal.

*Mixing.* Gas or mechanical mixing is used to stir the digester.

*Dimensions.* The depth can be between 8 and 40 ft depending upon soil conditions and the required tank volume.

*Methane recovery system.* A complete-mix digester is covered by a gas tight fixed solid top, a flexible top, or a floating cover to collect and direct biogas to the gas utilization system.

*Solid cover.* A solid cover is constructed to avoid cracking and leaks. Solid covers should resist corrosion. A solid cover allows for minimal gas storage.

*Inflatable Cover.* A coated fabric is generally used for inflatable covers. An inflatable cover can be designed for some gas storage. Wind protection may be necessary. The cover must have a gas tight seal. These materials are described in the covered lagoon discussion, above.

*Floating cover.* A floating cover is designed to lie flat on the digester surface. See discussion of floating covers for covered lagoons, above.

## **Operation and Maintenance of Complete-Mix and Plug-Flow Digesters**

Operation and maintenance of complete-mix and plug-flow digesters is very similar and therefore will be discussed together in this section. Proper operation and maintenance of plug-flow and complete-mix digesters is necessary for successful operation.

*Mix tank — operation.* On a daily or every other day basis, collectible manure is pushed, dragged or dumped into the mix tank. If necessary, dilution water or drier manure is added to the collected manure and mixed to achieve the design total solids mixture. The mixed manure is released via gravity gate or pumped into the digester.

*Mix tank — maintenance.* Mix tank maintenance consists of normal maintenance of pumps and mixers per manufacturers recommendations. The mix tank will require occasional cleaning to remove accumulated sand, gravel, steel and wood.

*Complete-mix and plug-flow digester — operation.* A complete-mix digester is fed hourly to daily, displacing an equal amount of manure from the outlet. A plug-flow digester is fed from the mix tank daily or every other day. The digester heating and mixing system should be checked daily to verify operation.

*Complete-mix and plug-flow digester — maintenance.* The digester temperature should be checked daily. The effluent outlet and digester gas pressure relief should be checked weekly to be sure that they are operating properly. The heat exchanger pump should be lubricated per the manufacturer's recommendations. The mixer in a complete mix digester should be lubricated per the manufacturer's recommendations. Sludge accumulation may require sludge removal every 8 to 10 years.

*Cover — maintenance.* The cover should be visually inspected weekly for rainwater accumulation, cracks, tearing, wear, and tensioning.



## Appendix C

### Conversion of Biogas to Biomethanol

Interest in neat methanol as a vehicular fuel has been steady for many years; the “Methanol Institute” promotes this chemical and major energy (oil, gas) companies also have some interest in this fuel. There are claims that methanol-using internal combustion engines reduce air pollution. Methanol is now also being considered as a storage fuel for hydrogen fuel cell cars. Nevertheless, during the past 20 years, no significant market has developed for methanol as fuel, although it is often used as an additive and can be blended with biodiesel to enhance cold weather properties. Methanol has only half the energy content of gasoline; it has a lower vapor pressure than gasoline; it can attack fuel and engine components; and it is toxic. Although these obstacles could be overcome, together with the lack of a methanol vehicle fueling infrastructure, they have limited the potential of this fuel.

#### Past Unrealized Projects

One company (TerraMeth Industries, Inc. of Walnut Creek, California) proposed building a landfill-gas-to-methanol plant in West Covina, Southern California during the 1990s. Despite legislation that supported the project and several years of trying to find financing, this project did not come to fruition. Another proposed project in Washington State was also abandoned. With the phase-out of MTBE, interest in methanol production waned.

The process for converting dairy manure biogas to biomethanol is challenging, primarily because it would need to be carried out at a scale several orders of magnitude smaller than current processes. For example, the unrealized TerraMeth landfill-gas-to-methanol project would have cost just under \$10 million (capital costs) for a facility that produced about 6 million gallons of methanol per year (and this cost is judged optimistic by many who have examined this conversion). An equivalently sized dairy facility would need over 50,000 cows to produce this much gas, which, by industrial standards is actually a very small plant.

#### The Smithfield Foods Utah Project: From Hog Manure to Biodiesel

A recent example of an animal-manure-to-methanol project is one proposed by Smithfield Foods in Utah. A subsidiary firm, Best Fuels LLC, announced an ambitious \$20-million project that would convert the manure from 23 hog farms (with a total of 257,000 finisher pigs) first to biogas and then to methanol for biodiesel production (Figure C-1). The farms were all within a 5-mile radius and the impetus for the project was the difficulty of marketing electricity from biogas produced from the animal manure.

As shown in Figure C-1, manure (about 40,000 tons dry matter/year) collected from swine houses is pumped to a central location, thickened by gravity to about 4.5% solids and digested in inground, heated (95 °F), floating cover digesters. The facility would produce about 1.2 million ft<sup>3</sup>/day of biogas.

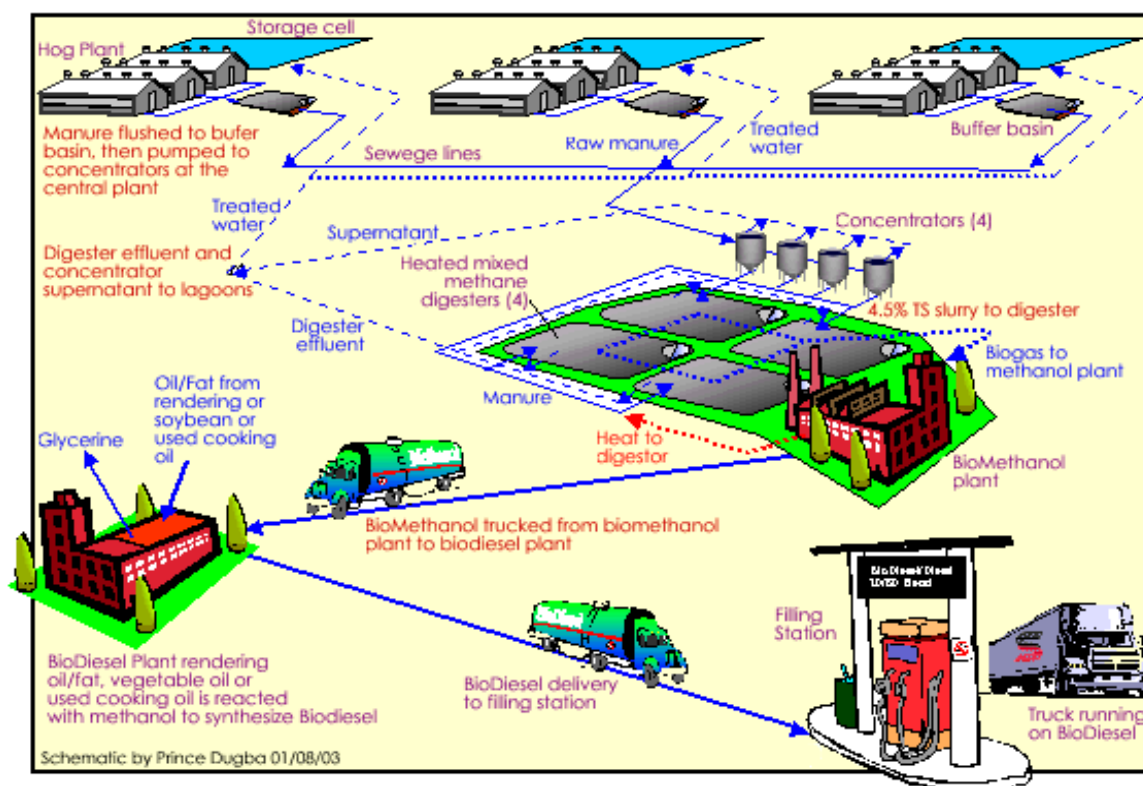
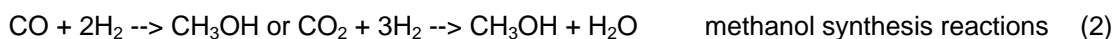


Figure C-1 Project of Best Fuels LLC/Smithfield Foods for Converting Hog Manure to Methanol

The biogas is next pumped to a central plant, where  $\text{H}_2\text{S}$  is removed with sodium hydroxide ( $\text{NaOH}$ ). The gas is converted to methanol in a conventional steam-reforming/water-gas shift reaction followed by high-pressure catalytic methanol synthesis:



The process at the Smithfield site is expected to yield 7,000 gallons of methanol per day. The methanol is used off-site for biodiesel production, expected to yield 40,000 gallons of biodiesel per day. The project literature states, “These processes should be considered industrial-scale processes, thus requiring a highly trained staff and high-tech equipment.”

However, after the initial much publicized announcement of the project no further information has become available. It is the opinion of the authors that if such an approach were even modestly economically attractive, it would have already been implemented under the much more favorable (from an engineering standpoint) opportunities made possible at stranded high- $\text{CO}_2$  natural gas wells. There the quality, quantity, pressure of the gas would much better justify their upgrading and conversion to methanol. It remains to be seen if this project actually moves forward.

## Appendix D

### Compressed Natural Gas and Liquefied Natural Gas Vehicles Available in California

#### CNG Vehicles

In 2004, the following types of CNG and LNG vehicles were available in California.

##### *Light-Duty CNG Vehicles*

The following types of light-duty CNG vehicles are currently available in California:

- Passenger vehicles
- Pickup trucks
- Passenger vans (including light-duty shuttles)
- Cargo vans

Light-duty CNG vehicle models are currently available from Honda, General Motors, Daimler-Chrysler and Baytech (a CNG vehicle converter specializing in GM vehicles). Ford, which had previously offered several CNG models (including the Crown Victoria sedan used in many CNG taxi fleets), announced in February, 2004 that they were stopping production of all CNG vehicles.

Examples of representative light-duty CNG vehicle types are shown below:

##### Passenger Vehicles

Honda Civic GX

American Honda Motor Co., Inc.

Four-door dedicated CNG sedan; auto

CVT; 1.7L four cylinder; 8 GGE fuel capacity;

200 mile range

Certification: SULEV



## Pickup Trucks

Chevrolet Silverado C2500 Pickup

General Motors Corp.

Dedicated CNG pickup truck; 2WD; 4-speed automatic; regular, extended cab or crew cab; 6.0L V8; 15 GGE fuel capacity; 180 mile range  
Certification: ULEV



## Passenger Vans

GMC Savana Van

General Motors Corp.

Dedicated CNG van; 8 – 12 passengers; 6.0L V8; 4-speed auto; 20.3 GGE fuel capacity; 320 mile range  
Certification: ULEV



## Cargo Vans

Chevrolet Express Cargo Van

Baytech Corp.

Dedicated CNG van; 258 ft<sup>3</sup> cargo space; 6.0L V8; 4-speed auto; 20.3 GGE fuel capacity; 320 mile range  
Certification: ULEV



## **Medium- and Heavy-Duty CNG Vehicles**

The following types of medium- and heavy-duty CNG vehicles are currently available in California:

- Transit buses
- School buses
- Refuse trucks
- Street sweepers
- Shuttles (medium-duty)
- Trolleys
- Miscellaneous heavy-duty trucks

Medium- and heavy-duty CNG vehicle models are currently available from a variety of truck manufacturers- and vehicle converters. Examples of representative medium and heavy-duty CNG vehicle types are shown below.

#### Transit Buses

##### Orion VII CNG

Orion Bus Industries

Dedicated CNG transit bus; max. 44 passengers; 30' – 40' length; low-floor; GVWR 42,540 lbs.; Detroit Diesel Corp. Series 50G/Cummins CG 280; range 350 miles  
Certification: ULEV, CARB Low NOx



#### School Buses

##### All American RE

Blue Bird Corporation

Dedicated CNG school bus; max. 66/84 passengers; 33' – 40' length; John Deere 6081H 250 6-cylinder  
Certification: CARB Low NOx



#### Refuse Trucks

##### LWT Refuse Truck

Crane Carrier Co.

Dedicated CNG low entry tilt (LWT) refuse truck; front loader; Cummins CG 275/280 hp or John Deere 6081H 280 hp 6-cylinder; single/ tandem rear axles; GVWR max. 60,000 lbs.; 70 GGE fuel capacity; 200 mile range  
Certification: ULEV, CARB Low NOx



## Street Sweepers

Crosswind J

Elgin Sweeper Co.

Dedicated CNG sweeper; recirculating air (vacuum) sweeper; Sterling SC 8000 chassis; Cummins 5.9L BG 195 6-cylinder; GVWR 33,000 lbs.; 8 cu. yd. hopper; 52 GGE fuel capacity

Certification: CARB Low NOx



## Shuttles

Crusader

Champion Bus, Inc.

Dedicated CNG transit shuttle; max. 25 passengers; Ford E-450/Chevrolet Express cutaway chassis; 4-speed automatic; GM Vortec 5.4L/6.0L V8; GVWR 14,050 lbs.; 37 GGE fuel capacity; 300 mile range  
Certification: ULEV, CARB Low NOx



## Trolleys

TR 35 RE

Supreme/Specialty Vehicles Inc.

Dedicated CNG trolley; max. 35 passengers; rear engine; CAP/Cat 3126 dual-fuel; GVWR 31,000 lbs.; 300 mile range  
Certification: CARB Low NOx



## Miscellaneous Heavy-Duty Trucks

Isuzu NPR HD (chassis)

Baytech Corp.

Dedicated CNG heavy-duty truck; multiple applications, e.g., box trucks, beverage/package delivery, landscaping; 5.7/6.0L V8; 4-speed auto; GVWR 14,500 lbs.; 30 GGE fuel capacity  
Certification: ULEV





## **LNG Vehicle Types**

LNG vehicle types are currently limited to heavy-duty vehicles. Common examples of heavy-duty LNG vehicles include transit buses, refuse trucks and Class 8 urban delivery (regional heavy delivery) trucks.

The following types of heavy-duty LNG vehicles are currently available in California:

- Transit buses
- Refuse trucks
- Class 8 urban delivery (regional heavy delivery) trucks

Heavy-duty LNG vehicle models are currently available from a variety of truck manufacturers- and vehicle converters.

Examples of representative heavy-duty LNG vehicle types are shown below:

### **Transit Buses**

#### **NABI 35LFW**

North American Bus Industries

Dedicated LNG transit bus; max. 30 passengers; 35' low-floor; GVWR 41,150 lbs.; Detroit Diesel Series 50G/Cummins CG 275; 408 gal. LNG fuel tanks; 350 mile range  
Certification: ULEV, CARB Low NOx



### **Refuse Trucks – Class 8 Urban Delivery**

Century Class (chassis)

Freightliner LLC

Heavy-duty dual- fuel (LNG/diesel) Class 8 truck; Caterpillar C-12 410 hp 6-cylinder; GVWR 80,000 lbs.; 120 gal. LNG/60 gal diesel fuel tanks; 430 mile range  
Certification: ULEV, CARB Low NOx







## Appendix E

### Energy Contents / Equivalencies for Natural Gas Fuels versus Electricity

1,000,000	Btu	In	1,000 ft <sup>3</sup>	Natural gas / biomethane
3,412	Btu	In	1 kWh	Electricity
3.4 ft <sup>3</sup>	Natural gas / biomethane	Same energy as	1 kWh	Electricity
120 ft <sup>3</sup>	Natural gas / biomethane	Same energy as	1 gal	Gasoline
140 ft <sup>3</sup>	Natural gas / biomethane	Same energy as	1 gal	Diesel
24 ft <sup>3</sup>	Natural gas / biomethane	Same energy as	1 gal	CNG/CBM
84 ft <sup>3</sup>	Natural gas / biomethane	Same energy as	1 gal	LNG/LBM
13,600 Btu	Natural gas / biomethane	Generates (at 25% efficiency)	1 kWh	Electricity
13.6 ft <sup>3</sup>	Natural gas / biomethane	Generates (at 25% efficiency)	1 kWh	Electricity
10,400 Btu	Natural gas / biomethane	Generates (at 33% efficiency)	1 kWh	Electricity
10.4 ft <sup>3</sup>	Natural gas / biomethane	Generates (at 33% efficiency)	1 kWh	Electricity
6,800 Btu	Natural gas / biomethane	Generates (at 50% efficiency)	1 kWh	Electricity
6.8 ft <sup>3</sup>	Natural gas / biomethane	Generates (at 50% efficiency)	1 kWh	Electricity



## Appendix F

### Cost of Building Dairy Anaerobic Digesters per Kilowatt

Source Document	Digester Name	Date Built	Type	Cost to Build	Avg kW Generated	Cost/ Avg kW
Lusk	Not Ident	1979	Plug, Slurry	\$510,000	182.6	\$2,792
Nelson and Lamb	Haubenschild	2000	Plug	\$355,000	98.0	\$3,621
Moser and Mattocks	Haubenschild	1999	Plug	\$329,851	85.0	\$3,881
Lusk	Craven Dairy	1997	Plug	\$247,450	78.3	\$3,161
Moser and Mattocks	Craven Dairy	1996	Plug	\$287,300	78.3	\$3,670
Moser and Mattocks	AA Dairy	1997	Plug	\$295,700	70.0	\$4,224
Lusk	Fairgrove Farms	1981	Plug	\$150,000	60.2	\$2,491
Mattocks	AA Dairy	1998	Plug	\$280,000	57.1	\$4,906
Mattocks	Haubenschild	1999	Plug	\$290,000	57.1	\$5,081
Lusk	Foster Brothers	1982	Plug	\$300,000	54.8	\$5,475
Lusk	Cushman Dairy	1997	Comp Mix	\$450,000	52.8	\$8,523
Lusk	AA Dairy	1998	Plug	\$343,300	50.5	\$6,796
Lusk	Cooperstown	1985	Comp Mix	\$500,000	37.1	\$13,477
Lusk	Langerwerf	1982	Plug	\$200,000	34.2	\$5,840
Lusk	Kirk Carrell Dairy	1998	Plug	\$100,000	30.0	\$3,337
Lusk	Oregon Dairy	1983	Slurry	\$120,000	25.7	\$4,672
Moser and Mattocks	Cal Poly	1999	Lagoon	\$230,000	19.4	\$11,852
Lusk	Agway	1981	Slurry	\$175,000	16.8	\$10,393
<b>Average dairy digesters over 50 kW</b>						<b>\$4,552</b>

Source: Lusk, 1998, Nelson and Lamb, 2000, Moser and Mattocks, 2000, Mattocks, 2000.



## **G. Linking Potential Biomethane Production with Possible Off-Farm Markets in California's Central Valley: Geographic Case Studies**

The following analysis focuses on compressed biomethane (CBM) as a substitute for compressed natural gas (CNG) in the transportation fuel market.

The analysis relies on the use of various data and geographic information system (GIS) maps to match areas with potentially high and sustainable biomethane production to local points of distribution for CNG as a transportation fuel. Additionally, the analysis includes three case studies of sites that may prove to be optimal for further research into siting a pilot/demonstration project. These case studies include the criteria and characteristics that identify them as potential locations for future projects or further studies.

The case studies examine only those areas with high production potential. They are not intended as comprehensive feasibility studies. Specifically, these case-studies do not explore the following:

- Financial costs to implement a pilot project
- Actual market demand for biomethane
- Opportunity costs for CNG users
- Transaction costs associated with the necessary plant and product permitting, product liability, establishing "rights of way," and determining market price points
- Political potential for support of renewable methane production from dairies at the local, state, and federal level

### **Selection Criteria for Regional Focus**

Three broad criteria were used to select a geographic region for further analysis:

- High concentration of dairies
- Regional demand for CNG as a transportation fuel
- Potential impact on local environmental quality

As discussed below, the San Joaquin Valley fit all three criteria.

#### ***Concentration of Dairies***

According to 2002 California Department of Food and Agriculture data (CDFA, 2004a), farmers in the state of California produced 35,065 million pounds of milk. Within California, 8 of the top 10 milk producing counties are located in the San Joaquin Valley (Table G-1). The other two counties are San Bernardino and Riverside, both in the Inland Empire.

Table G-1 Top Ten California Milk-Producing Counties

County	Thousands of Pounds of Milk Produced in 2002		
	Grade A	Grade B	Total
Tulare	8,928,146	27,204	8,955,350
Merced	4,729,013	55,209	4,784,222
Stanislaus	3,544,088	47,203	3,591,291
San Bernardino	3,319,084	9,547	3,328,631
Kings	2,819,534	6,607	2,826,141
San Joaquin	2,141,645	8,348	2,149,993
Riverside	2,047,366	1,835	2,049,201
Fresno	1,842,574	2,200	1,844,774
Kern	1,754,901	2,261	1,757,162
Madera	1,007,308	7,807	1,015,115
All other California counties	2,381,394	164,386	2,545,780
<i>Total</i>	34,515,053	332,607	34,847,660

Because the concentration of dairies plays a critical role in the analysis and case-studies, a calculation was made of dairy milk production as a function of the size of each of the top 10 milk-producing counties (Table G-2).

Table G-2 Amount of Milk Produced per Square Mile in California's Top Ten Milk-Producing Counties

County	Grade A	Grade B	Total	Square Miles	Pounds Milk / Square Mile
Tulare	8,928,146	27,204	8,955,350	4,884	1,834
Merced	4,729,013	55,209	4,784,222	2,008	2,383
Stanislaus	3,544,088	47,203	3,591,291	1,521	2,361
San Bernardino	3,319,084	9,547	3,328,631	20,164	165
Kings	2,819,534	6,607	2,826,141	1,436	1,968
San Joaquin	2,141,645	8,348	2,149,993	1,436	1,497
Riverside	2,047,366	1,835	2,049,201	7,243	283
Fresno	1,842,574	2,200	1,844,774	5,998	308
Kern	1,754,901	2,261	1,757,162	8,170	215
Madera	1,007,308	7,807	1,015,115	2,147	473
All other California counties	2,381,394	164,386	2,545,780	---	---
<i>Total</i>	34,515,053	332,607	34,847,660	---	---

While instructive, the numbers in Table G-2 can be deceptive. Milk production is highly concentrated in both San Bernardino and Riverside counties. However, the concentration of dairies per square mile is lower because these are two of the largest counties in the United States.

When viewed as a group, the top seven counties (in terms pounds of milk produced per square mile) form a contiguous area much larger than the two Inland Empire counties combined, despite their size.

As shown in Table G-2, the seven counties with the highest concentration of milk production per square mile are:

1. Tulare
2. Merced
3. Stanislaus
4. Kings
5. San Joaquin
6. Fresno
7. Madera

These seven counties in the San Joaquin Valley provide 72% of all the milk production in California. Together, they represent the densest concentration of milk production anywhere in the USA, and possibly, in the world. The characteristics of the dairies in some parts of the San Joaquin Valley would appear to support concentrating on the region. Also, the dairy industry is still growing in the Central Valley, while it is a mature industry and reportedly on the decline in both San Bernardino and Riverside County (CDFA, 2004b).

Because future pilot projects may rely on multiple variables (e.g., access to active landfills, wastewater treatment facilities, etc.) for selection of a project site, the ability to focus on one large, contiguous area that included several different county governments, with different levels of infrastructure investment, appeared to be beneficial.

### ***Regional Demand for Compressed Natural Gas as a Transportation Fuel***

According the San Joaquin Air Pollution Control District (District), the region is home to over 1,200 CNG vehicles. That total is equally divided between light-duty and heavy-duty vehicles, at roughly 600 vehicles each. However, we believe these numbers to be low, as the data only reflects the vehicles within the membership of the San Joaquin Clean City Coalition as of the end of 2003. The District also believes that there are 61 public and private CNG fueling stations within the region. However, the source of this data could not be produced when requested of the San Joaquin Valley Clean City Coalition. Regardless, accurate data from both the U.S. Department of Energy and WestStart-CALSTART was found on the number of known stations located within the San Joaquin Valley.

According to data compiled from the WestStart-CALSTART web site <<http://www.weststart.org>>, the San Joaquin Valley Clean Cities web site <<http://www.valleycleancities.org/>>, and the US DOE Alternative Fuels Data Center, the San Joaquin Valley has 23 verifiable CNG stations as opposed to 20 CNG stations in the Inland Empire counties.

Although Riverside County has 14 CNG fueling stations, which is the greatest concentration of CNG fueling stations of any 10 top milk producing counties in the state, on a regional basis there are a greater number of stations in the San Joaquin Valley. In terms of conducting a geographic analysis, the San Joaquin Valley appeared to provide more options both in terms of linking demand with supply, and in linking potential production facilities both with the dairies and with the market for CNG as transportation fuel.

### ***Summary of Reasons for Selecting San Joaquin Valley as Geographic Focus***

Seven of the eight San Joaquin Valley counties (Tulare, Merced, Stanislaus, Kings, San Joaquin, Fresno, and Madera Counties) were selected to be the focus of this GIS analysis for three complementary reasons:

- High concentration of dairies
- Substantive and dispersed demand for CNG as a transportation fuel
- Dairy's relative impact on local environmental quality

### **Data Sources**

To conduct this initial analysis, we attempted to gather data on four different variables:

- Dairies
- CNG demand
- Landfills (both active and collecting methane) and wastewater treatment plants (collecting methane)
- Local businesses with high CNG demand

### ***Dairies***

The data we wanted to acquire about the dairies in the seven counties of the San Joaquin Valley included geographic location and herd size. This data was obtained from three sources. The data for Fresno, Kings, Madera, and Tulare Counties was obtained from Kerry Elliot of the Regional Water Quality Control Board Region 5, Fresno office. The data for Merced and Stanislaus counties was obtained from Polly Lowry from the Regional Water Quality Control Board Region 5, Rancho Cordova office. Data for San Joaquin County and some additional data for Merced County were obtained from Jess Sitre of the Merced County Dairy Program, in Merced. (Jess Sitre provided a file with dairy locations in Merced County, but the file did not contain the number of cows per farm.)



Except for Merced County, the data seemed to be complete in terms of location and estimates of herd size. For the latter, we used the number of milking cows at each dairy. Many dairy farms also have other non-milking producing cattle on-site, but these animals are generally not fed in the “feed lanes” that are flushed to remove manure. As a result, their waste product (manure) is generally unavailable for CNG production. See Annex G1 for additional information regarding the characteristics of the dairy industry in the San Joaquin Valley.

### ***Demand for Compressed Natural Gas***

Demand for CNG as a transportation fuel is rising in California. The California Energy Commission (CEC) projects that California’s annual demand for CNG as a transportation fuel will rise 46 million to 150 million therms by 2020 (CEC, 2001). In terms of gasoline gallon equivalents, it was estimated that in 2002, California used between 59 million to 67 million “gallons” of CNG (CEC, 2003). Most of this CNG (70% to 80%) was consumed by medium- to heavy-duty vehicles of which there are 4,350 in the state (CEC, 2003). An estimated 607 such vehicles are operating in the San Joaquin Valley (Urata, 2003). This amounts to 14% of the state’s medium- to heavy-duty CNG vehicle population. As a relative comparison, the population of the region is just under 12% of California total population.

Regional data concerning the demand for CNG as a transportation fuel and its location within the Central Valley could not be found. As a proxy for establishing total demand and its location, we selected known CNG fueling stations. This data was obtained from three sources:

- A report on alternative fuel vehicles by Linda Urata of the San Joaquin Valley Clean Cities Coalition (prepared for the San Joaquin Valley Pollution Control District in 2003)
- WestStart-CALSTART Clean Car Maps (2004)
- DOE “Clean Cities” web site (2004)

The last two sources are both interactive databases found on the web. The Clean Car Maps database from WestStart-CALSTART was browsed for all seven counties of interest. The Alternative Fuels Center database was browsed using a 35-mile radius for all major metropolitan centers in the seven counties. Most CNG stations were identified in all three sources. The Urata report claimed upwards of 60 CNG fueling stations in the region. However, detailed locations of only 21 of the stations were provided. Upon further investigation it was determined that most of the CNG sites that could not be located were simply private holding facilities for small fleets that were serviced by CNG deliveries via truck.

For future efforts that attempt to further assess the feasibility of biomethane projects, we recommend a more comprehensive survey of CNG fueling stations be conducted. There are two reasons for this. First, the data from web sources does not appear to be updated often enough to be comprehensive. Additionally, each web-based database contained a different number of total

stations. Also, the data from Clean Cities Coalition needs to be more detailed in terms of both location and the annual equivalent (in millions of gallons) of CNG dispensed by each station.

### ***Landfills and Wastewater Treatment Facilities***

To build a system capable of economically converting dairy methane biogas into transportation fuel, other research indicated the necessity of using large waste-handling facilities as aggregators and/or processors of the fuel. To satisfy this requirement, data was collected on landfills and wastewater treatment facilities in the seven-county area that currently collect and/or process methane as a by-product of their operations. This data was obtained from the California Energy Commission's "List of Waste to Energy Power Plants in California" (<<http://www.energy.ca.gov/development/biomass/index.html>>).

### ***Local Businesses with High Demand for Compressed Natural Gas***

Prior to the research team's trip to Europe (see main report), data was collected on the natural gas demand of local businesses within the San Joaquin Valley from Dun & Bradstreet (<<http://www.zapdata.com>>). To determine natural gas usage, the Dun & Bradstreet industry information was cross-referenced by SIC code to the average energy consumption, which was provided by the DOE (Unruh, 2004).

### ***Analysis of the Accuracy of Data Collected***

Prior to conducting our analysis, we sought to determine the accuracy of two key variables: the number of cows per dairy and data point location. These data points included not only each dairy but also the CNG stations, wastewater treatment facilities, landfills, and business utilizing CNG. In terms of the number of cows per dairy, the only record of the number of cows per county and the number of dairies per county available from California State government resources was reported data from 1998 and 1999 (CEC, 2004). As mentioned previously, these numbers represent the number of milking cows, not total herd size.

The data is up to five years old and the CDFA (2004b) reports significant changes in the number of dairy farms each year. However, we believe the 1999 data can be used to determine the reasonableness of the data that we collected. The percentage differences between this 1999 data and the data we used are provided in Annex G2.

Annex G2 shows that the number of cows per farm in Madera has significantly increased while the number of dairy farms has remained consistent. Tulare County experienced a small increase in the number of farms and the number of cows. San Joaquin and Stanislaus Counties both experienced a decrease in the number of farms and in the number of cows. The one county where the data we received does not appear to be complete is Merced County. However, we feel we have compensated for this. Refer to Annex G2 for a fuller discussion.

We used several sources to determine the accuracy of the geocoded longitude and latitude location of facilities. Please see Annex G2 for a full description.

## **Determination of Viable Project Locations**

The methodology we used to determine the best locations for biomethane projects in the seven-county area is described below.

### ***Initial Criteria: Nearby Fueling Stations***

Research conducted in Europe determined that one of the more ideal off-farm uses of biomethane is as renewable natural gas for transportation uses. Based on this assumption, we sought data on the location of public and private CNG distribution stations in the San Joaquin Valley. An ideal scenario for a biomethane project would be a situation in which locally produced biomethane would be blended with CNG at nearby filling stations and utilized by CNG vehicle drivers.

First, even before we conducted a GIS analysis, we identified an initial 400-square-mile area surrounding each known CNG station location. The 400-square-mile area was centered at the CNG station and extended 10 miles in each direction: to the north, south, east, and west (Figure G-1).

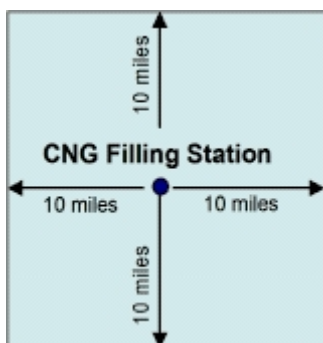


Figure G-1 Identification of 400-Square-Mile Area around CNG Filling Station

All of the dairy farms, wastewater treatment plants, landfills, and other CNG stations located within this initial area were then identified (through an analysis of their geocodes), relative to the main CNG station. The locations were ranked based on the purported number dairy cows nearby.

### ***Initial Site Rankings: Proximity to Dairies***

Table G-3 provides a list of the sites ranked according to their proximity to dairies. The table does not include CNG fueling locations that had no cows in the surrounding 400-square-mile area. (A complete list of all CNG stations that were included in this analysis is included in Annex G3).

The initial analysis identified three locations with more than 100,000 nearby cows. Detailed maps were then made of these top three sites (Tulare FleetStar, FleetStar – SoCal Gas, and Kings County Yard/PFC) to enable further study. Additionally, a detailed map was also made of the fourth-ranked site (W.H. Breshear’s FleetStar) for two reasons. First, the number of dairies relative to the number of overall cattle could indicate a very concentrated local industry. Second, the local concentration of businesses using a substantial amount of natural gas indicated other potential markets for the CBM outside of the transportation sector. Due to limited resources, we did not further investigate the remaining 14 locations shown in Table G-3. See Annex G4 for site descriptions of the sites ranked 4 through 8.

**Table G-3 Initial Ranking of CNG Filling Stations Based on Number of Cows in Surrounding Area**

Rank	CNG Location	Cows	Dairies	Wastewater Treatment	Landfill	Other CNG Stations
1	City of Tulare – FleetStar <sup>a</sup>	269,897	235	3	6	0
2	FleetStar - SoCal Gas <sup>a</sup>	132,291	129	3	5	0
3	Kings County Yard/PFC <sup>a</sup>	129,766	150	0	2	1
4	W.H. Breshear’s – FleetStar <sup>a</sup>	77,212	160	0	10	0
5	PG&E Merced Service Center <sup>a</sup>	68,600	92	0	3	0
6	Lemoore NAS	61,979	92	0	2	1
7	Kings Canyon Unified Sch. Dist. <sup>a</sup>	40,048	30	0	0	0
8	Tesei Petroleum <sup>a</sup>	37,488	30	0	2	0
9	City of Fresno Service Center	17,924	27	1	4	4
10	Visa Petroleum	14,424	23	1	7	4
11	Pinnacle CNG/UPS	12,324	21	1	7	4
12	San Joaquin County	10,895	29	3	9	1
13	PG&E Stockton Service Center	9,395	17	3	10	1
14	CSU Fresno	7,273	11	1	7	4
15	E.F. Kludt and Sons	7,245	12	0	1	0
16	Clovis Unified School District	4,840	6	0	5	4
17	Gibbs Auto Fuel Station	4,475	7	0	1	1
18	City of Delano	2,050	2	0	2	0

<sup>a</sup> These CNG stations are described in detail in this study.

### **GIS Analysis: More In-depth Rankings**

The initial analysis helped guide our selection of CNG sites for further analysis using GIS, a method that can provide more complete results. Our initial analysis examined only the total numbers of cows and potential facilities where biogas might be collected and upgraded; the GIS analysis would provide the additional detail needed for this study.

The upgrading of dairy biogas into a transportation fuel (biomethane) is capital intensive. In most cases, installation of an upgrading plant would be too expensive and complex for a single dairy—or even a group of dairies—to install and operate. Through GIS analysis, the location of

existing wastewater treatment facilities and landfills that were already processing methane could be identified and cross-checked against areas with high concentrations of dairy cows.

We began the GIS analysis by working backwards from the “point of demand” (i.e., the CNG station). First, we sought to determine first the number of cows and infrastructure within a 9-mile radius of the CNG station. Next, we sought to determine the number of cows within an approximate 3-mile radius of any identified infrastructure.

**Table G-4 Ranking of Wastewater Treatment Facilities and Landfills in Proximity to Dairies**

Rank	Facility Name (Wastewater Treatment Plant or Landfill)	Number and Potential Production of Wastewater Treatment Facilities, Landfills, and Nearby Dairies (9-mile radius)			
		Infrastructure	Dairies	Cows	Annual Biomethane Potential <sup>a</sup> (million ft <sup>3</sup> )
	City of Tulare	5	98	124,209	1,360
1	New Era #2		25	41,867	458
2	New Era #1		33	38,670	423
3	Soil Food		30	37,566	411
4	Woodville Disposal		21	29,971	328
8	Tulare County		18	12,685	139
	SoCal Gas, Visalia	5	42	41,446	454
5	Wood Industries		21	23,715	260
6	Tulare County		29	16,835	184
7	Visalia Disposal		9	13,681	150
	Other 2 are too small				0
	Kings County Yard/PFC	2	73	59,930	656
9	KWRA Materials & Composting		17	11,299	124
10	Hanford City Wastewater Treatment		11	7,329	80
	W.H. Breshear's of Modesto (Incorporates 4 other facilities)	5	77	35,565	389
11	Central Valley		14	4,870	53
12	Bonzi		13	4,305	47
13	City of Modesto		7	3,930	43

<sup>a</sup> Biomethane potential assumes 30 ft<sup>3</sup> biomethane per cow per day

While the selection of the 9-mile radius was relatively arbitrary—an attempt on our part to simply hold down the transportation and delivery costs of the refined and potentially compressed biomethane—the 3-mile radius around the infrastructure was not. It was selected because of the high variable costs of moving manure to a centralized point and/or the high capital costs of

permitting and installing piping to carry the raw biogas from on-farm anaerobic digesters to an aggregating facility.

Using only the top four CNG sites identified in the initial analysis, we then ranked the surrounding infrastructure within the nine mile radius based on their potential annual biomethane production from dairies within three miles of them. The table below organizes these sites around the CNG stations they would serve and supplies each one with a corresponding rank. Each of the four filling stations shows the potential volume of biomethane within a 9-mile radius; landfills and wastewater treatment plants within the 9-mile radius of the filling station are listed below each filling station. Next to each landfill or treatment plan is the potential volume of biomethane within a 3-mile radius of that facility. If the facility is on the edge of the original 9-mile radius, then its 3-mile radius may incorporate a dairy that is outside the filling station's 9-mile radius.

What we found was that the most promising pilot/demonstration project sites would almost all be centered on the CNG station in the City of Tulare. Table G-5 compares the results of the initial to those of the GIS survey, with the given parameters.

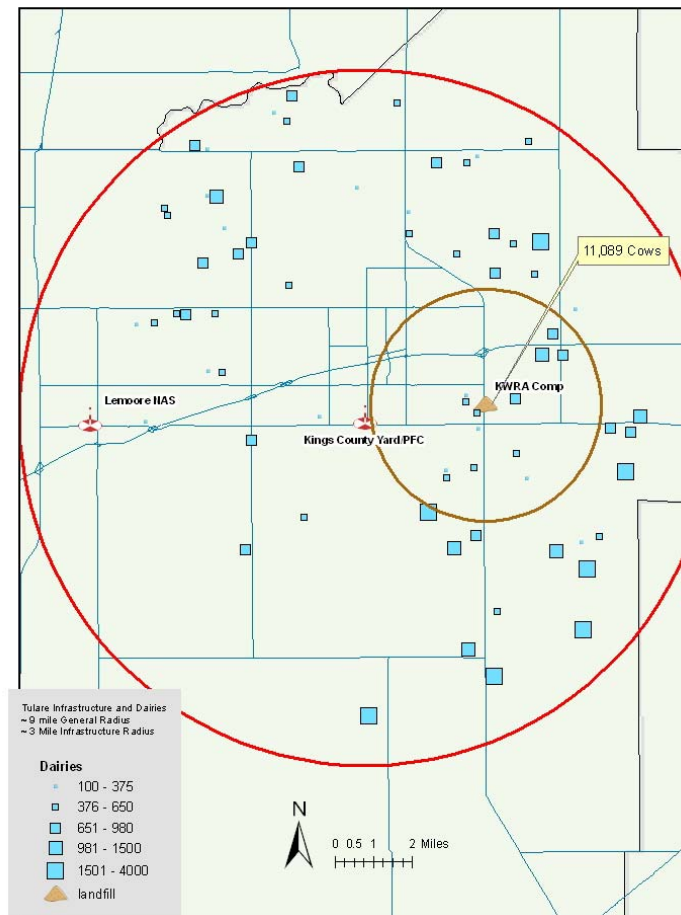
Table G-5 Comparison of Sites Based on Initial and GIS Rankings

	City of Tulare		SoCalGas, Visalia		Kings County Yard		W.H. Breshear of Modesto	
	400 mi <sup>2</sup>	9-mi radius	400 mi <sup>2</sup>	9-mi radius	400 mi <sup>2</sup>	9-mi radius	400 mi <sup>2</sup>	9-mi radius
Cows	269,897	124,209	132,291	41,446	129,766	59,930	77,212	35,565
Dairies	235	98	129	42	150	73	160	77
Annual Biomethane Potential (million ft <sup>3</sup> )	2,945	1,360	1,448	453	1,421	656	845	389
Infrastructure and other CNG Facilities	9	5	8	5	3	2	10	5

What seemed like promising sites after the initial analysis looked less promising on the basis of the GIS analysis. For example, the Kings County Yard CNG Station initially seemed appealing as its overlap with the Lemoore NAS indicated that these two stations might be able to somehow work in conjunction (e.g., sharing costs for biomethane aggregation and processing equipment). Additionally, under EPAct, the federal facility is under a mandate to use alternative fuels for up to 20% of their fleet vehicles. Based on the GIS analysis, however, this promising location would most likely not make a good spot for a pilot/demonstration project due to the low concentration of nearby dairies around local infrastructure (see Map 1).

## Map 1

### Proximity Analysis of Dairies to Infrastructure - Kings County Yard, Hanford -

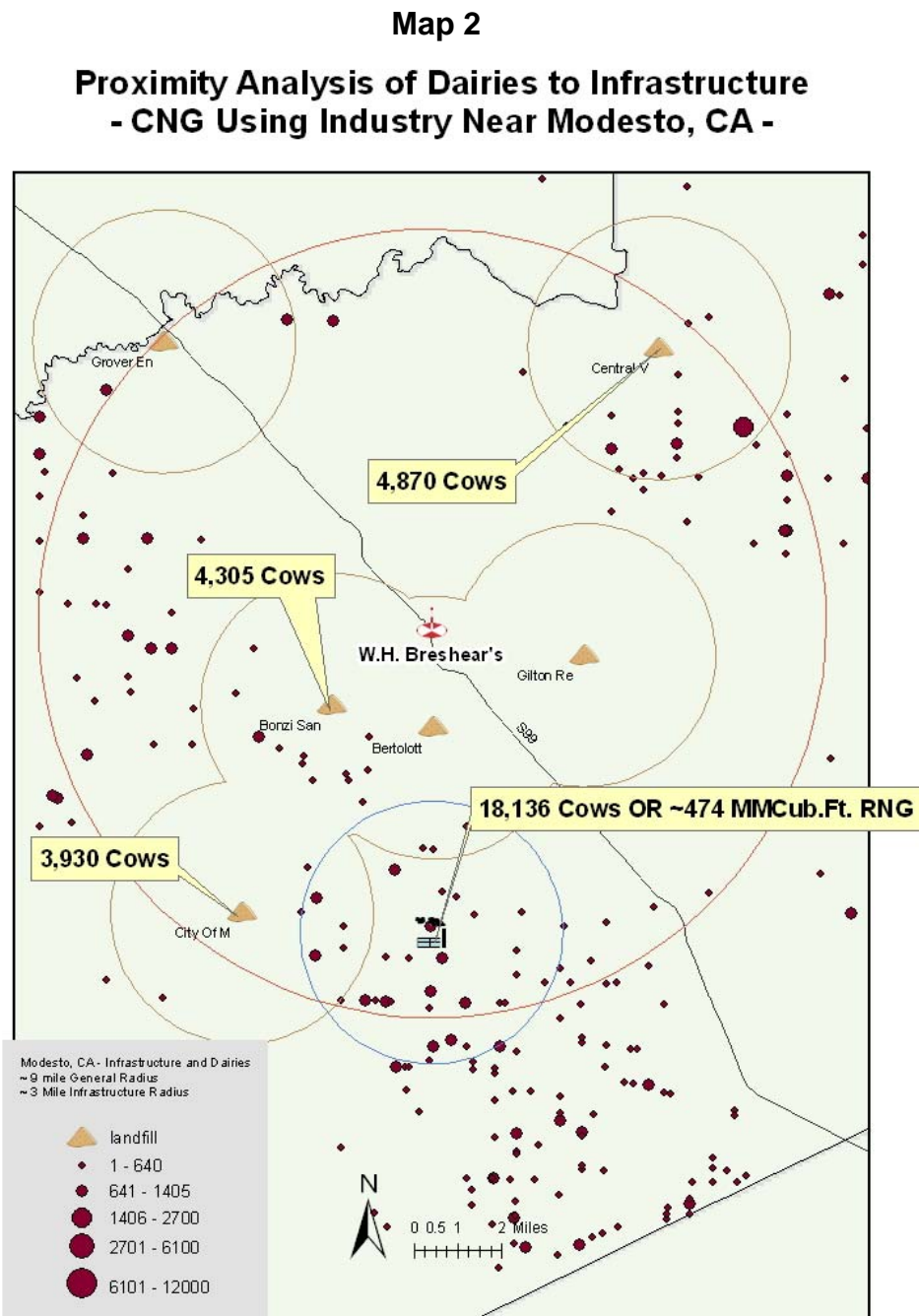


### **Additional Data**

In addition to the data collected on dairies, CNG facilities, wastewater treatment plants, and landfills, data was also collected on local businesses with high natural gas usage. This data was gathered initially as it was unknown as to what type of final biomethane “end-use” would be selected from the research done in Europe. We hoped that understanding the locations and demands of businesses with high demand for natural gas a potential might provide an insight into potential markets for dairy biomethane production.

Ultimately, it was determined that biomethane as a transportation fuel made the most economic sense for future pilot projects. Consequently, the number of potential biomethane end-use industries was not used to rank the locations. However, this information was included in the discussion of the sites because such buyers could provide an alternate market for excess biomethane.

It is interesting to note that in the analysis of Site #4, W.H. Breshear's of Modesto, the most compelling case for using biomethane involves a business with a large CNG demand. In fact this business is surrounded by more dairies than any landfill or wastewater treatment facility combined (see Map 2 below).





## **Description of Sites**

The following four case studies of the highest ranked sites (see Table 3) use raw GIS data to conduct cursory analyses of the potential for future research pilot/demonstration projects using biomethane as a transportation fuel. With the exception of Site #4, we chose 100,000 dairy cows as an arbitrary “cut-off” point for in-depth GIS analysis. For information on other top-ranked sites, please refer to Annex G4, which contains much of the same ranking information without accompanying maps.

### **Site #1: City of Tulare, FleetStar**

The number 1 ranked location is the City of Tulare FleetStar station. The exact location is:

3989 S K Street  
Tulare, CA 93274

This CNG station allows public access with restrictions. In 2003, the station sold 84,000 gasoline gallon equivalents of CNG (Al Miller, City of Tulare, personal communication).

This facility is located at the southern spur of the city of Tulare, Tulare County, in the Southern California Edison service territory (this service area is included as Annex G5). The facility is within a half mile of Highway 99. Of the 235 dairies in the area, 232 are located in Tulare County and 3 are located in Kings County. According to the 2000 US Census data (2002), the City of Tulare has a population of 43,994. The breakdown on “customers” for this station was 18 heavy-duty CNG vehicles and 42 light-duty CNG vehicles. The station is unique in that it receives LNG and converts it to CNG as needed.

The wastewater treatment plants and landfills located in the area of initial analysis are listed below. The following map (Map 3) details a smaller area that includes 9 miles around the CNG Station; only five wastewater treatment plants and landfills are included in this smaller zone. For more information about these facilities, see annexes G6 and G7.

1. City Of Tulare  
1875 South West Street  
Tulare, CA
2. Royal Farms #1 - #2  
Tulare, CA 93274
3. Tulare County Landfill and Recycling Complex  
26951 Road 140  
Visalia, CA 93292
4. New Era Farm Service #2  
Jim Nance Dairy  
6440 Ave 160  
Tulare, CA

5. New Era Farm Service #1  
Hoffman Dairy Ave 216 & Rd 140  
Tulare, CA
6. Tulare County Compost and Biomass  
24487 Road 140  
Tulare, CA
7. Soil Foods, Inc.  
20002 Road 140  
Tulare, CA
9. Woodville Disposal Site  
Rd 152 At Ave 198  
Tulare, CA

Three of the sites mentioned above—the City of Tulare, Royal Farms, and Tulare County—all currently generate electricity by burning methane produced by animal waste. The City of Tulare’s plant is 0.41 MW, the Royal Farm is 0.18 MW and the Tulare County Landfill is 1.9 MW.

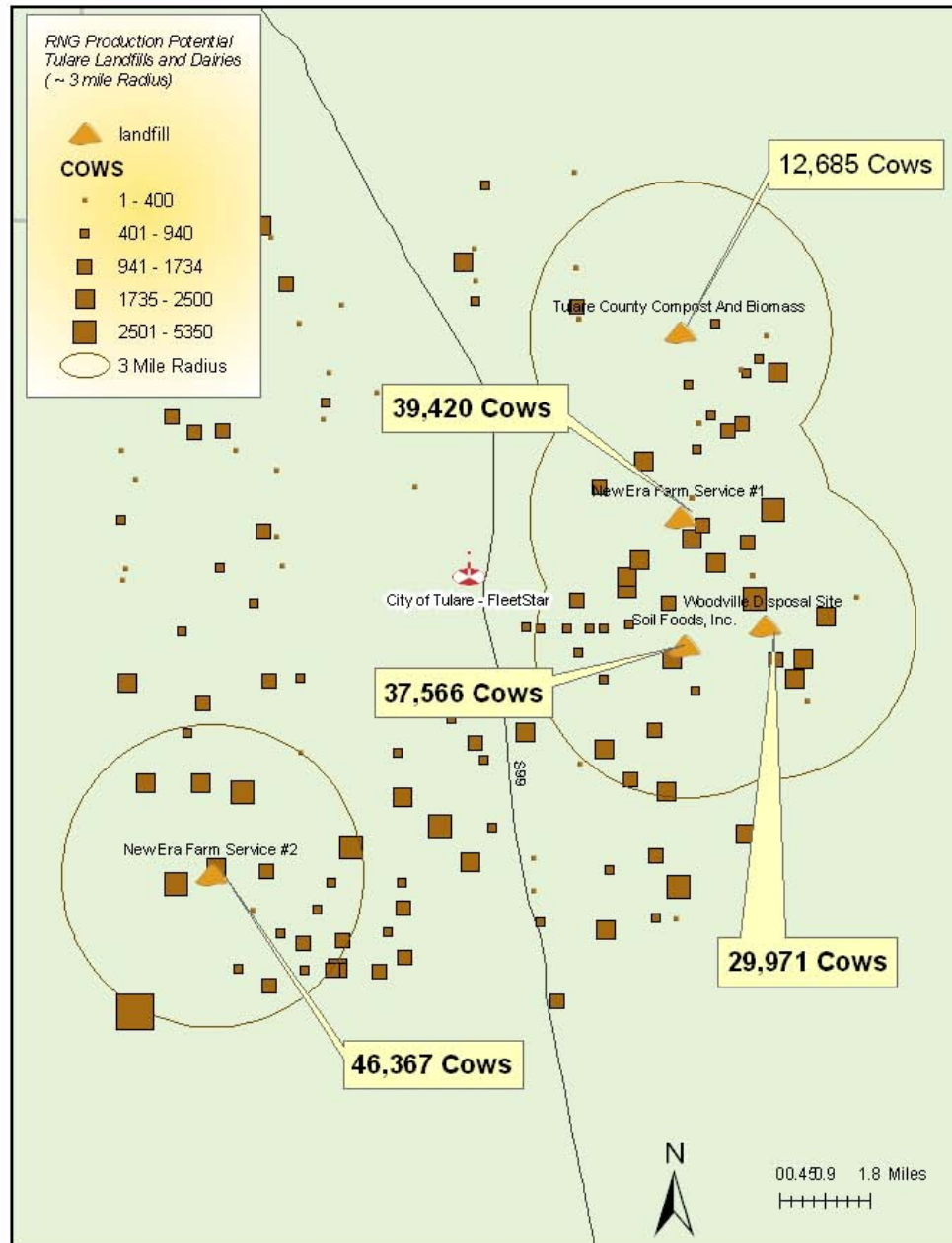
There are three businesses within the area of analysis that use large amounts of natural gas. Based on industrial sales and national average industry natural gas usage for these businesses, we estimate that these three locations would use a total of 129,564,000 kBtu/year.

The three businesses are:

1. JIT Steel Inc  
2000 S O St  
Tulare, CA 93274  
Process sheet metal  
Estimated Natural Gas usage = 33,400,000 kBtu/year
2. Golden Valley Dairy Products  
1025 E Bardsley Ave  
Tulare, CA 93274  
Mfg cheese and whole dairy products  
Estimated Natural Gas usage = 45,124,000 kBtu/year
3. CP International  
800 E Paige Ave  
Tulare, CA 93274  
Mozzarella cheese & whey manufacturing  
Estimated Natural Gas usage = 51,040,000 kBtu/year

### Map 3

## Proximity Analysis of Dairies to Infrastructure - City of Tulare CNG Station -



### **Site #2: Visalia SoCal Gas, FleetStar**

The second ranked location is the Visalia's SoCal Gas-FleetStar. The exact location is:

FleetStar-SoCal Gas  
320 N Tipton Street  
Visalia, CA 93292

This CNG location distributed 63,000 gasoline gallon equivalents of CNG in 2003.

This facility is located on the western end of the city of Visalia, Tulare County, and is approximately 18 miles NNW of Site #1. The 2000 US Census (2002) states that the city of Visalia had a population of 91,565. The CNG facility is within two miles of Highway 198, which provides easy access to Highway 99. The CNG station is in Southern California Edison's service territory (Annex G5).

Of the 129 dairies in the surrounding area, 127 are located in Tulare County and 2 are located in Fresno County. Much of the area surrounding this site and Site #1 overlap, including 72 dairies, 3 of the infrastructure facilities identified previously, and 2 of the 3 major industrial users of CNG identified. Please refer to the accompanying map (Map 4) for more details.

The wastewater treatment plants and landfills located in the area of initial analysis are listed below. The following map details a smaller area of 9 miles around the CNG Station and includes only three of these facilities. For more information about all the facilities, see annexes G6 and G7. Again, the first three landfill locations are identical to locations identified in Site #1 but are not shown on the following map as they are outside of the nine mile radius of analysis.

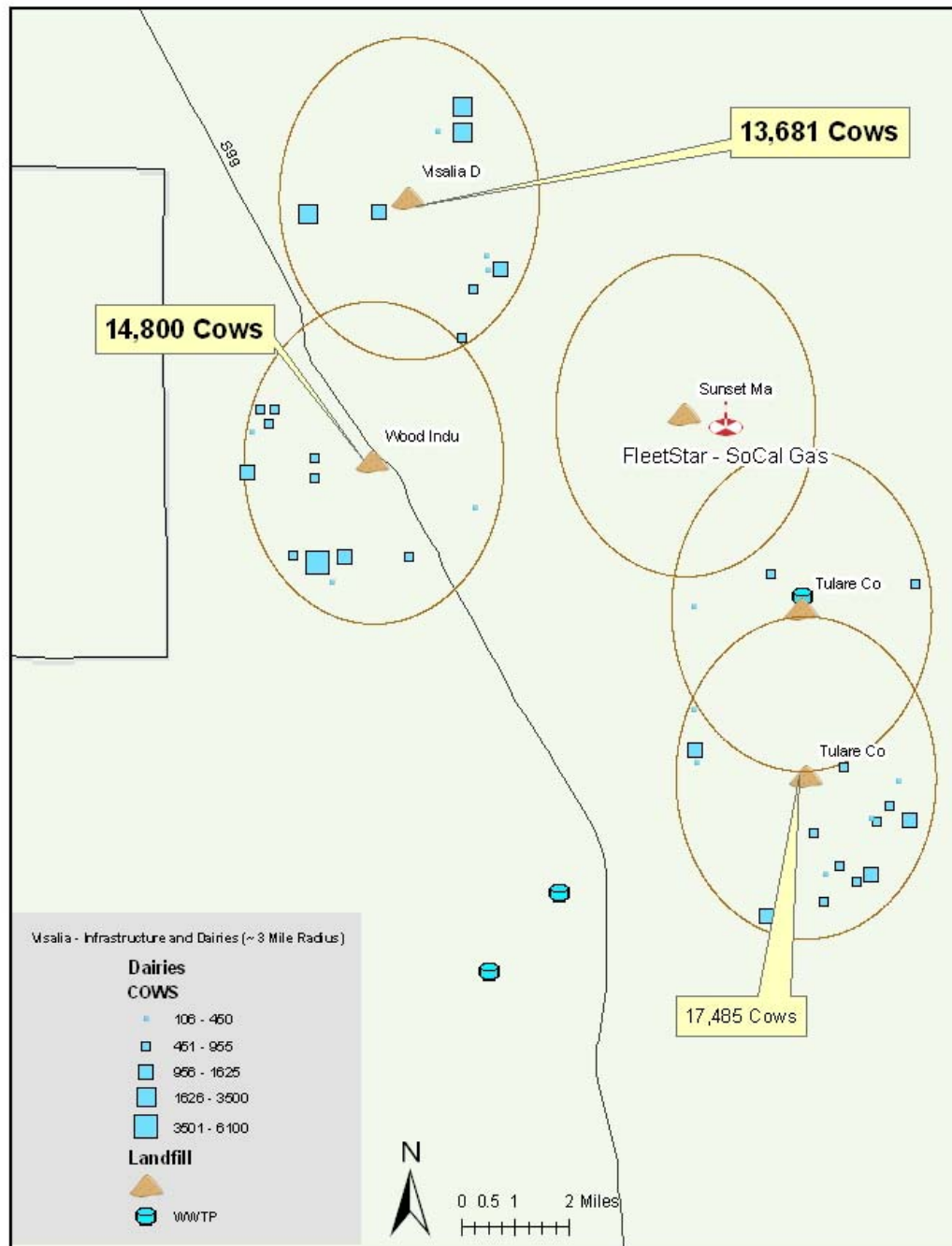
1. Tulare County Recycling Complex  
26951 Road 140  
Visalia, CA
2. Tulare County Compost and Biomass  
24487 Road 140  
Tulare, CA
3. Woodville Disposal Site  
Rd 152 at Ave 198  
Tulare, CA
4. Sunset Material Recovery Facility  
1707 East Goshen Road  
Visalia, CA
5. Visalia Disposal Site  
Rd 80 at Ave 332  
Visalia, CA

Two of the three businesses listed below were identified previously and are within the initial analysis area of Tulare's SoCal Gas CNG station. Based on the industries' sales and national average industry natural gas usage, it is estimated that these three locations would use a total of 124,924,000 kBtu/year. Please refer to the following map for greater details. The three businesses are:

1. JIT Steel Inc  
2000 S O St  
Tulare, CA 93274  
Process sheet metal  
Estimated Natural Gas usage = 33,400,000 kBtu/year
2. Golden Valley Dairy Products  
1025 E Bardsley Ave  
Tulare, CA 93274  
Mfg cheese and whole dairy products  
Estimated Natural Gas usage = 45,124,000 kBtu/year
3. California Pretzel Co Inc  
7607 W Goshen Ave  
Visalia, CA 93278  
Pretzel and cookie production  
Estimated Natural Gas usage = 46,400,000 kBtu/year

Map 4

# **Proximity Analysis of Dairies to Infrastructure - SoCalGas CNG Station, Visalia -**



### **Site #3: Kings County Yard/PFC**

The third ranked location is the Visalia SoCal Gas-FleetStar. The exact location is:

Kings County Yard/PFC  
11827 S 11<sup>th</sup> Ave  
Hanford, CA 93230

This CNG location allows public access with restrictions. In 2003, the station sold 45,000 gasoline gallon equivalents of CNG.

This facility is located in the southern half of the city of Hanford, in Kings County. According to the 2000 US Census (2002) the city of Hanford had a population of 41,685. The CNG station is also within 2 miles of Highway 198, providing easy access to Highway 99. Of the 150 dairies in the surrounding area, 116 are located in Kings County, 23 are located in Tulare County, and 11 are located in Fresno County. The CNG station is also in Southern California Edison's service territory (Annex G5).

Not surprisingly given the concentration of dairies in the region, the initial analysis of this site had a portion of the area surrounding this location overlapping with both Site #1 and Site #2. To be exact, there are 5 dairies that fall within the overlap with Site #1, and 24 dairies with Site #2. However, none the sites showed overlap under the more tightly focused GIS analysis.

Of the 30,000 gallon equivalents distributed by the Kings County CNG station, it was estimated that 33% was used by medium-to-heavy-duty vehicles.

Our analysis only indicated one wastewater treatment facility in the area of initial analysis surrounding this site and one landfill actively collecting and utilizing methane. The locations are:

1. KWRA Material Recovery and Composting Facility  
7803 Hanford-Armona Rd.  
Hanford, CA 93230
2. City of Hanford Waste Water Treatment Plant  
1055 Houston Ave.  
Hanford, CA 93230

As mentioned previously, there is another CNG filling station close by: the CNG station located near the Lemoore Naval Air Station (NAS). The Lemoore station is just 10 miles west of the Kings County CNG station. There are fewer than half the number of cows and dairies near the Lemoore location than there are near the Kings County CNG station. This is because of the significant size of the Lemoore NAS facility. The Lemoore NAS CNG station is a government site and there is no public access, however, federal facilities are under a mandate (EPAct) to use cleaner burning and/or renewable fuels in their fleet vehicles (up to 20%). Further investigation is necessary, but this site may provide an outlet for biomethane aggregated and refined at one of the two nearby infrastructure facilities.

Additionally, there are four businesses near the CNG station. Based on industrial sales and the national average natural gas usage for these industries, it is estimated that these four businesses would use a total of 342,930,000 kBtu/year. The four businesses, which represent a small additional potential demand, include the following:

1. Central Valley Meat Co Inc  
10431 8 3/4 Ave  
Hanford, CA 93230  
Meat Packing Plants  
Estimated Natural Gas usage = 52,896,000 kBtu/year
2. Mineral King Minerals Inc  
10585 Industrial Ave  
Hanford, CA 93230  
Nitrogenous Fertilizers  
Estimated Natural Gas usage = 51,487,500 kBtu/year
3. Moore Agricultural Products Co  
11521 Excelsior Ave  
Hanford, CA 93230  
Nitrogenous fertilizers  
Estimated Natural Gas usage = 188,318,023 kBtu/year
4. SK Foods  
1175 19th Ave  
Lemoore, CA 93245  
Canned Fruits and Specialties  
Estimated Natural Gas usage = 50,228,000 kBtu/year

#### **Site #4**

The fourth ranked location is W.H. Breshear's FleetStar, located at 428 7th Street, Modesto, California 95354. This CNG station will be shut down in December of 2004 due to the low volume of sales (personal conversation with FleetStar company representative).

This facility is located in the center of the City of Modesto in Stanislaus County. According to the US Census data for 2000 (2002), the city of Hanford had a population of 188,856. The facility is within a half mile of Highway 99. Of the 160 dairies in the surrounding area, 157 are located in Stanislaus County and 3 are located in San Joaquin County. Modesto has a history of using biomethane to fuel its fleet vehicles. However, the system was destroyed by a flood in the mid-1990s and was never repaired.

The dairies in this area are smaller than in the top three sites and thus it may take more work to coordinate biomethane production. Yet, there is a long history of dairies operating in this area. A combination of factors led us to believe that despite the higher number of dairies and smaller herd size, these dairies may be geographically concentrated that could compensate for such hurdles.



There is only one major wastewater treatment plant in the area. This facility is owned by the City of Modesto and does not currently collect methane for any purposes.

There are 10 landfills listed in the area, but many of them overlap. In all, there are only 5 distinct sites. This still shows a number of potential collaborating partners that could provide biomethane aggregating and processing capabilities for the numerous dairies. The 8 landfills, listed below, are shown on the Map 2. For more information about the landfills see Annex G7.

1. Grover Environmental Products/Salida  
6131 Hammett Road  
Modesto, CA 95358
2. City Of Modesto Co-Compost Project  
7007 Jennings Road  
Modesto, CA 95358
3. Modesto Disposal Svc TS/Res Rec Fac  
2769 West Hatch Road  
Modesto, CA 95358
4. Bonzi Sanitary Landfill  
2650 West Hatch Road  
Modesto, CA 95358
5. Bertolotti Transfer & Recycling Center  
231 Flamingo Drive  
Modesto, CA 95358
6. Valley Wood Disposal  
1800 Reliance Street  
Modesto, CA 95358
7. Gilton Resource Recovery  
800 S. McClure Rd.  
Modesto, CA 95357
8. Central Valley Agricultural Grinding, Inc.  
5707 Langworth Road  
Modesto, CA 95357

Twelve businesses in the area use a substantial amount of natural gas. This Modesto site provides the largest number and volume of alternative uses for biomethane. Accordingly, it minimizes the market risks associated with dependency on a single CNG filling station.

1. Formulation Technology Inc  
571 Armstrong Way  
Oakdale, CA 95361  
Intravenous solutions  
Estimated Natural Gas usage = 109,153,500 kBtu/year

2. Valley Fresh Inc  
680 D St  
Turlock, CA 95380  
Poultry, processed: canned  
Estimated Natural Gas usage = 162,168,000 kBtu/year
3. Sensient Dehydrated Flavors  
151 S Walnut Rd  
Turlock, CA 95380  
Vegetables, dried or dehydrated (except freeze-dried)  
Estimated Natural Gas usage = 150,800,000 kBtu/year
4. Pacific Southwest Cont LLC  
4530 Leckron Rd  
Modesto, CA 95357  
Boxes, corrugated: made from purchased materials  
Estimated Natural Gas usage = 656,949,000 kBtu/year
5. Boyd Corporation  
600 S McClure Rd  
Modesto, CA 95357  
Hard rubber and molded rubber products  
Estimated Natural Gas usage = 41,750,000 kBtu/year
6. Signature Fruit Company LLC  
2260 Tenaya Dr  
Modesto, CA 95354  
Fruits: packaged in cans, jars, etc  
Estimated Natural Gas usage = 59,160,000 kBtu/year
7. John F. Turner and Company  
1911 Yosemite Blvd  
Modesto, CA 95354  
Stationery products  
Estimated Natural Gas usage = 108,962,500 kBtu/year
8. Triad Waste Management  
204 Kerr Ave  
Modesto, CA 95354  
Fertilizers, mixing only  
Estimated Natural Gas usage = 247,140,000 kBtu/year
9. Gallo Glass Company  
605 S Santa Cruz Ave  
Modesto, CA 95354  
Glass containers  
Estimated Natural Gas usage = 594,909,000 kBtu/year

10. E & J Gallo Winery  
600 Yosemite Blvd  
Modesto, CA 95354  
Wines  
Estimated Natural Gas usage = 497,756,000 kBtu/year
11. Stanislaus Distributing Co  
400 Hosmer Ave  
Modesto, CA 95351  
Carbonated beverages, nonalcoholic: pkged. in cans, bottles  
Estimated Natural Gas usage = 42,920,000 kBtu/year
12. Horizon Ag-Products Inc  
P.O. BOX 1888  
Modesto, CA 95353  
Soil conditioners  
Estimated Natural Gas usage = 67,963,500 kBtu/year

## **Conclusion and Further Study**

Based on industrial sales and the national average natural gas usage for the represented industries, we estimate that the four locations investigated in this report would use more than 2.7 billion kBtu/year.

This GIS-based analysis was meant only to investigate the potential for more focused pilot/demonstration project in the future. The San Joaquin Valley was selected not only because it has a large and growing dairy industry, but also because the region and its inhabitants are disproportionately impacted by the dairy industry's waste by-products. A similar analysis could be conducted for the dairy industry in the Inland Empire (Riverside and San Bernardino counties).

In terms of selecting optimal sites for future pilot/demonstration projects, we suggest the following steps:

1. *Investigate Tulare project site.* Based on all of the available data, the best project site would be near the City of Tulare CNG station. The concentration of dairies near existing infrastructure already collecting methane (in some form) makes the Tulare area a prime location for further analysis into a pilot/demonstration project.
2. *Improve data for future analysis.* Prior to launching a pilot/demonstration project, resources must be invested in generating or collecting better data. While sufficient for the purposes of this study, a more exhaustive survey accounting for the location and size of each dairy farm should be undertaken; this is especially needed for Merced County. Any such survey should also identify the type of dairy manure collection system in place at each of the targeted dairies. Estimated volumes of potential biomethane production rest on several broad assumptions about manure collection and handling; these assumptions should be checked prior to launching a pilot and/or demonstration project.

Additionally, data for both the wastewater treatment plants and landfills reflect only those sites known to be collecting and using methane. No steps were taken to determine if other types of sites not currently collecting and using methane would be willing to accept dairy waste into their operations. Locations of these other sites are known, but a decision was made not to include them in this preliminary analysis. A more comprehensive survey is needed to ascertain the best possible sites for aggregating and processing biomethane for a pilot study.

Also, our estimate of the potential industrial use of natural gas was based solely on sales of the firm and the industry average use of natural gas based on sales. The natural gas usage of an individual business may vary significantly from the industry average. If it is determined that industrial biomethane demand is a viable market, these businesses should be contacted and their actual natural gas usage verified prior to final site selection.

3. *Explore utilization of other waste streams.* Provided that potential aggregating sites are willing to work with multiple feedstocks (other types of waste materials), it would be beneficial to determine if any other potential sources of biogas exist in the area of a future pilot/demonstration project. These sources could include non-dairy concentrated animal feeding operations (CAFO), by-products from local food-processing facilities, cull and surplus produce, yellow grease from restaurant operations, and potentially, waste from slaughterhouses. Combining of these waste streams into a single biomethane operation may create technical and permitting hurdles (especially from a transporting perspective), it can also increase the quantity of biomethane produced and improve a region's ability to sustainably handle its waste.
4. *Refining facility location.* Much of our analysis worked "backward" from the point of final distribution, the CNG station itself. All CNG stations and most aggregating and refining infrastructure are located in or near cities; however, it may be better to locate a biomethane refining facility farther out in the rural areas. A few miles difference in the final site location can have a significant impact on the number of nearby dairies. The GIS analysis could be applied to more rural sites to identify locations proximate to larger concentrations of dairies.

Although it would appear that demand for CNG as a transportation fuel is growing more robustly in the southern part of the San Joaquin Valley, CNG fueling station locations in the region are in a state of flux. During the course of this study, one of the top four potential locations for a pilot project moved and another was closed. This fact stress the importance of conducting a more thorough survey of local CNG vehicle operators and CNG fuel distributors prior choosing any potential pilot project site.

## **Appendix G References**

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## Annex G1: Characteristics of Dairy Industry in the San Joaquin Valley

There are 1,159 dairy farms in the seven counties included in this report. Dairy farms that have closed down and no longer have milking cows and dairy farms that are just starting and do not yet have milking cows are not included in the dairy farm count. Additionally, there were ten farms reported that had 6,825 cows between them for which we were not given the longitude and latitude coordinates. These records represent less than 1% of the total dairy farms and less than 1% of the total number of cows. Without the longitude and latitude coordinates the records could not be included in the GIS analysis.

The average number of cows per farm was 821, the median was 550 and the mode was 400. Only milking cows were included in the number of cows on the farm. Non-milking cows are not included in any aspect of this analysis. The smallest number of cows per farm was one and the largest number of cows per farm was 12,000. The following table shows the distribution of dairy farms based on the number of cows per farm for all seven counties.

Distribution of Farms based on the Cows per Farm

Cows per Farm	Number of Farms	Percent
1 - 500	543	46.9%
501 - 1000	341	29.4%
1001 - 2000	190	16.4%
2001 - 4000	70	6.0%
More than 4000	15	1.3%
	1159	100.0%

The variance in the number of milking cows per farm between the seven counties is statistically significant. Stanislaus, Merced and San Joaquin counties all average less than 550 cows per farm. Kings, Tulare, and Madera counties all average more than 1,000 cows per farm. The probability of this variance in size happening by chance is less than 1 in million. The causes for the variances in the average number of cow per farm by county were not investigated because that research is beyond the scope of this report.

Average Cows per Dairy by County

County	Number of Dairy Farms	Total Cows	Average Cows / Farm
Stanislaus	271	130,494	481.5
Merced	161	86,420	536.8
San Joaquin	134	73,153	545.9
Fresno	102	90,220	884.5
Kings	123	124,901	1,015.5
Tulare	317	379,318	1,196.6
Madera	51	69,795	1,368.5
TOTAL	1,159	954,301	823.4

## **Annex G2: Data Accuracy**

### **Discussion on the accuracy of the data for Merced County**

While the California Dairy Information Bulletin reports that Merced County has experienced a steady loss in the number of farms over the last five years, the amount of loss does not account for the 50% discrepancy in data. The data file provided by the Water Quality Control board had 51% the entries with no cow data reported. Jess Sitre of the Merced County Dairy Program provided some additional records dairy records with cow counts for Merced County. The data between the two sources was merged into one file. Based on the merged files we have approximately 60% of the dairy information for all of Merced County and at least 75% of all data for the area of interest surrounding the Merced County CNG filling station.

While the Merced cow data is not completely accurate we were provided the Merced dairy locations from two different sources; Jess Sitre and Polly Lowry. Both sources provided the exact same locations for 331 dairies. Therefore, we believe the dairy farm information provided to be very accurate. The missing cow data only impacted the analysis of the Merced CNG station. In instances where data on the number of cows were missing, we simply employed the county average of cows per farm. While an approximation, we feel confident that the analysis will be within 20% the number of cows in the area surrounding the CNG station.

**California Counties: Cows, Dairies, and Cows per Dairy**  
 Number of milk cows and heifers that have calved on farms,  
 number of dairies, and average number of cows per dairy  
 in California by counties and regions, 1998 and 1999

County	1998			1999		
	Number Cows	Number Dairies <sup>2/</sup>	Average Number Cows/Dairy	Number Cows	Number Dairies <sup>2/</sup>	Average Number Cows/Dairy
Fresno	84,172	106	794	84,172	105	802
Kings	109,512	151	725	124,668	146	854
Madera	32,021	49	653	35,507	52	683
Merced	178,241	336	530	185,130	338	548
San Joaquin	88,719	156	569	88,778	154	576
Stanislaus	142,546	319	447	146,285	323	453
Tulare	312,340	296	1,055	337,685	293	1,153
Total	947,551	1,413	671	1,002,225	1,411	710

<sup>2/</sup> Number of dairies source is Milk and Dairy Foods Control.

County	OUR DATA			Percent Difference Our Data and 1999 Data	
	Number Cows	Number Dairies	Average Number Cows/Dairy	Number Cows	Number Dairies
Fresno	90,220	102	885	7%	-3%
Kings	124,901	123	1,016	0%	-16%
Madera	69,795	51	1,369	97%	-2%
Merced	118,959	343 <sup>1</sup>	598	-36%	+2%
San Joaquin	73,153	134	546	-18%	-13%
Stanislaus	130,494	271	482	-11%	-16%
Tulare	379,318	317	1,197	12%	8%
Total	954,301	1,159	823		

1. 164 of the dairy farms reported from Merced did not include the number of cows located at the dairy.

### **Determining Location Accuracy**

To determine the accuracy of the GIS information we were provided, a comparison was made of geocodes from multiple sources. We also had geocode information for dairies from Tele Atlas and D&B. Tele Atlas is an internet geocode service at <<http://www.geocode.com>>. A random sampling of 23 dairies comparing the geocodes between the dairy records from the state and



county and Tele Atlas and the dairy record and D&B revealed the following variance between the sourced. D&B geocodes were not available for 11 of these dairies. Some variance is to be expected because the geocodes are for different locations on the dairy. The Merced County Dairy Program indicated that it takes geocodes from the front door of the barn. Tele Atlas is providing geocodes based on the postal address and it returns a code for a location along the street. The source of D&B geocodes is not known. Assuming that up to 1 mile is an acceptable variance based on the different locations the geocodes were taken from then there is an 87% accuracy rate between the state supplied records and Tele Atlas and there is a 75% accuracy rate between the state supplied records and D&B. Of the three sources of data D&B is assumed to be the least accurate and this data was used only for plotting businesses in high natural gas usage industries.

The accuracy rate between Tele Atlas and the state supplied records can be determined for the total population. Based on the 87% accuracy rate for the 23 records sampled and using a 95% confidence level it can be determined that the total population accuracy rate is between these two sources would be between 73% to 99%.

Inaccuracy between the sources does not mean that the state and county records were inaccurate. The accuracy of the three sources can not be determined without taking new geocode reading. Since the state and county supplied records were based on actual readings and Tele Atlas geocodes are computed using the address of record, we assume that the state supplied geocodes are more accurate than the Tele Atlas geocodes. The geocodes from the state were used in our analysis. Tele Atlas geocodes were used for two dairy records that were supplied without geocodes but with addresses.

#### Accuracy of Geocodes between the Records Received from the Water Quality Control Board and Tele Atlas and D&B

Mile Variance Comparison to Tele Atlas			Mile Variance Comparison to D&B		
<i>Miles Variance</i>	<i>Frequency</i>	<i>Percent</i>	<i>Miles Variance</i>	<i>Frequency</i>	<i>Percent</i>
0-.49	19	83%	0-.49	8	67%
.5-.99	1	4%	.5-.99	1	8%
1.0-1.49	1	4%	1.0-1.49	1	8%
1.5-1.99	0	0%	1.5-1.99	0	0%
2 or More	2	9%	2 or More	2	17%
	23	100%		12	100%

We were not provided geocodes for the CNG stations. Geocodes for CNG stations were determined from two different sources and compared. The geocodes from both sources were determined based on the CNG street address. The first source we used to identify CNG geocodes was Tele Atlas, an internet geocode service at <<http://www.geocode.com>>. The second source of

geodes was the California State University, Fresno Interdisciplinary Spatial Information Systems Center (ISIS). The two CNG stations for which there was a discrepancy of more than one tenth of a mile only occurred when Tele Atlas could not identify an exact location based on the street address and provided an approximate location. All of the other variances were less than 125 feet.

The Waste Treatment Plants file provided to us was not geocoded. We determined geocodes for these locations using Tele Atlas. The landfill location and the business locations were provided with geocodes and these geocodes were not verified. Based on the verification process that we undertook we found the geocodes provided to be highly accurate.

### Annex G3: CNG Filling Stations

Name	Phone	Address	City	State	Zip	Type of Access	County
California State University at Fresno	800-723-9398	385 E Barstow Ave	Fresno	CA	93710	Public with restrictions; card key required	Fresno
City of Fresno Service Center	800-684-4648	1900 E St	Fresno	CA	93706	Public with restrictions; card key required	Fresno
Clovis Unified School District	800-723-9398	1450 Herndon Avenue	Clovis	CA	93611	Government Personnel only	Fresno
Gibbs Automated Fuel Station	800-684-4648	3555 S Academy Ave	Sanger	CA	93657	Public with restrictions; card key required	Fresno
Kings Canyon Unified School District	213-244-5215	675 W Manning Avenue	Reedley	CA	93654	Private Station; limited access	Fresno
Pinnacle CNG/UPS	915-686-6487	1601 W McKinley Ave	Fresno	CA	93728	Public with restrictions; card key required	Fresno
Visa Petroleum	800-723-9398	2414 Monterey Street	Fresno	CA	93721	Public with restrictions; card key required	Fresno
Kings County Yard/PFC	888-732-6487	11827 S 11th Ave	Hanford	CA	93230	Public with restrictions; card key required	Kings
Lemoore NAS	213-244-5215	25000 Coalinga Highway - Transportation Division Building 765, NAS Lemoore	Lemoore	CA	93246	Government Personnel only	Kings
Tesei Petroleum	(559) 673-3597	1300 S. Gateway Drive	Madera	CA	93637	Public Access Allowed	Madera
PG&E Merced Service Center	800-684-4648	3185 M St	Merced	CA	95348	Public with restrictions; card key required	Merced
E.F. Kludt and Sons	(209)368-0634	1126 E. Pine Street	Lodi	CA	95241	Public Access Allowed	San Joaquin
PG&E Stockton Service Center	800-684-4648	4040 West Ln	Stockton	CA	95204	Public with restrictions; card key required	San Joaquin
San Joaquin County	209-468-3380	1810 E Hazelton Ave	Stockton	CA	95201	Private Station; limited access	San Joaquin
W.H. Breshear's - FleetStar	800-723-9398	428 7th Street	Modesto	CA	95354	Public with restrictions; card key required	Stanislaus
City of Tulare - FleetStar	800-723-9398 or 800-685-2376	3989 S K Street	Tulare	CA	93274	Public with restrictions; card key required	Tulare
FleetStar - SoCal Gas	800-723-9398	320 N Tipton Street	Visalia	CA	93292	Public with restrictions; card key required	Tulare

## Annex G4: Analysis of Sites 5 through 8

### Site #5 - PG&E Merced Service Center

The fifth ranked location is the PG&E Merced Service Center

3185 M St  
Merced, CA 95348

This CNG location allows public access with restrictions.

Cows	68,600
Dairies	92
Avg. No. of Cows	746
Annual biomethane Production Potential (million ft <sup>3</sup> )	751
Landfills	3
Wastewater plants	0

This facility is located in the center of the city of Merced. The city of Merced is located in Merced County. According to the 2000 US Census the city of Merced had a population of 63,893. The facility is within two and a half miles of Highway 99. Of the 92 dairies in the surrounding area, all are located in Merced County.

No wastewater treatment plants are located in the 400-square-mile area surrounding this site.

The landfills located in the 20-square-mile area surrounding this site are listed below. For more information about the landfills see Annex G7. None of the landfills are common to any other site. All three landfill sites have the same address and are located approximately 6 miles south of the CNG station.

1. Highway 59 Compost Facility  
6040 N. Highway 59  
Merced, CA 95340
2. Highway 59 Research Composting Op.  
6040 N. Highway 59  
Merced, CA 95340
3. Highway 59 Disposal Site  
6040 N. Highway 59  
Merced, CA 95340

There are five businesses in the area surrounding this location that represent industries that use large amounts of natural gas. Based on the industries' sales and national average industry natural gas usage it is estimated that these four locations would use a total of 305,975,000 kBtu/year.

These five businesses represent a small additional demand. The five businesses are:

1. Oasis Foods Inc  
9341 E Childs Ave  
Planada, CA 95365  
Fruits and fruit products, in cans, jars, etc  
Estimated Natural Gas usage = 33,640,000 kBtu/year
2. Pacific-Sierra Publishing Inc  
3032 G St  
Merced, CA 95340  
Newspapers, publishing and printing  
Estimated Natural Gas usage = 33,400,000 kBtu/year
3. CHEFS PRIDE  
2751 N Santa Fe Dr  
Merced, CA 95348  
Meat packing plants  
Estimated Natural Gas usage = 38,397,000 kBtu/year
4. Teasdale Quality Foods  
901 Packers St  
Atwater, CA 95301  
Tomato products, packaged in cans, jars, etc.  
Estimated Natural Gas usage = 53,940,000 kBtu/year
5. J R Wood Inc  
7916 Bellevue Rd  
Atwater, CA 95301  
Fruits, quick frozen and cold pack (frozen)  
Estimated Natural Gas usage = 146,598,000 kBtu/year

The three landfills in the area provide a poor potential number of collaborating partners that could help provide a steady flow of methane for refining and/or help build markets for biomethane. The five businesses in the area that are in high natural gas industries represent a small potential for additional demand of biomethane.

### **Site #6 – Lemoore NAS**

The sixth site is located near the Lemoore Naval Air Station. All of the characteristics of this site are shared with Site #3. For further information about this location see Site #3.

**Site #7 - Kings Canyon Unified School District**

The seventh ranked location is Kings Canyon Unified School District. The address is:

675 W Manning Avenue  
Reedley, CA 93654

This CNG location is a private station with limited access.

Cows	40,048
Dairies	30
Avg. No. of Cows	1,335
Annual biomethane Production Potential (Million ft <sup>3</sup> )	438
Landfills	0
Wastewater Plants	0

This facility is located in the center of the City of Reedley. Reedley is located in Fresno County. According to the 2000 US Census (2002), Reedley had a population of 20,756. The facility is 11 miles from Highway 99. Of the 30 dairies in the surrounding area, 5 are in Fresno County, 3 are in Kings County and 22 are in Tulare County. The largest dairy in the valley, the Boertje Dairy, with 12,000 cows is located in the surrounding area and skews the average number of cows per dairy. The data did not show any active landfills or wastewater plants in the area currently utilizing methane.

One other CNG Filling Station is located within the surrounding area. The Gibbs Automated Fueling Station is located in Sanger to the northwest of this location. The Gibbs Automated Fueling Station is a public station with restricted access.

There are five businesses in the area surrounding this location that are in high natural gas using industries. Based on the industries' sales and national average industry natural gas usage it is estimated that these four locations would use a total of 678,420,000 kBtu/year. These five businesses represent a good additional demand for biomethane, the largest potential demand of all Sites that are highlighted. The five businesses are:

1. Kaweah Container Inc  
13291 Avenue 404  
Cutler, CA 93615  
Corrugated and solid fiber boxes  
Estimated Natural Gas usage = 91,907,500 kBtu/year

2. Nutrient Technologies Inc  
1092 E Kamm Ave  
Dinuba, CA 93618  
Fertilizers: natural (organic), except compost  
Estimated Natural Gas usage = 73,602,000 kBtu/year
3. Ruiz Food Products Inc  
501 S Alta Ave  
Dinuba, CA 93618  
Ethnic foods, nec, frozen  
Estimated Natural Gas usage = 229,745,000 kBtu/year
4. Sanger Wrks Fctry Holdings  
1949 E Manning Ave  
Reedley, CA 93654  
Packaging machinery  
Estimated Natural Gas usage = 32,648,500 kBtu/year
5. Sun-Maid Growers California  
13525 S Bethel Ave  
Kingsburg, CA 93631  
Raisins  
Estimated Natural Gas usage = 250,517,000 kBtu/year

The lack of landfills and wastewater treatment plants in the surrounding area means that there are no potential collaborating partners to provide alternative sources of methane or to help market biomethane. The five businesses in the area that are in high natural gas industries represent a good potential for additional demand of biomethane.

### **Site #8 – Tesei Petroleum**

The eighth ranked location is Tesei Petroleum in Madera. The address is:

1300 S. Gateway Drive  
Madera, CA 93637

This CNG location allows public access.

Cows	30,488
Dairies	30
Avg. No. of Cows	1,016
Annual biomethane Production Potential (Million ft <sup>3</sup> .)	338
Landfills	2
Wastewater plants	0

This facility is located on the southern half of the city of Madera. The city of Madera is located in Madera County. According to the 2000 US Census (2002) the city of Madera had a population of 43,207. The facility is less than one tenth of a mile from Highway 99. Of the 48 dairies in the surrounding area, 45 are located in Madera County and 3 are located in Fresno County. The surrounding area does not overlap with any other highlighted sites.

No wastewater treatment plants are located in the area surrounding this site. The two landfills located in the area surrounding this site are listed below. For more information about the landfills see Annex G7.

1. Mammoth Recycling Facility  
21739 Road 19  
Chowchilla, CA 93610
2. Fairmead Solid Waste Disposal Site  
Avenue 22 At Road 19  
Chowchilla, CA 93610

No other CNG Filling stations are located within the surrounding area.

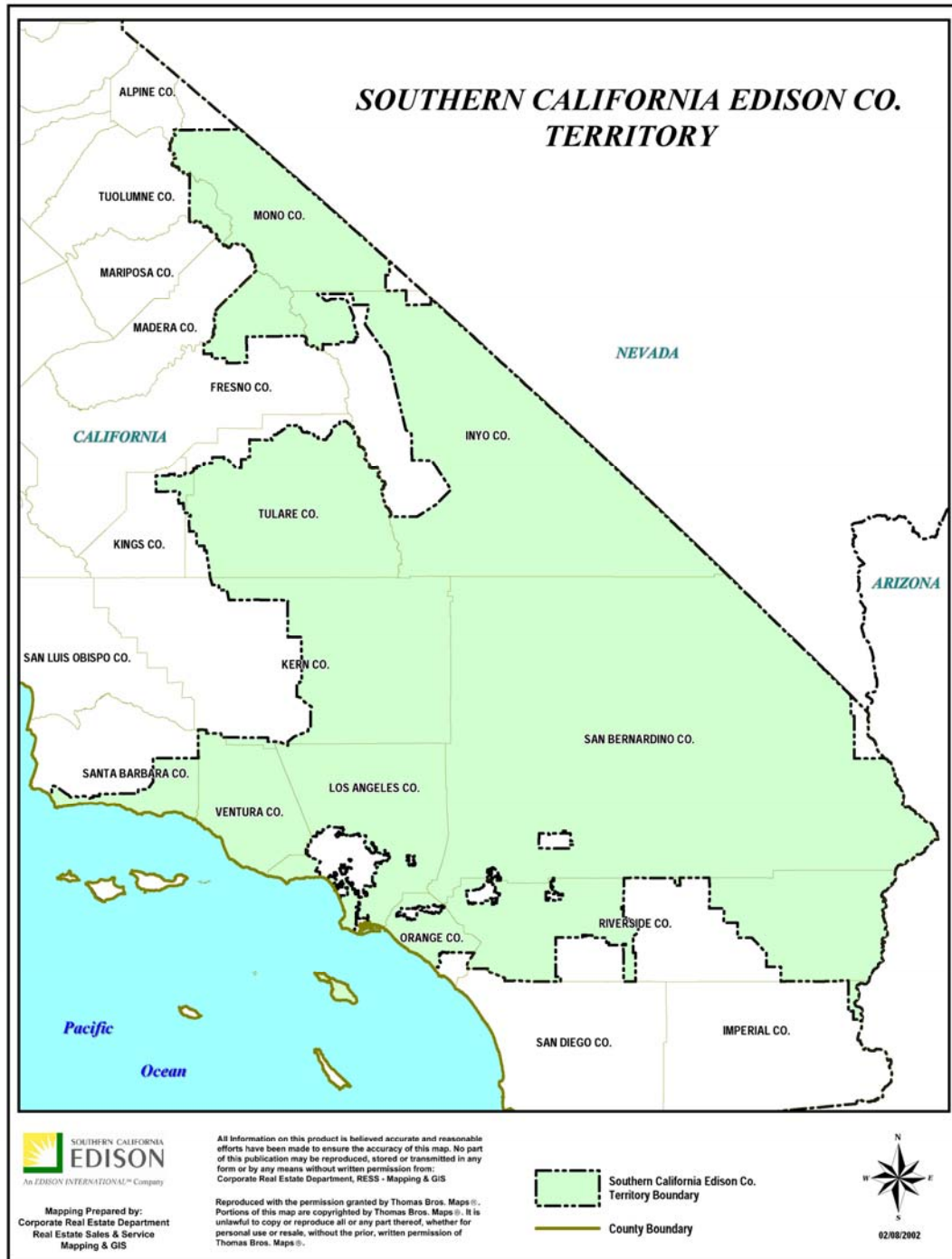
There is 1 business in the 400 square mile area surrounding this location that is in high natural gas using industries. Based on the industries' sales and national average industry natural gas usage it is estimated that these five locations would use a total of 62,524,000 kBtu/year. This business represents a very small additional demand. The business is:

Canandaigua Wine Company Cal  
12667 Road 24  
Madera, CA 93637-9020  
Wines, brandy, and brandy spirits  
Estimated Natural Gas usage = 62,524,000 kBtu/year

The two landfills in the area provide a poor potential number of collaborating partners that could help provide a steady flow of methane for refining and/or help build markets for biomethane. The one business in this area represents a very poor potential for an alternative demand for biomethane Site #7 represents the smallest potential alternative use of biomethane of all the sites highlighted.



## Annex G5 – Southern California Edison Service Territory



(Source: Southern California Edison, no date)

## Annex G6: Wastewater Treatment Plants

Biomass												
Plant Name (Alias)	Facility	Fuel Source (Cogen)	Technology	Online <MW> B>	Service Area	County	Plant Address	Plant Phone	Operator / Owner (if different)	Operator- Contact / Owner- Contact	Operator- Phone# / Owner Phone#	Operator- Address / Owner Address
Auberry Energy	WTE	Biomass - Ag. & Woodwaste (Cogen)		7.5	PG&E	Fresno	32180 Auberry Road New Auberry 93602	209- 855- 4001	Auberry Energy Inc	Doug Thompson	209-855- 4001	32180 Auberry Rd, Auberry Ca 93602
Delano Energy I-li	WTE	Biomass - Ag. & Woodwaste		49.9	SCE	Kern	31500 Pond Road Delano 93215	805- 792- 3062	Delano Power Co  Thermo Ecotek	Dale Hale Or Tony Collins  Tony Collins Or Jimmy Hakimiam	805-792- 3067  805-792- 3067	31500 Pond Rd, Po 1461, Delano Ca 93215
Mendota Biomass Power	WTE	Biomass - Ag. & Woodwaste (Cogen)	Fluidized Boiler	25	PG&E	Fresno	400 Guillen Parkway Mendota 93640	209- 655- 4921	Mendota Biomass Power  Thermo Ecotek	Glen Sizemore Or Bob Notoheis	209-655- 4921	400, Guillen Pkw, Po Box 99, Mendota Ca 93640
Tracy Biomass	WTE	Biomass - Ag. & Woodwaste		21	PG&E	San Joaquin	14800 W. Schultz Road Tracy 95376	209- 835- 6914	Tracy Operators  Community Energy Alternatives Inc (Cea)	Larry K. Lien  Art Nislick	209-835- 6914  201-652- 2772	Po Box 1211, Tracy Ca 95378- 1211 1200 E. Ridgewood Ave, Ridgewood Nj 07450
Diamond Walnut Growers	WTE	Biomass - Ag. Waste - Walnut Sh (Cogen)		4.5	PG&E	San Joaquin	1050 South Diamond Street Stockton 95205	209- 467- 6000	Diamond Walnut Growers Inc.	James Wagner Or Bo Thisted	209-467- 6000	1050 S. Diamond St, Stockton Ca 95205
California Cedar Products	WTE	Biomass - Woodwaste (Cogen)		0.85	PG&E	San Joaquin	1340 W. Washington Street Stockton 95201	209- 944- 5800	California Cedar Products	Patrick Lam	209-944- 5800	1340 W. Washington , Stockton Ca 95202

## Annex G6: Wastewater Treatment Plants (continued)

Digester Gas												
Plant Name (Alias)	Facility	Fuel Source (Cogen)	Technology	Online <MW>< B>	Service Area	County	Plant Address	Plant Phone	Operator / Owner (if different)	Operator- Contact / Owner- Contact	Operator- Phone# / Owner Phone#	Operator- Address / Owner Address
City Of Tulare	WTE	MSW - Digester Gas		0.41	SCE	Tulare	1875 South West Street Tulare		City Of Tulare	Milton Preszler		411 E. Kern Ave, Tulare 93274
Roy Sharp Jr.	WTE	MSW - Digester Gas		0.1	PG&E	Fresno	Caruthers					
Royal Farms #1- #2	WTE	MSW - Digester Gas		0.18	SCE	Tulare	Address Confidentia l Tulare 93274	209-686- 9779	Royal Farms	Confidentia l	Confidentia l	Confidential
Industrial Waste												
Plant Name (Alias)	Facility	Fuel Source (Cogen)	Technology	Online <MW>< B>	Service Area	County	Plant Address	Plant Phone	Operator / Owner (if different)	Operator- Contact / Owner- Contact	Operator- Phone# / Owner Phone#	Operator- Address / Owner Address
Landfill Gas												
Plant Name (Alias)	Facility	Fuel Source (Cogen)	Technology	Online <MW>< B>	Service Area	County	Plant Address	Plant Phone	Operator / Owner (if different)	Operator- Contact / Owner- Contact	Operator- Phone# / Owner Phone#	Operator- Address / Owner Address
Fresno Wwtp	WTE	MSW - Landfill Gas		1.3	PG&E	Fresno	5607 West Jenson Avenue Fresno 93706	209-277- 1475	Fresno Wastewater Treatment		209-498- 1707	5607 West Jenson Ave, Fresno Ca 93706
Pacific Energy (Stockton)	WTE	MSW - Landfill Gas		0.8	PG&E	San Joaquin	9075 S. Austin Road Stockton 95206	209-462- 4206	Pacific Energy  Ogden Energy Group, Inc.	Denice Marsh	209-462- 4206	9595 S. Austin Rd, Stockton Ca 95206
Tulare County Landfill	WTE	MSW - Landfill Gas	Gas Turbine Combined Cycle	1.9	SCE	Tulare	26951 Road 140 Visalia 93292		Minnesota Methane			

## Annex G6: Wastewater Treatment Plants (continued)

Municipal Solid Waste												
Plant Name (Alias)	Facility	Fuel Source (Cogen)	Technology	Online <MW>< B>	Service Area	County	Plant Address	Plant Phone	Operator / Owner (if different)	Operator- Contact / Owner- Contact	Operator- Phone# / Owner Phone#	Operator- Address / Owner Address
Modesto Energy	WTE	MSW - Tires		14	PG&E	Stanislaus	4549 Ingram Creek Road Westley 95387	209-894- 3161	Modesto Energy Co.  Oxford Energy	 Carl Levesque	209-894- 3161  209-894- 3161	Po Box 302, Westley Ca 95837
Covanta Stanislaus Inc. (Stanislaus Waste Energy)	WTE	MSW - Waste		18	PG&E	Stanislaus	4040 Fink Road Crows Landing 95313	209-837- 4423	Covanta Stanislaus Inc.  Ogden Martin	 Fred Engelhardt	209-837- 4423  209-837- 4423	

### Annex G7: Landfills and Disposal Sites

Name	Land Use Name	County	Location	Place
American Avenue Disposal Site	Agricultural	Fresno	18950 W American Av 4 Mi W/O Madera Av	Tranquillity
Cedar Ave. Recycling & Transfer Station	Industrial, Commercial	Fresno	3457 S. Cedar Avenue	Fresno
City Of Clovis Landfill	Rural	Fresno	15679 Auberry Road	Fresno
Coalinga Disposal Site	Rural	Fresno	30825 Lost Hills Road	Coalinga
Craycroft Brick Inert Site		Fresno	2301 W Belmont @ Marks	Fresno
Gallo Vineyards, Inc Compost Operation	Agricultural	Fresno	5686 East Olive Avenue	Fresno
Jefferson Avenue Transfer Station	Industrial, Agricultural	Fresno	5608 Villa Avenue	Fresno
Jefferson Inert Disposal Site		Fresno	Jefferson & Maple	Fresno
Kochergen Property Grease Trap Disposal	Rural	Fresno	15485 W Republic	Huron
Orange Avenue Disposal Inc	Industrial	Fresno	3280 South Orange Ave	Fresno
Shaver Lake Transfer Station	Rural	Fresno	1 Mi E of Hwy 168 on Dinkey Creek Rd	Shaver Lake
Sunset Wastepaper MRF and TS	Residential, Open Space, Industrial	Fresno	2721 S. Elm Avenue	Fresno
Avenal Landfill	Residential, Industrial, Commercial, Agricultural	Kings	201 North Hydril Road	Avenal
CWMI - B18 Nonhazardous Codisposal	Agricultural	Kings	35251 Old Skyline Road	Kettleman City
CWMI Kettleman Hills Facility	Agricultural	Kings	35251 Old Skyline Road	Kettleman City
Kochergen Farms Composting	Agricultural	Kings	Avenal Cutoff Rd. and Omaha Ave.	Avenal
KWRA Composting Facility	Agricultural	Kings	7803 Hanford-Armona Road	Hanford
KWRA Material Recovery Facility	Agricultural	Kings	7803 Hanford-Armona Rd.	Hanford
Emadco Transfer Station	Residential	Madera	Black Oak River Road	Oakhurst
Fairmead Solid Waste Disposal Site	Rural, Residential, Agricultural	Madera	Avenue 22 At Road 19	Chowchilla
Mammoth Recycling Facility And TS	Rural	Madera	21739 Road 19	Chowchilla
North Fork Transfer Station	Rural	Madera	33699 Road 274	North Fork

**Annex G7: Landfills and Disposal Sites (continued)**

<b>Name</b>	<b>Land Use Name</b>	<b>County</b>	<b>Location</b>	<b>Place</b>
A&D Transport		Merced	25077 West Hearst Road	Gustine City
Atlas Materials Inc. - White Crane Ranch	Rural	Merced	11550 West Highway 140	Atwater
Billy Grissom Fertilizer	Agricultural	Merced	5331 Columbus Ave	Hilmar
Billy Wright Composting Facility		Merced	17173 Billy Wright Road	Los Banos
Billy Wright Disposal Site		Merced	Billy Wright Rd; 1 Mi West of I-5	Los Banos
Foster Farms Manure Storage Facility	Range Land, Open Space, Industrial, Agricultural	Merced	12997 W. Highway 140	Atwater
Highway 59 Compost Facility	Wetlands, Rural, Agricultural	Merced	6040 N. Highway 59	Merced
Highway 59 Disposal Site	Wetlands, Open Space, Agricultural	Merced	Hwy 59; 6 Mi N Merced	Merced
Highway 59 Research Composting Op.		Merced	6040 North highway 59	Merced
Kenneth Stone & Family Spreading Service		Merced	W. of Lupin Ave& 1/4 Mile N. of Palm Ave	Winton
Nakashima Farms Composting		Merced	10397 West Walnut Avenue	Livingston
Robeson Farms		Merced	Le Grand	Le Grand
Stone Family El Nido Composting Facility	Agricultural	Merced	Vineyard Way At Grant Road	Merced
Valley Fresh Foods Inc.	Agricultural	Merced	1220 Hall Road	Merced
A-Plus Materials Recycling, Inc.		San Joaquin	Port 23 Port of Stockton	Stockton
Central Valley Waste Services		San Joaquin	1333 East Turner Road	Lodi
Central Valley Waste Services		San Joaquin	1333 E. Turner Road	Lodi
Delicato Vineyards	Agricultural	San Joaquin	12001 S. Hwy 99, Manteca	Manteca
East Stockton Transfer & Recycling Stn	Residential, Industrial, Commercial	San Joaquin	2435 East Weber Avenue	Stockton
Foothill Sanitary Landfill	Range Land	San Joaquin	6484 North Waverly Road	Linden
Forward Landfill, Inc.	Residential, Range Land, Agricultural	San Joaquin	9999 S. Austin Road	Manteca
Forward Resource Recovery Facility		San Joaquin	9999 S. Austin Road	Manteca
Jensen Farms Compost Operation		San Joaquin	5793 West Delta Avenue	Tracy
Lovelace Transfer Station		San Joaquin	2323 Lovelace Road	Manteca

### Annex G7: Landfills and Disposal Sites (continued)

Name	Land Use Name	County	Location	Place
Nilsen Farms		San Joaquin	17200 Liberty Road Galt, CA 95632	Acampo
North County Recycling Ctr.& Sanitary LF	Residential, Industrial, Agricultural	San Joaquin	17900 East Harney Lane	Victor
Scotts Regional Composting Facility	Agricultural	San Joaquin	23390 Flood Road	Linden
Stockton Recycling & Transfer Station		San Joaquin	401 South Lincoln Street	Stockton
Super Pallet Recycling Corporation	Residential, Park, Industrial, Commercial	San Joaquin	2430 South California Street	Stockton
Tracy Material Recovery & T.S.	Rural	San Joaquin	30703 S. Macarthur Drive	Tracy
USA Waste of California, Inc	Industrial	San Joaquin	1240 Navy Drive	Stockton
Bertolotti Transfer & Recycling Center	Commercial	Stanislaus	231 Flamingo Drive	Modesto
Bonzi Sanitary Landfill	Rural	Stanislaus	2650 West Hatch Road	Modesto
Central Valley Agricultural Grinding, Inc		Stanislaus	5707 Langworth Road	Riverbank
City Of Modesto Co-Compost Project	Agricultural	Stanislaus	7007 Jennings Road, Modesto	Modesto
City of Turlock Waster Qual. Control Fac		Stanislaus	901 South Walnut Road	Turlock
Covanta Stanislaus, Inc.		Stanislaus	4040 Fink Road	Crows Landing
Fink Road Landfill	Rural	Stanislaus	4000 Fink Road	Crows Landing
Gilton Resource Recovery CandD Proc Fac.		Stanislaus	800 South McClure Road	Modesto
Gilton Resource Recovery Composting Fac.	Industrial	Stanislaus	800 S. McClure Rd.	Modesto
Gilton Resource Recovery/Transfer Fac	Industrial	Stanislaus	800 McClure Road	Modesto
Grover Environmental Products/Salida	Industrial	Stanislaus	6131 Hammett Road	Modesto
Grover Environmental Products/Vernalis	Open Space, Agricultural	Stanislaus	3401 Gaffery Road	Vernalis
Modesto Disposal Svc TS/Res Rec Fac	Residential	Stanislaus	2769 West Hatch Road	Modesto

**Annex G7: Landfills and Disposal Sites (continued)**

<b>Name</b>	<b>Land Use Name</b>	<b>County</b>	<b>Location</b>	<b>Place</b>
Turlock Transfer	Industrial	Stanislaus	1100 South Walnut	Turlock
Valley Wood Disposal		Stanislaus	1800 reliance Street	Modesto
Badger Transfer Station	Rural	Tulare	Road 260 At Avenue 468	Badger
Balance Rock Transfer Station	Rural	Tulare	Balance Rock Landfill	California Hot Springs
Camp Nelson Transfer Site	Rural	Tulare	1/4 Mi N Camp Nelson	Camp Nelson
Earlimart Transfer Station	Agricultural	Tulare	7012 Road 136	Earlimart
Kennedy Meadows Transfer Station	Rural	Tulare	Goman Road West Of M-152 Station	Johnsondale
New Era Farm Service #1		Tulare	Hoffman Dairy Ave 216 & Rd 140	Tulare
New Era Farm Service #2		Tulare	Jim Nance Dairy 6440 Ave 160	Tulare
Pine Flat Transfer Station	Rural	Tulare	1/4 Mi S Pine Flat	California Hot Springs
Soil Foods, Inc.		Tulare	20002 Road 140	Tulare
Springville Transfer Station	Rural	Tulare	Avenue 122 At Road 338	Springville
Sunset Material Recovery Facility		Tulare	1707 East Goshen Road	Visalia
Teapot Dome Disposal Site	Rural, Residential, Agricultural	Tulare	Avenue 128 And Road 208	Porterville
Tulare County Compost And Biomass	Rural	Tulare	24487 Road 140	Tulare
Tulare County Recycling Complex	Rural	Tulare	26951 Road 140, Visalia	Visalia
Visalia Disposal Site	Rural, Agricultural	Tulare	Road 80 At Avenue 332	Visalia
Wood Industries Co	Agricultural	Tulare	7715 Ave. 296	Visalia
Woodville Disposal Site	Rural	Tulare	Rd 152 At Ave 198; 10 Mi Se Tulare	Tulare



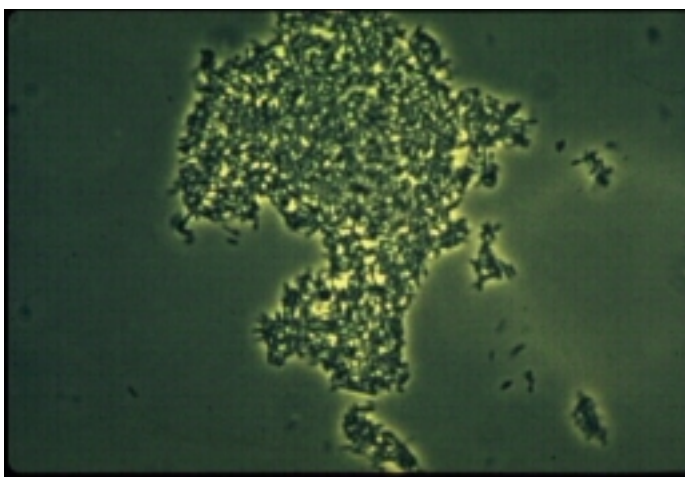
## Basic Principles

### What Is Biogas?

Biogas is actually a mixture of gases, usually carbon dioxide and methane. It is produced by a few kinds of microorganisms, usually when air or oxygen is absent. (The absence of oxygen is called “anaerobic conditions.”) Animals that eat a lot of plant material, particularly grazing animals such as cattle, produce large amounts of biogas. The biogas is produced not by the cow or elephant, but by billions of microorganisms living in its digestive system. Biogas also develops in bogs and at the bottom of lakes, where decaying organic matter builds up under wet and anaerobic conditions.



Plant-eating animals such as bison release large amounts of biogas to the atmosphere.



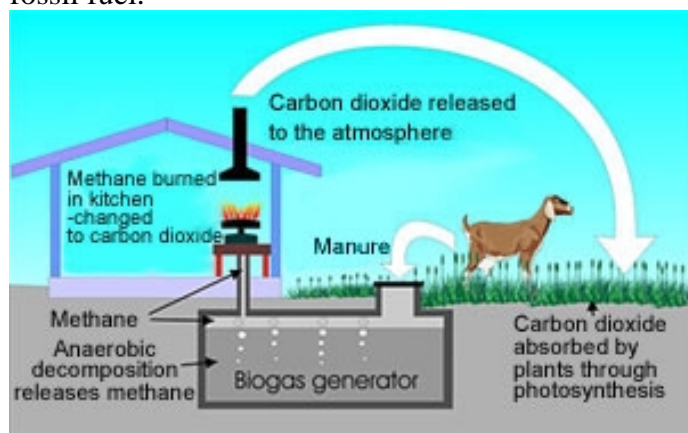
A microscope photo of the methane-producing bacteria.

*Photo courtesy of University of Florida,  
Agricultural and Biological Engineering Department*

Besides being able to live without oxygen, methane-producing microorganisms have another special feature: They are among the very few creatures that can digest cellulose, the main ingredient of plant fibres. Another special feature of these organisms is that they are very sensitive to conditions in their environment, such as temperature, acidity, the amount of water, etc.

### Biogas is a Form of Renewable Energy

Flammable biogas can be collected using a simple tank, as shown here. Animal manure is stored in a closed tank where the gas accumulates. It makes an excellent fuel for cook stoves and furnaces, and can be used in place of regular natural gas, which is a fossil fuel.



Biogas is a form of renewable energy, because it is produced with the help of growing plants.

Biogas is considered to be a source of renewable energy. This is because the production of biogas depends on the supply of grass, which usually grows back each year. By comparison, the natural gas used in most of our homes is not considered a form of renewable energy. Natural gas formed from the fos

# Build Your Own Biogas Generator

silized remains of plants and animals—a process that took millions of years. These resources do not “grow back” in a time scale that is meaningful for humans.

## Biogas is Not New

People have been using biogas for over 200 years. In the days before electricity, biogas was drawn from the underground sewer pipes in London and burned in street lamps, which were known as “gaslights.” In many parts of the world, biogas is used to heat and light homes, to cook, and even to fuel buses. It is collected from large-scale sources such as landfills and pig barns, and through small domestic or community systems in many villages.

For more information about biogas, read the backgrounder entitled Biomass Energy.

## Build It!

The apparatus you are going to build uses a discarded 18 litre water container as the “digester.” A mixture of water and animal manure will generate the methane, which you will collect in a plastic balloon. The 18 litre water container performs the same task as the stomach of a livestock animal by providing the warm, wet conditions favored by the bacteria that make the methane.

## Safety Precautions

The main hazards in this activity are from sharp tools such as tubing cutters and scissors. Exercise caution while using any tool. There is no risk of explosion due to the leakage of methane because the gas develops so slowly that it dissipates long before it can reach flammable concentrations in room air. Exercise the normal precautions in the use of Bunsen burners: keep hair and clothing away from the burner while it is lit.

## Tools

- Tubing cutter
- Scissors
- Adjustable wrench
- Rubber gloves
- Electric drill with ¼” bit, or cork borer
- Hot glue gun, with glue sticks
- Electrical or duct tape
- Sandpaper (metal file will also work)

## Materials

- Used 18L clear plastic water bottle
- Large Mylar helium balloon
- Plastic water bottle cap (with the “no-spill” insert—see photo)
- Copper tubing (40 cm long, 6.5mm (¼”) inside diameter)
- T-connector for plastic tubing (barbed, 6mm or ¼” long)
- 1 cork (tapered, 23mm long)
- Clear vinyl tubing (1.5 m long, 4mm or ¼-inch inside diameter)
- 2 barb fittings (¼” x ¼”)
- Ball valve (¼”)
- 6-8L manure pellets (goat, sheep, llama, rabbit, or other ruminant)
- Rubber gloves
- Large plastic funnel (can be made from a 4L plastic milk jug with bottom removed)
- Wooden dowelling or stick (30 to 50 cm long, 2-3 cm thick)



The materials and tools you'll need to build a biogas generator.



## Sources

**Water bottle:** Many hardware and grocery stores now sell purified water that they bottle on site. They often collect containers that can no longer be refilled because of dirt or damage to the bottle. These unrefillable bottles are frequently available for free. Ask to speak to the clerk in charge of refilling bottles. Ask for a used cap as well.

**Mylar balloons:** Check with any local florist or novelty store.

**Tubing, valves, T-connectors, barb fittings:** Check at your local hardware or plumbing supply store.

**Manure:** If you do not know someone who has domesticated rabbits, sheep, llamas or other similar pellet-producing animals, you can often purchase sheep or steer manure by the bag at your local garden center.

## A. Prepare the biogas collection system

1. Cut a 20cm piece of copper tubing. Round off the sharp edges of the freshly cut tubing using sandpaper or a metal file.

2. The Mylar balloon has a sleeve-like valve that prevents helium from escaping once it is filled. This sleeve will help form a leak-proof seal around the rigid tubing. Push the tubing into the neck of the balloon, past the end of the sleeve, leaving about 2cm protruding from the neck of the balloon, as shown below.



Inserting copper tubing.

3. Test the tube to be sure air can enter and leave the balloon freely, by blowing a little in through the tube. The balloon should inflate with little or no resistance, and the air should be able to escape easily through the tube.

4. Securely tape the neck of the balloon to the tube as shown in the illustration.



Taping the neck.

5. Using a drill or cork borer, make a small (4mm) hole in the center of the stopper. Add a few drops of hot glue around and inside the hole and insert the stem of the 1/4-inch T-adapter into the cork.



Gluing cork.



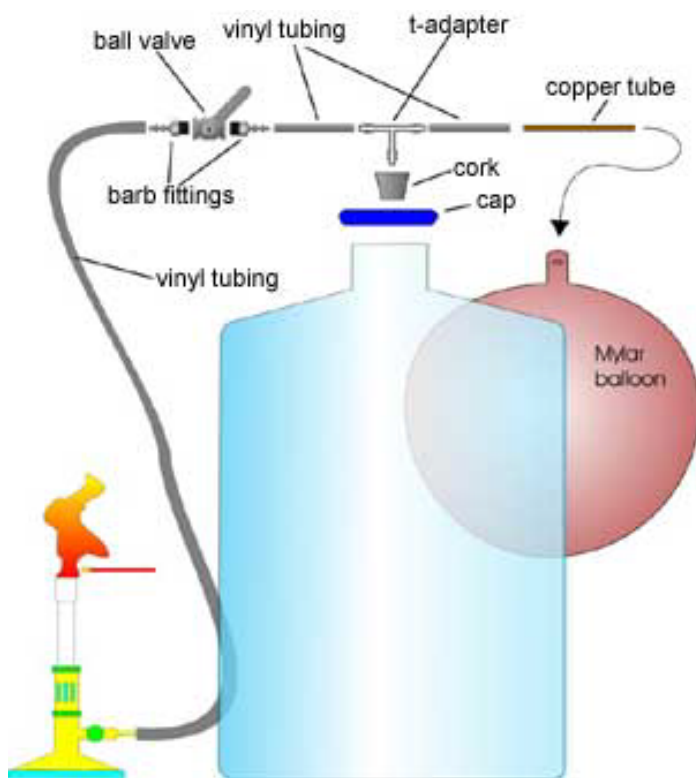
# Build Your Own Biogas Generator

6. Screw the two barb fittings into the body of the ball valve. Tighten with the adjustable wrench.



Installing the barb fittings on the ball valve.

7. Cut two sections of vinyl tubing, each 25cm long. Use them to connect the balloon to the T-adapter, and to connect the ball valve to the Bunsen burner. Assemble the rest of the gas collection system according to the diagram below.



Assembly of the biogas collection system.

## B. Prepare the manure mixture

This is a job best done outside, with rubber gloves!

1. Cut the bottom off a 4L plastic milk jug to make a wide-mouthed funnel.
2. Place the funnel into the neck of the plastic water bottle and scoop in small amounts of manure.



Scooping manure.

3. Use a stick or piece of dowelling to push the manure through the neck of the bottle if it gets plugged.
4. Add enough water to bring the level close to the top of the water bottle.



Slurry level.

5. Use the stick to stir up the manure and water mixture, releasing any bubbles of air that might be trapped.

6. Clean up carefully. Use soap and wash hands thoroughly.

## C. Final Set-up

1. Snap the cap onto the top of the manure-filled 18 litre water bottle.



Completed biogas generator.

2. Be sure the ball valve is closed, but that gas moving from the water bottle can pass freely through the T-adaptor to the balloon.

3. Set the biogas generator in a warm location, such as over a heat register or radiator or in a sunlit window. If

the biogas generator is placed in a window, be sure to wrap the outside of the container in black plastic or construction paper, to discourage algae from growing inside the bottle.

## Test It!

For the first few weeks, your biogas generator will produce mainly carbon dioxide. When the aerobic bacteria use up all the oxygen inside the bottle, the anaerobic bacteria, which make methane, can take over. It can take up to a month for the generator to start making biogas with enough methane to be flammable.

When gas begins to accumulate in the balloon, test it by attempting to light the Bunsen burner:



Use caution when testing the biogas.

1. First, open the clamp or valve so that biogas can flow back from the balloon to the Bunsen burner.
2. Have a friend squeeze the Mylar balloon gently while you attempt to light the Bunsen burner with a match or spark igniter.
3. If your Bunsen burner ignites, your biogas generator is a success!

## Questions

1. Why is biogas considered a source of renewable energy?
2. In what appliances or to what uses could biogas be applied?
3. What are some of the practical limitations to using biogas as an energy source on a large scale?
4. Where in Canada would biogas be a viable alternative to fossil fuels?
5. Why do you not want photosynthetic algae (see Part C, # 3) growing in your "digester"?

Contact us at: [education@pembina.org](mailto:education@pembina.org)



CHINESE BIOGAS DIGESTER

A Potential Model for Small-Scale, Rural Applications  
(A Manual for Construction and Operation)

Prepared by:

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U.S. Peace Corps Volunteer

with

Q. L. Honquilada

PRRM

A Joint Project of  
The Philippine Rural Reconstruction Movement (PRRM)  
The U.S. Peace Corps/Philippines  
The German Freedom From Hunger/Agro-Action

December 1981

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July 1985

## P R E F A C E

This manual is a result of a two-year project entitled "The Development and Promotion of Biogas Project Under Philippine Conditions", jointly undertaken by the Philippine Rural Reconstruction Movement (PRRM), the US Peace Corps/Philippines, and the German Freedom From Hunger/Agro-Action. In general, the project aims to contribute to the widespread dissemination and actual utilization of biogas technology particularly in the rural villages.

Singling out the Chinese design as the most appropriate type at the moment for small-scale, backyard livestock-raising families is dictated by the following reasons: (a) it is less costly, volume-for-volume, compared with other existing designs; (b) it is more durable and entails less maintenance for it has fewer metal components and moving parts; and (c) it is capable of delivering a higher gas pressure, thus making it possible to utilize the gas for lighting purposes.

The pieces of information in this manual provide the basic knowledge and guides for the construction and operation of a small-scale, family-size Chinese biogas unit as adapted to Philippine rural conditions. These are not original ideas of the writers but gathered and learned from a lot of people and reading materials, as well as from actual experiences in building a number of biogas units. Encouragingly, these units have already been operational.

We owe the following special thanks and acknowledgements: the Chengdu Biogas Research Institute Team - - composed of Dr. Xu Yiz Hong (team leader, and biologist), Dr. Cao Guo Qiang (architect), and Dr. Lo Xing Yun (translator) - - who were at one time with the Central Luzon State University, for painstakingly sharing the basic information, principles and other "secrets" of the Chinese biogas model with one of this manual's writers, Charles Nakagawa; Nestor de Guzman, a local ingenious mason who had made significant useful modifications in the construction of a Chinese biogas digester and which are now incorporated in this manual; and Esther dela Cruz for ably and patiently typing the manuscript.

By and large, this manual is only an initial attempt. Suggestions and comments for its improvement and refinement will be greatly appreciated.

The benefits a family can derive from having a biogas unit cannot be over-emphasized. The unit will not only provide an efficient disposal and treatment system for manure and other organic wastes but

also valuable fuel for cooking and even lighting, as well high quality organic fertilizers. On a larger scale, this means, among other things, environmental sanitation, energy self-reliance and savings on the part of the people.

It is hoped that this manual will, in certain little ways, be helpful to the villagers and development agency personnel in putting the biogas technology into practice.

C. H. N.

Q. L. H.



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## 1.0 INTRODUCTION

### 1.1 Why Biogas Production?

Biogas production has received growing attention as a project particularly in the rural areas and among small farmers. Technically, it is a process of converting animal manure and many other organic wastes into fuel and other beneficial uses.

More specifically, biogas production has the following benefits:

#### 1) Direct Benefits to the Farmer:

- a) Methane gas. It is a clean fuel for cooking and lighting, (at the household level), and even running diesel engines. In short, savings in fuel expenses.
- b) Fertilizer. What remains of the manure after gas has been extracted, is high quality organic fertilizer and soil conditioner. Some studies show that it increased crop yield by 10-20% compared to "undigested" ordinarily prepared compost.
- c) Sanitation and Health. Biogas production provides efficient disposal of manure -- controlling smell, water pollution, and access of flies and other disease-carrying pests to the manure. Furthermore, since biogas burns without smoke, irritation to eyes and lungs are prevented.

#### 2) General Benefits to the Country (After biogas production will have become widespread):

- a) Savings in the total economy. It will help conserve foreign exchange through reduced demand for kerosene, gas and commercial fertilizers.
- b) Cleaner environment. This will follow as individual families and enterprises practice an efficient waste disposal system.
- c) Increased possibility for backyard animal raising. With biogas production, animal raising in the homelots can now be undertaken without the usual undesirable smell and other sanitation problems.
- d) Reduced deforestation. In the longrun, biogas would reduce demand for firewood as a primary source of fuel in the rural areas.

## CLEANER ENVIRONMENT

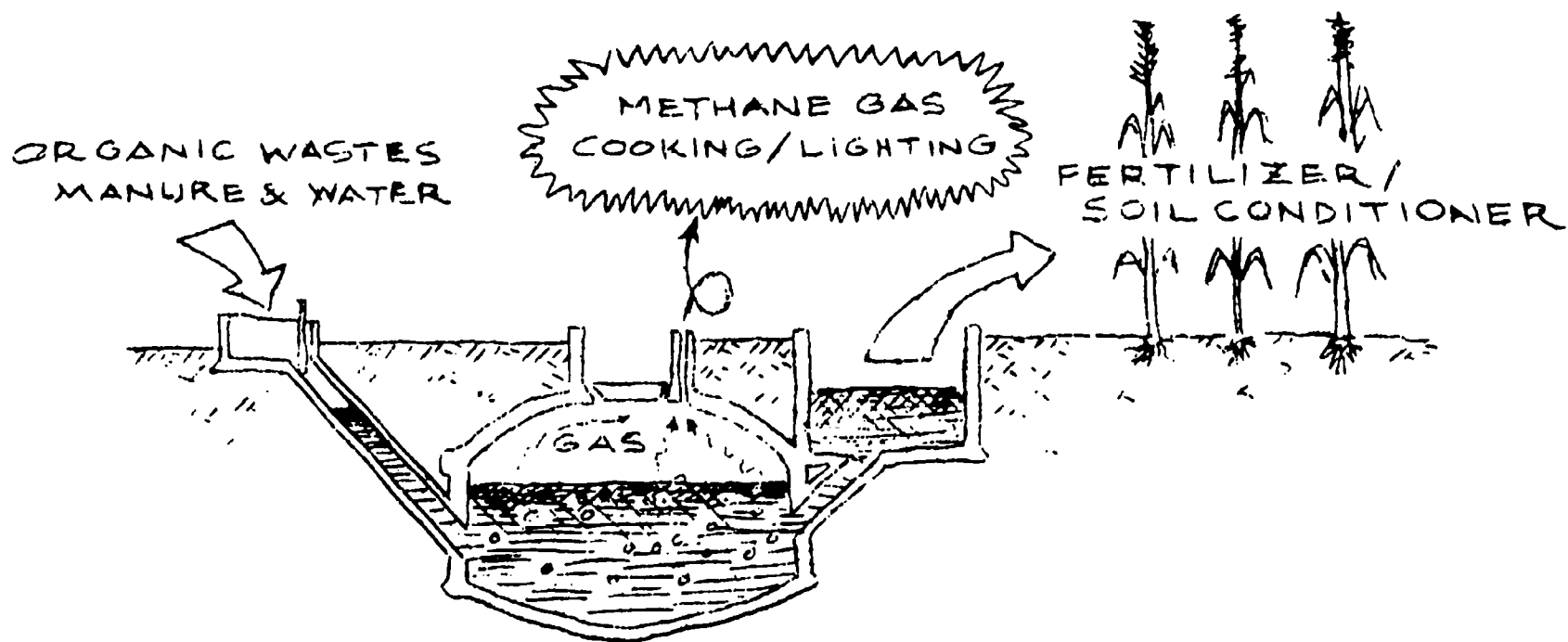


Figure 1: BIOGAS DIGESTER  
- CHINESE DESIGN -

## 1.2 The Chinese Biogas Model: Some Practical Advantages

There are many different biogas models but the Chinese model stands out as a highly promising in the rural areas. It originated from the People's Republic of China where about 7 million units are reported to have been existing. Some of its basic features are:

- 1) Circular in shape, with a fixed-dome top and saucer-shaped bottom. Being circular, it has the smallest lateral surface area with the pressure and load stresses even distributed, thus compact and solid. Additionally, it is economical in construction materials (up to 20% less than a quadrangle or square structure having the same volume).
- 2) No moving parts and metal components, except the structural reinforcements. An all concrete structure, hence, it is durable, almost a life-long investment. It is easier to maintain for it has no mechanical moving parts. No welding job is necessary.
- 3) Completely constructed underground. The digester is therefore insulated from extreme temperature changes. It saves land space for the area above the structure which can be utilized for other purposes like a pig pen. Input materials flow easily into the digester by gravity, thus simplifying operation.
- 4) Capable of generating higher gas pressure (on the average 10 times higher than floating cover type) is due to an unique gas storage mechanism which does not need a floating tank as other designs do. It uses the displacement principle where slurry moves up and down the specially designed outlet compartment as gas volume changes inside the digester. (See Figure 1 for diagram of the system.)

## 2.0 BASIC STRUCTURAL FEATURES AND CONSIDERATIONS

### 2.1 Components

The Chinese biogas model has 8 basic components:

- 1) Mixing Pit or Inlet. This is where manure and water are measured and mixed before feeding them into the digester. It is equipped with (a) sluice gate usually made of wood to control or allow for the proper mixture of water and manure before the release of the mixture into the digester, and (b) cover - - which can be made of recycled corrugated G.I. sheet.
- 2) Inlet Pipe. This serves as conveyor of the manure-water mixture or slurry from the mixing pit to the digester. It is a straight slanting pipe, using prefabricated concrete culvert 8 inches minimum inside diameter.

3) Digester/Gas Storage. This is where the slurry is allowed to ferment through bacterial action and where gas is being stored. It is a water and air-tight structure. Some features of the digester are:

- a) The flooring of the digester is concave or saucer-type where the inorganic solids and parasite eggs settle and collect.
- b) The wall is made of concrete hollowblocks with water-proofing plaster. The inlet/outlet pipes fit midway the wall height.
- c) Ringbeam, which acts as the "foundation" of the dome. Made of reinforced concrete; it indicates correct slurry level when the digester is being filled initially.

The gas storage is fixed into the digester. It is that portion above the ringbeam or the space inside the dome. The dome is made of reinforced concrete and is plastered twice and finally sealed with paraffin or wax for complete gas proofing.

4) Outlet Chamber. It serves 2 important functions: (a) where the effluent residue is taken out; and (b) where the slurry is forced out when the gas pressure within digester/gas storage exceeds atmospheric pressure.

The chamber consists of 3 parts:

- a) Outlet pit - - is circular in shape, made of concrete hollowblocks with plastering, and having a volume to  $1/3$  of the volume of the digester/cylinder ( $V_2$ ).
- b) Outlet pipe - - is prefabricated round concrete pipe with 8-inch inside diameter (same as inlet pipe).
- c) Cover - - to keep rain water, debris and children from falling into the pit. It can be made of recycled G.I. sheet.

5) Removable Manhole. It provides access to the digester for cleaning, inspection and maintenance. It is made of concrete and is water-sealed. Asphalt material is used for gasket seal.

6) Gas Outlet Pipe. It is located through the manhole sleeve. It is of 1-inch G.I. pipe.

- 7) Stirrer/Mixer. This is a mechanical devise inside the digester used to stir the fermenting slurry to stimulate gas production and to break the "scum" layer forming at the surface of the slurry. It is fabricated from G.I. pipes and flat bars. (The only component that requires welding.)
- 8) Backfill. It serves to protect and insulate the concrete dome from the sun (dry and heat) and provides rain water runoff. Soil and gravel with 70% and 30% proportion respectively is recommended.

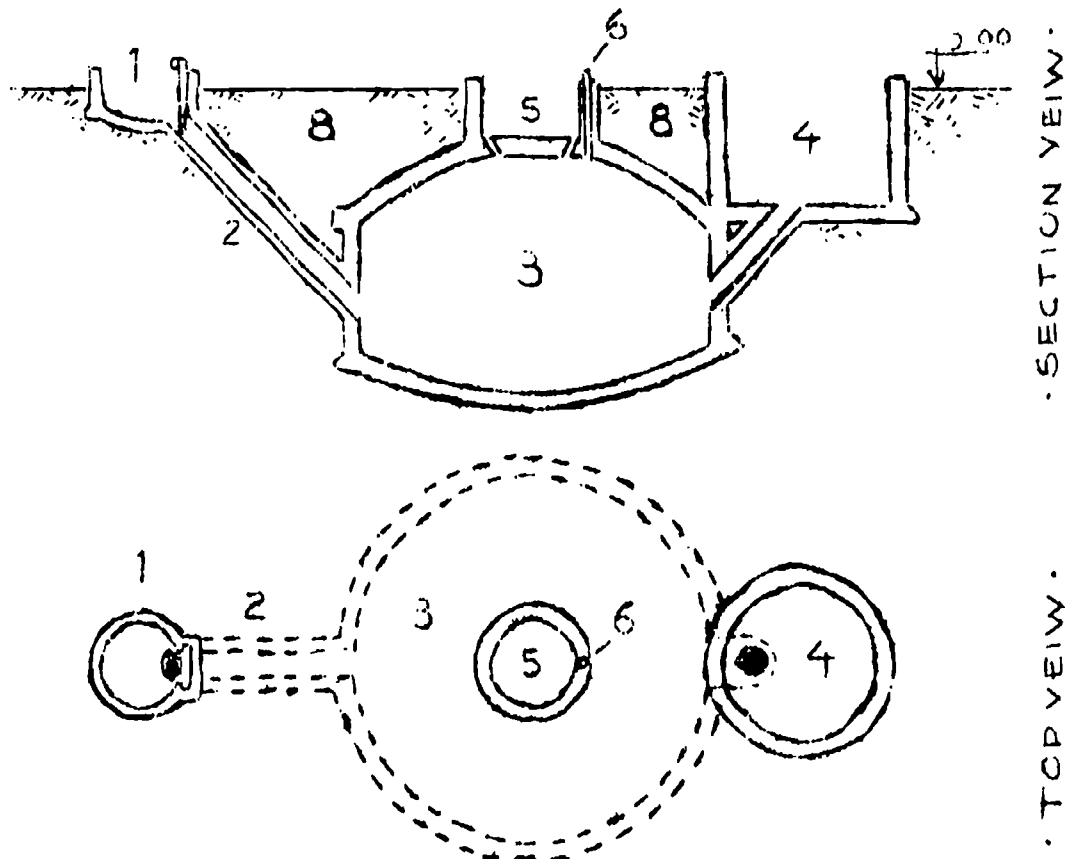


Figure 2: Components of a biogas Unit  
(stirrer/mixer not shown here)

## 2.2 Design Formulas

For structural stability and efficient performance, the design of a Chinese Biogas model is governed by certain mathematical formulas <sup>1/</sup> which are as follows:

- 1)  $\frac{h}{d} = \frac{1}{3}$ , That is, the diameter of the digester is three times its height.

---

<sup>1/</sup> Source: Chengdu Biogas Research Institute, Sichuan Province, People's Republic of China, June 1980.



2)  $\frac{f_1}{d} = \frac{1}{5}$  That is, the distance from the ringbeam to the manhole is one fifth the diameter.

3)  $\frac{f_2}{d} = \frac{1}{10}$  That is, the distance from the bottom center to the wall bottom is one-tenth the diameter.

4)  $V_{\text{outlet}} = 1/3 V_2$  That is, the volume of outlet chamber, Volume is one-third of the slurry chamber,  $V_2$ .

5)  $V_{\text{slurry}} = V_2 + V_3$  That is, the slurry volume,  $V_s$  is equal to volume of the digester below the ring beam.

6) Height of inlet/outlet pipes =  $1/2 h$ , that is, the inlet/outlet pipes are placed one-half the height of the wall.

7)  $V_{\text{slurry}} = 0.85 V_t$  That is, the slurry volume is 85% the total digester volume,  $V_t$ .

$V_{\text{dome}} = 0.15 V_t$  That is, the gas chamber volume (dome) is 15% of the total digester volume,  $V_t$ . This volume relationship allows for gas pressure sufficient enough to force the slurry to the outlet chamber.

8) Mixing pit volume should be slightly larger than the daily charge.

9) Manhole dimensions are standard for all volumes of digesters.

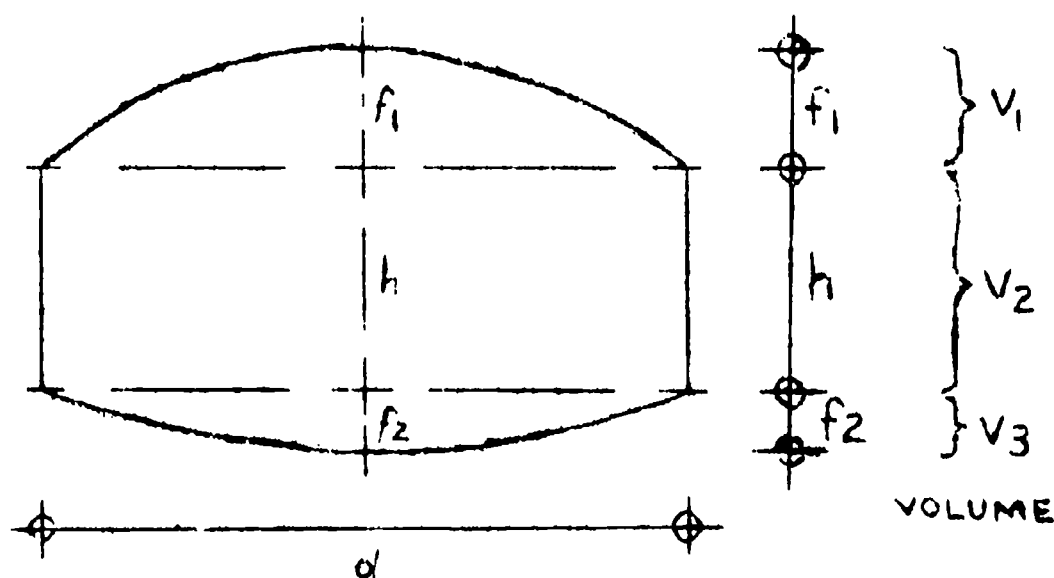


Figure 3: Design Formula

### 2.3 Sizing Biogas Units:

The success of the digester unit depends on the management/operation procedures. A small digester will produce more gas than a large digester with good scientific management. Larger digesters requires more capital costs, more materials and labor. It is often said that it is better to have two smaller digesters rather than one large one.

There are two approaches to sizing a biogas digester. This decision is made by the owner/operator to fit his needs depending upon the situation. These are:

- 1) The unit to produce a certain amount of gas needed; or,
- 2) The unit to process/treat a given amount of organic matter (pig manure, carabao manure, night-soil, etc.) as a waste management system, then to see the amount of gas produced, and if that gas produced, and if that gas could be put into good use.

There are cases wherein the volume of organic matter to be treated is large and the need for the gas is minimal. Or the case may be that there is a greater need to treat the waste over the actual gas to be retrieved. The gas need is minimal while there are abundant supplies of organic wastes. Thus, the two approaches in problem solving for the sizing of biogas units are illustrated as follows:

- Case A:
1. How much gas do I need daily? (Overriding Consideration)
  2. What digester volume is needed to produce this amount of gas?
  3. How much daily volume of materials (manure and livestock level) will be required?
  4. What is the cost involved? (Feasibility/viability study)

- Case B:
1. How much raw materials (manure and other organic wastes) is required to be treated? (Overriding Consideration)
  2. What digester volume is needed to handle these materials?
  3. What is the amount of gas expected?
  4. How will this gas be utilized?
  5. What is the cost involved? (Feasibility/viability study)

Following are data and computations needed to answer the different questions:

For Case A:

Question 1. How much gas I need daily?

Gas requirements for appliances:

- a) Cooking (medium burner) -  $0.28 \text{ m}^3/\text{hr.}$
- b) Lighting (gas mantle) -  $0.14 \text{ m}^3/\text{hr.}$
- c) Refrigerator (kerosene)  $7 \text{ ft}^3$  -  $0.20 \text{ m}^3/\text{hr.}$
- d) Gas engine -  $0.56 \text{ m}^3/\text{Hp/hr.}$

Calculate how many hours each appliance is used per day and multiply it with the energy consumption.

For example:

$$\begin{aligned} & - \text{Two stoves (3 hrs./day x } 0.28 \text{ m}^3/\text{hr. x 2 stoves)} = 1.68 \text{ m}^3/\text{day} \\ & - \text{One lamp (2 hrs./day x } 0.14 \text{ m}^3/\text{hr.)} = \underline{0.28 \text{ m}^3/\text{day}} \\ & \text{Total} = 1.96 \text{ m}^3/\text{day} \end{aligned}$$

Question 2. What is the digester (slurry) volume to produce this gas per day?

Under average Philippine climatic conditions, estimate gas production at  $0.4 \text{ m}^3$  (minimum production) for every  $1 \text{ m}^3$  of slurry volume. Thus, for a total daily gas requirement of  $1.96 \text{ m}^3$ , the unit required must have a digester (slurry) volume of  $4.9 \text{ m}^3$ .

This is solved by a simple ratio and proportion formula as follows:

$$\frac{0.4 \text{ m}^3}{1.0 \text{ m}^3} = \frac{1.96 \text{ m}^3 \text{ (gas needed)}}{x \text{ (digester volume)}}$$

Cross multiplying will yield:

$$0.4 x = 1.0 x 1.96$$

$$x = \frac{1.0 x 1.96}{0.4}$$

$$x = 4.9 \text{ m}^3 \text{ (digester volume)}$$

Since in the Chinese design the digester and gas storage are integrated in one unit, the total digester volume would be slightly higher. Refer to the design to find the slurry volume to correspond to the desired volume. The 6.14 m<sup>3</sup> design has a slurry volume of 4.68 m<sup>3</sup>, which seems to be most appropriate for this case.

Question 3. How much raw materials are needed daily to operate this digester?

Let us assume the normal retention time of 40 days (the period of time one sample of slurry remains in the digester.) Then:

$$4.68 \text{ m}^3 \div 40 \text{ days} = 0.117 \text{ m}^3$$

(daily slurry volume which is also equal to the mixing pit volume)

$$0.117 \text{ m}^3 \div 2 \text{ (or 1:1 manure - water mixture)} = 0.0585 \text{ m}^3$$

(volume of manure and water mixture needed daily)

$$\text{or} = 58.5 \text{ liters of manure and water needed per day.}$$

- determine the livestock level to provide 58.5 liters (kg.) of manures per day. Is it available?

Question 4. What is the cost of the digester?

This varies from place to place depending on the costs of construction materials and labor. Feasibility/viability study.

#### For Case B:

To process or recycle for waste management, a given amount of manure, determine the following:

- a) total amount of wastes to be treated;
- b) volume of digester needed;
- c) amount of gas to be expected from the given digester volume;
- d) what can be done with the gas generated;
- e) cost of building the biogas unit. Feasibility/viability study.

For example: Let us assume a piggery with 20 fatteners always available, and one 75 kg fatterer will give approximately 3.75 liters manure/urine per day.

Then:

$$20 \text{ fatteners} \times 3.75 \text{ liter/day} = 75 \text{ liters of manure per day}$$

$$75 \text{ liters} \times 2 \text{ (with water mixed)} = 150 \text{ liters of mixture}$$

$$150 \text{ liters} \times 40 \text{ (retention time)} = 6,000 \text{ liters}$$

$$6,000 \text{ liters} \times 0.001 \text{ (conversion of liter to m}^3\text{)} = 6.0 \text{ m}^3 \text{ (slurry) volume}$$

$$6.0 \text{ m}^3 \times 0.4 \text{ (gas production rate)} = 2.4 \text{ m}^3 \text{ of gas per day.}$$

$$\text{Digester to be built} = 8.66 \text{ m}^3$$

Biogas can be produced from a very wide range of vegetable matter and all types of animal manure. When vegetable matter is used it is important that it is to be cut into the smallest possible particles. For a continuous-operating biogas digester, it is recommended to avoid vegetable matter since this may lead to "scum" problems quickly. Recommend to use only animal manure (and very little vegetable matter) for continuous-operating biogas digesters.

In China, they base the size of their digesters on these assumptions: each cubic meter of raw material will produce from 0.15 - 0.3 m<sup>3</sup> of gas per day. The low gas production is mainly due to the lower annual temperature in China. (also no mixing; batch operation). Here in the Philippines, we may expect more gas to be produced from the same given volume of raw materials. Under average Philippine climatic conditions, the gas production rate is based on that each cubic meter of raw material will produce 0.4 - 0.6 m<sup>3</sup> of gas per day. This may be due to higher temperatures, mixing and a continuously operated digester. Usually, the size of household biogas digesters in China is from 6 m<sup>3</sup> to 10 m<sup>3</sup>, to compensate for the low gas production rates. Here in the Philippine (tropical climates), the household units may be from 4 m<sup>3</sup> to 8 m<sup>3</sup> due to the expected higher gas production.

### 3.0 CONSTRUCTION

#### 3.1 General Overview of the Construction Process

There are two main phases for the construction of this masonry-type Chinese bio-digester.

Phase I is basically the structural concrete work of the digester. This begins with the Planning/preparation stage to the final concrete plaster application to the inside of the digester/gas dome. The importance here is that all of the concrete work should be carried out continuously, day to day and to avoid any delays in the concrete work. Ideally, the entire digester should be poured all at one time (monolithic), but the impossibility creates the problem of having to pour sections at a time, which makes it hard to avoid "joints", which should be reduced to a minimum. If the joints are not well made, it provides the chance for cleavages/cracks which may lead to leaks in the digester, either water and/or gas leakages. Thus, this part of the construction phase must be continuous and meticulously handled for the desired results. Timing is important and the planning/preparation of the work to be done fully understood by the builder and any carelessness of attention to the quality of construction will interfere with gas production, durability and require even more work (labor, time and materials) to remedy the defect. Each biogas unit should meet specified technical requirements for it to be water and gas tight for the unit to function properly. (For more basic information on masonry work see Appendix H.)

After all of the main structural concrete work has been completed and the "curing" process of the concrete properly started, the Phase I construction is considered finished. The break between Phase I and Phase II is to allow for the proper curing of the concrete, a period of no less than 2 - 3 weeks. The main Phase II activity of paraffin/wax application must be done after this curing period (2-3 weeks), so that "most" of the water has been allowed to dissipate from the concrete during this process, leaving a dry surface. This is necessary in order for the paraffin/wax application stage since if the concrete surface is wet or moist to which the wax is to be applied, it will not adhere as well and will not be an effective gas-seal layer. (the last concrete plaster layer of the dome area to where the wax is to be applied is a "rough" finish). During this curing period ("break" between Phases I and II) the other activities of the Phase II may be done; i.e. stirrer/mixer assembly preparation (welding), gas-piping systems (from digester to the stove, manometer, etc.). The only activity that should be done after the 2 - 3 weeks period are the paraffin/wax application, backfill, manhole and finally, loading (testing for water and gas tightness). Also, during the Phase I period, inspection for any structural damages, check for water and gas tightness will be done before the actual loading of the digester. The basic outline/sequence of events and the process and procedures will be discussed and explained step-by-step so that the builder will have an idea of what should be prepared and required for the specific work.

There are many variations to the construction materials and procedures depending on the availability of building materials in the area. This is how the Chinese are able to build such inexpensive biogas digesters. In this manual we have used a "model" that can be built almost anywhere here in the Philippines, since all of the building materials presented are commonly available at most hardware supply stores, and with which most people are familiar. But by no means is this the only way to construct a Chinese biogas digester and that the builder is not limited to the construction materials specified here. Once the concepts are understood, techniques will be mastered. And having built a few with success, there is plenty of room for improvisation and experimentation, especially in the building materials used - - to lower the cost of construction. The materials presented here are not the lowest possible available, but it is quite inexpensive compared to the "floating" gas-storage type of biogas digester designs on a volume to volume basis. These materials were selected since they were the most commonly available (at local hardware supply stores), not on the merit that they are the most inexpensive available. It is recommended that the builder build at least one of this type presented here in this manual to familiarize himself with design dimensions, techniques and procedures involved. The design and dimensions of the units itself should not be changed from one digester to another of the same volume. Again, there is room for experimentation (try on a small scale first for "new" ideas before applying them on full scale). The method described in this manual has had success in our experience, in terms of materials and methods which were commonly/locally available. Whatever method used, remember that the structure must be solid, firm, water- and gas-tight and durable.

### 3.2 Phase I

#### 3.2.1 Planning/Preparation

It is recommended that the builder read through the entire construction procedures to have an idea of what is involved, the time period required, and construction materials used.

Here are important reminders in planning for the construction of a biogas unit:

- 1) Order and purchase all materials preferably in advance. It would be necessary to insure that all materials and tools will be available when needed. Prepare all tools. Have workers inform you if they are low on supplies or check the supplies yourself. Avoid delays in construction.
- 2) Building a biogas tank is not like building a house or a piggery structure. One crack in a house or piggery structure is permissible but not in a biogas digester. Any source of leak for gas will render the biogas structure useless. Meticulous construction work is stressed for obtaining desired results.

- 3) Water-proofing concrete is relatively easy, but gas-proofing it is difficult. This requires new skills and materials not applied in ordinary masonry work. Again, meticulous approach to construction and avoid carelessness in work.
- 4) Costing. Ask the question whether some materials could be suitably substituted by others which are less expensive but adequate enough for the job.
- 5) Available labor. Check if the required labor and technical skills are easily obtainable and, if not, where to secure them. Also check if some self-help labor is available for this will reduce costs.
- 6) Check water table. Consider the highest level the water table could rise. In no case should the groundwater level exceed half of the height of the digester wall. Checking water table height involves digging a hole equal to the total depth of the digester during the wettest season of the year. Check the water level in the hole. If necessary, the whole structure may be elevated to compensate for a high water table (although it will involve some problems like more backfill needed, more efforts in lifting/hauling manure in changing the digester.) As a rule, it is best to avoid high groundwater areas for biogas units.
- 7) Avoid construction during rainy season. High water table and occasional rains can cause delays in construction which in turn affect the quality of concrete work.
- 8) Follow strictly scientific methods of working with concrete. The payoff is high -- a durable, more lasting and efficiently functioning biogas unit. Equally important, follow the structural design requirements and specifications.
- 9) Other reminders. Consider the availability of building materials and skills, cost of materials, available animal wastes, type of soil, knowledge and experience of the builder, and amount of gas required vis-a-vis amount of manure available.

### 3.3.2 Site Consideration

The location of a biogas unit is a crucial factor to its success as well as to other environmental sanitation requirements. The following are helpful guidelines for choosing an ideal site for the project:

- 1) Biogas units should be at a site where water table is low. The maximum that water table may be allowed to rise is  $1/2$  of the height of the digester. If water table of a tentatively selected site is too high, look for another site.
- 2) It should be located as much as possible downhill or downstream with respect to a well or any water source. Ideally the minimum distance between a biogas unit and a well should be 15-20 meters to avoid water contamination in cases of leaks in the digester.



- 3) Should be not far from the house or the point of gas utilization to save gas piping cost, but at the same time close as possible to the source of raw materials such as piggery or toilet. This is also to save transport labor and thus guarantee normal gas production.
- 4) Should be where there is suitable soil and foundation conditions.
- 5) Should be away from big roots of trees that may damage the structure.
- 6) Since the biogas unit is completely underground it could be placed either (a) near the house, but in an open area which is exposed to sunlight and therefore heat, for greater gas production; or (b) underneath the house/kitchen or under the animal stalls (which arrangement is common in cold places to protect the digester from extremely low temperature).

In China, the popular arrangement for siting of household biogas units is referred to as "three-in-one" whereby the digester is connected with the piggery and the latrine. The "two-in-one" arrangement is common where either the latrine or the animal pen is attached to the digester.

- 7) Raw materials (manure, urine, wash water) should be able to "automatically" fed via sloped canals or troughs by the force of gravity to the mixing pit/inlet. This is advisable for increased efficiency and lesser labor cost of hauling and/or lifting the manure.
- 8) The site should be close to where the effluent is to be used or stored like a vegetable garden or a compost pit.

### 3.2.3 Excavation

Depending on the soil type, excavation may take 2-3 days. Accurate excavation is important. A poorly dug pit may be a major source of wall/floor settling, and therefore a waste of effort and materials.

Accurate layout of the complete biogas unit is a crucial starting point: from the piggery or source of **raw materials** to the digester and finally the outlet pit or effluent use.

In planning for excavation, thoroughly investigate the sizing, design, physical layout, materials and tools needed, and construction procedures. These should be discussed jointly by the owners and builders.

Observation of the soil structure/conditions is equally necessary. See if the foundation is sand, clay or solid. Check for groundwater level. See if large roots are present which may damage the structure, if possible destroy them, or find another suitable site.

Before actual digging begins, decide where the excavated soil will be placed. Most of the soil will later be used for backfilling and contouring the area to avoid flooding near the digester. There should be enough space for the movement of materials to the excavated pit when construction begins.

Try to dig as exactly as possible to specifications. Too large an excavation would mean excessive backfill and extra unnecessary expenses; too small, on the other hand, may need additional digging after concrete work has begun. This is undesirable for impurities might get into the concrete.

It is also advisable to dig the pit with sloping walls. In this way "cave-ins" or collapse at the excavated pit walls can be avoided. See following illustration.

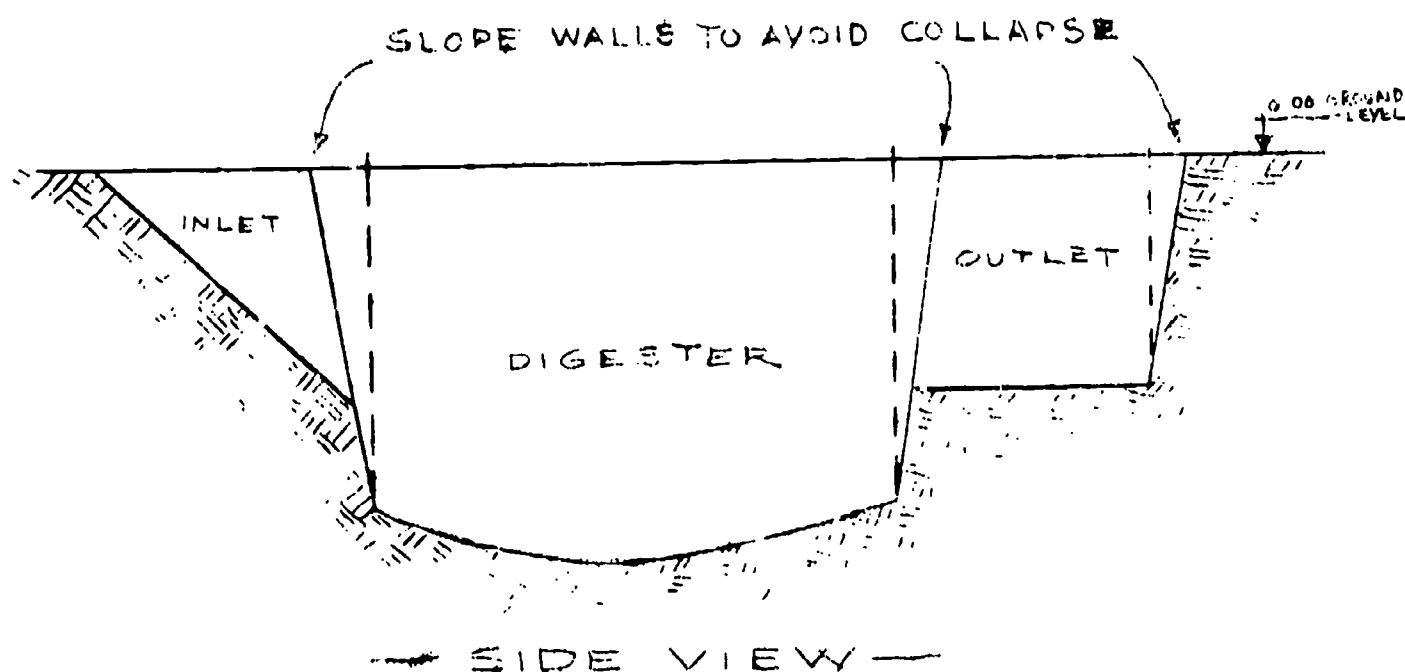


Figure 4: Slope-walled Pit

An allowance of 5-10 centimeters from the outside edge of concrete hollowblock (CHB) wall is sufficient. For example:

- For a  $4.66 \text{ m}^3$  digester unit (refer to the design/plan: Appendix B.)

$d = 2.3 \text{ m}$  ( $r = 1.15 \text{ m}$ ), which is the inside diameter;

CHB used for walling is 4" x 8" x 16", or 4" thick or 10 cm.

5-10 cm. allowance for backfill;

Thus,

$$\begin{aligned} & 115 \text{ cm. inside radius of digester} \\ & + \\ & 10 \text{ cm. CHB thickness} \\ & + \\ & \underline{10 \text{ cm. backfill allowance}} \\ & = 135 \text{ cm. excavation radius.} \end{aligned}$$

In actual digging, first the digester is dug out, then the outlet chamber and finally the inlet pipe groove. (See diagram below.) Note: all excavations should be completed before any concrete work begins.

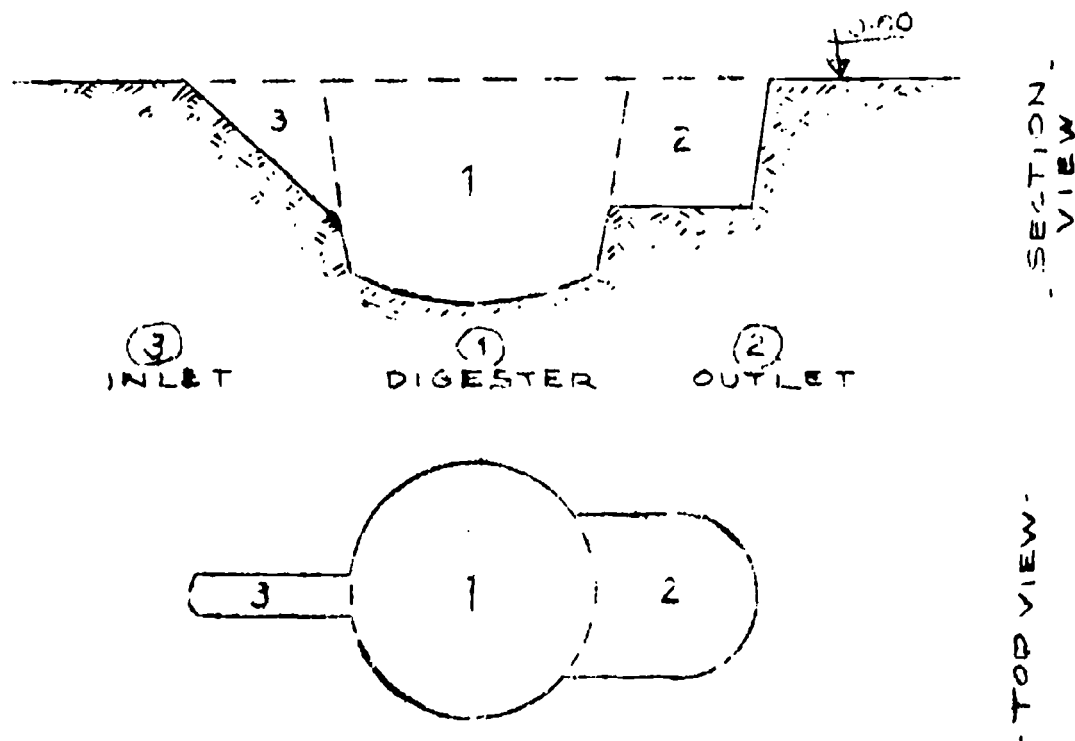


Figure 5:  
SEQUENCE OF EXCAVATION.

The excavation procedure is facilitated with the use of a center-pole technique and "f<sub>2</sub>" form guide. The center-pole technique is used as a guide for the following:

- 1) determining the correct radius of the pit;
- 2) determining the correct curvature for the bottom of the pit (or "f<sub>2</sub>" curve/arc);
- 3) determining the correct thickness of the flooring while concrete is being poured; and

4) laying the CHB<sub>s</sub> for the wall construction.

During excavation, at about 10 centimeters before reaching the specified center-depth of the digester, a "center-pole" is placed and fixed securely for the final "touch-up" digging. The procedure involves the following specific steps:

- 1) A GI pipe (1/2" diameter) is placed vertically at the center of the digester pit. Make sure that it is straight for accurate and also it will later be used for gas piping system.
- 2) A wooden lumber (2" x 2") spanning across the excavated pit is used to brace the GI pipe. The GI pipe is centered vertically in the pit with the use of a plumb-bob. The 2" x 2" lumber is staked at either ends of the excavated pit and firmly fixed in place.
- 3) A piece of deformed bar (40 cm. long) is staked at the bottom center of the pit. Through this stake it is advisable to place an end of a tin can so as the GI pipe will not change in position vertically during construction.
- 4) The GI pipe is placed to the center-stake guide. Check again center accuracy with a plumb-bob. To this GI pipe is attached the "f<sub>2</sub>" guide. It is attached in a fashion so that it can rotate on the GI pipe. Appropriate gradations or marking are made on the GI pipe center-pole for guides during construction. The point where the GI pipe is attached to the 2" x 2" lumber is ground level.

(See procedures and drawings below.)

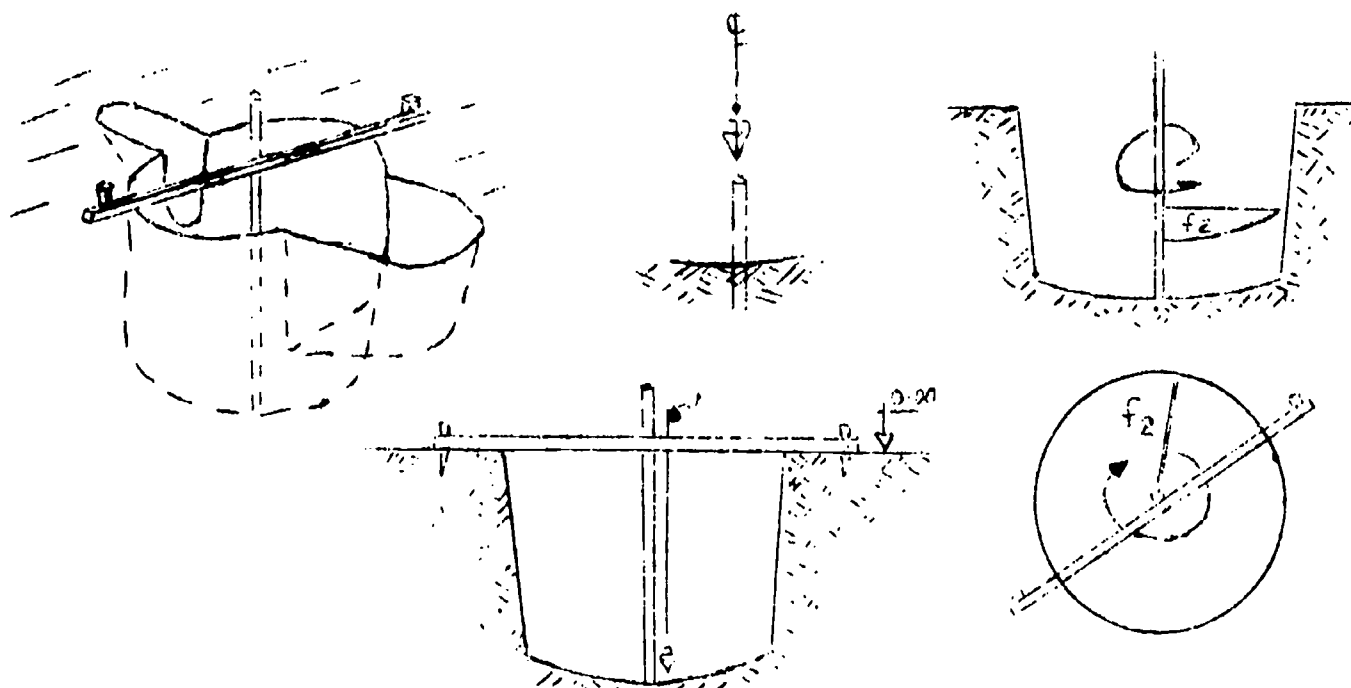


Figure 6:  
EXCAVATION. (CENTER POLE TECHNIQUE.)

It must be pointed out again that all "fine-touch-up" excavation should be completed before any concrete work is to begin. If not, it is difficult to keep the work area clean and impurities may get into the concrete. The excavation walls should be "sloped-in". The outlet chamber and inlet pipe groove should also be excavated. Most important, the curvature of the floor should be correct and checked with the use of the " $f_2$ " form guide.

The preparation of the " $f_2$ " form guide for a  $4.66 \text{ m}^3$  digester unit takes the following steps:

- 1) Obtain from the design/plan the dimensions for  $f_2$ ,  $d$  (diameter) and  $R_2$  (radius for  $f_2$ , floor curvature/arc). In the case of  $4.66 \text{ m}^3$  digester, the dimensions are:  $f_2 = 0.23 \text{ m}$ ;  $d = 2.3 \text{ m}$ ;  $R_2 = 2.8 \text{ m}$
- 2) Prepare tools: tape measure, chalk/pencil, saw, and lawanit or plywood.
- 3) Mark off the  $f_2$  and the radius of the digester on the lawanit (as shown in the diagram below).
- 4) Extend tape measure to the  $R_2$  distance (which is  $2.8 \text{ m}$ ). Lay the tape parallel along the  $f_2$  distance and the length of the lawanit (again see diagram).
- 5) The tape measure will act as a compass. The pivot at the  $R_2$  end of the tape measure and a pencil at the edge of the lawanit of the  $f_2$  mark (at the other end of the tape measure). The end of this  $f_2$  mark and the other mark of the radius of the digester should meet while moving from point "A" to point "B". Draw this curve using this large compass and cut out using the saw.

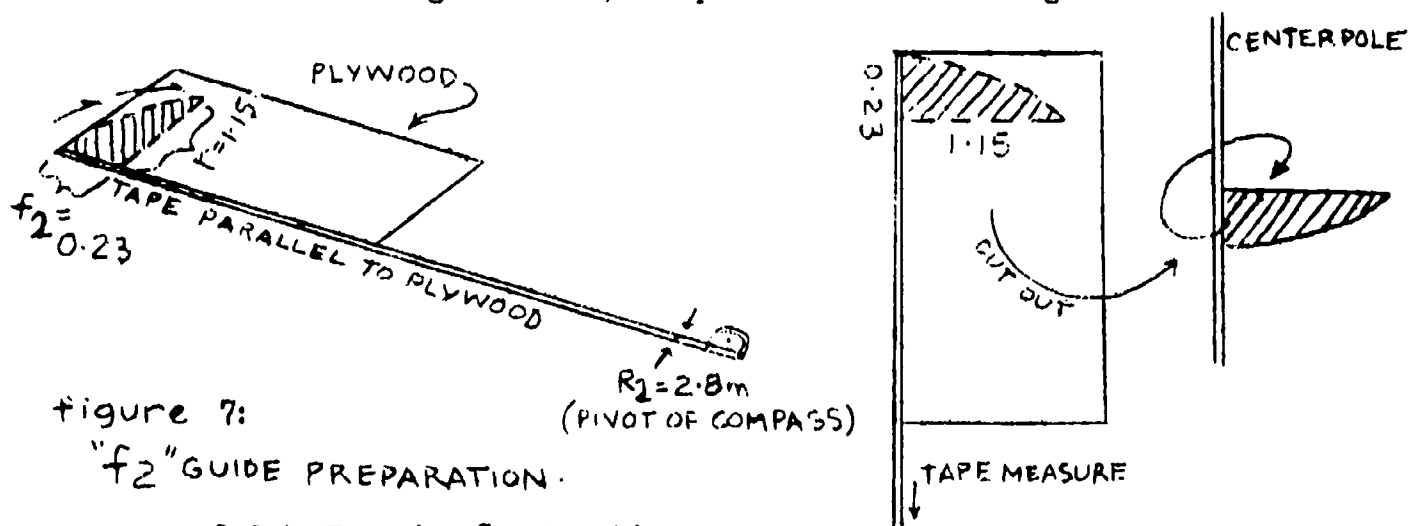


figure 7:  
" $f_2$ " GUIDE PREPARATION.

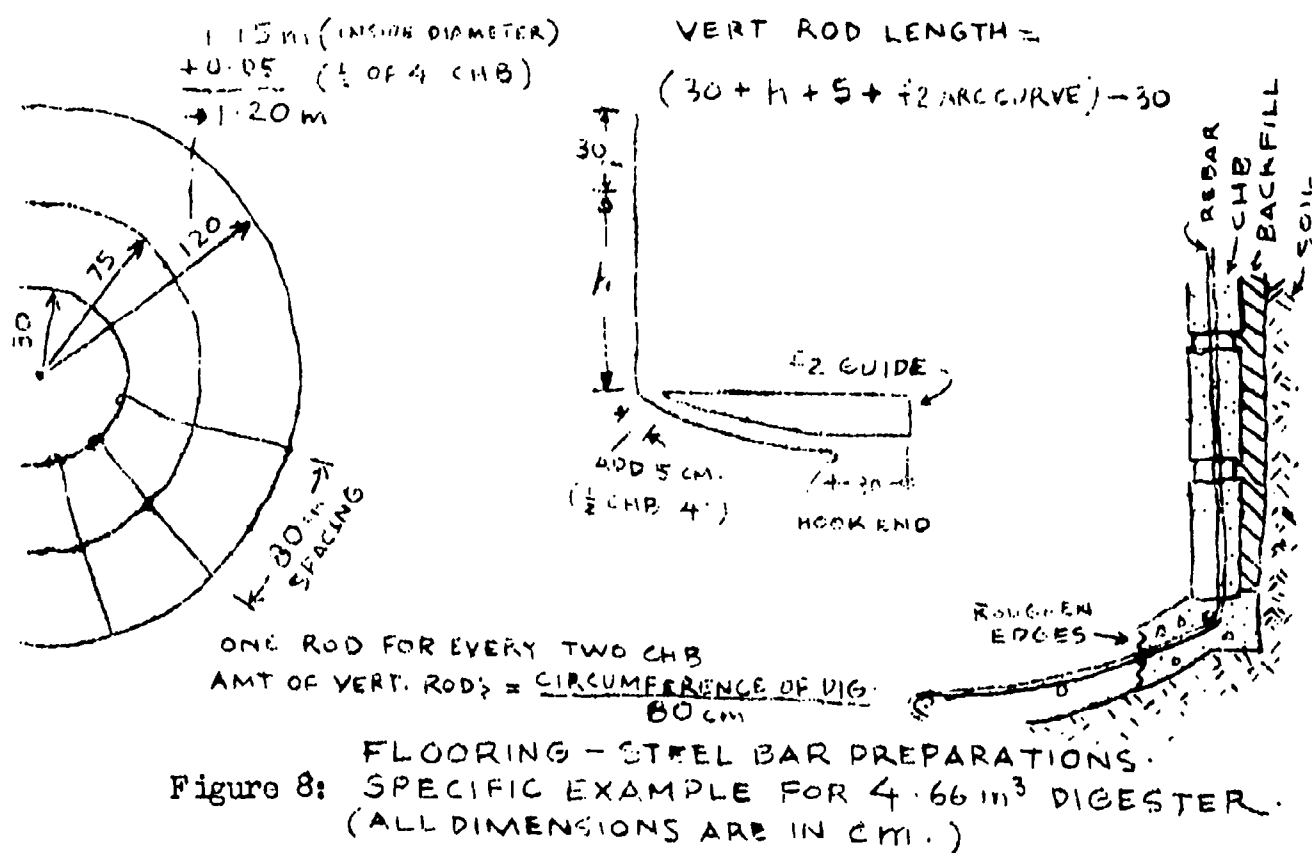
### 3.2.4 Flooring Construction

The concrete flooring will be laid out in two stages. This is so that the work will proceed quickly. The initial flooring section will be on the outer perimeter of the digester to allow for the continuation of the wall construction. If the entire flooring is to be poured all at the same time, there is a danger construction may be delayed since there would be no working space available on the newly laid concrete floor, since it must be cured before anyone is to walk on it.

The flooring should be reinforced concrete, thus there is a need to prepare the steel reinforcement bars. Reinforced concrete will assume the strength of the floor, along with being concave in shape.

Some guides in preparing the flooring reinforcement steel bars:

- 1) One vertical bar for every two CHB<sub>s</sub> (or every 80 cm.).
- 2) For a 4.66 m<sup>3</sup> digester unit, three circle bars are necessary. The first, or the smallest, is standard for all digester volumes. This would be the open-center circle about 60 cm. in diameter. The largest circle, placed on the outer perimeter of the digester, is directly on-center under the CHB wall. The second circle would be placed mid-way between the smallest and the largest circles. Note that this is sufficient reinforcement for this volume of digester, there may be a need to add more steel reinforcements for larger digester volumes.
- 3) Secure and tie all reinforcement bars together with GI wire.
- 4) Leave the joining edges of the flooring to be completed a rough finish so that the bond between the concrete flooring will be water tight.



### 3.2.5 Wall Construction

Wall of the digester is made of CHB<sub>s</sub>: 4" x 8" x 16" for digester volumes up to 6 m<sup>3</sup> and 6" x 8" x 16" for larger digester volumes. This CHB will be constructed to form a circular structure.

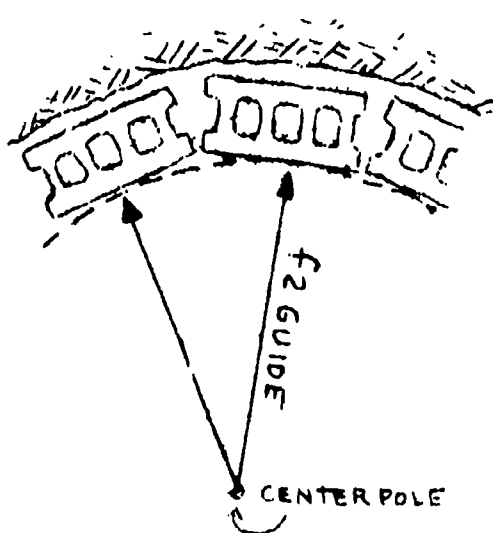
Wall construction is relatively easy and quick.

The following are important guides/reminders in constructing the wall:

- 1) There will be working space within the digester since the only portion of the floor that is laid is the area where the CHB is to be placed for the wall.
- 2) Use the "f<sub>2</sub>" form guide for correct radius distance from the center to the CHB and in turn, to achieve a circular structure. Check distance at CHB at centers of the block, both left and right edges would be equidistantly spaced.
- 3) Although the radius measurement is correct, double check to make sure the center-pole is vertically correct (use "plumb-bob").
- 4) Fill in mortar only in holes of the CHB with either vertical reinforcing bars or adjoining CHB. All other CHB holes may be left empty so it may act as insulation to increase temperature within the digester (e.g. double-wall insulation concept).
- 5) Use sufficient mortar when laying CHB<sub>s</sub>. Remove all excess mortar.
- 6) Place horizontal "ring" reinforcement bars for every two CHB height. Secure and tie with GI wire to the vertical reinforcements.
- 7) Placement of concrete culvert pipes (prefabricated RC pipes) for inlet/outlet is carried out simultaneously with wall construction.
- 8) Placement of inlet/outlet pipes should be at one-half the height of the wall. Be careful when placing the pipes; they are heavy and laid at a steep angle and the newly installed CHBs are fragile and will move. There may be a need to brace/support to hold the pipes in place (see diagram). The half-way position of the outlet pipe is designed to allow the parasites eggs to settle in the digester and not being easily expelled with the effluent, thus reducing the health hazard.
- 9) The correct angle with which the pipes are to be positioned is particularly important. Make sure that a line can be made from the outer lip of the outlet chamber to follow the angle of the outlet pipe. This is to make it possible to "purge" and clear the outlet pipe of blockage from time to time. The pipes should be straight so that a long stick or rod (such as a bamboo pole) may pass through for clearing the inlet/outlet pipes. (See diagram below)
- 10) The pipes should have a minimum of diameter of 8 inches. The larger the pipe the better since clogging will be reduced. The use of ready-made, culvert pipes may be substituted with "make-your-own" pipe with the use of banana stalk larger than 8" in diameter to serve as the inner mold. However, it should be

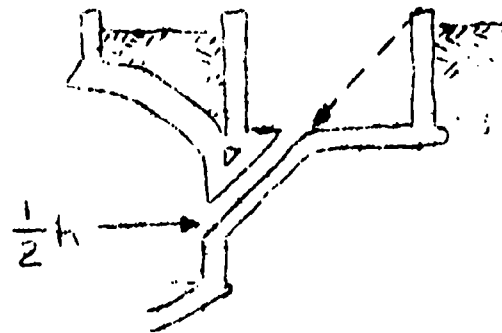
noted that this may consume more cement.

- 11) Don't move the pipes while the wall construction proceeds.
- 12) Pour sufficient concrete around the inlet/outlet pipes connections with the wall. Also, additional steel bars may be needed to reinforce the pipes to the walls.
- 13) The last layer of CHB<sub>g</sub> is filled at only one-half full capacity. This is important to insure that the ring beam will attach to the wall more strongly.
- 14) Apply backfill behind every two CHB layer height. Backfilling should be gentle as the CHB<sub>g</sub> are not yet completely set.



USE f2 GUIDE ON CENTER  
(NOT ON EDGE) OF CHB TO  
ACHIEVE CIRCULAR SHAPE.

ANGLE OF OUTLET PIPE  
MUST BE IN "LINE OF SIGHT" FROM  
THE OUTLET CHAMBER FOR  
PERIODIC PURGING TO CLEAR  
THE PIPE.



PLACEMENT OF INLET/OUTLET PIPES  
AT  $\frac{1}{2}h$  (SHOWN HERE OUTLET)

Figure 9: Wall Construction

### 3.2.6 Ring Beam

The ring beam is a crucial part of the structure: it is the foundation of the dome. The thrust and stresses of the dome can be counteracted by the ring beam to the soil.

Construction joints are utilized since the complete dome is not poured at one time (not monolithic). A banana stalk core (5 - 7 cm. diameter) is appropriate for making construction joints since it is easily workable and flexible to form a circle and that it is available at no cost at all.



Three circular reinforcement bars are needed for the ring beam, arranged with intermittent triangular stirrups (80 cm. spacing).

Forms are made of lumber (2" x 2" or 2" x 1"; 16" long) and lawanit/plywood or GI sheets. There are no forms for the back of the ring beam; instead, backfill and the soil are used. (See ring beam diagram below.)

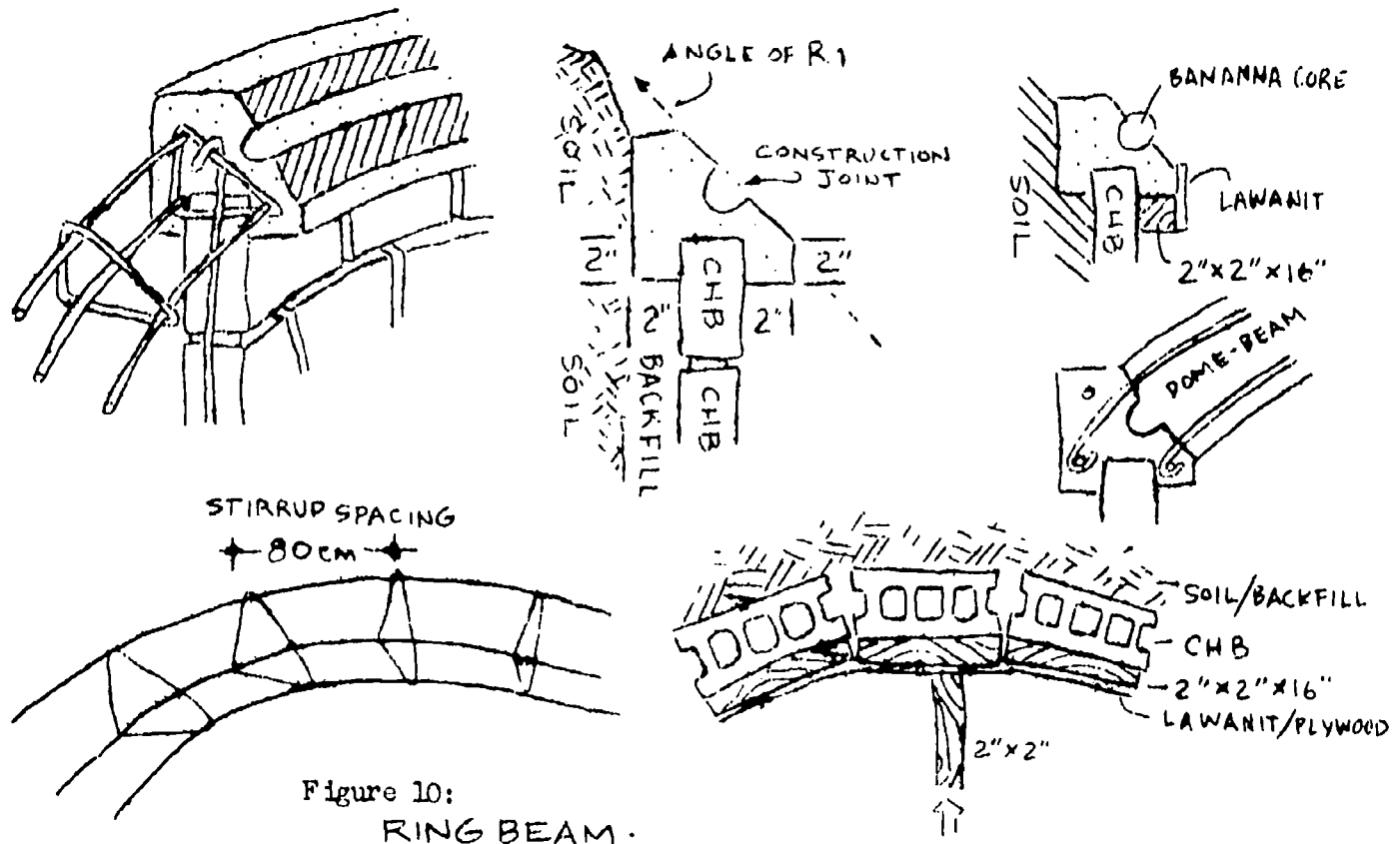


Figure 10:  
RING BEAM.

### 3.2.7 Dome Beams (Arch or Cross Beams of the Dome)

Construction of the reinforced concrete beams and manhole collar is carried out simultaneously. The difficulty is in achieving the perfect curvature or arc of the dome. Hence, the procedure presented here for dome construction is somewhat difficult, costly and time consuming. However, when it is constructed correctly and according to specifications, the dome will be structurally strong and therefore less expensive in the long run.

Prior to dome beam construction is the preparation of the forms to obtain the specified dome curvature. This is done by drawing the "cross-section" of the dome, in scale on the ground (preferably on a concrete floor, using chalk), complete with the top CHB wall portion, ring beam, dome, manhole collar and sleeve (see diagram below).

In drawing the "cross-section" the following step-by-step procedures are taken:

- 1) Draw one long line. This will be the center-line of the digester. The length should be longer than  $R_1$  distance.
- 2) Draw another line perpendicular to this line (or diameter of the digester). The intersection of the two lines will serve as the bottom point of " $f_1$ ".
- 3) Determine the radius length of the digester and mark off accordingly. Determine " $f_1$ " distance and mark accordingly on the  $R_1$  distance from the intersection.
- 4) Continue and draw the remaining according to the design/plan specifications: CHB, ring beam, dome curvature (using  $R_1$  dimension given; " $f_1$ " and the diameter points should meet on the  $R_1$  curve; similar process as making the " $f_2$ " form guide). Draw the manhole collar and sleeve. Remember, these are all drawn in scale on the ground.
- 5) Determine thickness of the dome beams according to specifications. Draw this on the "cross-section".
- 6) Place the lawanit/plywood on top of the drawing where the dome beams are located. This area is between the ring beam and the manhole collar. Using the  $R_1$  distance and the "large compass technique" (used in making the " $f_2$ " form guides described earlier), draw the inside and the outside curvature with the specified thickness of the dome beam on the lawanit/plywood sheet. The length of the beams will be the distance from the ring beam to the manhole collar. The angle corresponds to the  $R_1$  angle.
- 7) Cut out this form and re-check for accuracy by placing the cut-out form on the "large" scaled cross-section on the ground. There are four dome beams and therefore a total of eight of these dome beam forms are needed. Use the first cut-out form as the pattern for cutting out remainder.
- 8) Prepare four bottom pieces for the four dome forms. The width will be specified according to the thickness, and the length will be the distance from the ring beam to the manhole collar with the curve.

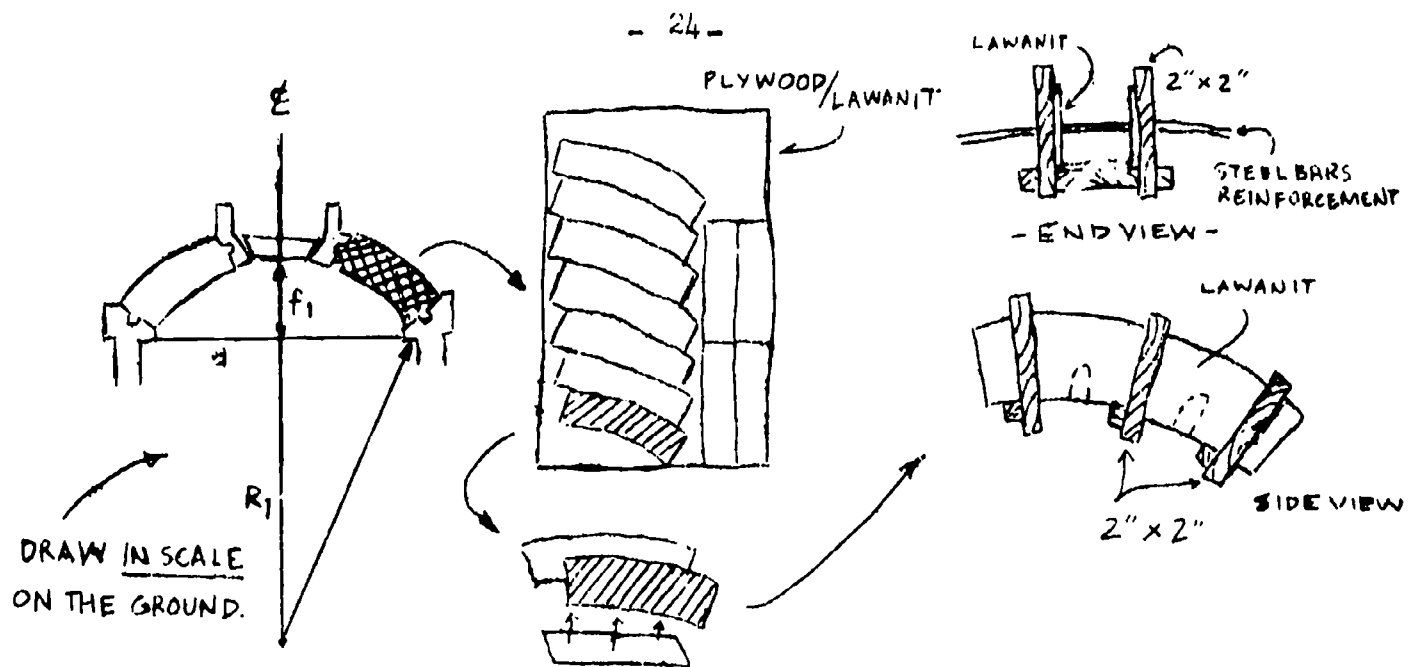


Figure 11:  
DOME-BEAM FORMS PREPARATION

Having prepared the forms as described above, the next step is now to construct the dome beams using the following procedures (See diagram below):

- 1) Install the forms within the digester, using sufficient braces to hold them firmly and to support the weight of the concrete to be poured.
- 2) Install circular iron bar reinforcements, stirrups and manhole sleeve.
- 3) Place construction joints.
- 4) Pour concrete into forms layer by layer. Be careful in pouring since concrete is heavy and the forms may collapse. Tap concrete lightly with a hammer or "poke" with a stick periodically in the forms as concrete is being poured. This is to settle the concrete completely around the rods and eliminate air pockets.

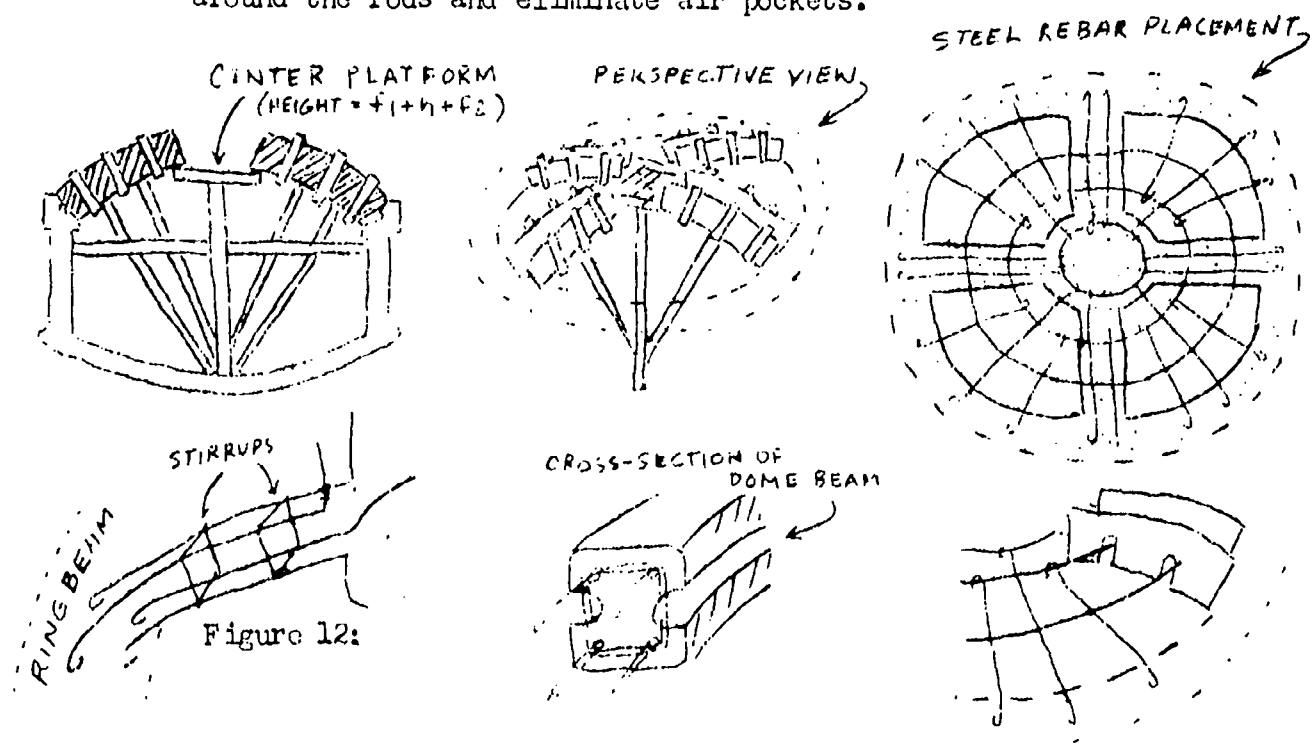


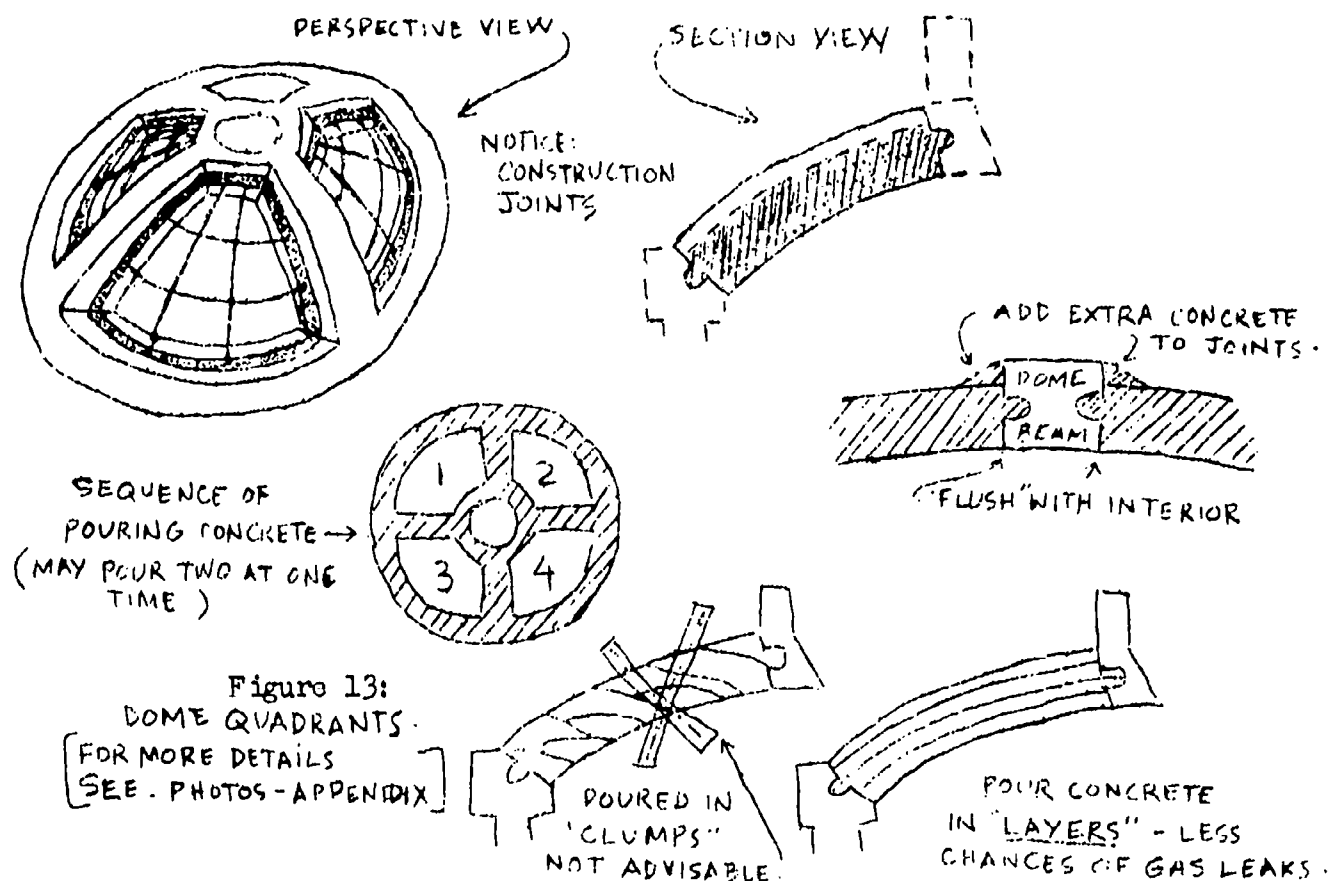
Figure 12:

### 3.2.8 Dome Quadrants

After the dome beams, the next to be constructed are the dome quadrants completing the dome structure (See diagram below).

The procedure in constructing them is as follows:

- 1) Remove all dome forms and clean "construction-joints" well of any debris. Extra care must be exercised in removing the forms and construction joints as pieces may break/fall off.
- 2) Prepare necessary forms, using lawanit/plywood, since it is easily bent or curved. Try to "flush" with the interior of the dome. Use as necessary braces to hold the forms in place (to support the poured-concrete weight).
- 3) Place reinforcement bars, and make sure they are properly spaced from the form materials. Add any additional reinforcement bars if necessary (again see diagram below), or use GI fencing wire for extra strength.
- 4) Pouring is done in two quadrants at a time. All joints should be "painted" with cement-water solution before actual pouring. Pour carefully and in layers instead of in "clumps". Use stick to "poke" concrete well into the construction joints. Place extra concrete to form mounds at all joints or seams or on all four edges of each quadrant.
- 5) Carry out concrete pouring job in one day or in one setting to avoid joints or seams.



### 3.2.9 Outlet Chamber/Pit

As mentioned earlier, the outlet chamber is circular in shape. Its floor is at the same level as the ring beam and they are connected at that point. Since the correct level of slurry in the digester is up to the ring beam, it is easily visible from the outlet chamber when filling the digester. This is because the slurry will be at the floor level of the outlet chamber at a "zero" gas pressure within the digester.

The volume of the outlet pit is one-third of the digester volume.

The outlet chamber is made of CHBs, 4" x 8" x 16". This CHBs size is sufficient enough for all digester volumes, since this chamber is not exposed to stresses.

The procedures in constructing the chamber/pit are as follows:

- 1) The CHBs are cut in half lengthwise in order to obtain a small diameter circular pit.
- 2) Steel reinforcements are not necessary, but may be added if extra is available.
- 3) The flooring is flat and made of poured concrete with a smooth finish.
- 4) The inside of the chamber is plastered smoothly.
- 5) The chamber is provided with a simple cover that may be made of ordinary or corrugated, recycled GI sheets. The reasons for the cover is to prevent rainwater and debris from entering the pit, to keep children from falling in, to increase temperature of slurry, and to improve sanitation by keeping mosquitoes and flies from it.

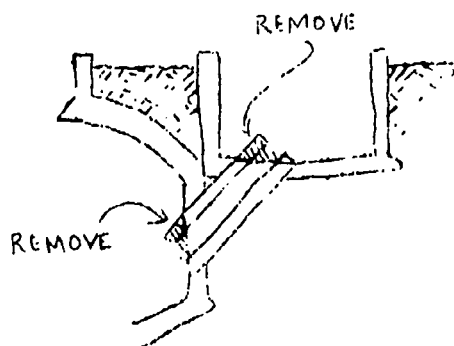
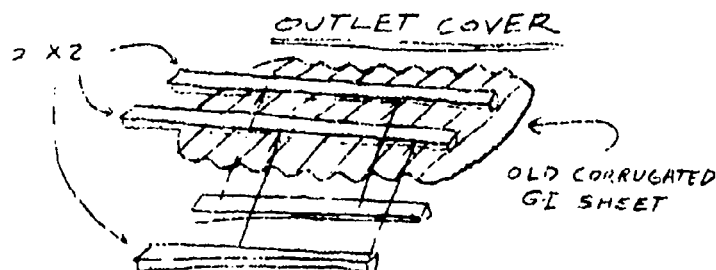


Figure 14.  
OUTLET CHAMBER

REMOVE ANY PORTION OF THE OUTLET PIPE THAT IS "EXPOSED" AT THE OUTLET PIT THE FLOOR SHOULD BE LEVEL; AND THE WALL OF THE DIGESTER FLAT.



### 3.2.10 Mixing Pit/Inlet

The mixing pit performs the following functions:

- 1) To mix the slurry with correct consistency, that is, the right proportion to manure and water.
- 2) To mix and measure the proper amount of slurry to be charged per day.
- 3) To settle out any inorganic solids (sand, grit, etc.) so they do not get into the digester.
- 4) To remove any floating vegetable or other materials before the slurry is allowed to flow into the digester.

The mixing pit volume should be slightly larger than the daily charge volume so there is sufficient space for mixing the materials.

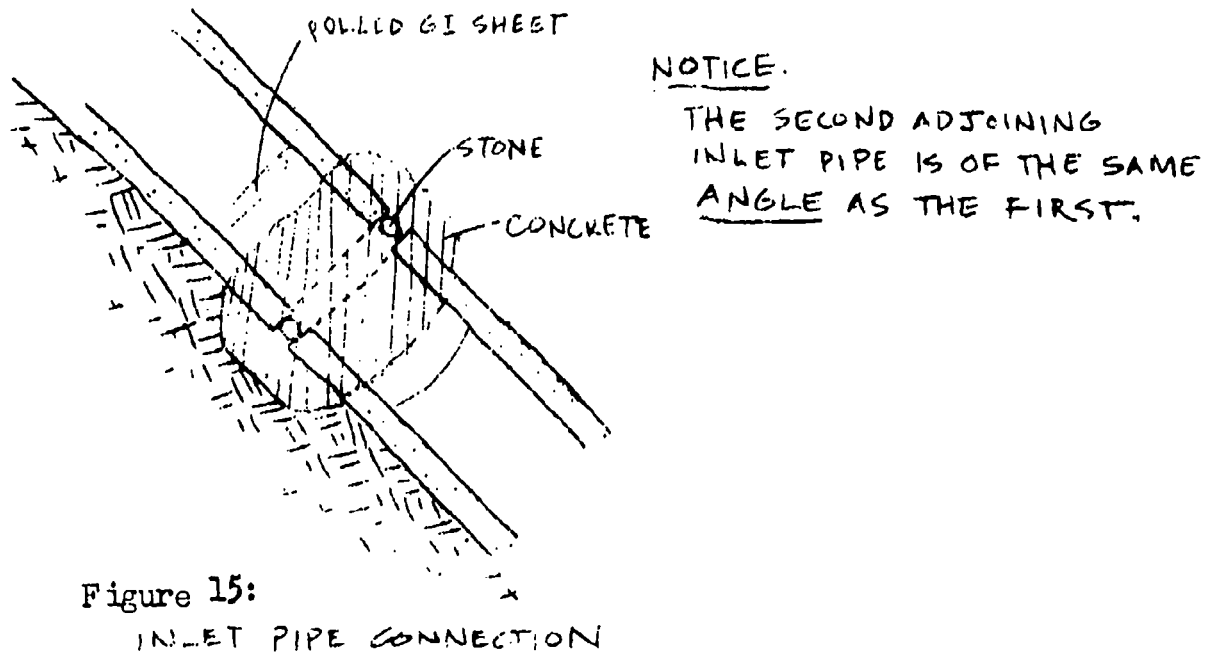
The mixing pit is circular, made of CHBs 4" x 8" x 16". Like the outlet chamber, the CHBs are cut in half to obtain a smaller diameter circular pit.

A wooden sluice gate is provided for the mixing pit to hold the slurry materials while it is being mixed and also to prevent excess rainwater from entering the digester. It should be watertight as much as possible.

Another component attached to the mixing pit is the inlet pipe which conveys the slurry to the digester. This requires an additional concrete pipe connected to the previously laid inlet pipe protruding from the digester wall. It is laid at the same angle as the first pipe so that the two adjoining inlet pipes are straight.

The procedures for laying the inlet/pipe are as follows:

- 1) Remove soil about 5 centimeters under and around the pipe connections so that there will be a good connection.
- 2) Make sure the two pipes are straight when connected to allow the periodic clearing of the inlet pipe with a stick or rod when it clogs.
- 3) Place a stone so that there will be a space for the concrete between the ends of the pipe where it is to be connected.
- 4) It is advisable to roll a plain GI sheet inside the point of connection to prevent concrete from falling into the pipes and to keep the inside of the pipes as smooth as possible.
- 5) Pour sufficient concrete to the joint and make it strong and clean.



### 3.2.11 Plastering

In the fixed-dome Chinese design, a major problem to overcome is gas leakage through concrete structure, particularly when the joints are not properly plastered. And the possibility of leakage is enhanced by the high gas pressure that this particular design digester encounters.

Efficient plastering of the inside walls of the digester and dome is therefore a very important part of biogas construction. The Chinese advocate multi-layer plastering with a final sealing layer of paraffin/wax solution. However, procedures vary slightly in different regions.

Plastering is a difficult work to master and the plastering of the digester must be performed professionally because the structure demands complete water and airtightness. The dome is extremely difficult to plaster because the area to be plastered is overhead and the surface is curved.

The following are some tips in plastering:

- 1) Always begin from bottom to top, not working in a sideward direction.
- 2) Avoid joints in plastering; if possible finish all plastering in one day. Joints may lead to leaks.
- 3) Don't mix more concrete mortar than can be used within one hour.
- 4) Use circular motion for plastering.
- 5) Provide a "rough" finish for the final plastering for the gas

portion of the digester dome. This is to provide a good adhering surface for the paraffin/wax application. Paraffin or wax does not adhere well to a smooth surface.

- 6) To further check if plastering is solidly done, examine the inner surface by "tapping" with a stick. If an area produces a "hollow-sound" when tapped, it is to be dug out and replastered. This is checked after the plaster has been dried.
- 7) Apply two layers of concrete plaster, 1 centimeter thick each layer.
- 8) Level off under the ring beam to avoid corners. (See diagram below.)

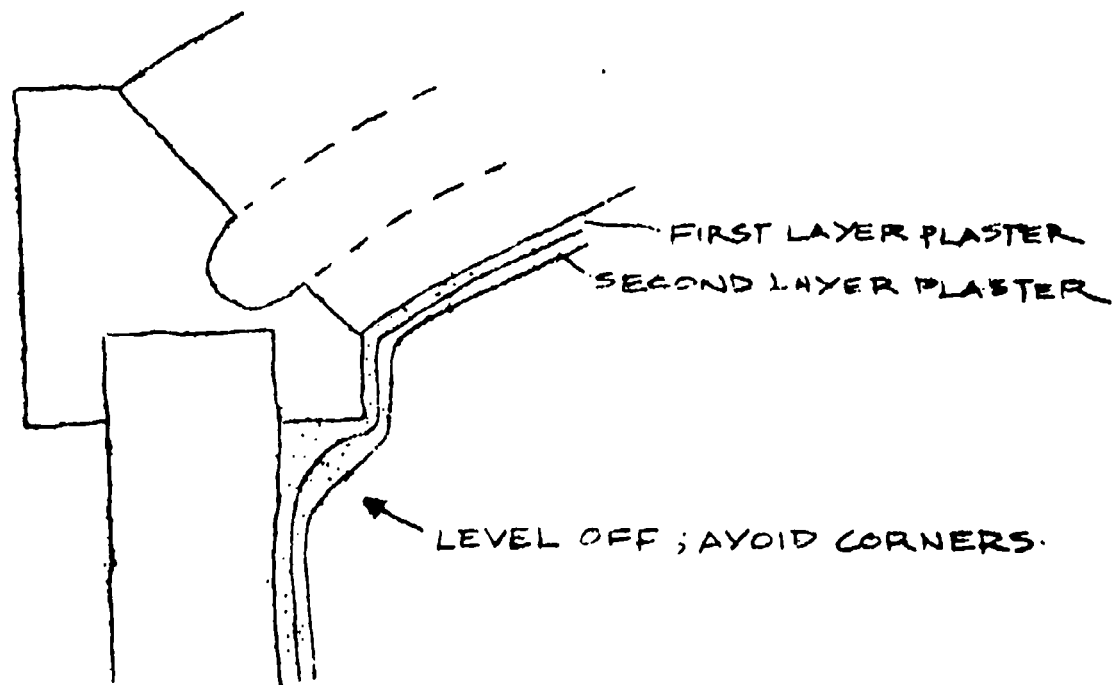


Figure 16.

LEVEL OFF UNDER THE RING-BEAM.

### 3.2.12 Flooring Finishing

After the plastering is completed the flooring can now be finished. Clean the inside of the digester and "joint of the flooring" to be connected with a steel brush and apply "cement-water solution". If the stirrer/mixer is to be incorporated in the unit, the mixer "center-pole guide" must be prepared beforehand. This will be placed at the bottom center of the digester (previously where the center stake was placed for the center-pole technique). Check again the center of the digester with a plumb bob.

In preparing for floor finishing:

- 1) Make sure that the reinforcement bars are clean and spaced evenly from the ground.



- 2) Place center-pole for use of the "f<sub>2</sub>" form.
- 3) Using "f<sub>2</sub>" form guide, pour concrete evenly according to the specified floor curvature. Pour from the outside towards the center.
- 4) Place the mixer "center-pole brace" at center. Check vertical and center position with the use of a plumb-bob.

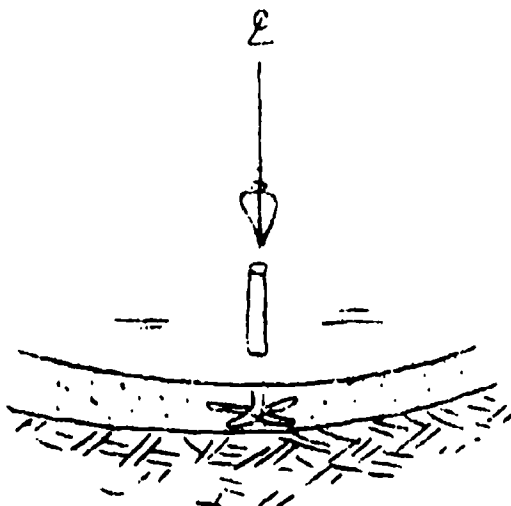


Figure 17.

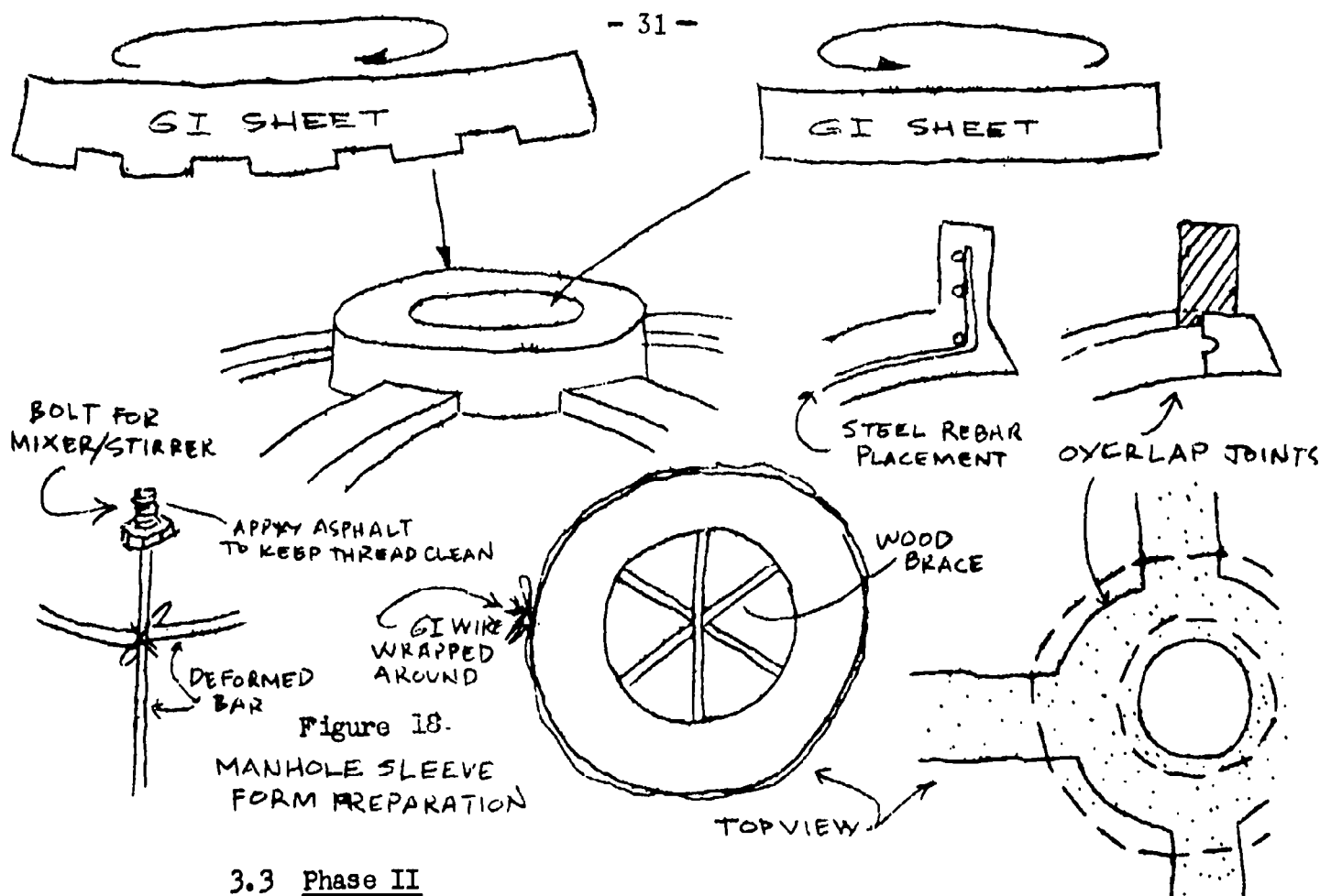
MIXER CENTER-POLE GUIDE PLACEMENT.

### 3.2.13 Manhole Sleeve

The next to be finished is the manhole sleeve, involving the following steps:

- 1) Prepare forms and the specified reinforcement bars. (Note: if the mixer/stirrer assembly is to be incorporated prepare 3 bolts for the manhole cover brace.)
- 2) Keep all joints/connections clean.
- 3) Apply "cement-water solution" to all joints/connections prior to pouring concrete.
- 4) Pour concrete.

Note: the dimensions for the manhole and manhole sleeve are the same for all digester volumes.



### 3.3 Phase II

#### 3.3.1 Paraffin/Wax Application

The different tools needed for this work are: a blowtorch, a paint brush 2½" size and may be slightly used, an old pot or tin can to melt the wax, a small bowl/can with wide mouth to hold the melted wax while being applied, and a steel brush.

As mentioned earlier, the sealing of the inside surface of the gas portion of the digester will be done at least 2 weeks after the concrete work has been completed.

The procedures involved in paraffin/wax application are as follows:

- 1) Inspect carefully the inside of the digester to see if:
  - a) There are any cracks in the structure, or portions producing "hollow" sounds. If so, make appropriate repair jobs.
  - b) The concrete structure exhibits some degree of dampness, that is, there is water visible. If so, check by spreading cement powder and observe if it "wets" the cement. If wetting is very slow, paraffin wax may relieve the small leak. If the leak rate is fast, concrete repair is necessary.
  - c) There is water in the bottom. Remove it and check the next day. If water returns, there is a leak which has to

be repaired. Use dry cement powder technique to determine where the leak is coming from.

- 2) If there are no damages to the structure, clean the dome and digester walls of loose particles (concrete and sand bits) with steel brush. Remember a rough finish is more desirable since wax will adhere to the surface much better. This applies only for the gas portion of the structure.
- 3) Melt the wax. Add kerosene to the melted wax: 3 unit-volume of kerosene to every 10 unit-volume of wax. This is to lengthen the hardening time of wax and makes it more pliable and easier to work with. Then place the melted wax in a smaller, wide-mouthed container which will be easier to work with inside the digester. Be careful when adding kerosene over fire; it may ignite!
- 4) Allow the melted wax to cool off a little. Hot wax does not stick to concrete very well and instead the hot wax drips off the paint brush, wasting much of the wax and may also burn the brush hairs. Besides, it is too hot to handle. A good sign of the correct temperature for wax is when it starts to develop a thin film on the surface.
- 5) Apply the melted wax using a paint brush. This is a tricky procedure requiring practice and the following are a few pointers:
  - a) Place the container always below the work area to collect any drippings. Wax is expensive. Another way of collecting the wax is to fill the bottom with water. This way the dripped wax floats and it is easily recovered.
  - b) Apply with up-strokes and "splashing" the wax on the surface using the brush.
  - c) Paint from the bottom of the ring beam and work up towards the manhole sleeve.
  - d) When finishing a small area, use left-right-left and diagonal strokes. This assures that most of the area is applied with a wax layer.
  - e) Place extra wax for jointed areas like under the ring beam, dome beams, manhole sleeve and gas pipe.
- 6) When the whole area has been applied with wax, smoothen it with the use of a blowtorch operating on medium-high flame. Also check for missed areas. You will notice that exposing the area to a blowtorch will render the wax finish into one smooth, homogenous/continuous layer of wax and therefore gas **tighting** the area completely. Important: When using the blowtorch, do not let the

flame remain on one section too long. This will remove all wax and the excessive heat may crack the concrete plaster on the surface. Left to right and circular moving motions when blow-torching work best for desired results.

- 7) After blowtorching, there will be many minute holes visible. These need "touch-up" patching with another layer of wax to those areas and another blowtorch application. Inspect again and repeat if necessary.
- 8) Inspect the adhesion of wax to the surface being worked on. Repeat waxing if necessary.

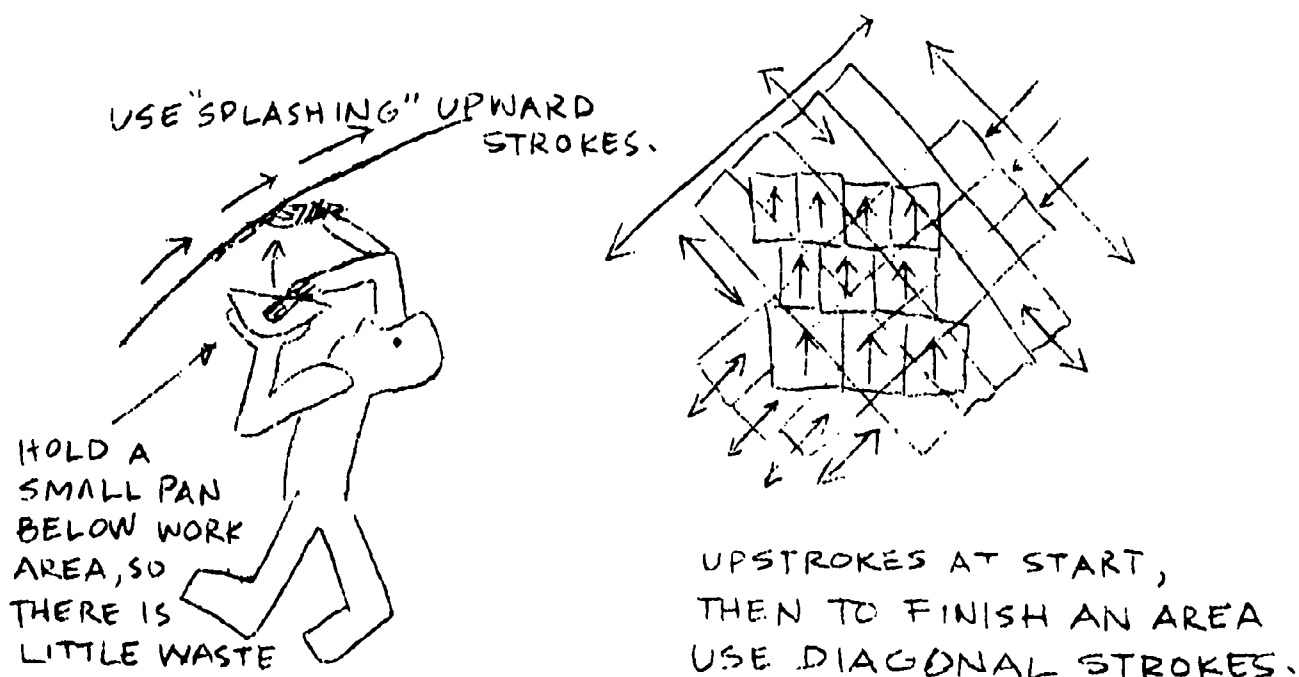


Figure 19. WAX APPLICATION

### 3.3.2 Stirrer/Mixer Assembly

This component is primarily a welding job. (For specifications, refer to the design/plan in Appendix B.) However, in installing the assembly requires that the removable manhole brace (which are described and diagrammed in the next section) and mixer guide (placed in the concrete flooring) be prepared beforehand. The 3 piece "fan-blades" of the manhole brace has a pipe at the center where the three blades converge. The location of this pipe must be in such a way that when the brace is attached to the three bolts, which are already fixed on the manhole sleeve, the stirrer assembly will be perfectly centered on the digester and thus the mixer guide at the base of the digester.

An example of the bill of materials for the mixer/stirrer assembly for a 4.66 m<sup>3</sup> digester includes:

- 1) GI (ordinary) pipe, 1" dia. x 1' (mixer guide)
- 2) GI (ordinary) pipe, 1½" dia. x 10' (center shaft of mixer)
- 3) GI (ordinary) pipe, 2" dia. x 4' (mixer sleeve and manhole brace center pipe)
- 4) Flat bar, 3/16" thick x 4" x 10' (blades of mixer, the fans of manhole brace)
- 5) Angle bar, 1/8" thick x 1" x 10' (reinforcement for the blades)
- 6) GI coupling, 1 pc. 2" dia. (connects manhole brace and mixer sleeve)
- 7) GI Tee, 1 pc. 1½" dia. (placed at center shaft top for attaching mixer manual handle)
- 8) Cap screw, 12 pcs., 7/16" dia. x 1" (to attach blades to mixer center shaft - - 4 ea. for each blade.)

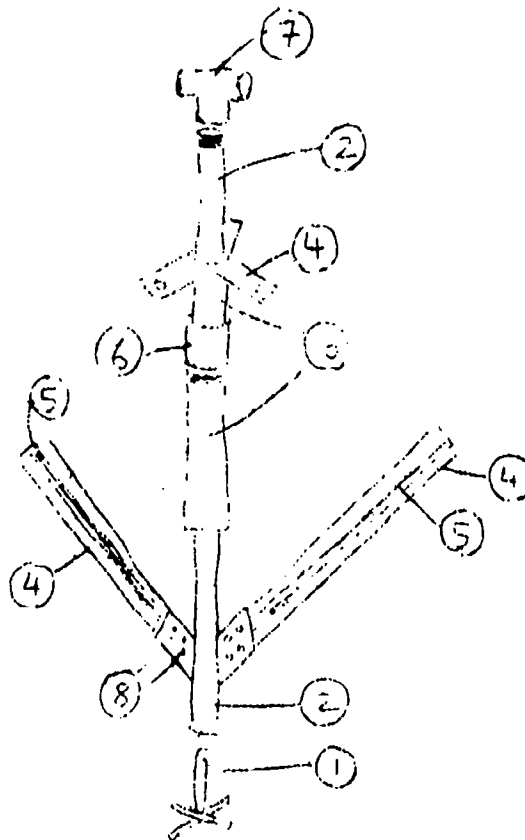
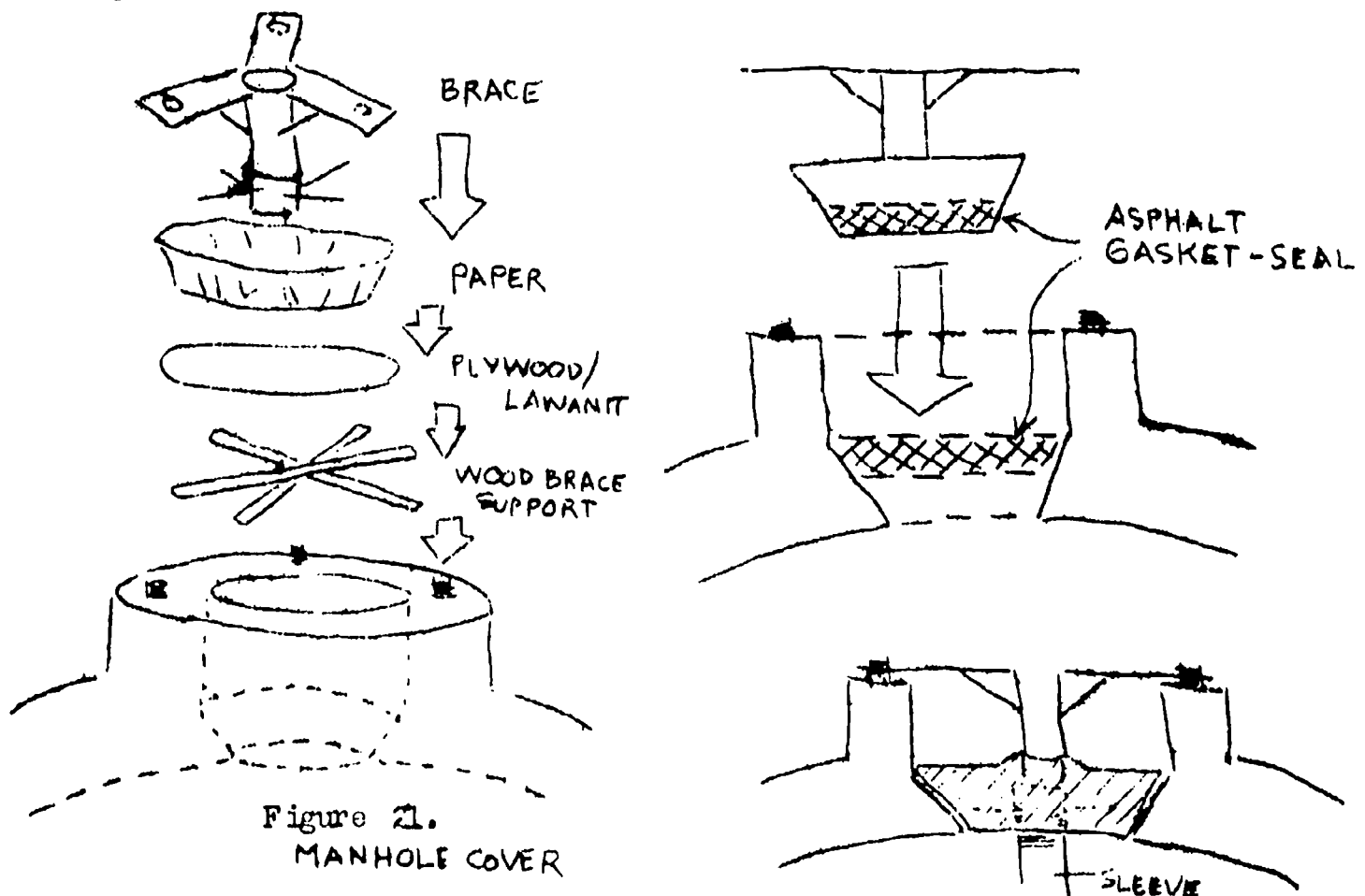


Figure 20. Stirrer

### 3.3.3 Removable Manhole Cover

As mentioned earlier, the size of a manhole cover is standard for all digester volumes. It is circular in shape, 65 centimeters in diameter and 12.5 centimeters thick. This thickness is sufficient to withstand the same pressures exerted on the sides and dome of the digester.

The removal of the manhole cover allows entry into the digester during cleaning, inspection and other maintenance activities. However, precaution must be observed when entering a digester which has been in operation for sometime. (The "Safety" precautions are discussed under topic on Maintenance and Operation.)



### 3.3.4 Gas Piping System Components

The piping system generally consists of four components, namely: gas line, consensation trap, flame arrester and manometer.

1) Gas line. There are two alternative types of materials used in the system:

- a) GI pipe is recommended especially for outside use and in situations where ultra-violet rays or sunlight is of high intensity. 1/2" diameter pipes are sufficient for most purposes. It is expensive but long lasting and may rust

badly if laid on acidic soils. In installation, the number of elbows and coupling should be minimized, where possible, since they are expensive.

- b) Flex tube, which is a heavy duty rubber hose with ply, is recommended in situations where turns/bends exist in the piping system and especially for indoor use. Ultra-violet rays deteriorates rubber tube quickly. Thus, when used outdoors, it should be protected from high sunlight exposure. 1/2" diameter pipes are generally used and which require 3/4" diameter rubber tubes for connections or elbows.
- 2) Condensation trap. Biogas contains moisture which "condenses" and must be removed. To solve this problem, the initial pipe leaving the digester should be sloped toward the digester so that the water will flow back automatically. If the pipe cannot be sloped, it is provided with a flex-piping joint so that it may be lifted up to occasionally drain the water back into the digester. The condensation water should be checked every month.
- 3) Flame arrester. This is a safety devise in case of accidental backfire flame returning to the digester and which may cause an explosion..

This devise is simply a ball or roll of fine copper wire mesh inserted in the gas line. Do not place it too tightly as it may block the gas flow. Two points are recommended for this device to be located: one close to the digester and the other near the manometer or point of gas use.

- 4) Manometer. It serves 2 purposes, namely: a) as an indicator of gas pressure, and it shows the relative amount of gas in storage within the biogas plant, and b) as a safety device which automatically controls the build-up of excessive high level of gas pressure within the biogas tank.

The manometer to be used is easy to make. It is a water column mechanism consisting of a piece of 1/2" diameter plastic tube nailed on a plywood in a U-shaped form. One end is connected to the gas line and the other is left open. The plastic tube is then filled half-way with water to the "0" level on the manometer. The water will rise and fall at the open-ended side of the tube depending on the pressure exerted by the gas on the water column. At zero pressure, the water levels in the 2 sides of the U-shaped tube are equal. Calibrations on the plywood will be made, starting at zero on the point coinciding with the level of the water at zero gas pressure.

As gas pressure continuously builds up, the gas pushes the water column until the water spills from the tube, thus releasing the gas.

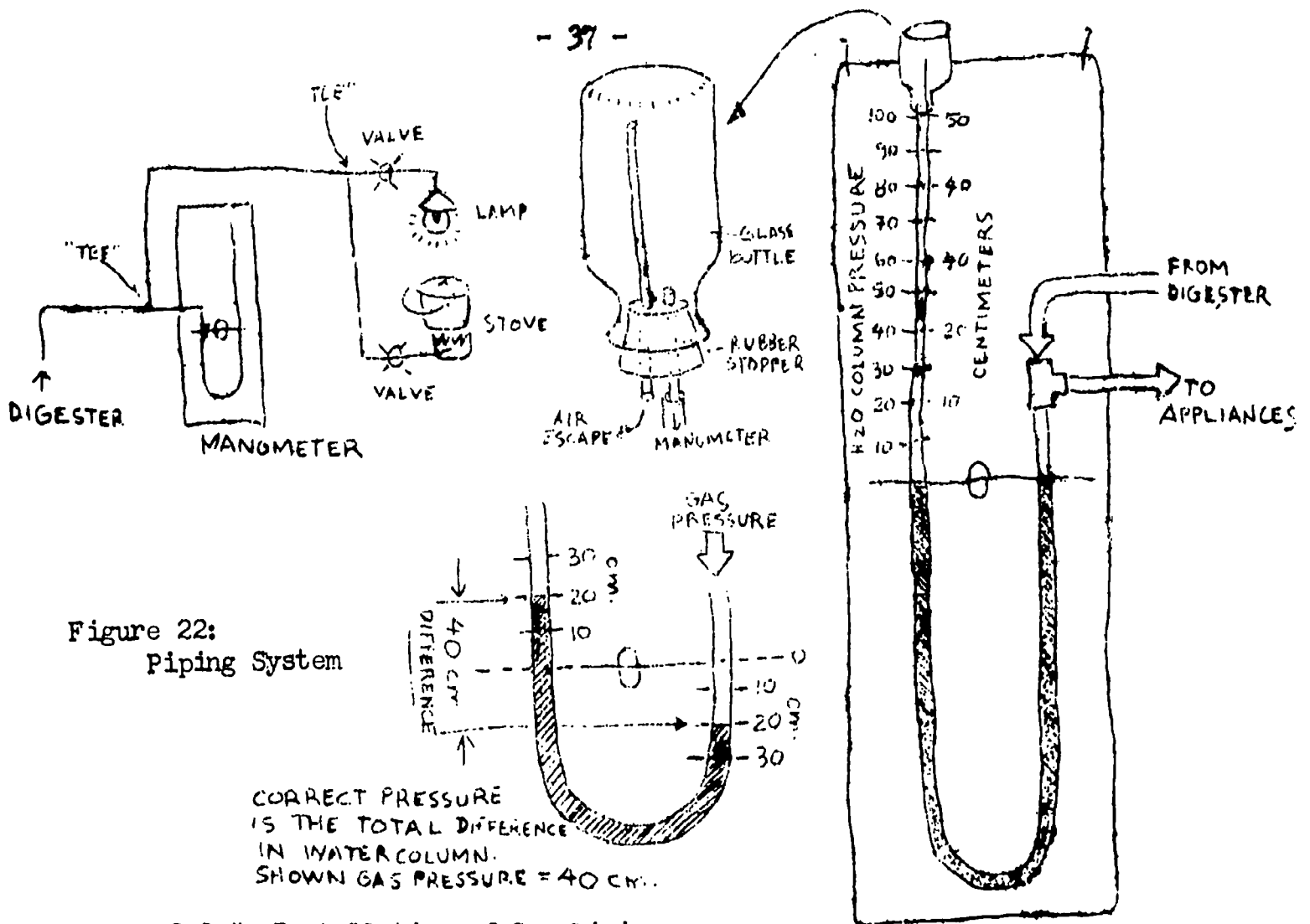


Figure 22:  
Piping System

### 3.3.5 Installation of Gas Piping

The following procedure is recommended to be observed in installing the gas piping:

- 1) Test if possible all hoses, valves and connections before installation. Submerge them in water tub and "blow" air (using bicycle pump, for instance) and see if any leaks or bubbles appear.
- 2) Study beforehand how the piping system will be fitted/installed. Prepare a rough plan indicating the valves, fittings, manometer and how the gas piping will flow from the digester to the stove.
- 3) The valves and manometer should be fitted securely to the wall at a visible location for easy monitoring.
- 4) Reduce the number of connections between valves, hoses and fittings to reduce chances of leaks.

### 3.3.6 Backfilling

Seven days after the whole unit is completed, backfilling may be done. Until then allow concrete dome to "cure" properly; otherwise the structure will be damaged by the backfill weight (For proper curing of concrete, refer to Appendix H.)



Ideally the mixture of the backfill should be 30% gravel or broken stones and 70% soil.

The backfill area should be well sloped to allow easy drainage of surface water. Water should not stand around the digester. A small trench may be provided so that water is easily drained.

Grass and plants but not trees, are recommended to be grown on the backfilled area.

### 3.3.7 Testing for Water Leakage

The digester must have to be finally tested for water tightness. To do this is fill the digester half with water and periodically measure the water level for several days. If water level drops, there is a leak somewhere in the tank.

When leaks occur, it is advisable to make a thorough check of the digester for any possible defective masonry work.

A large quantity of water is needed for this test. The procedure involved is as follows:

- 1) Fill the digester with water up to the inlet and outlet pipes level.
- 2) Let it set for 3-5 hours until the tank walls are saturated with water, mark the water level.
- 3) Let it set overnight. A significant drop in water level indicates leaks on the walls or the flooring.
- 4) When the water level no longer drops, a mark on the wall should again be made. This shows that the leak occurs between the first mark (Item 2) and this second mark.
- 5) Locate the source of leaks or any cracks. Use the wooden end of a hammer to lightly tap the area. If an empty or hollow sound is detected, the concrete should remove and redone.
- 6) Fill with water again and repeat test for water tightness.

### 3.3.8 Testing for Gas Leakage

This should follow the water tightness test. The steps are:

- 1) Close and seal the manhole as well as all the gas valves.
- 2) Begin to add water through the inlet to increase the air pressure inside the digester until the manometer registers 40

centimeters of water column. Or air may be blown into the digester up to the same pressure.

- 3) Leave the water in the digester for 24 hours.
- 4) If the drop in pressure is very small, say 1-2 centimeters, the digester is gas tight. But if the drop is noticeable, or more than 5 centimeters, the dome is not gas tight.
- 5) Be sure there are no leaks in the piping system. Repair the leaks accordingly.

Having insured the water and gas tightness of the digester, the unit is now ready for loading.

#### 4.0 OPERATION AND MAINTENANCE

Many biogas units have not produced as much gas as they should and many others have just gone out of use. A properly built structure and sufficiently available raw materials may not produce the desired results due to faulty operation and/or poor maintenance. The People's Republic of China, for instance, observed that generally success in biogas production is 30% due to structural or building process and 70% to proper operation and maintenance of the unit.

##### 4.1 Initial Loading

Proper initial loading contributes to the eventual good performance of the unit. There are a number of guides to keep in mind.

- 1) Starter/Seeding. The initial raw materials should contain slurry with a high bacteria population. This is the "starter". About 5-10% of the total slurry volume should be added when the digester is about 25% full.

Cattle dung is a good starter since cattle have methane producing bacteria in their stomachs. Starter can also be made from any manure by adding to it 5-10% "old" slurry obtained when cleaning the digester. Starter can be prepared by storing manure in a container while constructing the digester. At the time the digester is completed, the manure will reach a sufficient bacteria population.

- 2) Filling the Digester. The digester should be filled as quickly as possible. The following steps are involved in doing this:

- a) Before putting any slurry into the digester, be sure to first open all valves to relieve any built-up pressure in

the digester dome. It is advisable not to connect the piping system to the digester when loading.

- b) Mix manure and water thoroughly until there are no more "lumps" and the mixture will assume a "thick pea-soup" or "thick mungbean-soup" consistency. This will increase gas production since the bacteria will have more "surface" contact with the manure.
  - c) Fill up to the ring beam level, which is the same level as the outlet chamber floor. Check again to insure that there is not build-up of pressure at this time within the digester.
  - d) Do not add any new slurry to the digester until at least 3 days after burnable gas is produced.
- 3) Care should be taken that the following materials will not enter the digester:
- a) Earth or sand - - for it causes problem by hastening the accumulation of such materials within the digester. These materials should be allowed to "settle-out" while mixing the slurry in the mixing pit, before allowing them into the digester.
  - b) Straw, grasses, leaves, etc. - - since these materials will "float" on the surface of the slurry and cause "scum" problem which may consequently reduce gas production. Remove all floating materials at the mixing pit before allowing them into the digester.
  - c) Oil, soap, detergent, disinfectant, etc. - - these materials will disrupt bacteria activity or may even kill the bacteria.

#### 4.2 Mixing Slurry for Regular Loading

About 1 liter of water is usually added to every kilo of manure. As in the initial loading, the slurry should be mixed thoroughly until the right or "thick pea-soup" consistency is obtained. However, in actual practice, there is no fixed water-manure proportion since this will depend on the type of manure being used and its moisture content. The technique will be developed through experience. The material that should not get into the digester as previously mentioned should be strictly observed, sea water and brackish water with a high content of salts and impurities should not be used in the mixture.

#### 4.3 Regular Loading of Input Materials and Removal of Effluent from Outlet Chamber

The loading of materials should be done regularly. Ideally it should be daily. The amount of slurry should be in accordance with the requirement

of the particular digester volume and its retention time. Less slurry being loaded than what is required would result in poor gas production since the bacteria will be "starved"; likewise, excess slurry will result in raw material wastage since the slurry will not be able to be fully digested.

The loading of new slurry materials displaced an equal volume of effluent to the outlet chamber. This effluent must be removed. Otherwise the digester would be overloaded. One way to check correct digester level is that at zero gas pressure, the slurry should be at the level of the outlet chamber floor.

#### 4.4 Stirring/Agitation

Mechanically disturbing the slurry inside the digester with the use of the stirrer performs two vital functions: first, to stimulate bacterial activity; and second, to break the "scum" layer which forms a mat of vegetable/organic matter at the slurry surface and this restricts gas flow through the slurry to the gas holder. If left undisturbed, the scum would get thick and harden, which may require opening the digester to remove it.

Stirring should be done daily - - 3 minutes in the morning and 3 minutes in the afternoon. The stirring should be 360° in one direction, then 360° in the opposite direction.

#### 4.5 Condensate Removal

The condensate or water that settles in the piping system must be removed monthly since condensate accumulation may obstruct gas flow. This condensate removal may be done by lifting the gas pipe so that the water in the pipes will be drained back into the digester.

#### 4.6 Servicing Scum Problem

The steps in removing scum are as follows:

- 1) Release all gas within the digester. Manometer reading should be zero.
- 2) Disconnect gas piping closest to the digester.
- 3) Remove manhole.
- 4) Inspect the scum layer and check its thickness.
- 5) Remove scum manually with buckets through the manhole.

Caution: In removing the scum, be cautious about presence of fire nearby. Smoking near the digester is dangerous. The digester still contains gas and may explode!

#### 4.7 Periodic Cleaning of the Digester

The digester may need to be emptied at intervals to remove the settled sludge and other inorganic solids, like sands and stones that accumulate at the bottom of the digester. The materials are removed manually through the manhole, with the use of buckets or pumps. This is also an occasion to check for any possible leaks and structural damages.

Take necessary precautions when entering a digester. There are poisonous gases inside.

Apart from the regular schedule, complete emptying of the digester should be done if the following conditions occur:

- 1) Stirring becomes too difficult due to heavy accumulation of inorganic solids (sand, pebbles, etc.) and/or the presence of thick scum.
- 2) Gas production ceases completely. This may be due to the introduction of toxins (detergents or disinfectants) into the slurry.
- 3) Gas production slows down despite regular daily loading and stirring. There may be leaks in the structure.

#### 4.8 Repairing Masonry Work Within the Digester

Due to a variety of causes, a need to repair the digester may arise. If the damage is serious, the wall or a whole section may have to be rebuilt. But normally, the damage is only in the form of cracks or leaks and repair work would be much easier.

The technique for locating a damaged area was discussed earlier ~~pp. 38-39~~. Repairing the damaged area involves the following procedures:

- 1) Clean the damaged portion. Inspect and determine extent of damage.
- 2) Carefully chisel a wide "V"-shaped groove. Roughen the edges.
- 3) Attach 2-3 layers of chicken wire to the wall with nails at least 30 centimeters from either side of the crack. (See illustration below.)
- 4) Apply cement-water paste to the entire area. This is to insure good adhesion.
- 5) Plaster cement-sand (1:3) mortar at least 13 millimeters thick. Roughen the finish.
- 6) Allow to dry for at least 2 weeks. Inspect.
- 7) Apply wax/paraffin seal.

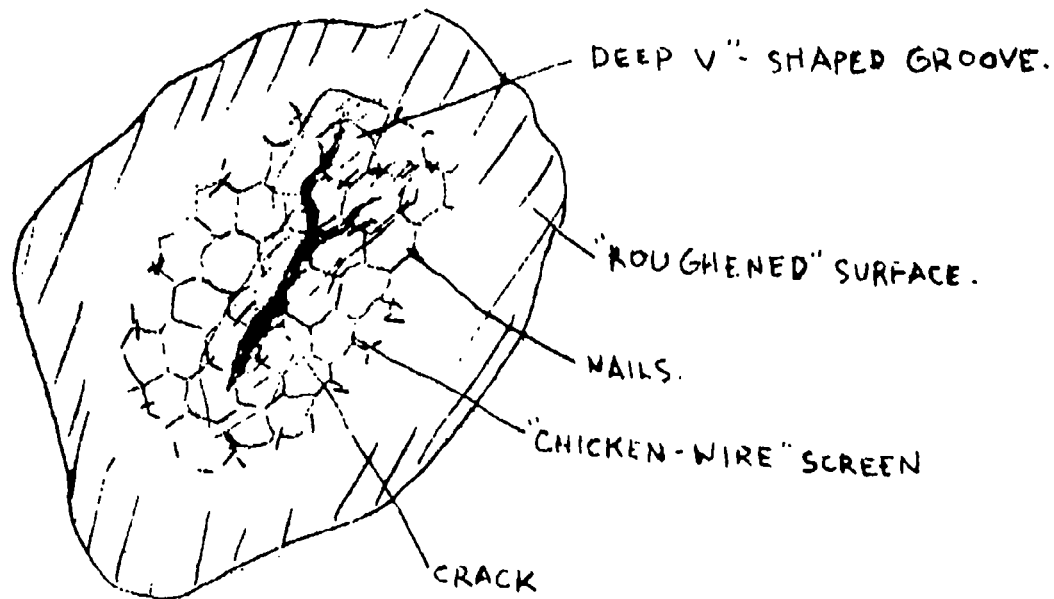


Figure 23. REPAIRING "CRACKS" IN MASONRY WORK  
"CHICKEN-WIRE" REINFORCING.

#### 4.9 Entering The Digester

The following should be observed when planning to enter, or upon entering, the digester which has been in use for some time:

- 1) Remove manhole cover for several days.
- 2) Disconnect gas line closest to the digester.
- 3) Remove contents of the digester through the manhole with buckets or a pump.
- 4) Ventilate the empty tank. A completely empty digester is likely to have carbon dioxide gas "lying" at the bottom. The gas should be removed either by "blowing-out" with fresh air or "lifted-up" by buckets. Allowing wind to recirculate within the digester with the use of air pump is advisable.
- 5) Before anyone enters the digester, it is best to check presence of harmful gases or of sufficient air, with a small animal (e.g. chicken, rabbits, etc.). This is a simple method used in the People's Republic of China. The animal is lowered in a small cage into the digester and brought up after a few minutes. If the animal behaves normally, this indicates that entering the digester does not pose any danger. If something unusual happens to the animal, like fainting for instance, it indicates lack of sufficient air circulation or ventilation inside the digester. Repeat test until satisfactory. One must always enter the tank with caution.

- 6) Use only flashlights inside the digester. No smoking or open flames (candles, lanterns, etc.) near or within the digester.
- 7) Prepare a long piece of pipe or hose (one end attached outside of the pit) through which the worker inside the pit may breath. Also it is advisable to have a second person to pull him out if he accidentally loses consciousness. Any feeling of dizziness or discomfort in breathing is enough warning for the person to get out of the digester. He should rest and take fresh air. It is not advisable for one person alone to do the work. Someone should be constantly watching from the outside of the pit who can respond to any emergency. A safety line should be attached to the worker inside.

#### 4.10 Gas Utilization

It must be pointed out again that biogas is a clean fuel -- non-toxic, odorless and smokeless. It has a blue flame. Chemically, biogas contains 60-70% methane ( $\text{CH}_4$ ), 30-35% carbon dioxide ( $\text{CO}_2$ ) and less than 1% other trace gases, particularly, hydrogen sulfide ( $\text{H}_2\text{S}$ ), hydrogen ( $\text{H}_2$ ), carbon monoxide ( $\text{CO}$ ), and nitrogen ( $\text{N}_2$ ).

In the rural areas the two most potential uses of biogas are for cooking and lighting, and also running kerosene-fed refrigerators.

The efficiency of gas use is largely determined by a suitable mixture of gas and air that enter the appliance and in turn is dependent on the following factors:

- 1) Pressure. The Chinese biogas digester unit generates variable pressure, thus there may be a need for frequent adjustment. Gas pressures above 20-centimeter water column give satisfactory results. This is adequate to force gas and air into the appliance. At pressures less than 20-centimeter water column, gas-air mixture may not reach the appliance. In this case, there is a need to adjust the "mouthpiece" further into the appliance, and re-adjust as gas pressure increases again. Remember that if the mouthpiece is too far from the appliance, there will be lack of air to the mixture.
- 2) Efficiency of the appliances used. A gas efficient-appliance should have the following basic features:
  - a) Inlet channel should be smooth to reduce resistance of the gas-air flow.
  - b) Spacing and size of air holes should be proper.
  - c) Volume of gas-air mixing channel should be large enough for complete mixing.

- d) Gas jet holes should not be too large nor too small but just large enough to allow for easy passage of mixed gas and air.
- e) Appliance should be simple, economical, and cheap to make or purchase, but at the same time be durable.

In using a stove, it would be helpful to observe the following:

- 1) A good flame is a pale blue in color, strong and even, and also produces a "hissing" sound.
- 2) If the flame shifts around or is unsteady, it may due to either insufficient air, or too large holes in the gas-feed tube. Adjustment is necessary.
- 3) If the flame has a red or yellow tint, this may mean either that there is too much air or gas intake or that the gas-feed tube needs to be enlarged.

In using the gas for lamps or lighting, the following are important guides:

- 1) First use the lamp without a mantle. Check if the flame is pointed down, pale blue in color, and burning evenly with a "hissing" sound. If so, the lamp is good and the mantle may now be attached.
- 2) Use denatured alcohol to soak and ignite the mantle. Leave the gas petcock off until all the alcohol has burned off. This provides the mantle to be "white".
- 3) Now light the lamp. If the flame wanders, this indicates either of two things: there is insufficient air and the gas tube has to be raised; or the gas-feed tube is too large which has to be changed to a smaller one.
- 4) If the flame is reddish, it either means there is not enough gas or there is too much air. Push the gas-feed tube further into the lamp, or make the gas-feed tube hole larger, or it may be due to mantle quality, or may be due to a high CO<sub>2</sub> content of the gas. Frequent adjustment and experiment are needed until the desired results are produced.

For making your own lamp, see Appendix K.)

#### 4.11 Biofertilizer (or Effluent) Utilization

As mentioned in the introductory part of this manual, the other two benefits from biogas production are efficient disposal of wastes and the generation of organic fertilizers after the wastes have been acted upon by bacteria within the digester.



It is estimated that 70 percent of the total solids put into the digester comes out as effluent or fertilizer material. This contains almost the same nutrients that were initially put in, but through the decomposition process the nitrogen and other elements are retained and in the form that is more readily available to plants. It is unlike composting, or letting the manure decompose in the open, where most of the nutrients are lost by leaching and volatilization.

The importance of organic fertilizers cannot be overemphasized. They provide vital functions in improving the fertility and productive capability of the soil particularly in terms of increasing its humus content, microbial activity, porosity and water-holding capacity. Furthermore, effluent fertilizer retains its fertility residual effect in the soil for about 3 years compared to that of chemical fertilizers which is about one year.

On the health and environmental sanitation aspects, the effluent is considerably "freer" from disease-carrying organisms than is fresh manure. Most of the bacteria and other pathogens are killed in the process of digestion, primarily due to the absence of oxygen, presence of ammonia and other conditions that exist inside the digester. Furthermore, dilution of the manure with water results in settling of worms and eggs to the bottom of the tank. The design of the Chinese biogas unit is such that the inlet/outlet pipes are half-way up the wall to insure that most of these parasites are not discharged until sufficient time has elapsed for their destruction.

Extensive research in the People's Republic of China have shown the effectiveness of biogas digesters in treating manure. <sup>2/</sup> Comparison of fecal liquid introduced into biogas units with that of the effluent showed that the number of parasite eggs was reduced by 93.6% and hookworm by 99%, while shistosomiasis v flukes disappeared and the number of dead ascaries was high. Eggs of parasites can survive in a biogas tank for 14 days in autumn and 36 days in winter. Ninety percent of hookworm eggs died within 30 days in winter and 99% filariasis parasites died during the same length of time in summer. Experiments on bacterial viability showed that E. Coli index was reduced, the shigeella v hucellus and the spirochetes, which oxygen-needing bacteria, died.

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<sup>2/</sup> FAO Soils Bulletin No. 40, "China: Recycling of Organic Wastes in Agriculture;" FAO/UNDP, Rome 1977, and FAO Soils Bulletin No. 41, "Azolla Preparation and Small-scale Biogas Technology", FAO/UNDP, Rome 1978.

#### 4.12 Troubleshooting: Common Operational Problems And Their Remedies

<u>Defects/Symptoms</u>	<u>Possible Causes</u>	<u>Remedies</u>
<u>Initial Loading Problems:</u>		
1) Pressure does not rise	a) Very few bacteria	<ul style="list-style-type: none"><li>- Have patience, wait for sometime</li><li>- Introduce "starter" slurry (approx. 20 liters)</li><li>- Stir/mix contents</li></ul>
	b) Lack of time	<ul style="list-style-type: none"><li>- Have patience (without "starter" and colder temperatures, it would take 2-3 weeks for gas to appear)</li></ul>
	c) Leak in digester or gas pipeline	<ul style="list-style-type: none"><li>- Locate leaks and repair</li></ul>
	d) Gas leaks at slope valves	<ul style="list-style-type: none"><li>- Locate leaks and close valves</li></ul>
2) First gas produced does not burn	a) Wrong kind of gas	<ul style="list-style-type: none"><li>- Gas should be released. It may not burn since it contains the initial air in the gas storage area.</li></ul>
	b) Air in the gas line	<ul style="list-style-type: none"><li>- The air should be released until there is definite smell of biogas</li></ul>
	c) Feeding in fresh slurry while waiting for gas pressure to rise	<ul style="list-style-type: none"><li>- This is a common fault. No slurry should be fed into the digester until the third day after burnable gas has been produced.</li></ul>

<u>Defects/Symptoms</u>	<u>Possible Causes</u>	<u>Remedies</u>
3) Gas pressure goes	a) Gas valve for stove or lamp is open	- Close valves.
	b) Major leak in digester or gas line	- Locate leak and repair
4) Gas pressure rises very slowly	a) Temperature is too low	- It is normal; gas produced is always reduced during colder weather.
	b) Thick "scum" builds up in the digester	- Stir/mix two times daily. If serious, may need to remove scum manually through the manhole.
	c) Too much or too little slurry put in daily.	- Correct amount should be "charged" daily/regularly. This should correct itself in a few weeks.
	d) Putting toxic substances (e.g. soaps, chemicals, etc.) into the slurry.	- The toxic substances may have killed the bacteria and stopped gas production. If no gas in 3 weeks and bad odor of slurry is observed, clean out digester and refill.
	e) Gas leakage	- Locate leaks and repair
	f) Slurry is too thick or too thin within the digester.	- Correct the slurry consistency. This should correct itself in a few weeks.

#### Stoves:

5) Gas will not burn	a) Air in gas pipe	- Allow some gas to escape until a definite smell of biogas appears.
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<u>Defects/Symptoms</u>	<u>Possible Causes</u>	<u>Remedies</u>
	b) Wrong kind of gas (probably CO <sub>2</sub> )	<ul style="list-style-type: none"> <li>- Allow gas to escape until "0" manometer pressure. Wait until the unit corrects itself.</li> <li>- Wait for enough time for gas to be produced.</li> </ul>
6) Flames are long and weak, or start far from flame ports, or does not stay lit.	a) Incorrect air supply b) Excessive gas pressure	<ul style="list-style-type: none"> <li>- Place pot in stove and adjust air/fuel mixture of stove.</li> <li>- Adjust and reduce pressure at stove valve.</li> </ul>
7) Small flame	a) Insufficient gas pressure b) Gas jets partially blocked c) Gas line blocked with foreign matter	<ul style="list-style-type: none"> <li>- Flexible plastic piping gone flat at some places. Locate and repair.</li> <li>- Clean out jets of stove.</li> <li>- Locate blockage and remove foreign materials.</li> </ul>
8) Flame pulsates	a) Condensation of water in pipeline	<ul style="list-style-type: none"> <li>- Remove or allow condensation water to flow back into the digester.</li> <li>-</li> </ul>
9) No gas at stove	a) Main gas valve closed b) Condensation water completely blocked gas line c) Stove gas jet blocked	<ul style="list-style-type: none"> <li>- Open main gas valve.</li> <li>- Remove condensation water as described earlier.</li> <li>- Clean gas jet.</li> </ul>

<u>Defects/Symptoms</u>	<u>Possible Causes</u>	<u>Remedies</u>
<u>Lamps:</u>		
10) Light is poor	a) Air/fuel regulator need adjustment	- Adjust accordingly
	b) Gas pressure is too low	- 20 cm. manometer pressure is sufficient.
11) Mantle breaks frequently	a) Gas pressure is too high	- Jet nozzle is too close to the diffuser. Set jet nozzle further from the diffuser.
	b) Wrong type of mantle	- Use correct type of mantle.
	c) Flying insects	- Provide appropriate type of cover/protector for the mantle, like glass or screen.
12) No gas at lamp	a) Lamp gas jet is blocked	- Gas regulator should be cleared. Inspect and clean.
<u>Slurry Inlet/Outlet:</u>		
13) Slurry does not flow into the digester	a) Inlet pipe blocked	- Clear inlet pipe by moving a long pole up and down until the pipe is cleared.
14) Slurry level at outlet is very high, but "0" pressure at manometer	a) Too much slurry in the digester	- Remove slurry from outlet and correct slurry level.
15) Excessive high pressure but low effluent level in outlet chamber	a) Outlet pipe blocked	- Clear outlet pipe by moving a long pole up and down until the pipe is cleared.
	b) Slurry too thick	- Adjust to correct slurry consistency.

<u>Defects/Symptoms</u>	<u>Possible Causes</u>	<u>Remedies</u>
<u>Manometer:</u>		
16) Manometer pressure is high but when valve is opened, manometer pressure drops immediately. Closing the valve manometer pressure returns to high pressure. Flame is weak.	a) Blocks in gas outlet or gas line, creating gas flow problems.	- Inspect gas outlet and gas line. Clear lines of any blockage or water.
17) When gas valve is opened, manometer water level fluctuates continuously. Flame is alternately strong and weak.	a) Water condensate in gas line. Gas flow is not steady.	- Remove water condensate in gas line.
18) When gas valve is closed, manometer level fluctuates continuously.	a) Leaks and/or presence of water condensate in gas line.	- Repair the leaking section; remove water condensate in gas line.
19) Manometer pressure rises rapidly when pressure is low, but rate of increase drops as pressure rises. And upon reaching a certain pressure, no further change occurs.	a) Rate of gas leakage is directly proportional to gas pressure, the higher the gas pressure, the greater the gas leakage.	- Inspect the gas section of the digester and repair the leaking area.
20) Gas production started normally, but the manometer pressure begins to drop or does not rise at all.	a) Leaks at gas line, at the manhole, at the dome, and/or on the digester wall.  b) Insufficient raw materials for fermentation; hence gas production is low.	- Inspect the gas line, manhole and dome for leaks. If none at these places, inspect the inside of the digester. Make appropriate repairs.  - Add fresh raw materials for fermentation on a scheduled basis and at proper level.

<u>Defects/Symptoms</u>	<u>Possible Causes</u>	<u>Remedies</u>
	c) Toxins introduced into the digester that killed the bacteria, and therefore stopped gas production.	- Take a sample of slurry in a glass jar. Observe after 24 hours. If no bubbles are visible, then the bacteria has died. Clean the digester completely and refill.
21) Manometer gas pressure	a) Blockage at inlet/outlet pipes, resulting in no flow of slurry and in turn leaving no gas space available.	- Clear inlet/outlet pipes using a long pole. Slurry consistency may be inspected and corrected.

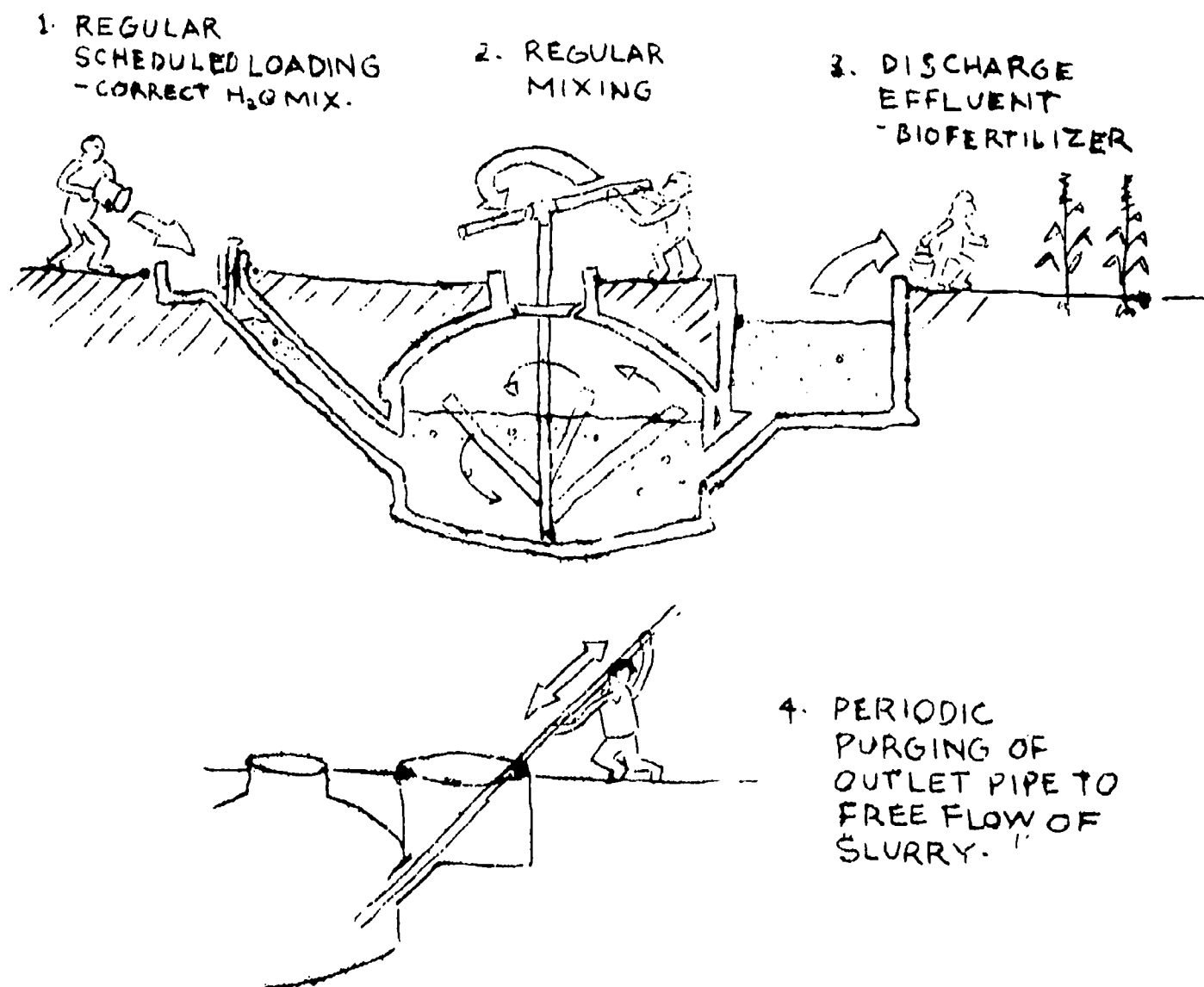


Figure 23. Operation and Maintenance of a Digester

## Appendix A

### THE BIOGAS PROCESS: A BRIEF INTRODUCTION

Biogas production is the process of decomposing organic materials (animals and plants) by bacteria under anaerobic conditions or in the absence of oxygen. The biogas thus generated is a mixture of 60-70% methane ( $\text{CH}_4$ ), 30-35% carbon dioxide ( $\text{CO}_2$ ) and the remaining consists of hydrogen sulfide ( $\text{H}_2\text{S}$ ), hydrogen gas ( $\text{H}_2$ ), nitrogen gas ( $\text{N}_2$ ), carbon monoxide ( $\text{CO}$ ), and other gases.

It is the methane content of the biogas that is flammable and is an excellent source of fuel. Carbon dioxide does not burn.

The production of biogas is naturally occurring around us, in ponds for instance where organic materials and bacteria are present under suitable conditions (i.e. anaerobic conditions, pH, etc.). But in nature the gas generated is simply lost to the atmosphere.

Hence the need to construct a biogas digester which enables us to control and accelerate the process and capture the valuable gas.

And we not only derive gas from a biogas digester, but also organic fertilizer/soil conditioner from what remains of the materials after being digested by the bacteria. In addition, the digestion process provides an excellent disposal system since it destroys disease carrying pathogens and parasites so commonly associated with decomposing organic materials.

In operation, the digester is full of slurry, which is a mixture of manure and water. Fresh slurry is prepared daily in the mixing pit and then fed into the digester. Likewise, an equal volume of effluent (or digested slurry) is taken out from the digester through the outlet pit, which may be "stored" in a nearby pit for eventual fertilizer use. The gas produced is collected in the gas chamber or dome portion of the digester and is directly conveyed via pipes to the house for use. This is how a digester essentially functions.

Inside the digester are millions of bacteria, which "digest" the slurry and in the process producing biogas and leaving a residue of organic matter and water. The biogas "bubbles" force their way through the slurry and gas begins to accumulate inside the gas-storage dome until it is to be used.

Basically, the digestion of organic wastes may be separated into two distinct processes, each process being carried by a specific group of bacteria.

The first group is the acid-forming bacteria which break down complex organic compounds into simple organic acids (primarily acetic acid and propionic acid). Other by-products of this process are ammonia and carbon dioxide. These bacteria are not very sensitive to their environment (i.e. temperature, pH, presence of  $\text{O}_2$ , etc.) and reproduce rapidly.



## Appendix A (Cont.)

Under average Philippine climatic conditions, the retention time is about 40 days. Given the digester (slurry) volume, the daily input is accordingly determined.

(See Appendix for relationship between temperature and retention time.)

- 3) pH or Degree of Acidity or Alkalinity of the Slurry. Methane forming bacteria are sensitive to pH conditions and changes. Their optimum range is between pH 6.8-7.2 although they may tolerate a pH level of 6.5-8.0.

Under acidic condition, the methane producing bacteria cannot consume all of the acids being produced by the acid-forming bacteria and may stop digestion. To remedy this, add lime, grass ashes and wait.

If alkaline, the acidic carbon dioxide produced during digestion will correct the condition overtime. Have patience and wait.

To determine whether the slurry is acidic or alkaline, a Litmus paper test is being used. Since the pH (litmus) paper only shows extreme changes in pH levels, this test is used only when gas production has ceased and the probable cause is due to pH problems.

- 4) Carbon-Nitrogen (C:N) Ratio. Bacteria need both carbon and nitrogen to survive. They consume carbon about 25-35 times faster than they consume nitrogen. Thus, proper digestion proceeds at an optimum rate when the carbon content of the slurry or input materials used is about 30 times the nitrogen content (or C:N Ratio = 30:1), all other things being favorable.

The common sources of carbon are leaves, grasses and raw materials rich in cellulose. Those of nitrogen are manure and urine.

Check specific raw input materials value for approximate C:N ratio guide. (See Appendix for C:N ratio guide.)

- 5) Kind of Raw Materials Used. As mentioned earlier, toxic substances added to the manure and other input materials will affect bacterial activity and at high concentrations, toxic substances may kill all bacteria within the digester. Extreme care should be taken to insure that materials with disinfectants, detergents and other chemicals are not allowed to enter the digester.

## Appendix A (Cont.)

The second group is the methane forming bacteria which further break down the simple organic acids, mainly acetic and propionic acids, into methane and carbon dioxide (or biogas). They are very sensitive to their environment and reproduce very slowly.

In a properly operating digester, these two groups of bacteria live together in balance. The acid-formers "provide food" for the methane-formers which in turn further convert it to produce biogas. But the balance may be disrupted when the acid-formers increase in activity, resulting in creating an acid condition which does inhibit gas production.

In other words, we are "culturing" within a biogas digester a population of bacteria and providing them proper food and suitable environment so they will effectively supply us with valuable by-products.

The major factors which stimulate gas production are temperature, retention time, pH (or hydrogen ion concentration), carbon-nitrogen ratio, and the "kind" of raw materials used. Note that these factors are directly related to the biogas fermentation process or to the creating of a suitable environment for the methane-producing bacteria within the digester.

- 1) Temperature. Generally, higher temperatures and less fluctuations in temperature are conducive to higher level of microbiological action. The temperature range at which normal anaerobic fermentation takes place is 18° - 32°C, reaching an optimal level of activity at 35°C. At 10°C bacterial activity ceases, and thus gas production stops. Wide changes or fluctuations in temperature are harmful to the anaerobic bacteria.

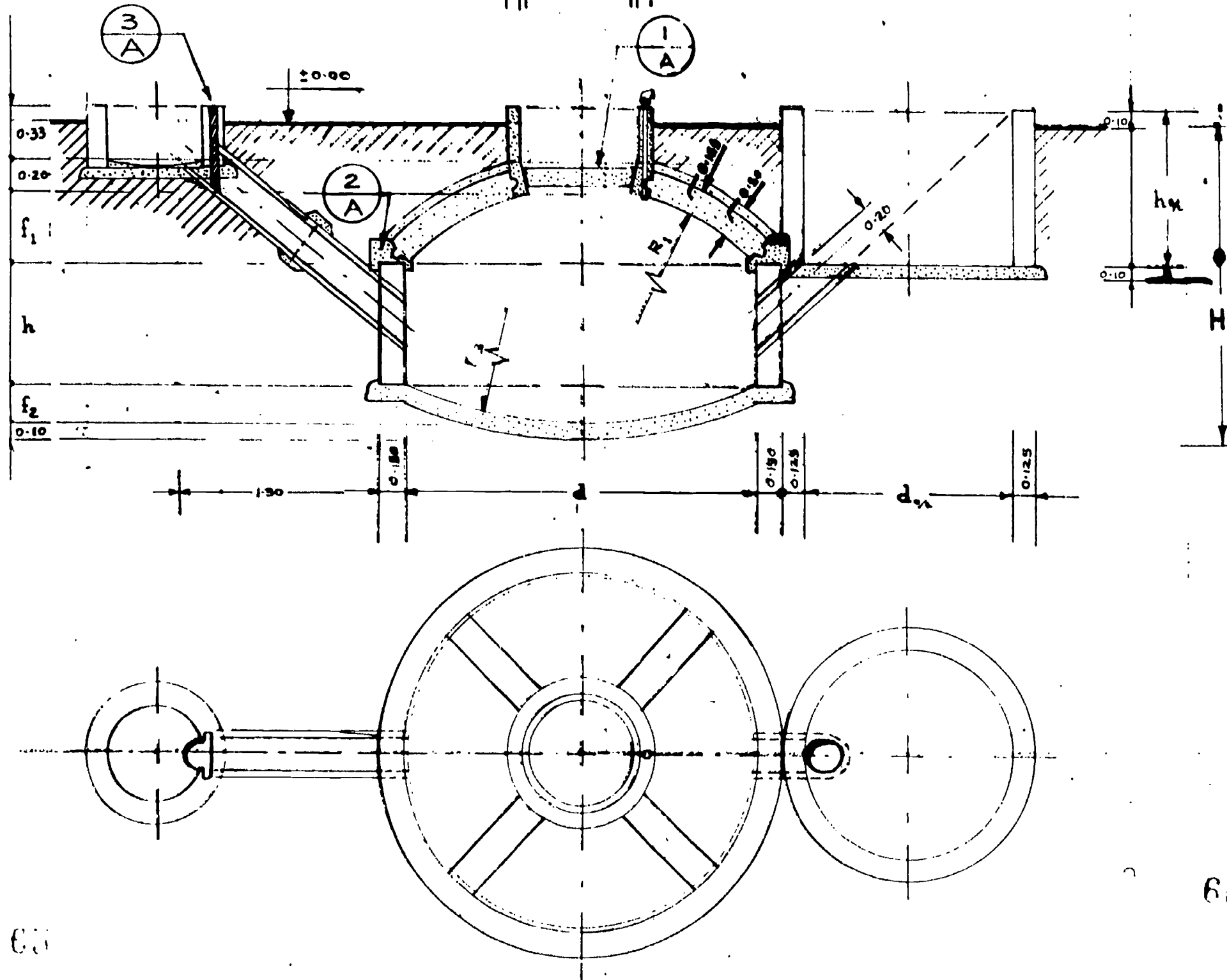
It is primarily for the reason that the Chinese design is completely underground in order to minimize the adverse effects of fluctuations in ambient temperature.

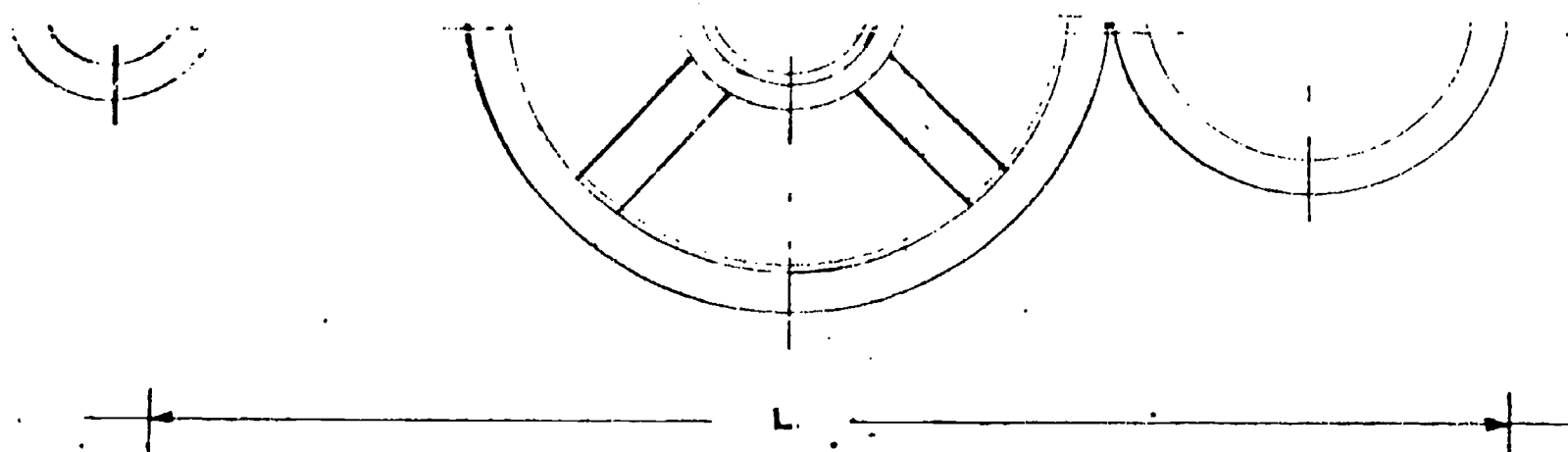
- 2) Retention time. Retention time is the theoretical time that one daily sample of input material remains in the digester before it is expelled. Temperature is directly related to retention time; the higher the temperature, the shorter is the retention time. This is an important relationship to be observed in the operation of a biogas unit in that the volume of slurry input should be such that sufficient time is given for the bacteria to digest the material before it leaves the digester.

Theoretically, retention time equals volume of digester divided by daily input, thus:

$$RT \text{ (in days)} = \frac{\text{digester (slurry) volume}}{\text{daily input volume}}$$

$$\text{or, Digester (slurry) volume} = RT \times \text{daily input.}$$





MEASUREMENTS IN METERS !!!

m <sup>3</sup>	L	H	d	h	f <sub>1</sub>	f <sub>2</sub>	R <sub>1</sub>	R <sub>2</sub>	d <sub>o/L</sub>	h <sub>o/L</sub>	V <sub>1</sub>	V <sub>2</sub>	V <sub>3</sub>
4.66	5.5	2.17	2.3	0.766	0.46	0.23	1.55	2.8	1.35	0.98	1.08	3.18	0.45
6.14	5.8	2.32	2.5	0.83	0.52	0.25	1.9	3.2	1.45	1.04	1.46	4.07	0.61
8.66	6.3	2.56	2.7	0.9	0.6	0.34	2.0	3.6	1.65	1.12	2.03	5.72	0.91
10.27	6.75	2.62	3.0	1.0	0.6	0.3	2.2	4.1	1.9	1.12	2.15	7.0	1.12
15	7.45	2.97	3.5	1.2	0.7	0.35	2.5	4.7	2.0	1.22	3.5	9.6	1.74

# CHINESE BIOGAS DIGESTER

## PLAN AND SECTION VIEW

- POURED REINFORCED-CONCRETE TYPE DOME

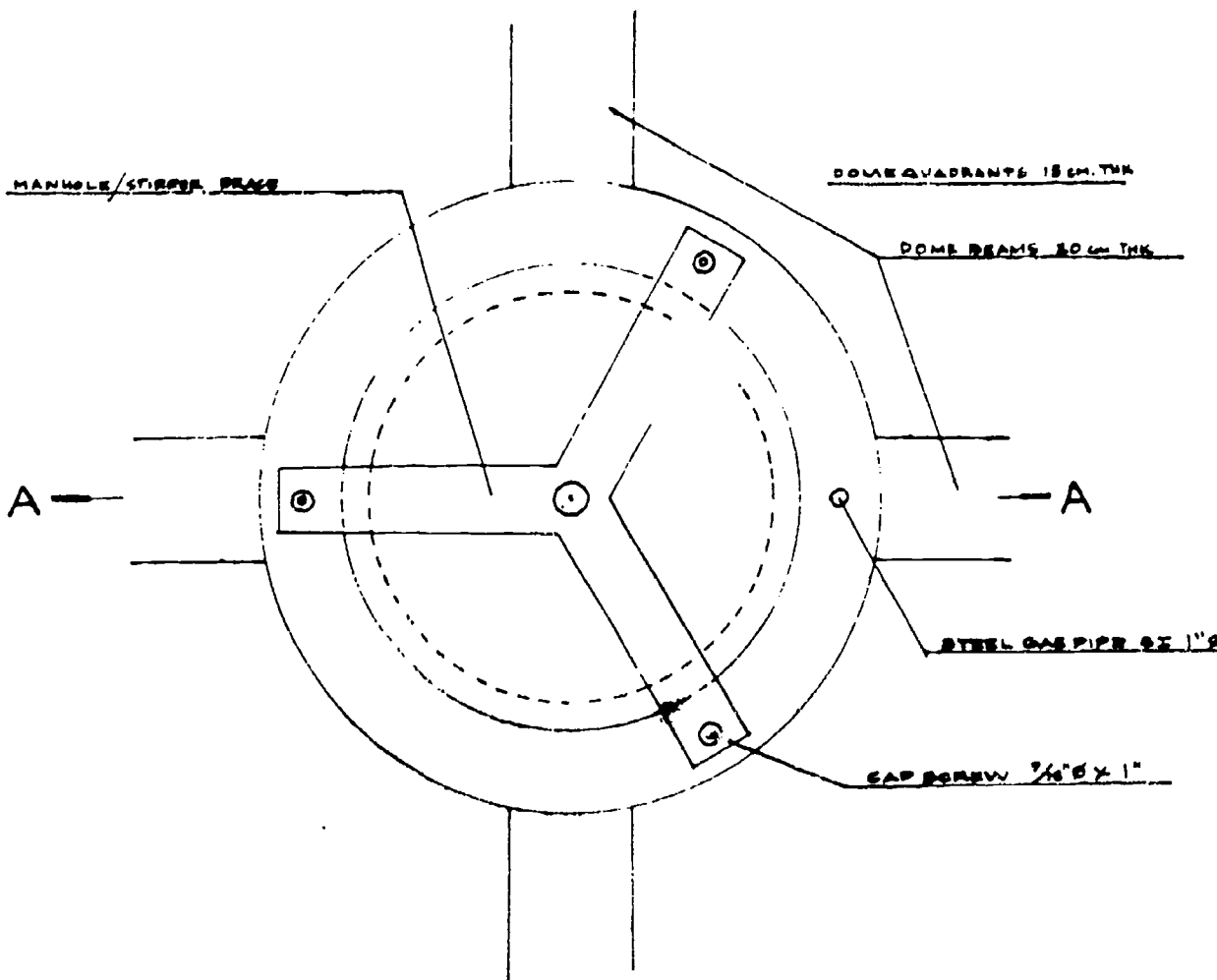
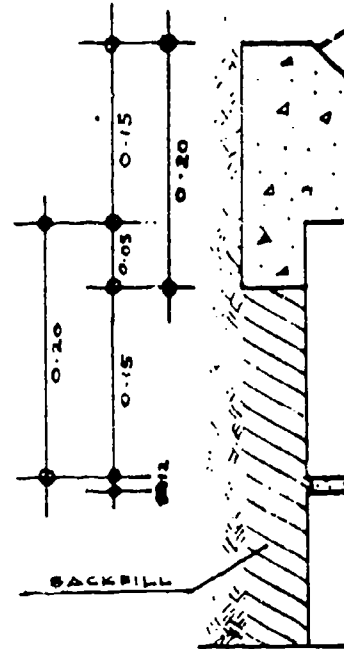
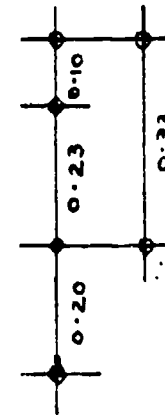
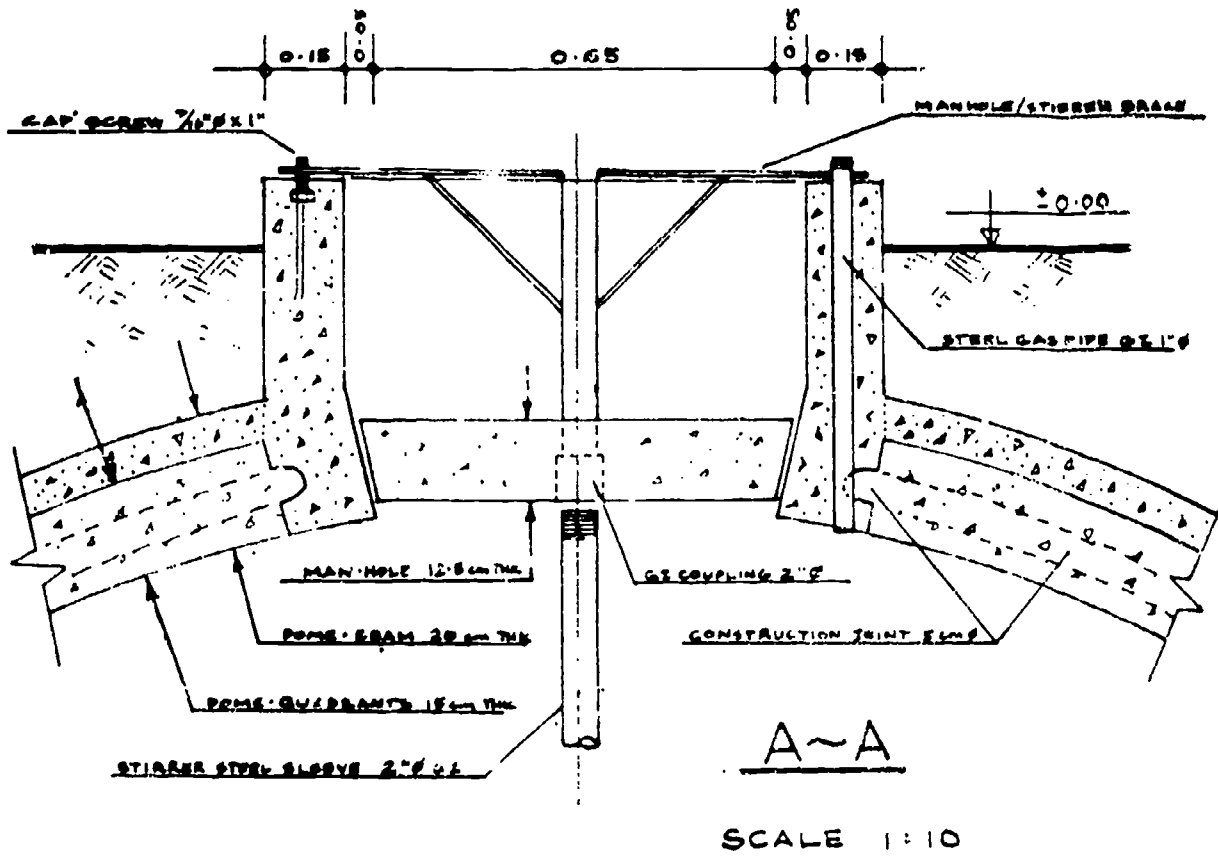
- DESIGN BY CHARLES H. NAKAGAWA, U.S. PEACE CORPS / PHILIPPINES;  
PHILIPPINE RURAL RECONSTRUCTION MOVEMENT (P.R.R.M.)

CODE NO.

1 / 4

DESIGN NO.

JULY 1981



## NOTES :

1. REINFORCEMENT
2. FURTHER DETAILS IN
3. CONSTRUCTION-JOINT DOME-BEAMS AND CONJUNCTIONS
4. CONCRETE HOLLOW SHOWN HERE ARE 4 m<sup>3</sup> AND 6 m<sup>3</sup> . U

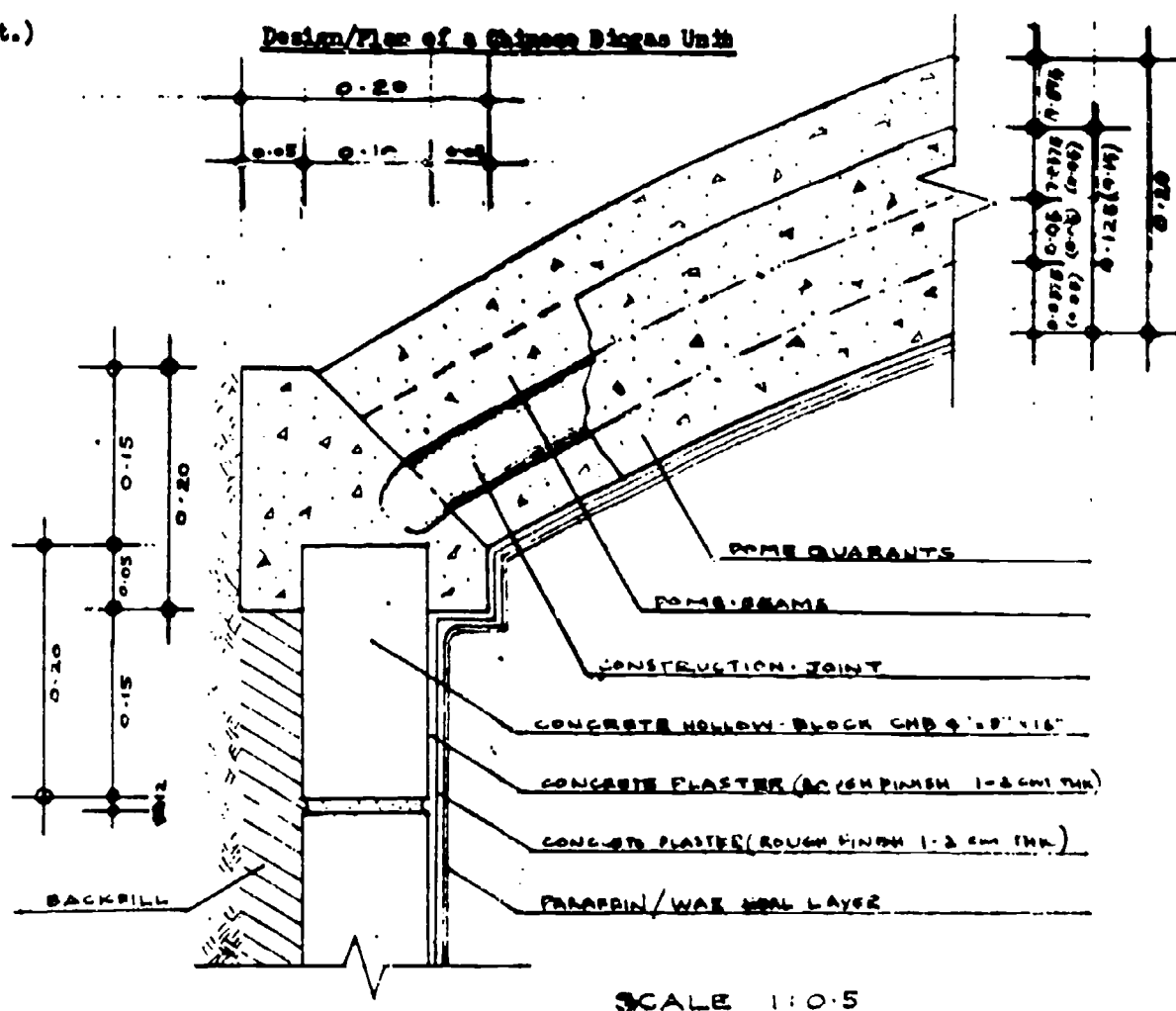
- ALL MEASUREMENT

## CHINESE BIC

DETAILS OF SECTION  
- MAN-HOLE  
- RING-BEAM

7 (Cont.)

Design/Plan of a Chinese Biogas Unit



## NOTES :

1. REINFORCEMENT IRON BARS NOT SHOWN HERE.
  2. FURTHER DETAILS OF STIRRER/MIXER ASSEMBLY SHOWN IN
  3. CONSTRUCTION-JOINTS ARE MADE ON THE RING-BEAM, DOME-BEAMS AND THE MAN-HOLE SLEEVE. AT ALL CONJUNCTIONS OF THE DOME-QUADRANTS.
  4. CONCRETE HOLLOW-BLOCKS FOR WALL CONSTRUCTION SHOWN HERE ARE C.H.B. 4"x8"x16". THIS IS ONLY FOR 4 m<sup>3</sup> AND 6 m<sup>3</sup>. USE C.H.B. 6"x8"x16" FOR 8 m<sup>3</sup>, 10 m<sup>3</sup> AND 15 m<sup>3</sup>.
- ALL MEASUREMENTS IN METERS (UNLESS STATED OTHERWISE)!!!

## CHINESE BIOGAS DIGESTER

DETAILS OF SECTIONS AND CONJUNCTIONS

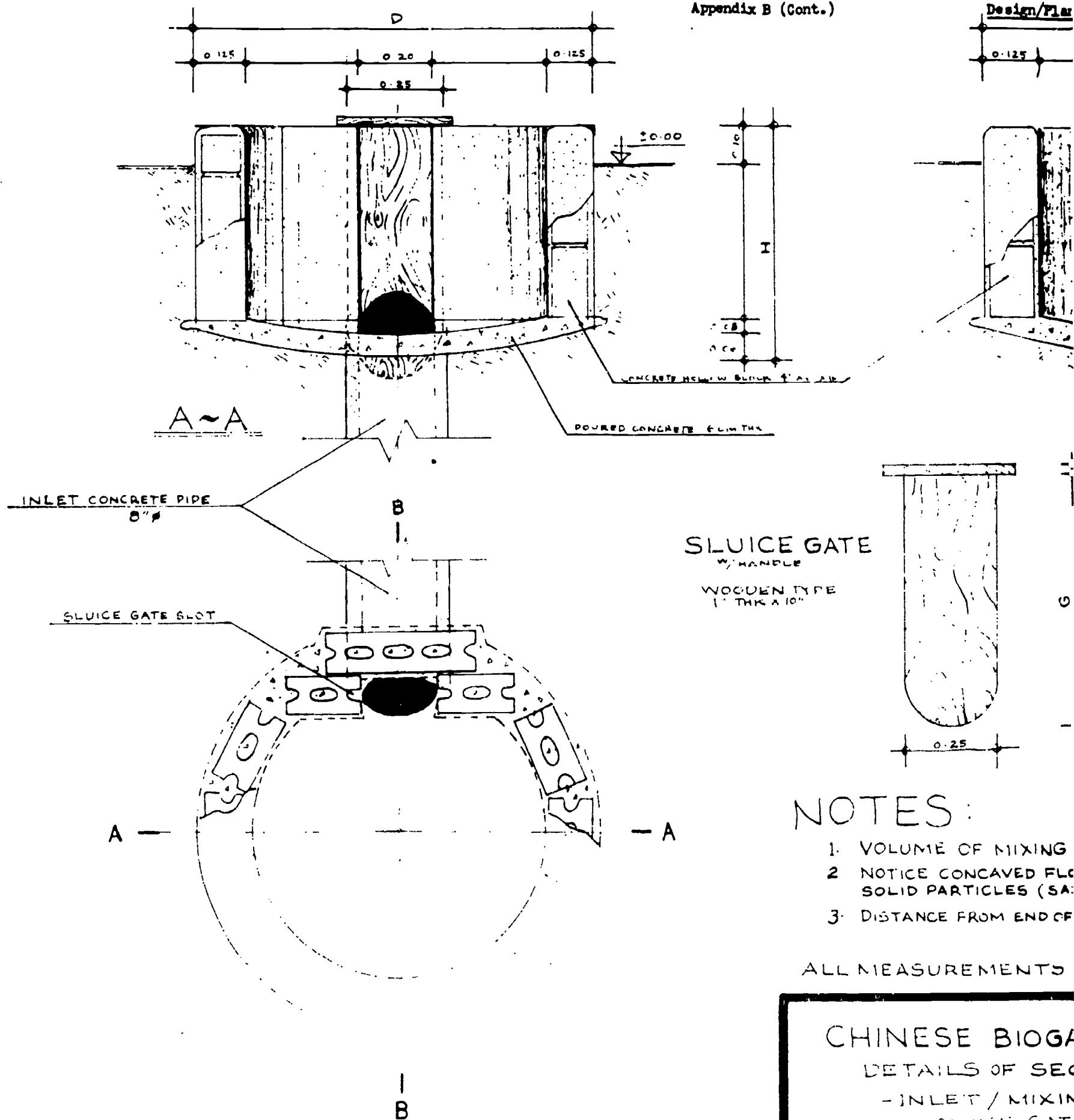
- MAN-HOLE SLEEVE AND COVER
- RING-BEAM

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2

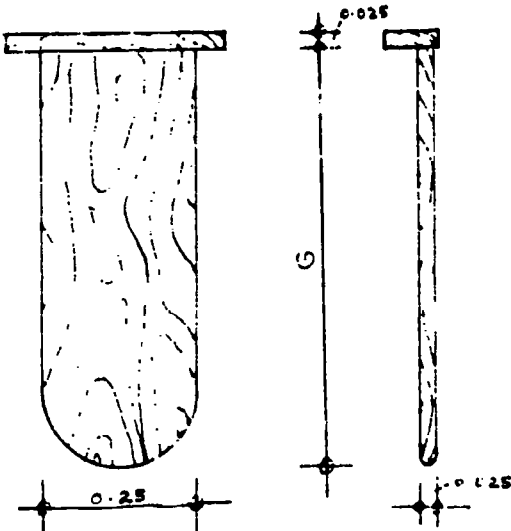
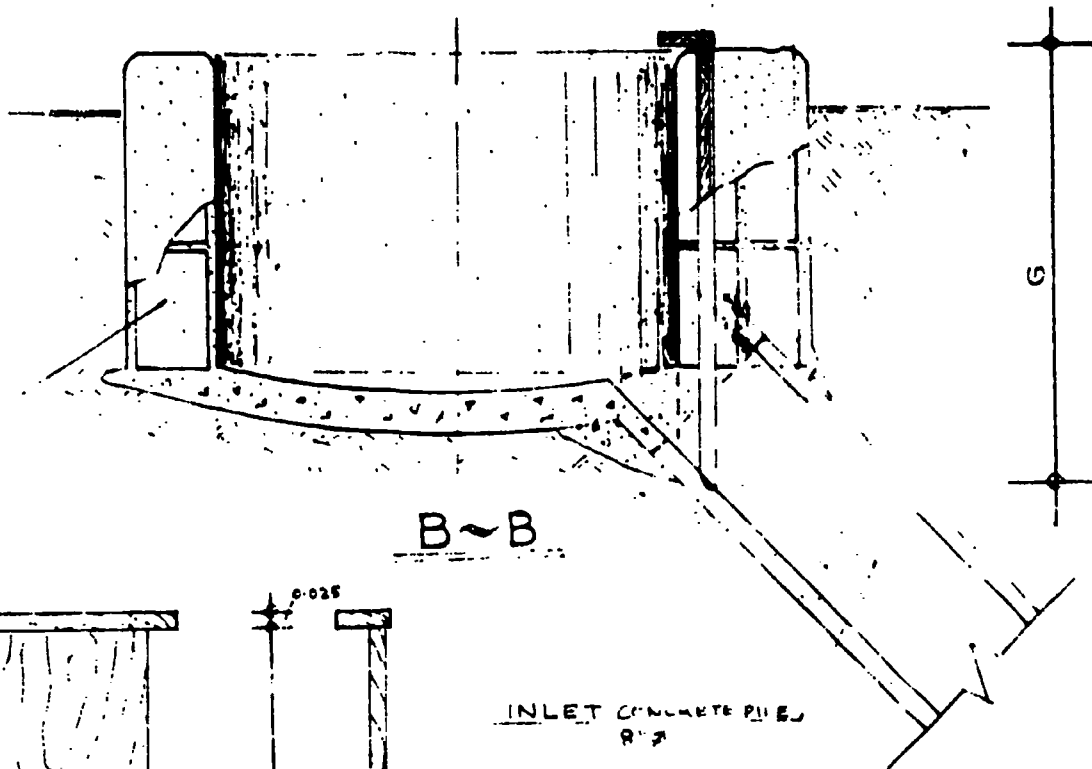
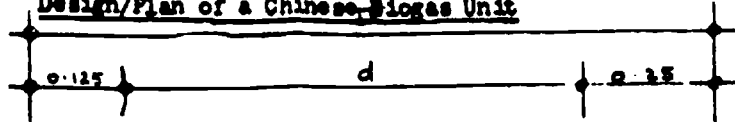
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JULY 1981



Cont.)

Design/Plan of a Chinese Biogas Unit



E GATE

TYPE 10"

INLET CONCRETE PIPE R 2

# NOTES:

1. VOLUME OF MIXING PIT SHOULD EQUAL LOADING VOLUME.
2. NOTICE CONCAVED FLOOR SO AS TO "TRAP"/SETTLE ANY INORGANIC SOLID PARTICLES (SAND, GRAVEL, ETC.) BEFORE CHARGING.
3. DISTANCE FROM END OF CULVERT PIPE TO THE DIGESTER WALL IS APPROX. 1.3 m.

ALL MEASUREMENTS IN METERS (UNLESS STATED OTHERWISE) !!!

## CHINESE BIOGAS DIGESTER

DETAILS OF SECTIONS AND CONJUNCTIONS

- INLET / MIXING PIT

SLUICE GATE

NOT SHOWN: COVER

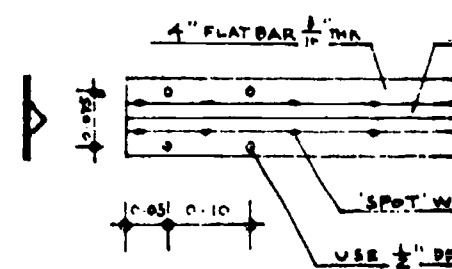
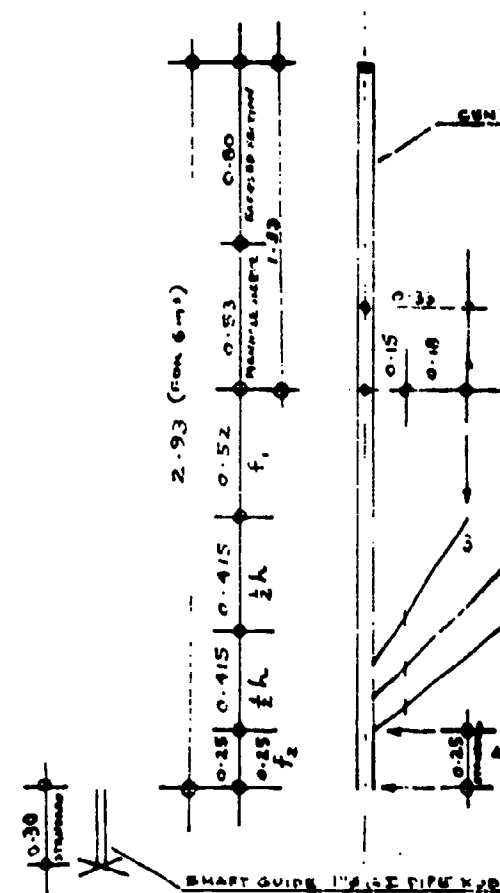
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3

4

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-CENTER-; HAFT; STICKER BL  
MAN-HOLE BRACE; CENTER S:



SCALE 1 0.075

-ALL MEASUREMENTS IN METERS (UNLESS OTHERWISE INDICATED) !!!

### DETAIL OF STIRRER/MIXER ASSEMBLY

- CENTER-SHAFT; STIRLER BLADE; SHAFT GUIDE; SWEVE PIPE;  
MAN-HOLE BRACE; CENTER SHAFT PLATE

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4

4

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## Appendix C

### ECONOMIC ANALYSIS/FEASIBILITY STUDY FOR A FAMILY-SIZE CHINESE BIOGAS UNIT

#### 1. Assumptions/Pre-Requisites

- 1) The family biogas unit has of a volume of 4.66 cubic meters. It requires roughly 45 liters of manure-water mixture (1:1 ratio) per day.
- 2) The gas produced will be used mainly for cooking and emergency lighting purposes.
- 3) Raw materials and water are available; this means 6-8 fatterer pigs will be maintained at any point in time and approximately 45 liters of water available.
- 4) The biogas unit will be maintained and operated by the family. (Family-size biogas digester is small enough that the family does not need to employ a biogas operator/maintenance man for the assured normal daily gas production sufficient for the family's needs).
- 5) The whole unit costs approximately ₱2282 (consisting of ₱1,582 for materials and ₱700 for labor). (Prices are as of March 1981 in Manila.)
- 6) The life of the unit is more than 20 years. The study is based on cooking fuel (LPG) only.
- 7) LPG consumption for a family of six is ₱65 (price of one 40-kg. tank) for 25 days. This means an average daily gas consumption of ₱2.60. Furthermore, the price of LPG is not likely to decline.
- 8) Other major benefits of Biogas production, i.e., waste management, biofertilizer retrieval, etc. are not computed in the calculations, because of its difficulty to make actual economic values, but should not be overlooked - "intangible benefits"

#### 2. Cost And Return Analysis

The cost of the unit, which is ₱2,282, is spread over a 20-year period, the estimated service life of the unit. (However, in actuality the unit may last much larger.) In short, this is equivalent to ₱114.10 per year for the service of the unit. There are no other major costs involved in operating the project. Labor used in day-to-day operation is supplied by the family and is not computed. Hence, the net return of the project is considered as labor income.

### Appendix C (Cont.)

The income from the project is reckoned from the saving on LPG only. It is assumed that a family of 6 persons consume on the average one tank of LPG costing ₱65 every 25 days, or ₱2.60 per day. In one year the cost of cooking LPG gas will cost ₱949.00. (Or, in 20 years the expense for LPG gas will be ₱18,980.00.)

Thus the estimated return per year to be derived from putting up a biogas unit is:

Annual Gross income (cost of gas)	-	₱ 949.00
Annual expense (cost of unit)	-	<u>114.10</u>
Annual net savings		<u>₱ 834.90</u>

Of a net saving of: ₱69.57/month, or ₱2.31/day.

It should be noted that the benefits derived from the fertilizers produced and the sanitation aspects are not included in the computation.

### 3. Payback Period

This is the time it takes to recover the initial investment out of the income expected as result from the investment. Payback period is computed as follows:

$$P = \frac{C}{E},$$

whereas; P = Payback period  
(in years),

C = Amount of investment,

E = Cost savings

Thus:

$$\begin{aligned}\text{Payback Period (in years)} &= \frac{\text{₱2282.00}}{834.90} \\ &= 2.7 \text{ years.}\end{aligned}$$

Appendix D

ESTIMATED BILL OF MATERIALS FOR DIFFERENT DIGESTER VOLUMES

Item	Unit	Total Digester Volume				
		4 m <sup>3</sup>	6 m <sup>3</sup>	8 m <sup>3</sup>	10 m <sup>3</sup>	15 m <sup>3</sup>
<u>Phase I. (Basic Construction)</u>						
<u>Materials:</u>						
Cement	: 40 kgm. bags	17	25	35	45	55
Sahara (for water proofing, optional)	: Bags	10	15	35	35	45
Concrete hollowblocks:						
- 4" x 8" x 16"	: pcs.	120	150	75	100	100
- 6" x 8" x 16"	: pcs.	-	-	100	125	150
Round concrete pipes, 8" dia. x 36"	: pcs.	3	3	3	3	3
Reinforcement bars, 3/8" dia. x 20', deformed	: pcs.	20	30	50	60	70
Wax/paraffin	: kgms.	7	10	10	15	15
Gravel and sand (mixed)	: m <sup>3</sup>	3.5	5	7	9	11
G.I. wire (#16)	: kgms.	3	3	4	5	5

Appendix D (Cont.)

Item	Unit	Total Digester Volume				
		4 m <sup>3</sup>	6 m <sup>3</sup>	8 m <sup>3</sup>	10 m <sup>3</sup>	15 m <sup>3</sup>
Lumber:						
- 2" x 2" x 10'	: pcs.	5	7	9	11	13
- 2" x 1" x 10'	: pcs.	4	6	8	10	12
Plywood or Fiberboard, 1/8" thk 4' x 8' (Lawanit)	: pcs.	3	3	4	5	6
Nails:						
- 2½"	: kgms.	2	2	2½	3	3
- 1"	: kgms.	1/2	1	1½	2	2
<u>Phase II (Finishing and Accessories) Materials:</u>						
Plastic brush	: kgms.	1	1	1	1	1
Paint brush	: pieces	2	2	2	2	2
G.I. pipe:						
- 1" dia. x 2'	: pcs.	1	1	1	1	1
- 1/2" dia. x 20'	: pcs.	2	2	2	2	2
G.I. elbow:						
- 1" dia.	: pcs.	1	1	1	1	1
- 1/2" dia. (straight)	: pcs.	1	1	1	1	1
- 1/4" dia. (straight)	: pcs.	1	1	1	1	1

Appendix D (Cont.)

Item	:	Unit	Total Digester Volume				
			4 m <sup>3</sup>	6 m <sup>3</sup>	8 m <sup>3</sup>	10 m <sup>3</sup>	15 m <sup>3</sup>
G.I. reducer:							
- 1" to 1/2" dia.	:	pcs.	1	1	1	1	1
- 1/2" to 1/4" dia.	:	pcs.	1	1	1	1	1
G.I. nipple, 1/4" dia. x 4"	:	pcs.	6	6	6	6	6
G.I. Tee	:	pcs.	2	2	2	2	2
Sprayer valve, 1/4" dia.	:	pcs.	2	2	2	2	2
Rubber hose with ply:							
- 3/4" dia.	:	meters	1/2	1/2	1/3	1/3	1/3
- 1/2" dia.	:	meters	10	10	10	10	10
Clear plastic hose, 1/2" dia.	:	meters	3	3	3	3	3
Corrugated G.I. sheet (New or used)	:	sheets	3	3	3	3	3

Appendix E

DIGESTER VOLUME AND QUANTITY OF DAILY SLURRY CHARGE  
(Based on 40-Days Retention Time a/)

Total Digester Volume ( $V_1 + V_2 + V_3 = V_t$ )	Digester Slurry Volume ( $V_2 + V_3 = V_s$ )	Slurry Charge per day (Mixing Pit Volume)	Manure-Water Ratio Charge (Liters/kilograms)			
m <sup>3</sup>	m <sup>3</sup>	m <sup>3</sup> b/	Liters/ kgms. c/	1:1 Ratio Manure : Water	1:2 Ratio Manure : Water	
4.66	3.63	0.09	90	45.0	45.0	30 60
6.14	4.68	0.117	117	58.5	58.5	39 78
8.66	6.63	0.166	166	83.0	83.0	55 110
10.27	8.12	0.202	202	101.0	101.0	67 134
15.0	11.34	0.28	280	140.0	140.0	93 186

a/ This is Hydraulic Retention Time (HRT).

b/ Arrived at by dividing Digester Slurry Volume ( $V_s$ ) by 40-days (Retention Time)

c/ Conversion Rate:  $1m^3 = 1,000$  liters/kilograms of water.



# Appendix F

## ESTIMATED DAILY QUANTITY OF MANURE AND URINE AVAILABLE WITH RESPECT TO NUMBER AND WEIGHT OF PIGS RAISED a/ b/ c/

No. of Pigs	Manure Available (in kilograms)		
	Average market weight	Average market weight	Average market weight
	: of 40 kgms./pig	: of 70 kgms./pig	: of 100 kgms./pig
1	2.0	3.5	5.0
2	4.0	7.0	10.0
3	6.0	10.5	15.0
4	8.0	14.0	20.0
5	10.0	17.5	25.0
6	12.0	21.0	30.0
7	14.0	24.5	35.0
8	16.0	28.0	40.0
9	18.0	31.5	45.0
10	20.0	35.0	50.0

a/ Estimated at 1 kilogram of manure and urine available for every 10 kilograms of liveweight, or a ratio of 1:10.

b/ Note: Above data are to be used as a guide. The best way is to check and measure the actual amount of wastes for 3 consecutive days and take the average. Quantity of manure may vary according to (a) size/age of animal; (b) feeds of animal; (c) degree of confinement; (d) urine collected, and (e) "wash"water included.

c/ Some other data: 1 cow or carabao gives 10-15 kgms. per day; 1 chicken; 0.09 per day.

### Appendix G

ESTIMATED GAS PRODUCTION RATE  
(Based on 0.4 - 0.6 m<sup>3</sup> of gas  
per 1 m<sup>3</sup> Slurry Volume Per Day)

Digester Volume (V <sub>t</sub> ) m <sup>3</sup>	Slurry Volume (V <sub>s</sub> ) m <sup>3</sup>	Gas Production/Day	
		Minimum <u>a/</u> m <sup>3</sup> /day	Maximum <u>b/</u> m <sup>3</sup> /day
4.66	3.63	1.45	2.17
6.14	4.68	1.87	2.80
8.66	6.63	2.65	3.97
10.27	8.12	3.25	4.87
15.0	11.34	4.50	6.80

a/ Slurry Volume (V<sub>s</sub>) multiplied by 0.4 m<sup>3</sup>.

b/ Slurry Volume (V<sub>s</sub>) multiplied by 0.6 m<sup>3</sup>.

## Appendix H

### MASONRY AS APPLIED TO BIOGAS CONSTRUCTION

Concrete is a versatile and relatively cheap building material. Most people are familiar working with concrete, either by observing its procedures or helping in building a simple structure. The method seems to be easy that everyone thinks that people who have constructed a concrete house or structure (that does not require strict specifications of being water-proof (and gas proof), can also build a concrete biogas unit. A word of caution: one crack and all the biogas leaks and renders the owner with the difficulty of repair that may also be costly and time consuming.

This material is an attempt to present certain basic facts about concrete work as particularly applied to building a successful biogas digester. These are simple facts which are often overlooked in common small-scale concrete work and may likely make a difference in the eventual overall performance of a biogas unit.

To prepare a durable concrete structure the builder should observe the following facts:

- No. 1: 1) Select, prepare, and store the ingredients properly;
- 2) Use precise proportions of ingredients suitable for the job; and
- 3) Mix the ingredients properly with each other prior to adding the correct amount of water.
- No. 2: 1) Select and use clean aggregates (free from soil, grass and other impurities);
- 2) Mix sand, gravel and cement thoroughly before adding water; and
- 3) Use the right amount of water (See No. 9).
- No. 3: Concrete works well, provided it is compacted to eliminate "air pockets". (Note: 5% air voids in concrete reduces strength of concrete by 50%.)
- No. 4: Concrete cannot be stronger than the aggregates used. Therefore, use mortar of the same strength as the aggregates.
- No. 5: Sloppy concrete methods result in weak concrete structures.

Appendix H (Cont.)

- No. 6: Concrete is porous, that is, it absorbs water through the minute voids in the concrete.
- No. 7: Concrete is sensitive to extreme acid or alkaline conditions. (The slurry in the digester is generally acidic due to the presence of ammonia and hydrogen sulfide, but is not of the extreme condition.)
- No. 8: There should never be more than 3 parts sand for every one part of cement in mixing concrete.
- No. 9: Use a little water as possible in the mixture. Too much water weakens concrete and makes it less watertight.
- No. 10: 1) The length of time spent for curing concrete is directly related to the strength of concrete. Concrete cured for 14 days is approximately twice as strong as concrete cured for 3 days.
- 2) Cover newly poured concrete with a wet material for at least 7 days. Prolonging the curing process strengthens and improves the water tightness of concrete.
- No. 11: Once mixed, concrete should be used within one hour after mixing.
- No. 12: Cleanliness of anything that has to do with concrete work means strength, watertightness and gastightness of the resulting concrete. Thus:
- 1) Clean aggregates (gravel and sand);
  - 2) Clean tools (shovel, measuring unit, mixing platform, trowel, buckets, etc.)
  - 3) Clean cement;
  - 4) Clean mixing area;
  - 5) Clean surface;
  - 6) Clean construction joints/connections;
  - 7) Clean molds/forms;
  - 8) Clean reinforcement bars;
  - 9) Clean mixture.

## Appendix H (Cont.)

### Basic Elements in Concrete Work

#### 1. Cement

Cement is a construction adhesive, essentially powdered, calcined rock and clayey material that forms a paste with water and "set" as a solid mass. The commercially available, commonly known as Portland Cement comes from the mill and packed at approximately 94 lbs. or 42.6 kg. packages.

Note: DO NOT BUY CEMENT UNTIL JUST BEFORE YOU ARE GOING TO USE IT. Under average conditions it may start to harden and deteriorate in 7-14 days. STORE IN A COOL, shaded and dry place, off the ground, and stack bags tightly. Once moisture reaches the cement, chemical reaction begins. Good quality cement is smooth and "flour-like". If it has hardened due to wetness to such an extent that the lumps could not be crumbled by hand, the cement should be rejected since its cementing value has already been destroyed.

#### 2. Concrete

The concrete is made up of three ingredients: cement, aggregates (sand and gravel), and water. Careful mixing and correct proportions of the ingredients is the key in obtaining the desired results. On the job, make it a practice to mix, pour and finish all concrete work once the mixture is mixed and watered.

#### 3. Aggregates

These are the hard materials such as sand, gravel and stone that are mixed with cement and water to make concrete. Aggregates should be clean and free from impurities. It should be always kept in mind that "the concrete cannot be harder than the aggregates being used". Therefore if cinders, coral, or broken soft bricks are to be used, the concrete will likewise be as strong or hard as the aggregates.

Aggregates are of two kinds: fine and course.

Fine aggregates are those particles that will pass through 1/4-inch screen mesh. This is possibly the most important ingredient in the concrete mix since it provides the "plasticity" of the mix making the mixture easy to work with. Ideally there should be no more than 3 parts sand for every one part cement. Too little sand may result in shrinkage or cracks when the concrete dries. Too much sand will produce a harsh mortar that will be difficult to work with and the overall structure may be weak. Never use sand from the ocean; the grains are too uniform in size and will not make good concrete. Any other sand source is good, but is crucial that it be clean.

## Appendix H (Cont.)

Course aggregates, on the other hand, consist of gravel, stones, crushed rocks, etc. They will not pass through a 1/4-inch screen mesh and are usually less than 2½ inches in diameter. Course aggregates add strength to concrete because they increase the range of grain sizes in the mixture. Generally they are the easiest ingredient to find and prepare locally. Aggregates must be coarse, hard and free from impurities such as organic matter, leaves, etc. As a rule of thumb, the size of the aggregate to be used should not be more than 1/2 the thickness of the concrete.

To determine the loam or soil impurities of aggregates, this simple test may be used.

- 1) Fill a one-liter bottle with sand up to 4 inches from the bottom and then fill it almost full of clean water.
- 2) Shake thoroughly and allow to settle overnight.
- 3) The loam and other fine materials will settle on top of the sand. If the layer is more than 1/8 inch thick, the sand should be washed, or another source of sand should be obtained.

### 4. Water

Water causes a chemical reaction in the cement, transforming it into an adhesive paste and hardening the concrete. Clean, pure water must be used for good quality concrete. Tap or spring water, or generally speaking, water fit for drinking is suitable for mixing concrete. Sea water and water high in alkali, acid or impurity contents should not be used.

It is a fact that for mixing concrete only a fraction of water in the mixture is used up in the chemical reaction that hardens the concrete. The remaining water escapes by evaporation, leaving minute voids that weaken the concrete. In theory, the mix should contain one part water (by weight) for every four parts cement. In this case, all the water would be absorbed in the hardening process and none left to evaporate. In practice, however, such a mix would be too stiff to use. Since in most cases the moisture content of the aggregates varies, it is impossible to state the exact amount of water to be used. To be safe, add just enough water to make the mix workable. And USE AS LITTLE WATER AS POSSIBLE.

The question of water is strongly emphasized since it is not uncommon to see many people who like to "drown" the mixture as it is much easier for them to prepare and work with the people who like to the mixture. This will lead to a much lower quality concrete. The best thing to do is to watch them carefully yourself. Supervise the addition of water to the mix.

Appendix H (Cont.)

5. Mixing the Ingredients

Different uses and the desired hardness of concrete require different mixing proportions:

<u>Uses</u>	<u>Proportion by volume of:</u>		
	<u>Cement</u>	<u>Sand</u>	<u>Gravel</u>
For structural members such as posts, beams, walls, etc.	1	: 2	: 4
For extra strength (rich mixture)	1	: 1½	: 3
For floors, walkways (medium mixture)	1	: 2½	: 5
For large massive structures like footing, etc. (lean mixture)	1	: 3	: 6

The mixing of the ingredients should be done in the following sequence or steps:

- 1) Spread the correct amount of sand on the mixing area with a shovel.
- 2) Dump the required amount of cement on the sand, and mix until the color of the pile is uniform; no streaks of color.
- 3) Add the required amount of gravel and mix it with the cement/sand mixture until the gravel is thoroughly distributed and coated. Again there should be no streaks of color, or "clumps" in the mixture. Note: Thorough mixing is essential for good concrete.
- 4) Hollow out a hole in the center of the mix. Add water slowly, pushing the ingredients toward the center while turning them over with a shovel. A good test for the correct amount of water is to walk on the mixture. If you sink to your ankles or higher, there is too much water; if you sink about 5-6 centimeters, you have the right mixture. THIS IS IMPORTANT AND VERY CRITICAL, OTHERWISE YOUR CONCRETE WILL NOT BE STRONG, AS WELL AS WATERPROOF AND GASPROOF. Too much or too little water renders the mixture uneven. Too much water causes a cement/water mixture to rise to the surface, weakening the mixture below, plus the minute voids in the concrete that the extra water will leave in the process of curing as mentioned earlier. Too little water leaves air spaces in

## Appendix H (Cont.)

the mixture and does not give sufficient water for chemical reaction.

Once the mix is prepared, the mixture should be poured within one hour after mixing. Once in place, the concrete should be worked in well in place. A rod or spading tool may be used to break the air pockets. The planned pouring job for the day must be continuous and completed in one "pouring". If for the unlikely event that pouring has to be resumed the following day, roughen the edge of the previously poured section and paint it with a "pure" cement-water paste before continuing the fresh concrete pouring.

### 6. Curing

Curing is the hardening process of concrete. The quality of concrete - - its strength, as well as its watertightness and gastightness - - largely depends on proper curing, all other requirements being favorably met. Although usually not followed strictly in other concrete work it should NEVER be neglected in the case of biogas digester construction. The dome portion must especially be of high quality.

The dynamics of the concrete drying process is such that the initial evaporation within a concrete occurs on the outer layer, but the interior is still saturated with water. Thus, the concrete may appear dry or "cured" a few days after pouring, but it actually is not.

Proper curing involves keeping the concrete wet for sometime after it is laid. The newly poured concrete should be covered with a clean, water-retaining material, like burlap, cloth or sand and kept damp for at least several days during the curing process.

Prolonging the curing process increases the quality of concrete. As mentioned earlier: concrete cured for 14 days is approximately twice as strong as one cured for 3 days. More specifically: concrete kept damp for the first 10 days is 72 percent stronger than if left to cure in dry air for 3 days. Keeping it damp for 21 days increases its strength by 124 percent; 4 months dampness, by 207 percent. While the flooring is being cured, it should be kept clean and protected from soil impurities and excessive loads.

### Important Considerations In Preparing Concrete

The following should be considered for proper masonry work:

#### 1. Mixing Area

Concrete should be mixed on a flat, clean surface which will not



## Appendix H (Cont.)

absorb water. A standard mixing platform is made from wood about 2 meters by 3 meters. Another is a cement-sand platform. (To build a cement-sand platform, mix 1 part cement and 6 parts sand on that ground close to the work site. Add water and spread the mixture in a circle before using the platform.)

Or usually the site for the biogas tank will be close to the pig pen, so it is convenient to use the pig pen floor as the mixing platform. Keep away foreign materials - - soil, grass, etc. - - from the mixing area.

### 2. Measuring Unit

The proportions of the any ingredient of concrete - - namely cement, sand and gravel - - are measured by volume. Decide on a standard measuring unit, such as a box that holds 1 bag of cement (or cubic foot). The box should have handles on both sides for easy lifting by two people. It is advisable not to change measuring units during construction. Measuring units should be cleaned if it had been used for hauling soil or other debris.

### 3. Molds or Forms

Molds are necessary to hold the concrete to the desired place and shape until it is cured. Being semi-fluid, concrete takes shape of anything into which it is poured.

The length of time necessary to keep the forms in place depends on the nature of the structure. For small construction work where the concrete bears no external weight, the forms may be removed as soon as the concrete will bear its own weight. Usually this is between 12 and 48 hours after pouring the concrete.

The forms must be relatively watertight, rigid and strong enough to sustain the weight of the concrete. They should also be simple and economical and if to be used again, designed so that they may be easily removed and re-erected without damage to themselves (or to the concrete). Wood, plywood or fiber board forms are versatile and cheapest, but for repetitive use, G.I. sheets may be advantageous as they are not easily damaged by water.

### Reinforced Concrete

Reinforcing concrete enables it to attain greater strength with reduced thickness. Concrete foundations, walls, floors and columns can increase their strength by 2-5 times when reinforced.

## Appendix F (Cont.)

Reinforced concrete combines two materials with different or opposite but mutually reinforcing strength characteristics needed by structures. Concrete resists compression or downward pressure; it does not bend but it breaks or cracks instead. Iron rods (or usually deformed bars) resist tensile or breaking pressure; they bend and buckle under compression.

The preparation and handling of reinforced concrete is the same as that of plain concrete, except that an iron rod, or a series of rods, are fastened inside the "form" or "mold" before the concrete is poured in.

Reinforced concrete is the strongest, long lasting material of all (especially in wet and stormy climates and earthquake-prone areas), but is expensive because of iron rods, time and labor.

The reinforcement rods must be free from dirt, oil or rust, to insure adherence of cement to them. If necessary, clean the iron rods of foreign particles with the use of a steel brush.

The iron rods must be completely surrounded by concrete, at least 2.5-5 centimeters. Any exposed rods will not be maximizing the use of such rods.

When using hollowblocks, there should be one horizontal iron rod for every two courses of hollowblocks. This is roughly 40 centimeter reinforcement spacing. There is also one vertical iron rod for every two layers of hollowblocks, meaning 80 cm spacing between hollowblocks.

There are certain proportions between "size of rods" and "thickness of concrete", but it is not always true that "the thicker the concrete, the stronger it is" (this is reinforced-concrete fiction No. 1). In fact, by increasing the thickness of the concrete may render the iron rods useless because they can no longer hold the tensile and shearing stresses exerted by the concrete mass.

In determining the thickness of circular or domed structures, the RULE OF THUMB is: Thickness of sphere (or by the circular form) is sufficient when it equals one-tenth of the inner radius of the circle. Hence:

for 4.66 m<sup>3</sup> biogas digester

- Radius (R<sub>1</sub>) = 1.5 m.
- Thickness of dome =  $\frac{1.5 \text{ m}}{10} = 0.1 \text{ m}.$

and

for 15 m<sup>3</sup> biodigester

- Radius (R<sub>1</sub>) = 2.5 m
- Thickness of dome =  $\frac{2.5 \text{ m}}{10} = 0.2 \text{ m}.$

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## Appendix H (Cont.)

### Watertight And Gastight Concrete: A Further Emphasis

The crucial need for having watertight and gastight concrete biogas digesters and the factors that will make it so have already been discussed. They are repeated here only to emphasize their importance in obtaining the desired results. It is very important to realize that the success of a biogas digester is dependent on the ability of the tank to hold water and gas at high pressure (sometimes up to 2 meters water column pressure).

In review, the essential requirements for concrete impervious to water and gas are as follows:

- 1) Good quality of aggregates: clean, correct size and proportions;
- 2) Limited amount of water; clean and in correct amount;
- 3) Thorough mixing: a plastic, workable mixture;
- 4) Proper placing and pouring; no voids and air pockets in the concrete; and
- 5) Favorable curing conditions.

It must be emphasized that water-proofing a concrete is difficult, and that gas-proofing it is even more difficult. A concrete additive may be used to further insure that the concrete will be watertight/gastight together with the above-mentioned requirements. Commercially available "water-proofing" agents/compounds come in various trade names in the Philippines (e.g. "SAHARA", "Philidelphia", etc.). It is recommended that an additive be used. Follow directions provided on the package. To further achieve gastightness of the gas portion of the digester, very good results have been experienced by applying paraffin/wax for the interior surface of the dome. This is recommended highly for achieving the desired results.

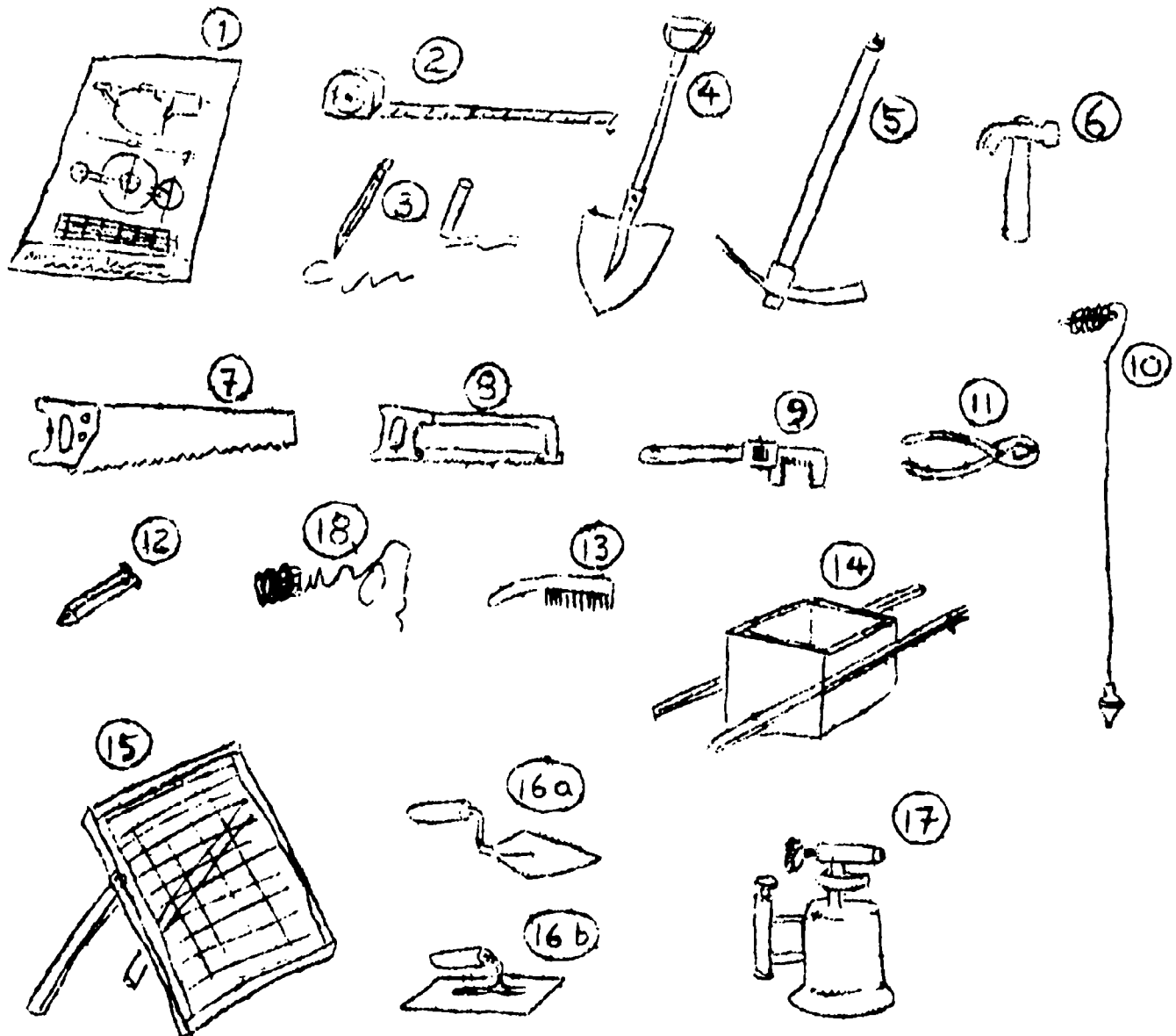
For practical purposes, the amount of mixing water should not exceed about six-gallons per bag of cement, and not more than five gallons if the sand is damp. The accumulation of undue water on the surface of the mixture should be avoided, and all whitish "scum" consisting of finer materials which may float and collect should be removed. Pouring of concrete should be continuous (or monolithic) especially the gas portion of the digester. Any interruptions in the pouring should be avoided; if for some reason it must be interrupted, proper construction joints and rough-finish (or "scratched") surfaces in which pouring is to resume should be adequately provided for.

Concrete should be kept wet for two weeks and longer when practicable. Keeping the concrete "damp" prolongs the curing process which is necessary for strengthening the concrete structure.

## Appendix I

### BASIC MANUAL TOOLS FOR BIOGAS CONSTRUCTION

1. Design/plan; 2. Tape measure; 3. Pencil or chalk; 4. Shovel; 5. Pick; 6. Hammer; 7. Saw; 8. Hacksaw; 9. Pipe wrench; 10. Plumb-bob; 11. Pliers; 12. Chisel (for concrete); 13. Steel brush; 14. Measuring box (1 cubic foot); 15. Sifter (G.I. screen); 16. Masonry trough (a. regular; b. plastering); 17. Blow-storch; 18. String (at least 3 meters).



Appendix J

USEFUL FORMULAS AND CONVERSIONS

Area of a Circle =  $\pi r^2$   
where:  $\pi$  = 3.1416 (constant)  
r = radius of circle

Circumference of a Circle =  $2 \pi r$

Volume of a Cylinder =  $\pi r^2 h$  or  $\frac{\pi d^2 h}{4}$   
where: r = radius of cylinder  
h = height of cylinder  
d = diameter of cylinder

Volume of a Sphere Segment =  $\frac{\pi h^2 (r - \frac{h}{3})}{3}$   
where: h = height of arc  
r = radius of sphere

Conversion factors:

<u>Centimeters</u>	x 0.3937	=	Inches
	x 0.3281	=	Feet
	x 0.01	=	Inches
	x 10	=	Millimeters

Cubic feet (Ft<sup>3</sup>)

x 283.2	=	Cubic centimeters (cm <sup>3</sup> )
x 1,728	=	Cubic inches (In <sup>3</sup> )
x 0.02832	=	Cubic meters (m <sup>3</sup> )
x 7.4	=	Gallons
x 28.32	=	Liters

Cubic meters (m<sup>3</sup>)

x 1,000,000	=	Cubic centimeters (cm <sup>3</sup> )
x 35.31	=	Cubic feet (Ft <sup>3</sup> )
x 61,023	=	Cubic inches (In <sup>3</sup> )
x 264.2	=	Gallons
x 1,000	=	Liters

Gallons (Liquid)

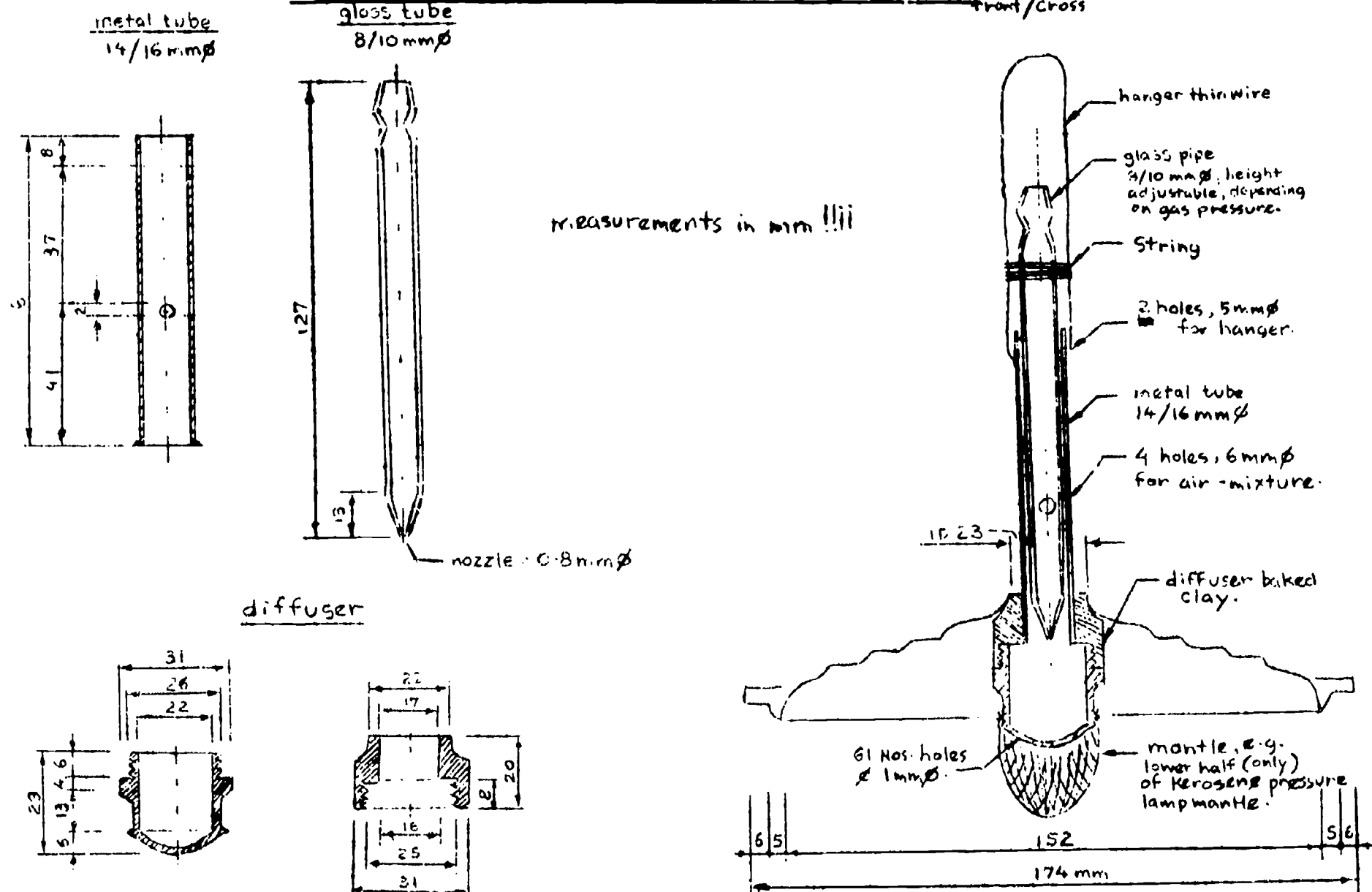
x 3,785	=	Cubic centimeters (cm <sup>3</sup> )
x 0.1337	=	Cubic feet (Ft <sup>3</sup> )
x 3.785	=	Liters

Appendix J(Cont.)

<u>Inches</u>	x 2.54	= Centimeters
	x 0.0833	= Feet
	x 0.0254	= Meters
	x 25.4	= Millimeters
<u>Meters</u>	x 3.281	= Feet
	x 39.37	= Inches
	x 1.094	= Yards
	x 100	= Centimeters
<u>Kilograms</u>	x 1000	= Grams
	x 2.205	= Pounds
	x 0.001102	= Tons
<u>Liters</u>	x 10 <sup>3</sup>	= Cubic centimeters (cm <sup>3</sup> )
	x 0.001	= Cubic meters (m <sup>3</sup> )
	x 0.0353	= Cubic foot (Ft <sup>3</sup> )
	x 61.02	= Cubic inches (In <sup>3</sup> )
	x 0.2642	= Gallons
<u>Others:</u>	1 psi	= 70.3 centimeter column of water
		= 27.68 inch column of water
		= 51 millimeter column of mercury
		= 0.068 atmosphere

Appendix K

"DETAILS FOR CONSTRUCTION OF A BIOGAS LAMP (HANGING MODEL)" <sup>a/</sup> front/cross



<sup>a/</sup> Source: FAO Soils Bulletin, #41, "China: Azolla Propagation and Small-Scale Biogas Technology", FAO/UNDP, 1978.

## Appendix L

### BACKGROUND NOTES AND ACCOUNT OF BIOGAS PRODUCTION IN THE PEOPLE'S REPUBLIC OF CHINA

The People's Republic of China is a country famous for the age-old tradition of recycling organic wastes in agriculture. It is claimed that its farmers meet two-thirds of their fertilizer needs from organic sources. Wastes of all kinds are viewed as resources "out-of-place"

Experimentation and promotion of biogas technology in response to the search for better ways of utilizing wastes began in China in the late 1950's. All-out efforts were made to improve on the traditional methods of composting human, animal and plant wastes to produce high quality fertilizers. The breakthrough came in early 1970's when they were able to develop a simple watertight and airtight digester from locally available building materials (bricks, limestone, etc.) at a cost individual households could afford.

Along with producing fertilizers of high quality, other benefits were recognized in the process. Methane-gas was produced as fuel not only for cooking and lighting but with larger biogas units for internal combustion engines to supply farm power and rural electricity. Rural sanitation greatly improved by destruction of pathogens that causes common rural diseases. In the past, night soil was bucketed out to the paddy fields untreated, resulting in the spread of diseases like schistosomiasis, blood fluke, round worms and hookworms, now, digestion of night soil in a watertight and airtight digester prevents the breeding and spread of disease-carrying organisms, thereby reducing public health hazards. All this has brought about the realization that biological treatment of organic wastes in a biogas digester is the simplest, cheapest and most practical method known for sanitary handling of human and animal wastes. Thus, biogas technology has been able to solve not only waste management and rural sanitation problems, but also produce high quality fertilizers and fuel.

The experience in China is that a household digester can be built from locally available materials and labor for as little as \$15 - \$25 (¥112.50 - ¥187.50). It is estimated that 95% of all biogas digesters built are of family-size where the gas produced is primarily used for cooking and lighting and the effluent for fertilizer of the family's own fields.

It is a general impression that the major constraint to the spread of biogas technology to the rural areas of the Third World is the high initial capital cost of the digester. Thus, conclusions were made that "community" digesters should be recommended over "individual" digesters in order to reduce costs, but there are many problems associated with community digesters. If digesters could be made at low-cost, there is a need to reexamine the notion that individual household digesters are capital intensive. The Chinese have shown us their resourcefulness and the example of building a digester inexpensively by utilizing locally available



## Appendix L (Cont.)

building materials and a different design concept. They make use of materials available in their own specific areas or regions. People along rivers use pebbles and stones; those in the plains use bricks, and those in the mountains may even carve their digesters out of sheer rock! They also make their own concrete, called, "triple-concrete" made out of a mixture of lime, clay and sand.

Biogas production technology is recognized as fairly sophisticated and complex. Construction is stressed to be meticulous so as to guarantee durability, watertightness and gastightness without having to be necessarily expensive in building materials. It also emphasizes that operation and maintenance of the biogas unit is equally important for satisfactory performance in producing gas and fertilizer and achieving sanitation.

A biogas manual, available in bookstores throughout China, points out that the technology is sophisticated and that special care must be taken in both construction and operation of the units. It advises people to try different techniques on a small-scale before attempting it on a large-scale, and to test carefully for safety and airtightness. The manual also tries to give the reader an idea of what goes on "out-of-sight", underground in a working digester.

The success of in the promotion of biogas technology in China can be largely traced to their system of organization and program integration on the national level. Biogas production is for social reconstruction and rural transformation supported through national conferences, training of biogas technicians; manufacture of simple gas stoves and lamps, rubber or plastic piping materials, and simple pressure gauges; making available financial support; and providing research and development for designs and construction techniques.

The technology transfer process is likewise well organized. Before the start of a biogas project a brigade will send several members to another brigade as "apprentice" to learn all aspects of the technology. After having experienced in construction and maintenance there, these people return as "technicians" to begin a biogas program in their own brigade. They are responsible for the construction and operation of the biogas plants, for the training of other technicians, and for the supervision and assistance needed by individual families building their own digesters. The families receive instructions on how to release the gas, how and when to feed the digester, and how to maintain the proper liquid-solid balance within the digester.

The Chinese empty or clean their digesters twice a year (or "batch" type of operation) since their primary concern is to produce biofertilizer. And also, the use of grasses, rice straw, water weeds and crop residues, which commonly leads to "scum" problems necessitates periodic and shorter-interval cleaning of the digesters. Another limitation in China, of course, is lower climatic temperatures especially in the northern areas. This lowers gas production considerably during the cold winter months.

## Appendix L (Cont.)

Some example of common combinations of raw materials used in China are:

- 1) 20% urine, 30% nightsoil, 50% water;
- 2) 10% night soil, 30% animal manure, 10% straw, 50% water;
- 3) 20% night soil, 30% pig manure, 50% water;
- 4) 10% night soil, 10% animal manure, 30% grass, 50% water.

In popularizing the technology, the Chinese claim the following advantages of biogas:

- 1) Biogas production protects forest and timber -- saves firewood which is in short supply in most areas of the country.
- 2) Manure from biogas digestion is richer in nitrogen content and contains more quantity of nutrients than that from conventional composting. Through research findings they claim that:
  - a) ammonia up by 120%;
  - b) quick-acting phosphorus up by 150%
  - c) wheat yield increases by 17% over that treated ordinary compost.
- 3) Manure from biogas plant is free from offensive odors, compared to manure from compost pits/heaps. Parasites are killed during digestion process, thereby resulting in a healthier environment.
- 4) Biogas conserves local fuel -- firewood, coal, kerosene. Additionally, the process produces excellent fertilizer from human, animal and plant wastes which otherwise would present health hazards or merely burned away.
- 5) Biogas can substitute for petroleum to run internal combustion engines to supply electricity and other power needs in the rural areas.
- 6) Biogas provides clean, convenient fuel for household cooking and good light for reading. Rice straws which once were burned for fuel can now be used for animal bedding or feed.
- 7) Biogas saves time in cooking, thus reducing housekeeping chores for women.
- 8) Biogas production is complementary to piggery development.

## Appendix I (Cont.)

As of 1972, China has seven million biogas units. How could China have achieved such record success while other countries were struggling with problems of technology dissemination. The answer may lie in at least two important reasons. One is the Chinese national spirit of self-reliance and determination to make the most of its available resources and ingenuity. The other reason is in the practical aspects of both the design breakthrough of the biogas digesters as well as of the application of technology itself.

The practical design attributes of Chinese digesters are:

- 1) Simplicity - - no moving parts in operation;
- 2) Use of locally available building materials;
- 3) low cost;
- 4) minimum metal materials and welding necessary;
- 5) requires a comparatively simple way of building/construction;
- 6) use of local skills and workmanship;
- 7) considerations given for local conditions;

The biogas technology attributes, on the other hand, focus on real felt needs:

- 1) conservation of natural resources;
- 2) utilization of abundant animal and agricultural wastes;
- 3) strongly directed toward pollution control and environmental sanitation;
- 4) exploitation of a self-reliant based source of energy.

Appendix M

G L O S S A R Y

Aerobic decomposition - Decay of organic matter in the presence of oxygen.

Anaerobic decomposition - Decay of organic matter in the absence of oxygen.

Anaerobic bacteria - Bacteria which do not use oxygen to live.

Batch-Load Operated Digester - A method of filling a digester wherein the digester is filled all at once, sealed and emptied when the materials have stopped producing gas. The digester is then filled again.

Biogas - A combination of gases produced by anaerobic decomposition.

"Charge" - A mixture of manure and water to be fed into the digester; also an act of filling the digester with manure-water mixture.

Continuous-Loading Operated Digester - A method of filling a digester a little at a time or regularly so that gas and fertilizer are produced continuously.

Digester - The part of a biogas unit where wastes undergo the digestion process.

Digestion - The breakdown of organic materials by biological action. Or the process by which complex organic compounds are broken down into simpler organic molecules; in biogas production, the anaerobic process by which bacteria accomplish this breakdown of organic matter.

Effluent - The liquid and/or solid that comes out of the digester, such as slurry, sludge or scum.

Manometer - A low-cost device for measuring gas pressure, such as a water-column gas pressure gauge.

Night-soil - Human feces.

Parasite - An organism which lives on a different larger animal, such as worms living in the stomach of an animal.

Pathogen - An organism which causes disease in both animals and humans.

## Appendix M (Cont.)

**pH** - A measure of acidity and alkalinity of a substance or a solution. For instance, pH 7 is neutral; pH lower than 7 is acidic; pH greater than 7 is alkaline.

**Retention time** - The time the slurry spends in the digester.

**Scum** - Light materials that rise to the surface of the slurry in the digester. The accumulation and removal of scum is one of the serious problems with biogas digesters.

**Sludge** - The materials consisting mostly of solid particles that settle at the bottom of the digester.

**Slurry** - The mixture of manure and water to be fed into the digester.

**Toxins** - Substances that can kill or "poison" bacteria, like pesticides, disinfectants, etc.

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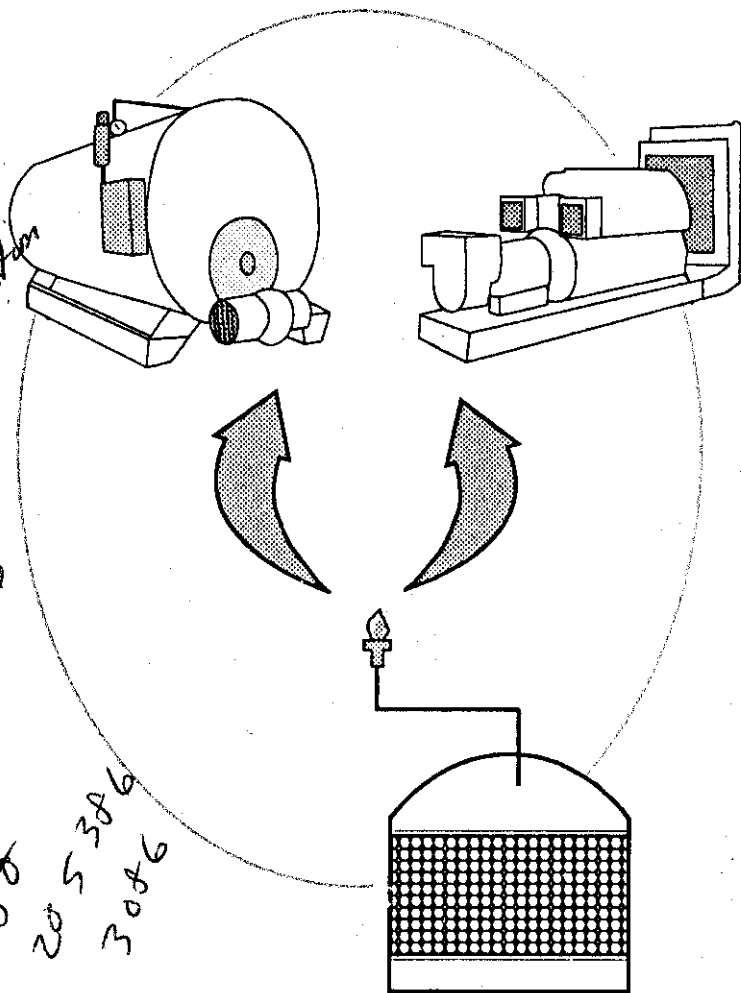
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# Biogas

## Utilization

## Handbook

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## CHAPTER 1 INTRODUCTION

Biogas is a combination of methane, carbon dioxide, and other constituents produced by the anaerobic digestion of hydrocarbons. For many years, biogas was considered a waste product of anaerobic sludge digestion systems, and was simply flared off to prevent injury to personnel. In fact, some plants converted to aerobic digestion systems to eliminate this and other problems associated with anaerobic sludge disposal systems. At covered landfills, biogas was a nuisance which would simply migrate out of the ground. Many landfills installed peripheral gas collection systems and flares to burn the gas and prevent injury to personnel as well as the surrounding community.

The energy crisis initiated by the 1973 Arab oil embargo brought a new awareness of the use of renewable fuels, including biogas. Subsequently, a number of projects sponsored by the U. S. Department of Energy (USDOE), other governmental funding agencies, and private industries, evaluated the use of anaerobic treatment systems for the production of energy. In addition, private enterprises have successfully recovered biogas from more than 200 landfills for production of thermal or electric energy. Although economic feasibility remains dependent upon waste characteristics, treatment system efficiency, and fluctuations in the energy market, these projects have clearly demonstrated the technical feasibility of anaerobic systems for the production of energy.

The interest in anaerobic systems has been furthered by more stringent pretreatment requirements imposed by many Publicly Owned Treatment Works (POTW's). Faced with making pretreatment choices and considering the rising cost of electric power in many localities, many industries favor low energy consumption systems such as anaerobic treatment. However, many of the industries which have chosen anaerobic processes simply flare the biogas produced, illustrating that anaerobic treatment is a good pretreatment alternative irrespective of the energy production potential.

One of the major obstacles to effective industrial use of biogas is the lack of a single source of information on the handling, storage, compression, clean-up, combustion, and safety equipment requirements. The information on the projects sponsored by the USDOE and other private or public organizations are scattered throughout the literature. Design and management strategies for energy recovery are unique with almost every new initiative, and manufacturers of equipment

specifically designed for biogas are sometimes difficult to locate. A unified approach and information clearinghouse are clearly needed to guide development efforts into the 1990's. This handbook is designed to provide a single source of information to help guide industries in their choice of technologies for cost-effective utilization of biogas.

This handbook evolved from literature searches of available publications on landfills, wastewater pretreatment systems, and biogas utilization systems, and contains information on laboratory-, pilot-, and full-scale anaerobic treatment systems and landfills. This information has been analyzed, condensed, and combined where appropriate to provide guidelines generic to most anaerobic treatment systems. The handbook contains an extensive list of references, and the reader is encouraged to use these to obtain more specific information on particular designs or operating strategies.

A list of suppliers for the equipment needed to recover and utilize the biogas from an anaerobic treatment system is contained in the appendix. These manufacturers were identified through a mail survey and the Thomas Register. However, the listing does not include suppliers of common items such as pipe, fittings, valves, gauges, etc. The authors do not wish to imply that the firms listed are the only manufacturers of this equipment, and it is recommended that any firm considering the installation of a system consult publications such as the Thomas Register for other potential equipment suppliers. The Thomas Register can be found in many libraries.

The handbook does not extract design information from national standards such as those published by the American Society for Testing and Materials (ASTM), the American Society of Mechanical Engineers (ASME), and the American National Standards Institute (ANSI). In places where information from these standards is appropriate, the standard is referenced. The purpose of referencing these standards is to avoid any conflict between the handbook and these standards. These standards are updated and revised on a periodic basis, and the potential exists for future revision to conflict with recommendations set forth in this handbook. Before finalizing a design, it is recommended that the most current ASTM, ASME, or other applicable national and local codes be consulted.

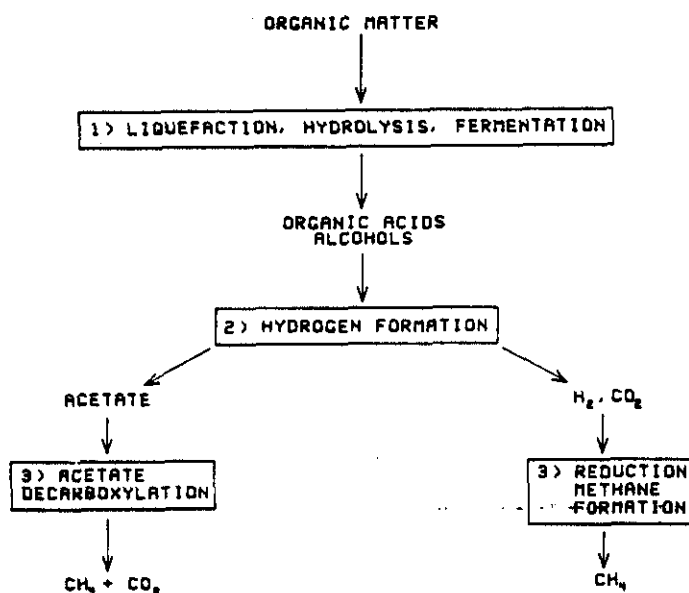


**Introduction**

Biogas is a product of microbiological degradation processes. The primary sources of biogas in the United States are currently waste treatment systems utilizing anaerobic digesters, or solid waste landfills. Both of these waste treatment systems rely upon anaerobic bacteria to convert organic matter to methane ( $\text{CH}_4$ ) and carbon dioxide ( $\text{CO}_2$ ). The major differences between these processes is that landfills are more analogous to batch digesters rather than continuous treatment systems. Moreover, optimum conditions for methane production in landfills are established over a period of years rather than days, thus control requirements for landfills and continuous treatment systems vary greatly.

**Anaerobic Treatment Fundamentals.** Anaerobic treatment processes rely upon the microbiological degradation of organic wastes in an environment absent of molecular oxygen. Fundamentally, the process can be divided into three stages (Figure 2-1) with three distinct physiological groups of microorganisms. The process is briefly summarized here, and is discussed in more detail by McInerney and Bryant (1981).

**Figure 2-1. Steps Involved in the Anaerobic Biological Production of Biogas**



Source: McInerney and Bryant 1981

The first stage involves the fermentative bacteria (and fungi in landfills) including both anaerobic and facultative (aerobic/anaerobic) microorganisms. Complex organic materials, carbohydrates, proteins, and lipids are hydrolyzed and fermented into fatty acids, alcohols, carbon dioxide, hydrogen, ammonia, and sulfides.

In the second stage, acetogenic bacteria consume the primary organic products and produce hydrogen, carbon dioxide and acetic acid. The third stage utilizes two distinct types of methanogenic bacteria. The first reduces carbon dioxide to methane, and the second decarboxylates acetate to methane and carbon dioxide.

The objective of the biogas process is to completely degrade all organic material to methane. Therefore, it is important to optimize biochemical conditions for all reactions leading to the formation of methanogenic precursors and, most importantly, for those reactions responsible for the formation of methane itself. At the same time, production of carbon dioxide, nitrogen, and other gases which dilute the energy content of the gas should be minimized to the greatest extent possible.

## Anaerobic Digesters

Anaerobic digesters are typically used for treating biological sludges, manure, and other high solids wastes. These are most often intermittently fed a slurry of municipal or agricultural wastes at prescribed time intervals. In the reactor, the wastes are held at a certain temperature range for a specified retention time. The nature and composition of the wastes determines the optimum loading rate, temperature, and retention time required for successful operation of the system. Most systems are site-specific, and these variables are best determined experimentally for each individual operation. The type of digester used can vary from simple plug-flow trench type to more complex multi-tank batch systems, or continuously fed and well-mixed continuously stirred tank reactors (CSTR's).

Due to their low cost and relative ease of operation, most farm digesters are of the plug-flow type. Process descriptions and discussions of the advantages and disadvantages of various digester types and their applications can be found in publications by the USEPA (1979c), Stafford (1980), Berdoll (1985), Walker *et al.* (1985), Pratt *et al.* (1986), Sasser (1986), Walsh *et al.* (1986), and Splinter (1987).

Biogas from various sources varies in quality and is dependent upon certain factors. The composition of the biogas depends on the kinds of wastes being digested, and the length of the retention time in which the waste undergoes

digestion. The biogas produced from anaerobic digesters is a mixture of gases. This mixture typically consists of 60-70%  $\text{CH}_4$ , 30-40%  $\text{CO}_2$ , and less than 1% hydrogen sulfide ( $\text{H}_2\text{S}$ ). The  $\text{H}_2\text{S}$  levels are generally from about 100 to 2000 ppm, but levels as low as 2 ppm and as high as 8000 ppm have been reported. Trace amounts of nitrogen (up to 10%), hydrogen (up to 5%), oxygen, and various other constituents may also be present. However, as a result of their very small quantities, they are often very difficult to detect and most often inconsequential.

The production of biogas in digesters is influenced by a number of factors which are presented together with a general commentary in Table 2-1. In general, potential gas production can usually be estimated from the volatile-solids (VS) loading of the digester and the percentage of VS reduction. Gas production rates can vary over a wide range, depending on the VS content of the sludge feed and the level of biological activity in the digester. Typical methane yields for various wastes, loading rates, temperatures and retention times are presented in Table 2-2.

## Landfills

Biogas from landfills typically has a lower methane content (approximately 40-55%) than that of gas produced from digesters. The remaining volume is comprised primarily of carbon dioxide and a total of 1 to 2% of hydrogen sulfide and miscellaneous inorganic gases and organic vapors. Gas composition data from a number of full-scale landfill sites are listed in Table 2-3. The  $\text{H}_2\text{S}$  levels are usually less than 100 ppm, due in part to the low sulfur content of fill material and the complexation of  $\text{H}_2\text{S}$  with metal ions produced by landfill degradation. Unlike digester gas, landfill gas can contain a larger variety of trace constituents. A representative list of these constituents is compiled in Tables 2-4 and 2-5. The low concentrations of these constituents make them very difficult to detect, and their potential impact remains to be fully evaluated and documented.

Optimum conditions for methane production are rarely, if ever, observed in landfills. The rate of gas production may be limited by any of the contributing factors in Table 2-6. Methane production may be increased by monitoring and controlling (to a varying extent) these factors, as outlined by Harper and Pohland (1988).

**Table 2-1. Factors Affecting Digester Biogas Production**

Temperature	most popular is within the mesophilic range of 80°F to 104°F; optimum occurs around 86°F to 95°F; thermophilic digestion also possible (113 to 141°F); small fluctuations from established effective temperature range can upset process.
Retention Time	depends on influent concentration, type of influent, and temperature. Typically 1 to 30 days in full-scale treatment systems and 10 to 20 years in landfills.
Air	must be excluded; toxic to anaerobic processes.
Bacteria	dependent upon waste and temperature; <u>Methanosarcina</u> might be preferred for high rate methane production processes.
C/N Ratio*	less than 43:1.
C/P Ratio*	less than 187:1.
pH	successful range of 6.0-8.0; optimum is near 7.0.
Volatile Acids	bicarbonate alkalinity should exceed volatile acids alkalinity.
Solid Contents	optimum influent solids content is 7-9% by weight; but higher rates have been observed at higher concentrations.
Toxic Substances	the presence of certain cations and heavy metals in sufficient concentrations are toxic to the anaerobic process; too numerous to generalize, but, in general, high concentrations of halogenated organics can be harmful.

\*\* based on the anaerobic biomass approximation of  $C_5H_7NO_2P_{0.1}$  assumed by Pohland and Harper (1987b)

Source: Price (1981), ESCAP (1980), and Pohland and Harper (1987a)

**Table 2-2. Digester Performance Characteristics**

Feed Slurry	Temp (°F)	Loading (lb VS/ft <sup>3</sup> day)	Retention Time (days)	Methane Yield (ft <sup>3</sup> /lb VS added)	Methane Content (vol %)	VS Reduction (%)	Productivity (ft <sup>3</sup> /lb TS)	Reference
Beef Manure	95	.29	14	22.10 (1)	-	-	3.15	Safley (1986)
Beef Manure	140	1.10	6	22.26 (1)	-	-	3.20	Safley (1986)
Beef Manure	131	.21	20	3.52	58	44.2	-	Price (1981)
Beef Manure	131	.71	6	3.68	53	46.1	-	Price (1981)
Beef Manure	131	.47	9	4.48	52	-	-	Fannin (1982)
Dairy Manure	95	.28	14	17.45 (1)	-	-	1.71	Safley (1986)
Dairy Manure	140	1.07	6	18.58 (1)	-	-	1.70	Safley (1986)
Dairy Manure	95	.44	12	.78	65	21	-	Price (1981)
Dairy Manure	91	.54	10	2.27	64	29	-	Price (1981)
Dairy Manure	99	.25	13	3.52	60	42	-	Fannin (1982)
Swine Manure	95	.25	14	24.50 (1)	-	-	4.10	Safley (1986)
Swine Manure	140	.83	6	24.66 (1)	-	-	4.07	Safley (1986)
Swine Manure	54	.19	15	-	-	55	-	Smith (1980)
Poultry Manure	95	.17	14	53.65 (1)	-	-	3.99	Safley (1986)
Poultry Manure	140	.73	6	54.29 (1)	-	-	3.98	Safley (1986)
Poultry Manure	54	.15	40	-	-	55	-	Smith (1980)
Potatoe Tops	-	-	6	9.77	75	-	8.49	Stafford (1980)
Wheaten Straw	-	-	24	5.93	78	-	5.60	Stafford (1980)
Wheat Starch	95	.03	-	-	-	91 (7)	.18 (8)	Joseph Oat Corp. (
Brewery By-Products	99	.37	10	4.80	60-65	-	-	Fannin (1982)
Tomato Solids	95	.19	25	1.60	62	33	-	Fannin (1982)
Whey	72-77	.12 (2)	-	7.21-8.01 (3)	-	97-98 (4)	-	Price (1981)
Milk & Cheese	-	-	-	-	-	-	-	-
Meat Packing	-	.197 (5)	.53	7.16 (6)	-	96 (7)	-	Stafford (1980)
Slaughterhouse	-	.075 (5)	1.4	8.00	81	93.1 (7)	-	Stafford (1980)
Sewage Sludge	-	-	16	9.77	78	-	-	Stafford (1980)
Municipal Garbage	-	-	12	10.09	62	-	-	Stafford (1980)

(1) Methane yield as cft/lb Live Weight added

(2) Loading as lb COD/cft day

(3) Methane yield as cft/lb COD added

(4) COD reduced

(5) Loading as lb BOD/ft<sup>3</sup> day

(6) Methane yield as ft<sup>3</sup>/lb BOD added

(7) BOD reduced

(8) Productivity as volume methane produced per volume of reator per day

VS - Volatile Solids

TS - Total Solids

**Table 2-3. Landfill Performance Characteristics**

<u>Landfill and Location</u>	<u>Depth (ft)</u>	<u>Area (acres)</u>	<u>MSW In Place (tons)</u>	<u>No. of Gas Wells</u>	<u>Depth of Wells (ft)</u>	<u>LFG Recovered (scf/day)</u>	<u>Heat Content (Btu/scf)</u>
Azusa, CA	170	74	7,000,000	41	100-160	4,240,000	500
Palos Verdes, CA	150-250	42	20,000,000	12	150	1,800,000	720
Cinnaminson Newark, NJ	60	62	2,500,000	29	50-60	700,000	550-600
Fresh Kills Staten Island, NY	50	400	75,000,000	123	55	5,000,000	700
Chicago, IL	128	296	7,000,000	14	128	3,531,000	707
Louisville, KY	46	-	900,000	30	-	700,000	354
Royalton Road, OH	40-120	74	2,000,000	20	40-80	1,400,000	354
Aikin Co., SC	33	40	-	-	-	700,000	-
Houston, TX	62	297	-	-	-	7,700,000	-
Richmond, VA	39-118	99	1,500,000	30	59	7,000,000	-

Sources: Pohland and Harper (1987a) and GRCDA (1983)

**Table 2-4. Trace Constituents Detected in Landfill Gas**

<u>Constituent</u>	<u>Mountain View, CA</u> <u>(grains/100scf)*</u>	<u>Scholl Canyon, CA</u> <u>(grains/100scf)*</u>
Hydrogen Sulfide	0.40-0.91	<0.01
Mercaptan Sulfur	0.00-0.33	0.01**
Sulfides (as S <sub>2</sub> )	0.41-0.80	-
Residuals	0.93-1.65	-
Acetic Acid	-	0.27
Propionic Acid	-	0.41
Butyric Acid	-	0.39
Valeric Acid	-	0.13
Caproic Acid	-	0.08
Water Vapor	-	3.0

\* grain/100scf = .00034 lb/scf

\*\* Reported as organic sulfur compounds

Source: EMCON 1980

**Table 2-5. Organic Compounds Identified in Landfill Gas**

Benzene	Hexene
Bimethylbenzene	Iso-octane
Butycyclohexane	Iso-octanol
Chlorobenzene	Isopropylbenzene
Cycloheptane	Methylbenzene
Cyclohexyl-eicosane	Methylcyclopentane
Decahydroaphthalene	Methylene-butanediol
Decane	Methylheptane
Dichloroethane	Methylhexane
Dichloroethylene	Methyl(methylethenyl)-cyclohexene
Dichlorofluoromethane	Methylnonene
Dichloromethane	Methylpentane
Diethylcyclohexane	Methylpentylhydroperoxide
Dimethylcyclohexane	Methylpropylpentanol
Dimethylcyclopentane	Napthalene
Dimethylheptane	Nonane
Dimethylhexane	Nonyne
Dimethylhexene	Octahydromethylpentalene
Dimethyl(methylpropyl)cyclohexane	Octane
Dimethylpentane	Pentane
Ethylbenzene	Propylbenzene
Ethylbutanol	Tetrachloroethene
Ethylcyclohexane	Tetrahydrodimethylfuran
Ethylmethylbutene	Tetramethylbutane
Ethylmethylcyclohexane	Tetramethylcyclopentane
Ethylmethylcyclopentane	Tetramethylhexane
Ethylmethylheptane	Tetramethylhexene
Ethylpentene	Tetramethylpentane
Heptane	Trichlorethane
Heptanol	Trichloroethylene
Hexadiene	Trimethylcyclohexane
Hexane	Trimethylcyclopentane

Source: GRI 1982



**Table 2-6. Factors Affecting Landfill Gas Production**

Nature of Refuse	availability of usable substrate; organic material moisture and nutrient contents; presence of potential inhibitors; protection from microbial activity (i.e., encapsulation in bags or containers).
Moisture Content	provides transport phase for organic substrates and nutrients; expect increasing $\text{CH}_4$ production rates with increasing moisture up to approximately 60% (40% solids).
Particle Size	particle size reduction by refuse shredding may be expected to increase gas production rates; however, due to the large number of variables involved, studies are contrary and not clearly conclusive.
Refuse Compaction	may impede moisture and gas flow through wastes, but will minimize volume of wastes; studies give conflicting results.
Buffer Capacity	beneficial in accelerating biological stabilization and increasing gas production rates; buffer needed to moderate effects of volatile and other acids; site specific based on leachate analysis.
Nutrients	whether or not nutrient sufficiency exists may be evaluated through leachate analysis; some have found $\text{PO}_4$ to be limiting; area needs more study.
Temperature	affects microbial activity within landfill and vice versa; winter time activity is usually slower.
Gas Extraction	should not exceed biological production; if so, this may lead to excessive amounts of $\text{N}_2$ and $\text{O}_2$ ; $\text{O}_2$ is toxic to the anaerobic process and excess $\text{N}_2$ decreases the energy value and requires expensive gas treatment.

Sources: EMCON (1980) and Pohland and Harper (1987a)

There are several methods available for formulating projections of gas yields from landfills. Theoretical and empirical approaches are reviewed in detail by EMCON (1980) and Pohland and Harper (1987a). These are not useful in sizing recovery equipment, but can be used to predict gas yields. The theoretical models make use of stoichiometric and kinetic methods. Because they fail to include numerous factors and assume 100% recovery of gases produced, at best these are rough estimates of potential gas production. Field and laboratory observations are the best indicator of actual gas yields in landfills. Gas yield production rate predictions are generally obtained by comparing the overall gas yields from laboratory studies to stabilization time, by installing observation wells, or by literature comparison.

## CHAPTER 3

### BIOGAS COMBUSTION CALCULATIONS

#### Approximate Fuel Value

Pure methane at standard temperature and pressure has a lower heating value of approximately 912 Btu/ft<sup>3</sup>. Typical biogas of 65% methane has a heating value of approximately 600 Btu/ft<sup>3</sup> since only the methane portion will burn. Approximate equivalents of biogas to other fuels are presented in Table 3-1.

**Table 3-1. Fuel Equivalents of Biogas (per 1000 ft<sup>3</sup>)\***

600 ft <sup>3</sup> of natural gas
6.6 gal. of propane
5.9 gal. of butane
4.7 gal. of gasoline
4.3 gal. of #2 fuel oil
44 lb. of bituminous coal
100 lb. of medium-dry wood

\* Biogas with 65% methane

Source: Palmer 1981

#### Properties of Gases

The physical and chemical properties of biogas affect the choice of technology used for clean-up and combustion; therefore, a knowledge of these properties is useful for optimizing biogas utilization. Since biogas contains primarily methane and carbon dioxide (see Chapter 2), this discussion is focused on their respective physical characteristics, as listed in Table 3-2. Other components (nitrogen, hydrogen sulfide, trace organics) are present in relatively small quantities, the magnitude of which varies greatly and depends on the composition of the material digested. Although the small concentration of these trace gases have little effect on the physical properties of the gas, they influence the choice of technologies. Therefore, individual components should be evaluated on a site-specific basis.

**Table 3-2. Physical Constants of Methane and Carbon Dioxide<sup>a</sup>**

	Methane (CH <sub>4</sub> )	Carbon Dioxide (CO <sub>2</sub> )
Molecular Weight	16.04	44.01
Specific Gravity, Air=1 <sup>c</sup>	0.554	1.52
Boiling Point @ 14.7 psia	259.0°F	109.4°F <sup>b</sup>
Freezing Point @ 14.7 psia	-296.6°F	-69.9°F
Specific Volume	24.2 ft <sup>3</sup> /lb	8.8 ft <sup>3</sup> /lb
Critical Temperature	116.0°F	88.0°F
Critical Pressure	673 psia	1,072 psia
Heat Capacity C <sub>p</sub> 1 atm	0.540 Btu/lb-°F	0.205 Btu/lb-°F
Ratio C <sub>p</sub> /C <sub>v</sub>	1.307	1.303
Heat of Combustion	1012 Btu/ft <sup>3</sup> 23,875 Btu/lb	
Limit of Inflammability	5-15% by volume	
Stoichiometry in Air <sup>c</sup>	0.0947 by volume 0.0581 by mass	

a - Properties of pure gases given at 77°F and atmospheric pressure

b - Sublimes

c - Air at 14.7 psia, 60°F

### Volumetric Compensation

Volumetric measurement of biogas, like any gas, must be compensated for pressure and temperature differences. The equation below (Salisbury 1950) illustrates a simple method of gas volume compensation for a saturated gas:

$$V_s (\text{sat.}) = V \times 17.626 \times \frac{(H - A)}{(459.6 + T)}$$

Where:

V = observed volume

V<sub>s</sub> = volume at standard conditions, 60°F and 30 inches Hg

H = absolute gas pressure, inches Hg

A = water vapor pressure, inches Hg, for gas at temperature T

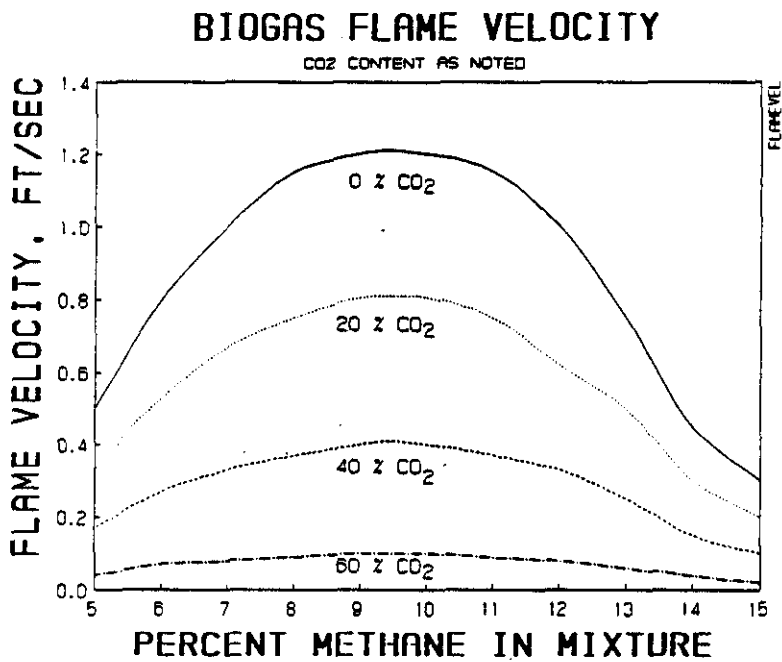
T = temperature of gas, °F

### Flame Velocities

A major consideration in analyzing gaseous fuels, particularly those such as biogas with low energy contents due to dilution with various non-combustible gases is the flame velocity of that fuel during combustion. Flame velocity is defined as the speed at which a flame progresses into a mixture relative to the speed of the fuel mixture. It is important in the design of systems for feeding fuel and air to burners and in the setting of the spark advance for internal combustion engines.

The impact of carbon dioxide concentrations on flame velocities over the limits of inflammability of a methane/carbon dioxide mixture are illustrated in Figure 3-1. The information can be used to compare the performance of a combustion system designed for natural gas that will be modified for operation on biogas. The data were computed using techniques outlined in Salisbury (1950).

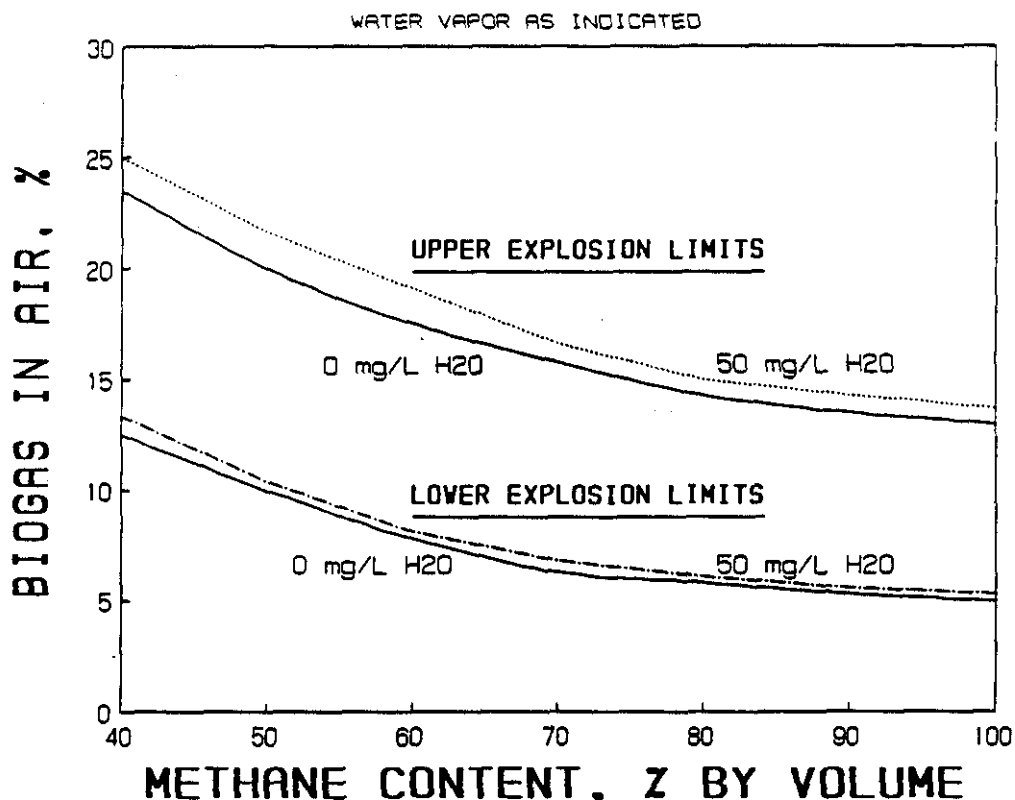
**Figure 3-1. Flame Velocity as a Function of Carbon Dioxide Concentration**



### Flammability Limits

Flammability limits (or limits of inflammability) indicate the maximum and minimum percentages of a fuel in a fuel and air mixture at which the mixture will burn. This is a critical parameter in biogas combustion due to the dilution of methane in a biogas fuel with carbon dioxide and other inert gases. The flammability limits of methane are listed in Table 3-1, and range from 5% to 15% in air. These two values are also known as the lower explosive limit (LEL) and upper explosive limit (UEL), respectively. The impact of CH<sub>4</sub> dilution (by CO<sub>2</sub> and water vapor) on flammability limits are illustrated in Figure 3-2. The data were computed using techniques in Salisbury (1950).

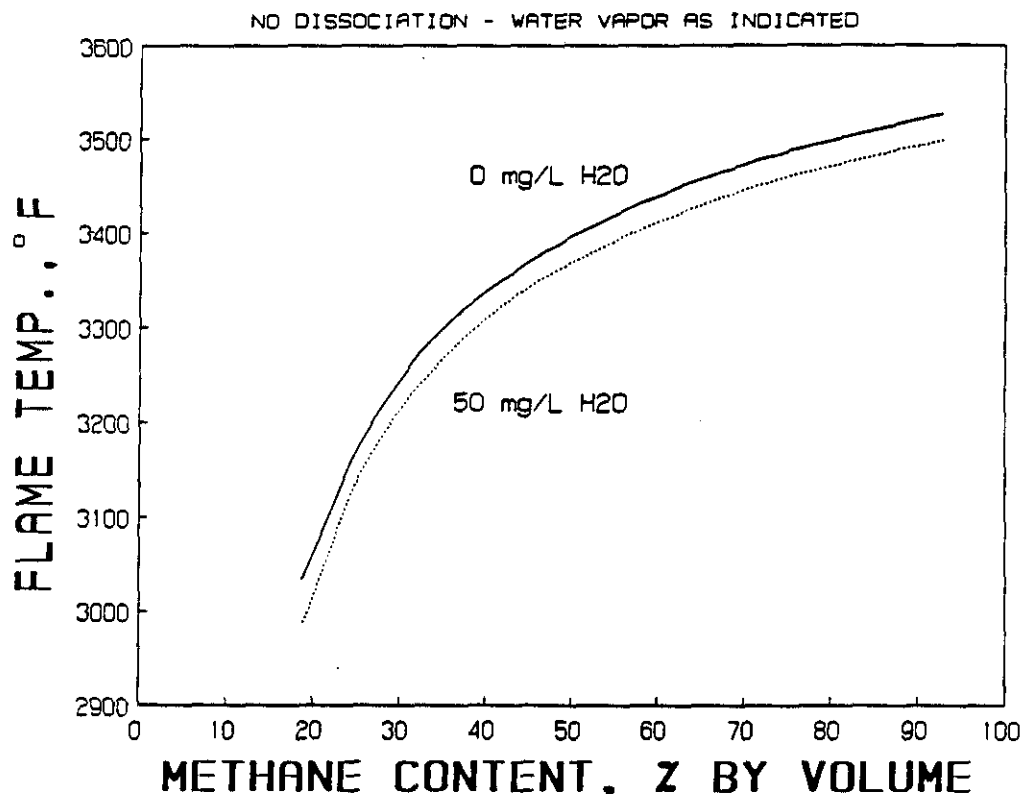
**Figure 3-2. Flammability Limits as a Function of Carbon Dioxide and Water Vapor Concentration**



### Flame Temperatures

The temperature of the flame front created by a combustible mixture is important with respect to the performance of all types of combustion systems. In the operation of boilers, flame temperature (sometimes referred to as hot mix temperature) is an indication of thermal efficiency. The temperature of the exhaust gases from a combustion system will affect the potential for heat recovery and the formation of nitrogen oxides in the exhaust. The theoretical flame temperature of methane in a stoichiometric mixture with air and including dissociation is 3484°F (North American Mfg. 1978). However, the theoretical flame temperature decreases as the concentration of non-combustibles increases; accordingly, the theoretical flame temperature as a function of water vapor and methane content is shown in Figure 3-3. The data were computed using techniques in Salisbury (1950).

**Figure 3-3. Theoretical Flame Temperatures as a Function of Methane and Water Vapor Concentration**



### Fuel Energy Value

The gross and net heating values of simple fuels are important in defining the energy available from different gases and are compared in Table 3-3. Since different gases have different heating values, calculation of the net heating value of a mixture such as biogas must take into account not only the amount of methane but also all other combustible and non-combustible gases. The higher heating value (HHV) is the energy released from a given mass of a fuel where the energy required to vaporize the water in the fuel is recovered. The HHV of methane, the primary combustible in biogas, is listed as 1012 Btu/SCF. The lower heating value (LHV) is defined as the higher heating value less the energy required for the vaporization of water in the fuel and combustion products. For methane, the net or lower heating value is 912 Btu/SCF. The effect of biogas moisture content and CH<sub>4</sub> content on the net heating value of biogas is illustrated in Figure 3-4. The data were computed using techniques in Salisbury (1950). A comparison of energy values for several commercial fuels is provided in Table 3-4.

**Table 3-3. Comparative Fuel Values for Several Simple Fuels**

<u>Fuel</u>	<u>Heating Values</u>		<u>Air-Fuel Ratio</u>	
	<u>Btu/ft<sup>3</sup></u>	<u>Btu/lb</u>	<u>Vol Air</u>	<u>Wt Air</u>
	<u>Higher Heating Values</u> (Lower Heating Values)		<u>Vol Fuel</u>	<u>Wt Fuel</u>
Butane, n-C <sub>4</sub> H <sub>10</sub>	3,271 (3,018)	21,321 (19,678)	31.0	15.50
Hydrogen, H <sub>2</sub>	325 (275)	61,095 (51,623)	2.38	34.50
Hydrogen Sulfide, H <sub>2</sub> S	646 (595)	7,097 (6,537)	7.15	6.08
Methane, CH <sub>4</sub>	1,012 (911)	23,875 (21,495)	9.53	17.20
Octane, C <sub>8</sub> H <sub>18</sub>	6,260 (5,806)	20,796 (19,291)	----	15.10
Propane, C <sub>3</sub> H <sub>8</sub>	2,524 (2,322)	21,669 (19,937)	23.8	15.70

Source: North American Manufacturing 1978

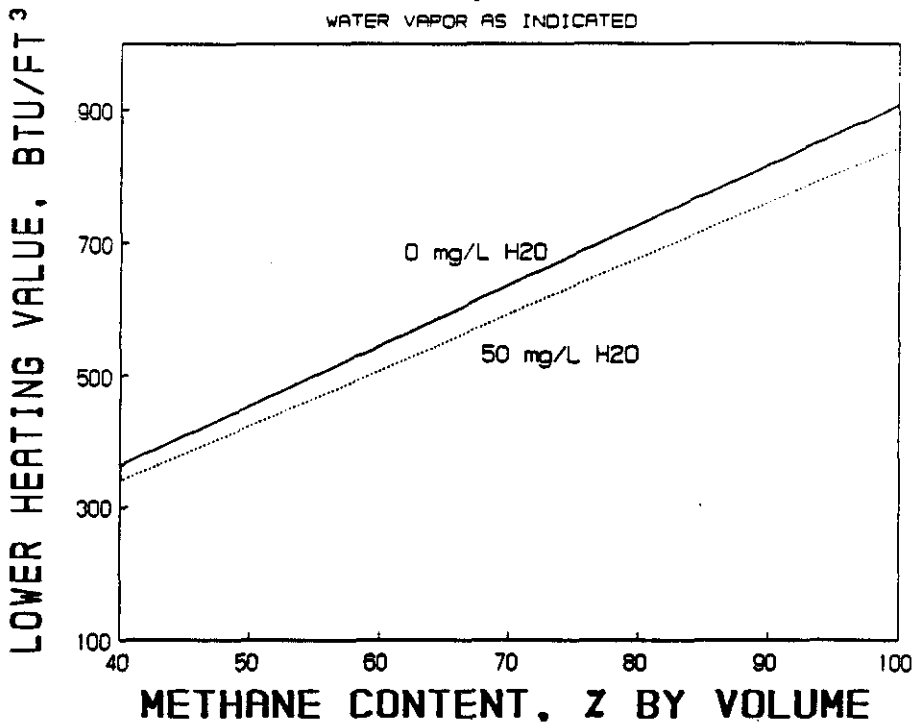
**Table 3-4. Comparison Fuel Values for Commercial Fuels**

<u>Fuel</u>	<u>Heating Values</u>		<u>Air-Fuel Ratio</u>	
	<u>Btu/lb</u>		<u>Wt. Air</u>	<u>SCF</u>
	<u>Higher</u>	<u>Lower</u>	<u>Wt. Fuel</u>	<u>Gal.</u>
Natural Gas	21,830	19,695	15.73	----
Gasoline	20,190 (123,361)	18,790 (114,807)	14.80	1,183
Diesel (#2)	18,993 (137,080)	17,855 (128,869)	14.35	1,354
Fuel Oil (#4)	18,884 (143,010)	17,790 (135,013)	13.99	1,388
Propane	21,573 (91,500)	19,886 (84,345)	15.35	851

Source: North American Manufacturing 1978



**Figure 3-4. Lower Heating Values as a Function of Methane and Water Vapor Content**



### Fuel Mixtures

As described under flammability limits, methane and air mixtures will combust between 5% and 15% methane in air. The optimum concentration of  $\text{CH}_4$  in air is often referred to as the stoichiometric mixture (i. e., the concentration at which complete combustion occurs without unused air or fuel) is 9.4%. This is also referred to as the Air-Fuel Ratio, which is defined as:

$$\text{Air-Fuel Ratio (AF)} = \frac{\text{mass flowrate of air}}{\text{mass flowrate of fuel}}$$

For methane in air, the stoichiometric AF is 17.21 lb air/ lb  $\text{CH}_4$ .

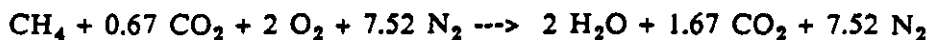
Equivalence ratios ( $\phi$ ) are used to describe the degree of variation from the stoichiometric ratio, from excess air to excess fuel. The equivalence ratio is defined as:

$$\text{Equivalence Ratio } (\phi) = \frac{\text{AF Stoichiometric}}{\text{AF Actual}}$$

Where:

- $\phi = 1$  is a stoichiometric ratio
- $\phi < 1$  is a lean mixture, excess air
- $\phi > 1$  is a rich mixture, excess fuel

The stoichiometric ratio of biogas will obviously vary with the amount of non-combustible gases mixed with the methane. For example, a mixture of 60% methane and 40% carbon dioxide will have the theoretical chemical reaction with air of:



and will have a stoichiometric ratio ( $\phi=1$ ) of 6.03 lb air/lb biogas.

For comparison, the Air-Fuel Ratio of biogas can be defined as (Stahl 1983):

$$\text{AF Actual} = \frac{m_{\text{air}}}{V_{\text{bg}} r P_{\text{CH}_4}}$$

Where:

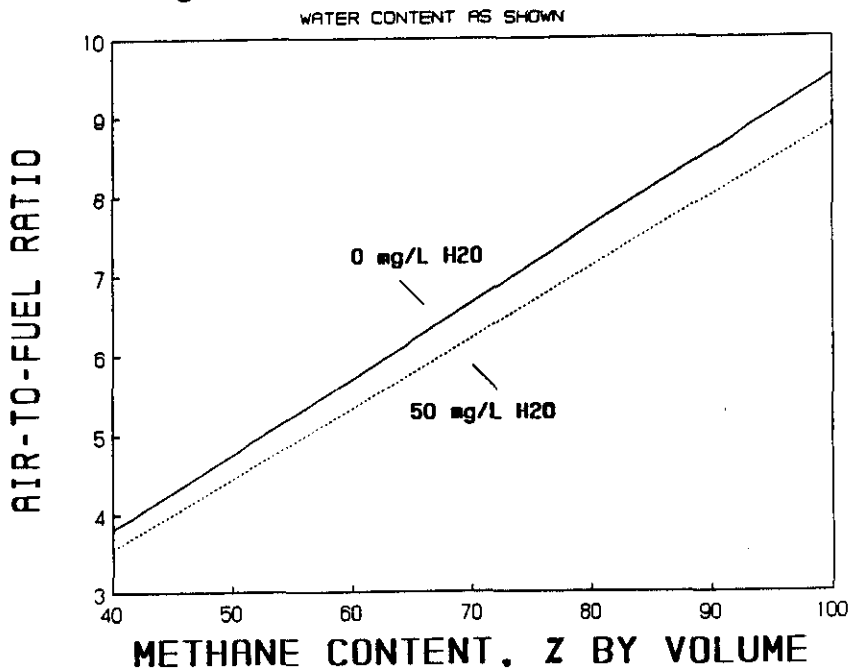
$m_{\text{air}}$	=	mass flowrate of intake air
$V_{\text{bg}}$	=	flowrate of biogas at standard conditions
$r$	=	volume ratio of $\text{CH}_4$ in biogas
$P_{\text{CH}_4}$	=	density of methane (See Table 3-1)

This ratio is directly related to the concentration of methane, and can be compared to the stoichiometric ratio for air and methane of 17.21 to calculate equivalence ratios. Additional comparative data on combustion characteristics of methane and other fuels are illustrated in Tables 3-3 and 3-4, and the variation of Air-Fuel Ratio for biogas as a function of the methane and water vapor content is illustrated in Figure 3-5. The data were computed using techniques in Salisbury (1950).

A rule-of-thumb often used by combustion engineers is one cubic foot of air required to produce 100 Btu of heat. North American Mfg. (1978) recommends for gaseous fuels having more than 400 gross Btu/SCF the following empirical formula:

$$\frac{\text{Required Air Volume}}{\text{Fuel Gas Volume}} = \frac{\text{gross heating value in Btu/SCF}}{100} - 0.6$$

Figure 3-5. Air-Fuel Ratio Variation



### Water Vapor

While not as prevalent a diluent as carbon dioxide, water vapor can have a significant effect on biogas combustion characteristics. As illustrated in Figures 3- through 3-5, water vapor has a small but noticeable impact on flame temperature, flammability limits, lower heating value, and Air-Fuel Ratios of biogas.

These effects plus the potential for corrosion highlight the need for water vapor reduction in biogas. Depending on temperature, biogas samples immediately after the outlet from a digester may contain as much as 50 mg/L water vapor, which is near the saturation level.

### Application of Data

Much of the data presented in this section will be utilized by the engineer during the design of equipment for biogas systems. The information is needed to determine the sizing, flow rates, and configuration for equipment specifically designed for the combustion of biogas. The data can also be used to modify equipment designed for other fuels such as natural gas and propane for operation on biogas fuels. Many of the systems designed for these conventional fuels can be simply modified for biogas combustion by using the appropriate design factors.

However, as discussed in Chapter 2, the biogas produced from a digester and landfill can change in composition depending on a number of factors. Changes in feed, loading rates, temperature and other factors can significantly affect the composition of the biogas produced. Therefore, a knowledge of the data discussed in this chapter is important to the operator of a biogas utilization system when analyzing problems in the performance of a biogas combustion system.

## CHAPTER 4

# HANDLING AND COLLECTION OF BIOGAS

### Introduction

The systems and equipment required for collection of biogas from an anaerobic system or landfill, and for biogas transport to the combustion equipment, and/or to other pieces of equipment such as compressors, clean-up systems, and storage tanks are discussed in this chapter. Most of this equipment consists of piping and valves but special designs and materials are required for the removal of condensed water and the prevention of corrosion.

### Piping Systems

Design and Operating Pressures. The operating pressure of most biogas handling systems will generally be less than 1 psig (30 inches water column, w.c.) However, if the system contains a compressor, some piping in the system could have an operating pressure as high as 500 psig. Most systems will need a relief valve; therefore, the maximum operating pressure will be the set pressure of the relief valve. If a system with a compressor does not have a relief valve, the maximum operating pressure will be the shut-off pressure of the compressor which occurs when the gas flow through the compressor is zero and the output pressure is a maximum.

The design pressure used for determination of pipe and valve wall thickness schedules should be computed as follows:

$$\text{Design Pressure} = 1.5 \times \text{Maximum Operating Pressure}$$

High pressure systems should be hydrostatically tested to assure that there are no safety problems with the system. The pressure at which the system should be hydrostatically tested is computed as follows:

$$\text{Hydrostatic Test Pressure} = 1.5 \times \text{Design Pressure}$$

Design and Operating Temperatures. The temperature of the biogas will be approximately the same as the temperature of the source from which the gas is produced, i. e., digester or landfill. The maximum operating temperature of a biogas handling system will be approximately 150°F since the highest temperature biogas generators known are thermophilic digesters which operate best at a temperature of

131°F. If the gas is compressed without cooling to remove the heat of compression the gas temperature will be significantly increased. The gas temperature can be computed as follows:

$$T_{\text{compressor out}} = T_{\text{compressor in}} \times (P_{\text{out}}/P_{\text{in}})$$

where:

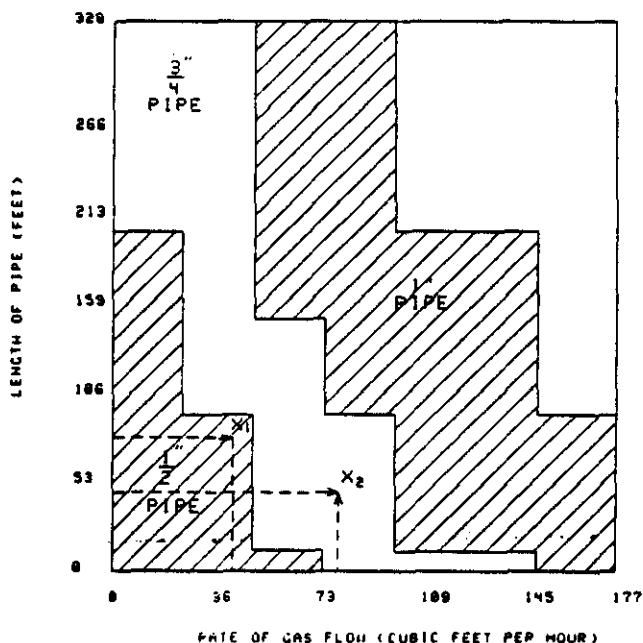
$$\begin{aligned} T_{\text{compressor out}} &= \text{Compressor Outlet Gas Temperature (°R)}, \\ T_{\text{compressor in}} &= \text{Compressor Inlet Gas Temperature (°R)}, \\ P_{\text{out}} &= \text{Compressor Outlet Pressure (psig)}, \\ P_{\text{in}} &= \text{Compressor Inlet Pressure (psig), and} \\ T^{\circ}\text{R} &= T^{\circ}\text{F} + 460 \end{aligned}$$

The design temperature is computed as follows:

$$\text{Design Temperature} = 1.5 \times \text{Maximum Operating Temperature}$$

**Pipe Sizing.** A quick determination of pipe size can be made using the diagram presented in Figure 4-1. In order to use the figure, the rate of gas flow in cubic feet per hour and the length of pipe must be determined. As shown in the figure, a flow rate of 50 cubic feet per hour in a pipe 75 feet long requires a pipe diameter of 1/2 inch. Likewise a flow of 80 cubic feet per hour in a 50 foot pipe requires a 3/4 inch pipe.

**Figure 4-1. Recommended Pipe Sizing**



Source: ESCAP 1980

Pipe Thickness Selection. The design pressure and temperature computed in the preceding sections are used to select the pipe thickness. In general, most low pressure systems can use standard weight pipe (Schedule 40), but high pressure systems usually require heavier walls. Carbon steel should be adequate for all low pressure systems but other materials may not. The temperature and pressure rating of any material other than carbon steel, stainless steel, or galvanized iron should be checked, and the pipe should not be used if this information cannot be obtained.

Some materials may be marked with an indication such as ASTM D-124. This indicates that information on the material can be obtained from the American Society for Testing and Materials (ASTM).

The wall thickness needed for high pressure piping depends on several factors such as the design pressure, material, corrosion allowances, and allowances for threaded ends (if used). ANSI B31.1, Code for Pressure Piping, should be used for the determination of the wall thickness of all high pressure piping systems.

Materials. Once the design temperature and pressure of the handling and collection system have been established, the materials for the system can be selected. The advantages and disadvantages of the more common materials used in biogas handling and collection systems are compared in Table 4-2. High pressure systems will require steel or iron pipe, but plastic piping may be preferred for ease of installation with low pressure systems.

Piping Codes. State and local building codes and/or insurance carriers may require that the biogas piping systems be designed in accordance with national codes or standards. Table 4-3 lists the principal codes that may apply to biogas piping systems as published by the American Society for Testing and Materials (ASTM) and the American National Standards Institute (ANSI).

Special Considerations for Pipe Installation. There are other additional considerations which should be incorporated in the design of a piping system.

Accidental Breakage - One of the major dangers with piping systems transporting a combustible gas (particularly plastics) is the susceptibility of these systems to accidental breakage by plant personnel, vehicles, or animals. Methods of pipe protection include burying pipes in soil and placing heavy steel pipes near plastic piping that could be accidentally broken.

**Table 4-1. Advantages and Disadvantages of Materials for Gas Piping**

<u>Material</u>	<u>Advantages</u>	<u>Disadvantages</u>
Plastic (PVC, CPVC)	Easy to work with, relatively inexpensive	Subject to breaking, can be eaten by rodents; valves more expensive than galvanized, also subject to ultraviolet degradation
Galvanized Iron	Less breakable	Can rust, pipe more expensive than plastic
Flexible (5 ply rubber hose)	Ease of connection to equipment	Expensive
Plastic (ABS)	None	Not Recommended

Sources: ESCAP 1980 and EMCON 1980

**Table 4-2. National Standards Applicable to Piping Systems**

ANSI B-31, "Piping Codes"

ASTM D-3350, "Polyethylene Plastics Pipe and Fitting Materials"

ASTM D-2774, "Underground Installation of Thermoplastic Pressure Piping"

ASTM D-2321, "Underground Installation of Flexible Thermoplastic Sewer Piping"

ASTM D-2513, "Thermoplastic Gas Pressure Pipe, Tubing and Fittings"



Vibration Isolation - Compressors can potentially transmit vibration loads to plastic pipe or plastic storage vessels, which could eventually damage these components. Vibration dampers may be required to preclude transmission of vibration loads.

Thermal Expansion - Thermal loads could be placed on plastic pipe or storage vessels by steel pipe heated by combustion or compression equipment. Thermal expansion loops or joints may be required to reduce these loads and prevent damage to equipment.

## **Valves**

A summary of the advantages and disadvantages of the different types of valves that can be used in biogas systems is presented in Table 4-3. Valve material selection is subject to the same restrictions as piping systems. Brass ball valves (brass taps) can be used; but, these must not contain any lead as hydrogen sulfide tends to attack the lead and destroy the tap.

## **Painting**

All metallic piping should be painted to prevent rust or corrosion. Painting should be accomplished regardless of whether or not the pipe is indoors, outdoors, or buried. Table 4-4 contains some recommendations on paint for biogas handling and collection equipment.

## **Condensate Drains**

One of the major problems associated with handling biogas is the large quantity of water vapor contained in the gas. In order to remove water from the pipe, all horizontal runs of pipe should be installed with a pipe slope of 1:100. A condensate drain must be located at all low points in the piping.

There are a number of different systems which can be used for draining condensate from a pipe. Figures 4-2 through 4-5 illustrate a manual system (tee), U-pipe drain, a siphon system, and a water outlet device. The main advantages and disadvantages of each system are listed in Table 4-6.

**Table 4-3. Advantages and Disadvantages of Valves for Biogas Systems**

<u>Type</u>	<u>Advantages</u>	<u>Disadvantages</u>
Gate	Low Cost	Moisture can be trapped in slot
Globe	Slightly higher cost than gate	Not good for quick shut-off
Butterfly	Low cost	Not recommended for combustible gas service
Ball	Best choice for shut-off	Cost

Source: ESCAP 1980

**Table 4-4. Recommendations for Painting**

<u>Cost</u>	<u>Primer Type</u>	<u>Number of Coats</u>	<u>Paint Type</u>	<u>Number of Coats</u>
Low	Red Oxide	1	Normal	2
Medium	Anti-saline	1	High-Build Black Bitumen	2
High	Epoxy	1	*Epoxy	2

\* Steel must be sand- or grit-blasted.

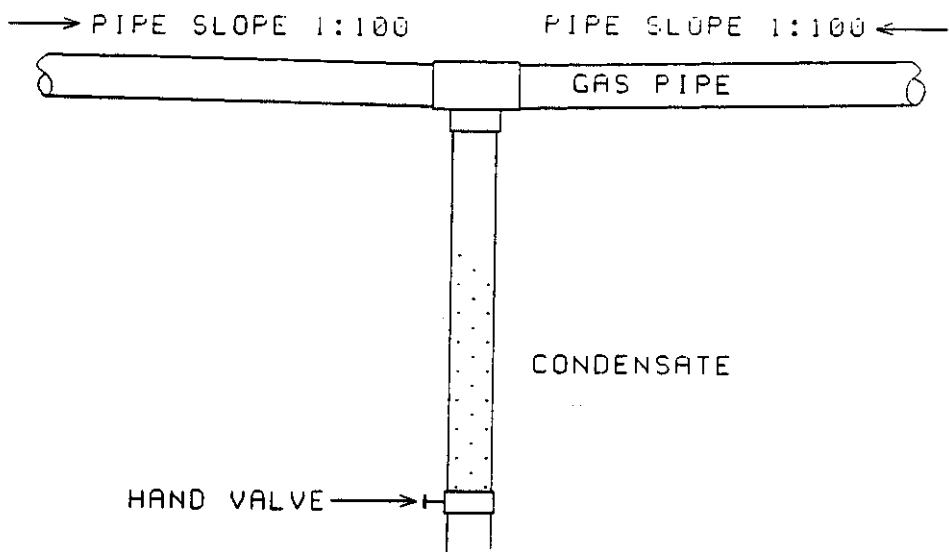
Source: ESCAP 1980

**Table 4-5. Condensate Draining Systems**

<u>Type</u>	<u>Advantages</u>	<u>Disadvantages</u>
Tee	Inexpensive, no danger of flooding if checked	Manual attention required
U-pipe Design	Automatic	Danger of gas leak in the event of evaporation
Siphon and block gas line if underground	Automatic	Expensive, can flood
Water Outlet Device	Automatic	Expensive

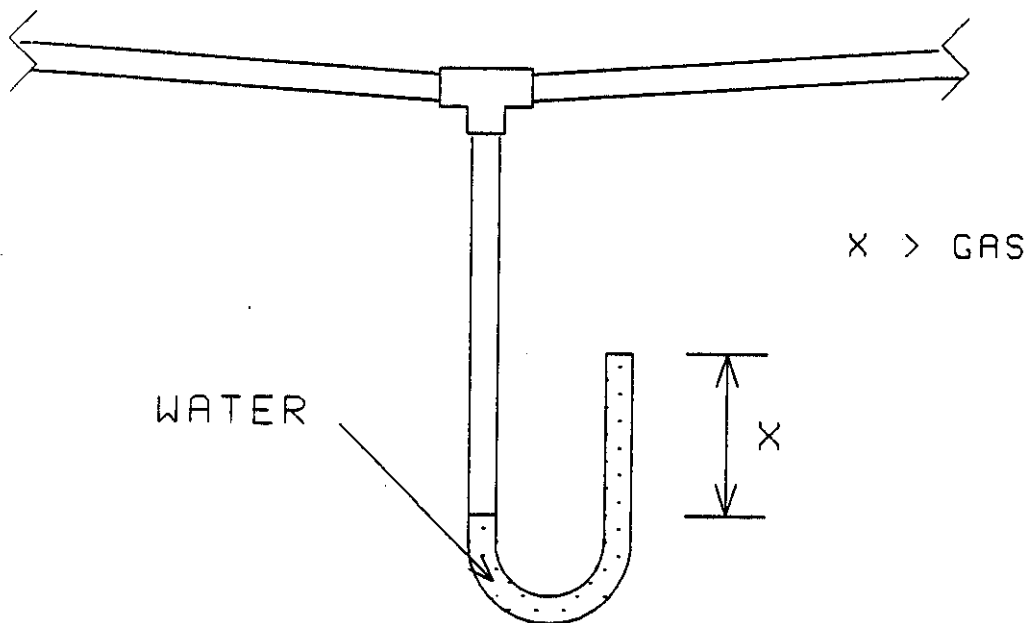
Source: ESCAP 1980

**Figure 4-2. Manual Condensate Drain**



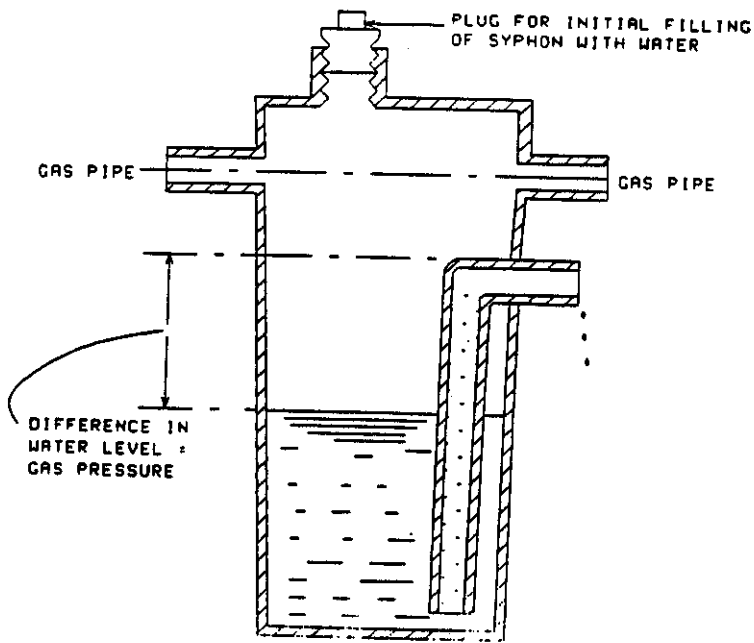
Source: ESCAP 1980

**Figure 4-3. U-Pipe Condensate Drain**



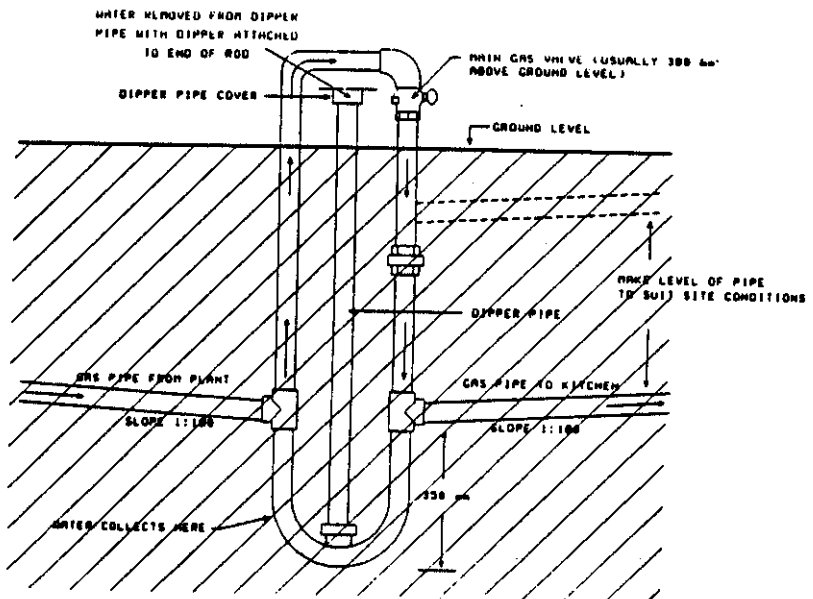
Source: ESCAP 1980

**Figure 4-4. Siphon Condensate Drain**



Source: ESCAP 1980

**Figure 4-5. Water Outlet Device**

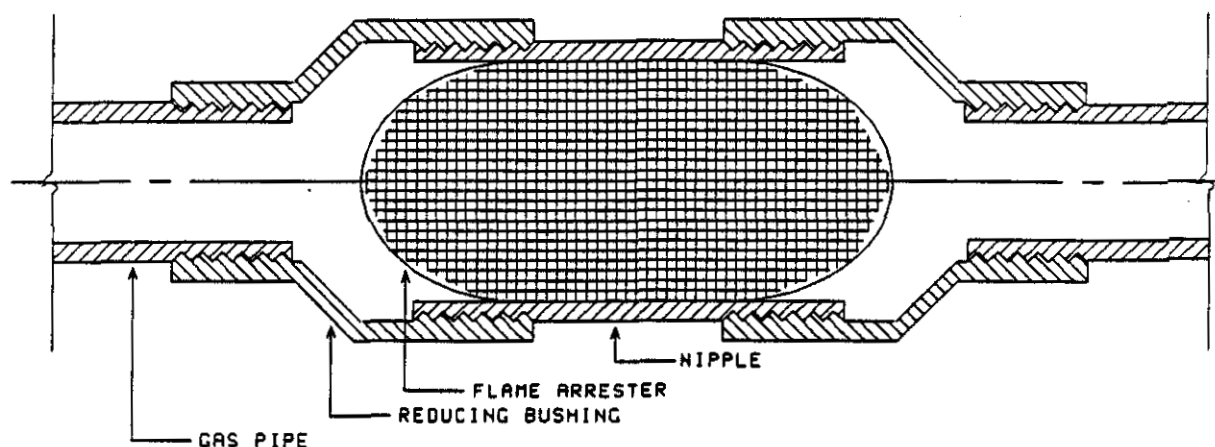


Source: ESCAP 1980

## Flame Arresters

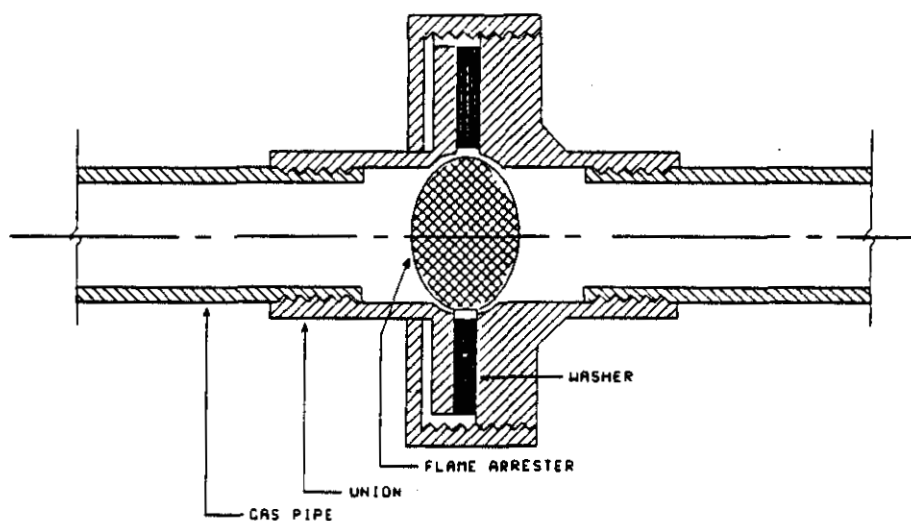
A flame arrester should be located in the gas line just downstream of the gas source. The purpose of this device is to prevent a flame from running back down the pipe and causing an explosion. A ball or roll of fine mesh copper wire works well for this application. Two typical flame arrester installations are shown in Figures 4-6 and 4-7.

**Figure 4-6. Flame Arrester Installation A**



Source: ESCAP 1980

**Figure 4-7. Flame Arrester Installation B**

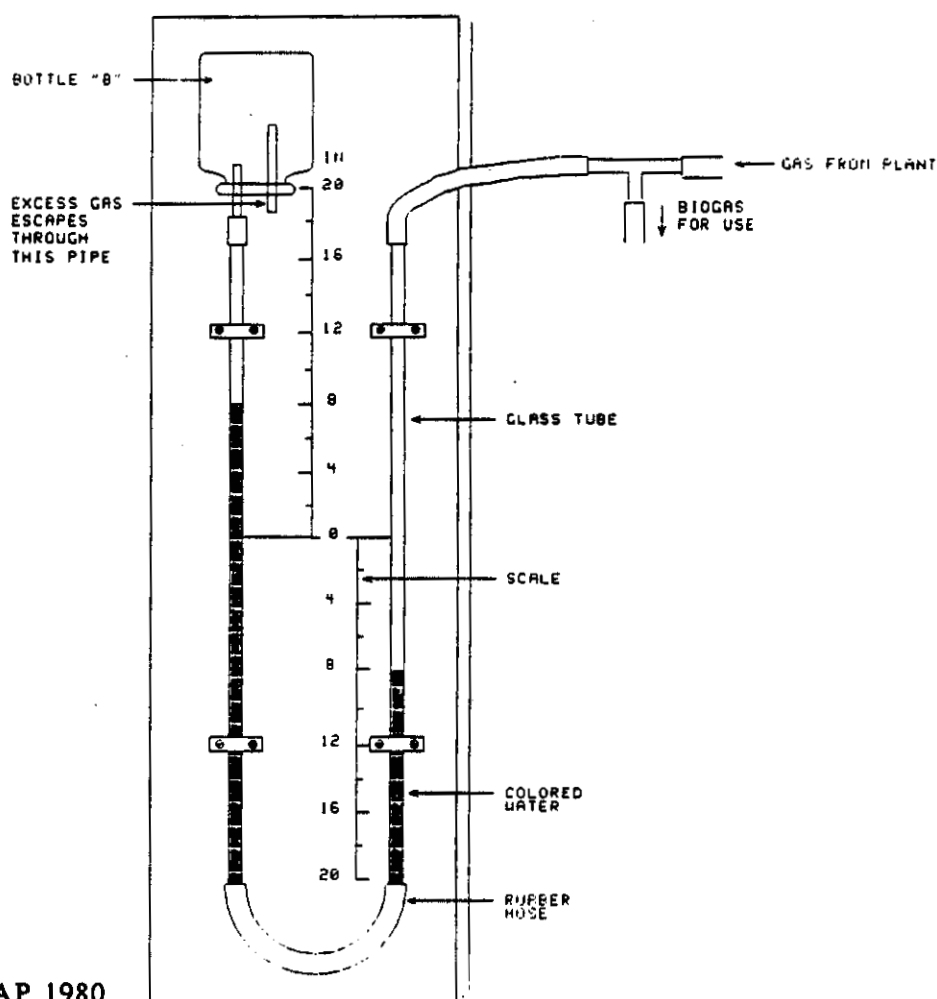


Source: ESCAP 1980

## Leak Checks

The entire piping system should be pressure tested for leaks. The method for checking for leaks depends on the pressure at which the system will operate. High pressure systems can be checked for leaks during hydrostatic testing. Low pressure systems can be checked using a simple pressurization system such as the one illustrated in Figure 4-8. The elevation level between the top and the water in the bucket and the top of the water level in the U-tube should be equal to the design pressure of the system. If the water level in the bucket remains constant for 24 hours, the system can be considered "leak free." If the water level drops, the leak can be found by brushing or squirting soapy water on joints and other connections until bubbles identify the source of the leak.

**Figure 4-8. Leak Test Pressurization System**



Source: ESCAP 1980

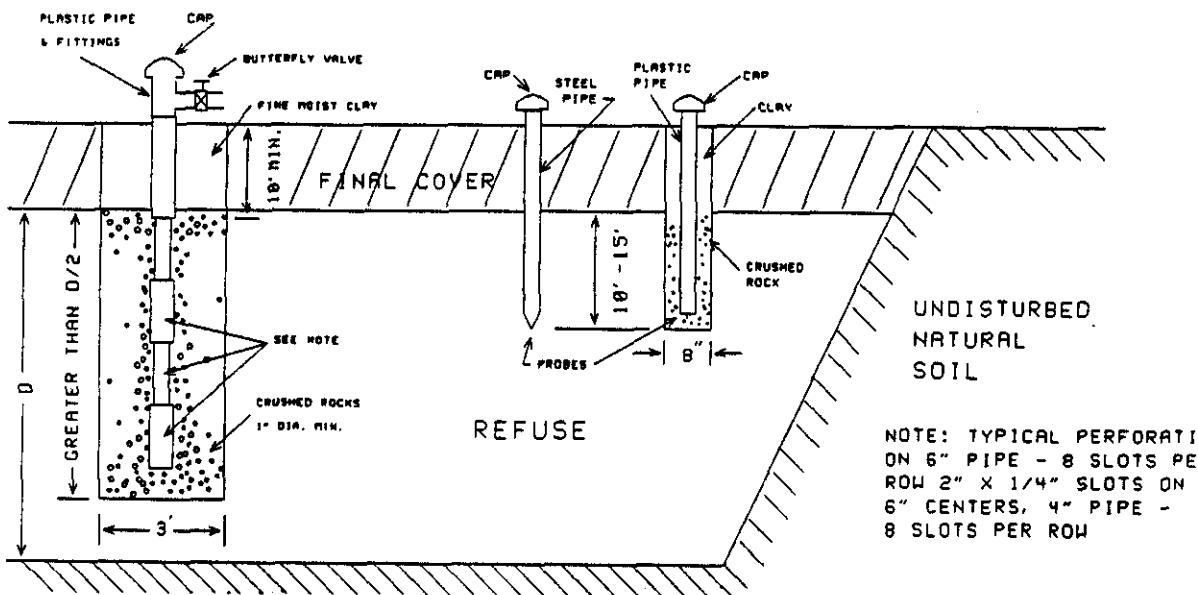
## Collection from Digesters

Biogas is typically extracted from digesters with a pipe inserted in the gas space. The pipe may be vertically or horizontally aligned. Care must be taken to insure that the pipe is not blocked by the material being digested, by any scum or foam layers at the top, or by the collapse of a flexible cover.

## Collection from Landfills

The most common system for extraction of biogas from a landfill is the induced well system. The system uses a compressor to pull the gas from the decomposing material and through a piping network. A typical vertical pipe landfill extraction system is illustrated in Figure 4-9. A series of vertical wells with perforated pipe inserted in these wells is used for gas removal. The wells are spaced such that the radii of influence overlap and the pipes are inserted below the refuse level. The lower portion of the pipe is perforated, and the insertion hole is backfilled after insertion to prevent air infiltration. Horizontal trenches can be used to remove gas, but these tend to be more difficult to operate without undue air leakage or air intrusion (USEPA 1979a).

**Figure 4-9. Vertical Pipe Landfill Extraction System**



Source: USEPA 1979a





## CHAPTER 5

### BIOGAS CLEAN-UP

#### Treatment of Biogas

The equipment selected for the treatment of biogas will depend upon the intended use of the gas. Product gases may be withdrawn from treatment systems and landfills and simply flared to prevent migration and environmental impact. Alternatively, the gas can be withdrawn and sold to a consumer directly, used on site with or without prior treatment, or treated and sold to a consumer as pipeline gas.

The type and extent of treatment needed depends on the composition of the gas. As seen in previous chapters, raw biogas typically has a relatively low heating value due to dilution of methane with  $\text{CO}_2$ ,  $\text{N}_2$ , and possibly  $\text{O}_2$ . Biogas also often contains water and hydrogen sulfide, which can be corrosive. In some cases, trace levels of hydrocarbons are also present (particularly in landfill gases) and may be of some concern with respect to migration and environmental impact, but these compounds may be expected to oxidize rapidly and be of minimal concern if the gas is burned (except in internal combustion engines). Therefore, the primary objectives of gas treatment are either the removal of corrosive constituents (hydrogen sulfide and water), or those which dilute methane and affect the volumetric heating value (carbon dioxide and nitrogen), or both.

Accordingly, there are a number of treatment processes available for removing water, hydrogen sulfide, carbon dioxide, and nitrogen either singularly or in combination. These have been carefully reviewed by Jones and Perry (1976), USEPA (1979a), Ashare (1981), Love (1983), and EMCON (1983). These are summarized and reviewed in the remainder of this section. The gases produced by such treatment systems may be classified on the basis of heating value as either medium BTU (500-600 Btu/SCF) or high BTU (600-1000 Btu/SCF) gases.

#### Medium BTU Gases

Medium BTU gases are useful for process heating and for driving internal combustion engines. They are generally produced from raw biogas by removing water vapor and/or hydrogen sulfide, with nitrogen and carbon dioxide remaining untreated.

## Hydrogen Sulfide Removal

As indicated in Figure 5-1, hydrogen sulfide can be removed using a variety of liquid absorbents and/or solid phase oxidants. Hydrogen sulfide can be selectively removed with a few of the aqueous processes, but most of these also remove carbon dioxide which is unnecessary for some applications. Therefore, the so-called dry processes are preferred for medium BTU applications, where CO<sub>2</sub> removal is not necessary, and are also more economical on the scale of most biogas-producing processes.

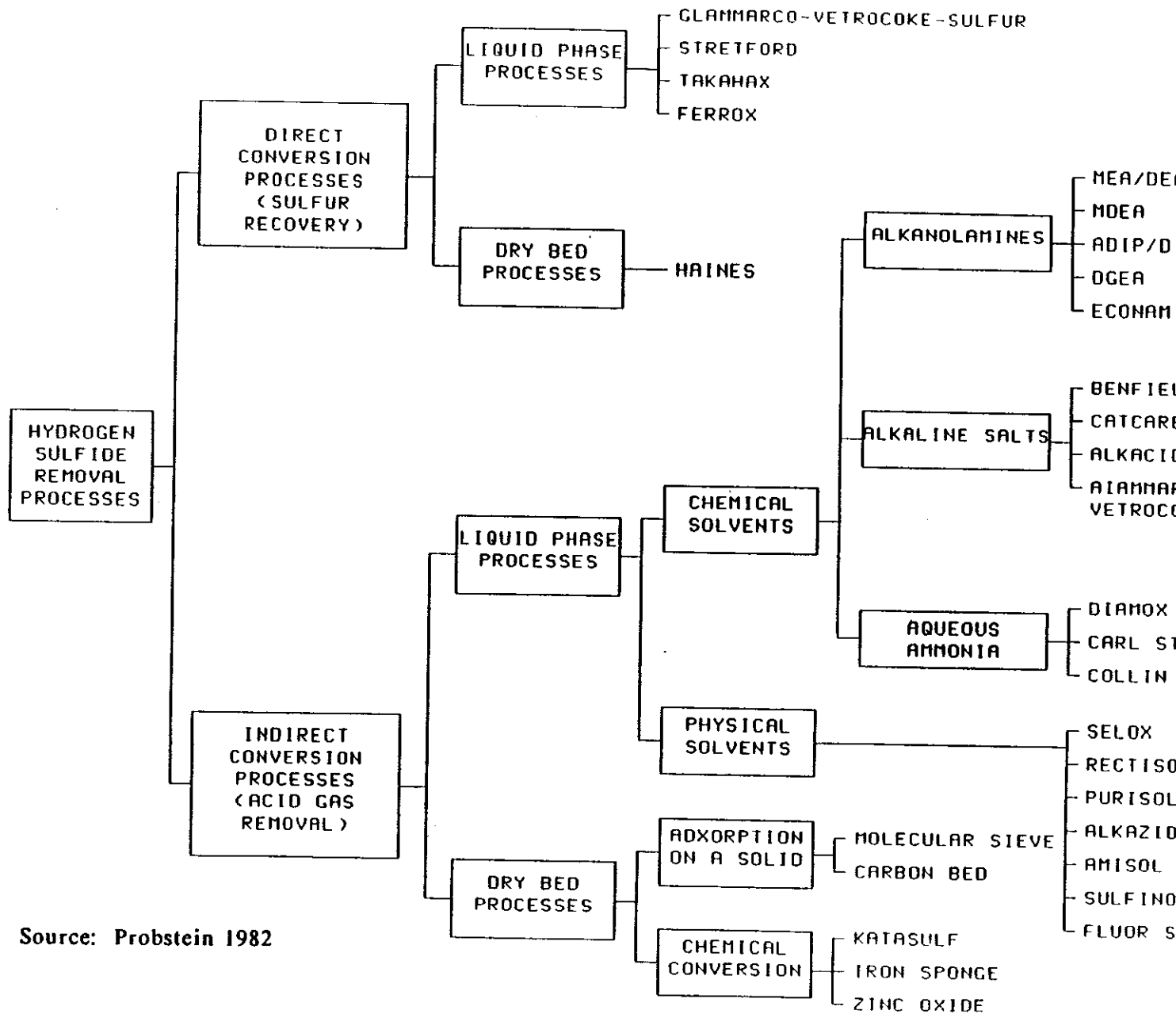
Aqueous Absorption Processes. Hydrogen sulfide can be somewhat selectively absorbed in a variety of aqueous solutions. To accomplish this, the biogas is blown through a scrubbing tower (Figure 5-2) equipped with fixed trays, baffles, or some other packing material which provides a high surface area and small film thicknesses. Aqueous solutions which can be used to remove H<sub>2</sub>S are listed in Table 5-1, and include an assortment of sodium or potassium carbonates, ammonia, and glycols in combination with various intermediate oxygen carriers and corrosion inhibitors.

**Table 5-1. Aqueous Solutions Used To Remove Hydrogen Sulfide From Biogas**

<u>Process Name</u>	<u>Aqueous Medium</u>
Ferrox	Sodium carbonate with ferric hydroxide
Giammarco-Vetrocoke	Sodium or potassium carbonate with arsenic
Stretford	Sodium carbonate with sodium vanadate and anthraquinone disulfonic acid
Takahax	Sodium carbonate with naphthaquinone
Townsend	Ethylene glycol with sulfur dioxide
Purox	Ammonia with hydroquinone

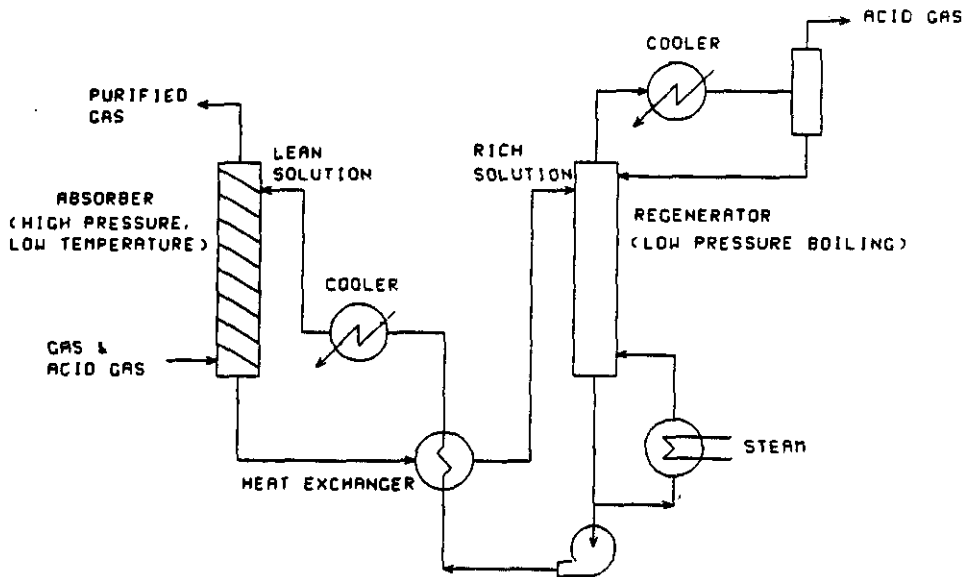
The Ferrox process uses a solution of sodium carbonate and ferric hydroxide while the Giammarco-Vetrocoke process uses sodium or potassium carbonates in combination with arsenic compounds to absorb hydrogen sulfide. The Stretford process uses sodium carbonate to convert hydrogen sulfide to sodium bisulfide which is then converted to elemental sulfur with sodium vanadate and sodium salt of anthraquinone and disulfonic acid. The Takahax process uses naphthaquinone in solution of sodium carbonate. The Purox process also uses quinones, dissolved in a

Figure 5-1. Hydrogen Sulfide Removal Processes



Source: Probst 1982

**Figure 5-2. Simple Biogas Purification Arrangement**



Source: Probst 1982

solution of ammonia, to absorb sulfide. The Townsend process uses a concentrated solution of di- or triethylene glycol in combination with sulfur dioxide.

For very large systems with gas flow rates in excess of  $10^6$  ft<sup>3</sup>/day, the solutions indicated above can be regenerated, and sulfur recovered for industrial use. Absorption is initially carried out at low temperatures and high pressures where sulfide solubilities are highest, and regeneration of the absorbent is most typically accomplished by heating the solution to decrease solubility and release concentrated gas. Sulfur may then be recovered from the concentrated gas by the Claus process, wherein part of the sulfide is burned to form elemental sulfur and sulfur dioxide and the remaining sulfide is catalytically converted to elemental sulfur in the presence of aluminum oxide.

Most of these chemical solutions are expensive, and the treatment systems are also capital intensive. Therefore, these systems are more feasible for large scale biogas recovery projects. For smaller scale systems, dry adsorption is the more feasible option and is described in the next section.

**Dry Adsorption Processes** For small scale biogas producers, an alternative to the wet absorption systems described above is dry adsorption, or chemisorption.

Several dry processes are available, using particles of either activated carbon, molecular sieve, or iron sponge to remove sulfide from the gas phase to the solid phase. These are sometimes referred to as dry oxidation processes because elemental sulfur or oxides of sulfur are produced (and can be recovered) during oxidative regeneration of the catalyst.

Activated carbon adsorbs and oxidizes sulfide to elemental sulfur. Activated carbon has a very high surface area (4,400 to 5,300 in<sup>2</sup> per ounce), a wide variety of pore sizes, and a slightly charged nature which attracts both inorganic and organic compounds. The carbon is loaded into two or more sequential pressure vessels and the gas pumped through the packed beds. As the surface area of the carbon becomes saturated with sulfur, the acid gas begins to appear in the gaseous effluent, and indicates that one of the vessels needs to be recharged or regenerated. Activated carbon is typically regenerated with steam, at temperatures up to 750 °F. Activated carbon is widely available from a large assortment of commercial manufacturers.

Molecular sieves can be used to remove hydrogen sulfide, mercaptans, water, and a number of other impurities. Molecular sieves consist of activated alumina or silica compounds which have a high affinity for polar molecules. They provide surface areas up to 1,300 in<sup>2</sup> per ounce and have well-defined pore sizes which allow for selective removal of different compounds. Regeneration of the surface area on saturated materials is accomplished by passing a heated gas (400 to 600°F) through the reactor bed. Molecular sieves are best suited to selective water and sulfur removal on a small to medium scale.

The iron sponge process uses coated pellets or wood shavings impregnated with ferric oxide to chemically bind sulfur to iron. The amount of sulfur which can be removed is stoichiometrically linked to the amount of iron provided. System design is based on the concentration of sulfide in the gas and the bulk density of the sponge material.

In the removal (scrubbing) process, hydrogen sulfide reacts with ferric oxide impregnated in wood shavings to form ferric sulfide and water. The gas is pumped through a sponge bed similar in construction to an activated carbon or molecular sieve reactor, where the iron sponge is supported on screens or trays in a cylindrical or rectangular tower. The linear gas velocity is kept below 10 ft/min to assure adequate reaction time and contact opportunity. The process may be operated at pressures ranging from ambient to several hundred psig. Efficient operation can

be achieved at ambient temperature or warmer, but the moisture content of the sponge should be maintained between 30 and 60%. Operation at pH 8.0 to 8.5 is best, and pH should never drop below 7.5.

In the regeneration stage, oxygen is added to convert the ferric sulfide to ferric oxide and elemental sulfur. This can be accomplished by removing the sponge and exposing it to air by spreading it out in thin layers and periodically turning it. The sponge can also be recharged in the reactor by bleeding in oxygen. However, this process must be carefully controlled because the regeneration reaction is exothermic. The catalyst may be poisoned with hydrocarbons above 120 °F, therefore, oxygen feed rates should be controlled to keep the vessel temperature below this value. Scrubbing and regeneration can take place at the same time by bleeding oxygen into the feed gas and maintaining temperature at a prespecified level.

Sponge materials can be regenerated 3 to 5 times, depending on the amount of sulfur removed and the care exercised in maintaining appropriate temperatures, pH, and moisture content. The sponge will eventually become oversaturated with elemental sulfur, but shorter lifetimes are caused by destroying the inert support material with acid and heat, or by catalyst poisoning. In general, 50 to 60% of the original weight of the sponge can be adsorbed as elemental sulfur.

The sizing of an iron sponge system is illustrated in Table 5-2. The calculations are based on an iron sponge bulk density of 15 pounds per cubic foot and a linear gas velocity of 10 ft per minute.

## High BTU Gases

High BTU gases of pipeline quality can be produced by removing sulfide, carbon dioxide, and water vapor. This can be accomplished with aqueous scrubbers operated over a wide range of temperatures and pressures, depending on the nature of the solvation or chemical equilibrium responsible for acid gas removal. Otherwise, semipermeable membranes are available to selectively remove specific gases in high pressure reverse osmosis processes.

Carbon dioxide and Hydrogen Sulfide removal. In addition to those aqueous absorbents described for hydrogen sulfide removal in the previous section, there are many chemical solutions commercially available which can be used to remove carbon dioxide and hydrogen sulfide concurrently. These are listed in Table 5-3 with the operating conditions and the advantages and disadvantages of each process.

## Table 5-2. Design Example for a Small Scale Iron Sponge Process

### Design Basis:

5000 scf/day  
0.3 grains  $H_2S$ /scf (30 grains/100 scf)

### Sulfur Produced:

5000 scf/day  $\times$  0.94 lb S/lb  $H_2S$   $\times$  0.3 grains/scf  $\times$  1 lb/7000 grains =  
0.20 lbs sulfur/day

### Iron Sponge Required:

0.20 lbs sulfur  $\times$  2.0 lb  $FeO_3$ /lb sulfur  $\times$  safety factor (1.5) =  
0.6 lb iron oxide/day or 220 lb/year

### Reactor Volume:

0.6 lb iron oxide/day  $\times$  1.0 ft<sup>3</sup> iron sponge/15.0 lb iron oxide =  
0.04 ft<sup>3</sup> reactor/day or 15 ft<sup>3</sup>/year (110 gallons)

### Reactor Dimensions:

volume = 15 ft<sup>3</sup> = height  $\times$  flow area  
flow velocity = 2 ft/min = flowrate/flow area  
$$\text{height} = \frac{\text{volume} \times \text{velocity}}{\text{flowrate}} = \frac{15 \text{ ft}^3 \times 2 \text{ ft/min} \times 1440 \text{ min/day}}{5000 \text{ ft}^3/\text{day}} =$$
  
height = 9 ft (maximum)  
area = volume/height = 15 ft<sup>3</sup>/9 ft = 1.67 ft<sup>2</sup>  
diameter =  $\sqrt{4 \times \text{area} / \pi}$  = 1.5 ft

In general, these processes employ either solvation solutions where the objective is to dissolve  $CO_2$  and  $H_2S$  in the liquid, or solutions which react chemically to alter the ionic character of these gases and, therefore, also drive them into solution. Solutions of the former category include the Solvents and the latter include the Alkanolamines and Alkaline Salts detailed in Table 5-3.

The Solvent processes are typically operated at low temperatures, since the solubilities of  $CO_2$  and  $H_2S$  both increase with decreasing temperature. These processes are also operated at high pressure, since solubility is a function of the partial pressure of the gas being dissolved.

Table 5-3. Liquid Absorption Processes for CO<sub>2</sub> and H<sub>2</sub>S Removal

Gas Treatment Process	Absorbent	Operating Temperature	Operating Pressure	Method of Regeneration	Acid Gases Removed			Supplier(s)	Advantages	Disadvantages
					CO <sub>2</sub>	H <sub>2</sub> S	Mercaptans			
<u>Wet Scrubber</u>	Water	41 to 50°F	>200 psig	High Temp Low Pressure	Yes	Yes	Yes	-	Low solvent cost, no nitrogenous vapors	Low efficiency
<u>Alkanolamines</u> Amine-guard	Mono-ethanolamine (MEA)	up to 120°F	High	Reboiling Low pressure	Yes	Yes	-	AmineGuard	High efficiency, moderate solvent cost	High capital cost, corrosive inhibitors toxic, foaming agents needed
SNPA-DEA	Diethanolamine (DEA)	up to 120°F	>500 psig	Heating Low pressure	Yes	Yes	-	Ralph M. Parsons, Fluor Engineers	High efficiency, noncorrosive & nonfoaming	High capital and solvent costs
Econamine	Hydroxy-amino ethylester (DGA)	up to 120°F	>500 psig	Heating Low pressure	Yes	Yes	-	Fluor Engineers	Moderate capital and operating costs	High solvent cost, corrosive inhibitors needed
<u>Alkaline Salts</u>										
Benfield	Potassium carbonate	240°F	100 to 2000 psig	Steam	Yes	Yes	-	Benfield	Low solvent cost, high efficiency	High capital cost, corrosive inhibitors needed, foaming agents needed
Catacarb	Potassium carbonate plus amine borate	60 to 450°F	100 to 1000 psig	Steam	Yes	Yes	-	Eickmeyer & associates	Low solvent cost, high efficiency, Non toxic additives	High capital cost, corrosive inhibitors & foaming agents needed
Giammarco-Vetrocoke	Potassium plus arsenic trioxide or glycine	120 to 250°F	0 to 1100 psig	Steam or boiling	Yes	Yes	Yes	Giammarco-Vetrocoke	Low solvent cost, high efficiency	High capital cost, corrosive inhibitors & foaming agents needed



Table 5-3. Liquid Absorption Processes for CO<sub>2</sub> and H<sub>2</sub>S Removal (con't)

Gas Treatment Process	Absorbent	Operating Temperature	Operating Pressure	Method of Regeneration	Acid Gases Removed			Supplier(s)	Advantages	Disadvantages
					CO2	H2S	Mercaptans			
Alkaline Salts (Con't)										
Alkazid-M	Potassium salt of methyl amino propionic acid	-	-	-	Yes	Yes	Yes	I. G. Farber Industries	-	-
Alkazid-DIK	Potassium salt of methyl or dimethylamino-acetic acid	-	-	-	Yes	Yes	Yes	I. G. Farber Industries	-	-
Alkazid-S	Sodium phenolate	-	-	-	Yes	Yes	Yes	I. G. Farber Industries	-	-
Solvents										
Sulfinol	Tetrahydro-thiophene dioxide plus diisopropanolamine	Ambient	0 to 1000 psig	Reboiling or flashing at low temperature	Yes	Yes	Yes	Shell Co. Development	Moderate capital and chemical cost, flexible, low corrosion	-
Selexol	Dimethyl ether of poly-ethylene glycol	-10 °F to ambient	>300 psig	Low Pressure	Yes	Yes	Yes	Allied Chemical	High efficiency Selective for H2S, non corrosive and nontoxic	High capital and chemical costs
Fluor	Anhydrous propylene carbonate	-50°F	>300 psig	Low pressure	Yes	Yes	Yes	Fluor Engineers	High efficiency Non corrosive and nontoxic	High capital and chemical costs
Purisol	N-methyl pyrrolidone	Low	High	High temp	No	Yes	-	Lurgi Kohle	High efficiency	High capital cost
Rectisol	Methanol	.5 to	High	High temp low pressure	Yes	Yes	Yes	Lurgi Mineral-oeltechnik Union Carbide	High efficiency low chemical cost	High capital and solvent loss
Amisol	Activated carbon surface area	Ambient	Ambient	Low pressure steam	-	-	-	-	-	-

The Alkanolamines are typically operated as warm processes, since heat helps the chemical reaction. However, excessive heat can cause vaporization and loss of the chemical solution. Therefore, these processes are usually operated at ambient temperatures (up to 120 °F). These chemicals are somewhat corrosive, and anti-corrosion agents are usually needed.

Alkanolamine absorption methods have a widespread acceptance for CO<sub>2</sub> removal from natural gas. Monoethanol (MEA), diethanolamines (DEA), and diglycolamine (DGA) have also been successfully applied. MEA is corrosive at 19% concentrations, whereas, DEA may be used at solution strengths approaching 35% without undue corrosion. DGA is even less corrosive and is also nonfoaming. Therefore, DEA, which does not absorb heavy hydrocarbons and, therefore, selectively removes CO<sub>2</sub>, and DGA are generally preferred.

The Alkaline Salts are operated at very high temperatures (up to 450 °F) and very high pressures (up to 2000 psig). These solutions, like the Alkanolamines, are corrosive and require the addition of corrosion inhibitors if steel tanks are used. These solutions also usually employ a chemical activating agent and have a tendency to foam, therefore, anti-foaming agents are often included in the treatment strategy. The activating agents are proprietary, and in at least one case (Giammarco Vetrocoke), toxic and undesirable.

Another method of removing CO<sub>2</sub> and H<sub>2</sub>S is using Semipermeable Membrane Processes (reverse osmosis). Commercial processes are available from General Electric and Monsanto. In these systems, organic polymer membranes in one of several configurations (spiral wound, tubular, and hollow fiber) are used to "filter" carbon dioxide out of the gas stream. Under relatively high pressures ranging from 150 to 2000 psig and temperatures below 120°F, CO<sub>2</sub> is chemically bound to the membrane surfaces and migrates by diffusion through the membrane.

The membrane materials are specially formulated to selectively separate carbon dioxide from methane. The permeability of the membrane is a direct function of the chemical solubility of the target compound in the membrane. To separate two compounds such as CO<sub>2</sub> and CH<sub>4</sub>, one gas must have a high solubility in the membrane while the other is insoluble. Accordingly, rejection (separation) efficiencies are typically quite high when the systems are operated as designed.

However, the membranes used are rather fragile by construction, and with extremely small pores, require a particulate-free input gas. However, variations in input composition do not result in wide variations in gaseous components such as

hydrogen sulfide, and mercaptans does not greatly affect separation efficiencies. These systems are very capital intensive and not well suited to small scale applications.

**Dehydration.** Many of the Alkanolamine solutions also remove a large percentage of the water vapor in biogas. However, if a dry oxidation process such as iron sponge is used (this operates best with an iron oxide moisture content of 30 to 60%), further water vapor removal may be needed.

For large scale applications, the gas is typically compressed and cooled prior to being dehydrated by absorption with glycol or triethylene glycol. As indicated in Table 5-4, silica gel, alumina, or molecular sieves are also acceptable alternatives for adsorbing excess water vapor, although these techniques can be prohibitively expensive for large applications and are typically the preferred alternatives for small scale operations.

**Nitrogen Removal.** Nitrogen may be removed by liquefying the methane fraction of biogas by mechanical refrigeration, leaving the other gas fractions to be exhausted. Considerable refrigeration equipment is required for this process and it is usually prohibitively costly. The best practice is to avoid drawing air into the treatment system to the greatest extent possible, thereby minimizing the nitrogen content.

## **Economics of Biogas Treatment**

The economics of implementing the preceding gas collection and treatment alternatives have been reviewed in detail by others ( Ashare 1981, USEPA 1979a). In the EPA study, four gas treatment alternatives were considered, including dehydration, dehydration plus CO<sub>2</sub> removal, dehydration plus CO<sub>2</sub> and N<sub>2</sub> removal, and dehydration plus CO<sub>2</sub> removal and propane blending.

Each alternative was analyzed at several gas production rates, as summarized in Table 5-5. These data illustrate the high costs of carbon dioxide and nitrogen removal and underscore the importance of minimizing the introduction of air during gas extraction from landfill projects. Based upon an energy value equivalent to revenue of \$2 per million Btu (1979 dollars), the probable payback periods associated with each alternative ranged from <3 years (Alternative I) to 10 to 30 years (Alternatives II and IV) and >30 years (Alternative III).

Ashare (1981) presented a slightly more recent summary of the costs of several commercially available systems, as reproduced in Table 5-6. Costs were presented for

**Table 5-4. Summary of Gas Treatment Methods Available for the Removal of Water, Hydrocarbons, and Carbon Dioxide**

<u>Compound</u>	<u>Process Type</u>	<u>Process Alternatives Available</u>
Water	Adsorption	<ol style="list-style-type: none"> <li>1. Silica Gel</li> <li>2. Molecular sieves, and</li> <li>3. Alumina</li> </ol>
	Absorption	<ol style="list-style-type: none"> <li>1. Ethylene glycol (at low temperature -20°F)</li> <li>2. Selexol</li> </ol>
	Refrigeration	<ol style="list-style-type: none"> <li>1. Chilling to -4°F</li> </ol>
Hydrocarbons	Adsorption	<ol style="list-style-type: none"> <li>1. Activated carbon</li> </ol>
	Absorption	<ol style="list-style-type: none"> <li>1. Lean oil absorption,</li> <li>2. Ethylene glycol, and</li> <li>3. Selexol</li> </ol> all at low temperatures (-20°F)
	Combination	<ol style="list-style-type: none"> <li>1. Refrigeration with Ethylene glycol plus activated carbon adsorption</li> </ol>
CO <sub>2</sub> and H <sub>2</sub> S	Absorption	<ol style="list-style-type: none"> <li>1. Organic Solvents Selexol Fluor Rectisol</li> <li>2. Alkaline Salt Solutions Hot potassium and Inhibited hot potassium (Benfield and Catacarb processes)</li> <li>3. Alkanolamines mono-, di-, tri-ethanolamines; diglycolamines; UCARSOL-CR (proprietary chemical)</li> </ol>
	Adsorption	<ol style="list-style-type: none"> <li>1. Molecular Sieves</li> <li>2. Activated Carbon</li> </ol>
	Membrane Separation	<ol style="list-style-type: none"> <li>1. Hollow Fiber Membrane</li> </ol>

**Table 5-5. Relative Economics of Several Gas Treatment Alternatives**

<u>Treatment Alternative</u>	<u>Cost Item</u>	<u>Production Rate, scf/min</u>		
Alternative I.				
Dehydration, compression	Input	485	1,225	2,450
	Output	460	1,160	2,320
	Capital Cost, 10 <sup>6</sup> \$	636	957	1,388
	Annual Operating Cost, 10 <sup>6</sup> \$	185	273	387
	Annual Energy Output, 10 <sup>9</sup> Btu	109	273	484
	Energy Cost, \$/10 <sup>6</sup> Btu	1.7	1.0	0.8
Alternative II.				
Dehydration and CO <sub>2</sub> removal	Input	1,670	2,276	5,000
	Output	485	959	1,495
	Capital Cost, 10 <sup>6</sup> \$	1,740	2,772	3,792
	Annual Operating Cost, 10 <sup>6</sup> \$	359	537	702
	Annual Energy Output, 10 <sup>9</sup> Btu	212	413	587
	Energy Cost, \$/10 <sup>6</sup> Btu	1.7	1.3	1.3
Alternative III.				
Dehydration plus CO <sub>2</sub> removal and N <sub>2</sub> removal	Input	1,670	3,335	5,000
	Output	420	870	1,425
	Capital Cost, 10 <sup>6</sup> \$	2,612	4,038	5,450
	Annual Operating Cost, 10 <sup>6</sup> \$	555	807	1,051
	Annual Energy Output, 10 <sup>9</sup> Btu	198	404	657
	Energy Cost, \$/10 <sup>6</sup> Btu	2.0	2.0	1.6
Alternative IV.				
Dehydration plus CO <sub>2</sub> removal and propane blending	Input	1,670	3,335	5,000
	Output	502	1,004	1,543
	Capital Cost, 10 <sup>6</sup> \$	1,802	2,847	3,877
	Annual Operating Cost, 10 <sup>6</sup> \$	463	730	992
	Annual Energy Output 10 <sup>9</sup> Btu	244	456	709
	Energy Cost, \$/10 <sup>6</sup>	1.9	1.6	1.4

Source: USEPA 1979a

several medium-to-large scale systems, with gas processing rates of 3.6 MM SCF/D, 36 MM SCF/D, and 108 MM SCF/D. These systems are on the large end of the biogas scale, and are probably only meaningful for large landfill gas recovery projects. Obviously, these costs are not bearable for small systems, and it is unwise to project cost for systems two orders of magnitude or smaller.

Moreover, the degree of treatment provided by these systems is only required for pipeline gas production. For most on-site uses, these systems are not recommended. Especially on the farm, it is more advisable to use more rudimentary systems such as the iron sponge for sulfide control, and adapt to the lower heating value (i.e., do not attempt to remove carbon dioxide). Iron sponge treatment systems can be purchased from commercial manufacturers or be home-made relatively inexpensively. As an alternate, it may be more economical to pay the higher maintenance costs resulting from corrosion, or purchase corrosion resistant equipment and avoid cleaning the gas altogether.

**Table 5-6. Summary of Capital and Operating Costs  
For Some Commercial Gas Treatment Systems**

Commercial Process	<u>3.6 MM SCF/D</u>		<u>36 MM SCF/D</u>		<u>108 MM SCF/D</u>	
	Capital Cost (Thousands of \$)	Operating Cost (Thousands of \$)	Capital Cost (Thousands of \$)	Operating Cost (Thousands of \$)	Capital Cost (Thousands of \$)	Operating Cost (Thousands of \$)
Selexol	----	----	1,195	224	2,321	489
Amine-Guard	358	40	915	271	1,802	645
Benfield	----	----	777	194	1,601	426
Catacarb	283	30	893	226	1,727	513
Membrane	97	12	432	128	921	253

Source: Ashare 1981

## CHAPTER 6

# COMPRESSION OF BIOGAS

### Applications For Compression

Compressing biogas reduces storage requirements, concentrates energy content and increases pressure to the level needed to overcome resistance to gas flow. Sometimes the production pressure of a biogas source does not match the pressure requirements of the gas utilization equipment. Compression can eliminate the mismatch and guarantee the efficient operation of the equipment.

Systems that use biogas for digester mixing employ compressors (or blowers) to overcome the resistance to gas flow imposed by the digester contents. Moreover, large biogas systems rely on compression to reduce the size of the gas storage facility or to transport the biogas to a pipeline. Biogas systems that fuel cars or trucks use compressors to achieve the high energy density required by the application. The choice of either a blower or compressor depends on the amount of pressure increase needed. Regardless of the pressure requirements, both devices must meet stringent design specifications for handling biogas.

### Special Requirements for Handling Biogas

Compressing biogas requires a gas compressor suitable for flammable gases. These differ from regular compressors in several respects:

- o the cylinder is located further from the crankcase,
- o higher quality packing is used,
- o hardened connecting rods are used,
- o passageways are provided to vent leaks away from the crankcase and prevent explosions,
- o inlet and exhaust ports are designed to let contaminants pass through instead of collect in the compressor, and
- o explosion proof motors and electrical connections are used on all equipment.

Compression requires a "clean" gas that has had the  $H_2S$  removed. Biogas typically contains 1000 ppm to 2%  $H_2S$  by volume.  $H_2S$  must be removed before compression since it forms an acid when combined with the water vapor present in the gas. The resulting acid corrodes compressor parts and will lead to premature equipment failure. Additionally, removing the  $CO_2$  and water vapor also improves

the energy value of the compressed biogas and eliminates the cost of compressing undesired and unusable gas components.

Condensation can be a problem in the compressor's gas outlet line or at other locations in the gas train experiencing excessive pressure drop. Coolers are used (e.g. shell and tube exchanger), especially between the stages of a multi-stage machine to localize and control condensation. Water traps should be provided on the inlet and discharge gas lines of all compressors used in biogas systems.

Some researchers have reported problems with freezing in piping downstream of the compressor, when pressure regulating devices expanded the compressed gas. Typically, the gas is passed through a restriction that lowers the pressure (i.e. throttling the gas.) The temperature of a throttled gas may be either higher or lower after throttling than before throttling, depending on the values of the initial pressure and temperature ( $P_1$  and  $T_1$ ), respectively, and the final pressure ( $P_2$ ). For certain values of these properties, the value of the final temperature ( $T_2$ ) may decrease enough to cause freezing. Freezing can be predicted by determining the slope of a constant enthalpy line on a T vs. P diagram for the biogas. The slope is known as the Joule-Thompson coefficient, and is mathematically described by the equation:

$$\mu = (T/P)_h.$$

where:  $\mu$  = Joule-Thompson coefficient

$(T/P)_h$  = change in temperature (T)  
with respect to pressure (P)  
at constant enthalpy (h).

If  $\mu$  is positive, the temperature will decrease during throttling. If it is negative, the temperature will rise. If freezing could occur, the system design parameters may be altered to change the values of  $P_1$ ,  $T_1$ , and  $P_2$ . If design changes are impossible, heat may be added (e. g., from engine cooling water) to the throttling process.



## Selecting a Blower or Compressor

The choice of blower or compressor will depend on the amount of pressure increase required by a system. Blowers are employed to overcome piping pressure drop or for filling low pressure storage vessels. Compressors are typically used to obtain either medium (around 200 psi) and high (2000 psi or more) pressures. Some medium pressure compressors that handle small biogas flows are called boosters.

A typical biogas compressor and the accessories and controls needed for effective operation is depicted in Figure 6-1.

When deciding which equipment is best suited for a system, the following points should be considered:

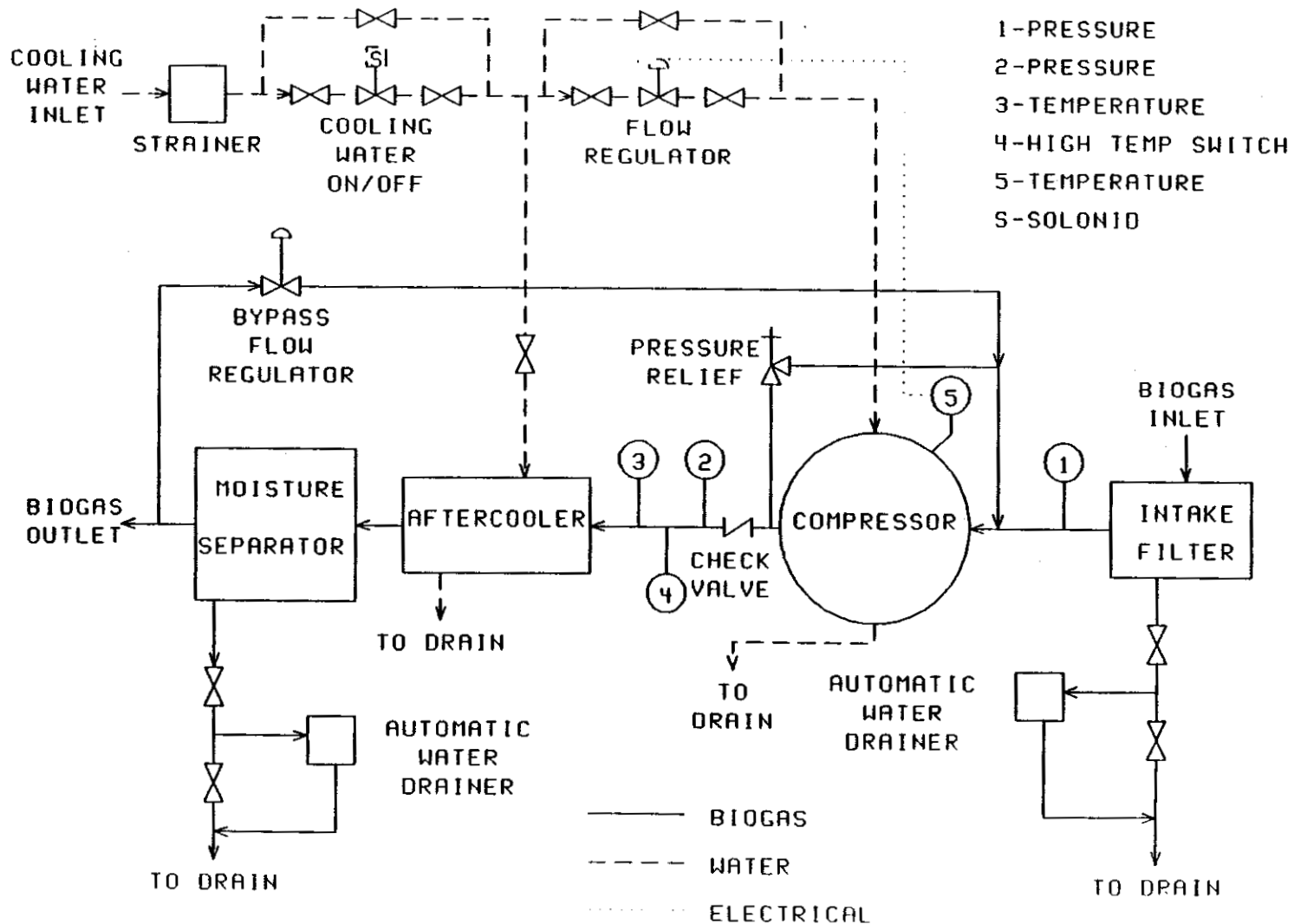
- o Any part of a component that contacts the biogas stream should be stainless steel, if possible. Other materials such as aluminum, ductile iron, and high grade carbon steel can be used in some cases since they provide good corrosion resistance and cost much less.
- o Copper or brass components should not be used where they may contact biogas.
- o Accessories like flame arresters and check valves are not always essential, although they may be required by local codes and insurance companies. They make a system safer and their use is highly recommended.
- o Some companies (especially valve manufacturers) use special coatings on equipment used in biogas systems. These coatings are less expensive than stainless steel, but it must be assured that the coating will provide sufficient protection against biogas corrosion.

In the short term view these requirements only appear to increase the cost of a biogas system. However, using the wrong materials or skimping on condensate traps and other accessories will shorten the useful life of the system, and will compromise not only its long-term reliability, but also personnel safety.

## Power Needed for Compression

The energy required for compression represents a major operating cost of a biogas system. Accordingly, estimating the energy requirement becomes an important component of the system design effort. Estimates are usually based on an adiabatic compression process (compression without cooling) since such a calculation estimates the maximum energy required for compression in a frictionless compressor.

Figure 6-1. Components of a Typical Biogas Compressor



Source: AC Compressor 1986

The non-linear relationship between the horsepower required to compress the gas and the compression ratio (the final pressure divided by the initial pressure) is illustrated in Figure 6-2. The figure was generated by holding the compressor's capacity constant while allowing the value of the compression ratio to change. A linear relationship between the horsepower requirement and the compressor capacity exists when the compression ratio is held constant, and is shown in Figure 6-3. In general, the horsepower requirement is a non-linear function since the capacity and compression ratio are both likely to change in an actual system.

Mathematically, the relationship between the system pressure, the compressor capacity, and the energy required for compression in a frictionless, adiabatic compressor can be stated as:

$$w = C_1 R T_1 [ (P_2/P_1)^{C_2} - 1 ]$$

where:

$w$  = shaft work required for compression (horsepower)

$$C_1 = k/(k - 1)$$

$$C_2 = (k - 1)/k$$

$k$  = the ratio of specific heats of the biogas ( $C_p/C_v$ ), 1.3\*

$R$  = gas constant for the biogas (Btu/lb/°R), 0.0729\*

$T_1$  = initial temperature (°F)

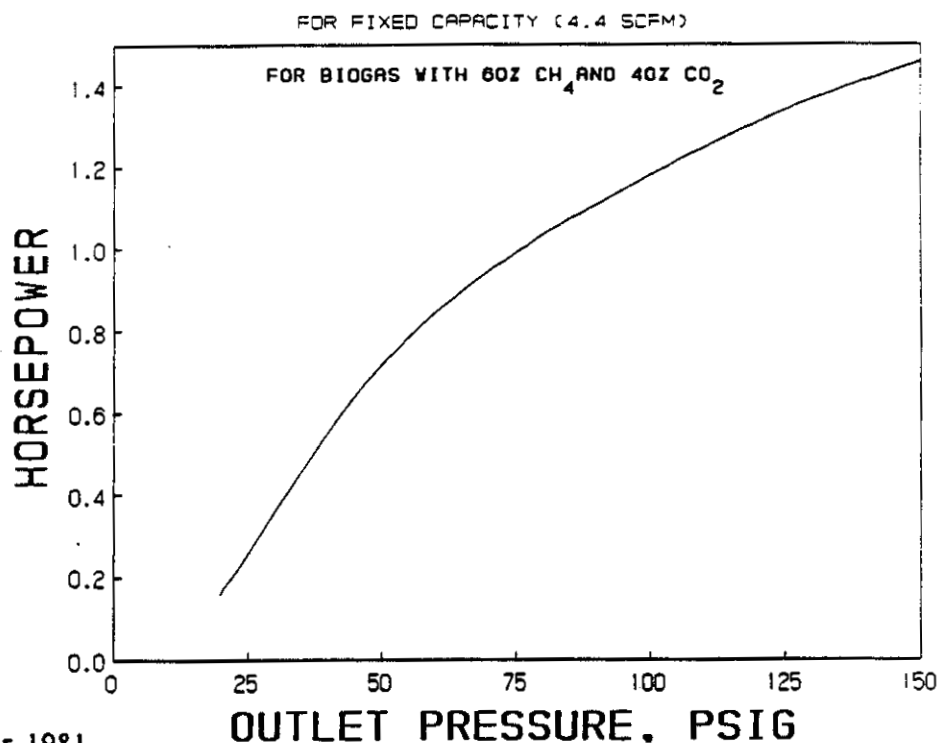
$P_1$  = initial pressure (psig)

$P_2$  = final pressure (psig)

\* values for 60% CH<sub>4</sub>, 40% CO<sub>2</sub> biogas

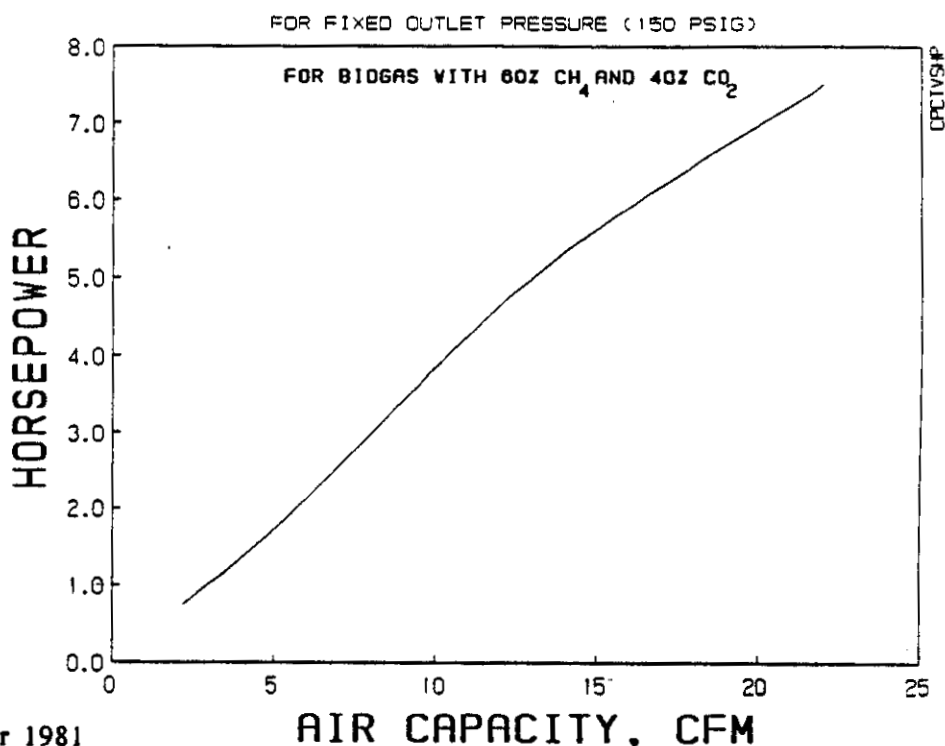
The value of "w" represents the amount of energy required to compress biogas of a known composition adiabatically and reversibly from  $P_1$  to  $P_2$ . However, compressors are never 100% efficient because of friction and heat transfer that occur during the compression process; and, therefore the actual energy required will be greater than computed using the preceding equation. It should be noted that manufacturers literature will indicate different efficiencies for almost every compressor. Confusion can be avoided by asking the manufacturer of the compressor being analyzed for the actual energy consumption of the equipment.

**Figure 6-2. Compressor Horsepower Variation with Discharge Pressure**



Source: Heisler 1981

**Figure 6-3. Compressor Horsepower Variation with Capacity**



Source: Heisler 1981

Compressor energy requirements are typically presented as percentages of the available energy in the biogas. However, these figures do not include the energy required to power the prime mover of the compressor. Adiabatically compressing biogas just a few psi requires less than 1% of the available energy. The energy requirement increases to 3% of the available energy when compressing to 200 psi. About 8% of the energy in the generated biogas is needed to achieve pressures of 2000 psi or more. Some horsepower requirements for various pressures and compressor capacities are presented in Table 6-1.

The choice of prime mover and fuel for the compressor can be identified by an economic analysis of the biogas system. The costs of the equipment and the required energy must be balanced against the savings and/or revenues generated by operating the system. Rarely will biogas be an economical choice for fueling the prime mover unless the biogas system includes cogenerating capability.

Start-up energy could become a major operating cost if the compressor is improperly sized. An oversized compressor starts and stops more than a properly sized one. With start-up energy requirements being 2 to 4 times that needed for continuous operation, oversizing should be avoided.

**Table 6-1. Horsepower Requirements for Compressing Biogas**

Inlet Condition : P = 14.696 PSIA, T = 60° F  
Capacity = 4.375 cfm

<u>Final Pressure (PSIA)</u>	<u>Horsepower</u>
19.8	0.17
50.0	0.72
75.0	0.98
100.0	1.17
125.0	1.33
150.0	1.46
175.0	1.57

Source: Heisler 1981

## Energy Density and Storage Volume

As the biogas is compressed to higher pressures, its mass is pushed into smaller volume. This raises the energy density of the gas and reduces the required storage volume. The storage requirements and energy density for a gas that has been isothermally (constant temperature) compressed are listed in Table 6-2. Note that the energy densities are much higher for biogas that has had the  $H_2S$ ,  $CO_2$ , and water vapor removed (100% methane). Keep in mind that the higher the compression ratio, the higher the costs associated with compressing the biogas.

**Table 6-2. Effect of Pressure on Energy Density and Storage Volume**

Compression Ratio	Volume <sup>a</sup> (cft/cft)	Energy Density <sup>b</sup> (Btu/scf)	Storage Medium
<u>For 60% Methane Biogas Mixture</u>			
1	1	545	in digester
2.4	2.4	1,310	floating roof or flexible bag
7.8	7.8	4,600	low pressure steel tank
21.4	21.4	11,450	medium pressure steel tank
69.0	72.0	39,240	high pressure steel tank
205.1	250.0	136,250	high pressure steel tank
<u>For 100% Methane Biogas Mixture</u>			
69.0	72.0	66,000	high pressure steel tank
205.1	250.0	228,000	high pressure steel tank

a - Gas volume at standard temperature and pressure, per unit of storage

b - Lower heating value

Source: Pearson 1979

## CHAPTER 7

# STORAGE OF BIOGAS

### Purpose of Storage

Biogas is not always produced at the time or in the quantity needed to satisfy the load that it serves. When this occurs, storage systems are employed to smooth out variations in gas production, gas quality, and gas consumption. The storage component also acts as a buffer, allowing downstream equipment to operate at a constant pressure.

### Types of Storage

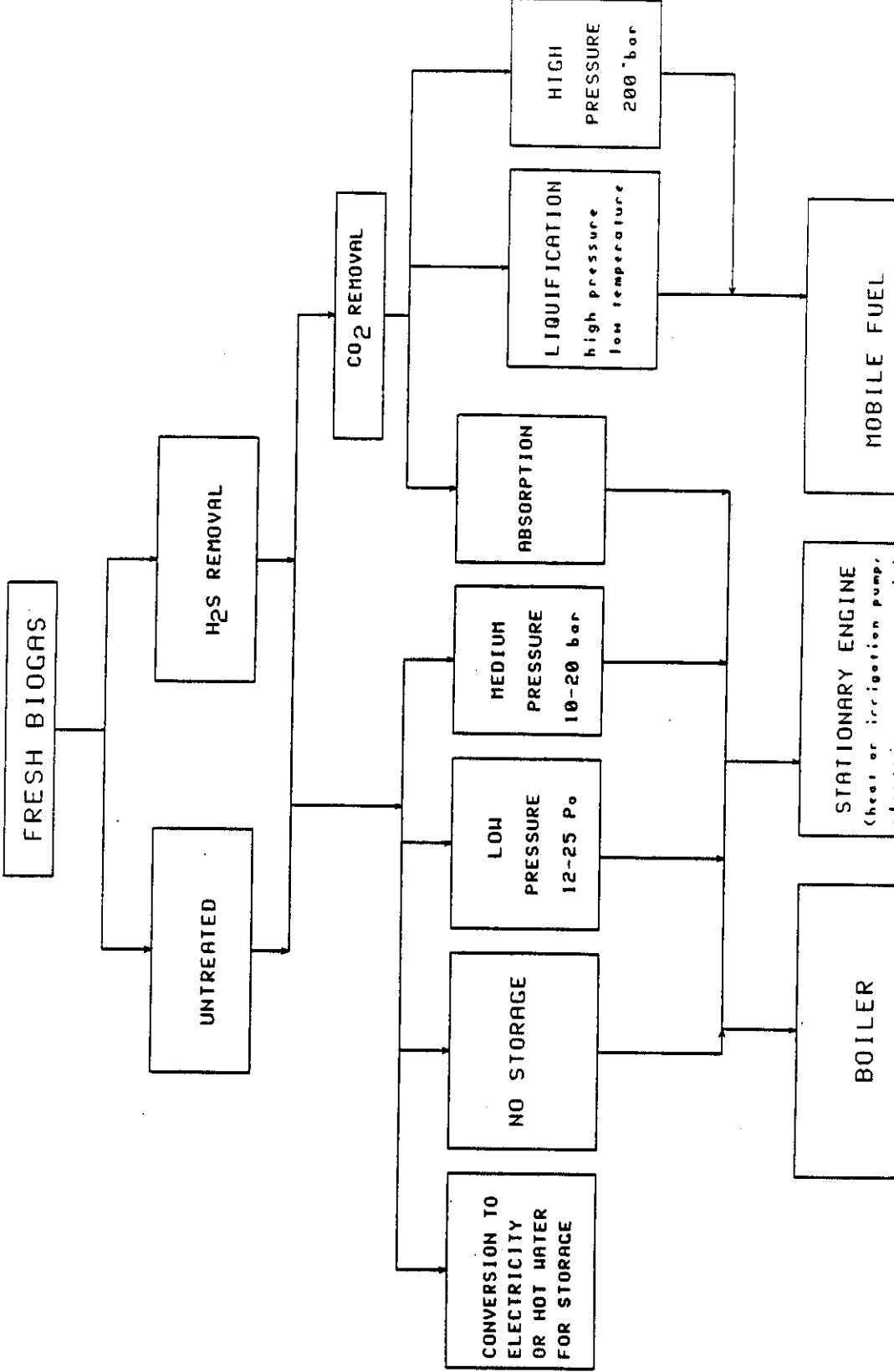
Several methods for storing biogas have been successfully demonstrated or suggested by researchers working in the area of biogas utilization. Seven possible options (Stahl 1983) are illustrated in Figure 7-1.

A biogas system with 3 possible gas utilization options; including direct use, compression by a blower and storage at low pressure, and compression and storage at medium pressure are illustrated in Figure 7-2. The technical requirements, capital cost, and operating cost of each option (Heisler 1981) are also shown in the figure.

Direct Use. In some cases the match between gas production and gas usage is close enough to allow direct use of the gas. Any gas that is not used as it is produced is vented to the atmosphere. Some direct use systems usually rely on a pressure regulating device in the gas line to ensure that sufficient gas pressure is available at the burner or gas converter. Other direct use devices such as the Tracker-Trol ® by Perennial Energy, Inc. (Walsh et al. 1986) adjust the engine or burner throttling according to pressure or biogas availability. Direct use systems are lower in capital cost and less complex than systems employing storage. However, it is rare that the match between production and usage is good enough to prevent biogas waste or make the direct use system very efficient.

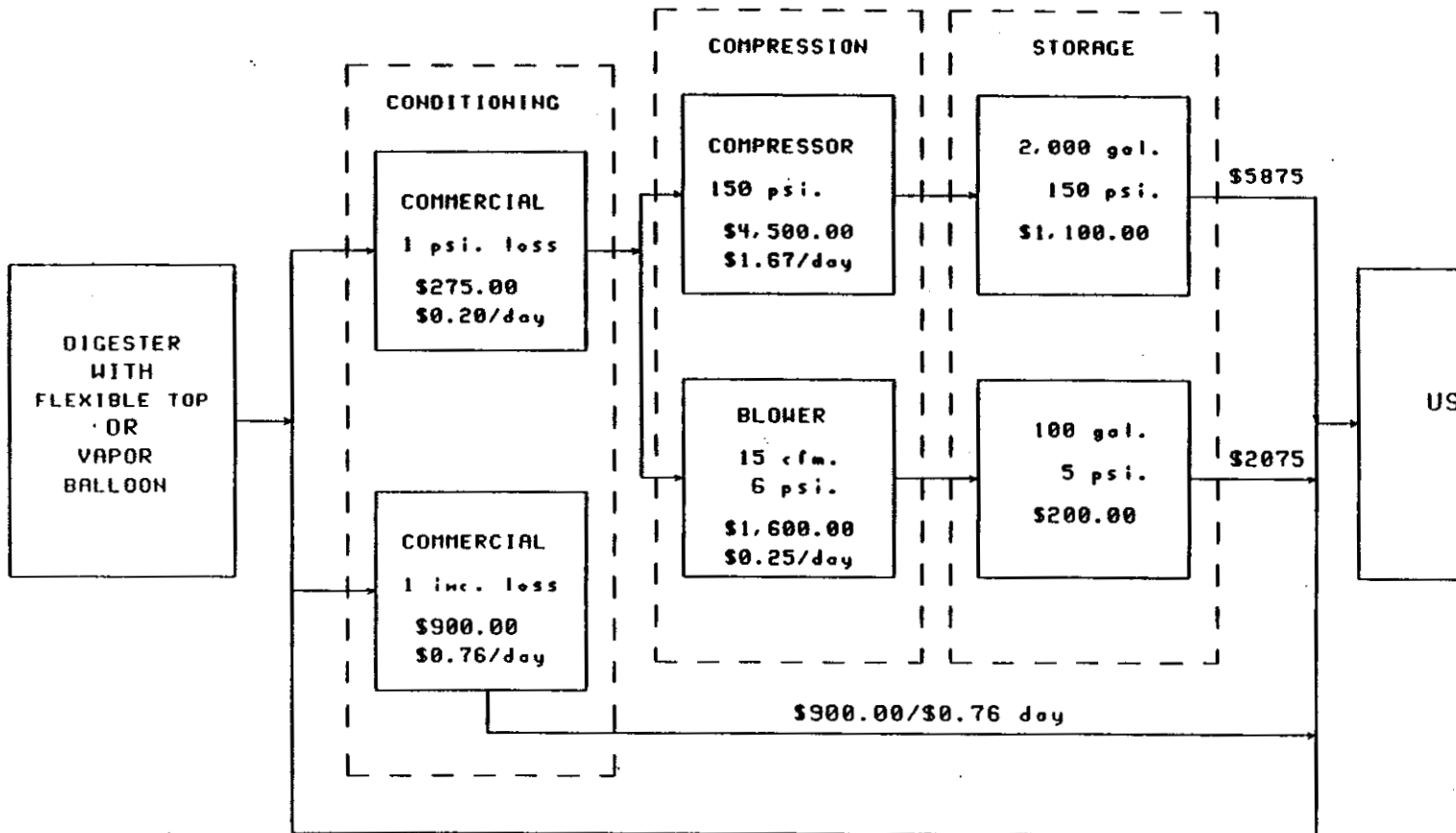
Low Pressure Storage. Low pressure storage options have been successfully demonstrated by several research organizations and universities. They typically operate below 10 inches water gauge, but some options are capable of much higher pressures. Generally, low pressure storage vessels cost more but the systems feature the lowest operating cost of any storage option.

Figure 7-1. Biogas Storage Options





**Figure 7-2. Typical Biogas Storage System**



Source: Heisler 1981

Biogas can be stored between the liquid level of the digester and the digester cap. The roof can float (i.e. rise as more gas is stored) or can be made of flexible material. Restraining the top will increase the pressure under which gas can be stored. Most systems employing these types of storage vessels hold biogas at pressures under 10 inches of water gauge. The major advantage of a digester with an integral storage component has to be the reduced capital cost of the system. However, such a design features several areas that require special attention. The roof of the digester must be insulated. Uninsulated covers are susceptible to large temperature fluctuations which will cause operating problems in the digester. Floating and flexible covers present a second problem. They must be protected against wind loading, perhaps by a building or shelter.

Biogas may be stored in flexible bags. The bags are manufactured from impermeable materials such as rubber, plastic, or fiber-reinforced plastic. These bags are tough but can suffer damage by puncture. They are also subject to heat gains and losses if they are not insulated. Bags have also been used between the liquid level and cap of a digester but most are used as liners in steel or concrete tanks. Some larger systems use a bag or flexible roof to hold biogas at low pressure and then draw the gas off for cleaning, compression, and subsequent storage at a higher pressure.

Some systems use water sealed gas holders for low pressure storage. Such a unit operates between 6 inches and 10 inches water gauge. Care must be taken to prevent the water in these devices from freezing.

**Medium Pressure.** If a system requires a gas pressure greater than several psi but less than 200 psi, clean biogas ( $H_2S$  removed) may be compressed and stored in tanks such as propane gas tanks. These tanks are typically rated to 250 psia. Compressing biogas to this pressure range costs about 5 kwh per 1000  $ft^3$  or approximately 3% of the energy content of the stored biogas. At these higher pressures, insurance investigations may be required. Local pressure vessel code may also apply. Pressure safety devices are a must (and are required by law).

Tanks, compressors, blowers, and all metal hardware must be protected from corrosive "raw" biogas.  $H_2S$  must be removed from the gas to insure safe operation of these components. Unscrubbed biogas can lead to early failure of compressors and other metal components. Once corrosion starts, the safety of the entire biogas system is compromised.

Medium pressure storage tanks are less expensive than their low pressure counterparts but the requirements for compression and gas cleanup make medium pressure storage more expensive. In exchange for the higher cost, the same volume of gas can be stored in a smaller vessel and the stored biogas possesses a higher energy density than that in a low pressure system.

### **High Pressure Biogas Storage**

High pressure storage of gas is used in cases where very high energy densities are required or the size of a system's storage facility must be limited. High pressure storage systems are intended to maintain pressure between 2000 - 5000 psi. Compression to 2000 psig requires nearly 14 kWh per 1000 ft<sup>3</sup> of biogas, or about 8% of the available energy. The gas is stored in steel cylinders similar to those used to store commercial compressed gases such as nitrogen. Large high pressure storage facilities have made use of longer, interconnected, convex-ended cylindrical steel tanks.

Since corrosion becomes more of a problem as pressure increases, the requirements for drying and scrubbing the gas are more stringent than for medium pressure systems. Safety also becomes more important. Tanks must be properly constructed and fitted with suitable safety devices (bursting disk devices are suitable in this case). System controls must prevent overpressurization of the storage facility. Although the initial cost of storage vessels is low, overall system costs are high and limit high pressure storage to large facilities or special applications like vehicle fuel or the sale of pure methane.

### **Absorption Storage**

Absorption of methane in liquid propane has been suggested as a way to store clean, dry biogas. The methane dissolves in the propane resulting in a 4- to 6-fold increase in the amount of gas stored at a given pressure. Only 4% of the storage medium (propane) escapes when the methane is removed. However, the technology remains unproven, and some researchers think the technique may require refrigeration. The requirements of H<sub>2</sub>S, CO<sub>2</sub>, and water vapor removal coupled with the need for refrigeration make this an extremely expensive storage alternative suitable only in special cases.

## Liquefaction

It is a common error to assume methane can be liquefied at ambient temperatures like propane and butane. Liquefaction of biogas requires a temperature of  $-59^{\circ}\text{F}$  at atmospheric pressure. Since  $\text{CO}_2$  solidifies at  $-11^{\circ}\text{F}$ ,  $\text{CO}_2$  can be present. Trace impurities in the gas can cause problems at these low temperatures as well. Although the liquefying temperature can be raised by increasing the pressure ( $-14^{\circ}\text{F}$  at 682 psia), the technology is limited to large systems because of the extremely high costs.

## Considerations

Five factors must be studied to determine the type of storage facility required by a biogas system. These are:

- o safety,
- o volume,
- o pressure,
- o location,
- o and fluctuations in gas production.

**Safety.** Unscrubbed biogas contains  $\text{H}_2\text{S}$  and is extremely corrosive. Moreover, its corrosiveness increases with increasing system pressure. Unless cleaned, the biogas will quickly corrode metals, drastically reducing their useful life and creating a safety hazard. The  $\text{H}_2\text{S}$  in biogas is also toxic to humans. Therefore, all storage vessels should be adequately vented when personnel must enter them. If not, death can result. This also goes for buildings which house digesters and their storage facilities. In these facilities, adequate ventilation must be provided to prevent a buildup of biogas in the space from small leaks. Biogas can be heavier or lighter than air depending on its  $\text{CH}_4$  to  $\text{CO}_2$  ratio. The danger of fire is reduced for outdoor installations.

**Volume.** Proper sizing of a storage vessel depends on the volume of gas produced and the volume of gas required by the end user. The designer compares the daily production pattern to the need for biogas throughout the day. The storage vessel is sized so that the usage requirements are economically satisfied. Storing more than one day's production has proven uneconomical for small scale systems (Heisler 1981) and any unused gas is usually vented or flared to the atmosphere.

**Pressure.** The minimum pressure will be dictated by the gas utilization equipment. Piping losses must be included when determining the minimum system pressure. The system pressure must be sufficient to insure the safe, efficient operation of all equipment. Increasing storage pressure can reduce the required storage volume as shown in Table 6-2. Pressurization equipment allows the use of less expensive filters (with higher pressure drop specifications). This helps offset the increased operating costs when blowers or compressors are used.

**Location.** Safety and system losses are influenced by the location of the storage facility. Long piping runs with bends and valves may require blowers to maintain system pressure at the required level. Proximity to buildings and the general public must be considered from a safety standpoint and in light of local building codes.

**Production Fluctuations.** Daily fluctuations in gas production can lead to pressures below the minimum pressure required by the gas utilization equipment and peaks in gas pressure above the maximum specification as well. Adding pressurization equipment would prove more economical than designing the digester to handle these wide fluctuations in pressure.

## **Materials**

A wide variety of materials have been used in making biogas storage vessels. Medium and high pressure storage vessels are usually constructed of mild steel while low pressure storage vessels can be made of galvanized iron, concrete, and plastics. Each material possesses advantages and disadvantages that the system designer must consider. Plastics reinforced with scrim appear to be the most popular material for flexible digester covers in the United States. The materials are similar to those used as liners for treatment ponds and containment of hazardous wastes. In several cases, exposed scrim fibers have wicked in solutions that have weakened the fabric joints of these materials. The newest reinforced plastics feature polyester fabric which appears to be more suitable for flexible digester covers. A summary of the devices, materials, and equipment sizes for storage of biogas at low, medium and high pressure is provided in Table 7-1. The most popular materials of construction for storage vessels and details some of the pros and cons of each one are listed in Table 7-2.

**Table 7-1. Examples of Biogas Storage Options**

<u>Pressure</u>	<u>Storage Device</u>	<u>Material</u>	<u>Size</u>
Low (2-6 psia)	Water Sealed Gas Holder	Steel	3,500ft <sup>3</sup>
Low	Gas Bag	Rubber, Plastic, Vinyl	150- 11,000ft <sup>3</sup>
Low	Weighted Gas Bag	Same	880- 28,000ft <sup>3</sup>
Low	Floating Roof Reinforced Plastic	Plastic,	Var. Vol. Usually less than 1 Day's Production
Medium	Propane or Butane Tanks	Steel	2000 ft <sup>3</sup>
High (2900 psia)	Commercial Gas Cylinders	Alloy Steel	350 ft <sup>3</sup>

**Table 7-2. Materials of Construction for Biogas Storage Vessels**

<u>Material</u>	<u>Advantages</u>	<u>Disadvantages</u>
Mild Steel	Usually the lowest cost material. Has a long life when properly painted and maintained.	Mild steel rusts, especially on the outside. Surface must be properly prepared. Grit- or sand-blasting is the preferred method. Remove all rust and mill seals before painting.
Galvanized Iron	Available at low cost. Years of good service when properly painted and maintained.	Must be treated before paint will adhere. Unpainted tanks have a useful life of about five years.
Concrete	Low cost, long life	Requires coating on inside to prevent H <sub>2</sub> S "crowning" or erosion
Ferrocement	A new technology consisting of rich cement mortar impregnated with wire mesh. Less expensive than mild steel vessel of the same size. Suitable for pre-cast products.	Requires skilled labor to manufacture. Requires a coating on the inside and outside to improve the impermeability to gas. Must be leak tested.
Plastic (PVC, HDPE, <3 mm thick)	Readily available and easy to work with.	Plastics degrade in sunlight unless UV treated. Expensive.
Hypalon ®	Reinforced for added strength	Prone to "wicking" when used as a floating top.
XR-5 ®	Polymer based fabric reinforced sheet that addresses the wicking problem. Good resistance to chemicals. Does not readily absorb water.	Sometimes difficult to seal.

Source: ESCAP 1980





## CHAPTER 8

### BIOGAS UTILIZATION TECHNOLOGIES

#### Introduction

There are several viable options for the utilization of biogas as shown in Figure 8-1. Foremost among these are:

- o direct combustion,
- o fueling engines, and
- o sales to natural gas pipelines.

#### Direct Combustion

Direct combustion is inarguably the simplest method of biogas utilization. Conversion of combustion systems to biogas combustion is basically a matter of fuel orifice enlargement and intake air restriction, with attendant modification of the fuel delivery and control system.

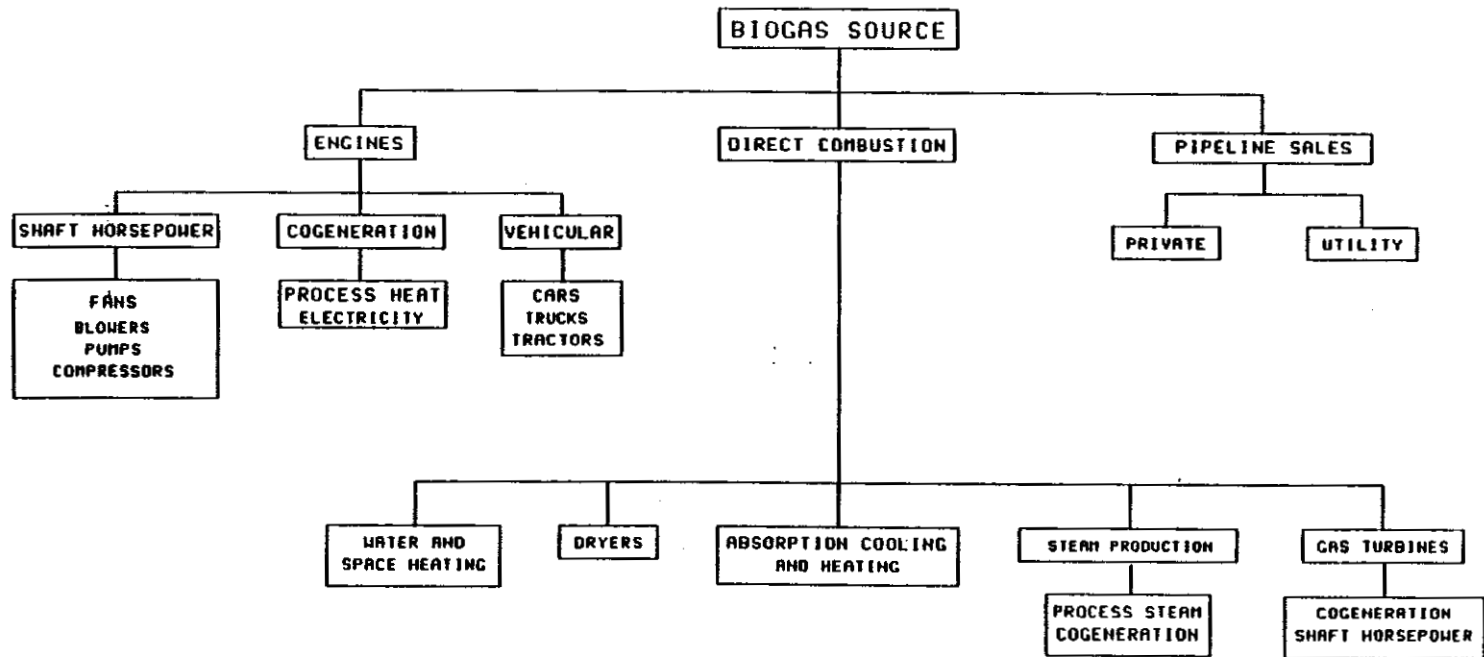
However, when implementing these modifications with either new or retrofitted systems, a number of variables should be considered; including the heat input rate, the fluid handling capabilities, flame stability, and furnace atmosphere.

Heat input rate. Because biogas sometimes has energy values lower than 400 Btu/SCF, some combustion systems will be restricted by a limit in volumetric fuel throughput, including the supply to the combustor. The result is a decrease in equipment output (derating) which must be evaluated for each combustion unit.

Fluid handling capability. Besides the combustor, the rest of the fuel system (flues, piping, valves, and controls) must be evaluated to determine if increased fuel and exhaust flows, and decreased flow of combustion air, can be handled.

Flame stability. Since flame or burner stability is primarily a function of flame velocity and flammability limits, it must be evaluated both theoretically and empirically for individual sources of biogas. Biogas may produce a slower flame speed (relative to natural gas) and a higher volume of biogas must be fed to a burner to maintain an equal heat input, or the flame may "blow off" the burner tray.

**FIGURE 8-1. BIOGAS UTILIZATION OPTIONS**



Furnace atmosphere. Because of the corrosive nature of biogas containing hydrogen sulfide and moisture, the burner and its combustion zone should be adequately protected. Corrosion of iron, copper, and steel components in the combustion, heat transfer, and exhaust zones of a combustion system should be carefully evaluated. To help protect from moisture and H<sub>2</sub>S corrosion, system temperatures should be maintained above the dew point temperature (approximately 260°F) to prevent condensation. In biogas fuels with high H<sub>2</sub>S levels, sulfur compounds have been reported to accumulate at and around the burner.

To help maintain operation above the dew point, boiler water temperatures should be maintained in excess of 220°F at all times. In the case of a "cold start", a boiler should be fired with natural gas, propane, or fuel oil until the system is up to operating temperature (Parish 1986). Also, preventing the stack temperatures from falling below dewpoint may be accomplished by bypassing the second pass of a boiler unit. Although this helps prevent sulfurous and sulfuric acid formation and subsequent corrosion, boiler efficiency may be adversely affected. Similar concern should be given to the use of stack gas economizers, which should not use feedwater with temperatures less than 250°F or reduce stack gas temperatures below dew point.

### **Burner Conversion**

Burner conversion to fire biogas rather than natural gas or propane involves insuring that an exit velocity and corresponding pressure drop of the biogas is maintained for proper fuel and air mixing (Parish 1986). The pressure drop across a burner orifice will increase with decrease in heating value and specific gravity of biogas relative to natural gas and propane.

This increase in the pressure drop can be determined by the equation:

$$\frac{P_{\text{Gas A}}}{P_{\text{Gas B}}} = \frac{(\text{Heating Value Gas B})^2}{(\text{Heating Value Gas A})^2} \times \frac{\text{Spgr Gas A}}{\text{Spgr Gas B}}$$

For example, if natural gas (1050 Btu/SCF, 0.65 spg) is replaced by a typical biogas (550 Btu/SCF, 0.80 spg) the increase in pressure drop across the orifice would be:

$$\frac{P_{\text{Biogas}}}{P_{\text{Nat Gas}}} = \frac{(1050 \text{ Btu/SCF})^2}{(550 \text{ Btu/SCF})^2} \times \frac{0.80}{0.65}$$

= 4.490 times the pressure drop across the natural gas burner orifice.

To compensate for this increase in pressure drop, the orifice diameter must be increased. An estimated orifice diameter multiplier for converting natural gas and propane appliances to fire on biogas at different methane contents is provided in Table 8-1 (Parsons 1984). Permanently increasing an orifice diameter to accommodate biogas, however, may degrade the performance of the burner if returned to use with natural gas or propane. This is an important consideration when an operation requires the flexibility of switching between fuels due to biogas availability.

To maintain dual-fuel capability, gas blending or dual-fuel burners can be implemented. An orifice modification can be made based on a fuel gas of either biogas or a biogas/ natural gas/ propane blend. To maintain burner performance, the fuel gas mixture must provide an equivalent heat input and pressure drop to the fuel gas mixture used for the orifice design. This can be accomplished by blending biogas, natural gas, or propane, or by blending natural gas or propane with air to produce a mixture with an equivalent heat input (and pressure drop) as the biogas.

**Table 8-1. Orifice Diameter Multiplier for Gas Appliances**

<u>Percent Methane in Biogas</u>	<u>Orifice Diameter Multiplier</u>	
	<u>Natural Gas (1,050 Btu/ft<sup>3</sup>)</u>	<u>Propane (2,500 Btu/ft<sup>3</sup>)</u>
70%	1.32	1.63
65%	1.39	1.72
60%	1.46	1.81
55%	1.54	1.92
50%	1.64	2.04

Example: A natural gas appliance with an orifice diameter of 0.1" would have to be enlarged to  $0.1 \times 1.54 = 0.154$ " diameter for a biogas with 55% methane.

Notes: The area multiplier is the diameter multiplier squared.

Gas densities @ 68°F and 14.7 psia  
 Carbon dioxide= 0.01147 lb/ft<sup>3</sup>  
 Natural gas = 0.0506 "  
 Methane = 0.0417 "  
 Biogas, 60% methane= 0.0709 "  
 Dry Air= 0.0752 "

Source: Parsons 1984

An indicator of this fuel mixture compatibility with the burner orifice design is the Wobbe Index. This index is defined as:

$$\text{Wobbe Index} = \frac{H_o}{(G_o)^{1/2}} = \frac{H_m}{(G_m)^{1/2}}$$

Where:

H = heating value of gas

G = specific gravity of gas

o = original gas

m = substitute mix including pure substitute and air

Source: North American Manufacturing 1978

The concept is to create mixtures with similar Wobbe Index Numbers to allow proper combustion system operation.

The other option for achieving fuel flexibility is the use of dual-gas burners that can maintain the orifice pressure drop for each fuel gas independently. A dual canister burner can provide a separate set of orifice jets for each gas (Parish 1986) to allow for independent fuel flow. On smaller systems such as water heaters, burner trays can be easily removed and interchanged so that a biogas tray can be replaced by a propane gas tray in the event of a biogas shortage (Walsh et al. 1986).

Since many systems operate intermittently, consideration must be given to the type of pilot used to ignite the fuel mixture. Biogas pilots have been used with success; however, some installations have experienced problems with pilot extinguishing, which led to the installation of a separate propane pilot (Walsh et al. 1986). Some water heater and boiler systems are specifically designed to operate on biogas fuels. Several of these are listed in the Appendix A.

### **Absorption Chillers**

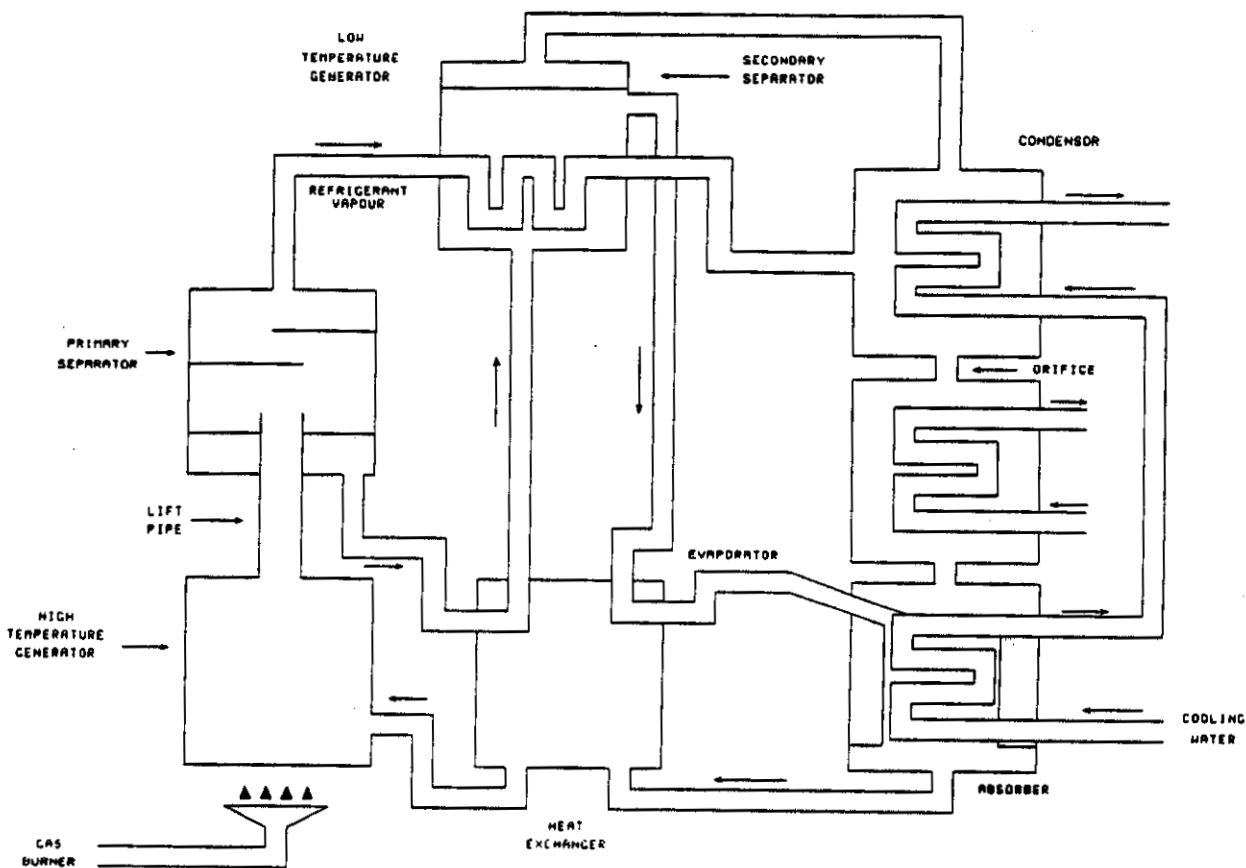
A biogas conversion method with limited application to date involves absorption heating and cooling. Utilizing biogas in a gas burner, a double-effect absorption chiller-heater can be used to provide chilled water for refrigeration and space cooling and hot water for industrial processes and space heating.

This system is similar to vapor-compression refrigeration, except that the high pressure side of the system has a series of heat-transfer vessels and a pump rather than a compressor. Most absorption systems utilize ammonia as the refrigerant and an ammonia solution as the solvent/absorbent (Salisbury 1950). However, for air-

conditioning work, brines of lithium chloride and lithium bromide have been used.

An example of a double-effect absorption cycle is shown in Figure 8-2. As discussed in a preceding section, conversion of the burner from natural gas to biogas is relatively simple. While most of these systems are sized in the range of 100 ton capacities, some smaller units are commercially available. Since 1985, two direct-fired, double-effect chillers have provided refrigeration for egg storage and space heating in an egg processing plant with no problems with burner conversion or operation (Knight and Clement 1986). These particular systems have an advertised cooling coefficient of performance (COP) of 0.95 and heating efficiency of 83% (Yazaki 1987). These double-effect systems also can be configured for simultaneous heating and cooling applications. Costs for these units are in the range of \$150 to \$500 per ton of capacity.

**Figure 8-2. Double-Effect Absorption Chiller Cycle**



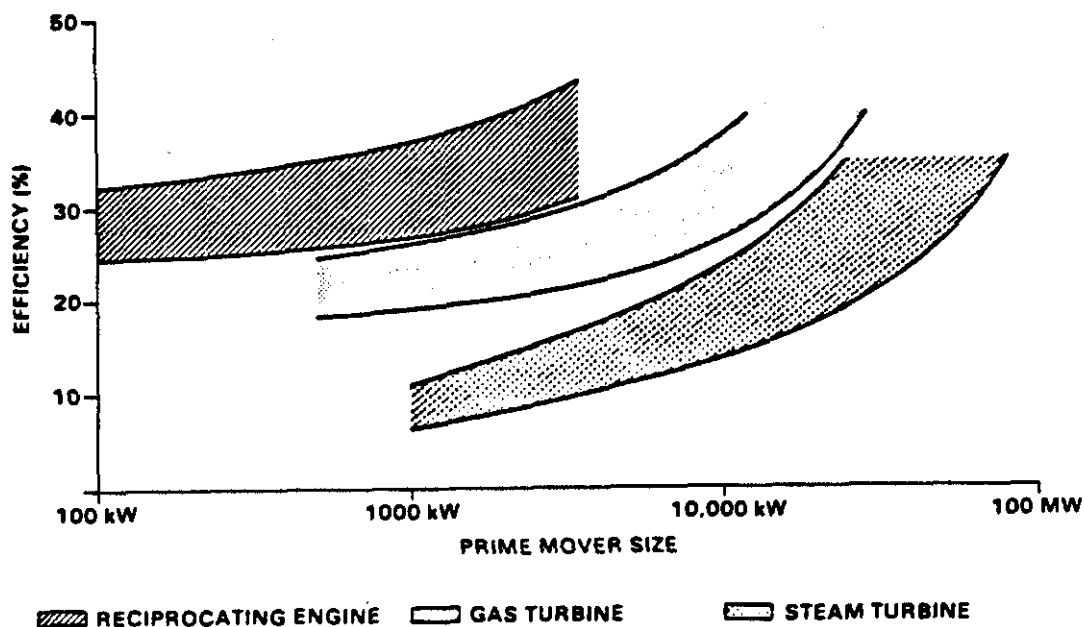
Source: Yazaki 1987

## Gas Turbines

There is limited information on the fueling of gas turbines with biogas. These machines and their peripheral equipment require fuel gases with very low concentrations of particulates and moisture. Many manufacturers recommend gas qualities similar to those required by utilities for pipeline quality natural gas.

As shown in Figure 8-3, gas turbines have a theoretical efficiency advantage over steam turbines for systems at low and medium capacities and an advantage over internal combustion engines at higher capacities. Therefore, gas turbines offer efficiency advantages over other systems, if the problems of particulates and moisture can be cost effectively overcome. However, there have been only a few successful applications in biogas fueling of gas turbines to date (Energy Research and Applications 1981a).

**Figure 8-3. Efficiency Ranges of Prime Movers**



Source: Waukesha 1986

## Engine Systems

Internal combustion engines have been fueled by biogas from municipal digester systems for more than 40 years with varying degrees of success. In recent years, this application has been extended to agricultural and industrial systems for a variety of power requirements. Stationary spark ignition engines can supply power for many loads including:

- o cogeneration,
- o pumps,
- o fans and blowers,
- o elevators and conveyors, and
- o heat pumps and air conditioners.

There is also the potential for biogas fueling of cars, trucks and industrial equipment including tractors.

Evaluation of which system would provide optimum economic use of a biogas source hinges on a number of considerations including:

Degree of utilization. What combination of engine systems will provide the most efficient use of biogas on a daily basis throughout the year? Will a gas compression system or other special gas handling system be required?

Cost of installation. Cogeneration systems are fairly expensive when compared to reducing a high electrical load by replacing electric motor shaft with horsepower from a biogas fueled engine. Cogeneration systems also typically require costly interconnect and control systems. Before making electricity, look at shaft horsepower applications first.

Cost of operation and maintenance. One large engine plant will inevitably have lower operating costs than a few smaller plants. The larger loads should be satisfied first before looking to relieve smaller loads. The costs of providing backup power to a conversion in the case of an engine failure or fuel unavailability should be carefully evaluated.

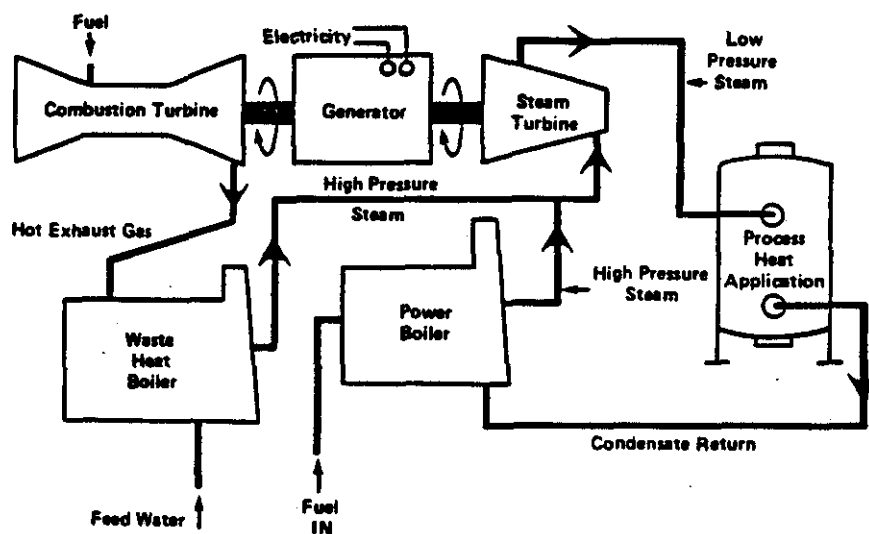
Degree of interference with current operations. Any engine application to replace an electric motor in an industrial process will mandate that consideration be given to load management and control. Engines also have higher maintenance requirements, in both materials and labor.



## Cogeneration

Cogeneration is best defined as the simultaneous production of two or more forms of energy from a single fuel source. In the following discussion, the two forms of energy exemplified are electricity and thermal energy in the form of hot water. Other applications include fueling an engine for shaft horsepower (for pumps, blowers, etc.) and thermal energy (space heating, hot water, absorption chilling, etc.). Additionally, cogeneration can take the form of using biogas to fuel a steam boiler for producing steam for a steam turbine for producing shaft horsepower, electricity, and hot water. An example of an industrial cogeneration system is illustrated in Figure 8-4.

**Figure 8-4. Industrial Cogeneration System**



Source: Wilkinson and Barnes 1980

The layout of a small-scale (55 kW) cogeneration system including the major components of power unit, generator, heat recovery system, and controls is shown in Figure 8-5. This section will provide practical technical information on the selection and operation of these various components relative to fueling by biogas.

## **Power Units**

**Unit Sizing.** The sizing of a cogeneration system will have an impact on the overall capital cost of the system, and the efficiency of the system to produce electricity and hot water. Optimal utilization is a function of operational energy needs (electrical and thermal), the output of the cogeneration system, and the rate of production and storage of biogas for use by the system.

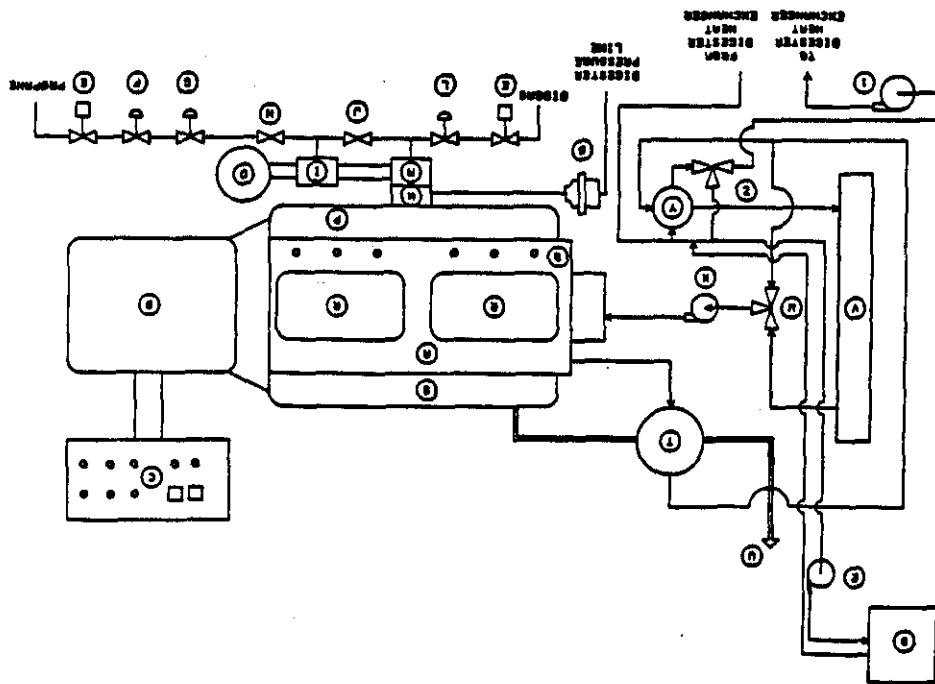
As illustrated in Figure 8-3, there are three basic options for prime mover in a cogeneration system: reciprocating (internal combustion) engines, gas turbines, and steam turbines. The ensuing discussion will be limited to internal combustion engines, specifically spark ignition and compression ignition units.

**Matching an Energy Load.** Once the diurnal energy pattern of an operation has been established, an attempt can be made to match cogenerator operation to provide the most power over the longest period of time. This procedure is illustrated in Figure 8-6 where the electrical load of a dairy is evaluated for cogenerated electricity. In this example, if biogas availability allows for the production of 1000 kWh of electricity per day, it may be economical to provide 50 kW for 20 hours per day rather than 100 kW for 10 hours per day. Most engine manufacturers recommend continuous operation of their units over intermittent operation for maintenance and longevity reasons.

In other operations, however, it may be more economical to use the cogeneration system to either match or shave peak loads in order to reduce utility demand charges. Sizing of a cogeneration system, therefore, would primarily be a function of the amount of biogas that can be economically stored and the peak demand period that must be met. Peak shaving requires a greater degree of system control and reliability to be effective.

In all cases, the radiator for a cogeneration system should be sized to meet the full load cooling requirements of the system. This will permit operation of the system at full electrical power output during periods of low thermal energy demand or heat recovery system failure.

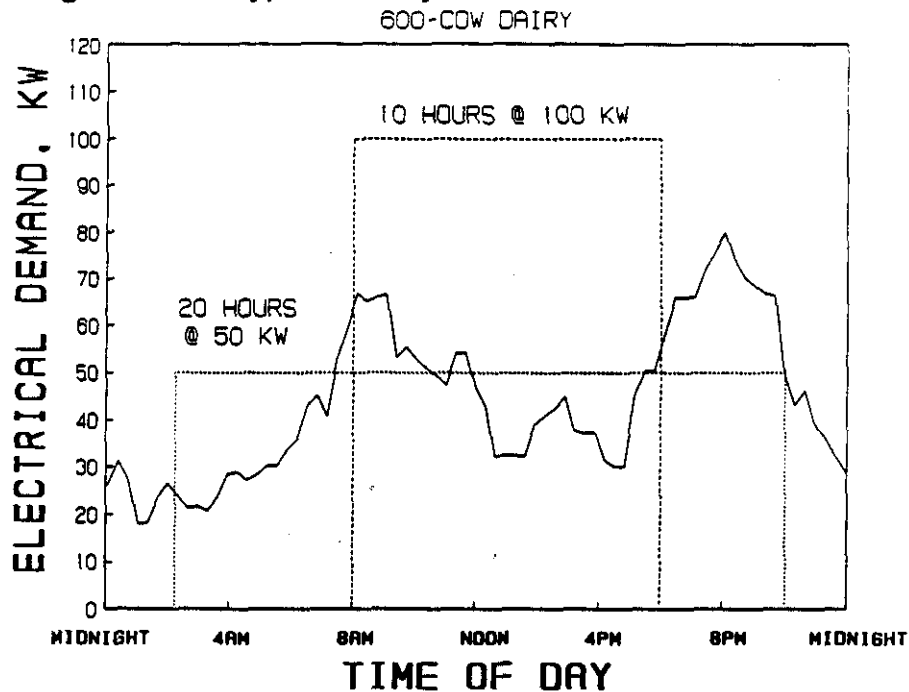
Figure 8-5. Typical Biogas Cogeneration System



- A Engine  
B Generator  
C Control Panel  
D Air filter and combustion air intake  
E Solenoid valve for propane automatically opens when engine starts and controls are set to propane fuel position  
F Propane high pressure regulator  
G Propane low pressure regulator  
H Propane fuel line manual isolation valve - closed when switching to biogas  
I Propane fuel carburetor  
J Biogas fuel line manual isolation - opened when switching to biogas  
K Solenoid valve for biogas automatically opens when engine starts and controls are set to biogas fuel position  
L Biogas pressure regulator  
M Biogas fuel carburetor  
N Throttle  
O Throttle-Trol pressure regulator which increases throttle setting with increase in digester pressure  
P Engine intake manifold  
Q Spark plugs (6)  
R Engine valve covers (2)  
S Engine exhaust manifold  
T Heat exchanger to recover heat from engine exhaust  
U Engine exhaust to atmosphere  
V Radiator  
W Control valve to maintain engine inlet cooling water temperature at 190°F  
X Circulation pump for engine cooling water  
Y Heat exchanger to recover heat from engine cooling water  
Z Control valve to keep heating water to digester below 140°F  
1 Circulation pump for digester heating water  
2 Circulation pump for emergency heater  
3 Emergency heater for digester start-up

Source: Walsh and Ross 1986

**Figure 8-6. Typical Dairy Farm Load Variation**



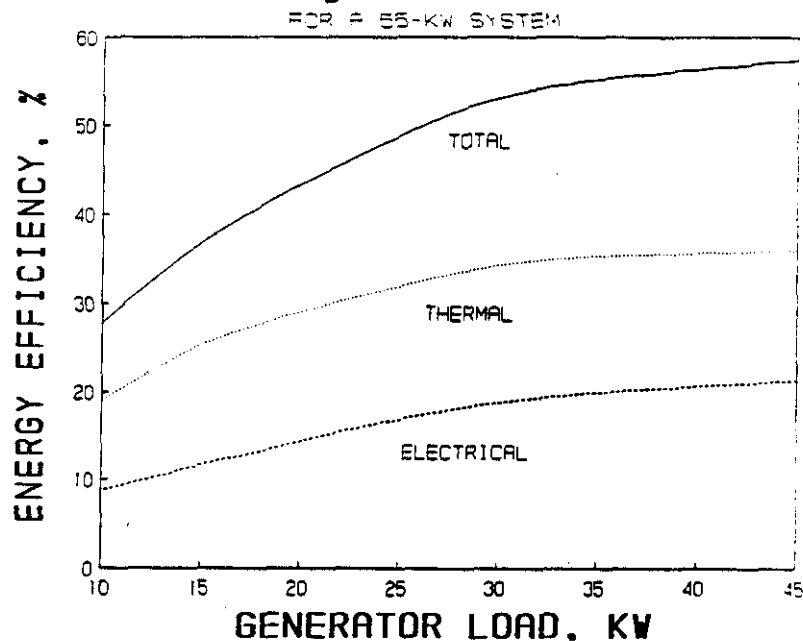
**System Oversizing.** Oversizing a unit can have serious ramifications on the electrical efficiency of a system. As shown in Figure 8-7, the efficiency of a 55 kW cogeneration system experienced a sharp decrease in electrical efficiency once the generator load fell below 30 kW or 55% of the maximum output (Walsh *et al.* 1986). Similarly, Jewell *et al.* (1986) suggests that a cogeneration unit be sized to operate at no lower than 60% of the maximum power.

While evaluating the thermal load of an operation, the quality (i. e., temperature) of the heat recovered should be considered. Additional energy may be required to upgrade this energy for actual use. Also, consider that controlled temperature anaerobic systems could require 40% or more of the energy output in the form of biogas to maintain temperature.

**Engine Derating.** Because biogas has a lower volumetric energy content than either natural gas or diesel fuel, an engine may be derated. For natural gas engines, this derating may be as much as 13% of the natural gas rating. Further derating can occur if changes are not made in timing, spark plug size and gap, and valve lash (Gill 1971).

Additional consideration should be given to the overall gas consumption of a unit including start-up and cool-down cycles associated with shut-downs to meet operational schedules or a lack of biogas. During these periods, engines are not

Figure 8-7. The Effect of Engine Load on Electrical Efficiency



Source: Walsh and Ross 1986

operating at maximum and loss of output must be accounted for in the overall fuel budget. Moreover, cogeneration engines can be tuned for either maximum output to meet a certain demand, or for maximum fuel economy, producing the most power for the fuel available.

**Biogas Quality.** In addition to the energy content of the biogas, engine manufacturers also have concerns with the  $H_2S$  and moisture content of the fuel. Many recommend  $H_2S$  limits of 10 ppm or 0.001% by volume (Cummins 1985). If these limits are exceeded, warranties on the engine may be voided. This highlights the need for some form of gas cleanup or filtering system prior to engine fueling. Additionally, manufacturers suggest operating the engines on a clean gas during start-up and shut-down and maintaining engine oil temperatures high enough (190°F) to prevent condensation of water vapor and  $H_2S$  in the oil (Cummins 1985 and Waukesha undated). The use of positive crankcase ventilation (PCV) filters for purging moisture laden contaminated air from the crankcase is also encouraged. Although the use of mercaptan filters are strongly encouraged by most manufacturers, some research has questioned the overall performance of these filters (Clark and Marr 1985, Walsh *et al.* 1986).

## Spark Ignition Engines

Engine Modification. Spark ignition (SI) engines are the easiest engines to convert to biogas due to the wide availability of natural gas fired units and the relative similarity of biogas to natural gas. There is also a large selection of diesel powered cogeneration systems in the higher output ranges (over 500 kW).

Engine conversion to biogas fueling involves engine modification in the following areas:

- o carburetion,
- o spark gap settings,
- o spark timing, and
- o maintenance requirements.

Carburetion. Carburetion modification basically involves accounting for the lower volumetric heating value of the biogas relative to the primary fuel. For a natural gas fired engine, this amounts to increasing the fuel intake capacity of the carburetor and restricting the combustion air intake.

Conversion of a gasoline fueled engine would require complete conversion to a gaseous fuel carburetor sized to provide the volumetric flow necessary for maximum power output. The anticipated fuel consumption of a biogas engine is a function of the engine itself, load considerations, engine speed, air-fuel ratio, and fuel dilution. The specific power output of an engine operated at 900 rpm and a compression ratio of 15:1 can be predicted using the equation shown below as developed by Neyeloff and Gunkel (1981).

$$SPO = -154.8 - 9.24 \times 10^{-2}D + 41.9R - 3.24 R^2 + 7.78 \times 10^{-2}R^3$$

Where:

SPO = specific power output, HP/L CH<sub>4</sub>/min x 100

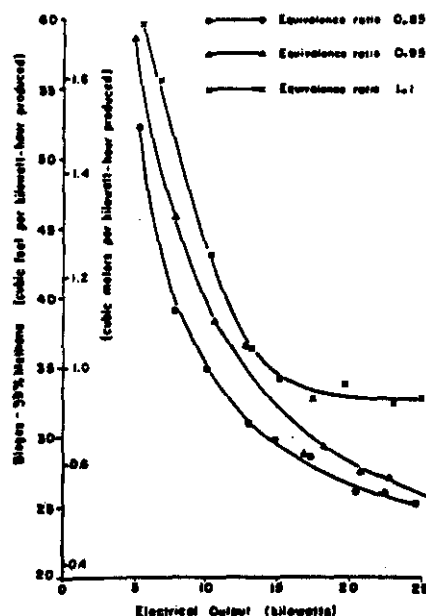
D = percent dilution, (CO<sub>2</sub>/CH<sub>4</sub>) x 100

R = percent fuel-air ratio, (CH<sub>4</sub>/air) x 100

(Note: 28.3 L/SCF)

The fuel consumption pattern of a 25 kW cogeneration unit at various loads and air-fuel mixtures is illustrated in Figure 8-8. Walker et al. (1985), noted the difficulty in physically adjusting the carburetor for maximum efficiency.

Figure 8-8. Fuel Consumption of a 25 kW Cogeneration Unit

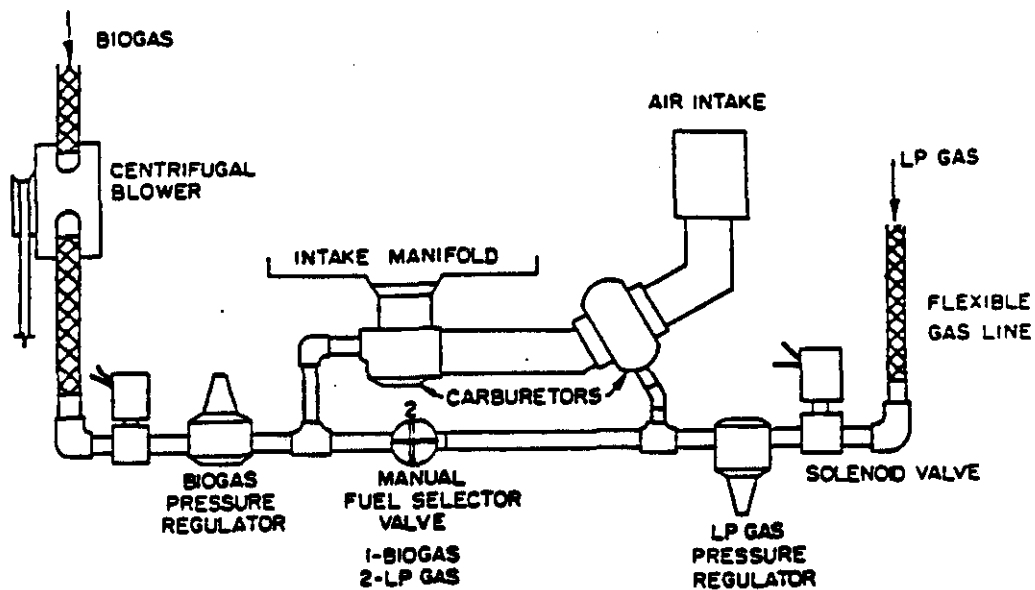


Source: Koelsh 1982

In the design of a system, the incorporation of a secondary fuel supply such as natural gas or propane should be considered in case the biogas fuel supply is interrupted and continued service is required. An example of biogas carburetion with a secondary fuel supply is illustrated in Figure 8-9. Recommended fuel pressure requirements will vary between 2-20 psig for naturally aspirated engines and 12-20 psi for turbocharged engines (Caterpillar 1972). Caterpillar also recommends providing engine air intake at a rate of 3 CFM per engine horsepower.

Throttle Controls. In lieu of fixed throttle controls for maintaining a constant power output, there are some throttle control devices which track certain fuel or load factors to vary engine power. A commercially available system is the Tracker-Trol® which allows for the throttle to vary with the biogas fuel pressure (Walsh *et al.* 1986). This permits continuous engine operation without substantial gas storage; however, the floating throttle setting reduces the engine load causing a reduction in engine power efficiency (Walsh *et al.* 1986). There are also other commercial products on the market that utilize microprocessor controls to optimize power output by monitoring fuel quality, intake air conditions, engine conditions, and system load (Waukesha 1987a).

Figure 8-9. Biogas Carburetion with Secondary Fuel Supply



Source: Stahl *et al.* 1982b

**Air-Fuel Ratio.** When modifying engine carburetion, consideration must be given to the Air-Fuel Ratio in order to obtain optimum performance. As seen in Chapter 3, the stoichiometric Air-Fuel Ratio for a biogas of 60% methane is 6.03.

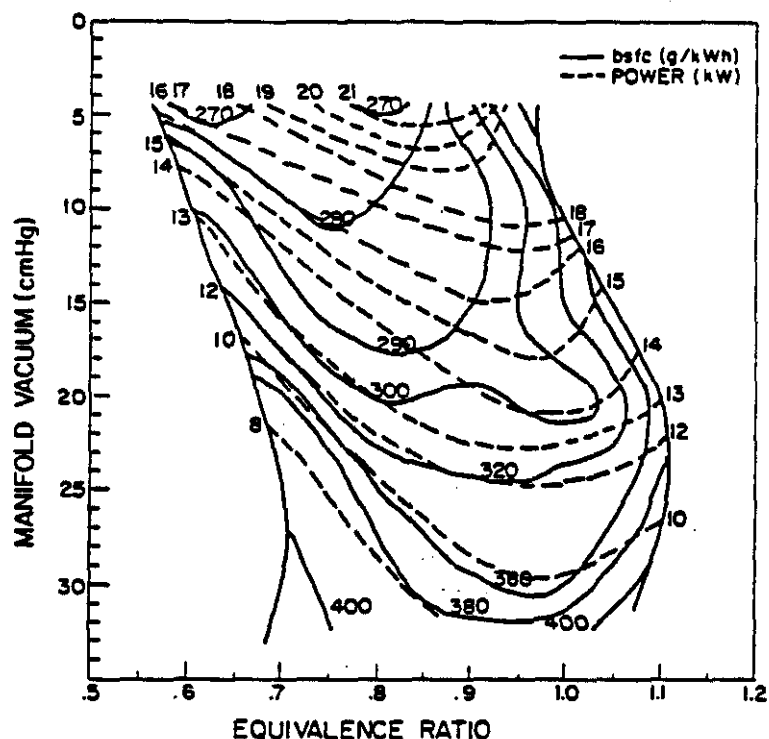
Derus (1983) recommended that minimum methane concentrations of 35% and heating values of 400 Btu/SCF be maintained for operation of a four cycle internal combustion engine. Similarly, a methane and carbon dioxide mixture will not combust if the volumetric amount of carbon dioxide is greater than three times the amount of methane (Coward and Jones 1952). This is of particular concern when using biogas generated from landfill operations.

**Equivalence Ratio.** Jewell *et al.* (1986) noted that optimum electrical efficiency ( $E_{el} = 26\%$ ) was obtained by operating a cogeneration unit at an equivalence (Air-Fuel) ratio of 0.8 - 0.9. The  $E_{el}$  dropped markedly below 20% as the equivalency ratio was raised with a rich fuel mixture (up to 1.3). Optimum performance under lean fuel conditions was also confirmed by Stahl *et al.* (1982b) using similar tests.



The effect of Air-Fuel Ratio on the performance of a power unit is illustrated in Figure 8-10. Neyeloff and Gunkel (1981) determined that optimum Air-fuel Ratios were between 7.69 and 11.76 pounds of air per pound of methane.

**Figure 8-10. Effects of Equivalence Ratio on Engine Performance**

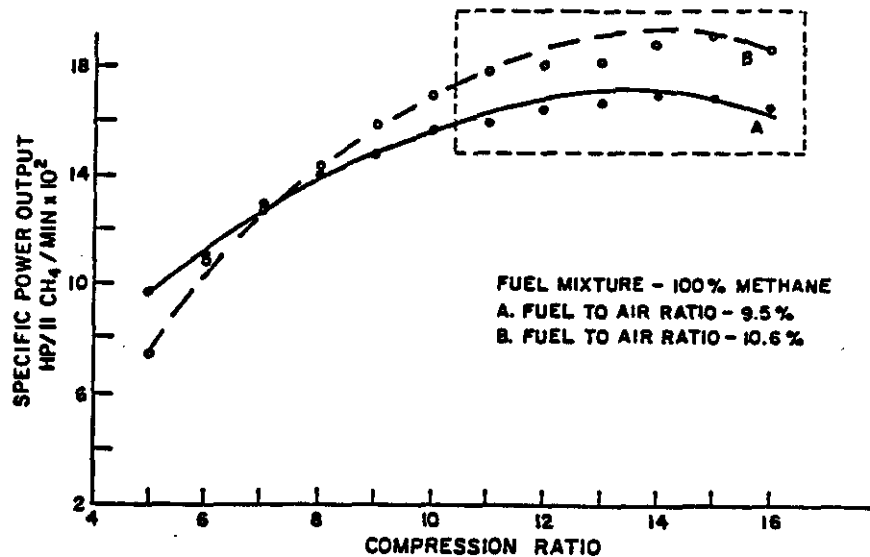


Source: Stahl 1983

**Spark Plugs.** While engine manufacturers suggest the use of cooler plugs for gaseous fuels, Jewell *et al.* (1986) recommends the use of a hotter plug for biogas. Spark gaps between 0.017 and 0.030 inches proved to be adequate with no noticeable difference in performance within this range. Jewell noticed that plugs with nickel alloy electrodes experienced severe erosion within 100 hours of operation. Spark plugs were exchanged with inconel electrode plugs, which operated successfully for more than 500 hours. Similarly, Walsh *et al.* (1986) used Champion J-6 spark plugs with a spark gap of 0.025 inches with good performance and service intervals above 1000 hours.

**Compression Ratio.** Optimum compression ratios for a biogas fueled engine has been determined to be in the range of 11:1 to 16:1 (Figure 8-11). However, most industrial natural gas engines have compression ratios of 7:1 to 10:1.

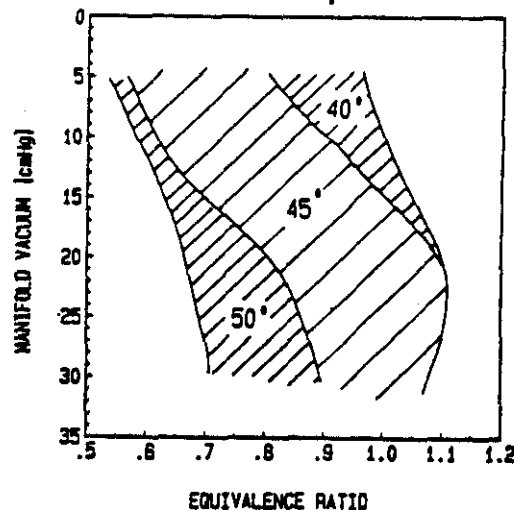
Figure 8-11. Compression Ratio Versus Specific Power Output



Source: Neyeloff and Gunkel 1981

**Engine Timing.** As seen in Chapter 3, biogas typically has a slower flame velocity relative to other gaseous fuels. Because of this, spark timing must be retarded to allow for smoother combustion and engine operation. Figure 8-12 illustrates the impact of timing on engine power (manifold vacuum) output for a biogas of 60% methane. Jewell *et al.* (1986) noted optimum spark timing for a 25 kW engine fueled by a biogas of 60% methane to be between 33° and 45° BTDC. Walsh *et al.* (1986) also operated a 55 kW unit using a similar biogas with a spark timing of 45° BTDC.

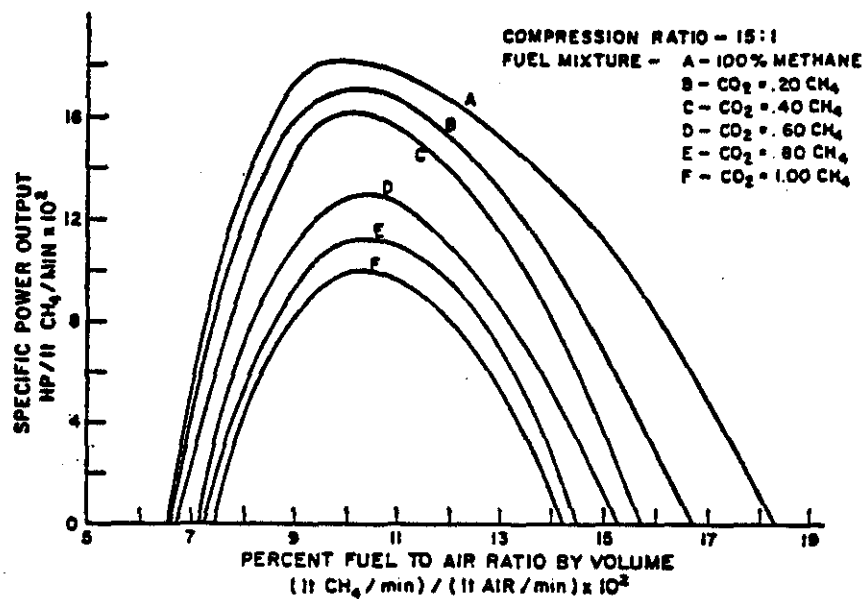
Figure 8-12. Recommended Spark Advance



Source: Stahl *et al.* 1982b

Derating. Regardless of the success of implementing these conversion techniques, a reduction in the continuous power rating of the engine should be anticipated, its magnitude depending on the methane content of the gas. Jewell *et al.* (1986) noted a 15-20% derating for an engine using biogas of 60% methane. The derating of a CFR engine using various levels of methane is illustrated in Figure 8-13. Similarly, torque and power outputs for a converted natural gas engine to biogas yielded outputs of 80-95% of operation on natural gas (Clark and Marr 1985).

**Figure 8-13. Effect of Biogas Methane Content on Engine Derating**



Source: Neyeloff and Gunkel 1981

Heat Recovery - Other than shaft horsepower, a tremendous amount of thermal energy is produced by combustion and most of this energy is available for recovery. A thermal energy balance for a natural gas engine is illustrated in Figure 8-14. As shown in the figure, recovery of the thermal energy from the lubricating oil, coolant cycle, and exhaust can yield as much as 80% of the fuel energy input to the engine.

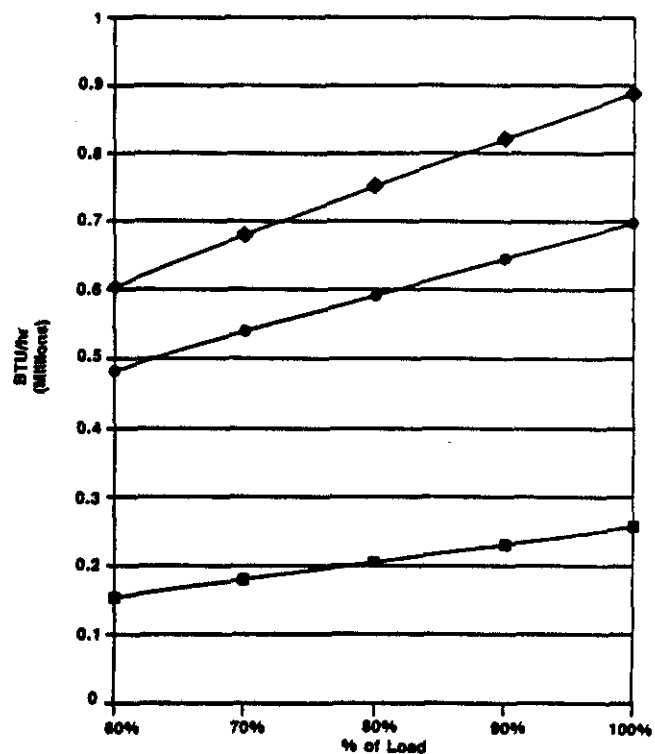
On a cogeneration system with thermal energy being recovered from the engine block, there exists a critical balance between maximizing heat recovery efficiencies and maintaining proper engine block temperatures. On the one hand, engine temperatures should be maintained high enough to prevent the condensation of acid bearing fumes leading to degraded lubricating oil conditions. On the other hand, temperatures should be kept low enough to avoid damage to engine components. With a heat recovery system, great care should be taken in system design to insure adequate heat rejection from the block and to avoid "hot zones" in the engine. In both cases, the engine manufacturer should be consulted before modifications of design coolant flow rates and temperatures are made. Additionally, engine manufacturers may have recommendations for the minimum exhaust temperatures required to prevent condensation of vapors and corrosion of the exhaust vent.

For recovering energy from the engine coolant, a water-to-water, shell-in-tube heat exchanger has proven very satisfactory in performance (Stahl et al. 1982a, Walsh et al. 1986). Exhaust heat exchangers using gas-to-water heat exchangers must be able to withstand high (600-1200°F) exhaust temperatures. Utilization of the thermal energy collected from a heat recovery system is a function of the storage system employed and the energy quality requirements of a process. The temperature of hot water derived from heat recovery will probably be limited to under 190°F.

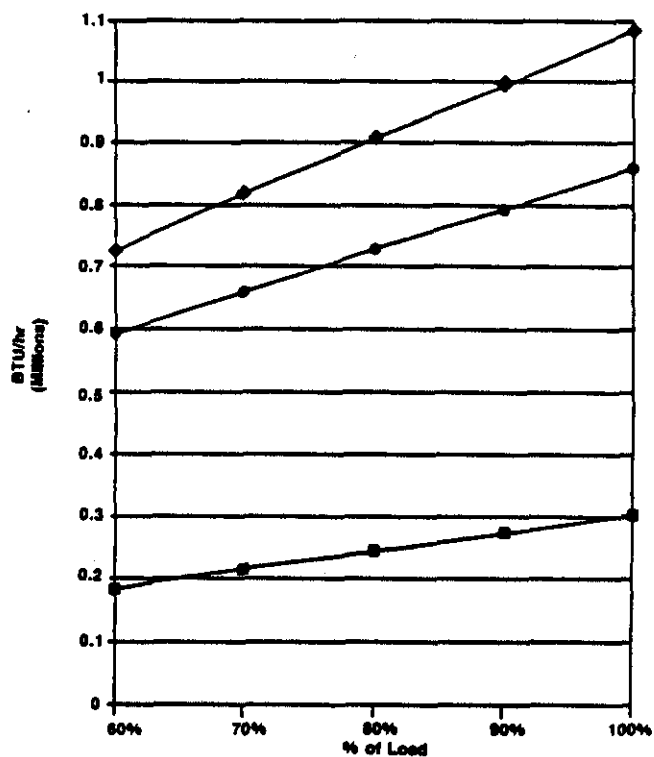
Maintenance Requirements - Even though an engine may be designed for long-term operation (in the range of 20,000 hours) without a major overhaul, certain maintenance procedures must be followed to assure engine longevity. Compounding the problem of maintenance is the use of a non-standard fuel such as biogas that affects engine wear allowances and component replacement cycles. Therefore, engine manufacturers recommendations should be used carefully since these typically apply only to operation on standard fuels such as propane, natural gas, and gasoline.

Figure 8-14. Thermal Energy Balance

1200 RPM, 75kW



1500 RPM, 90kW



● Fuel Consumption

● Heat Recovered

■ Electric Power

Source: Waukesha 1987a

For this reason, it is very difficult to estimate the maintenance cycles for these engines, and subsequently, the costs of maintenance. It is very important, however, that the costs of engine maintenance be reviewed in the context of biogas fueling of the engine. Oil and filter change intervals may be shorter, as may be the intervals for minor and major overhauls. This will have a serious impact on the cost per kWh of electrical production or Btu/hour of thermal energy production. Since engine maintenance costs are primarily based on the hours of engine operation, there exists a distinct economy of scale factor, i. e., a 40 kW unit will have higher costs per kWh output than a 150 kW unit.

Operation and maintenance costs of \$3,700 for a 55 kW system operated for 7,880 hours per year have been reported (Walsh and Ross 1986). Pellerin et al. (1988) indicated similar costs for a 35 kW unit, \$3,200 for 7,440 hours. Table 8-2 illustrates the various cost items and maintenance frequency for the 55 kW cogeneration system. These data compare well with a rule-of-thumb for maintenance costs of \$0.0125 per kWh (Cummins 1982). A 55 kW unit operated 7,800 hours per year at 80% load would have maintenance costs of \$4,300 per year.

Oil Tests - A major consideration in engine maintenance is the frequency of oil changes and type of oil used. Most manufacturers have recommendations for oils to be used in their engines fueled by biogas or "sour" gases and for the frequency of oil changes based on general engine operation.

In order to monitor the general well-being of an engine using biogas, oil testing is essential. Selecting an oil testing lab could be considered as important as selecting a good medical doctor. Although cost is a consideration, it should be third on the list following lab reliability and response time. Because signs of engine failure can appear within a short span of operation, being able to take an oil sample, send it to a test lab, and receive the lab report within a two week period is essential. Most test labs will provide a sample mailer with a label for detailing the source of the oil and other operational data.

Test results from the test lab must be interpreted; therefore, it is important that the laboratory chosen understands the type of engine and fuels being used. The concentration of wear metals in the sample will be dependent on the make of engine, fuel, and total hours of operation. A sample of an oil test performed on a biogas fired engine as determined by Walsh et al. (1986) is shown in Table 8-3. Additional information regarding the type of wear metals and the concentrations to expect, should be available from the engine manufacturer.

**Table 8-2. Engine Generator Maintenance Costs**

7,884 Hours Per Year Operation

<u>ITEM</u>	<u>QUANTITY</u>	<u>UNIT COST</u>	<u>FREQUENCY</u> (hrs)	<u>ANNUAL COST</u>
Oil (gal.)	5	\$6	600	\$394
Oil filter	1	\$10	600	\$134
Oildex filter cartridge	1	\$10	1,000	\$79
Wix coolant filter	1	\$10	500	\$156
Air filter	1	\$15	2,000	\$63
Spark plugs	6	\$6	1,000	\$47
Mercaptan filter	1	\$400	4,000	\$788
Grease generator	1	negl.	4,000	negl.
Minor overhaul	1	\$1,600	16,000	\$788
Major overhaul	1	\$5,000	32,000	<u>\$1,230</u>

TOTAL

\$3,679

Source: Walsh and Ross 1986

The oils most commonly recommended are those with a high Total Base Number (TBN). TBN is an indication of the ability of the oil to neutralize strong acids formed during the combustion process. This is important where  $\text{CO}_2$  and  $\text{H}_2\text{S}$  in a biogas can react with water vapor to form carbonic acid and sulfuric acid, respectively. A TBN test measures the quantity of chemically basic additives in detergent/dispersant, alkaline oils.

Engine manufacturers also provide data on other characteristics of lubricating oils including barium, zinc, and calcium contents and sulfated ash levels. For fuels with  $\text{H}_2\text{S}$  levels over 0.1%, manufacturers recommend an oil with a TBN greater than 8.0 with a minimum operating level of 4.0 (Cummins 1985 and Waukesha 1981). In order to minimize condensation of acid-bearing fumes in the crankcase, manufacturers also recommend keeping engine coolant temperatures above 190°F.

Table 8-3. Engine Oil Analysis

Sample Date	10/24/83	9/26/84	1/10/85	11/21/85	12/15/85	1/12/86	1/16/86	2/11/86	4/15/86
Unit Hours	171	327	391	629	945	1525	1624	2143	3473
Oil Hours	171	156	64	238	316	580	99	519	559
Oil Type/Manufacture	10W-40	10W-40	10W-30	10W-30	10W-30	10W-30	10W-30	10W-30	10W-30
	Unknown	Unknown	Mobil	Mobil	Mobil	Mobil	Exxon	Exxon	Mobil
			Delvac	Delvac	Delvac	Delvac	XD3	XD3	Delvac
			1330	1330	1330	1330	EXTRA	EXTRA	1330
Oil Added (Quarts)	4			1					
Viscosity (Centistokes)	15.8	12.4	12.4	13.8	13.2	16.4	14.0		
	13.6								
	13.4								
Water (% Vol)	-0.05	0.3 C	0.3 B	-0.05	-0.05	-0.05	-0.05		
	-0.05								
	-0.05								
Solids (% Vol)	0.2	1.5	0.1	0.2	0.4	0.2	-	-	0.5
Fuel Soot (% Wt)	-	-	-	-	-	-	0.1	0.1	-
Total Base Number (TBN)	11.8	9.4	13.1	13.4	13.7	13.9	10.4	9.7	9.9
Silicon (ppm/Wt)	11.2	10	6.2	9.8	7.5	6.2	2.0	2.0	6.3
Iron (ppm/Wt)	43.0	75.0	23.3	42.4	23.3	17.2	12.1	11.5	31.5
Chromium (ppm/Wt)	1.8	1.3	1.1	5.3	2.2	1.2	0.9	1.2	1.5
Molybdenum (ppm/Wt)	0.9	0	0.7	1.1	0.9	0	0.6	0	0
Nickel (ppm/Wt)	1.3	2.1	0	0	0	0	0.7	1.1	0.4
Aluminum (ppm/Wt)	5.8	2.0	2.2	4.1	3.6	3.1	0.6	0.3	3.2
Tin (ppm/Wt)	5.6	0	0	0	0	0	0	2.7	0
Copper (ppm/Wt)	26.5	41.9 B	19.2	34.8	12.6	3.5	6.3	8.9	6.6
Lead (ppm/Wt)	14.7	22.4	12.8	24.6	12.3	10.8	4.1	6.9	12.6
Sodium (ppm/Wt)	74.5	103	28.1	31.9	270.0 B	211.0 B	37.9	9.7	223
Boron (ppm/Wt)	102	19.4	6.2	4.3	2.9	2.9	180	181	23.4
Magnesium (ppm/Wt)	562	131	25.7	15.9	12.4	12.2	925	1035	194
Calcium (ppm/Wt)	2725	2928	5045	6388	6253	5169	1536	881	6909
Barium (ppm/Wt)	26.6	8.9	0	0.2	0.6	0.8	3.8	13.5	1.6
Phosphorous (ppm/Wt)	1364	931	1319	963	725	960	1542	1346	1781
Zinc (ppm/Wt)	1541	1063	1385	1583	1495	1183	1611	1321	1541

(ppm/Wt)-Parts per Million by Weight

Abnormal Value Codes

B - Slightly Above Normal. Requires monitoring.

C - High Value. Normally requires corrective action.

D - Severely Abnormal. Requires immediate corrective action.

Source: Walsh et al. 1986



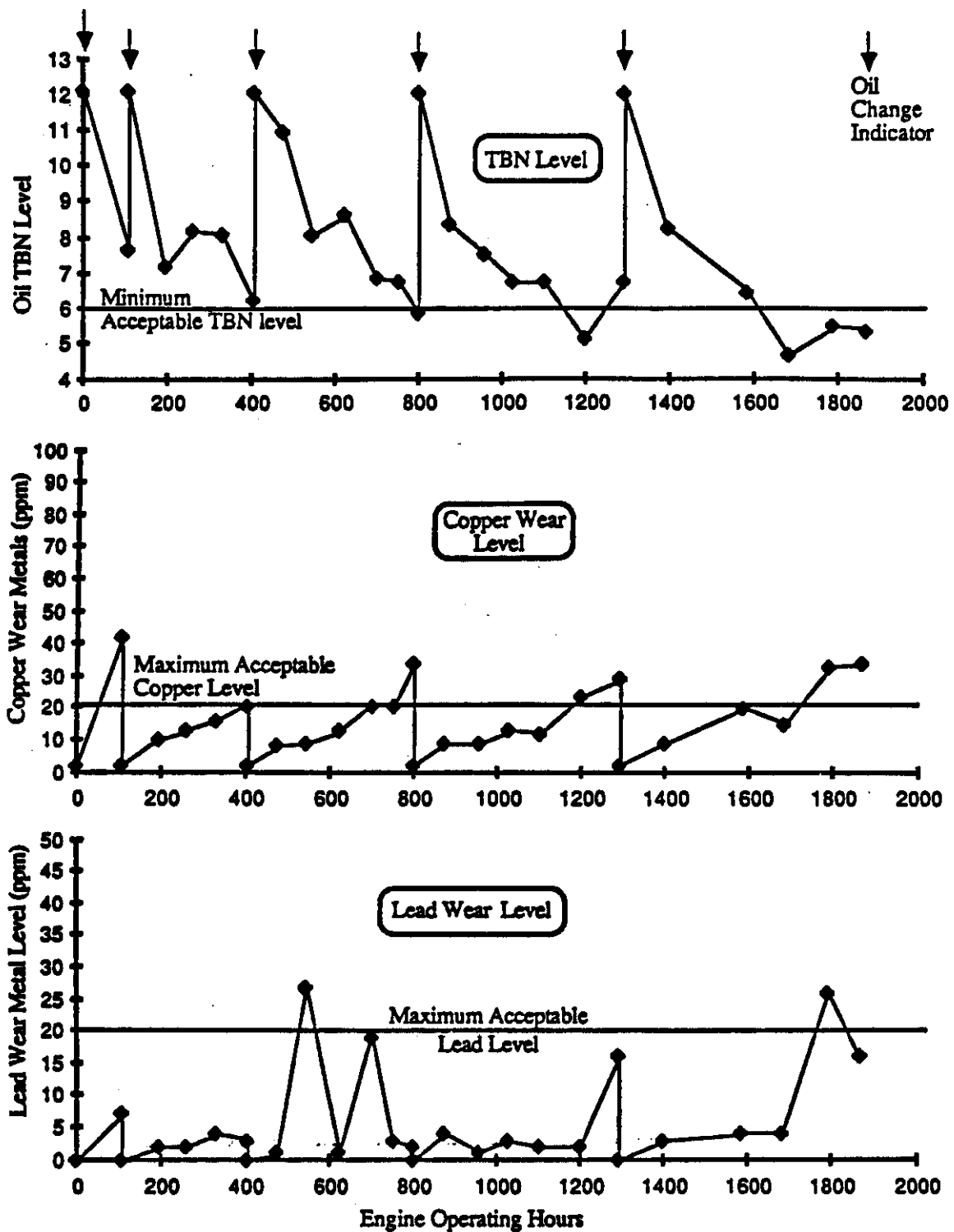
Walsh et al. (1986) reported reaching oil changing intervals of approximately 600 hours for an engine using a 13.0 TBN oil and fueled by a biogas with 0.54 mg/L  $H_2S$  and 0.49 mg/L mercaptan levels. Jewell et al. (1986), however, noted that the TBN level of an engine operated on biogas with 3000 ppm hydrogen sulfide levels fell from 10.0 to 2.0 in only 55 hours. Jewell also recommended not relying solely on TBN levels for determining oil change intervals. Walker et al. (1985) was able to achieve oil change intervals in the range of 300 hours using a high TBN oil. Walker was able to double this interval to 600 hours using a chemically treated oil by-pass filter. The effect of oil change intervals on oil TBN is illustrated in Figure 8-15.

Extending oil change intervals can be accomplished by maintaining continuous operation of the engine to avoid condensation of acid-bearing fumes inside the combustion chamber and by "scrubbing" the gas of  $H_2S$ , mercaptans, and water prior to entering the engine (Figure 8-16). In any case, determination of oil change intervals should include input from the engine manufacturer, oil test lab, and oil manufacturer.

Because the maintenance requirements of biogas engines are not standardized or fully understood, engine failure is a distinct possibility. Bearing-related failures are commonly blamed on acid degradation of copper bearings, bushings, and pins. Jewell et al. (1986) experienced an engine failure after 2940 hours of operation on a high  $H_2S$  biogas. The failure was determined by the engine manufacturer to be due to the failure of a copper wrist pin bushing with subsequent destruction of the connecting rod bolt and connecting rod. Similarly, Walker et al. (1985) experienced failure of copper alloy wrist-pins and bearings after only 1,128 hours of operation with 3000 ppm  $H_2S$  biogas.

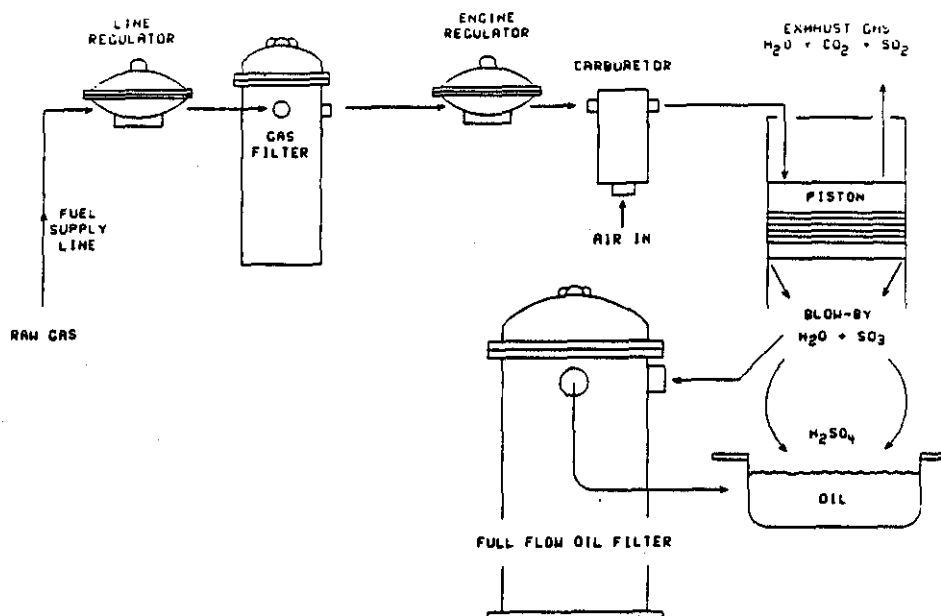
Jewell discovered additional pitting on rod bearing inserts, the main bearings, the contact face of the tappets, and other oil contacted engine components. Jewell et al. (1986), Walker et al. (1985), and Walsh et al. (1986) also noted carbon and oil deposits on top of the engine piston heads and scoring of the cylinder bores from these deposits. Walker reported that the persistence of this problem resulted in an engine overhaul to replace damaged pistons and piston sleeves.

Figure 8-15. Effect of Oil Change Interval on Wear Metal Content



Source: Walker et al. 1985

**Figure 8-16. Typical Filter Treatment System Installation**

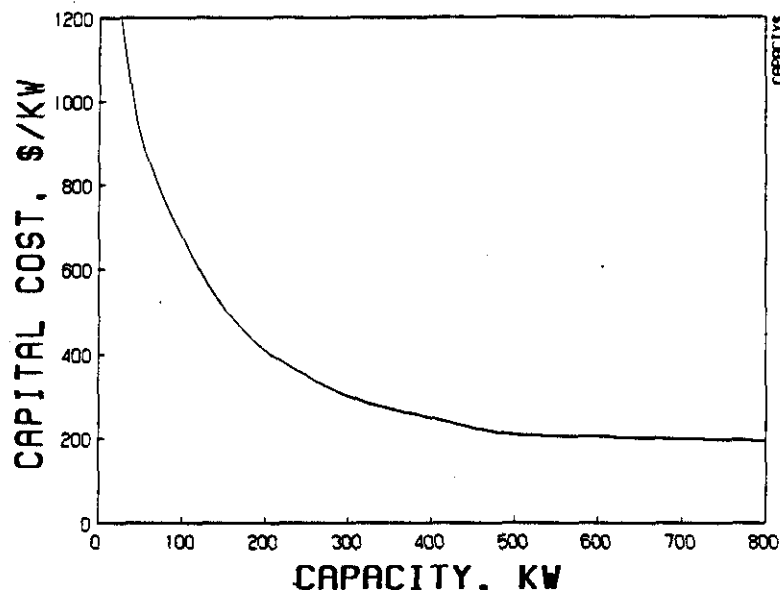


Source: Waukesha 1981

Both Jewell and Walsh noted tarnishing of electronic contacts in the distributor and relays due to exposure to biogas. This problem can be alleviated by isolating the engine system from the biogas source as much as possible and by providing good ventilation in the engine room. The increased probability for excessive engine wear and failure highlights the need for selecting a cogeneration system with an engine with a good service record and a local distributor. Consideration should be given towards entering into a service contract with the dealer for frequent engine inspection and service.

**Cogeneration System Costs** - Costs will vary from system to system based on the amount of gas cleanup required and the type of interconnect required by the utility. The relationship between system size and capital costs is illustrated in Figure 8-17. Typical costs for systems under 100 kW are in the range of \$1,000 per kW capacity. As shown in Figure 8-17, larger systems will provide a substantial economy of scale.

Figure 8-17. Cogeneration System Costs



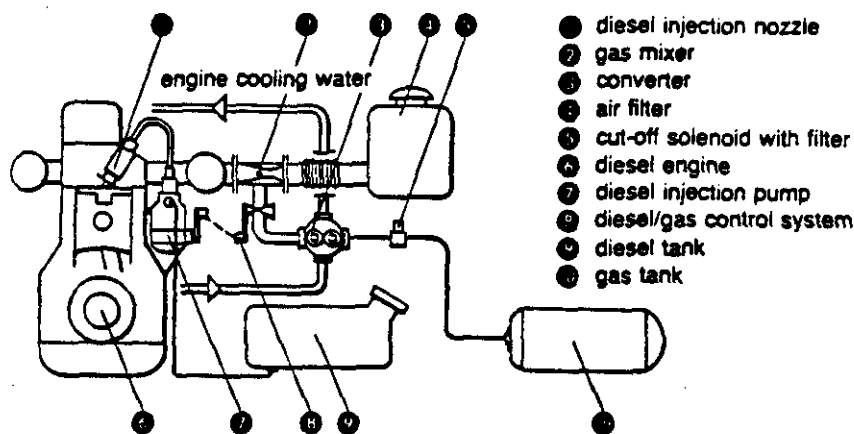
Source: Jewell et al. 1986

### Diesel Engines

Biogas fueling of diesel engines requires the use of diesel fuel for ignition, since there is no spark and biogas has a low cetane rating (Stahl 1983). This requires some modification of the engine including a carburetor for the mixing of biogas with intake air and a means for maintaining the desired diesel fuel setting on the injection pump, and for advancing the ignition timing (Figure 8-18).

Ortiz-Canavate et al. (1981) conducting tests on a Ford 4000 diesel engine (54 HP, 16.5:1 compression ratio) used a synthetic biogas (60% methane) with a diesel fuel injection rate to account for 20% of the input energy to the engine. At medium speeds (1300-1600 rpm) and high torque conditions, the dual-fueled engine exhibited efficiencies comparable to those for diesel fuel only. High speed efficiencies dropped and exhaust temperatures rose above recommended limits (1100°F) when the dual-fueled engine was operated at higher speeds. Because of the low flame speed of the biogas, timing was advanced from 19° BTDC to 23° BTDC. Similarly, Persson and Bartlett (1981) reported an optimum spark advance of 24° BTDC.

Figure 8-18. Diesel Engine Schematic



Source: Busenthur 1986

Excessive diesel fuel (pilot fuel) injection has been reported as the cause of knocking problems in converted diesel engines (Kofoed and Hansen 1981) leading to increased cylinder head pressures and engine temperatures. Maximum engine output and greatly reduced levels of nitrogen oxides and smoke have been obtained using lean mixtures for methane dual-fueled engines (Bro and Pedersen 1977). Saez *et al.* (1986) also noted a considerable decrease in exhaust contaminants (Bosch Smoke Number) from a biogas/diesel fueled engine bus.

Diesel engines can also be converted to biogas fueled, spark-ignition engines by replacing injectors with spark plugs and the injector pump with a gas carburetor (Persson and Bartlett 1981). The high compression ratio and heavy construction of a diesel engine are desirable features for a spark-ignition biogas engine.

## **Cogeneration Policies**

Electricity produced by cogeneration from biogas can be used in basically four ways:

- 1) isolated consumption for loads on-site,
- 2) parallel consumption on-site and re-sale to a utility grid,
- 3) third party sales, and
- 4) direct sale to a utility grid.

In all cases, design considerations must be given to the metering of power and the protection of loads, metering equipment, generating equipment, and personnel.

When considering sale of electricity to a utility, most of the negotiations will fall under the tenants of the Public Utilities Regulatory Act of 1978 (PURPA). These include:

- o requiring a utility to buy all power from any qualifying facility,
- o exempting a cogenerator from utility commission regulations,
- o blocking utilities from charging excessive rates for backing up a cogenerator, and
- o exempting a cogenerator from the Public Utility Holding Company Act and other federal utility acts.

Although PURPA has been implemented since 1978, several court challenges have and continue to change its exact meaning and intent (Wooster and Thompson 1985). Subsequently, there are as many interpretations of PURPA as there are utilities.

This means that each cogeneration project should be considered site-specific and negotiated as such. Items for negotiation include:

- o metering requirements,
- o buy-back rates,
- o stand-by or backup rates,
- o liability insurance,
- o protection system design,
- o power quality (power factor, etc.),
- o project scheduling (when and who will build system),

- o interconnect ownership (important in third party systems), and
- o utility service charges for operating the system.

The issue of interconnecting with a utility should not be considered trivial. A significant amount of time and effort may be invested in the preliminary discussions, planning, and for implementation of an interconnect system between a cogenerator and the utility (Ross and Walsh 1986, Regulatory Policy Inst. 1983).

Technical requirements for a utility interface are based on reliability and speed for the protection of equipment and personnel. These technical requirements typically are not negotiable with a utility and may be found in the interconnection standards published by the prospective utility. A number of variables will affect the design of an interconnect system including:

Generator type. Generally, electrical generators are basically grouped into two types: synchronous and induction (asynchronous). Induction generators are basically induction motors operated overspeed and are typically used for parallel cogeneration to a utility grid and to plant loads. The inherent protection characteristic of the induction generator in that it requires power from the grid to operate makes it well suited for this application. Synchronous generators require the use of additional components to maintain synchronous operation with the grid.

Condition of the utility grid. The age of the utility grid and the type of grid components within the affected area of a cogeneration project are interrelated with the performance of a cogeneration interface.

Proximity to other power producers. Utilities are concerned with a power phenomena called "islanding" whereby induction power units could conceivably support each other in the event of a grid outage causing mayhem in the system.

Power quality. Utilities will require that measures be taken for the cogenerator to match or exceed the power quality (power factor) of the power supplied to the cogenerator. Many small generators have power factor ratings below 0.80 while many utilities require them to be over 0.90. In most cases, this can be accomplished by using power factor correcting capacitors or similar devices.

Of additional concern are the types and quality of relays for sensing and signaling abnormal conditions in either the interconnect, the grid, or the cogenerator and quickly signaling for disconnection. While some utilities will allow a less-expensive industrial grade relay for this function, most utilities prefer utility

grade relays which will quickly signal for disconnection (Reason 1984).

The physical disconnection of the generator from the grid can be accomplished using either a breaker or a contactor. Utilities prefer breakers over contactors because they open faster (within 5 cycles versus 7 cycles), and they provide a greater separation, thus decreasing the possibility of reverse current flow or arching (Ross and Walsh 1986). An example of a cogeneration interconnect with metering and protection systems for a 100 kW system is illustrated in Figure 8-19.

### Vehicular Fuel

It is possible to utilize biogas for vehicular fuel (cars, trucks, tractors, loaders, etc.), with the major components of a system consisting of gas cleanup, compression, filling station, and vehicular storage and carburetion as shown in Figure 8-20. Accordingly, the critical factors which need to be evaluated for the utilization of biogas as a vehicular fuel include:

Degree of Utilization - A determination must be made on how much fuel biogas can replace on a continuous basis. Because biogas typically must be used within a day or two of generation, there must be a daily consumption pattern established for a vehicular fleet to warrant the conversion of vehicles to biogas and the cost of compression, storage, and refilling systems. Seasonal variations in daily consumptive patterns must be taken into account. Large packaged compressed natural gas systems for vehicular fueling have minimum compression rates of 18 cfm @3600 psi and require a daily consumption of gasoline of 100 gpd to be economically justified (Meloy 1981).

Quality of Biogas. Biogas quality has a significant impact on the amount of gasoline and diesel fuel equivalents per cylinder of compressed gas. The bulky nature of biogas versus gasoline and diesel creates some range problems due to fuel storage. Removal of CO<sub>2</sub> and other inert gases will increase the fuel equivalence for a cylinder of gas. Because of the corrosive nature of H<sub>2</sub>S and water on compression, storage, and fueling systems, the biogas would have to be relatively clean.



Source: Walsh and Ross 1986

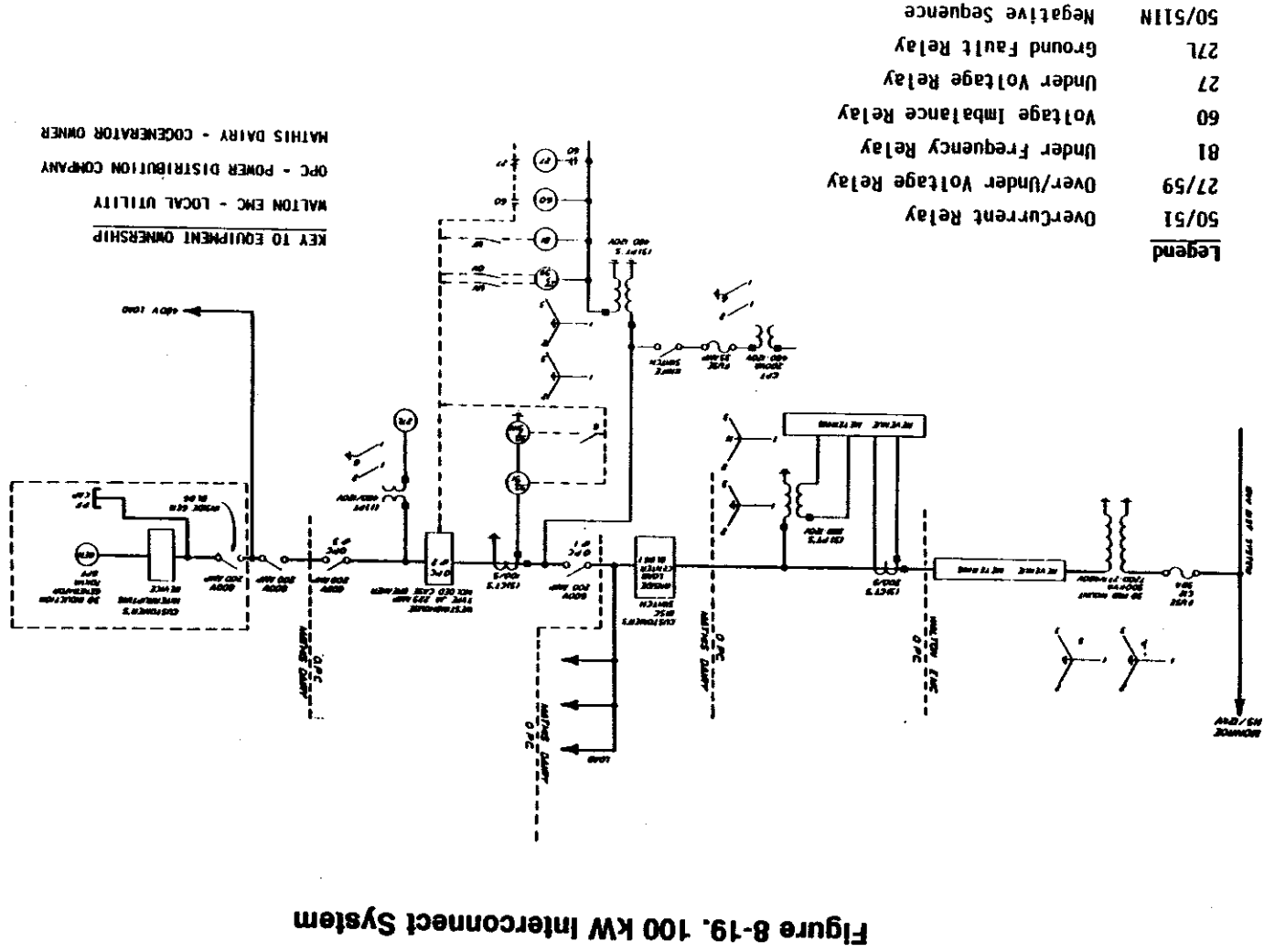
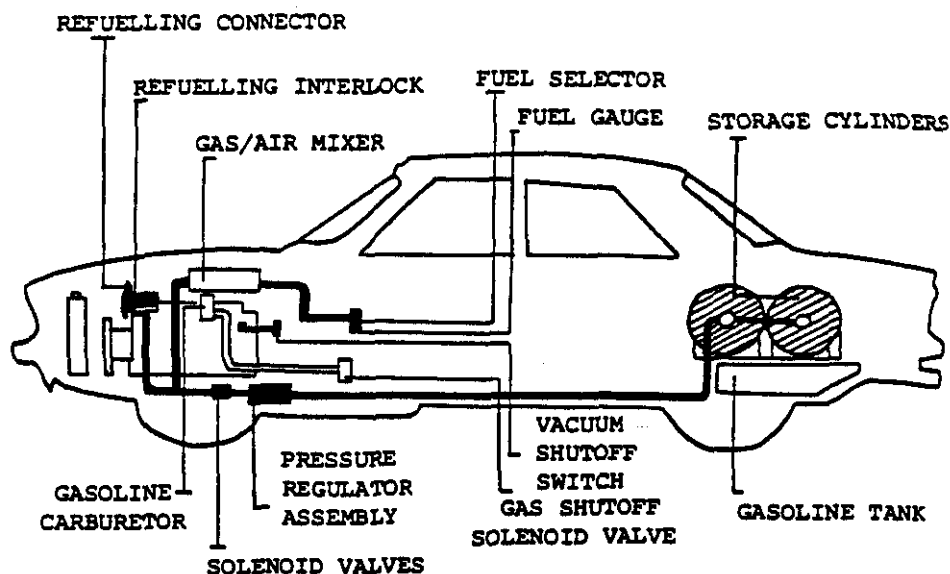


Figure 8-20. Vehicular Fuel System



Source: Born 1982

Vehicle Range. Consideration must be given to take into account the gasoline and diesel fuel equivalents per cylinder of compressed gas and the physical limits associated with mounting the storage cylinders on a vehicle. The number of hours of tractor operation or the number of potential miles of vehicle travel are direct function of storage cylinder volume. Consideration also must be given to refilling schedules, filling station location, and system safety.

Regarding fuel economy, Henrich and Phillips (1983) suggest a rule-of-thumb equivalence of 100 SCF of pure methane per one gallon of gasoline. A 372 SCF (2400 psi) cylinder (actual volume of 16 gallons) of pure methane would have a gasoline equivalent of roughly 3.7 gallons. Four cylinders of 60% methane biogas compressed to 2900 psia corresponds to about 10.6 gallons of diesel fuel and allows for tractor operation up to 3.5 hours under full load (80 HP) and 7 hours under 40% load (Fankhauser *et al.* 1983).

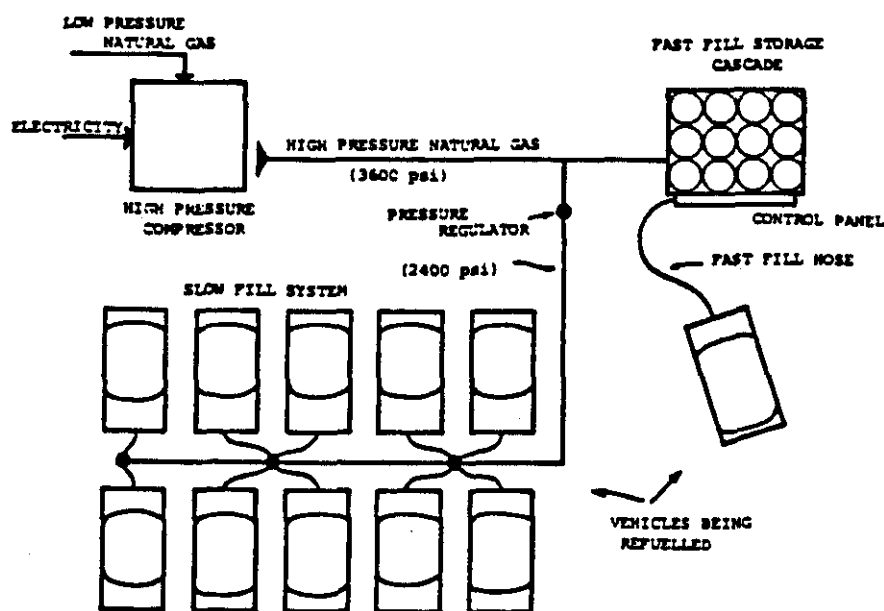
Engine Conversion. Although conversion kits are available for dual fuel (biogas or gasoline/diesel) operation, allowances must be made for losses in engine performance (see Engines section above), including decreased acceleration and fuel economy. Diesel tractor conversions have been successful; however, problems were encountered with freezing of CO<sub>2</sub> while the gas was expanded for use from the compressed gas cylinders. While the torque and brake power characteristics of the

tractor were comparable with diesel fuel only, there was some difficulty with maintaining constant engine speed at low partial loads (Fankhauser *et al.* 1983). Likewise, conversion for a gasoline automobile engine to compressed natural gas has been shown to reduce maximum power by 10-15% (Born 1982 and Evans *et al.* 1986).

**Equipment.** Commercial systems have been operated for the compression, storage, and fueling of small fleets of vehicles on methane (EMCON 1983). Smaller refuel stations of 3 cfm @2400 psi are available; however, no operational data are available on performance or economics (OMC 1982).

Refill stations fit into two categories: 1) cascade or rapid fill and 2) timed fill. While a cascade fill system is more expensive, it will refuel a vehicle in 3-5 minutes. A timed fill system requires more planning to allow for vehicles to be fueled usually overnight over a 14 hour period. A natural gas refueling station is shown in Figure 8-21. The cost of a refueling station is in the range of \$50,000 (1983) for a system providing compressed methane with the equivalent energy content of 250 gallons of gasoline per day (Henrich and Phillips 1983).

**Figure 8-21. Vehicular Fuel Refueling Station**



Source: Wright 1982

Vehicle storage requires the use of Department of Transportation approved gas cylinders, most with a capacity of 372 SCF of gas at 2400 psi and the dimensions of 9.25 inches in diameter and 55 inches in length (16 gallons). Tanks should include pressure and heat fusible rupture discs for controlled gas release under stressed conditions.

Gasoline engine conversion kits for propane and compressed natural gas are commercially available from a number of domestic and foreign suppliers (EMCON 1983). Some systems allow for dual fueling by mounting the fuel gas carburetor between the existing carburetor and the intake manifold. These can be switched between gasoline and biogas by flipping a switch inside the vehicle. The cost of converting a car or truck to compressed methane averages \$1,500 per installation including labor (Henrich and Phillips 1983 and Adams 1986).

As previously discussed, diesel engine conversion involves a more radical modification which allows for simultaneous injection of some diesel fuel (pilot fuel) to aid in ignition of the biogas which is introduced with the intake air to the engine. There are no known commercial systems for diesel conversion to biogas for vehicular use.

Problems. A number of problems have surfaced in the conversion of a fleet of gasoline vehicles to methane (EMCON 1983); including:

- o loss of power (10-20%),
- o difficulty in starting, particularly in cold weather,
- o gas leaks at filling stations, vehicle storage tanks, and carburetors,
- o corrosion of equipment from biogas,
- o limited range,
- o re-fueling scheduling and capacity, and
- o driver dissatisfaction.

### Pipeline Quality Gas

To maintain the high heating value and purity standards for pipeline quality gas, biogas must be treated to meet the following standards (Cairns and Pincince 1984):

- o water levels less than 7 lbs/MMSCF (0.11 mg/L),
- o hydrogen sulfide levels less than 2.7 ppm, and
- o carbon dioxide and nitrogen levels sufficiently low (3% or less) to provide gas energy contents of 975 Btu/SCF or greater.

These gases, particularly landfill gases, may also contain other trace elements that are not acceptable to the local natural gas utility for purchase (GRI 1982). A number of gas treatment methods for the removal of these components are detailed in Chapter 5. Besides gas quality, other considerations for resale of pipeline quality biogas include meeting pipeline pressures and maintaining flowrates to the purchaser.

### Environmental Considerations

All methods of biogas utilization should be evaluated for environmental impact on the site surroundings. Most of these considerations are associated with the technology rather than the fuel and are regulated by existing state and federal statutes. These include the emission of nitrogen oxides and smoke particulates from combustion systems. Noise pollution from the operation of engines and compressors may also require site-specific modifications.

Fuel specific environmental concerns may include the proper handling and disposal of chemicals and compounds used for biogas clean-up. Handling of common materials such as anti-freeze solutions and engine oils should also receive special attention.

Any biogas utilization system should be reviewed early in the planning stages for environmental compliance with the appropriate state agencies.



## CHAPTER 9

# INSTRUMENTATION AND CONTROLS FOR BIOGAS EQUIPMENT

### Introduction

There are a number of measurements that are desirable for designing, monitoring, and controlling both the anaerobic processes which produce biogas and the systems which recover the energy from the biogas. The equipment required will vary depending on the source of the biogas (digester versus landfill) as well as the complexity of the utilization system. Some of these measurements are performed continuously, but some portable and laboratory equipment is essential. There is a wide variety of equipment available off-the-shelf which can be used to measure all parameters of interest for gas production and quality. The operation and maintenance costs of such equipment can be high due to the corrosive nature of the gases. A list of suggested equipment and processes for almost every measurement derived during anaerobic digestion is provided in the U. S. Environmental Protection Agency Process Design Manual (USEPA 1979c). Price (1981) and EMCON (1980) have also reviewed basic measurement processes, and the Sierra Monitor Corporation summarizes guidelines of proper gas monitoring management for wastewater systems. Based on these reviews and practical experiences, this chapter provides an overview of equipment and strategies needed for proper biogas monitoring and control.

### Gas Composition

Gas composition ( $\%CH_4$ ,  $\%CO_2$ ,  $\%N_2$ ,  $\%O_2$ ,  $\%H_2S$ ) is a useful parameter for energy and mass calculations and for monitoring the relative health of the anaerobic process. Data on composition is needed for design of clean-up equipment, burners, and engine modifications such as compression ratio and spark advance. Variations in gas composition can indicate problems in digester operation or depletion of gas being produced by a landfill. Natural gas distributors purchasing pipeline quality biogas may require periodic or continuous measurements of gas composition. Composition can be measured with simple, hand-held instruments or complex continuous monitoring equipment. The more common instruments used for determination of biogas composition are briefly described in the following sections.

Diffusion Tube. Chemical sensing diffusion tubes are hand-held instruments that determine biogas composition by measuring the chemical reaction of a single constituent in the gas with material in the tube. These devices can be used to

measure most all of the constituents of biogas including water vapor, but different tubes must be used for each constituent. In addition, the tubes are designed for a specific concentration range, and thus, the appropriate tube must be used to measure a specific range of concentration. The expendable tubes are packed with a material that changes color when exposed to a specific gas. Gas is pulled through the tube by a bellows or pump which determines the quantity of the gas sample. As the gas is pulled through the tube, the constituent being measured reacts with the material in the tube and causes the material to change color. The exterior of the tube is calibrated such that the point at which the color change stops determines the quantity of a particular constituent in the gas. These devices are manufactured by a number of companies.

Chemical Absorption. Chemical absorption analyzers such as the one manufactured by Bacharach Instruments are hand-held devices and are typically used to determine the concentration of  $\text{CO}_2$  and  $\text{O}_2$  in boiler exhaust. These devices can be used to determine the approximate composition of biogas by determining the concentration of  $\text{CO}_2$  and  $\text{O}_2$  in the biogas and assuming the balance of the gas is  $\text{CH}_4$ . A separate tester is used for  $\text{CO}_2$  and for  $\text{O}_2$ .

A quantity of gas is pulled into the analyzer with a hand pump and the fluid in the analyzer absorbs a portion of the gas constituent being analyzed. The absorption of a portion of the gas causes the pressure inside the analyzer to fall below atmospheric. The atmospheric pressure on the outside of the analyzer pushes on a rubber diaphragm in the analyzer wall and causes the fluid level in the analyzer to rise. The height of the fluid rise determines the concentration of the specific constituent in the biogas.

Gas Chromatograph. The best equipment for measuring gas composition is an on-line chromatograph. This instrument contains a packed column (tubing filled with absorbent material) which serves to separate the different components of the gas on the basis of molar weight and other molecular properties. The individual components of the exiting gas are measured by a detector (preferably a thermal-conductivity detector since flame ionization detectors are not useful for measuring carbon dioxide). The output from the detector is plotted as a function of time, and component concentrations are calculated from the areas under each output peak.

Mass Spectrometer. Another instrument capable of on-line gas composition analysis is the mass spectrometer. The principal of operation is similar to that of the gas chromatograph except that detection of the constituents separated by



molecular weight differences is accomplished by electronic detection. However, this instrument is prohibitively expensive for most applications.

### **Gas Caloric Value**

The caloric value of the gas is the most important parameter as it indicates the heat value of the gas. The caloric value must be determined to compute the Wobbe Index for a specific burner orifice (See Chapter 8). This value can be used to directly control any blending operations, or to control variable burner orifices to ensure a constant heat input to the process. The caloric value is typically computed from the percentages of combustibles in the biogas, but equipment can be used to determine this parameter.

**Continuous Recording Calorimeter.** In order to determine the caloric value of biogas, a gas sample of known volume is burned under strictly controlled conditions in a calorimeter, where heat developed by combustion is measured (ASTM D-1826). Accuracies of  $\pm 1.5\%$  of full scale can be expected; however, the response of the calorimeter is slow.

### **Gas Density**

Measurement of gas density alone is made infrequently, since this parameter can often be computed from data from other analyses such as gas chromatography. The density of the gas is also needed to compute the Wobbe Index for a specific burner.

**Balance Detector.** The density of the gas can be determined by the use of a balance detector cell which is the pneumatic analog of a Wheatstone bridge. In this method, a reference gas and the sample gas are passed through the cell. The temperature differential created is measured with thermocouples in the device, and related to the difference in the density of the reference gas and the unknown density. Because the process has a complex purging system, analysis of wet or dirty biogas or biogas from long sample lines may be difficult.

### **Gas Flow**

One of the more basic biogas instrumentation requirements is that of gas flow. Gas production from a digester is an indication of performance and is directly related to the general "health" of the anaerobic system. Biogas being blended with an auxiliary fuel must be controlled and thus the flow rate must be known. The total quantity of biogas supplied to a natural gas pipeline must be recorded to

establish the basis for payment for the fuel. There are a number of methods available to measure gas flow which are briefly described in the following sections:

Rotating Vane Meter. The most common method of measuring gas flow is by the use of a rotating vane gas meter such as those used on natural gas wells. The gas flowing through the meter causes internal vanes to rotate which in turn move the dials on the front of the meter. These meters are typically totalizing types that indicate the total quantity of gas produced, but can be modified to read rate if needed. Electronic pick-offs can be added for automatic recording of data.

Maintenance of rotating meters in biogas systems can be a problem due to corrosives in the biogas. Care must be taken to insure that the lubricating oils for the meter do not become contaminated, and that the oil is changed on a periodic basis. These meters should be removed and cleaned if the system is not operated for an extended period of time.

Differential Pressure. Another common method for determination of biogas flow is detecting the differential pressure across a fixed (normally concentric) orifice or venturi which is installed between flanges in the gas piping. The flow rate is calculated from the differential pressure using a discharge factor for the measuring device. Measurements made at approximately 100 in. of water column differential pressure are the most accurate. This high pressure occurs if the gas is being pumped from the digester. When the digester pressure governs flow, differential pressures of approximately 1 in. water column are used, making the measurement more difficult and less accurate.

Pitot Tube. The pitot tube used in conjunction with a manometer or a Magnehelic gauge, is the most common method of measuring velocity. Accuracies of  $\pm 15\%$  may be achieved with the pitot tube. A pitot tube is a probe with a 90° bend at the end which is inserted into the gas stream such that the open end at the tip of the bend faces directly into the gas flow. The dynamic pressure measured with the probe and the static head measured at the wall of the gas pipe are used in Bernoulli's equation to determine gas velocity. Flow rates can be determined by utilizing the continuity equation which states that the flow rate equals the average gas velocity times the area normal to the flow. However, when these devices are subjected to a very wet, corrosive gas, maintenance requirements can be very high. This fact also makes device material selection very important.

Thermal Mass Flow Meter. A thermal mass flow meter measures the flow rate by determination of the cooling rate of the fluid passing the heated probe. Another

type of device heats a portion of the gas stream and correlates mass flow to the rate of heat transfer to the gas. Both designs must be calibrated for the thermal properties of the specific gas being measured.

Selection of materials for biogas flow measurement equipment is critical since parts of the equipment will be exposed to the gas stream (See Chapter 4). Hydrogen sulfide and other corrosives (particularly those found in biogas from landfills) can cause corrosion problems.

Flow monitoring equipment must be accurately calibrated before operation and at periodic intervals after the start of operation. Erosion of surfaces or plugging by contaminants can cause changes in output. Calibration curves must be corrected for differences in the density of air and biogas unless the equipment is calibrated using biogas or a synthetic biogas ( $\text{CH}_4/\text{CO}_2$  mixture).

## **Pressure**

Pressure can be used to control system operation such as the starting and stopping of an engine or the power output of the engine. It is also an indicator of the health of the digester or landfill in that low pressure can be used to indicate a lack of biogas production. On high pressure systems which use a compressor, pressure data can be used to control compressor operation and indicate its performance. The type of instrumentation required depends on the operating pressure of the system.

**Low Pressure Systems.** Low pressure systems which operate at a maximum of approximately 1 psig (27.7 inches water column) typically use manometers for pressure measurement. A manometer indicates pressure in inches of water column (in. w.c.) by the difference in level of the water in a "U" shaped tube with one end connected to the system and the other end open to atmosphere. Gauges are also available for reading pressure in inches water column. The gauges can be combined with electrical contacts for the starting and stopping of equipment. The simplest pressure measurement device is the inclined manometer. The Dwyer Magnehelic differential pressure gauge is an alternative to the manometer. These gauges are accurate to  $\pm 2\%$  of scale (EMCON 1980), but need to be calibrated prior to each use.

**High Pressure Systems.** Standard pressure gauges are used for high pressure systems. Materials selection is not as critical with these components since  $\text{H}_2\text{S}$  and other corrosives are usually removed before compression.

## Ambient Exposure Potential

Biogas presents a number of toxicity and explosive hazards due to  $\text{CH}_4$ ,  $\text{H}_2\text{S}$ , and other constituents. The details of these hazards are discussed in Chapter 10. Gas concentrations which present a hazard to personnel can be detected through the use of a diffusion tube and by obtaining a gas sample and analyzing the sample with a gas chromatograph or mass spectrometer. There are several devices available to actively monitor for biogas in areas where gas buildup could occur.

Combustible Gas Sensors. These devices are remote catalytic type sensors which consist of a heated catalytic element which is exposed to the ambient air, and a similar inert reference element. A collar protects the reference element from the ambient conditions. When the element is exposed to a flammable gas its temperature rises above that of the reference element and the differential is sensed. The rise in temperature of the element is attributed to the catalytic oxidation of the gas by the element which produces heat. A flame arrester will provide operating safety with fast sample diffusion.

Metal Oxide Semiconductor (MOS). These hydrogen sensitive electronic sensors can be used for the detection of various hydrogen based gases including  $\text{CH}_4$ ,  $\text{H}_2$ , and  $\text{H}_2\text{S}$ . The sensor works on the principle of ionadsorption whereby oxidation/reduction reactions at the sensor surface change the conductive properties of the material. This effect can then be measured as a change in the resistance correlated to a gas concentration.

Combustible gas sensors utilize this technology; however, they are often prone to drift and must be calibrated frequently. While some sensors are designed to monitor only a particular gas, they tend to indicate the cumulative presence of all hydrogen containing gases.

Electrochemical. This series of sensors incorporate the use of ion selective membranes and/or electrolytes to selectively sense a single gas component. They work on the principle of ion transport across a membrane filter to react with an electrolyte. The change in the electropotential between the measuring cell and a reference cell is correlated to the gas concentration.

These sensors have been used for monitoring a variety of gases including  $\text{H}_2$ ,  $\text{CO}$ ,  $\text{CO}_2$ , and  $\text{H}_2\text{S}$ . Like MOS sensors, they require frequent calibration and maintenance.

## CHAPTER 10

# BIOGAS SAFETY CONSIDERATIONS

### Introduction

This chapter discusses the major safety aspects of biogas installations. There are three major dangers to property and personnel that must be considered: toxicological dangers due to poisonous and asphyxiating gases, fire and explosion dangers due to combustible gases, and physical dangers due to operation of the system at both positive and negative pressures. The specifics of each of these three dangers will be presented first. Recommendations for prevention of accidents will be discussed later since accident prevention techniques often apply to more than one danger.

### Toxicological Dangers

The toxicological dangers of biogas are essentially a combination of the individual component gases: methane, carbon dioxide, hydrogen sulfide, and methyl mercaptan. A summary of these characteristics are presented in Table 10-1. Data on the color and odor characteristics which could be used to identify the presence of the gases are presented in the table. The minimum identifiable odor (MIO) listed is the concentration level in parts per million at which the gas can be detected.

The Threshold Limit Values (TLV's) for various industrial hazardous chemicals are established by the American Conference of Governmental Industrial Hygienists in Cincinnati, Ohio. The definitions of the two values shown in the Table 10-1 are as follows:

Threshold Limit Value - Time Weighted Average (TLV-TWA) is the time-weighted average concentration for a normal 8-hour workday and 40-hour workweek, to which nearly all workers may be repeatedly exposed, day after day, without adverse effect.

Threshold Limit Value - Short Term Exposure Limit (TLV-STEL) is the 15 minute time weighted average exposure which should not be exceeded at any time during a work day even if the eight-hour time weighted average is within the TLV.

The table also indicates the major physiological effects of each of the gases which compose biogas. It can be concluded from the table that biogas should be considered a poisonous gas since it contains more than 10 ppm of hydrogen sulfide.

As noted in the table, there is no TVL established for methane. Methane causes death by asphyxiation by reducing the level of oxygen available for breathing. At sea level, the minimum acceptable oxygen concentration level is 18% by volume. Usually, a high methane concentration will cause an explosion danger before it causes a danger from lack of oxygen.

A brief summary of major symptoms of overexposure to the components of biogas is presented in Table 10-2. The purpose of the table is make plant management aware of the warning signs of gas leaks.

**Table 10-1. Toxicity Characteristics of Biogas Constituents**

<u>Gas</u>	<u>Color</u>	<u>Odor</u>	<u>MIO (1)</u> <u>(ppm)</u>	<u>TVL</u> <u>TWA (2)</u> <u>(ppm)</u>	<u>TLV</u> <u>STEL(3)</u> <u>(ppm)</u>	<u>Physiological</u> <u>Effects</u>
Methane	None	None	-	(4)	(4)	Asphyxiant
Hydrogen Sulfide	None	rotten egg	0.7	10	15	Poison
Methyl Mercaptan	None	strong garlic	0.5	0.5	(4)	Poison
Carbon Dioxide	None	None	-	5,000	30,000	Asphyxiant

(1) MIO - Minimum Identifiable Odor

(2) TLV-TWA - Toxic Limit Value - Total Weighted Average

(3) TLV-STEL - Toxic Limit Value - Single Total Exposure Limit

(4) Not Established

Source: ACGIH 1987

**Table 10-2. Typical Symptoms of Overexposure to Biogas Constituents**

<u>Gas</u>	<u>Symptoms</u>
Carbon Dioxide	Headache, Dizziness Restlessness, Sweating
Hydrogen Sulfide	Eye Irritation Convulsions
Methyl Mercaptan	Nausea Convulsions

Source: ACGIH 1987

**ANY PERSONNEL WHO EXHIBIT ANY OF THE SYMPTOMS LISTED  
SHOULD BE CHECKED BY MEDICAL PERSONNEL AND THE SYSTEM  
SHOULD BE CHECKED FOR ANY LEAKS.**

**Flammability Dangers**

The flammability characteristics of the components of biogas are presented in Table 10-3. Carbon dioxide is not combustible and thus the only characteristic applicable to this gas is specific gravity. The significance of each of the characteristics provided is as follows:

**Vapor Density.** The vapor density is the ratio of the density of the gas to the density of air at the same temperature and pressure. As shown in Table 10-3 methane is lighter than air and will tend to collect near the ceiling of an enclosed building. Therefore, it is important to adequately vent a building containing biogas equipment. The other gases are heavier than air and would tend to collect in any sumps or low areas near the biogas system.

**Lower Explosive Limit.** The lower explosive or flammability limit is the minimum concentration of a combustible gas in air which sustains combustion. If the concentration of the gas is below this level, combustion will not be sustained since there is insufficient fuel to maintain burning.

**Upper Explosive Limit.** The upper explosive or flammability limit is the maximum concentration of a combustible gas which sustains combustion. If the concentration of the gas is above this level, combustion will not be sustained since there is insufficient air to maintain burning.

**Autoignition Temperature.** The autoignition temperature is the temperature at which combustion will be initiated without the addition of source of ignition such as a spark. The concentration of the combustible must be within the flammability range.

**Table 10-3. Flammability Characteristics**

<u>Gas</u>	<u>Specific Gravity</u>	<u>Explosive Limits</u>		<u>Autoignition Temperature °F</u>
		<u>Lower</u> %	<u>Upper</u> %	
Methane	0.5	5	15	650
Hydrogen Sulfide	1.2	4	46	550
Methyl Mercaptan	1.66	4	22	(1)
Carbon Dioxide	1.5	None	None	None

(1) Data not available

### **Physical Dangers**

There are a number of physical dangers associated with biogas systems that are common to almost all industrial systems. These dangers include open-top sumps, low hanging pipes, slippery floors, etc. The major physical dangers associated with biogas systems due to their operational characteristics are caused by positive and negative system pressures.

**Positive Pressure Dangers.** Systems operating at low pressure (less than 30-in. water) present only minor dangers from pressure. An overpressure situation could cause a slow escape in areas where personnel may be injured. However, systems with compressors can present severe problems if a high pressure line ruptures.

**Negative Pressure.** Negative pressure can occur when a digester is drained without opening a vent to allow air to fill the void space left by the draining liquid. The vacuum pressure created can collapse the roof or walls of a digester causing damage to personnel and property. The mixture of air and biogas could fall within the explosive limits resulting in a potentially dangerous situation.



## **Safety Equipment**

A list of safety equipment recommended for installation at all plants is presented in Table 10-4. The details of the instrumentation are discussed in Chapter 9. A list of the manufacturers of this equipment is included in the Appendix.

Although commercial low-pressure relief valves and vacuum breakers are available, experience has shown that water contained in the biogas can tend to jam mechanical equipment. A water relief valve can eliminate this problem. Care must be taken to insure that the water levels in the valve are maintained at the proper level. A rupture disk fabricated from a non-metallic material can eliminate problems with corrosion of metallic vacuum breakers.

## **Recommended Safety Practices**

A list of recommended safety practices is presented in Table 10-5. These practices address safety hazards from toxicological, flammability, and pressure problems. As discussed earlier, some of the recommendations apply to more than one hazard. It is recommended that a plant design be analyzed to assure that the design meets all the criteria identified in the list.

**Table 10-4. Recommended Safety Equipment**

<b><u>Safety Device</u></b>	<b><u>Function</u></b>
Pressure Relief Valve	Prevents injury to personnel due to rupture and prevents leakage of biogas due to overpressurization of seals.
Vacuum Breaker	Prevents collapse of digester walls and roof during draining of liquid in digester.
Combustible Gas Sensor	Detects leak of biogas which could become an explosion hazard.
Hydrogen Sulfide Sensor	Detects a build-up of H <sub>2</sub> S which could become a toxicological danger to personnel.

**Table 10-5. Safety Precaution Check List for Biogas Systems**

1. Prevent gas discharge in confined areas with gas-tight pipes and valves and safety relief valve discharges to building exterior or open areas.
2. Purge air from biogas delivery lines before operation of combustion equipment since exclusion of air will insure the biogas concentration is above the upper flammability limit.
3. Install flame traps in lines near combustion equipment to prevent flashback into the digester or storage tank.
4. Ensure adequate ventilation around all gas lines.
5. Install a vent at the ridge line of all buildings to allow escape of gases such as methane which are lighter than air.
6. Slope all gas lines 1:100 and install a water trap at the low point to prevent blockage of lines by the water condensed from the gas.
7. Protect gas lines from freezing which can result in damage to the line and blockage of the line by frozen water condensed from the gas.
8. Remove any potential source of sparks or flame from areas where biogas is present.
9. Have one or more carbon dioxide or halon fire extinguishers in the area where biogas is present.
10. If the gas is compressed, use storage tanks with a minimum design pressure of 2,400 psig.
11. Install safety relief valves to prevent overpressurization of both high and low pressure systems.
12. Install vacuum breakers on all systems connected to digesters to prevent injury to personnel and damage to equipment due to draining of digester liquid.
13. Install combustible gas monitors and hydrogen sulfide detectors to detect leaks of gases in any area where personnel may be injured.
14. Do not allow smoking in the area.
15. Incorporate explosion proof lighting and electrical service when biogas exposure is considered likely.
16. Post signs indicating an explosion hazard near the biogas equipment and storage. Also post no smoking signs.

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## APPENDIX A

### ALPHABETICAL LISTING OF EQUIPMENT SUPPLIERS

A-C Compressor Corporation  
1126 South 70th Street  
West Allis, WI 53214  
414-475-4305

Advanced Industrial Technology Corp.  
P.O. Box 555 T  
Lodi, NJ 07644  
Industrial Gas Systems  
201-265-1414

Advanced Manufacturing Systems, Inc.  
110 Technology Parkway  
Technology Park Atlanta  
Norcross, GA 30092  
404-448-6700

Aero Tech Labs, Inc.  
Spean Road Industrial Park  
Ramsey, NJ 07446  
201-825-1400

Aerzen USA Corporation  
313T National Rd.  
Exton Industrial Park  
Exton, PA 19341  
215-524-9870

Airco Industrial Gases  
575 Mountain Ave.  
Murray Hill, NJ 07974  
201-464-8100

Airovent, Inc.  
Gartmer Equipment Company  
P.O. Box 206  
Syracuse, NY 13208  
315-476-8321

Alemite & Instrument Div.  
Stewart - Warner Corp.  
1826 Diversey Pkwy.  
Chicago, IL 60614  
312-883-6000

Alphasonics, Inc.  
12010 Hwy. 290 W., Ste 200-C  
Austin, TX 78737  
512-288-3661

American Yazaki Corp.  
13740 Omega Rd.  
Farmers Branch, TX 75244  
214-385-8725

Applebee-Church, Inc.  
P.O. Box 80186 - Chamblee  
Atlanta, GA 30341  
404-451-2747

Applied Cogeneration  
11341 San Fernando Rd.  
San Fernando, CA 91340  
818-896-7443

Applied Thermal Systems, Inc.  
P.O. Box 101493  
Nashville, TN 37210  
615-366-0221

Automatic Switch Co.  
50-60 Hanover Rd.  
Florham Park, NJ 07932  
800-972-2726

Babcock & Wilcox, Industrial Power  
Generation Div.  
4282 Strausser Street NW  
P.O. Drawer 2423T  
North Canton, OH 44720  
216-497-6223

Bauer Compressors, Inc.  
1328 W. Azalea Garden Rd.  
Norfolk, VA 32502  
804-855-6006

The Bigelow Co.  
142 River St.  
P.O. Box 706-T  
New Haven, CT 06503  
203-772-3150

Boulder Associates, Inc.  
473 E. Church Rd.  
P.O. Box 88  
King of Prussia, PA 19406  
215-277-7730

Bradford-White International Ltd.  
2401 Ellsworth St.  
Philadelphia, PA 19146  
215-546-3800

Calvert Environmental Equipment Co.  
5191-T Sante Fe St.  
San Diego, CA 92109  
619-272-0050

Carolina Technical Representatives, Inc.  
P.O. Box 1115  
Matthews, NC 28105  
704-847-4494

CECA, Inc.  
Adsorption Technology  
4150 S. 100th East Ave., Ste 300  
Tulsa, OK 74146  
313-737-4591

CH2M Hill  
Solid Waste Specialists  
P.O. Box 4400  
Reston, VA 22090  
804-471-1441

Chemical Design, Inc.  
285 Market St.  
Box 513-T  
Lockport, NJ 14094  
716-433-6744

Coen Company, Inc.  
1510-12 Rollins Rd.  
Burlingame, CA 94010  
415-697-0440

Connelly-GPM, Inc.  
200 S. Second Street  
Elizabeth, NJ 07206  
312-247-7231

Continental Products, Inc.  
P.O. Box 418165 M  
Indianapolis, IN 46241  
317-241-4748

Coppus Engineering  
344 Park Ave  
Worcester, MA 01610  
617-756-8393

Corken International Corp.  
P.O. Box 12338  
Oklahoma City, OK 73157  
405-946-5576

Distral Energy Corporation  
1125 NE 7th Ave.  
Dania, FL 33004  
305-920-8100

Dresser Measurement  
Dresser Industries, Inc.  
P.O. Box 42176 - TR  
Houston, TX 77242  
713-972-5000

Duall Industries, Inc.  
760 S. McMillan St.  
Owosso, MI 48867  
517-725-8184

Ecolaire, Inc.  
2 Country View Rd.  
Malvern, PA 19355  
215-647-9900

Edwards Engineering Corp.  
101-A Alexander Ave.  
Pamilton Plains, NJ 07444  
800-526-5201

EMCON Assoc.  
1941 Ringwood Ave.  
San Jose, CA 95131  
408-275-1444

EnerTech Corp.  
201 Allen Rd.  
Atlanta, GA 30328  
404-432-1234

Enerquip, Inc.  
Dept. M  
P.O. Box 368  
611 North Rd.  
Medford, WI 54451  
715-748-5888

Enterra Instrumentation Technologies  
251-ET Welsh Pool Rd.  
Exton, PA 19341  
215-363-5450

Ergenics  
681-T Lawline Rd  
Wycoff, NJ 07481  
201-891-9103

ESCOR, Inc.  
550 Frontage, #208  
Northfield, IL 60093  
312-501-2190

Fermont  
141 T North Ave.  
Bridgeport, CT 06606  
203-366-5211

Fischer & Porter Company  
51 Warminster Rd.  
Warminster, PA 18974  
215-674-6000

Flaregas Corporation  
100 Airport Executive Park  
Spring Valley, NY 10977  
914-352-8700

The Foxboro Company  
86 Neponset Ave.  
Foxboro, MA 02035  
617-543-8750

Friedrich Air Conditioning  
& Refrigeration Co.  
4200 N. Pan Am Expwy.  
San Antonio, TX 78295  
512-225-2000

Getty Synthetic Fuels, Inc.  
P.O. Box 1900  
Long Beach, CA 90801  
213-739-2100

Groth Equipment Corp.  
P.O. Box 15293  
1202 Hahlo  
Houston, TX 77020  
713-675-6151

Hamworthy USA, Inc.  
Pump & Compressor Div.  
10555 Lake Forest Blvd., Ste. 1 F-T  
New Orleans, LA 70127  
504-244-9074

Hedland Div. of Racine Federated, Inc.  
2200 South St.  
Racine, WI 53404  
800-433-5263

Henderson Sales & Service, Inc.  
P.O. Box 830876  
Richardson, TX 75083  
214-234-3226

Hydronics Engineering Corp.  
Godwin Ave.  
P.O. Box 179-T  
Midland Park, NJ 07432  
210-444-4376

Industrial Marketing Assoc.  
11642 Knott Ave., Suite 5  
Garden Grove, CA 92641  
714-836-4706

Industrial Gas Systems  
13477 Prospect Rd.  
Dept 207  
Cleveland, OH 44136  
904-445-4200

Industronics, Inc.  
489 Sullivan Ave.  
South Windsor, CT 06074  
203-289-1551

Industry Hills  
SCS Engineers  
4014 Long Beach Blvd.  
Long Beach, CA 90807  
213-426-9544

John Zink Co.  
4401 S. Peoria  
Tulsa, OK 74105  
918-747-1371

Kemlon Products & Development Corp  
P.O. Box 14666-TR  
Houston, TX 77021  
713-747-5020

Kennedy Van Saun Corp.  
P.O. Box 500  
Danville, PA 17821  
717-275-3050

Kurz Instruments, Inc.  
2411 Garden Rd.  
Monterey, CA 93940  
800-424-7356

Linde Specialty Gases,  
Union Carbide Corp.  
P.O. Box 6744-T  
Somerset, NJ 08873  
800-982-0030

Matheson Gas Products, Inc.  
30-T Seaview Dr.  
Secaucus, NJ 07094  
201-867-4100

Microtrol Environmental Systems, Inc.  
One Oscar Hammerstein Way  
P.O. Box 426-T  
New Hope, PA 18738  
215-862-9465

Midwesco Energy Systems  
7720 Lehigh Ave.  
Dept. T115  
Niles, IL 60648  
312-966-2150

Monroe Environmental Corp.  
11 Port Ave.  
P.O. Drawer 806-T  
Monroe, MI 48161  
800-992-7707

Natco  
P.O. Box 1710  
Tulsa, OK 74101  
918-663-9100

Nelson Filter  
P.O. Box 280  
Stroughton, WI 53589  
608-873-4300

Neotronics N.A., Inc.  
P.O. Box 370  
2144 Hilton Dr. SW  
Gainesville, GA 30503  
404-535-0600

O'Brien Energy Systems  
Green Street & Powerhouse Place  
Downington, PA 19335  
215-269-6600

Parker Engineering & Chemicals, Inc.  
Dept. G  
3077 McCall Dr.  
P.O. Box 81226  
Atlanta, GA 30366  
404-458-9131

Perennial Energy Inc.  
Route 1, Box 645  
West Plains, MO 65775  
417-256-2002

Pierburg Metering Systems, Inc.  
41-T Vreeland Ave.  
Totowa, NJ 07512  
201-785-0136

Power Flame, Inc.  
2001 S. 21st Street  
Parsons, KS 67357  
316-421-0480

Process & Cryogenic Services, Inc.  
2170-T Old Oakland Rd.  
San Jose, CA 95131  
800-826-3062

Public Service Electric & Gas Company  
Research Corp.  
P.O. Box 570 T-16A  
Newark, NJ 07101  
201-430-7000

Resource Systems, Inc.  
B-6 Merry Lane  
East Hanover, NJ 07936  
201-884-0650

Scientific Gas Products  
Ashland Chemical Co.  
2330-T Hamilton Blvd.  
South Plainfield, NJ 07080  
201-344-6998

SCS Engineers  
11260 Roger Bacor Dr.  
Reston, VA 22090  
804-471-6150

Semplex  
1635 W. Walnut  
Springfield, MO 65806  
417-866-1035

Sierra Monitor Corp.  
1991-T Tarob Court  
Milpitas, CA 95035  
408-262-6611

Spectra Gases, Inc.  
3033 Industry St.  
Oceanside, CA 92054  
800-932-0624

Stahl, Inc.  
Farrier Products Div.  
Church Rd. & Derry Ct.  
Box M-34A  
York, PA 17405  
717-767-6971

Stevens Electric Company, Inc.  
810-812 N. Main St.  
Memphis, TN 38107  
800-874-5909

Super-Ice Corp.  
P.O. Drawer 783  
San Leandro, CA 94557  
415-483-1778

Syn Fuels  
1221 Ave of the Americas  
New York, NY 10020  
212-512-3916

Technotherm Corporation  
5508 West 66th Street  
South Tulsa, OK 74131  
918-446-1533

ThermaFlo Marketing Dept.  
3640 Main St.  
Springfield, MA 01107  
800-556-6015

Turbo Refrigerating Co.  
P.O. Box 396-T  
Denton, TX 76202  
817-387-4301

Turbosystems International  
7 Northway Lane  
Latham, NY 12110  
518-783-1625

U.S. Turbine Corporation  
7685 South State Route 48  
Dept. A  
Maineville, OH 45039  
513-683-6100

Virginia Technical Associates, Inc.  
7202 Impala Drive  
Richmond, VA 23228  
804-266-9654

Vooner Equipment Co., Inc.  
Dept. T, P.O. Box 240360  
4725 Stockholm Court  
Charlotte, NC 28224  
800-345-7879

Vulcan Waste Systems, Inc.  
300 Huron St.  
P.O. Box 4030  
Elyria, OH 44036  
717-822-2161

Waste Management, Inc.  
3003 Butterfield Rd.  
Oak Brook, IL 60521  
312-572-8800

Waukesha Engine Division  
Dresser Industries, Inc.  
1000 West St. Paul Ave.  
Waukesha, WI 53188  
414-547-3311

Wehran Engineering  
666 East Main St.  
Middletown, NY 10940  
914-343-0660

Wittmann - Hasselberg, Inc.  
2 Commerce Blvd.  
Palm Coast, FL 32037  
904-455-4200

Wormser Engineering, Inc.  
225 Merrimac Street  
Woburn, MA 01801  
617-983-9380



## APPENDIX B

### LISTING OF COMPANIES BY PRODUCT OR SERVICE

#### GAS RECOVERY

Getty Synthetic Fuels, Inc.  
John Zink Co.  
Wehran Engineering

#### GAS PURIFICATION

Advanced Industrial Technology Corp.  
Calvert Environmental Equipment Co.  
Chemical Design, Inc.  
Connelly-GPM, Inc.  
Duall Industries, Inc.  
Ergenics  
Hydronics Engineering Corp.  
Industrial Gas Systems  
Microtrol Environmental Systems, Inc.  
Morrow Environmental Corp.  
Natco  
Nelson Filter  
Process & Cryogenic Services, Inc.  
Resource Systems, Inc.

#### COMPRESSORS

A-C Compressor Corporation  
Aerzen USA Corporation  
Airovent, Inc.  
Bauer Compressors, Inc.  
Corken International Corp.  
Ergenics  
Hamworthy USA, Inc.  
Henderson Sales & Service, Inc.  
Kemlon Products & Development Corp  
Vooner Equipment Co., Inc.  
Wittmann - Hasselberg, Inc.

## CONSULTING

Advanced Manufacturing Systems, Inc.  
Industry Hills  
O'Brien Energy Systems  
Perennial Energy Inc.  
SCS Engineers  
Vulcan Waste Systems, Inc.  
Waste Management, Inc.  
Wormser Engineering, Inc.  
CH<sub>2</sub>M Hill

## BURNERS

Babcock & Wilcox  
Coen Company, Inc.  
Cleaver Brooks  
EnerTech Corp.  
Power Flame, Inc.

## BOILERS

Applebee-Church, Inc.  
Applied Thermal Systems, Inc.  
Bradford-White International Ltd.  
Carolina Technical Representatives, Inc.  
Technotherm  
Virginia Technical Associates, Inc.

## COGENERATION

Applied Cogeneration  
Automatic Switch Co.  
The Bigelow Co.  
Boulder Associates, Inc.  
Caterpillar  
Coppus Engineering  
Cummins Engine  
Distral Energy Corporation  
Ecolaire, Inc.  
Enerquip, Inc.  
Ford  
Fermont  
Industronics, Inc.  
Midwesco Energy Systems  
O'Brien Energy Systems  
Parker Engineering & Chemicals, Inc.  
Perennial Energy, Inc.  
Stahl, Inc.

Stevens Electric Company, Inc.  
Technotherm Corporation  
Turbosystems International  
U.S. Turbine Corporation  
Vulcan Waste Systems, Inc.

#### ABSORPTION CHILLERS

American Yazaki Corp.  
Continental Products, Inc.  
Edwards Engineering Corp.  
Friedrich Air Conditioning  
& Refrigeration Co.  
Super-Ice Corp.  
ThermaFlo Marketing Dept.  
Turbo. Refrigerating Co.

#### INSTRUMENTATION AND HANDLING

Aerzen USA Corporation  
Alemite & Instrument Div.  
Alphasonics, Inc.  
Dresser Measurement  
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# **Final Report: Haubenschild Farms Anaerobic Digester**

## **Updated!**



August 2002

Carl Nelson  
John Lamb

the  
minnesota  
project

## **Acknowledgments:**

Many members of the Project Advisory Group (listed at the end of this report) reviewed the original version of this report. We are grateful for their participation in this project and for their technical and constructive contributions to this report. The project would not have been possible without the cooperation and participation of Haubenschild Farms. We also thank the many businesses, foundations, and agencies who supplied the funding to make this project possible. The update for this report was made possible by a grant from the U.S. Department of Energy and the Minnesota Department of Commerce. A special thanks to former Minnesota Project staffer John Lamb, who was instrumental in the success of this project, and has since retired to the family farm in Iowa.

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## **A note about the updated report...**

Much has changed in the world of agricultural biogas systems since the original publication of this report in December 2000. In Minnesota, the success of the Haubenschild project captured the imagination of many policy leaders and led to initiatives to encourage more projects like the Haubenschild's (see page 30).

Meanwhile, the Haubenschild's continue to have great success with their digester, which continues to exceed expectations for performance. This updated report expands upon the half year of operating data available at the time of the original report, and gives the results of nearly 3 years of operating experience. Although the report has not been entirely overhauled, other information available to the author on digesters in general has been added as well.

--Carl Nelson, August 2002



## **Executive Summary**

This report is an update of the December 2000 report and documents the installation and 34-month performance of a heated plug-flow anaerobic digester for managing dairy manure at Haubenschild Farms. This type of digester is appropriate for treating manure with a high solids content, such as cow manure that is collected by scraping.

Haubenschild Farms is a 1000-acre, family owned and operated dairy farm near Princeton, Minnesota. In 1998 the owners were planning to increase the size of their operations, and considered the possibility of installing an anaerobic manure digester. They knew that this type of system could result in environmental benefits while offering a return on their investment.

Some of the key expected benefits of an anaerobic digester are:

- Odor control
- Renewable energy production
- Pathogen reduction
- Greenhouse gas reduction
- Reduction in total oxygen demand of the treated manure (total oxygen demand is a measure of potential impact on aquatic systems)

Haubenschild Farms applied for and was selected as an AgSTAR “Charter Farm,” one of 13 such farms selected nationwide to demonstrate farm-scale anaerobic digestion technologies. AgSTAR is a joint program of the Environmental Protection Agency, Department of Energy and Department of Agriculture, designed to promote the use of anaerobic digestion systems. In addition to the AgSTAR program, the Haubenschild Farms project received assistance from the Minnesota Department of Agriculture, Department of Commerce and Office of Environmental Assistance. With financing complete, construction of the digester was started in the summer of 1999 and completed in October of the same year. Total construction cost of the digester and generator system was about \$355,000.

The Haubenschild Farms digester is a covered 350,000-gallon concrete tank installed in the ground, with suspended heating pipes to heat the manure inside the digester where bacteria breaks down the manure, creating methane. A 135-kilowatt engine-generator set is fueled with methane captured from the digester. The hot water to heat the digester is recovered from the engine-generator’s cooling jacket. Barn floor space is also heated with the recovered heat. The digested effluent, odor reduced, flows to a lined storage pond where it is kept until it can be injected or broadcast spread on fields for crop production.

When the digester was started, it was processing manure from about 425 dairy cows, which was about half of its total design capacity of 1000 cows. In 2000, Haubenschild Farms built a second free stall barn and has expanded to a current size of about 750 cows.

Since startup in the fall of 1999, the biogas output of the digester steadily increased to about 65,000 cubic feet by May 2000. Currently, more biogas is being produced than can be used by the engine-generator, so it is hard to estimate exactly how much biogas is being produced. The Haubenschilds are considering adding generation capacity to utilize the





excess biogas. Approximately 70,000 cubic feet/day of biogas is used by the engine-generator; the rest is currently flared. With 425 cows, the biogas output per cow was almost twice projections – with 750 cows, the output per cow has come down somewhat to about 40 percent above projections. Haubenschild's cows are producing about 50 percent more manure per cow than the digester was engineered for, which somewhat explains the high biogas production per cow.

The sale of the electricity generated is an important benefit of the project. Before the digester was built, Haubenschild Farms entered into a power purchase contract proposed by the local electric cooperative, East Central Energy, who greeted the project with enthusiasm and offered Haubenschild Farms a very favorable contract. Since the expansion of the milking herd size from 425 to about 750 cows in the summer of 2000, the digester has been producing enough electricity to provide all the electric needs on-farm, plus enough surplus electricity to power about 75 additional homes.

The building and operation of the Haubenschild Farms project has offered several key lessons for future digesters:

- Payback of 5 years on investment is possible
- A good time to install a digester is when changing or expanding operations
- Electric utility cooperation is important
- Active management is crucial for stable digester and engine operation
- Digester design and engineering expertise is key
- There are barriers to financing digester systems
- Cooperative agency participation reduces the barriers to a project's success
- Manure collection method and collection frequency are important





## **Purpose**

This report documents the installation of a heated plug-flow anaerobic digester at Haubenschild Farms. It is intended to serve a broad audience, including the nearly 800 people who attended tours at the farm in early April 2000. We provide answers to some of the questions raised by project observers during the course of the installation and the first few months of operation. This report is intended to provide a base of information for continued discussion.

## **Introduction**

Dairy farms and other confined animal feedlots, especially larger ones, have been under increasing public and regulatory pressure to manage their animal manure to control environmental problems. A major concern is odor, which has been a prime force behind local ordinances to control feedlot expansion. There are also potential problems with storing and spreading the manure, along with the potential for catastrophic spills (see sidebar). Anaerobic digesters have been getting attention in the last several years for their potential to address some of the environmental impacts of manure management while providing farmers with economic benefits.

Anaerobic digesters biologically treat manure and produce a stable effluent with slightly different chemical characteristics than raw manure. In the process, a biogas composed primarily of methane is produced, captured, and the gas is then combusted in an engine, boiler or flare. Manure treatment reduces total oxygen demand, odors and pathogens.

### **Environmental Concerns with Animal Feedlots**

Improperly managed manure can result in severe consequences to the environment.

#### ***Groundwater Contamination***

Manure contains pathogens and the nutrients phosphorus and nitrogen. When properly managed and applied, growing plants use these nutrients, and a healthy soil and water can absorb limited pathogens. Spreading more manure than can be used by growing plants can result in the extra nutrients leaching into and contaminating groundwater. As well, an improperly designed or damaged storage facility can leak manure, where it can enter the groundwater. The MN Department of Agriculture and counties test livestock and other nearby wells for the presence of nitrogen and bacteria.

#### ***Surface water runoff***

The improper application of manure to fields can pollute rivers and lakes with runoff of nitrates, phosphorus and pathogens. Manure in water consumes oxygen required by fish and other aquatic life. If too much oxygen in the water is used to break down manure, natural stream life will suffer or be killed.

#### ***Catastrophic spills***

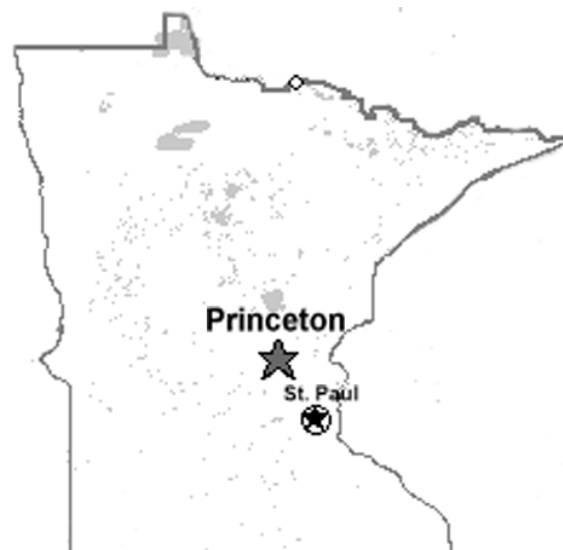
An accidental spill during storage or transport of manure can also result in sudden ground and surface water contamination.



There are many questions that Minnesota farmers and policy-makers have about anaerobic digesters:

- What are the environmental benefits and what are the concerns?
- What is the cost of building a digester?
- Can the energy produced pay back the investment?
- Who should install a digester?
- What are the pitfalls and barriers to installing a digester?
- What is the potential for digesters in Minnesota?
- What are the impacts on the community?

The installation in September of 1999 of an anaerobic digester at Haubenschild Farms Inc., a dairy farm in east central Minnesota, provides an opportunity to examine some of these questions. The results of 34 months of operation at the Haubenschild Farms digester are examined in detail. The type of digester installed at Haubenschild Farms is limited in its application to cow manure collected by scraping, and cannot be used for a swine or dilute cow manure, since the solids concentration would be too low. Thus the lessons learned from the Haubenschild Farms digester do not apply to all feedlots in Minnesota.



Available information from the Haubenschild Farms digester and other sources is synthesized in this report as a baseline for looking at the future of anaerobic digestion in Minnesota and recommendations are suggested.

## **A Resurgence of Interest**

Anaerobic digesters have been used successfully for sewage and industrial waste treatment in the U.S. since the 1940s. Over one million small-scale digesters have been used in China and India for decades, and nearly 2,000 farm-based digesters operate in Europe.<sup>1</sup> Anaerobic digestion and power generation at the farm level began in the United States in the early 1970s, largely in response to rising energy prices. Many universities installed small digester systems and conducted basic digester research, including the University of Minnesota, which operated a 10,000-gallon digester on a swine farm for about 10 years.

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<sup>1</sup> Erwin Koeberle, "Animal Manure Digestion Systems in Central Europe," Second Biomass Conference of the Americas, August 21-24, 1995, Portland OR reports at least 450 digesters, more recent information suggests about 90 in Austria, 45 in Denmark, 70 in Switzerland and 1,650 in Germany (personal communication, Joe Kramer, Resource Strategies, July 2002).



In the 1980s, federal tax credits spurred the construction of over 100 digesters in the United States. However, many of these systems failed because of poor design, faulty construction, improper operation and lack of a service infrastructure. By the end of the decade, adverse publicity about the system failures and operational problems reduced enthusiasm for farm-scale anaerobic digesters.

In recent years, however, there has been a renewed interest in the technology. This has been stimulated by an increasing awareness that properly designed and operated anaerobic digesters can help control animal waste odor and other environmental problems. Dairy farmers faced with increasing federal and state regulation of manure are looking for ways to comply. Digesters are now being built because the owners hope to reduce the environmental hazards of dairy farms and other animal feedlots. As of spring 2002, there were over 40 digester systems in operation at livestock farms in the United States, with dozens more in the planning stage.<sup>2</sup>

## **Digester Types<sup>3</sup>**

Anaerobic digesters work on the principle that in the absence of oxygen (anaerobic means “without oxygen”), naturally occurring bacteria will break down the manure. The digestion of the manure occurs in four basic stages (hydrolysis, acidogenesis, acetogenesis, and methanogenesis). It is the final stage, methanogenesis, that breaks down the intermediate compounds to produce methane.



**Anaerobic plug-flow digester. Haubenschild Farms, Inc.**

Anaerobic digesters capture the gas released in the digestion process. This biogas is composed of about 55 to 70 percent methane. Most of the rest of the biogas is carbon dioxide, with a small amount of hydrogen sulfide and other trace gases. The digested manure needs to be stored until land applied.

Methane producing bacteria flourish at around body temperature (95°-105°F),<sup>4</sup> and thus heated digesters are more efficient producers of methane than non-heated ones. There are three conventional digester designs for on-farm use. Design standards for all three have

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<sup>2</sup> See the AgSTAR website for a partial list of operating digesters: [www.epa.gov/agstar/](http://www.epa.gov/agstar/).

<sup>3</sup> Parts of this section are adopted from a report from the Oregon Office of Energy entitled “Anaerobic Digester at Craven Farms: A Case Study,” by John G. White and Catherine Van Horn (September, 1998).

<sup>4</sup> This range is called the mesophilic temperature range. There is also a set of methanogenic bacteria, which flourish at much higher temperatures (125°-135°F), called the thermophilic range, which can digest waste faster than bacteria in the mesophilic range. Thermophilic digesters are not commonly used on-farm because they require more heat input, the bacteria at this range are more prone to upset by small temperature fluctuations, and thus thermophilic digesters require close monitoring. There is a third set of methanogenic bacteria that flourish at around 70°F, but digest waste slower than bacteria in the mesophilic range.



been adopted by the US Department of Agriculture's Natural Resource Conservation Service (NRCS).<sup>5</sup> The designs differ in cost, climate suitability and the concentration of manure solids they can digest.

### ***Covered Lagoon Digester***

A covered lagoon digester consists of a manure treatment lagoon with an impermeable cover and is generally not heated. The cover traps gas produced during decomposition of the manure. Covered lagoon digesters are used for liquid manure (less than 2 percent solids) and require large-volume lagoons. Because the methane production rate is dependent on ambient temperatures with a covered lagoon system, it is not considered cost-effective to use the biogas for energy production in Minnesota's climate. It has been used in cold climates for odor control, however, including in Wisconsin. This type of digester is the least expensive of the three.

### ***Complete Mix Digester***

A complete mix digester is suitable for manure that is 3 to 10 percent solids, such as swine manure or dairy manure collected by a flush system. Complete mix digesters process manure in a heated tank above or below ground. A mechanical or gas mixer keeps the solids in suspension. However, complete mix digesters are expensive to construct and cost more than a plug-flow digester to operate and maintain.



**Shredding newspaper for bedding, Haubenschild Farms Inc.**

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<sup>5</sup> See the AgSTAR website ([www.epa.gov/agstar](http://www.epa.gov/agstar)) for an on-line version of these standards.

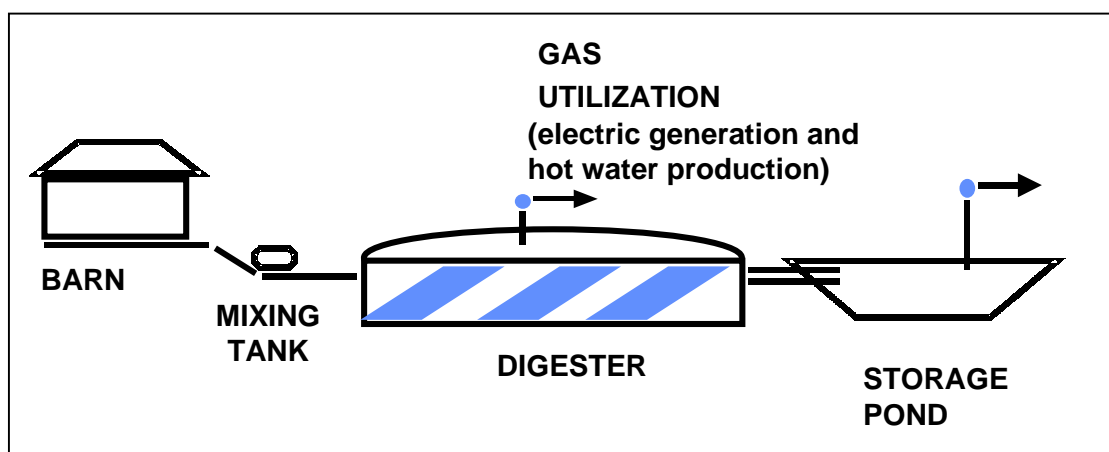




## Plug-Flow Digester

Plug-flow digesters are suitable for ruminant animal manure having a solids concentration of 11 to 14 percent, such as cow manure collected by scraping. A flush system for manure collection is not appropriate for this system, since this would reduce the total solids content of the manure below specified levels. In manure with lower solids concentrations, such as swine manure, solids cannot stay in solution and tend to settle to the bottom of the tank, limiting their digestion. A plug-flow digester has few moving parts and requires minimal maintenance.

**Figure 1: Anaerobic Plug-Flow Digester System**



Before entering the digester, raw manure is mixed in a mix tank. It then enters one end of the plug-flow digester, a rectangular tank, and decomposes as it moves through the digester. New material added to the digester tank pushes older material to the discharge end. Coarse solids in ruminant manure form a thick sticky material as they are digested, limiting solids separation in the digester tank. As a result, the material flows through the tank in a “plug”. Anaerobic digestion of the manure slurry creates biogas as the material flows through the digester. A flexible, impermeable cover on the digester traps the biogas. For optimal digestion, it should take about 15 to 20 days for a plug to pass completely through the digester.

Inside the digester, suspended heating pipes allow hot water to circulate and heat the digester. The heating pipes also serve to mix the slurry through convection. Recovered heat from an engine fueled with digester gas usually provides the hot water required for heating the digester. Figure 1 shows how a plug-flow digester system works.

There is a variation on the basic plug-flow design called a slurry loop digester. It works on the same principle as a plug-flow, except the digester tank is designed in a U-shape or circular configuration, so that the discharge end of the tank is near the point of entry. This design is used in Wisconsin, at Gordondale Farms near Stevens Point. The Gordondale digester represents a hybrid of complete mix and plug-flow designs, as collected biogas is injected into the digester to further mix the slurry.



## ***Other Digester Types***

Besides the three digester types discussed above, there are many other anaerobic digester designs that have been used for processing municipal sewage as well as industrial waste.<sup>6</sup> Most of them treat waste streams with a low solids content, and thus have found various ways to speed up the digestion process or increase solids content in order to reduce the volume required for digesting, thereby reducing costs. Without providing details of how they work, other digester designs include:

- 1) batch-fed reactor, such as the anaerobic sequential batch reactor (ASBR);
- 2) temperature-phased anaerobic digester (TPAD);
- 3) suspended particle reactor;
- 4) anaerobic filter reactor;
- 5) upflow solids reactor;
- 6) continuously stirred tank reactor with solids recycle;
- 7) upflow anaerobic sludge blanket reactor;
- 8) anaerobic pump digester;
- 9) fluidized- and expanded-bed reactors,<sup>7</sup> and
- 10) fixed-film anaerobic digester.<sup>8</sup>

In the last several years, there has been a tremendous growth in the farm digester industry, including research and development to attempt to apply these technologies to the treatment of agricultural animal waste. For example, the Iowa Energy Center is operating a test project to investigate the use of an ASBR, and a TPAD design is being tested at a dairy south of Green Bay, Wisconsin. These designs tend to be much more capital intensive and operationally complex, however, and are not currently commercially viable compared to more established and proven designs. This could change quickly, however.

## ***Midwest Operating Digesters***

As of spring 2002 in the Great Lakes region (Minnesota, Iowa, Wisconsin, Illinois and Michigan) there were 16 digesters, most constructed within the last 2 years, and half of which were still in the start-up phase.<sup>9</sup> Three more digesters were still under construction. Of the total 19 digesters:

- 15 are at dairies (12 plug-flow or modified plug-flow, 2 covered lagoon, and one temperature-phased anaerobic digester or TPAD);
- 3 are at swine operations (2 complete mix and one anaerobic sequential batch reactor or ASBR)
- one is at a duck farm (complete mix)

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<sup>6</sup> Industries that use anaerobic digestion to treat their wastes include: food processing (milk and milk products, starch products and sugar confectionery, brewing, and distilling and fermentation are some of the largest), and the paper industry. The treatment of the industrial waste, as well as municipal sewage, is often driven by regulations.

<sup>7</sup> For a description of these digester designs, see, for example, David Chynoweth and Ron Isaacson, "Anaerobic Digestion of Biomass," Elsevier Applied Science: New York, 1987.

<sup>8</sup> "Reducing Dairy Manure Odor and Producing Energy," Ann C. Wilkie, Biocycle, September 2000.

<sup>9</sup> From a forthcoming Agricultural biogas case studies report from the Great Lakes Regional Biomass Energy Program, a link to which will be provided at [www.mnproject.org](http://www.mnproject.org) when the report is available.



## Benefits of Anaerobic Digesters

Anaerobic digesters offer many potential benefits to farmers and the environment, including:

- **Odor and fly control.** Anaerobic digesters consume odor-causing compounds in manure as it moves through the digester, reducing odor problems (note that odors will still exist at normal levels until the manure enters the digester). One study showed that anaerobic digestion reduced odor by 97 percent over fresh manure.<sup>10</sup> For some projects, odor control is a primary reason for installing a digester, especially covered lagoon systems. Fly propagation is also extremely limited in digested manure compared to fresh manure.
- **Renewable energy production.** Not all digester systems are used to produce energy; in some cases odor is removed and the gas produced is simply flared. However, using the gas to produce energy may offer significant economic payback depending on farm scale. Most commonly the gas is burned in an engine-generator to produce electricity, and the waste heat can be used to produce hot water for heating the digester and other applications, such as space heating.
- **Distributed generation of electricity.** The electricity generated by an anaerobic digester, as opposed to a large central station power plant, is a distributed form of electricity generation. This offers potential benefits to the electric utility, including increased generation capacity (especially valuable during periods of peak electric demand), voltage support, deferred transmission and distribution line construction, and less loss of power through transmission. The benefits of distributed generation to the utility have been estimated to be from \$100 to \$800 a year per kilowatt of capacity.<sup>11</sup>
- **Potential increase in value as a fertilizer.** Manure is already widely spread on fields as a soil amendment. For many farmers, anaerobic digestion may increase the value of their manure as a fertilizer. The digestion process converts organic nitrogen into a mineralized form (ammonia or nitrate nitrogen) that can be taken up more quickly by plants than organic nitrogen.<sup>12</sup> Timing of the plant uptake of ammonia and nitrate nitrogen, similar to that used in commercial fertilizers, is more predictable than the plant uptake of organic nitrogen from raw manure. However, nitrogen in ammonia form can easily be lost to the air (called volatilization), where it is a pollutant (see below). Therefore, care must be taken to handle the digested manure in such a way as to minimize nutrient leaching and volatilization.

In addition, some research suggests that the microflora present in digested manure may lead to increases in crop yields. One study found yields to increase an average

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<sup>10</sup> As reported in Philip Lusk, "Methane Recovery from Animal Manures: The Current Opportunities Casebook," Department of Energy, National Renewable Energy Lab (DOE/NREL), 1998.

<sup>11</sup> Philip Lusk, 1998 (see reference 10).

<sup>12</sup> See, for example, Andrew Wheatley, "Anaerobic Digestion: A Waste Treatment Technology," Elsevier Applied Science: New York, 1990.





of 10 percent over commercial fertilizer.<sup>13</sup> The Minnesota Project is partnering with the University of Minnesota to study the effectiveness of digested manure compared to raw manure and commercial fertilizer.



**Manure Wagon with Injectors, Haubenschild Farms, Inc.**

- **Pathogen reduction.** Anaerobic digestion at mesophilic temperatures (95°-105°F) has the potential to practically eliminate many, but not all, kinds of pathogens, greatly reducing this potential source of water pollution.<sup>14</sup> The effectiveness of a particular digester in pathogen destruction will vary.
- **Weed seed destruction.** Weed seeds in manure subjected to anaerobic digestion can exhibit reduced weed seed germination and viability compared to weed seeds contained in untreated manure. The Minnesota Project is also partnering with the University of Minnesota to study the extent to which this occurs.
- **Greenhouse gas reduction.** Methane is a greenhouse gas 23 times more potent than carbon dioxide in causing global warming. By capturing and burning the methane produced from animal manure, anaerobic digesters help to slow down the rate of global warming. (Note: manure management systems that result in aerobic decay of manure, such as grazing systems and dry manure packs, do not produce significant amounts of methane; thus the benefit of methane reduction reported here is only in comparison to other anaerobic systems of treating manure, such as a lagoon system).<sup>15</sup>
- **Sale of digested fibers.** With the addition of a solids separation system, the fibers can be separated from the digested effluent and sold as a soil amendment. After solids separation, the effluent can still be spread on the fields, retaining about 75

<sup>13</sup> As reported in Philip Lusk, 1998 (see reference 10).

<sup>14</sup> See, for example, John Olsen and Holger Larsen, "Bacterial Decimation Times in Anaerobic Digestions of Animal Slurries," *Biological Wastes*, Vol. 21, 1987, pp. 153-168.

<sup>15</sup> Note that a calculation of the methane prevented from entering the atmosphere is equal to the amount of methane emitted by the manure management system that would be used in place of the digester, and not the amount of methane that is simply captured by the digester. The methane produced by a digester is considerably more than, say, a 90-day storage tank.



percent of the total nutrients of the original manure. Although Haubenschild Farms chose not to separate the fibers, many other digester owners have sold the fibers as a soil amendment off the farm. These fibers, if sold, could raise as much as \$40,000 per year for a farm the size of Haubenschild Farms.<sup>16</sup>

- **Reduction in Total Oxygen Demand.** Total Oxygen Demand (TOD) is a measure of how much oxygen could potentially be consumed by breaking down organic matter, such as that found in manure. This is an issue if there is a catastrophic spill of manure that enters surface water. If too much oxygen in the water is used to break down manure that spills into a stream, natural stream life will suffer or be killed. By reducing TOD, anaerobic digestion reduces the hazards of a potential catastrophic spill.

## Potential Concerns about Anaerobic Digesters

- **Nitrogen and ammonia emissions.** Care must be taken in the storage and application (spreading or injection) of digested manure, since ammonia can be lost to air through volatilization. Ammonia in the air is a pollutant. Maintaining a crust on the storage pond or reducing its surface area can reduce this loss. Nitrogen loss can also be minimized by injecting the digested manure into the soil as opposed to spreading it, where it will be exposed to air.
- **Water pollution.** As with managing untreated manure, care must be taken to minimize the risk of contaminating surface and groundwater. Digested manure must still be applied in a manner that will minimize the risk of nitrate leaching to groundwater. It must also be managed to minimize the risk of surface runoff.
- **Air emissions from combusting biogas.** Generally this is a cleaner burning fuel than coal, but some sulfur dioxide and other emissions will be exhausted in the combustion of the biogas (see page 25).
- **Safety.** Well-designed and managed anaerobic digesters have few safety concerns. However, care must be taken in designing the gas handling components of the digester and engine-generator to ensure safety. Inhalation of biogas can pose health risks, and biogas is flammable.

## Haubenschild Farms Project Description

Haubenschild Farms is a 1000-acre, four-generation family owned-and-operated dairy farm near Princeton, Minnesota. In 1998 Haubenschild Farms president Dennis Haubenschild and his wife Marsha Haubenschild were considering expanding their dairy operation from 100 cows to 500 and eventually 1000 cows. Their two sons, Tom and Bryan, were interested in moving back to the farm with their families and an expansion was necessary to make this plan feasible. Dennis, who serves on the Minnesota Feedlot and Manure Management Advisory Committee (FMMAC), was very aware of the problems involved in

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<sup>16</sup> Personal correspondence, Mark Moser, Resource Conservation Management, July 25, 2000.



expanding feedlot operations. He was also aware of the potential of anaerobic digesters to reduce these problems while at the same time producing energy and providing other benefits.

### ***The Opportunity***

In order to see if an anaerobic digester would work at his farm, Dennis submitted an application for consideration as an AgSTAR Charter Farm, and after completing a pre-feasibility assessment was one of 13 farms selected. AgSTAR is a national program, sponsored jointly by the Environmental Protection Agency, the Department of Energy and the Department of Agriculture. The Charter Farm Program was designed to facilitate demonstration of appropriate digester systems at various livestock farms. As a Charter Farm, AgSTAR provided Haubenschild Farms design and operational assistance in building their digester. AgSTAR



**The Haubenschilds: Dennis, Bryan, Marsha and Tom (l to r)**

contracted with RCM, a company with a proven track record of building successful on-farm digesters, to assist with the project. Mark Moser was the engineer, while RCM's Richard Mattocks handled all onsite issues and helped to build the system.

The farm also required a feedlot permit, including a manure management plan. The Minnesota Pollution Control Agency granted the permit. The digester qualified as manure storage, reducing the size of the storage pond required for storing digested manure. Even with this assistance, there were still barriers to be overcome, since traditional lending agencies in Minnesota are reluctant to provide the full financing for such projects, and Dennis needed help in securing financing.

At this point the unique opportunities of the digester project at Haubenschild Farms were brought to the attention of several Minnesota governmental and non-profit agencies. The Onanogozie Resource Conservation and Development Council, The Minnesota Project, Minnesota Department of Commerce, Minnesota Office of Environmental Assistance, and Minnesota Department of Agriculture joined together to assist with the Haubenschild Farms project. These agencies saw the unique potential of manure digesters to mitigate negative environmental impacts while providing a source of renewable energy and promoting sustainable economic development. They agreed to help with the financing if the Haubenschild Farms project could be studied to determine its feasibility for other farms in Minnesota.



## ***Haubenschild Farms' Goals for Installing a Digester***

The Haubenschilds have a long-term outlook on their farming operations. When looking at the expansion of their farming operations, they considered the future needs of the land and the impact of the increased operations on the environment. An anaerobic digester seemed to fit in well with their plans.

Specifically, Haubenschild Farms wanted to design, build, start-up, and operate a digester with the following goals:

1. **Increase the value of the manure for fertilizer.** The sandy acres at Haubenschild Farms needs the addition of organic matter supplied by manure. By applying digested effluent to the fields instead of raw manure, the Haubenschilds expected to increase the useable nutrient value of the manure, and thereby phase-out the use of commercial starter fertilizer. At the same time, weed seeds and pathogens would be reduced. This fit the Haubenschild's strong environmental ethic by reducing outside inputs to the land while returning value.
2. **Reduce animal waste odor.** An increase in herd size could bring a significant increase in odor and fly problems. This would not only create a more unpleasant work environment, but could also cause tension with neighbors and regulatory agencies.
3. **Produce enough electricity** and hot water to recover digester installation costs.
4. **Produce enough hot water** to offset propane use and supply heat for the barn in the winter.
5. **Demonstrate the viability** of an anaerobic digester system on an operating dairy farm in Minnesota.

## **Haubenschild Family Farms**

Dennis's father and mother, Don and Myrtle, started farming at the present location in 1952 with 160 acres and 10 cows. The farm is in the Green Lake watershed on the Anoka Sand Plain in southwestern Isanti County, about 40 miles north of the Twin Cities metropolitan area.

In the early 1960s the family began to notice a decrease in organic matter content in their soils. They realized that by increasing manure use, they could improve soil tilth and reduce erosion potential. Dennis, who went to college and worked a number of years, returned to the farm with Marsha in 1972. By 1979 their milk herd numbered 80. Dennis had researched digesters while at college and was interested in alternative energy production. In the 1970s they installed a solar collector system for heating water for the dairy which is still functioning.

They were milking 150 cows in 1998 when sons Tom and Bryan and their families wanted to farm with their parents and grandparents. The family decided that they should expand the dairy. When fully expanded they expect to use digested manure on all their crop acres for growing their 600+ acres of corn silage, 300 acres of alfalfa haylage, 30 acres of soybeans, and 40 acres of pasture. Freshening cows use the pasture. They purchase additional fresh hay to add to their total managed rations.

An anaerobic digester requires a manure handling method that is compatible with the operation of the system. A water flush system for collecting the manure makes it unsuitable for a plug-flow digester, because the manure slurry will become too diluted. Animal bedding systems using sand are also not appropriate for an anaerobic digester, due to sand build-up, which will eventually clog the system.





## Will a digester work for my farm?

The AgSTAR Handbook lists 5 criteria for preliminary screening of project opportunities for installing an anaerobic digester at a dairy or swine feedlot:

1. **“Large” confined livestock facility.**  
AgSTAR defines large as at least 300 head of dairy cows/steers or 2000 swine, although digesters have successfully been used at smaller farms. The issue of a “threshold” size at which digesters are economic is discussed later in this report.
2. **Year-round, stable manure production and collection.** A digester needs to be constantly and regularly “fed” manure to maintain methane-producing bacteria.
3. **A manure management strategy that is compatible with digester technology.**  
Digester technology requires the manure to be: managed as a liquid, slurry, or semi-solid; collected at one point; collected regularly; and free of large quantities of bedding and other materials (rocks, sand, straw, etc.). A water flush system for manure collection is not compatible with a plug-flow digester.
4. **A use for energy recovered.** Can a generator be installed to produce electricity, and is the local utility willing to purchase this electricity? Are the electricity costs for on-farm use high? Is there another use for the energy on-farm?
5. **Someone to efficiently manage the system.**  
Successful digester operation requires an interested operator who will pay attention to performing daily routines and possesses a basic “screwdriver friendliness” for necessary maintenance.

Farmers interested in installing a digester should do a complete pre-feasibility assessment. The AgSTAR handbook can assist with this.

**Source:** Kurt Roos and Mark Moser, “AgSTAR Handbook,” Environmental Protection Agency, EPA-430-B-97-015, 1997. See “Resources...” section, page 32 for more information.

Because Haubenschilds were planning the digester to be a part of the expansion of their whole operations, it was easier to design a manure management strategy compatible with the digester. They chose a free-stall barn for their expansion, which allows for easy scraping of the manure into a collection pit, without the use of water. For bedding, the Haubenschilds used newspaper, which is picked up from a local recycling facility. About 600 pounds per day of newspaper were used for 420-430 cows. With the current herd size of about 750, approximately 1 ton per day is used. The newspaper bedding is scraped three times a day along with the manure into the collection pit.

## Components of the Digester System

The complete digester system required several components:

- Manure collection pit
- Mix tank
- Piping system
- Plug-flow digester
- Effluent storage
- Gas utilization

Fresh manure is scraped into the barn collection pit, where it flows by a gravity system into a 14,000-gallon mix tank. The mix tank also allows any sand and rock to settle out.

From the mix tank, the manure slurry is pumped to the plug-flow digester twice a day. About 20,000



gallons of manure enter the digester per day. The digester was designed to process manure from 1000 cows. When the original report was written, the digester was operating at less than its design capacity, and the manure took about 30 days to pass through the digester. Currently with 750 cows, it takes about 15 days for the manure to travel through the digester, 5 days shorter than it was designed for. This is due to a higher production of manure per cow than was accounted for in the design (see table 3). The digested manure slurry flows to a lined storage pond, where it is kept until it can be applied on the fields for crop production. The biogas collected in the digester is piped to an engine-generator for combustion. Before entering the engine, the gas pressure is increased with a blower to a half-inch water column pressure.



**Engine - Generator**

Haubenschild Farms chose a Caterpillar 3406 engine, attached to a generator with a capacity of about 135 kilowatts, to produce the electricity from the biogas.<sup>17</sup> The engine, originally designed for commercial natural gas usage, required retrofitting with larger-orifice carburetor valves and a larger regulator but was otherwise unchanged.

Should gas pressure build up in the system, for example when the engine shuts down or gas production exceeds engine capacity, a safety valve diverts the gas from the digester to a self-igniting odor control flare.

The equipment used to connect the generator to the public electric grid ensures that the connection is both safe and reliable. The generator's field is excited with line voltage from the electric grid, thus when power to the farm is interrupted, the generator will shut down. The fused output of the generator is fed directly to the secondaries of the on-site (75 kva) transformer.

The heat from the engine coolant and engine exhaust is captured through heat exchangers to heat water, which is used to heat the manure slurry during the digestion process. A regulator maintains a constant manure temperature of 95 to 105 degrees inside the digester. Hot water pipes were installed in the floor of the milking parlor, holding pen, breezeway and tanker bay (where the milk is stored) to heat barn space and keep the floors free of ice during the winter. Excess hot water is piped to a radiator outside the engine building, and cooled with a 10 horsepower fan.

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<sup>17</sup> The engine rated capacity is 150 kilowatts, but the lower Btu content of the biogas results in a lower actual peak capacity.



## ***Electricity Sales***

The sale of the electricity is an important part of the success of the project. Before the digester was built, Haubenschild Farms entered into a surplus power purchase contract proposed by the local electric cooperative, East Central Energy. Unlike the electric utilities servicing some digester projects installed in other parts of the country, East Central Energy greeted the project with enthusiasm and offered Haubenschild Farms a very favorable contract.

Normally a utility will offer the customer full retail prices to off-set electricity purchases for electricity used on-farm, and buy any excess electricity at the utility's avoided cost of generating power (typically 2-3 cents per kilowatt-hour).<sup>18</sup> However, East Central Energy offered to buy all excess electricity produced at the full retail rate (at the time, 7.25 cents per kilowatt-hour; currently 7.3 cents per kilowatt-hour), as well as giving them the same retail rate for all electricity generated and used on-farm. East Central Energy sees this as achieving their business goal of customer service to Haubenschild Farms, as well as providing a reliable source of electricity for its green power program, which it sells to its customers at a slight premium. East Central was the first utility in the nation to offer its customers "cow power," or electricity specifically generated from digesters. This program is now fully subscribed.

## ***Construction***

Construction for the project was started in the spring of 1999 and finished by September. Construction was performed by local contractors, supervised on-site by Richard Mattocks and Dennis Haubenschild. Table 1 compares projected with actual costs of installing the system. Only the incremental costs of adding a digester system are included. Other costs of the manure management system, such as the storage pond, would have occurred whether or not the digester was built. However, the costs of storage may have been higher had the digester not been constructed.

Construction costs overran projections by about \$47,300. There were several reasons for this. The cost of the engine-generator was higher than expected, perhaps due to increased demand for generation sources around the turn of the century. The digester itself was also more expensive than projected, due to changes in design specifications that were suggested by the Minnesota Pollution Control Agency (MPCA). The original digester design called for 8-inch thick walls. Because of the newness of the technology, the MPCA asked Haubenschild Farms to increase the thickness to 12 inches. As well as increased concrete, the amount of re-bar required for a 12-inch thickness approximately tripled.

Electrical wiring costs were also higher than projected. Haubenschild Farms installed extra wiring to allow for the possible future installation of a second engine-generator set that could be used just to supply only on-farm energy usage (using a stand-by generator). If this is installed, it will add to future costs as well as supply future benefits.

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<sup>18</sup> Minnesota has a "net metering" rule that requires utilities to buy back power at the average retail rate for excess electricity from renewable energy sources (MN Rules 7835.3300). This is limited to less than 40 kW, however, and thus Haubenschild Farms would not have been eligible under this rule.



**Table 1: Projected and Actual Costs of Haubenschild Farm Digester System**

<b>Component</b>	<b>Projected \$</b>	<b>Actual \$</b>
<b>Mix Tank/ Manure Collection</b>		
Excavation/grading	3,400	0*
Cement work	12,500	18,800
Manure pump	10,000	11,300
Other (piping, installing)		2,300
<b>Subtotal</b>	<b>25,900</b>	<b>32,400</b>
<b>Digester</b>		
Excavation/grading	10,600	8,500
Digester tank	68,500	88,700
Heating	8,500	19,800
Cover	4,600	8,100
Start-up	5,000	0*
Miscellaneous	7,800	0*
<b>Subtotal</b>	<b>105,000</b>	<b>125,100</b>
<b>Energy Conversion</b>		
Building	17,400	16,400
Gas pipes	2,000	2,100
Gas pump/meter	6,000	2,000
Engine-generator/hot water recovery	87,000	106,000
Components and installation	13,700	31,000
<b>Subtotal</b>	<b>126,100</b>	<b>157,500</b>
<b>Miscellaneous</b>		
Engineering	25,000	40,000
Contingencies	25,700	0*
<b>Subtotal</b>	<b>50,700</b>	<b>40,000</b>
<b>TOTAL</b>	<b>307,700</b>	<b>355,000</b>
<b>COST/COW (assuming 1000 cows)</b>	<b>\$307</b>	<b>\$355</b>

\*Costs for these items are embedded in other items for which costs are shown

### ***Project Financing***

Haubenschild Farms had difficulty financing the digester project from traditional lending institutions. Project financing was achieved by a collaboration of government agencies, through a combination of direct technical assistance, grants and low-interest loans. Total project financing is outlined in Table 2. The AgSTAR program provided the technical assistance for the project, estimated at \$40,000. The Minnesota Department of Commerce and the Minnesota Office of Environmental Assistance offered grants totaling \$87,500 for construction of the system. Due to a legislative action creating a \$200,000 revolving loan fund for the installation of anaerobic digesters, the Minnesota Department of Agriculture was able to offer a \$150,000 no-interest loan to Haubenschild Farms for the project. This left \$77,500 that Haubenschild Farms paid directly.





In addition to this, The Minnesota Project received \$67,500 from the MN Office of Environmental Assistance, the MN Department of Commerce and Unity Avenue Foundation to coordinate publicity, collect data, and document and evaluate the project.

**Table 2: Project Financing for Installation of Digester**

Source	Type of assistance	Amount
AgSTAR	technical assistance	\$40,000
MN Office of Environmental Assistance	grant	\$37,500
MN Department of Commerce	grant	\$50,000
MN Dept. of Agriculture	no-interest loan	\$150,000
Haubenschild Farms	equity	\$77,500
<b>TOTAL</b>		<b>\$355,000</b>

## System Operation

Operation of the digester and engine/generator requires a certain amount of “screwdriver friendliness.” Dennis Haubenschild performs most of the operation and maintenance of the digester. To help prepare Dennis for this task, Richard Mattocks conducted a series of walk-around sessions on system operations. Routine operation takes approximately 45 minutes per day. This includes system inspection, mixing and pumping manure into the digester twice a day, and checking and recording gauges to measure biogas and electricity output.

The engine-generator requires the most maintenance. The engine oil needs to be changed every month. Valve adjustment and spark plug cleaning is also performed periodically by Dennis. Other routine maintenance performed since 1999 includes replacing the battery, alternator and the mag needle (which creates the spark). It is estimated that engine maintenance for an on-farm biogas engine-generator, including periodic engine overhaul, costs about \$3,700 per year.<sup>19</sup> Other operating costs include periodic maintenance of the gas blower, gas flare and manure pumps and checking pipes for gas leaks.

In May 2000 the manure pump broke and required replacement under warranty. Because Haubenschild Farms used a manure pump for manure management before the digester was installed, this is not a potential problem unique to an anaerobic digester system.

On June 5, 2000, the generator circuit breaker blew out due to defective manufacturing and was also replaced under warranty. The generator was out of commission for about four days while this was being replaced. The biogas was flared during this period.

<sup>19</sup> About 1.5 cents/kwh, as projected in the Charles Ross and James Walsh, “Handbook of Biogas Utilization,” United States Department of Energy, Southeastern Regional Biomass Energy Program: Muscle Shoals, Alabama, 1996.



When the digester was started, it was processing manure from between 420 to 430 dairy cows, about half of its total design capacity. In June 2000, Haubenschild Farms finished building their second free-stall barn and began expanding their herd size. Since the fall of 2000, the herd size has averaged about 750 cows.

**Haubenschild Farms, Inc.**



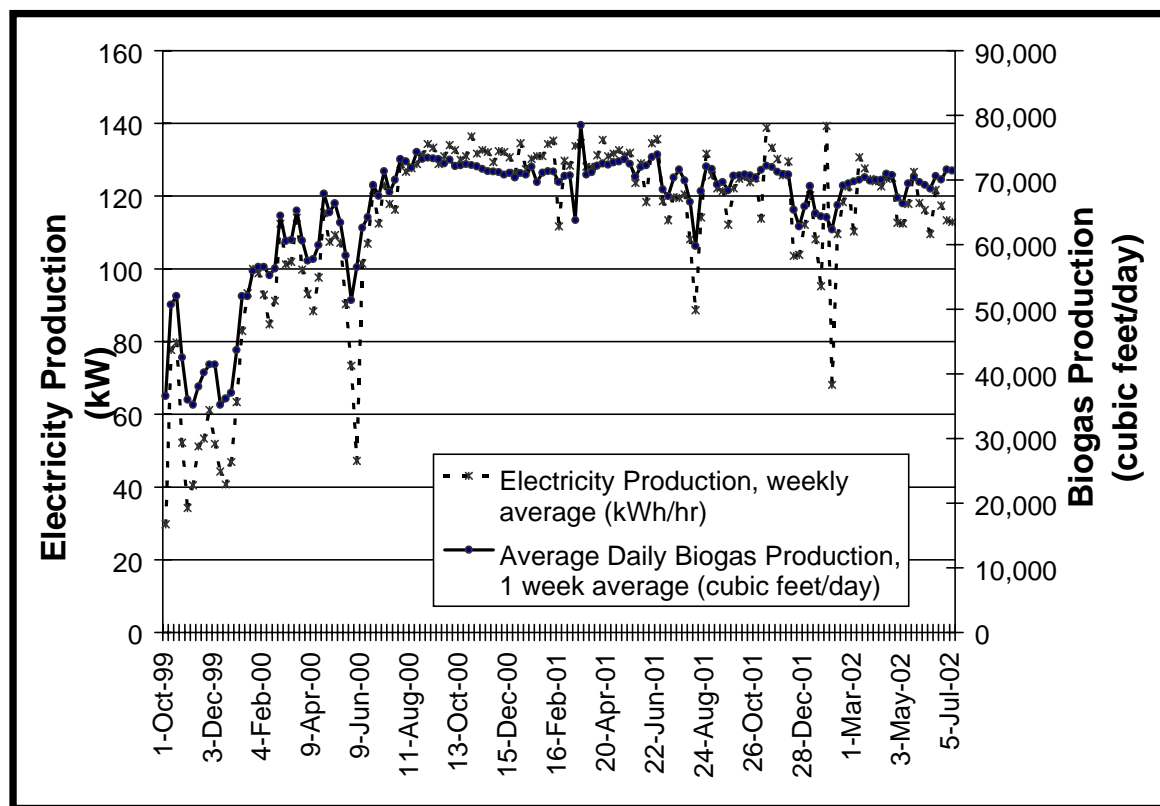
## Results to Date

In September 1999, construction was complete and the manure began to be fed to the digester. On September 9, the engine was started using propane in order to heat the manure in the tank. By October 1, biogas production was sufficient to fuel the engine.

### *Electricity and Biogas Production*

Figure 2 shows the production of biogas and electricity by the installation from October 1, 1999 until July 7, 2000. As the bacteria in the digester have grown and flourished, and as the herd size was expanded, the measured biogas output of the digester steadily increased from about 30,000 cubic feet/day of biogas in October 1999 to about 70,000 cubic feet/day by July 2000, where it has remained fairly constant.

**Figure 2: Measured Biogas and Electricity Production to Date<sup>20</sup>**



<sup>20</sup> Biogas volume is calculated from meter readings of biogas going into the generator. If the generator is down or cannot accommodate the full volume of biogas produced, the biogas is flared and will not be metered. During engine down time, biogas production is estimated from the average biogas production during engine operating hours on a weekly basis. However, since at least July 2000, the digester has been producing excess biogas that cannot be accommodated even with the engine in service, so full biogas production is not known.



Since summer of 2000, more biogas was produced than could be accommodated by the engine, which means it is then flared. Since this flared biogas is not metered, it is impossible to know much biogas is being flared. The excess biogas tends to be produced just after manure is added to the digester, and doesn't occur constantly, perhaps 5 hours per day. Haubenschild Farms are currently considering options for adding to their generating capacity to utilize the biogas that is currently being lost in this manner. Since summer 2000, the generator has been running nearly constantly at peak capacity, producing enough electricity to supply the electric needs on-farm and enough surplus electricity to provide for about 75 average homes. The engine has been running a remarkable 98.8 percent of the time (1.2 percent down-time).

The performance of Haubenschild Farms digester to date has been excellent, exceeding expectations. Table 3 on page 22 compares the system design performance calculations with the actual performance for two periods, representing 425 cows (from January 14 to June 2, 2000) and after the herd size had been expanded to about 750 cows (September 1, 2000 to July 15, 2002).

***Initial output per cow was about twice design specifications***

In the initial design specifications, AgSTAR calculated that the Haubenschild Farms digester would eventually produce 65,000 cubic feet/day of biogas from 1000 cows or 65 cubic feet/day of biogas per cow.

The daily biogas production was estimated to result in electricity generation of 2.3 kWh per cow per day. The estimated biogas production is in the range of biogas output from other plug-flow digesters installed around the country, which a 1998 study showed to vary from about 44 to 118 cubic feet/day per cow.<sup>21</sup>

Shortly after the Haubenschild Farms digester started (with 425 cows), the design calculations were exceeded, and biogas production was over twice the expected output at about 139 cubic feet/day per cow, resulting in electricity generation of 5.5 kWh per cow per day.



**Silage Pillows, Haubenschild Farms, Inc.**

***Current output per cow is slightly higher than design specifications***

With 750 cows, current output per cow is over 93 cubic feet/cow/day, and electricity production is about 4.0 kilowatt hours/cow/day, or about 40 percent greater than design specifications. Again, because some of the biogas is being flared and thus not metered, it is impossible to know the exact biogas production.

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<sup>21</sup> Derived from Philip Lusk, 1998 (see reference 10).

***Comparing apples with apples: performance vs. design specifications***

In looking for an explanation of the high biogas production of the Haubenschild digester, an important factor to consider is the high manure production of Haubenschild's cows. More manure means more volatile solids that can be converted to biogas. Haubenschild Farm's cows are high milk producers, and since there is a direct relationship between milk production and manure production, it makes sense that their cows would also produce more manure than average.

An examination of Table 3 reveals that Haubenschild's cows produce about 50 percent more manure slurry than the design specification.<sup>22</sup> So it might be more appropriate to compare biogas production *per gallon of manure* instead of *per cow*. The Haubenschild digester, at 425 cows, had about a 40 percent higher biogas production per gallon of manure than design specifications, while at 750 cows it is operating very near design specifications per gallon of manure, not considering the biogas that is flared.

***Reasons for high performance***

The especially high performance of the digester in its first year of operation with 425 cows may be due in part to the fact that the digester was operating at less than design capacity. This resulted in the manure staying in the digester for about 30 days instead of 20 days, and thus capturing more biogas. However, studies suggest that most of the potential biogas is captured within the first 15 to 20 days of being in the digester, so this may not fully explain the first year's high production.

There are other factors influencing biogas production that may explain the high biogas output of Haubenschild Farms digester (Refer to the box on page 23 – “What determines how much biogas is produced?”). Manure is scraped and almost immediately fed into the digester, resulting in higher methane capture. Dennis Haubenschild is an incredibly knowledgeable and careful manager of the digester. He monitors the performance closely, taking careful records and making adjustments as necessary, such as keeping the solids content of the manure slurry above 10 percent.

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<sup>22</sup> Manure slurry is excreted manure plus wash water and bedding. Since the Haubenschields are careful to minimize water usage to keep solids content above 10 percent, it is likely that most or all of the 50 percent increase in volume of the total manure slurry over design specifications is from manure excreted from the cows.



**Table 3: Digester Design and Actual Performance**

	Design	Actual, 425 cows	Actual, 750 cows
<b>Time frame</b>	1998	Jan - May 2000	Sep 2000 - Jul 2002
<b>Cows (average)</b>	1,000	425	750
<b>Manure production</b>			
gallons (per cow per day)	14	n/a	n/a
<b>Manure slurry</b> (including wash water and bedding)			
gallons (per cow per day)	17.5	27	27
total gallons slurry (per day)	17,500	11,500	20,000
<b>Digester size</b>			
volume (cubic feet)	47,000	47,000	47,000
volume (gallons)	352,000	352,000	352,000
retention time (days)	20	31	15
<b>Gas production</b>			
per gallon of manure slurry (cubic feet/day)	3.7	5.1	3.5*
per cow (cubic feet per day)	65	139	93*
total (per day)	65,000	58,900	70,000*
<b>Electrical output</b>			
per cow (kWh per day <sup>23</sup> )	2.3	5.5	4.0
total (kWh per day)	2340	2350	2970
generator capacity (kW)	120	135	135
generator availability	90%	98%	98.8%
yearly output (kWh)	766,500	860,000	1,080,000
<b>Thermal output</b>			
total thermal output (mmBtu/day)	18	n/a	n/a
<b>Revenue Generation</b>			
offset heating costs (per year)	\$4000	\$4000	\$4000
offset electricity use on-farm (\$/kWh)	\$0.07	\$0.0725	\$0.073**
excess electricity sales (\$/kWh)	\$0.02	\$0.0725	\$0.073**
projected annual electric revenue <sup>24</sup>	\$40,300	\$62,200	\$80,957 (actual, 2001)
total projected annual revenue	\$44,300	\$66,200	\$84,957

n/a means not available

\* Actual biogas production is higher than reported here, because more biogas is being produced than the engine can accommodate, and thus cannot be metered with the current metering configuration

\*\* A rate increase from 7.25 cents/kWh to 7.3 cents/kWh occurred effective Jan 1, 2001.

<sup>23</sup> For the design calculations of kWh per cow, this assumes an energy value of 600 Btu per cubic foot biogas and a heat rate of 15,000 Btu per kWh.

<sup>24</sup> Projected annual electric revenue for the 425 cow column is calculated based on the average electric production from January 14 to June 2. See later discussion on revenue generated.





## What Determines How Much Biogas is Produced?

Haubenschild Farms exceeded initial estimates of how much biogas they would produce. The heart of the digester is composed of living organisms, and thus a certain amount of nurturing is necessary to maximize their efficiency. It can take a year before the methane-producing bacteria grow to their maximum potential. The microchemistry of digesters is not yet fully understood, and undoubtedly there are other factors, but based on research and the experience of existing digesters, the following can influence how much biogas is produced:

1. **Animal rations.** Higher-energy food will tend to produce manure with more potential to produce methane. Studies suggest that a higher-energy diet can more than double the methane potential of manure compared to manure from animals fed a lower energy diet.
2. **Solids content of the manure.** The solids portion of manure contains volatile organic matter, which is what the anaerobic digestion breaks down. The higher the solids content, the greater the biogas production per gallon of manure. In the case of a plug-flow digester, the solids content of manure entering the digester should be kept about 10 percent or above, or the solids will tend to settle to the bottom of the digester, where they will slowly fill the digester. As well, solids not in suspension have less exposed surface area and are harder for bacteria to digest.
3. **Frequency and regularity of manure collection.** The more frequently the manure is added to the digester, the less biogas is lost. The manure should also be added to the digester on a regular basis.
4. **Maintaining optimal digester temperature.** Maintaining an even temperature throughout the digester is also important, and is determined by the engineering of the heating rack inside the digester as well as tank insulation. Reducing temperature fluctuations inside the digester will stabilize the methane-producing bacteria and increase biogas output.
5. **Residence time in the digester.** The longer the manure remains in the digester, the more methane will be produced. For cow manure in a plug-flow digester, after approximately 20 days, 70 to 80 percent of the methane potential of the manure will be captured.
6. **pH balance.** A pH level that is too high or low can kill the methane-producing bacteria.
7. **Addition of volatile solids.** The addition of other digestible solids to the manure slurry can increase biogas production. Newspaper is one such solid that is easily digestible.
8. **Introduction of antibiotics.** Antibiotics and other disease-inhibitors like hoof baths introduced to the digester can kill the methanogenic bacteria.

**Source:** This section derived from Kurt Roos and Mark Moser, "AgSTAR Handbook," Environmental Protection Agency, EPA-430-B-97-015, 1997, See "Resources..." section, page 34 for more information; Wheatley, 1990 (see reference 11); Stafford, Wheatley and Hughes, ed., "Anaerobic Digestion," Applied Science Publishers, Ltd: London, 1979; Elizabeth Bird and Marty Strange "Mares Tales and Mackerel Scales," Center for Rural Affairs: Walthill, NE, 1992.



### ***Hot Water Production***

Hot water is produced from recovered engine heat. In addition to providing the necessary heat for the digester, in the winter the hot water is used to heat barn space, saving about \$4000 per year in propane gas costs.

### ***Odor Reduction***

The reduction in odor from the digester is very noticeable. Near the pond where the digested manure is stored, there is only a slight odor. Haubenschild Farms injected the digested manure on their fields several times in the spring of 2000. Neighbors have not reported noticing a smell, where as when Haubenschild Farms would apply raw manure neighbors would notice the smell for several days, although no complaints were made.

### ***Weed Seed Destruction***

Dennis Haubenschild did a simple germination test of the digested manure to test for presence of weed seeds and no weeds were detected. The Minnesota Project is partnering with the University of Minnesota to study weed seed germination of samples run through the Haubenschild digester, and results will be available in 2003.

### ***Greenhouse Gas Reductions***

Burning methane at Haubenschild Farms has resulted in a reduction in greenhouse gases. In the first 10 operating months, it was estimated that the equivalent of approximately 680 tons of carbon dioxide were mitigated.<sup>25</sup>

### ***Emissions***

Anaerobic digestion, besides methane and carbon dioxide, also produces small amounts of hydrogen sulfide (toxic to humans in certain situations<sup>26</sup>), nitrogen, ammonia and other trace gases. After combustion, this results in emissions of sulfur dioxide (SO<sub>2</sub>) and small amounts of nitrogen oxides (NO<sub>x</sub>) and particulate matter (PM). It should be noted that hydrogen sulfide would be emitted without the digester, and that by burning the biogas, hydrogen sulfide is converted into sulfur dioxide, which is less toxic to humans.

Using generic estimates of emissions from engines run on biogas, and assuming that Haubenschild Farms engine ran at current production rates as reported in Table 3, it could be expected to annually produce 3.1 tons SO<sub>2</sub>, 1.1 tons NO<sub>x</sub>, and 0.1 tons PM.<sup>27</sup> Emissions

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<sup>25</sup> Estimated by Peter Ciborowski, Minnesota Pollution Control Agency, based on comparative emissions from an earthen basin system for storing manure. More recent estimates of the global warming potential of methane would slightly increase the figure reported here (ie, scientists have increased their estimate of the global warming potential of methane from 21 times to 23 times more potent than carbon dioxide).

<sup>26</sup> Anaerobic digestion of manure typically results in hydrogen sulfide concentrations of around 1500 parts per million (ppm). Concentrations over 1000 ppm can result in severe health problems for humans.

<sup>27</sup> Given an assumed annual biogas production of 25.6 million SCF (standard cubic feet), hydrogen sulfide (H<sub>2</sub>S) concentration of 1500 ppmv (parts per million by volume), H<sub>2</sub>S density of 0.0901 lb/SCF, sulfur dioxide (SO<sub>2</sub>) emission rate from H<sub>2</sub>S of 1.78 lb/lb H<sub>2</sub>S, SO<sub>2</sub> emission rate from methane of 0.6 lb/10<sup>6</sup> SCF, biogas methane content of 60%, particulate matter emission rate from methane of 13.7 lb/10<sup>6</sup> SCF, Nox emission rate of 140.0 lb/10<sup>6</sup> SCF. Derived from "Handbook of Biogas Utilization," Charles Ross, Thomas Drake III and James Walsh, 1996.





testing of the engine exhaust could provide a more precise estimate of emissions, although these numbers suggest that emission rates from digesters are small compared to similar-sized power generation sources, for example diesel fueled.

### ***Financial Viability***

During the reporting period of the original report (September 10, 1999 until July 7, 2000), the Haubenschild Farms digester generated \$41,307 in revenue from offset electricity costs and electricity sales. In 2001, the digester's generator offset \$38,655 worth of electricity used on-farm, and Haubenschild Farms sold \$42,302 of electricity back to East Central Energy, for a total 2001 electricity value of \$80,957. In addition, an estimated \$4000 annually is being saved in winter heating costs.

In order to examine the financial viability of the Haubenschild Farms project and its applicability to other projects, several hypothetical scenarios are compared and presented in Table 4. For the purposes of this analysis, it was assumed that the entire project cost (\$355,000) would have to be paid back, although this is not the case for Haubenschild Farms, who received some grant assistance. We calculated only the simple payback period for each scenario described below. The simple payback method is not a rigorous indicator of feasibility, but does provide a useful comparison for hypothetical situations.

For all of the scenarios, net annual revenue is the total revenue minus assumed operating and maintenance costs of 1.5 cents per kWh of electricity generated.<sup>28</sup> The scenarios considered are as follows:

- A. **1998 Projection.** This uses the projections made for electrical output before the digester was built (lower than actual production), offset on-farm electricity value of 7 cents/kWh, and an electricity sales price for excess electricity of 2 cents/kWh (Table 3).
- B. **1998 Projection with high price for electricity.** Assumes the original design calculations of electrical output (lower than actual performance), but that both the offset on-farm electricity value and excess electricity price is 7.3 cents/kWh (current price that Haubenschild Farms is receiving for their electricity).
- C. **750 cows (actual results for 2001).** This scenario uses the actual electricity generated in 2001 at the actual price (7.3 cents/kWh), carried through the life of the project.
- D. **750 cows, mid-range electricity price.** Same as scenario 3, but assumes a 3.5 cent/kWh buy-back rate from the utility, which seems a plausible rate for future digester owners in Minnesota.

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<sup>28</sup> The figure is probably high compared to actual experience at other digesters, even after more than 10 years of operation. See Mark A. Moser and L. Langerwerf, "Plug Flow Dairy Digester Condition After 16 Years of Operation." Proceedings of the Eighth International Symposium on Animal, Agricultural, and Food Processing Wastes, Des Moines, IA, July 9-12, 2000, American Society of Agricultural Engineers, St. Joseph, MI.

**Table 4: Financial Analysis**

Scenario	Value of offset electricity (cents/kWh)	Value of excess electricity sales (cents/kWh)	Net annual revenue	Simple payback (years)
A. 1998 Projection	7.0	2.0	\$31,489	11
B. 1998 Projection w/ high electricity price	7.3	7.3	\$53,538	7
C. Actual, 2001	7.3	7.3	\$72,616	5
D. Actual 2001 w/ mid electricity price	7.3	3.5	\$50,596	7

Table 4 presents the results of this analysis. The financial viability of the project is sensitive to the selling price of excess electricity. With a selling price of 2 cents/kWh (scenario A), the simple payback for the 1998 Projection scenario is 11 years, but reduces to 7 years if the sale price of excess electricity increases to 7.3 cents/kWh (scenario B). The selling price of electricity could make or break a project for a farmer, unless they received some other financing assistance, or were able to achieve high biogas production, as Haubenschild Farms has.

In the scenario with actual results from 2001 (scenario C), the simple payback is 5 years. If a mid-range price is assumed for excess electricity sales (scenario D), the simple payback would increase to 7 years.

There are other potential financial benefits that are not included in this analysis:

- Lawsuits over odor may be avoided with a digester;
- The increase in value as a fertilizer may have significant economic value if it displaces commercial fertilizer;
- Herbicide use may decrease with the destruction of weed seeds.

## Lessons Learned

The scope of our documentation for this project was limited to the Haubenschild Farms digester. Also, in the course of our review of other digesters and through discussions with project advisors, we have learned some general lessons to offer the reader.

- **Demonstrable benefits.** There are significant benefits to the operation of a plug-flow anaerobic digester. The most important are undoubtedly production of a high-quality fertilizer, odor control and the generation of electricity.
- **Reliable operation.** Haubenschild Farms has operated the generator at over 95 percent availability. This far exceeds even the highest-performing coal plants.
- **Payback of 5 years on investment is possible.** If Haubenschild Farms continues operating at current levels, the total cost of the digester and generator system will pay for itself in about 5 years through energy savings and revenue.



There may be other elements of risk, however, that cannot be assessed even after nearly 3 years of operating experience. For example, engine lifetime may be shorter using biogas than the fuel it was originally designed for and could add to operation and maintenance costs.

- **Electric utility cooperation is important.** Many digester projects have had a more difficult time interconnecting and selling electricity to their utility companies. Contracts to buy electricity for less than half the amount Haubenschild Farms receives are common. The financial success of the project is in a great part due to the cooperation of East Central Energy.
- **Utilities can profit from sale of this “green power.”** Capturing methane for generating electricity reduces our dependence on fossil fuel power sources and customers are willing to pay a small surcharge for this benefit.
- **There are many non-market benefits.** Greenhouse gas reductions, odor control and benefits to the neighbors from reduced odors and reduced impacts from catastrophic spills are all benefits that are not captured by the market.
- **A good time to install a digester is when changing or expanding operations.** The digester system needs to be integrated and compatible with the manure management system on-farm. A good time to install a digester is when a dairy farm makes large capital investments, such as installing a new barn or modifying their manure management system.
- **Good management is crucial.** The operation of a digester requires a certain amount of “tinkering,” regular oversight and attention to detail. If this is not done, digester and engine performance can suffer.
- **Good digester design is key.** A digester must be designed to be compatible with the needs of the farm, sized appropriately to the volume of manure to be digested, and engineered to provide the proper heating and movement of the manure through the digester. As digesters are still an emerging technology, there is a wide variance in digester performance and design testing. It is safest under these circumstances to design and build the digester with the help of an engineer with a proven track record.
- **Barriers to financing digester systems.** The difficulty Haubenschild Farms had with securing project financing suggests a barrier that potential digester owners may encounter while getting funding from traditional lending sources.
- **Cooperative agency participation helped the success of the project.** In addition to the support received from the AgStar program, several Minnesota agencies (Onanegozie RC & D Council, MN Department of Commerce, MN Department of Agriculture, MN Office of Environmental Assistance) embraced the technology with interest and enthusiasm. They believed that the project had potential to demonstrate multiple benefits for agriculture and would stimulate interest and investigation across many sectors.



## **Trends Affecting the Future for Anaerobic Digesters**

### ***Regulation and Conflict***

Farmers, especially those considering building larger regulated feedlots, will be under increasing pressure to find solutions to treating waste. The odor and potential for pollution from animal agriculture are increasingly coming into conflict with neighbors and will likely result in greater regulatory controls. Anaerobic digesters can offer multiple benefits to the farmer and the environment.

### ***Size of Farms***

Trends in dairy size suggest that herd size is increasing, and in another 10 years, there will be 300-400 Minnesota family farms with herds greater than 400 cows. Some experts have calculated that there is a threshold size below which installing a digester is not economic for generating electricity. One such estimate is that it would require a minimum of 400 cows on a dairy, earning a \$0.06 kWh electric rate, to operate a profitable digester enterprise.<sup>29</sup>

There are various reasons for this. The minimum expense required to install a digester system with all its parts is great, and thus there are economies of scale in construction.

### ***Specialization***

On a smaller dairy labor is usually less specialized than on a larger one, and requires fewer workers. Haubenschild Farms employs 11.5 full time equivalent workers, with a small percentage of total time devoted to digester operation. On a smaller farm with fewer workers, operating a digester would probably require the same amount of effort, thus a higher percentage of time available from the work force. However, it may be economic to install and operate at smaller farms where thermal energy is captured by methane combustion, reducing the cost required for electric generation. For the Haubenschild Farms project, electrical generation represents over one third of the project cost, but without it the system probably would not be able to pay for itself.

### ***Cooperative Ventures***

Building a centralized digester where manure is pooled and blended to proper consistency from surrounding farms may be a possibility, and is fairly common in Europe. The manure transport costs to get manure to and from the digester can be quite costly, and this may limit the extent to which centralized digesters can operate.

Another possibility is “turn-key” operations. Digester operation and maintenance requires time and learned skills. Farmers may not be interested in performing this job. It may make sense for a utility or enterprise to build and operate multiple digesters in multiple locations and either charge a manure management fee or return part of the profits of energy generation or carbon credits (if they become a reality), or sale of the separated solids.

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<sup>29</sup> 7/19/00 telephone conversation with Mark Moser, RCM, Inc.



## Policy

Since the Haubenschild digester was built, Minnesota leaders have implemented several initiatives to encourage digesters, many of which were policy recommendations in the original Haubenschild report:

- A state production payment of 1.5 cents per kilowatt-hour was extended to include on-farm digesters;
- The Minnesota Department of Agriculture's zero interest loan program for digesters was expanded;
- The Minnesota Department of Commerce released a report in August 2002 that considers the total potential for biogas production on Minnesota farms;
- The Minnesota Pollution Control Agency has considered anaerobic digesters as a mitigating technology when negotiating with feedlot operators;
- Great River Energy, the electric generation and distribution cooperative utility for a majority of farms in Minnesota, has recently announced a special grant program for digesters; and
- East Central Energy, Haubenschild's utility, has instituted the first green electricity marketing program in the country exclusively for digester-produced power, by offering their customers the option to purchase "cow power".

Policies to encourage digesters are rolling along, not only in Minnesota and other states, but at the federal level as well. The near future may see a rapid expansion in the number of digesters on farms, without the need for additional incentives.

### *Digester policy and equity*

The capital-intensive nature of digester systems, as well as economies of scale in their construction and operation, are major barriers to their development on smaller and mid-sized farms. The way policies are currently structured, this means that tax dollars to encourage the construction of digesters will tend to go towards larger farms. Unless there is a way to balance this out, smaller operations will be at a competitive disadvantage, since they don't have as easy access to these funding sources as larger operations do. Future policies should consider this equity question.



## **Resources for More Information on Anaerobic Digestion**

**Minnesota Project website:** [www.mnproject.org](http://www.mnproject.org) contains links to many of the other resources described in this appendix, as well as other useful sources of information.

**AgSTAR** provides assistance to farmers considering installing an anaerobic digester system. They can be reached by calling 1-800-95AgSTAR. The AgSTAR web site [www.epa.gov/agstar](http://www.epa.gov/agstar) contains a wealth of information for farmers interested in installing a digester, including:

- The AgSTAR Handbook, a guide to thinking about installing an anaerobic digester. This can be downloaded from the web site.
- FarmWare, a free software program that can assist a farmer with a pre-feasibility analysis of installing a digester. Available for downloads.
- List of vendors with contact information and a description of project experience with farm-scale digestion.

### **Methane Recovery from Animal Manures: The Current Opportunities Casebook.**

This report was published by the Department of Energy's National Renewable Energy Lab and gives an overview of digester technology, as well as information on currently operating digesters in the United States. Available for downloading at the Minnesota Project web site.

### **Haubenschild Farms web site:**

[www.ecenet.com/%7ehauby/farmpresentation.prz/odyframe.htm](http://www.ecenet.com/%7ehauby/farmpresentation.prz/odyframe.htm)





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# Biogas Digester Construction Photos & Details

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## Anaerobic Digestion

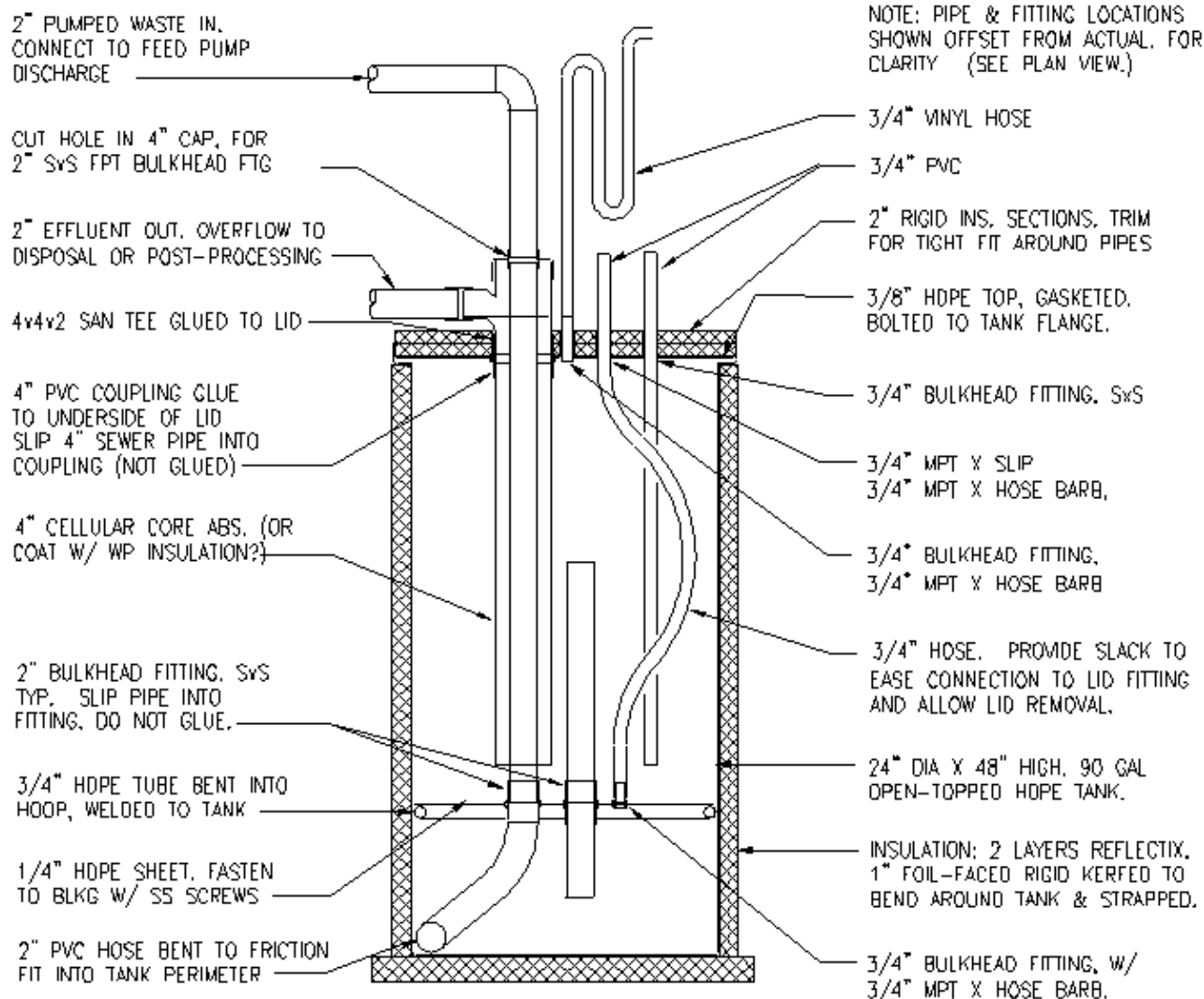
The process by which anaerobic bacteria decompose organic matter into methane, carbon dioxide, and a nutrient-rich sludge involves a step-wise series of reactions requiring the cooperative action of several organisms. In the first stage, a variety of primary producers (acidogens) break down the raw wastes into simpler fatty acids. In the second stage, a different group of organisms (methanogens) consume the acids produced by the acidogens, generating biogas as a metabolic byproduct.

On average, acidogens grow much more quickly than methanogens. They are also much hardier organisms, able to survive a broader range of temperature and pH conditions.

## Problems with Conventional Single-Stage Digesters

As a result of these dependencies, single-stage digesters, where both species are cultured together in the same environment, are inherently unstable. In such systems, any imbalance between the two organisms creates a positive feedback (runaway) situation which can quickly bring the entire process to a halt. That is, a slight drop in methane production rate without a corresponding reduction in substrate production will cause volatile acids to accumulate, causing the pH to drop, killing more methanogens, causing further accumulation of acids...and so on, until the system crashes.

Conventional single-stage digesters are not only unstable, they are also relatively inefficient. For example, if the system is operated at a hydraulic retention time (HRT) conducive to growth of acidogens (2-3 days), any methanogens present will be washed out of the system faster than they can reproduce, preventing them from ever becoming established. On the other hand, if the system is operated at an HRT conducive to growth of methanogens (20-25days), the faster growing acidogens will be maintained at the low growth rates of the endogenous growth phase - essentially at starvation level.



## Acid/Methane Tank Baffle Construction:

Tools required for welding plastic:  
Welder, small air compressor, HDPE welding rod.



Looking down into open tank, showing 3/4" HDPE tube bent into hoop and welded into tank. Hoop acts as support blocking for baffle partitioning vertical tank into two chambers.



Closeup of hoop welded to wall of HDPE tank.



Assembled baffle plate, top view: Disk is cut from 1/4" HDPE sheet, holes/fittings in baffle are for 3/4" gas vent, 2" transfer pipe (center), 2" influent in.



Assembled baffle plate ready for installation in tank.

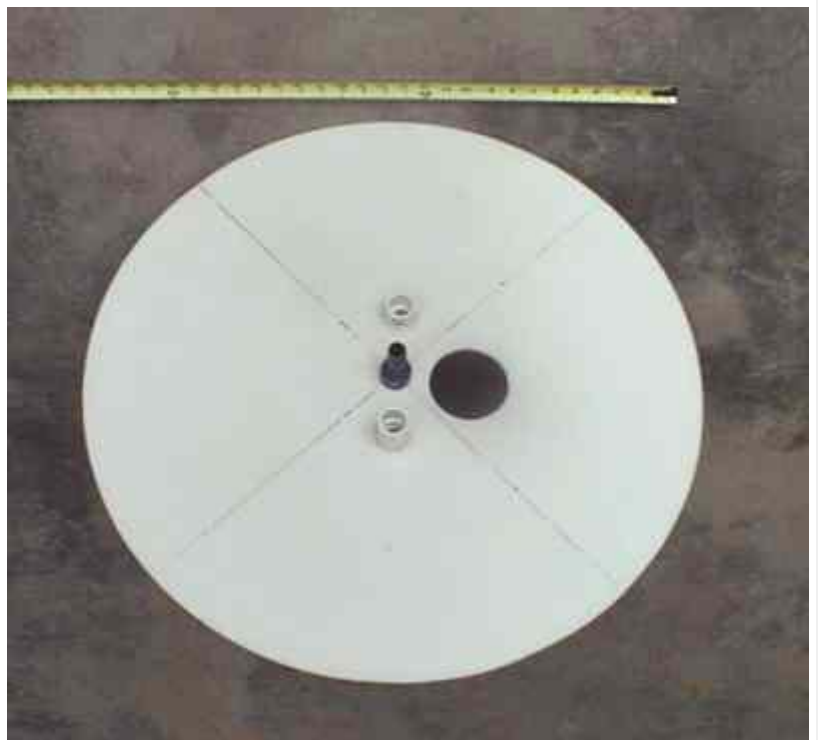


Looking down in tank with completed baffle plate in place. Baffle is attached to support blocking (3/4" tube hoop) with self-tapping stainless steel screws, sealed with silicone caulk. (Note: 3/4" hose connecting gas vent to lid is not shown.)



### Digester Lid Construction

Cut tank lid from 3/8" thick HDPE sheet to fit inside flange of open top HDPE tank. (Diameter varies depending on tank selected -- which will depend on amount of material to be digested. Use [design tool](#) to select tank.) Holes cut in tank are for influent/effluent heat exchanger assembly, biogas out, biogas recirculation, and gas vent from acid reactor. Top view.





Closeup view of underside of lid showing silicone caulk bead and fittings. Large hole is caulked in preparation for inserting 4" ABS heat exchanger assembly (see photos below).



Assembled lid with gas vent hose and gas recirculation conduit attached to fittings.



Influent/effluent heat exchanger, assembled from 4" ABS pipe with 2" PVC inside





Closeup of top of HX assembly showing 2" PVC bulkhead fitting inserted into hole drilled through 4" ABS cap.



Completed digester prior to final installation of lid and wrapping with insulation. Heat tape is wrapped around tank and attached with aluminum tape.

(Note also an immersion well installed in lid, for temperature measurement -- not included in construction drawings.)



# Biogas Digester Operation

## Incoming Waste

A system can be designed to digest a wide variety of organic wastes, from kitchen scraps to sewage, to livestock manure, to industrial wastes. The ideal feedstock is a 6-8% slurry with a Carbon to Nitrogen ratio of about 30:1. Incoming waste material should be macerated, and as close to the operating temperature (95 degF) of the digester as possible. The small scale system described below will handle the toilet wastes produced by a family of 6, each flushing a 1-1/2 Pint/flush toilet 5 times per day.

## Gas Handling:

Gas can be stored in low pressure gas bags (i.e. truck tire inner tubes, etc.), rigid tank(s) with floating cover and water seal, compressed and stored in pressure tank, and/or burned as it is produced, (minimizing storage requirements). For safety reasons, it is recommended that the gas be burned as soon as possible, avoiding the requirement to store and handle larger quantities of flammable gas.

The gas produced typically consists of about 30% CO<sub>2</sub> and about 60-65% methane, depending on the content of the wastes. Small amounts of hydrogen, hydrogen sulfide, and nitrogen gas will also be produced, as well as water vapor.

One use of this gas is to heat domestic hot water in a gas-fired tank-type water heater installed between the cold water inlet and the conventional (backup) water heater. A small, weighted inflatable gas bag will be used to collect up to an hour's worth of gas (i.e. about 5 cu ft at design conditions), and to provide required pressure for proper burner operation.

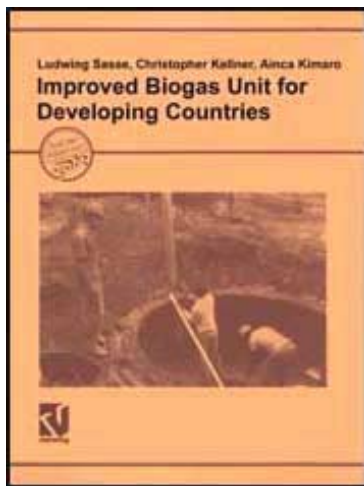
Gas burner should be as small as possible, with intermittent ignition with continuous retry and maximum lock-out time. Sufficient hot water storage capacity should be provided to make use of all available energy without having to store flammable gas. This may require addition of one or more insulated storage tanks piped together, and a small circulator pump and controls.

## Digester Effluent:

Effluent from the digester will be returned to the conventional backup sewer system. A hydraulic loading rate (total liquid throughput) of about 60 gallons/ day is assumed. Estimated solids loading will be about 35 lbs/day. Assuming that volatile solids will be reduced by about 60-70% in the digester, additional volatile solids entering the sewer system will be about 35 - (35 x .65) ~ 12-15 lbs/day.

## Digester Sludge:

The volume of sludge solids accumulating in the digester will depend on the digestibility of the influent material and the extent to which digester contents are mixed (i.e. kept in suspension and discharged with effluent), or allowed to settle. Tanks are designed to facilitate sludge removal (e.g. quick disconnect fittings provided for connection to vacuum pump, etc.). To reduce solids loading on backup sewer system and recover sludge solids as a valuable soil amendment, a settling tank can be installed in the line between the effluent overflow and the sewer system



# Improved Biogas Unit for Developing Countries

by **Ludwig Sasse, Christopher Kellner & Ainea Kimaro**

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## Acknowledgments

Deutsches Zentrum für Entwicklungstechnologien - GATE - stands for German Appropriate Technology Exchange. It was founded in 1978 as a special division of the Deutsche Gesellschaft für Technische Zusammenarbeit (GTZ) GmbH. GATE is a centre for the dissemination and promotion of appropriate technologies for developing countries. GATE defines "Appropriate technologies" as those which are suitable and acceptable in the light of economic, social and cultural criteria. They should contribute to socio-economic development whilst ensuring optimal utilization of resources and minimal detriment to the environment. Depending on the case at hand a traditional, intermediate or highly-developed can be the "appropriate" one. GATE focusses its work on the key areas:

- Dissemination of Appropriate Technologies: Collecting, processing and disseminating information on technologies appropriate to the needs of the developing countries: ascertaining the technological requirements of Third World countries: support in the form of personnel, material and equipment to promote the development and adaptation of technologies for developing countries.
- Environmental Protection. The growing importance of ecology and environmental protection require better coordination and harmonization of projects. In order to tackle these tasks more effectively, a coordination center was set up within GATE in 1985.

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- providing an advisory service to other agencies also working on development projects
- the recruitment, selection, briefing, assignment, administration of expert personnel and their welfare and technical backstopping during their period of assignment
- provision of materials and equipment for projects, planning work, selection, purchasing and shipment to the developing countries
- management of all financial obligations to the partner-country.

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Msafiri Athumani, construction and technology. Albert Butare, plant construction and appliances modification. Thomas Hoerz, rural energy and fertilizer utilization. Reimund Hoffmann, extension services and rural financing procedures. Christopher Kellner, agricultural and technical adviser to the BES. Ainea Kimaro, research and training of engineers and technicians. Sanford Kombe, privet entrepreneur, construction of biogas units. Mubezi Lutaihua, agricultural structures, technologies and construction. Harold Ngowi, agriculture, research and organisational topics. Petro Omalla, bricks production, construction of biogas units and biolatrines. Alexander Schlusser, had been responsible for technology development and adaptation.

I would like to thank the colleagues of CAMARTEC for their efficient and friendly cooperation while writing the text and preparing the drawings.

I am greatly indebted to Mwanaidi and Christopher Kellner who did everything possible to provide me a cosy home and a most suitable working place while staying in Arusha.  
Ludwig Sasse

## Foreword

Tanzania is facing energy problems in both urban and rural areas. Fuel wood is the major source of supply of energy in rural areas. CAMARTEC was established in order to develop alternative sources of energy among its other objectives

In the process of looking for International support to strengthen its activities, the West Germany Government through GATE a branch of GTZ, accepted to establish a technical assistance to CAMARTEC that would deal with development and extension of renewable sources of energy which is BIOGAS. The Biogas Extension Service was then established in 1983.

The results that are seen today, are due to tireless effort by German experts and local counterparts who have designed, field tested and installed over 200 biogas units. The team has worked beyond the gas requirement to include slurry use for agricultural purposes. The technology has been accepted by farmers as indicated by their demand through willingness to pay for the biogas units. The ownership of a family size biogas unit which is built through CAMARTEC has become a status symbol and has improved the quality of life in the home. Energy obtained from the gas and the light at night have both given utility to the owners of the plants.

I am very thankful to GTZ for the assistance extended to CAMARTEC. I also appreciate the expatriates contribution towards the success reached so far. Tanzanian counterparts who work in the project also have contributed a lot and deserve my thanks. Lastly, I thank Mr. Ludwig Sasse for compiling this book which will be a useful reference material to many lovers of BIOGAS. I am looking forward to the use of the content embedded in the text and hope that his knowledge will contribute to solving Tanzania's rural energy needs.

E.M. Ngaiza  
DIRECTOR GENERAL  
CAMARTEC



## **1. Preface**

This booklet reflects seven years of experience of the Biogas Extension Service (BES) of CAMARTEC (Centre for Agricultural Mechanization and Rural Technology) in Arusha/ Tanzania which was carried out in cooperation with Deutsche Gesellschaft fuer Technische Zusammenarbeit (GTZ), Eschborn, FRG, 1983 - 1986 as part of the Biogas Extension Programme and as part of the Special Energy Programme during 1983 1990.

We appreciate the patient cooperation of the farmers, especially during the starting phase of the programme when the technology was not yet mature.

This publication is meant as a teaching aid in agricultural colleges and as a reference book for professionals working in the field of rural biogas extension. For that reason, the ideal set-up of a biogas unit is described. The CAMARTEC Biogas Extension Service does not claim to have reached the ideal in practice, but has tried to achieve the maximum for the farmer with the least possible interference in their farm management. Used biogas plants are the best proof of an appropriate biogas unit.

Biogas Units have to be appropriate to the farmers condition. Therefore, the findings and conclusions reported here, must be seen in context with the geographical and socio-economic situation of the project area. For the coffee-banana-belt of Arumeru District of Tanzania the fixed dome plant is the most appropriate. It does not require expensive steel for the gasholder and can be operated with a minimum of daily cars. It took the CAMARTEC team quite some time to come to a reliable structure and a user-friendly layout and design. The basic problems are solved, but minor improvements may still be possible. Beginners in biogas are advised to first follow the given standard design. A non appropriate but functioning solution is still better than an appropriate one which does not work reliable. Nevertheless, we hope that CAMARTEC's experience may encourage the reader to find appropriate solutions for her or his applicable location.

CAMARTEC  
Biogas Extension Service

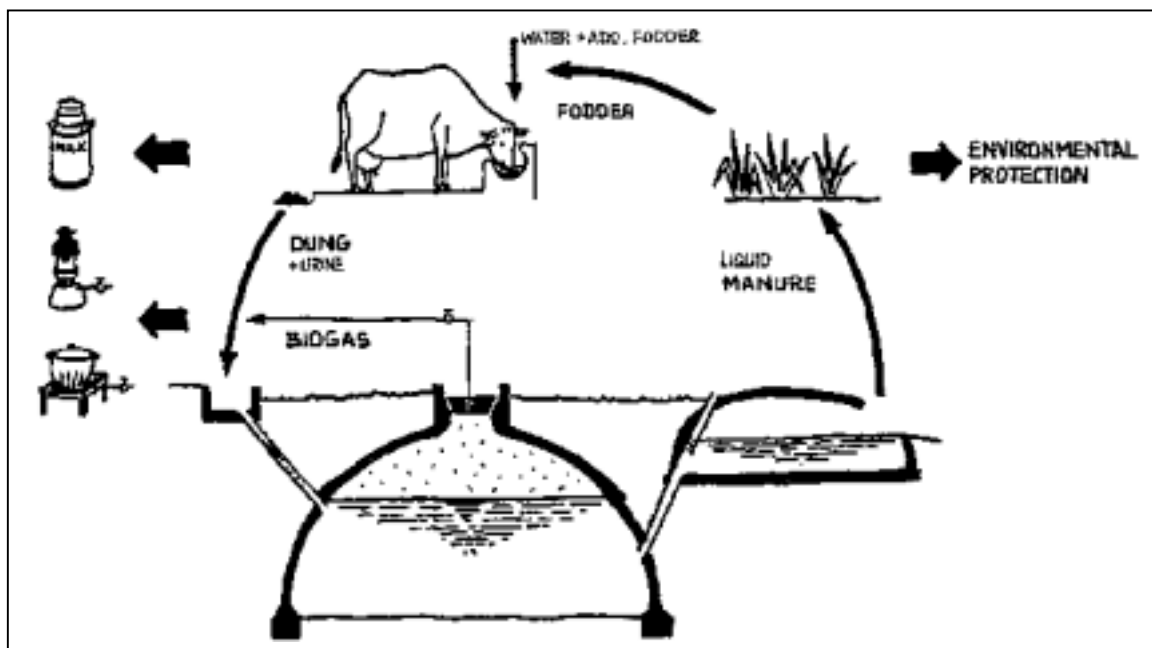
## 2. Why biogas ?

There are several alternatives to solve a farmers energy problem and there are different ways of manure management on a farm. Biogas might not be the best solution for all problems but it is one method to take care of many aspects. The biogas unit is a system in which the three components biogas plant, animal production and fodder grass plantation form a natural cycle.

Each of the three parts has direct benefits to the farmer and his economy:

- The animals generate income by supplying milk and meat.
- The gasplant provides comfort and saves expenditure by supplying clean cooking and lighting fuel.
- The fodder grass plantation creates sustainability by protecting the soil against erosion. Fodder plantation gives most profit from a small patch of land and often is less labour intensive than cutting fodder grass outside the farm. Beside the fodder grass, vegetables and fruits benefit the use of digested slurry as fertilizer.

Biogas is Just a clever way of exploiting nature without -destroying it. Biogas optimizes farm economy. Biogas Plants support self-reliance and fit in concepts of sustainable development.



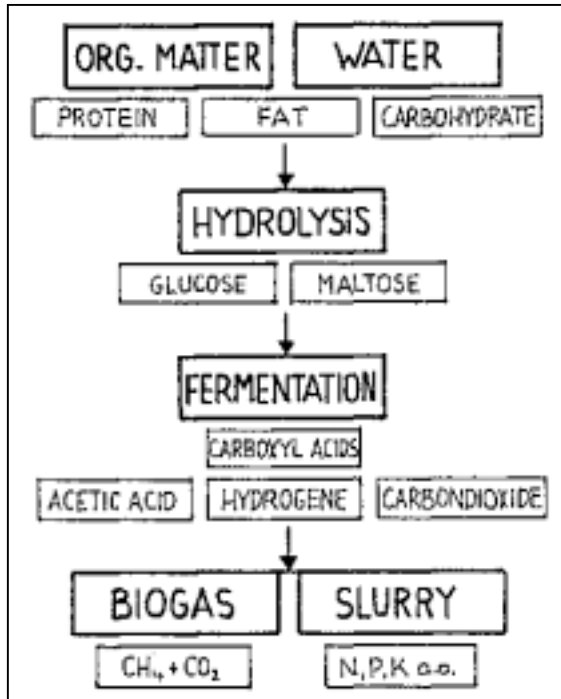
**Fig.1:** The cycle of organic matter and the benefits of an agricultural biogas unit

The animals provide dung to the biogas plant, the gasplant provides manure to the fodder plantation and the plantation provides feed to the animals. If enough water is given to the animals, no additional water is required for the biogas plant.

### 3. Explanation of terms

#### Biogas

Biogas is produced by bacteria during digestion or fermentation of organic matter under airless condition (anaerobic process). The gas consists mainly of  $\text{CH}_4$  and  $\text{CO}_2$ . This mixture of gases is combustible if the methane content is more than 50%. Biogas from animal dung contains approx. 60% methane.



**Fig.2:** The big-chemical process of anaerobic digestion

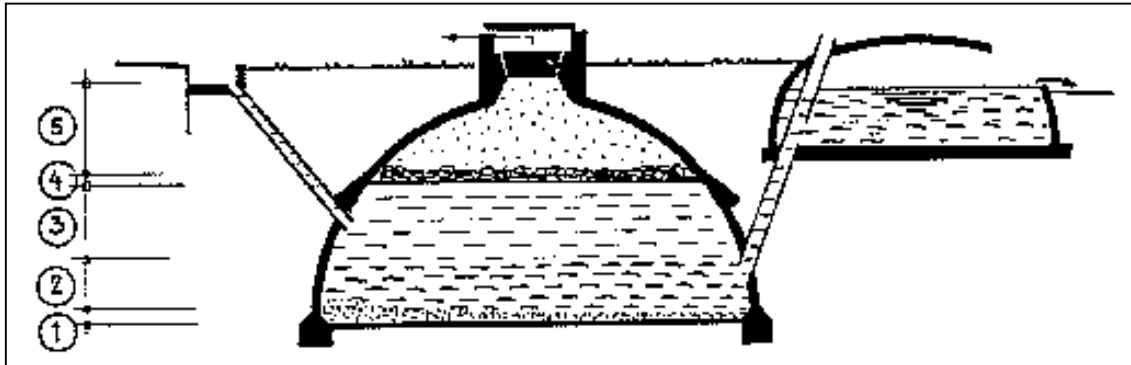
The different groups of bacteria responsible for fermentation live in an interacting eco-system. Each type of bacteria depends on others. The fermentation time is shortest when populations of different bacteria are adequately balanced.

#### Slurry

In practice, the term slurry is used for the digester content or the digested substrate flowing out of the plant. In digesters observed by CAMARTEC, slurry is found in different conditions inside the digester:

- a light and rather solid fraction, mainly straw or fibrous particles, which float to the top forming the scum
- a very liquid, watery fraction remaining in the middle layer of the digester
- a viscous fraction below which is the real slurry or sludge
- heavy solids, mainly sand and soil particles which rest at the bottom.

Slurry separates less if the feed material is homogeneous and the TS-content is high.



**Fig.3:** Slurry condition inside the CAMARTEC digester (1) Settlement of sand and soil. (2) Viscous slurry or sludge, having a TS-content of 6-7%. (3) Liquid slurry fraction, having a TS-content of 12%. (4) Floating scum, having a TS-content between 15 and 50 %. (5) Biogas.

### Biogas Technology

Biogas Technology includes everything which is needed to produce and utilize the products of anaerobic digestion which are biogas and manure. Beside energy and fertilizer. other benefits of biogas technology are improved sanitation and environmental protection. The conditions to produce biogas are:

- digestable substrate, i.e. organic matter plus water
- a vessel where the substrate is not in contact with air
- a digestion temperature between 15°C and 35°C
- a retention time longer than 30 days to allow the bacteria to produce the biogas. (The retention time is considerably reduced in industrial high-tech plants).

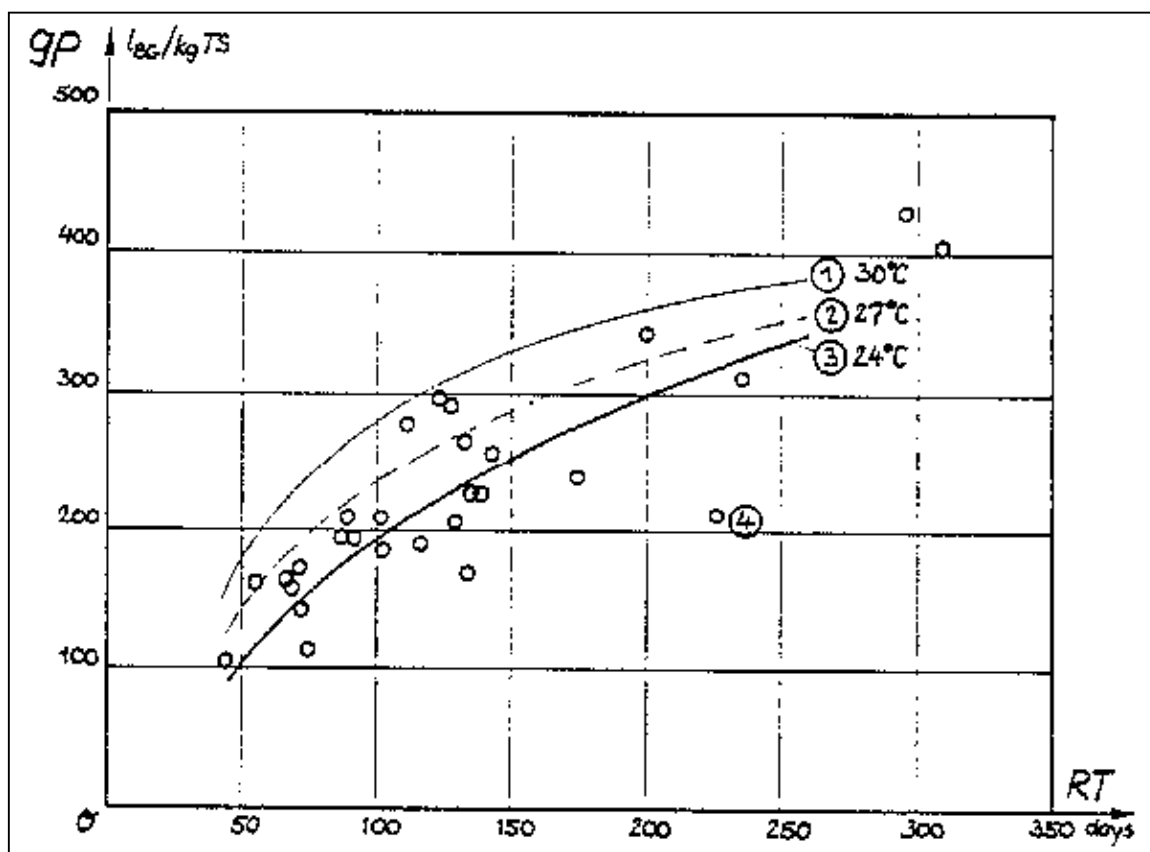
If methane producing bacteria are already present in the substrate (e.g. in dung from ruminants), biogas production begins within 3 to 5 days. At the farm site, biogas plants are filled slowly and gas production is used only after the plant has been filled completely. If there are problems with certain substrate starting the gas production, 20% of cattle dung should be mixed in the first filling as a starter.

### Gas Production

The gas production potential of a certain substrate is high when organic matter content is high and the C/N ratio ranges from 20: 1 to 40: 1. The speed of the gas production depends further on the physical properties of the substrate and the temperature (optimum at 35°C). Dry and fibrous material takes longer to digest than fine-structured and wet substrate. Favoured total solid (TS) contents of the undigested substrate are between 7% and 11% which is approximately reached if dung is mixed with an equal volume of water or urine. A healthy digestion process shows a pH of 7.0 (neutral stage of substrate).

### Biogas Plant

A biogas plant consists of the digester and the gas storage space. A continuous gas plant is charged and discharged regularly, e.g. every day. A batch-plant is filled once and emptied only after the material has been digested. A normal farmers biogas plant is a continuous plant with automatic discharge at the overflow.



**Fig.4:** Relation of gas production and retention time

The daily gas production (8p) is measured in litre of biogas produced by 1 kg of total solids (TS) added per day. The total solids content of fresh cattle dung is 15-25 %. The retention time (RT) is the calculated period of days the substrate remains in the biogas plant before it reaches the overflow. The gas production per day depends on the slurry temperature.

Curve (1) is taken from different sources at 30°C, mainly from India. Curve (2) shows results from field research by UNDARP/BORDA in India on floating drum plants at a temperature of 27°C. Curve (3) is the average gas production with CAMARTEC fixed dome plants at 24°C average digester temperature. The points (4) show some selected samples of CAMARTEC plants of average performance, recorded during the BORDA Biogas Survey 1988. Performance is defined as daily gas production per square root of the total solid content of the daily fed substrate times the active digester volume  $(8p \cdot (TS \cdot VD)^{-0.5})$ .

Biochemical problems are rare, even in simple gasplants. Technical problems may occur with immature designs and unsuitable, i.e. scum forming, feed material. There are three well performing and mature designs available which are suitable for farm households:

- the fixed dome plant
- the floating drum plant
- the plastic covered ditch.

In most large scale extension programmes fixed dome plants have been chosen for dissemination because they are long lasting and cheaper than the floating drum plant. Fixed dome plants need the

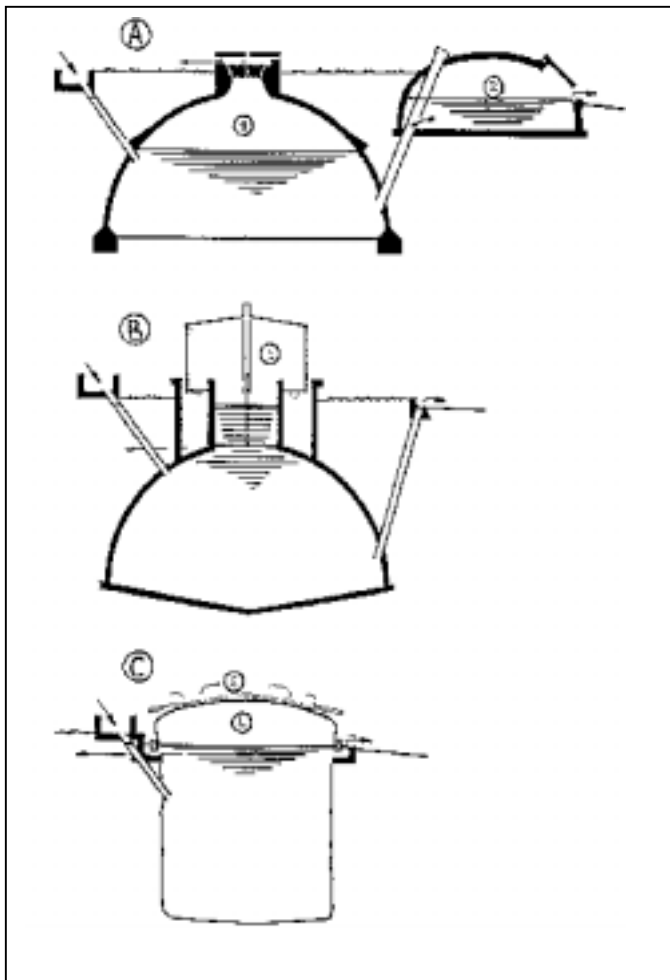
least maintenance of all other types. But building them requires great care in design and workmanship. Once they are constructed well, they are robust and of reliable performance.

The size of the digester depends on the required digester volume (VD) which is found by multiplying the wanted retention time (RT) with the volume of daily fed substrate (VS). In fixed dome plants, the active digester volume is defined by the digester volume below the zero-line, minus half the expansion chamber volume below the overflow line.

The gasholder volume (VG) depends on the daily gas production and the pattern in which the biogas is used. If gas consumption is regular and equally distributed over day and night and from day to day, gas storage space can be small. Irregular and rather concentrated gas consumption demands larger gas holder.

Experimental biogas plants for schools can be made out of 4 kg paint-tins (Ø 17,5 cm) and 2 kg milk powder tins (Ø 15 cm). The gas valve of such a floating drum model is made by a U-pipe filled with water. For gas release, the water is drained off and must be re-filled for closing the valve again.

#### Fixed Dome Plant



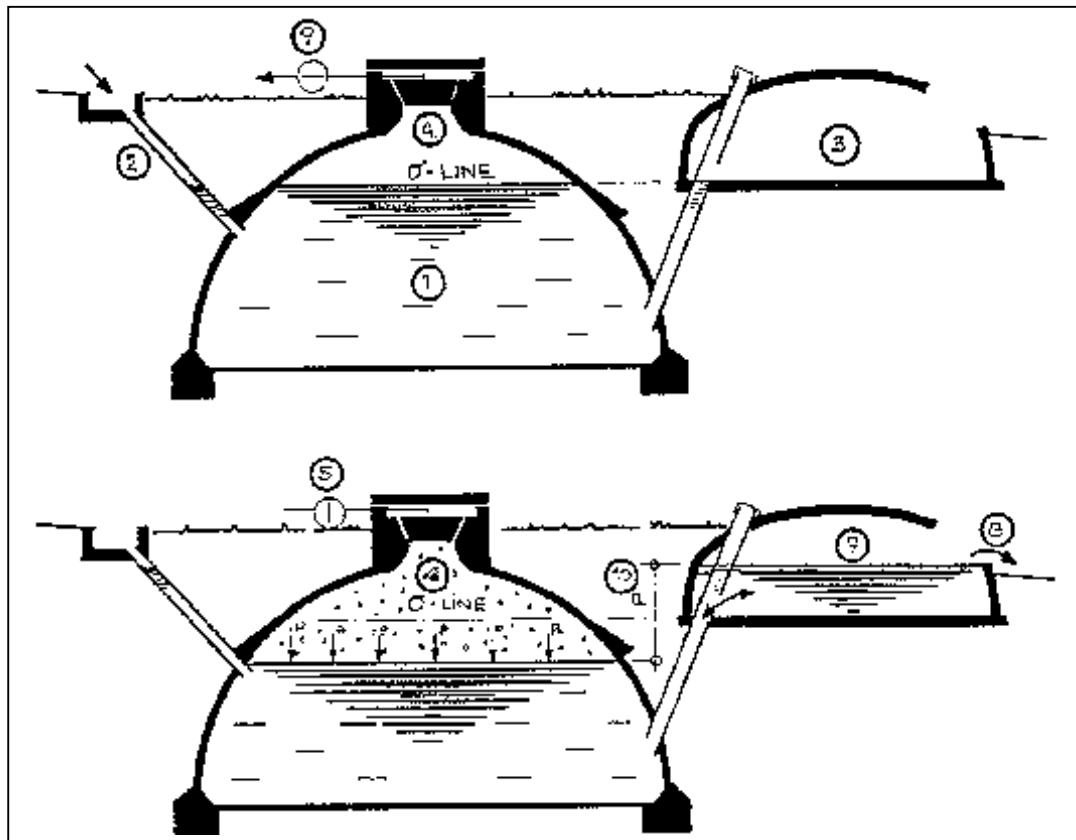
In fixed dome plants the gas is stored in the upper part of the rigid digester structure. Fixed dome plants are sometimes called "Chinese" or "hydraulic" digesters. The accumulating gas needs room and pushes part of the substrate into an expansion chamber, from where the slurry flows back into the digester as soon as gas is released. The volume of the expansion chamber is equal to the volume of gas storage. Gas pressure is created by the difference of slurry levels between the inside of the digester and the expansion chamber. The main building material is plastered brickwork.

**Fig.5:** Small-scale biogas plants for rural areas in tropical countries

(A) Fixed dome plant. The gas collects in the upper part of the digester(1) and displaces the slurry into the expansion chamber(2).

(B) Floating drum plant. The gas collects in a floating steel gas holder (3) which rises according to the volume of gas production.

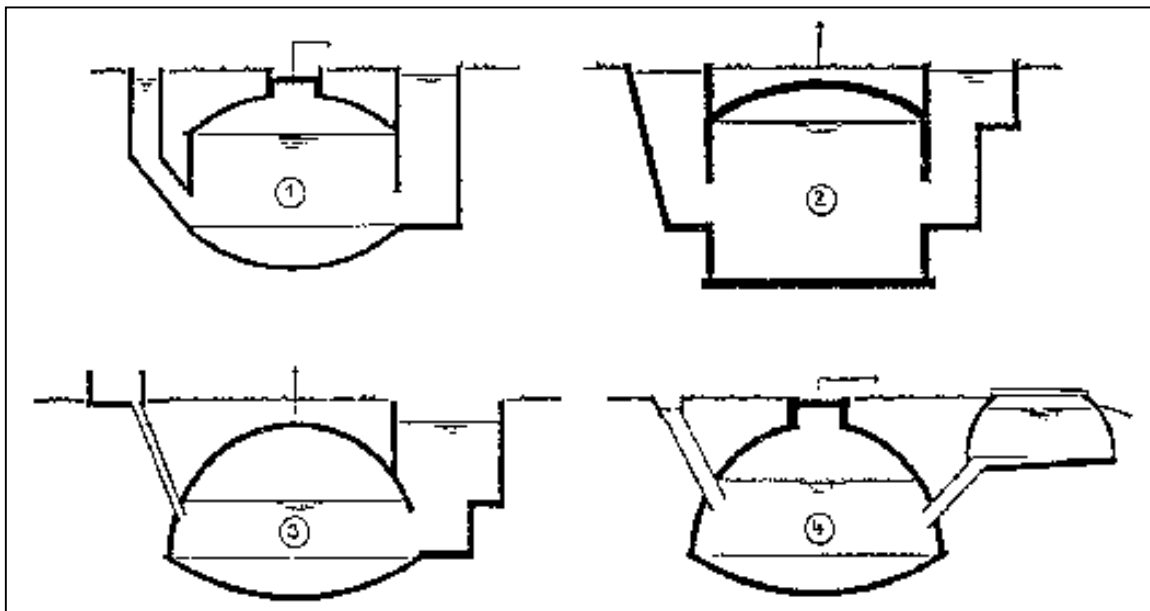
(C) Plastic covered biogas plant. The gas is collected under an inflating plastic cover (4). A wooden roof (5) protects the plastic against sunlight and increases the gas pressure by its weight.



**Fig.6:** System of the fixed dome plant

The digester (1) is filled via the inlet pipe (2) up to the bottom level of the expansion chamber (3). The level of original filling is called the zero line. The gasplant is closed by a gas-tight lid (4). Under the airless (anaerobic) condition, biogas is produced. When the gas valve (5) is closed, biogas collects in the upper part of the digester, called the gas storage part (6). The accumulating gas displaces part of the slurry into the expansion chamber. When the expansion chamber is full, slurry overflows into the slurry drain for use as manure. When the main valve (9) is opened, the gas escapes off the gas storage part until the slurry levels inside the digester and inside the expansion chamber balances. The gas pressure "p" depends on the prevailing difference of the slurry levels (10).

The substrate is filled daily so that slurry flows out daily at the time when large amount of gas is stored. Regular gas consumption requires smaller gas storage space. Consequently, the zero-line will rise. While daily feeding of the plant continues, gas is released before the slurry reaches the overflow level. The slurry level rises also when there is gas leakage. The level in the expansion chamber at zero gas pressure indicates the level of the zero line. The volume of slurry above the zero line inside the expansion chamber is equal to the gas storage space.



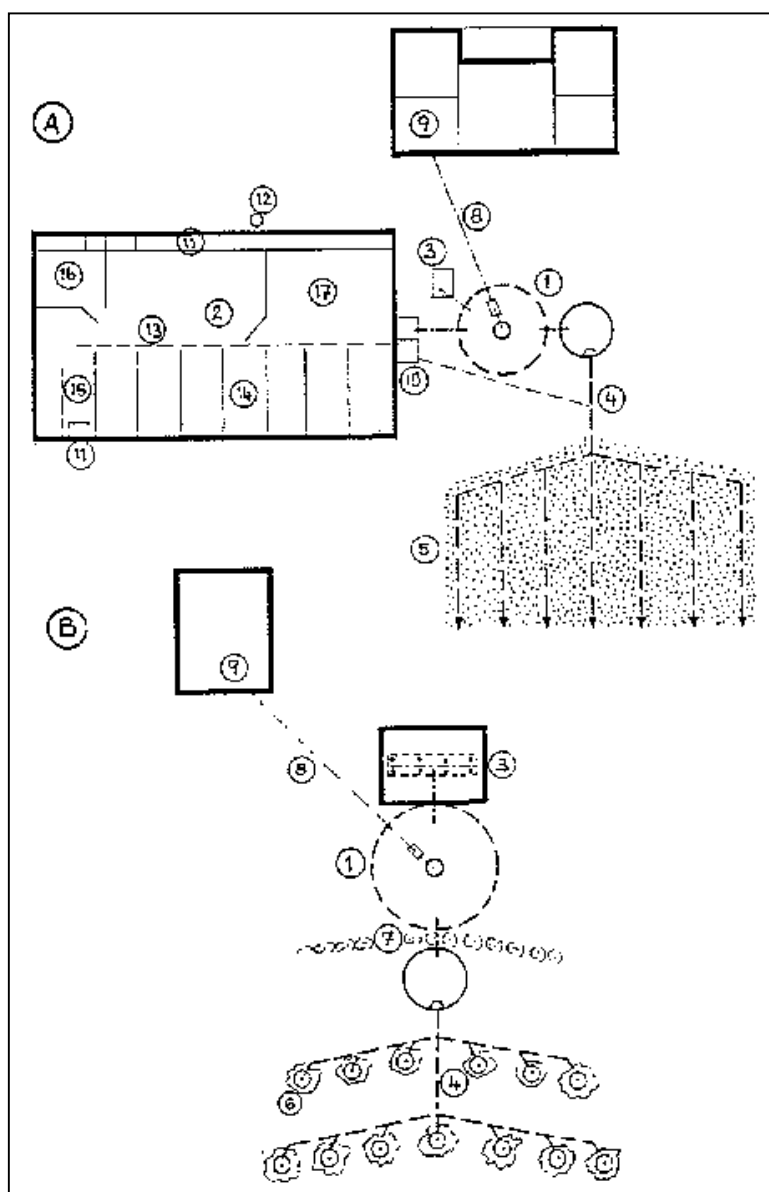
**Fig.7:** Different models of fixed dome plants Fixed dome plants originate from China and were built already before 1960. Several variations with or without a removable cover at the top have been developed. (1) Biogas plant from Chengdu/China; (2) Janata Plant from India; (3) Dheenbandhu Plant of AFPRO from India; (4) Modified BORDA plant from Cankuso in Burundi..

#### Biogas Unit

The terminus "biogas unit" should underline the importance of integrated planning when applying biogas technology. The biogas unit describes the total package offered to the farmer in connection with biogas extension work. The main components are: The biogas plant itself, the stable, the toilet, the slurry storage pit, the slurry distribution canals, the gas piping system, the appliances and the tools to handle the substrate. In individual cases other components could as well be part of the biogas unit, for example, rain water tanks, fish ponds, compost pits, demonstration fields, gas generators or engines with their attachments, etc., etc. one may distinguish between agricultural biogas units and sanitary biogas units.

The big-latrine is the centre part of a sanitary biogas unit. The septic tanks of big-latrines are designed as integrated fixed dome biogas plants. Sanitary aspects, i.e. rather maintenance-free but clean toilets, are more important than a high gas production.





**Fig.8:** Principal lay-out.(A) Agricultural Unit; (B) Sanitary unit

(1) Biogas plant; (2) Cattle stable; (3) Toilet; (4) Slurry distribution system; (5) Fodder grass or vegetable plantation; (6) Shrub or tree plantation; (7) Hedge between public area and slurry area; (8) Gas pipe; (9) Place of gas consumption; (10) Dung and urine collection chamber; (11) Fodder trough; (12) Chaffing block; (13) Urine drain (14) Sleeping boxes; (15) Milking stand; (16) Calves' box; (17) Exercising area, separated for cows and heifers.

### Biogas Appliances

Biogas Appliances are pieces of equipment for utilizing the energy of the gas. Either special biogas appliances are used or LPG equipment is adapted. Biogas is mainly used in stoves for cooking and in gas lamps for lighting. Frequently, refrigerators and incubators, coffee roasters, baking ovens and water heaters, chicken or piglet heaters, Power engines for milling or generating electricity are fuelled with biogas.

## Biogas Extension Service

The biogas extension service (BES) comprises of the organization, the staff and the logistic needed to work for the extension of biogas technology. The BES might be a governmental body, a non-governmental voluntary or commercial organisation or a development project of international cooperation. Normally, the costs for the superstructure of the extension work are not included in the price the gasplant owner has to pay. Because of the benefits for the society as a whole it is justifiable to cover the cost of the superstructure from public funds.

## 4. Biogas extension work

### General

The following chapter describes extension work within the framework of a project dealing exclusively with biogas units. But most of the points are also relevant when biogas extension is promoted within more general development programmes.

### Target Group

The target group of a rural biogas extension programme are farms having at least 50 kg of cattle dung (or 35 kg of pig droppings) available per day' which means they have at least three milk cows or 10 adult pigs fully stable bound, or nine heads of local cattle half stable bound There are several conditions to be fulfilled before a farmer of the target group becomes a customer:

- He has to have enough income to buy a plant or repay a loan.
- He must be educated enough to understand the system.
- He must know about biogas and its suitability for his individual case.
- He must have easy access to sufficient water.
- He has no real fuel alternatives.

### Standardization

Standardization means to define exactly and restrictives the materials, measurements and methods off the work. Given standards must be clear and universally adaptable.

Technical standardization is needed because it can not be expected that an artisan or farmer will fully understand the essentials of a biogas unit. Biogas plants are easy to construct but difficult to comprehend totally. Artisans must be trained to precisely observe all details and methods of construction. This is especially important for extension programmes that aim at handing-over the construction activities to the private sector, where permanent quality control is difficult. It should also be mentioned, that management training of artisans is needed to improve the efficiency of the enterprise and thus the quality of workmanship).

A farm benefits from a biogas plant if the plant works trouble free, gas and slurry are used profitably and operation of the plant is comfortable and easy. In fact feeding the plant must be less labour intensive than not feeding the plant. This user-oriented approach leads to a standardized biogas plant, if possible, connected to a standardized stable which are integrated as much as possible into the existing farm economy.

### Strategy

The final goal of the extension project is to have independent artisans who construct standardized biogas units on demand of independent farmers against appropriate payment. connection to zero-grazing units is favoured.

Each biogas extension project starts by building demonstration units at selected farms which might be fully subsidized. The farmers must be willing to cooperate with the biogas extension service by allowing potential customers to visit their installations. It is most important that those farmers maintain and utilize their gasplants well.

After sufficient number of demonstration units have been installed, further biogas units are only constructed on demand and against full payment. Payment is usually done in 2 to 3 instalments. It is helpful to have standardized procedures for application, payment and realization of the construction (see sample of forms in the appendix).

When a potential customer first comes to the Biogas Extension Office he is given general informations including a price list. He is asked to file a written request which describes his farm and the proposed site of construction. Then the site is visited by BES-staff, assessments are made, technical details are worked out and a fixed price is given to the farmer.

After a contract agreement has been signed and a 50% down payment has been made, the biogas unit will be erected by trained private contractors under supervision of BES-technicians. When the construction is finished, the plant has been filled, appliances are connected and the final payment has been made, the unit is legally handed over to the customer. The customer receives a user manual, detailed explanations about plant operation, gas and slurry utilization and maintenance in his specific case. The customer is also given a set of tools and equipment for cleaning the stable, chopping the fodder and handling the slurry.

The main points of instruction are:

- to keep the overflow free from slurry
- to check the water trap from time to time, especially when there is no gas available for consumption
- to clean the burner regular like other cooking vessels
- to poke from time to time the inlet and outlet pipe, especially if substrate does not enter the plant
- how to change the mantle of the gas lamp
- the meaning of the slurry level in the expansion chamber
- where to turn to in case of problems the farmer cannot solve himself

The biogas unit is then visited once a month until the persons attending the plant are acquainted with the daily routine work and the utilization of gas and slurry.

#### Advertisement

As a principle, the farmer should decide freely whether he wants to have a biogas unit or not. Therefore, advertisement means mainly information and awareness building. Image cultivation is also a part of the publicity work. The biogas unit is presented as a clever way of running a modern farm unit. Well operated biogas units are the best advertisement.

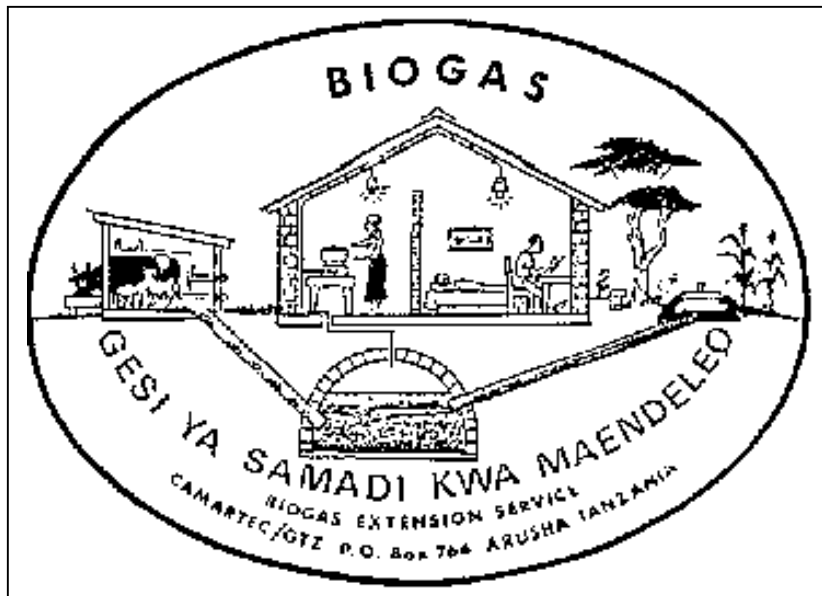


Fig.10: A Biogas sticker used by CAMARTEC for advertising

### Special Requests

Besides the standard applications for biogas plants there will always be special requests for individual solutions reaching the Biogas Extension Service. Special requests often demand individually designed units which differ either in size or proposed utilization of gas or slurry. The BES has to keep planning and supervising capacity for such services' because they often are requested by VIPs (Very Important Persons) who are important for the support of the biogas programme.

### Research and Development

In addition to standardization, research and development needs will arise from the project activities. New ideas have to be tried out which will disturb the standardized routine. To minimize problems and preserve the standard of quality of construction, innovations and modifications should be restricted to a few that really improve the performance of the biogas unit or eliminating severe short-comings.

As for CAMARTEC, the most important research was the development of the weak-ring and the strong-ring. Tests on reducing the requirements for gas-tight plaster are under way. Own appliances have been developed and others from outside have been tested. A bench-scale test has been carried out to define the flow of slurry inside the digester more exactly.

## 5. The agricultural biogas unit

### General

Most faults in biogas units are caused by planning mistakes. Siting of the biogas plant and layout of the biogas unit is as important as the construction itself. A good biogas plant at the wrong place is a useless installation. Similarly, filling a plant with unsuitable material will result in an unproductive unit. Careless planning of the site may require unnecessarily additional structures or cause further labour input. Thorough inspection and assessment of site are preconditions for a profitably functioning biogas unit. This is especially true when using standardized structural elements;

### Survey of Site

BES staff first check the proposed feed material for its suitability. After observing the overall environment of the farm, the master plan of the biogas unit is made on the spot in cooperation with the persons having decision making power at the farm. The technician must check if the space is sufficient and must take the levels of the proposed structures. Planning the utilization of slurry is probably the most important point to be discussed at the first site meeting with the farmer. The cost of the slurry distribution system should be calculated and made known to the farmer before starting the construction.

To allow swift construction work, access for transport and place for storage of material and excavated soil must be clear before starting. The farmer must be informed about providing approx. 500 l of water per day during the building period for masonry and concrete construction. There must also be agreement as to which building materials are to be provided by the farmer and which quality requirements are to be observed.

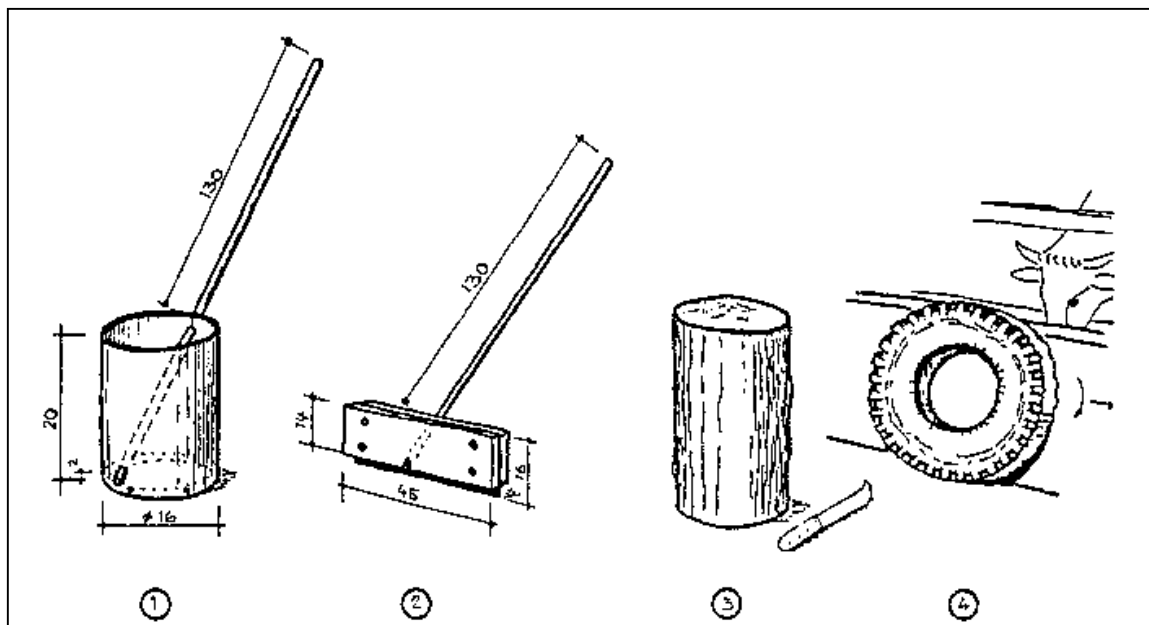
The BES staff writes a report about the findings and assessments and gives reasons for decisions made at site. This is required to keep colleagues at the BES headquarter informed. Such records are also helpful in case of customers trying to save money by constantly complaining about the plant's performance.

### Tools and equipment

There are three essential tools which are given to the farmer because they are part of the biogas unit:

- The dipper to scoop urine and water from the urine chamber into the mixing chamber and to take out and pour slurry in case of compost preparation. Several designs have been tested. The most durable solution was found to be a dipper made from a Ø 6" plastic pipe and a 1,30 m long wooden handle. The handle passes through both rims of the pipe and is fixed with a nail to the upper rim. Dippers from metal proved to corrode quickly and handles fixed on a shaft broke within a short time.
- The squeegee is used to clean the stable floor with only a little water, pushing the urine into the urine chamber and the solids into the mixing chamber.
- The chopping block is needed to chaff the fodder with a panga (machete). Chaffed grass is eaten completely by the animals without leaving the stems or allowing them to be tossed out of the trough where they would mix with the dung and might block the biogas plant. The chopping block can be a standing solid log of wood but it is better to use the wood across the fibre to avoid the knife getting stuck. Truck tires have proved to be an elegant solution instead of wooden blocks because the knife jumps up by itself when chaffing the grass. Mechanical chaff-cutters are, of course, an even better solution.

As farmers are not aquatint with this kind of equipment, It is best to provide these in order to stress the importance for adequate operation of the biogas unit.



**Fig.12:** Necessary equipment to operate a biogas unit

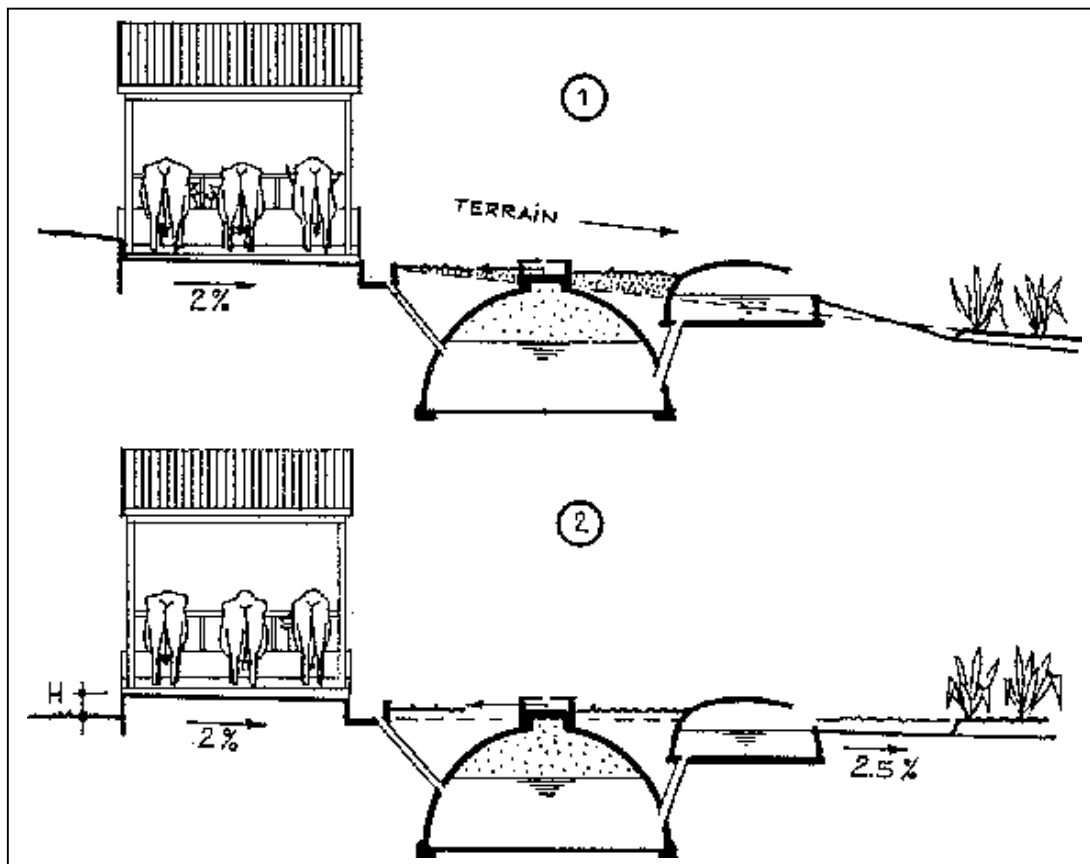
(1) Dipper made of a piece of plastic pipe with a wooden handle coming through. (2) Squeegee made from wooden boards with tyre rubber clamped between and wooden handle coming through both the boards and the rubber lip. (3) Chopping block or (4) used truck tyre for chaffing of fodder grass. The tyre leans against the trough and may be rolled to the place of use.

### Principles of Layout

A biogas unit is a considerable investment. It should not be looked at as a temporary structure.

The agricultural biogas plant belongs to the stable. Without any exception. The distance to the kitchen is of secondary importance. With fixed dome plants, there is no practical limitation to the length of gas pipes, except for the cost. As a matter of principle, sustainability has first priority over cost reduction. This means that everything must be arranged in such way that it is less work to feed the plant than not.

On sloping ground, the stable lies higher than the biogas plant. On flat grounds the floor of the stable might be elevated in order to allow dung and urine to enter the plant by gravity. Handling of slurry demands high labour input and can be avoided by proper planning. The outlet of the biogas plant is directed towards, or drains into, the fields. Overflowing slurry should never be allowed to accumulate on neighbour's or public ground. The biogas unit must be functional even when attendance and maintenance is poor. The owner has the final decision, but he often can not oversee the consequences of a decision. Beware of false compromises!



**Fig.13:** Position of gasplant to stable floor The ideal situation is a sloping ground, falling from the stable via the gasplant to the crop plantation (1). On horizontal ground (2), it might be necessary to lift the floor of the stable (H).



## 6. Construction of the biogas plant

### General

The overflow of the biogas plant must be higher than the slurry bed or the slurry distribution channel. The inlet must be lower than the stable floor. The biogas plant should be so far from trees that roots will not grow into its brickwork. It should not be in areas where heavy machinery move frequently. Biogas plants are not meant to be a playground, still they should be safe for children and animals.

A gasplant of a rural biogas unit is standardized and preferably a fixed dome plant. Once the decision for standardization is made, modifications are only allowed in order to join existing local structures. The plant itself is not to be changed.

The size of the plant depends on the substrate available. In practice its volume is chosen according to the number of cattle or pigs and their stabling. In case of doubt, the energy demand may also be considered. The biomethanation process is rather hardy and robust and does not require defined loading rates. Therefore, it is possible to consider only a few standard digester volumes. The standard volumes of digester and gasholder have to be estimated in each project area according to gas production rates and general gas consumption patterns.

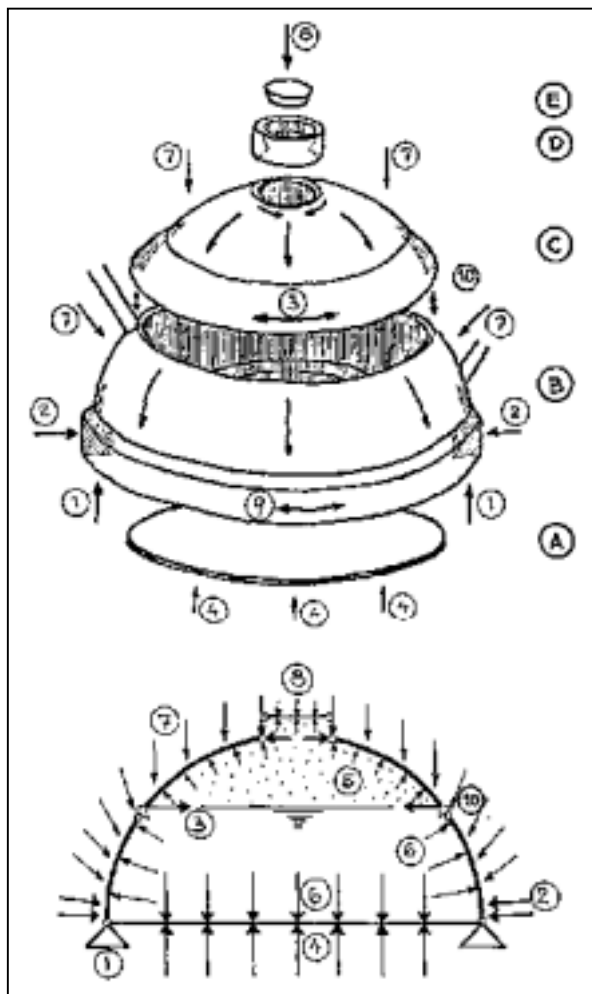
Larger gasplants have longer retention times and, therefore, higher gas production rates. Nevertheless, the amount of daily fed substrate has more influence on gas production than the volume of the digester. In case of doubt, criteria used are the investment costs and security of gas supply. Larger gas plants have higher gas storage capacity.

The most common size in the Arusha Region is the 16 m<sup>3</sup>-plant which can provide gas for cooking and lighting for a normal family. The 12 m<sup>3</sup>-plant is reserved for places of little gas demand, e.g. small families, or where ground temperature is above 24°C and therefore, retention time could be less. 30 and 50 m<sup>3</sup>-plants provide gas not only for household use but fuel for big institutional kitchens and special appliances like refrigerators, incubators, hatching heaters or power engines, etc. Structural drawings for the standard plants are to be found in the Appendix.

### The Principle Design

The standard fixed dome plant has a half-bowl spherical shape with flat bottom and a top opening. The outer walls rest on a foundation ring beam. The floor has no static function. The upper part of the sphere is separated from the lower part by a joint, called the "weak ring". Gas tightness of the upper part is achieved by a crack-free structure and a gas-tight inner surface plaster.

The Inlet pipe is connected to the spot of dung disposal in the stable. The outlet pipe connects the digester with an expansion chamber of reduced spherical shape. The overflow of the expansion chamber - really the final outlet of the gasplant - leads to the slurry disposal system, i.e. the distribution channel, storage tank or compost pit.



**Fig.14:** Principle of statics of fixed dome plant

The plant consists of a non-load bearing bottom (A), the lower slurry-tight digester (B), the upper gas-tight gas storage part (C), the neck (D) and the gas-tight lid (E). Gas storage part and digester are separated by the weak-ring (10) in order to allow free reaction of the strong-ring (3) and to prevent cracks which have developed in the lower part of the digester to "grow" into the gas storage space.

The plant rests on a foundation ring (1) bearing mainly the vertical loads of the construction and the soil cover (7). The surrounding soil supports the construction to resist gas pressure (5) and slurry pressure (6). Concrete at the outside of the lower layer of bricks (2) helps to reduce tangential forces at the foot point (9). The ring forces of the upper part are absorbed by the strong-ring (3).

### The Reference Line

Because the slurry is a liquid, the biogas plant follows the physical law of communicating tubes. A reference line is used in construction to keep the exact levels, which are of outmost importance for the functioning of the system. Main vertical measurements of the working drawings are given in relation to the reference line. The reference line is 35 cm above the overflow of the expansion chamber and marks the lowest possible point of the stable floor from where the dung is pushed into the mixing chamber. It is also the minimum level for soil covering of the dome.

At the site, the reference line is marked by a string passing over the centre of the digester, preferably in direction from inlet to outlet. The string is fixed in absolute horizontal position with a spirit or hose-pipe level. The pegs for the reference line should be sturdy and well protected during construction time. In order not to lose the level of the reference line it is advisable to also mark it on a tree or a building near to the plant.

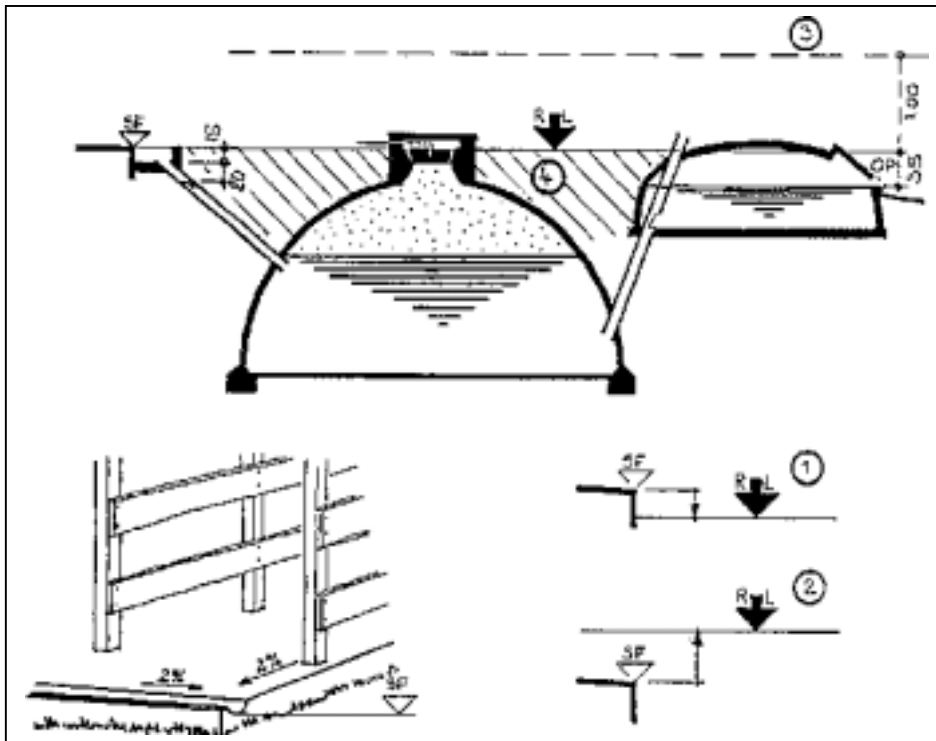
In case there is an existing stable, a horizontal string is fixed from the lowest point of the floor to the place of the proposed overflow of the expansion chamber. The overflow might be 35 cm or more below this string. The convenient overflow level might be decided and the string of the reference line is tied 35 cm above that point. In all cases, it will be at, or below, the lowest floor level of the stable. In case of a 16 m<sup>3</sup> standard plant, the centre of the digester is 3,30 m away from the inlet point. The point of overflow is 5,00 m away from the centre.

In case a new stable will be constructed, the point of overflow of the expansion chamber might be decided according to the convenience of slurry disposal. A horizontal string 35 cm above this point forms the reference line. The lowest point of the stable floor might be on the same level or preferably above the reference line; but never below this level. In case of a 16 m<sup>3</sup> standard plant, the centre of the digester is 5,00 m away from the point of overflow. The inlet chamber attached to the stable is 3,30 m away from the centre.

#### Digging the Pit and Casting the Foundation

For safety of the labourers, the sides of the pit must be sloped according to the soil properties. Excavated soil should be placed 1 m away from the rim of the pit. Place of inlet and expansion chamber should be kept free from excavated soil.

The pits of the digester and the expansion chamber are excavated in their proper sizes and positions down to their respective final depths. If soil is soft or of unequal strength, stone or sand packing below the foundation is required. Provide drainage facilities in case of ground or hill water.



**Fig.15:** The reference line

The reference line (RL) is marked by a string during construction to maintain proper levels of essential parts of the gas plant. The lowest point of the stable floor (SF), i.e. the lowest point of the urine drain, must be 35 cm above the overflow point (OP) in order to allow sufficient depth (min. 15 cm) of the inlet chamber. On uneven ground it may be required to fix the string 1 m above the real reference line. Then, 1 m must be added to all measurements. The reference line may be lower than the stable floor (1). It should never be higher as to avoid lifting up the feed material for filling the plant. The reference line also marks the necessary soil cover above the dome (4).

The foundation ring is excavated immediately before filling the concrete of the foundation. A mixture of 1: 2: 4 (cement: sand: aggregate) is used and the concrete is firmly rammed. Casting of the foundation should be done early in the day as to allow sufficient time to place the first two layers of brickwork into the fresh concrete at the same day. These two layers are back-filled with a lean concrete mixture of 1: 3: 9.

## Brickwork of Spherical Wall

The centre point at the bottom of the digester is the heart of the construction. The centre peg should be firmly driven in at proper position and level according to the reference line. A nail on the head of the peg marks the exact centre.

To construct the spherical masonry wall, a guide stick is used which keeps the radius constant and helps to create an absolute half bowl shape. Each brick of the wall is laid against the nail of the radius stick. It is easier to do than to describe. Just start putting brick by brick, keeping the top of the brick in the same slope as the direction of the radius stick, which is radial, pointing to the centre. Automatically, brickwork will turn out in spherical shape.

Bricks must be of good quality, preferably of 7-12-23 cm in size. If bricks are less than 5 cm in thickness they should be used in flat layers. The wall becomes then 10-12 cm thick and more bricks will be required. The bricks are soaked in water before laid into 1 cm mortar bed of mixture 1: 1/4 : 4 (cement: lime: sand). Gauge boxes are used to measure the volumes for mixing the mortar. Only sieved and washed river sand is permitted; otherwise the amount of cement must be increased if only quarry sand is available. Vertical Joints should be "squeezed" and must, of course, be offset. The inner edge of the brick forms always a right angle with the radius stick.

## Inlet and Outlet Pipe

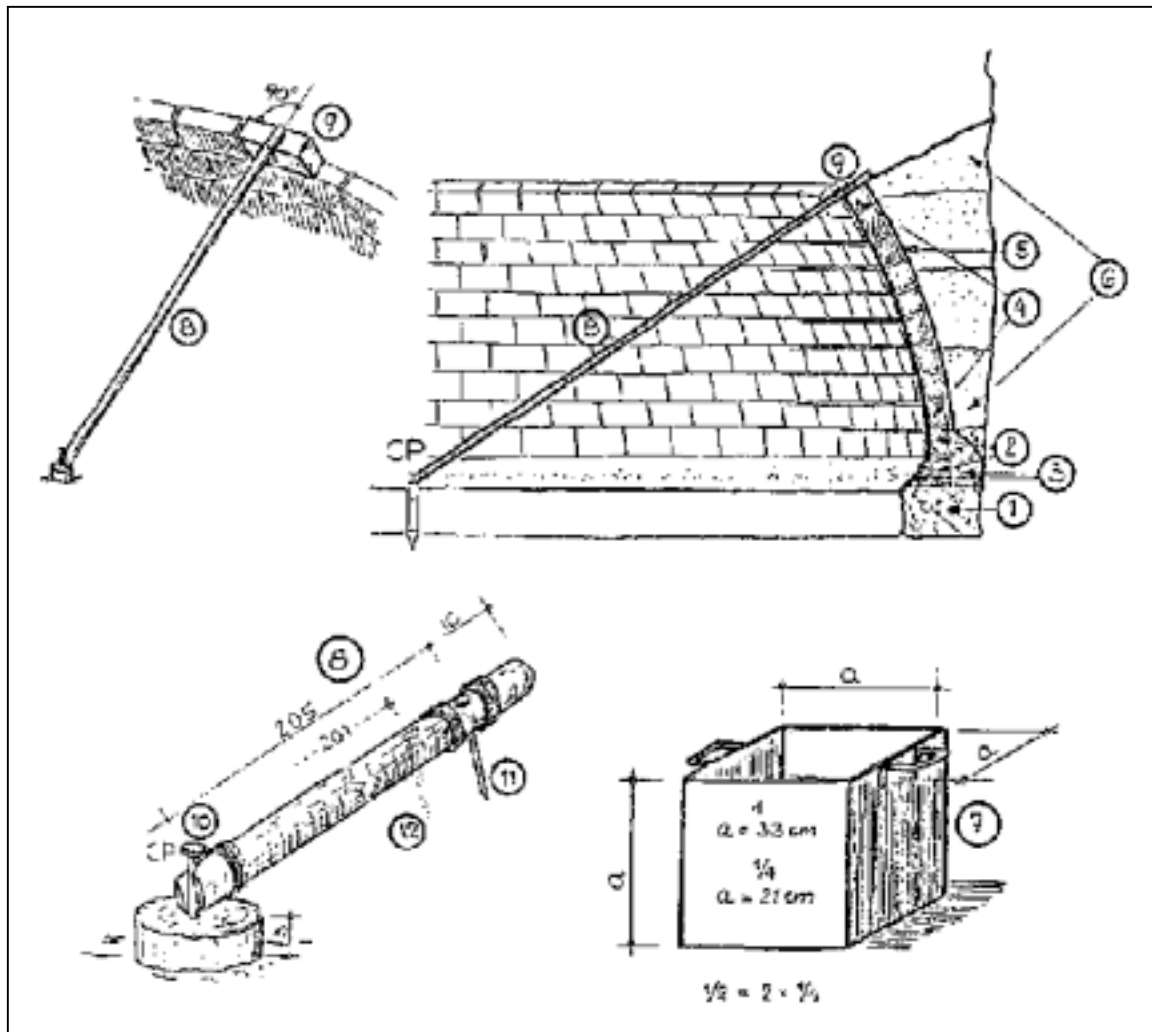
Inlet and outlet pipe must be placed in connection with brick-laying. It is not possible to break holes later into the spherical shell; this would spoil the whole structure. The pipe rests below on a brick projecting 2 cm to the inside. Above, it is kept in position by being tied to pegs at the rim of the excavation.

The inlet pipe is of 10 cm (4") diameter. Its upper side is in line with the top of the weak ring. The outlet pipe which connects the digester with the expansion chamber is of 15 cm (6") diameter in order to avoid clogging. It starts at the bottom at the 4th layer of bricks and continues above the dome of the expansion chamber to allow poking in case of blocking. A collar of cement mortar 1: 1/4: 4 at the outside of the wall seals the Joint between the outlet pipe and the brickwork. At the level of the expansion chamber it is cut out to allow for slurry flowing in and out.

## Outside Plaster of the Lower Part

Only sieved and washed river sand is to be used for plaster. After brickwork has reached the level of the weak ring, smooth plaster of 2 cm thickness and of 1: 1/4 : 4 mixture is applied all over the outside. The plaster should harden over night before back-filling of soil is done.

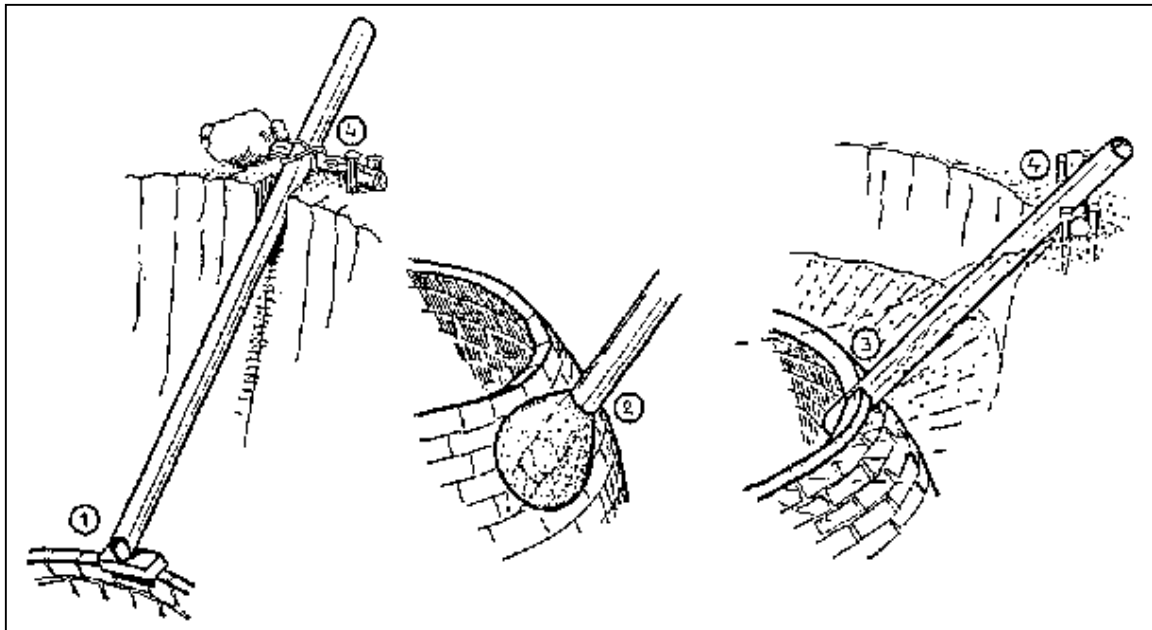
The outer plaster protects the brickwork against roots growing into the joints. It forms also a smooth surface which reduces friction between soil and structure and thus, reduces static stress of the brickwork.



**Fig.16:** Construction of the lower part of the sphere

(1) Foundation ring of concrete 1: 2: 4; (2) First two layers of bricks laid in cement-lime mortar 1: 1/4 : 4; (3) Supporting concrete ring 1: 3: 9; (4) Brickwork up to the bottom of the weak ring laid in mortar 1: 1/4 : 4; (5) 2 cm thick outside cement-lime plaster 1: 1/4 : 4; (6) Backfilling soil rammed in layers of max. 30 cm height.

For measuring the correct mixtures a gauge box is used (7). The brickwork is erected with the help of a radius stick (8). The radius stick is set at the centre of each brick. The surface of the brick follows the direction of the radius stick (9). It rests with a groove at the nail of the centre point (10). Because the floor has not yet been laid, the peg of the centre point is 3 cm above the excavated ground. The upper nail (11) of the radius stick (11) marks the inner edge of the brick. The measure of the stick is reduced by 4 cm for placing the headers of the strong ring (12). When laying the bricks, they are first knocked horizontally, then vertically.



**Fig.17:** Inlet and outlet pipe

The outlet pipe (Ø 6" ) rests on a flat brick (1) above the 4th layer of the spherical wall. At the outside of the wall it is surrounded by a mortar collar (2). The inlet pipe (Ø 4") penetrates the weak-ring (3). The pipe is not allowed to be higher than the top of the weak-ring, because it would then disturb the strong-ring. From the outside it is sealed only by the plaster of the lower brick work. At the top, the pipes are kept in position by pegs (4).

#### Back-filling

Once the digester is in use, the brickwork is under high pressure from the inside and therefore, must be supported from the outside by firmly back-filling of sand. The first two lines of brickwork are back-filled by lean concrete, mixed in ratio 1: 3: 9 as described before. Back-filling is done one day after the outside plaster is completed; layers not exceeding 30 cm are firmly rammed. Only sand or non-bounding soil is suitable for back-filling. Pure sand may be washed in instead of ramming.

#### The Weak-Ring

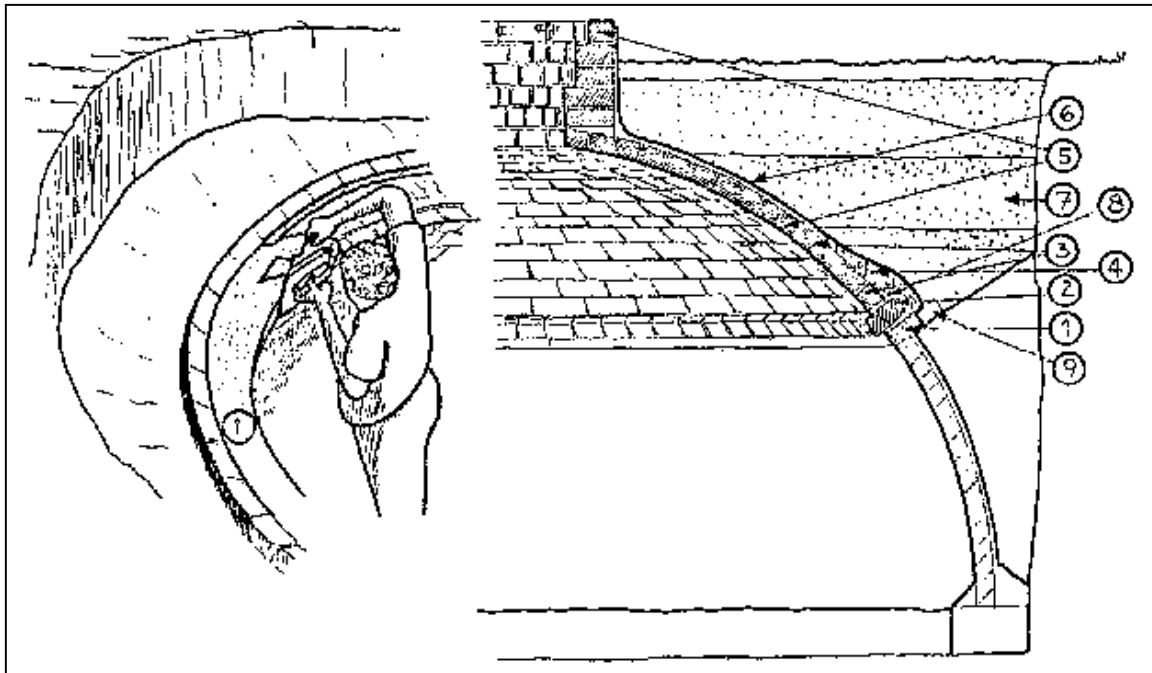
The weak-ring separates the bottom part of the digester from the gas storage part. The weak-ring shall prevent vertical cracks of the bottom part entering the upper part which must be gas-tight as it is the gas storage space. Vertical cracks are diverted into a horizontal crack remaining in the slurry area where it is of no harm to the gas-tightness. The weak ring acts as a swivel-bearing allowing free movement of the above strong ring.

The weak ring is formed by a 5-7 cm thick layer of lean mortar having a mixture of 1: 3: 15 (cement: lime: sand). The top of the weak ring restores the horizontal level. It is interrupted only by the inlet pipe passing through.

#### Brickwork above the Weak-Ring

The upper part starts above the weak ring with a strong ring to receive tension forces from the dome. It can be seen as a foundation of the upper part of the spherical shelf. It consists of a row of header bricks with a concrete package at the outside. In case of soft or uncertain ground soil one may place a ring reinforcement bar (Ø 10 mm or 2-Ø 6 mm) in the concrete of the strong ring. The brick of the strong ring should be about three times wider than the brickwork of the upper wall. In

practice this would mean a width of the full brick laid in headers if the spherical wail is of quarter brick. The radius stick must be changed to reduce the radius by 4 cm for Placing the bricks of the strong ring properly.



**Fig.18:** Wall construction of the upper part of the dome

A row of temporary bricks is laid on the backfilling soil to mark the outer edge of the weak-ring (9). A 20 cm-wide strip of lean cement-lime mortar 1: 3: 15 is levelling the brick wall below and forms the weak ring (1). It should not exceed 7 cm in thickness. A row of full brick header projects 4 cm to the inside, forming the base of the strong-ring (2). For that layer, the nail of the radius stick is put back, shortening the radius by 4 cm. After 4 layers of bricks (3), a wedge of concrete 1: 2: 4 completes the strong-ring (4). Then, brickwork continues up to the neck (5). Outside plaster 1: 1/4 : 4 (6) must be cured for 4 days before backfilling of soil is done (7). The soil is rammed in layers not exceeding 30 cm.

Brickwork continues after the strong ring until an opening of precisely 64 cm in diameter remains. Bricks must be chopped to get the exact round form of this size. The bricks rest now in a slanting position and might fall down before the layer forms a closed ring. Therefore, at least the first and last brick of a layer must be temporarily supported. This can be done by clamps, hooks or leaning poles.

Above the header bricks of the strong ring, 2-3 rows (30 cm) of the following brickwork are covered with concrete of 1: 2: 4 mixture, forming a wedge to the strong-ring which Joins the outside plaster of the upper part. The concrete ring and the plaster is cured by sprinkling water for 4 days before back-falling is done and masonry work of -the neck continues. In this time construction of the expansion chamber is done.





## The Expansion Chamber

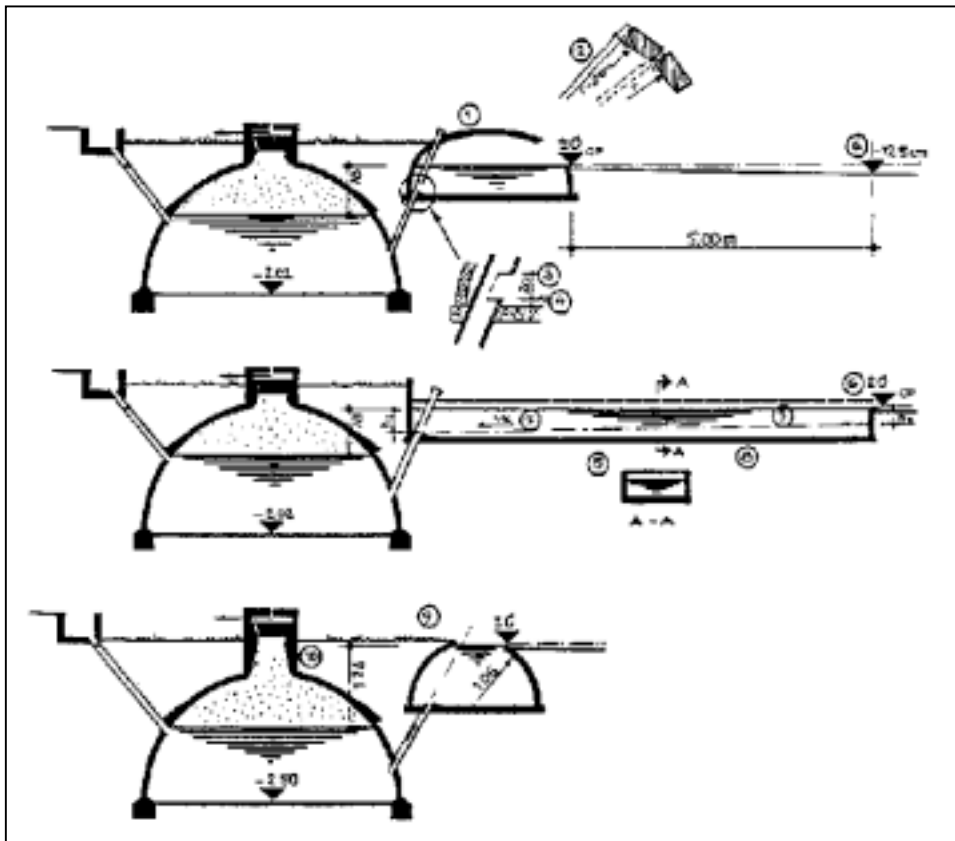
The foundation of the expansion chamber may be done like that of the digester or more simply by using a flat concrete slab of 7-10 cm thickness.

The lower part up to the overflow level is of spherical shape constructed with the help of a radius stick like building the digester. Above the overflow level, the structure continues, covering the pit in a flattened shape.

The overflow opening is the size of a manhole. During construction it is closed by brickwork laid in mud which can be easily removed after completion of the shell. For the safety of children and small animals, the manhole is provided with a cover. Only the overflow hole is left open.

The digester outlet pipe extends over the brick dome to allow poking from the outside. There is a side opening of a 20 cm height to allow slurry flowing into and out of the digester. The lower part may be plastered from the inside for better water tightness. The outside plaster is merely for beautification but also against mechanical wear and tear.

The expansion chamber can also have the shape of a covered channel. This is of advantage when slope is not enough to distribute the slurry.



**Fig.21:** The expansion chamber

The standard expansion chamber is of spherical shape (1), made from brickwork, plastered from the outside only. For the part above the overflow level the radius stick is reduced by 5 cm for each row as to flatten the dome (2). The outlet pipe passes through the dome in order to allow poking through from the outside. The - slurry opening (3), 2 cm above the bottom of the chamber (4), is 20 cm high and cuts out half the pipe. An expansion channel (5) is used to gain height at the point of overflow (6). It is also very handy in case of compost preparation. The volume of the expansion

chamber represents the gas storage capacity. In case of a prolonged expansion channel, only the part above a 3% slope may be calculated (7). The bottom of the canal remains horizontal to allow sedimentation (8). A higher slurry level inside the expansion chamber (9) allows a smaller radius but increases the gas pressure. A higher neck is also required to keep the gas outlet pipe above the point of overflow (10). Therefore, this is not recommended.

### Water-proofer

Water-proofer is added to the cement for gas tightness. Water-proofer based on plastic is preferred over crystalline components because of greater elasticity. To obtain gas-tightness, twice the manufacturer's recommendations for water-tightness is added to the cement.

The use of water-proofer has solved the problem of gas tightness of the plaster. Any kind of surface paint is difficult to apply because the structure is still "sweating" for a long time and the surface will not be as dry as recommended for painting. Other methods, like paraffin coating require higher skill and close supervision. Bituminous paints are washed away in little time by the movement of slurry. Further, materials composed of carbohydrate are principally affected by methane bacteria.

### The Neck and the Lid

The gasplant is closed on top with a removable concrete cover of conical shape and 20 cm thickness. The mixture is 1 : 3 (cement : sand ) with water-proofer added to it. Casting of the lid is done in a mould which is also used to shape the supporting surface at the neck.

The gas outlet ( $\phi$  3/4") passes through the centre of the lid. It has a steel ring collar welded on to prevent gas leakage between the pipe and the concrete. Two handles made from iron bars are normally provided for lifting the cover. As they may hinder later tinning the wedges and pressing the lid into its clay bedding, a steel ring which folds down is preferable.

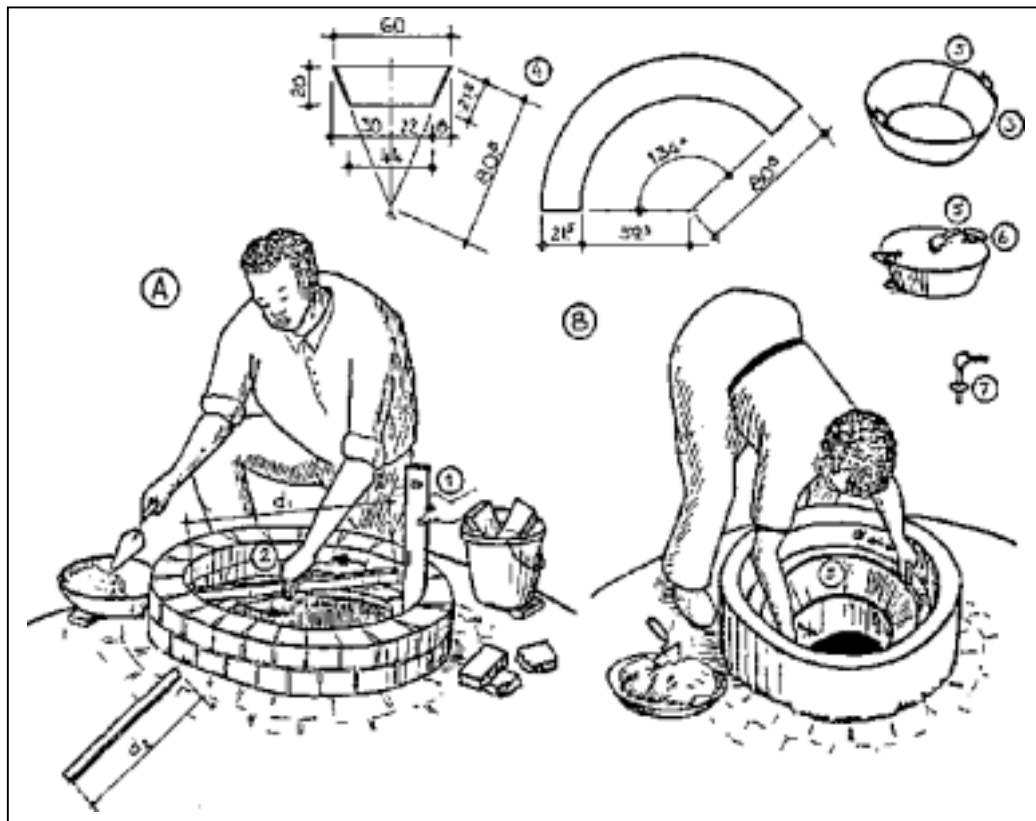
At the neck, the frame of the lid is formed by pressing the mould into the mortar bedding. For preparing the cone in proper shape, the same mould is used in which the lid has been cast.

The gas outlet should be well above the highest slurry level in order to avoid slurry particles entering the gas Pipe. Therefore, the conical support of the cover is raised 2 layers of bricks above the dome structure. For chocking the lid, three pre-manufactured devices are fixed into the brickwork.

A  $\phi$  3/4" gas pipe of 30 cm length with threads on both ends is fixed horizontally in the brickwork of the neck and later connected to the pipe coming out of the lid by a piece of flexible hose pipe. The pipe projects only 6 cm into the inner space of the neck in order not to hinder the placing of the lid. The top of the lid should be above the terrain to prevent grass roots from growing into the clay for sealing the lid.- There is a top-most lid above the water bath. The lid and the neck could also be made from pre-fabricated concrete rings but it is difficult to make them in pieces not exceeding 70 kg of weight.

### Inside Plastering

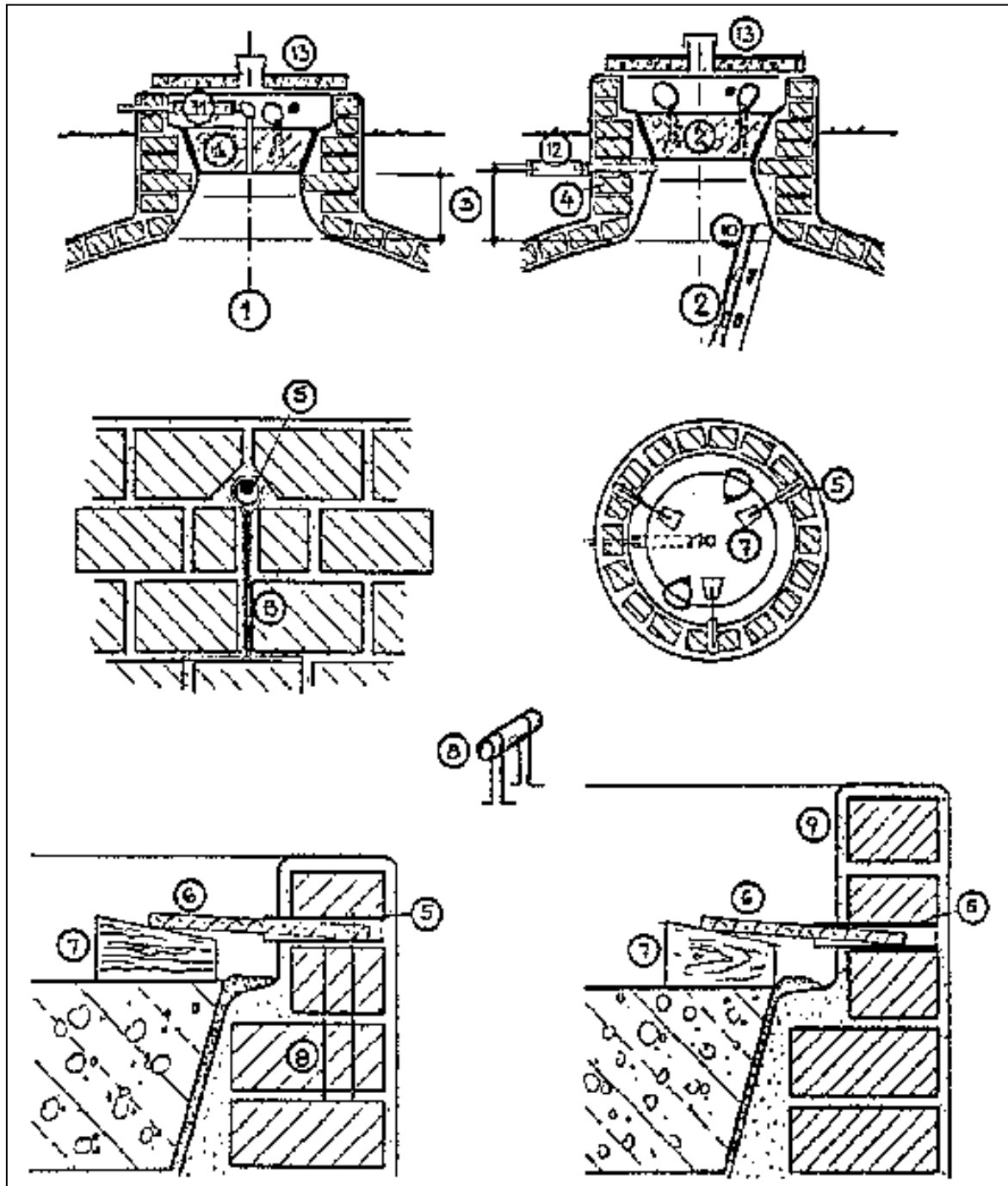
Only sieved and washed river sand is to be used for any plaster. The inner plaster of the lower part of the digester is for water-tightness. It consists of 2 cm cement-lime-plaster of mixture 1: 1/4 : 4, applied in two successive layers. Its surface is wooden trowelled because a rough surface is a better growing place for the bacteria Inlet and outlet pipe should be closed with paper or rags during plastering.



**Fig.22:** Construction of neck and lid

(A) The neck is built with the help of sticks having the length of the inner diameter of the cylinder. Separate measuring sticks are used for the different diameters ( $d_1$ ,  $d_2$ ). When keeping the wall vertical (1), a proper round shape is controlled by rotating the stick around the centre (2).

(B) For shaping the cone to receive the lid, the same mould is used as for making the lid (3). The mould is a conical ring made from mild steel (4). Two handles are fixed for easy turning while shaping the cone of the neck. The mould might be not exactly round. Therefore, in case the gas outlet passes through the lid, the mould should be marked in order to form the cone according to the direction of the gas pipe (5). The lid has two handles of steel (min 8mm thick) which can fold down as not to hinder the fixing of the wedges. The gas pipe has a steel plate collar welded to it to prevent gas leakage alongside the pipe (7).



**Fig.23:** Details of the neck and the lid

The gas pipe may pass through the lid (1) or the neck (2). When it passes through the lid, it will be connected to the gas pipe at the neck by a rubber hose (11). If the gas pipe passes through the neck below the lid, an additional layer of bricks (4) is needed to preserve sufficient height above the highest slurry level (3). The gas pipe lies lower than when passing through the lid which might result in saving a water trap

In case settling of the structure can be expected, a rubber hose connection is advisable (12).

Above the cone there are 3 pieces of 3/4" pipe (5) to receive the 14 mm steel bars (6) for wedging

in the lid (7). There are two wire anchors fixed to the case-pipe (8). In case no anchors are used, an additional layer of bricks is required above (9). The inside of the lower part of the neck widens downwards to allow using a ladder without narrowing the manhole (10). The part below the lid must be gas-tight, above, it must be water-tight. The neck is covered by a removable top-most lid 01° 5 cm concrete (13). A hole of 4" diameter is kept in the centre to control the water level above the lid. It might be made by a piece of pipe which can be covered with a tin.

The plaster of the upper part has a smooth surface for better gas-tightness. It is applied in seven courses which must be completed within 24 hours. Because the mortar is to be waterproof there is no bond once the mortar has dried. The plaster consists of the following layers:

1. Cement-water brushing
2. 1 cm cement plaster 1: 2 1/2
3. Cement water brush in 9
4. 1 cm cement-lime-plaster with water-proofer mixed 1: 1/4 : 2 1/2 + WP
5. Cement water brushing with water-proofer applied consecutively
6. Cement-lime-plaster with water-proofer made of fine sieved sand, mixed 1: 1/4 : 2 1/2 + WP and applied consecutively
7. Cement screed (New) made of cement-water paste with water-proofer, applied consecutively.

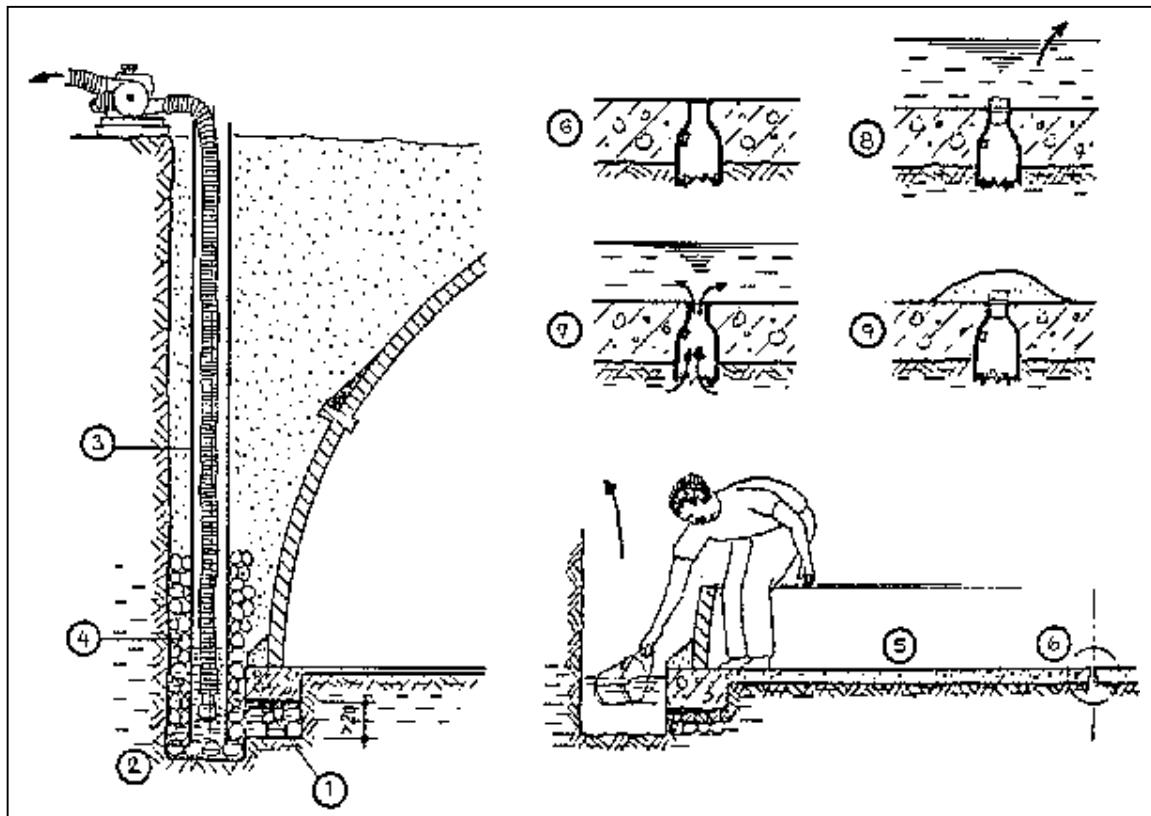
#### Flooring

The first base for the flooring is formed by dropped mortar from bricklaying and plastering. A 3 cm cement screed (mixture 1: 1/4 : 4) applied to the ground would be sufficient. In case of laterite or volcanic murrum soil. If the structure itself is sound and solid, water losses are a temporary problem until sludge particles have sealed the surface sufficiently. In case of unstable soil, e.g. black cotton soil, high ground water table or hill water flows, a water tight floor should be achieved right from the beginning. A 30 cm thick layer of rocks covered by 5 to 10 cm of concrete might be necessary to create a proper floor before cement screed can be applied.

In areas where generally unstable soil is found, foundation and flooring is integrated by forming a conical or spherical shell of 12 cm thickness under the digester and if necessary under the expansion chamber as well. To avoid floating up of the whole biogas plant and when lowering the ground water table by pumping is not possible, the construction must be flooded until the top structure is ready and soil covering of 35 cm in height has been packed above the top of the sphere. The mason has then to work while standing in the water.

#### Supplement Structures

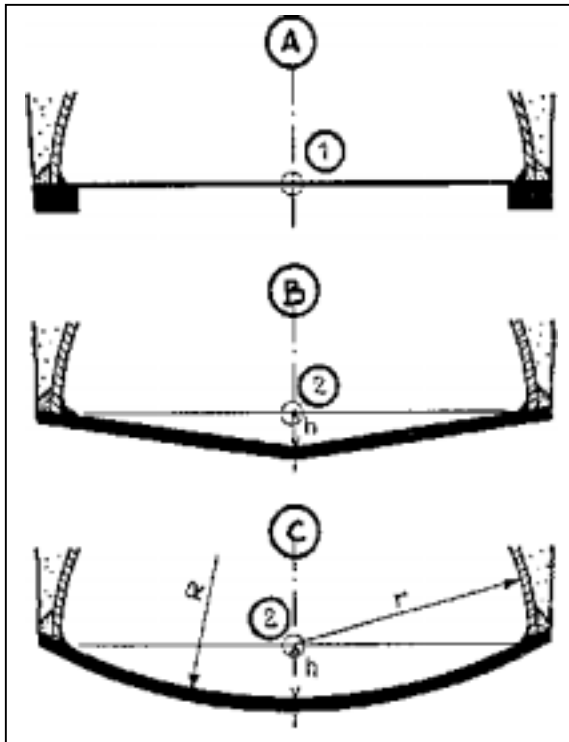
Supplement structures are inlet chambers, slurry channels and gas control chambers. It takes a surprising lot of time to construct these little items. They can be built in brickwork or made from pre-fabricated concrete. When the biogas plant is directly connected to the stable - and this should be the usual case - the inlet chamber consists of the dung and the urine/water collection box. The control chamber houses the main gas valve and the gas control or testing unit. It is a rectangular concrete box with cover to protect the accessories and is placed directly beside the neck of the digester. Pavements for wheelbarrow transport, erosion control or just for beautification are also part of the unit. They may be done from tiles of 1: 2: 4 concrete mixture and 30 30 5 cm in size.



**Fig.24:** Construction below the ground water table

During construction, ground water must be kept away. The foundation rests on a stone packing (1) to drain the water into the pump-sink (2). A layer of gravel prevents blockage of the drain. A vertical pipe (3) allows pumping even when backfilling has been done. The lower part of the pipe is surrounded by a stone packing (4).

If the ground water is only slightly higher than the digester bottom or if no pump is available, the construction must be flooded. The floor must be of solid concrete (5). Water must be kept away until the outer wall has reached above the ground water table and has been plastered from the outside. One or several bottles without bottoms are placed into the concrete (6). When scooping off water has stopped, ground water passes through the bottle and floods the floor (7). After completing the masonry work and covering the dome with soil, the bottle is closed and water might be taken off the digester bottom (8). The cap of the bottle is covered with cement mortar (9). In case of high ground water table a conical or bowl-shaped solid concrete slab is required.

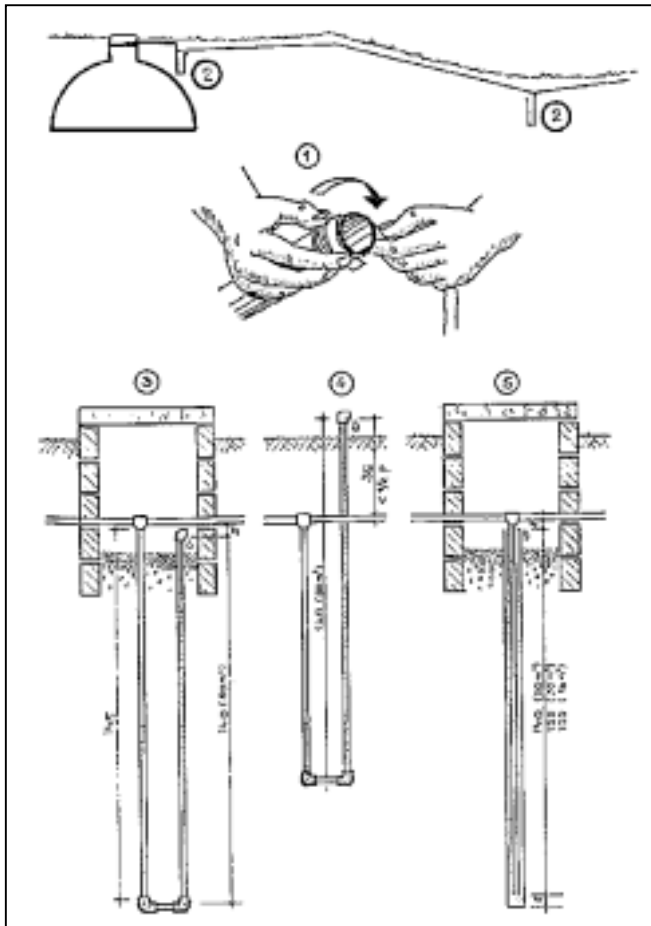


**Fig.25:** Shape of the digester bottom slab

A flat bottom (A) is the weakest in view of statics, but it is a great advantage for the mason to work on an even floor. The centre point can be pegged-in easily (1). A conical shape (B) is much stronger and as well easy to construct. The steeper the slope, the stronger the structure. The centre point must be high above ground in line with the foot point of the brick wall (2). The strongest solution is a bowl-shaped bottom (C). The radius of the digester can be reduced because of the additional volume gained below the centre point. It is uncomfortable to work on a curved base and scaffolding becomes necessary because of the increased height to the top of the dome. Therefore, solutions B and C are used only when ground water pressure is high or the sub-soil is too soft for only a ring beam foundation.

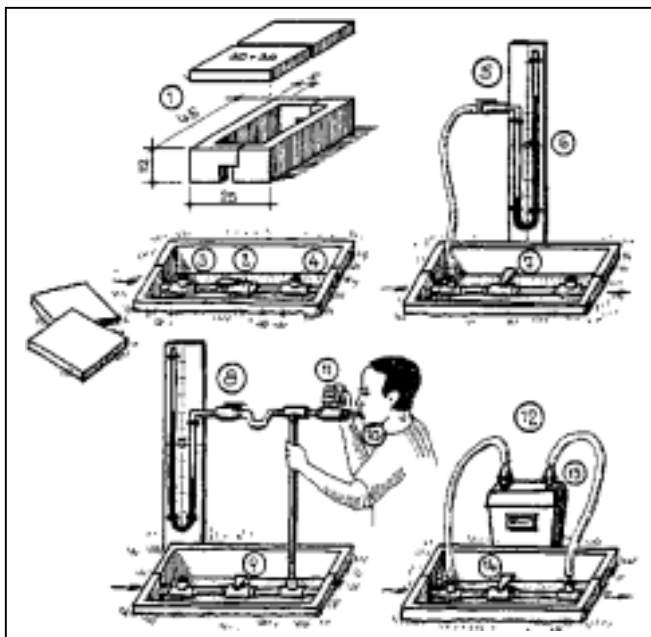
### The Piping System

Pipes should be short and straight, preferable 30 cm under ground. Biogas contains water vapour. If the gas cools below the dew point of the water vapour then condensation forms. The water always collects at the lowest point in the pipe. Therefore, pipes are laid in slope of min. 1%. At the lowest level is either the biogas plant itself or an automatic water drainage device, called the water trap. If pipes are not laid in slope and do not have a water trap at the lowest point, the gas supply system will collapse after only a few weeks. Therefore, the bottom of the pipe trenches must as well be even, otherwise water might collect at hollows blocking the gas-flow. The best way of placing a water trap is to avoid it by careful planning of the pipe line.



**Fig.26:** Installation of gas pipe

All joints have to be sealed by grease and hemp of 5 clock-wise turns of teflon tape (1). The water trap collects condensed-water and is needed at each of the lowest points in the pipe line (2). The length of the open water pipe should be 40 cm more than the water column of the highest gas pressure. The most common automatic water trap is a U-pipe below the line (3). Cheaper and easier to control is the asymmetric U-trap (4) where the open water pipe ends above ground. The maximum length above the pipe line is half the highest regularly appearing gas pressure. The pipe-in-pipe trap (5) functions like the U-trap (3).



**Fig.27:** The test-unit

The test-unit is placed near the plant in a pre-fabricated concrete frame (1). It houses the main valve (2) and two T-joints on each side (3). Normally, the T-joints are closed by plugs (4). For testing the plant (5) a pressure gauge is connected to the T-joint between the valve and the plant. The manometer is made from transparent plastic tubes fixed to a scaling board (6). The main valve is opened (7) and pressure can be read. To test the piping system (8), the pressure gauge is connected to the T-joint after the valve. The main valve is closed (9). Air is blown into the pipe by mouth or compressor (10). When the valve at the inlet point (11) is closed, pressure remains in the pipe. A pressure drop indicates leakage. For testing gas consumption (12), a gas flow-meter (13) is installed between the T-joints (13). When the main valve is closed (14), all gas has to pass the meter and can be measured.

installed between the T-joints (13). When the main valve is closed (14), all gas has to pass the meter and can be measured.



Gas pipes should not pass roads or trenches with potential danger of soil erosion. If this is unavoidable, pipes must be protected by concrete casing. All gas pipes are of 3/4" diameter and preferably of galvanised iron. Whenever possible they lay 30 cm under ground. Joints must be sealed by grease and hemp (not sisal!) or by 5 layers of teflon tape. Bends and junctions should be kept to the minimum because they reduce gas pressure and are potential points of leakage. Unions are especially harmful and should be avoided unless absolutely necessary. Their outer threads must be sealed with hemp or teflon, their inner threats with silicon latex.

For long distances without junctions or joints, PVC or PU pipes which are suitable for underground installation may be used. They are cheaper, but pipes of smaller diameters might be attacked by rodents. Care must be taken by Joining plastic pipes with G.I. pipes. Avoid flexible hose pipes, if not avoidable, use fibre reinforced material.

Before fitting the pipe, dust must be blown out of each piece of pipe or fitting. Pressure tests are to be undertaken for every 30 m of piping installed. If the gas pressure of 1.40 m W.C. does not hold for 10 minutes, all joints must be checked for leakages by help of soap water. Pressure tests can only be carried out under steady temperature conditions. Direct sunlight and alternating cloudy periods have great Influence on the temperature and hence, gas pressure inside exposed pipes. The final pressure test is done with all the accessories connected.

For gas production-, pressure- or leakage control a test unit is permanently Installed directly behind the gasplant inside the control chamber.

#### Filling and closing the plant

The initial filling of the gasplant has to be done via the inlet pipe in order to avoid bulky substrate entering the plant which later might block the outlet pipe.

The lid should not be closed until the plant is filled above the Inlet opening, preferably after it is filled up to the level of the bottom of the expansion chamber. Sealing of the lid is done by fine clay applied on the supporting surface at the neck. In order to keep the clay moist the lid will remain constantly under water when the gasplant is in operation. The lid is chocked with wooden wedges in order to resist the gas pressure from below and to press the sealing clay firmly between rest and cover.



**Fig. 28:** Closing the lid

The lid is sealed by clay which is kept moist by a water bath above. The clay is dried and groined before being mixed with water into a putty like paste. It is then applied by hand approximately 2 cm thick ( 1). The lid is placed into the clay bedding and rammed in (2?). Iron bars are put into the case-pipes of the neck and the lid is fixed by wooden wedges (3). In case the gas pipe passes through the lid, the pipe is connected by a rubber hose, The neck is then filled with water (4) and the topmost lid is laid above (5).

## 7. Construction of cattle stable

### General

The stable should be near the house in order to keep the pipeline from the gasplant to the kitchen short. The fodder trough must be easily accessible. Water for the animals should be near the trough. The milking place lies at the highest floor level of the stable, opposite to the biogas plant. The roof should not drain its rainwater onto the biogas plant.

The stable should allow easy collection of dung and urine to charge the biogas plant. Whenever possible, the existing stable should be kept and modified if necessary to fulfill the above requirements. In many cases a new concrete or tiled floor will do. A new stable should be constructed in cases the farmer wishes to modernize his live stock or if adaptation would demand intolerable compromises.

The size of the stable depends on the number of animals and whether they are freely moving or tied-up. A stable suitable for a biogas unit might require more space than the existing one. Later extension should also be possible without changing or affecting the biogas plant.

### The Principles of Design

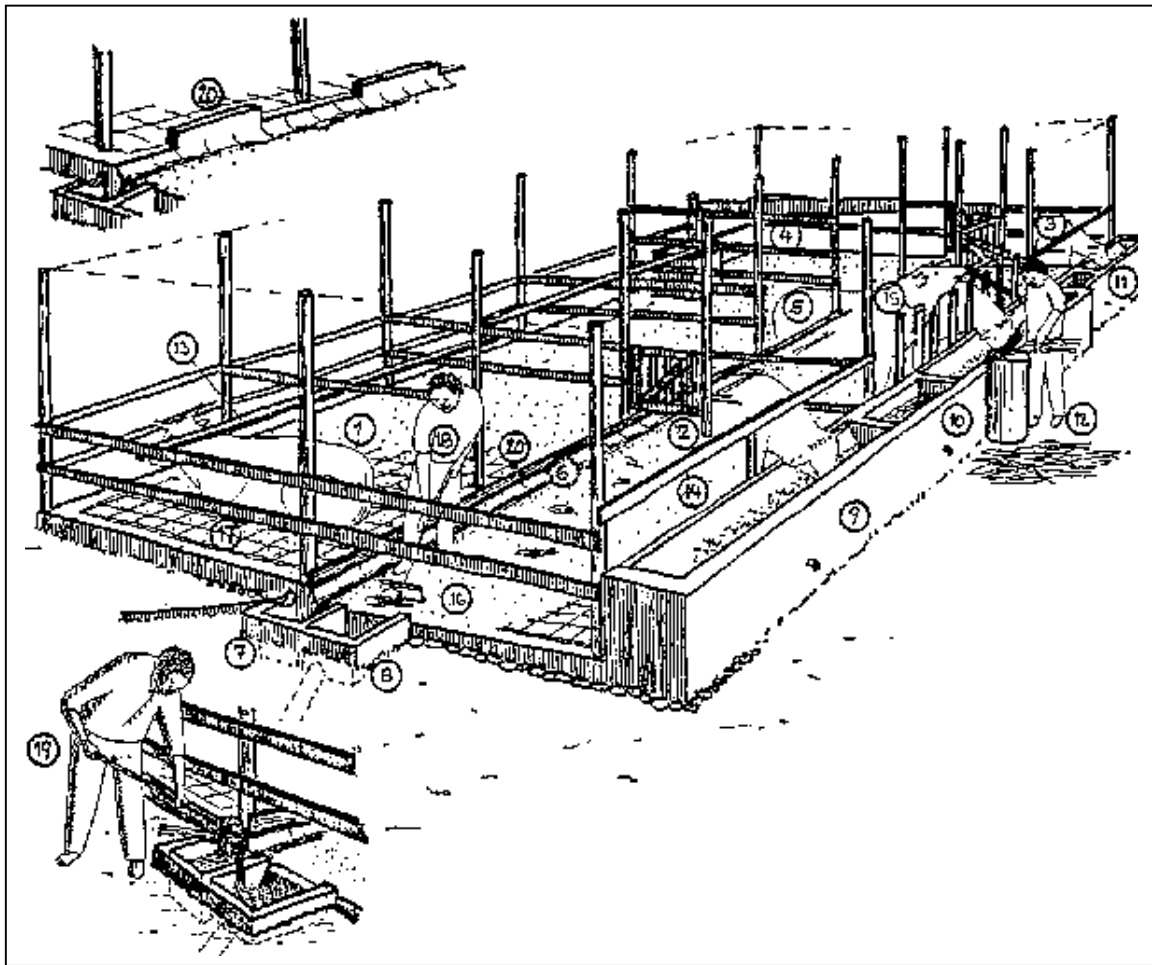
The ideal cattle stable is a zero-grazing unit with separation of milk cows, heifers and calves, roofed or non-roofed exercising area, separate milking stand, restricting fodder trough and solid floor with urine channel. The fodder chopper, the squeegee and the dipper are essential tools for operation of the stable.

A stable connected to a biogas plant has to fulfill the following indispensable criteria:

- solid floor with urine drain in order to collect dung and urine without soiling
- dung and urine collection point lies higher in level than the inlet of the biogas plant in order to avoid laborious handling and losses of substrate
- animals are fed from a trough with neck restriction in order to avoid spreading of too much of fibrous material on the floor which will then enter the plant.

Additional favourable criteria are:

- stable is roofed in order to avoid rain water washing away too much of urine and dung
- resting and exercising area are separated in order to limit the area of dung dropping and to keep animals clean
- calves, heifers and milk cows are separated because of their different sizes to allow an optimal design of the stable
- there is a separate milking stand in order to improve hygienic conditions and optimize milk production by undisturbed milking.



**Fig. 29:** Principle design of the cattle shed.

The stable is divided into a resting area ( 1 ) and an exercising cum feeding area (2). Calves' boxes (3) and the milking stand (4) are at the far end. Milking cows are placed adjacent to it (5). The urine drain (6) ends in the urine chamber (7). The dung and mixing chamber (8), which is the inlet of the biogas plant, are placed beside. The fodder trough passes along the feeding area (9); a water trough (10) is provided between, Calves have smaller troughs (11). The chopping block is at the centre of the trough (12). A bar passes over the necks of the cattle in the sleeping area (13) to force the cows to move back when getting up to drop dung. The necks of the cattle are also restricted at the trough to prevent them from scattering fodder to the floor. This can be done by a bar (14) or by narrow standing poles (15). The floor of the stable is concreted (16) or laid out with concrete tiles (17). The dung is pushed into the mixing chamber daily with the help of the squeegee (18). Urine is taken by a dipper (19) and mixed with the dung before entering the biogas plant. There is a verge of timber (20) or concrete (21) at the end of the sleeping box.

#### The Floor

The condition of the floor influences most the operation of the gas plant. Smooth stable flooring with appropriate slope encourages and simplifies daily cleaning of the stable. The floor should be even without holes. It should not be slippery but plain and slightly rough. There is a 2% slope of the floor into the urine drain and of the urine drain into the urine chamber. The urine drain is shaped one sided at the lowest end of the slope floor. Its corner is bottle curved.

Normally, floor is of 10 cm concrete (mixture 1: 2: 4) on stone bedding. Anti-termite chemicals

should be spread on the stone bedding where applicable. The concrete is firmly rammed or vibrated. A good solution are concrete tiles of 15~15~5 cm in size and 1: 2: 4 by mixture. They are laid into solid sand bedding without joints. The tiles should be cured for at least one week by keeping them moist and cast in steel moulds in order to maintain exact rectangular shape to avoid unwanted wide Joints.

The floor of the calves pen is preferably of wooden boards raised 30 cm above the concrete floor leaving 2,5 cm slats between for faeces to be pushed between in order to keep the place dry and clean.

### The Feeding Trough

Well designed fodder troughs prevent too much waste fodder from entering the gasplant. The feeding trough must fit the anatomy of the animal. A trough which is too small increases work for feeding, too big a trough increases waste of fodder. The trough should have rounded bottoms and corners for easy reach of fodder. A drain pipe for cleaning and drainage of rain water should also be provided.

There are different ways to prevent the cows from scattering fodder from the trough to the floor where it could mix with the dung and enter the biogas plant. One alternative is vertical poles of 1,50 m height and 20 cm free space between. These are erected in front of the trough. The poles should be rounded and smooth so as not to cause friction at the cows neck. The distance from the inner side of the trough and the outer side of the poles should not exceed 16 cm in order to allow the cow to reach the full width of the trough. The other, cheaper and easier method, is to place a bar above the cow's necks to restrict movements of their heads. In both cases, the outer wall of the trough is shaped in such a manner that animals do not push fodder off the trough while eating. Troughs may or may not be placed under the roof of the stable. Wooden troughs wear quickly.

### Compartment Walls

All walls should be strong and smooth. Movable wooden bars used for closing of door openings are not recommended because they might be lifted Off by the animals. Normal wooden doors with solid hinges are more appropriate. Built-in wooden poles have to be protected by burning their surface when surrounded by mortar or concrete.

### Sleeping Boxes

Sleeping boxes should be clean and dry. Therefore, for defecating, the cow has to get In a position in which she can not soil the floor. A 15 cm raise of the floor above the level of the exercising area prevents the cow from entering the box In reverse. A 15 cm high timber or concrete verge forces the cow to lay fully inside the box.

The neck bar allows the cow to lay inside the box in full length but if she gets up for defecating she has to step back dropping dung and urine outside the sleeping box. The floor should be of concrete or tiles in order to avoid too much of sand or soil being collected with the dung. If bedding is wanted or required, it should neither be of straw nor of sawdust but dried slurry could be used instead. To train cows using the sleeping box, requires tying them up for the first few nights after being placed in the new stable.

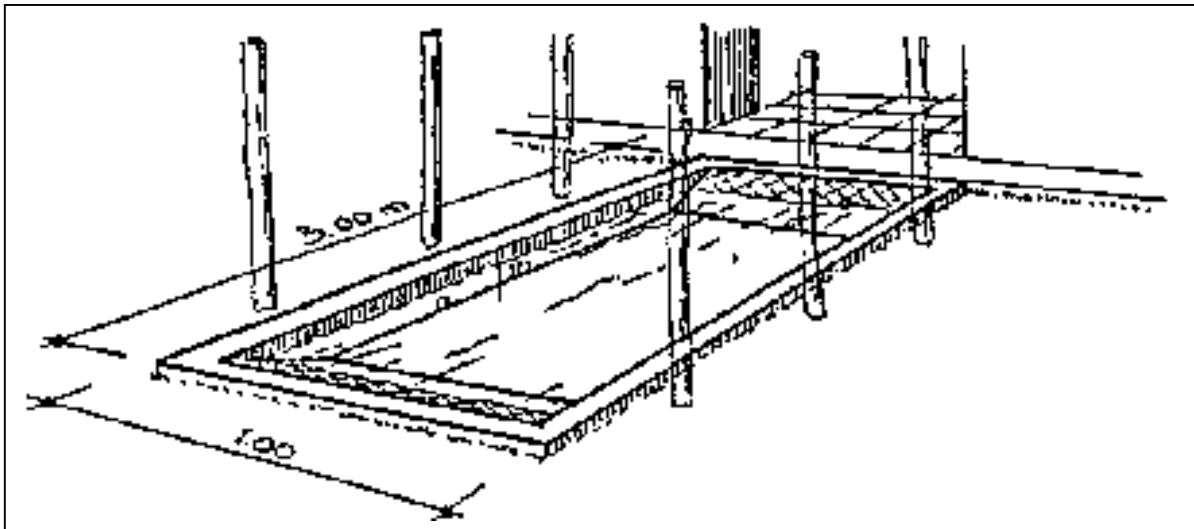
### Dung and Urine Chamber

When cleaning the stable, dung is pushed into the dung or mixing chamber, which is actually the inlet chamber of the biogas plant. Urine and water collects in the urine chamber from where it is taken out with the help of a dipper and mixed with the dung in the dung chamber. The mixed substrate is then released into the biogas plant.

The urine chamber is in fact a storage and dosing tank designed for the capacity needed to get the right TS-content for the slurry. If rain or washing water exceeds the required amount, the urine chamber overflows into the slurry distribution channel. If too little urine gets collected, which might be the case in dry places or seasons, the urine chamber has to be filled with water to the required amount.

#### The Roof

The roof should at least cover the sleeping boxes, the calves pen and the milking stand. In case with no sleeping boxes, part of the exercising cum resting area should be covered. If the roof covers the total area of the stable it should be 3 m high in order to allow ventilation and sunshine. The roof should not drain on the biogas plant.



**Fig.30:** Cattle foot bath. If cattle are regularly out grazing, they should pass a cleaning foot bath before entering the stable in order to prevent too much soil from entering the gasplant. A drainage pipe would allow easier cleaning.

## 8. Construction of the pigsty

### Principles of Design

The ideal pigsty allows easy dung and urine collection and separates the different age groups of the animals. The pigsty should be at the backside of the house in order to avoid disturbance by bad odour. The pigsty is divided into the following compartments:

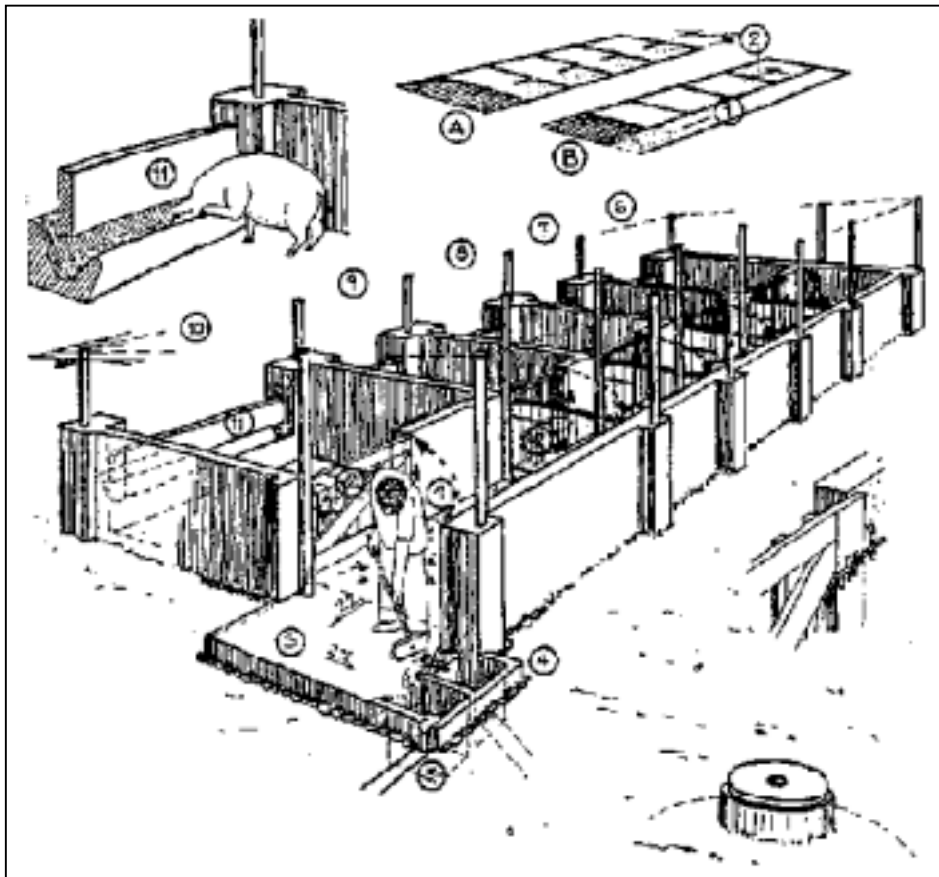
- The boar box, which is big enough to accommodate both the boar and the sow for mating.
- The farrowing box, with protection rails for piglets to hide when the sow lays down.
- The gestating box for sow and weaning piglets
- The finishing box (boxes) for growing piglets no longer weaning.
- The finishing box (boxes) for pigs to grow to market size.

Each of the compartments consists of a clean resting and feeding area and a dirty area where pigs defecate. The dirty areas of several boxes are Inter-connected and form a corridor in order to allow easy cleaning and washing of the floor. Pigs need a draft-free and rather uniform environment (min 15°C for adults, 22°C for piglets). Therefore, the wall of the boxes should be built to a height of 1,50 m completely closed and a roof of only 1,80-2,00 m above the floor.

### Construction Details

The slope of the floor of the boxes to the corridor and that of the corridor to the dung and urine chamber is 2%. The doors of the boxes close the individual compartments when opening the corridor and vice versa. Walls of the boxes are made from brickwork with rough plastering.

The fodder trough is covered or protected by bars to prevent the pigs from laying in the fodder. There is a pipe for draining and easy cleaning at the bottom of the trough.



**Fig.31:** Principle design of the pigsty

Pigs have a natural habit of defecating always in the same corner of their stable. Therefore, cleaning becomes easy if the dung areas of several stable boxes are inter-connected to form a corridor ( 1). The doors of the boxes are of the same width as the corridor (2). Normally the doors are open and divide the corridor into compartments belonging to the boxes (A). During cleaning of the stable, the doors are closed, leaving the corridor free (B). The floor of the stable slopes to the urine drain and the drain into the urine chamber (5). The dung chamber (4) is placed beside. A platform at the open end of the corridor is for easy transport of pigs (3). The stable consists of boxes for boar and sow for mating (6), weaning mother sows (7), older piglets (8), smaller pigs (9), and grown up pigs ready for slaughter (10). The troughs are each of appropriate size to the size of the pigs and are protected by a concrete apron to prevent pigs from laying into the fodder (11).

## 9. The sanitary biogas unit

### General

Sanitary Biogas Units are installations where the gasplants have been built in order to treat the waste of latrines. Human faeces are the main digestion material. Additional feeding with animal dung or kitchen waste is possible. Hygienic latrines have to fulfill the following requirements:

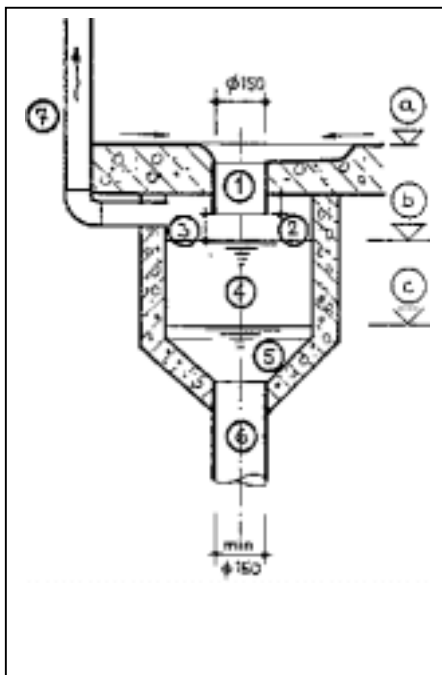
- no handling of human excrete by man; even accidental touch should be avoided
- no access of flies to undigested excrete
- no worms may escape from the latrine pit
- no bad odour and no indecent appearance

Important design criteria concerning hygiene and construction quality must be observed. Main planning criteria are the expected sanitary conditions which depend on frequency of use, frequency of cleaning, and safe slurry disposal. Slurry should be used for fertilizing trees or shrubs but not vegetables. The slurry may also drain into a soak pit. Energy and manure provision are of lesser importance but should be optimized whenever possible.

### Construction of Toilets

Toilets connected to a simple fixed dome biogas plant should be latrines where a minimum of water is used for cleaning. Flushing toilets are not suitable for connection to biogas plants of less than 30 m<sup>3</sup> digester volume because of the danger of diluting the slurry and thus reducing the retention time.

The toilet chamber is connected to a vent pipe which passes the roof. It is placed outside, if possible not shaded, and is painted black as to heat up for better draft.



**Fig.32:** Construction details of toilets

The toilet floor (a) has a groove serving as the toilet pan. The highest slurry level (b) and the lowest slurry level (c) depend on the gas storage requirements of the biogas plant. There are a few but very important details to be observed: (1) The inlet consists of a piece of pipe of 6" diameter placed absolutely vertical in order to avoid soiling the sides. (2) The bottom rim of the inlet piece is separated from the lower system in order to prevent worms from crawling out of the toilet. (3) The inlet piece ends always above the highest slurry level. (4) Below the inlet piece is a chamber of larger surface in order to avoid floating feces piling up in the pipe. Feces should drop directly into the slurry but never on parts of the structure which are normally above the slurry level. On the other hand, the dropping chamber should be as small as possible in order to release fresh feces as quickly as possible into the biogas plant. This is important for avoiding bad odour and for producing the biogas there, where it can be collected and utilized, which is the inside of the dome. (5) The down pipe is straight and at least of the same diameter as the inlet piece (6). A vent pipe passes above the roof (7)



## 10. Use of slurry

### General Properties of Digested Organic Matter

Digested substrate has almost no smell and is more liquid than undigested dung. These facts are the result of the same process which leads to the production of biogas, the transformation of long carbon chains (cellulose, alcohol and organic acids) into short carbon molecules such as  $\text{CH}_4$  and  $\text{CO}_2$ . As part of the total carbon content of the substrate is transferred into biogas, the carbon/nitrogen ratio becomes more narrow. Only if the C/N ratio of a manure is narrower than that of the soil, one may talk of nitrogen supply by the manure.

Nitrogen is a major nutrient required for the plant growth. Nitrogen from organic manure has to be extracted by bacteria from large organic molecules and transformed into smaller inorganic water soluble compounds before plants can use it. This transformation is called mineralisation. During the digestion process in a biogas plant, part of the organic nitrogen is mineralized to ammonium ( $\text{NH}_4^+$ ) and nitrate ( $\text{NO}_3^-$ ) and thus, may be taken up by the plants immediately. The short term fertilizer value of the dung is doubled while the long term fertilizing effects are cut by half. Under tropical conditions the short term value is of greater importance because rapid biological activities degrade even the slow degrading manure fraction in relatively short time.

If ammonia is not dissolved in water it may escape as gas into the air. Therefore, digested slurry has to be kept moist or covered by soil to preserve its fertilizer value. The best way is to bring it immediately in liquid form to the roots of the plants. An other possibility is to compost the slurry together with other organic material. During composting ammonia is bound again in organic form by bacteria and does not evaporate.

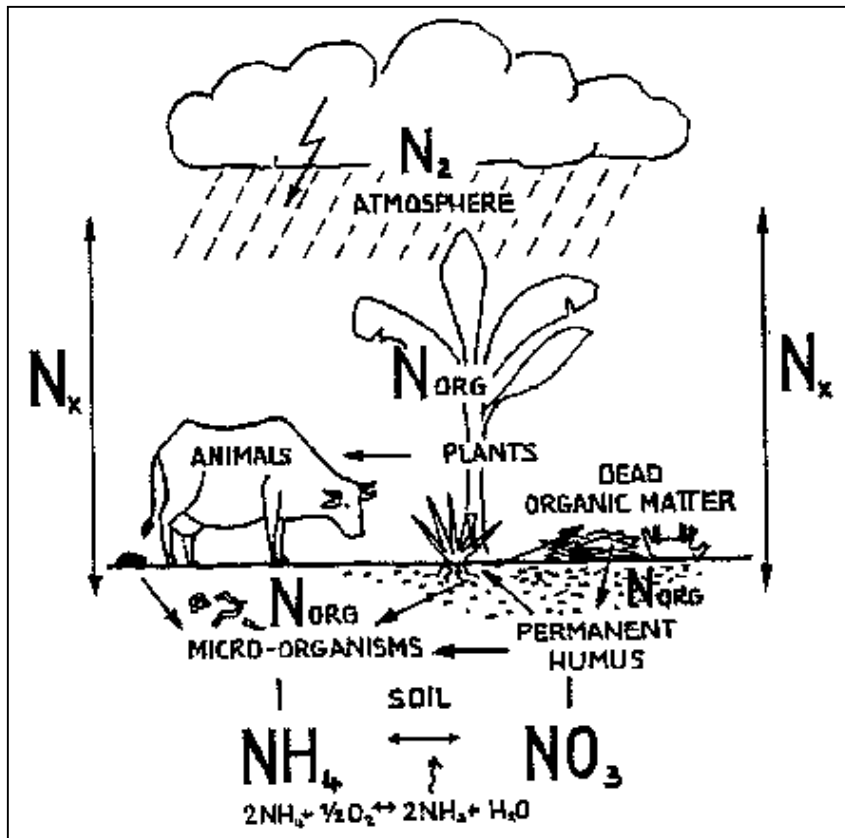
Many chemical processes take place at the same time which need different attention. But in general, two rules must be followed for preserving the plant nutrients of both the undigested dung and the digested slurry:

- avoid long storage times and
- keep manure moist, cool and covered.

To avoid long storage times it is better to clean the stable twice a day instead of every second day. It is also better to use the slurry directly on permanent crops like fodder grass, trees or vegetables than on annual crops like maize or millet.

### The Slurry Disposal

Clever and realistic planning of the site of slurry utilization is the key to an economical biogas unit. Insufficient slurry disposal leads to blockage of the outlet and rising gas pressure inside the fixed dome plant. The volume of digested slurry is about twice as much as that of fresh dung. Slurry manure must reach the crops without losing too much of its fertilizer value. Whenever possible, slurry should be distributed directly to the crop by gravity. The best way is using irrigation channels for slurry distribution. To prevent loss of nitrogen, the manure pits and slurry distribution channels should be covered or placed under shade of plants. A compromise must be found between shading the manure and not disturbing the flow of the slurry by roots growing into the canal. Shading by fodder grass itself might be less troublesome than by trees.



**Fig.33:** The nitrogen-cycle in nature

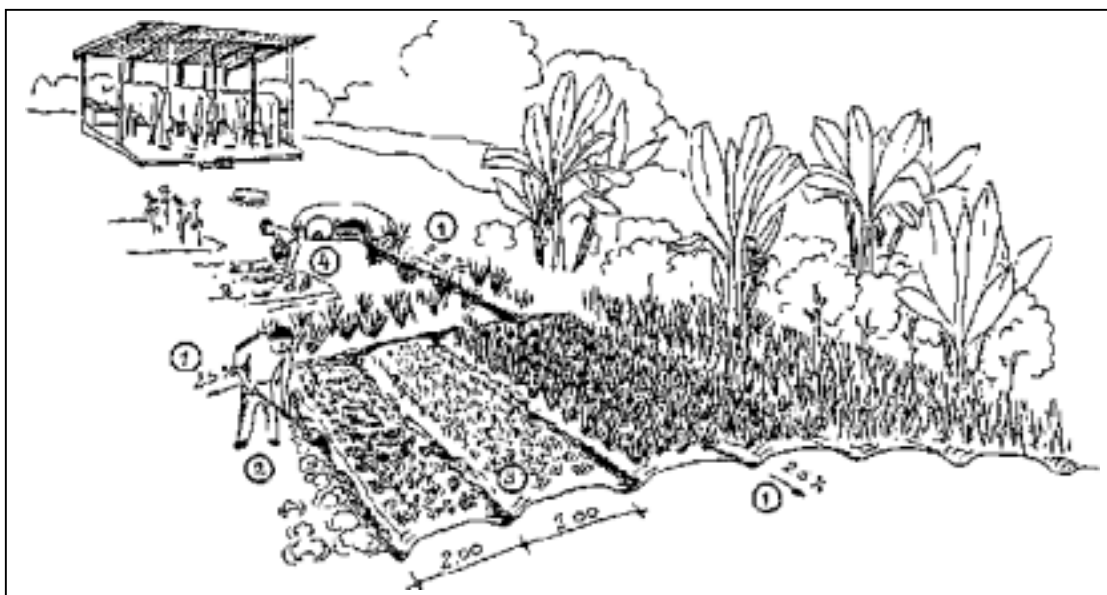
If fertilizing follows the cropping pattern, space for a liquid storage tank of sufficient size must be provided beside the point of overflow to bridge the time of no fertilizer use. Similar space would be needed if composting of slurry is envisaged.

The point of overflow can be extended nearer to the field to allow sufficient slope when the expansion chamber is shaped like a canal. There is also the possibility of arranging the compost heap parallel to this expansion canal. Slurry might then be taken out at convenient spots for pouring over the compost.

#### Use of Liquid Slurry

It is more important to use the slurry instead of propagating complicated and labour intensive systems of optimum manure utilization. Any use of slurry is a good use. Therefore, whenever possible, slurry should be used in liquid form immediately after leaving the overflow of the biogas plant. A minimum slope of 2.5% is required for short distance distribution. Slope is to be increased for longer distances and in dry areas. Distribution of liquid slurry needs management. Uncontrolled distribution may create swamps or thick layers of dried slurry sealing off the roots of crops or trees from necessary oxygen supply.

The most labour saving slurry utilization is for fodder grass. It should be encouraged when controlled fertilizing is unlikely. The fodder is planted near the stable where it is used. The gasplant is near to keep slurry distribution channels short.



**Fig.34:** Slurry distribution by gravity

Distribution channels need a minimum slope of 2,5% (1), in dry areas 5X may be required. The slurry is dumped amongst the fodder grass when cleaning the channels (2). Slurry flows mainly to recently harvested areas (3). Slurry is spread on vegetable fields higher than the outlet and near the plant by buckets (4), The stable in the background fulfils the minimum requirements.

Fodder grass should be cut when it is only 80 cm high. Slurry is led always to the freshly cut area. Per cow 500 m<sup>2</sup> of fodder grass are a guiding figure. Fodder grass is a permanent crop which makes the installation of a permanent distribution system advisable. The main distributor could be constructed even in concrete or laid out with concrete slabs. Branch canals every 2 m would allow equal fertilizer supply. Covered channels would be the best.

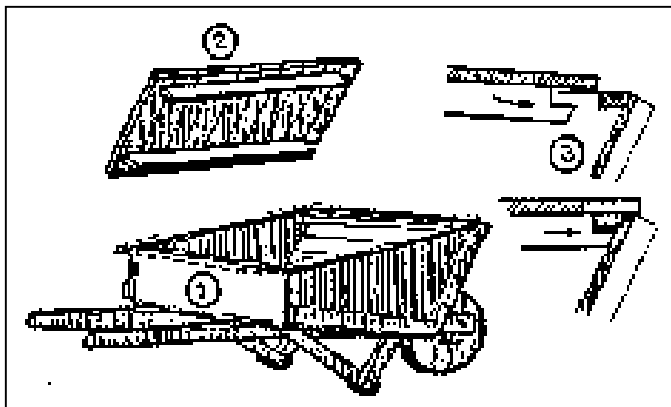
Where gravity distribution is not possible, liquid slurry must be carried to the plants by buckets or on specially adapted wheelbarrows. Wheelbarrow transport needs passable pathways.

#### Use of Slurry for Compost

The preparation of compost is best if distribution by gravity is not possible. Investment and labour input are reasonable and the nutrition value of the manure is preserved. Composting is a form of storing the slurry over some time without losing too much nitrogen. Compost is also a method of increasing the amount of organic manure which stabilizes the soil structure. Compost is superior to liquid slurry for long-term improvement of soil fertility. Compost releases its nutrients slowly and therefore, is applied in few but larger doses over the year.

In principal, compost is, prepared in alternate layers of liquid slurry and fibrous agricultural residues. Compost should be made in heaps instead of pits because air is required to promote the rotting process. Compost should be kept in shade and should never dry out. A less optimal but utilized compost is better than propagating the ideal method which will not be applied by the farmer. The compost dam which is regularly poured over with slurry and sometimes turned over, is a reasonable compromise.

When compost is prepared, it is advisable to shape the expansion chamber of the biogas plant like a canal running parallel to the compost heap.



**Fig.35: The slurry-cart**

A wooden wheelbarrow ( 1 ) developed by CAMARTEC is modified to serve as a slurry transport cart. It is heavy but stout and has almost no metal parts which could corrode. The lid (2) prevents the slurry from spilling over. At the front it is held by a slot (3) at the longitudinal slat. The slurry is either dumped into a distribution system or taken out from the wheelbarrow by buckets.



**Fig.36: Compost preparation**

Compost consists of slurry and fibrous organic residues, like grass, leaves, and straw. It has a total solids content of 50%. The compost heap must be turned over several times during the 6 months ripening period. The inside temperature of a good compost heap is 60-70°C. The rotting process demands air. Therefore, the compost heap should be narrow and above the ground. The ideal compost heap is roofed and set in alternating layers of residues and slurry ("Indore" method) (1). In connection with an expansion canal of a biogas plant, the compost dam (2) is an appropriate compromise. Dumping of residues starts at the far end. The compost dam "grows" to the front and is poured over regularly with slurry (3). After some weeks it is turned over to the side (4).

## 11. Use of gas

### General

As biogas burns with an open flame, the place of gas consumption should be ventilated but free of draft directly at the flame. The flame will be more stable. For lighting, the lifetime of lamp mantles will also be prolonged. Sensitive equipment like refrigerators or incubators should be situated where they can be controlled.

Biogas can be used like any other combustible gas, e.g. LPG. Each gas has its own properties which must be observed for efficient combustion. The main influencing factors are:

- gas/air mixing rate
- flame speed
- ignition temperature
- gas pressure

Compared to LPG, biogas needs less air per cubic metre for combustion. This means, with the same amount of air more gas is required. Therefore, gas jets are larger in diameter when using biogas. About 5.7 litre of air are required for total combustion of 1 litre of biogas, while for butan it is 30.9 litres and for propan 23.8 litres.

The flame speed is lower with biogas than with LPG. Therefore, speed of gas at the burner heads must be reduced. This can be achieved by conical orifices, but normally, the bottom of the cooking pot functions as a speed breaker for the flame.

The ignition temperature of biogas is higher than of diesel. Therefore, when biogas is used in engines, ignition spark plugs are required or partly diesel must be added to the gas (dual fuel) to run the engine. Slow turning diesel engines (approx. 2000 RPM) suit biogas better than fast turning Otto-engines (above 5000 RPM).

The efficiency of using biogas is 55% in stoves, 24% in engines but only 3% in lamps. A biogas lamp is only half that efficient than a kerosene lamp. The most efficient way of using biogas is in a heat-power combination where 88% efficiency can be reached. But this is only valid for larger installations and under the condition that the exhaust heat is used profitably. The use of biogas in stoves is the best way of exploiting the energy of farm household units.

### Gas Stoves

All gas burners follow the same principle. The gas arrives with a certain speed at the stove. This speed is created by the given pressure from the gasplant in the pipe of a certain diameter. By help of a jet at the inlet of the burner, the speed is increased producing a draft which sucks air into the pipe. This air is called primary air and is needed for combustion. Therefore, it must be completely mixed with the biogas. This happens by widening the pipe to a minimum diameter, which is in constant relation to the diameter of the Jet. By widening the pipe further the speed of the gas again is reduced. This diffuse goes over into the burner head. The cone of the diffuse and the shape of the burner head is formed in such a way as to allow the gas pressure to equal everywhere before the gas/air mixture leaves the burner through the orifices with a speed only slightly above the specific flame speed of biogas. For final combustion the gas needs more oxygen which is supplied by the surrounding air. This air is called the secondary air.



If combustion is perfect, the flame is dark blue and almost invisible in daylight. Stoves are normally designed to work with 75% primary air. If too little air is available the gas does not burn fully and part of the gas escapes unused. With too much air supply the flame cools off and thus, prolonging the cooking time and increasing the gas demand.

### Manufacturing Stoves

Gas stoves are relatively simple appliances which can be manufactured by most blacksmiths or metal works. Gas stoves of mild steel may corrode if the hydro-sulphur content in the biogas is high. This is often the case when biogas is produced from human excrete or pig dung. Therefore, high quality steel or cast iron is advantageous. Clay burners are widely used in China and have proved to render good service. For experimental use in schools, stoves can be made from used food-tins.

When manufacturing stoves in an ironmongers workshop, the shape of the burner must be simplified. This is justifiable because the methane content and the gas pressure are changing. Full adaptation is not possible for that reason. A standard design used for biogas delivered from fixed dome plants has been developed.

When it happens that all the flames are torn off the flame port and ignition becomes impossible the flow speed must be reduced. This can be done by reducing the volume of the gas/air mixture by partly closing the air intake holes.

The stove itself, i.e. the stand for the pots, needs consideration as local food habits have high influence on the design. The stand must be strong to allow stirring of even thick foods like "ugali", rice or stew.

### Modification of LPG Stoves

LPG stoves can be modified to fit the properties of biogas. The efficiency will often not be as good as with a genuine biogas stove. Hence, the geometry of the burner will not be known exactly, modification remains subject to trial and error. The easiest way is to close the primary air inlet completely and then widen the Jet according to the wanted heat supply. The air intake might then again be opened little by little. When lighting the burner about half of the orifices should bear flames. After a pot is placed on the fire, all orifices are ignited.

The jets of LPG burners can be widened with a drill. It is better to go step by step instead of spoiling the burner by opening the jet too far. For example, an original 1.2 mm jet should be widened in the first step to 1.4 mm only, in the second step to 1.6 mm until it gives the wanted result. If there is no vice at hand, the drill can even be used without a drilling machine when jets are of soft brass metal.

### Gas Lamps

Although biogas lamps have proved not to be economical compared to kerosene lamps, they are often the major reason for wanting a biogas plant rather than the clean and smokeless cooking fuel.

The principal of a gas lamp is similar to that of the stove. With a stove, the burning gas heats a pot. In a lamp, the burning gas heats a mantle until it glows brightly. The secret behind a lamp is to adjust the flame in such a way that the hottest part of the flame exactly matches the form of the mantle. Proper air mixture and appropriate size of the mantle play the biggest roles. The methane content of biogas sometimes changes. Therefore, brightness of the light will also change.

Local production of lamps is far more problematic in design and more complicated to manufacture than producing efficient stoves. Trial and error provides the best method in most cases. There are several lamps available that could be imported from India, China, Kenya, Brazil or Italy. The Patel outdoor lamp (Pate Crafters, Bombay/India) has proved to be the most expensive but also the best

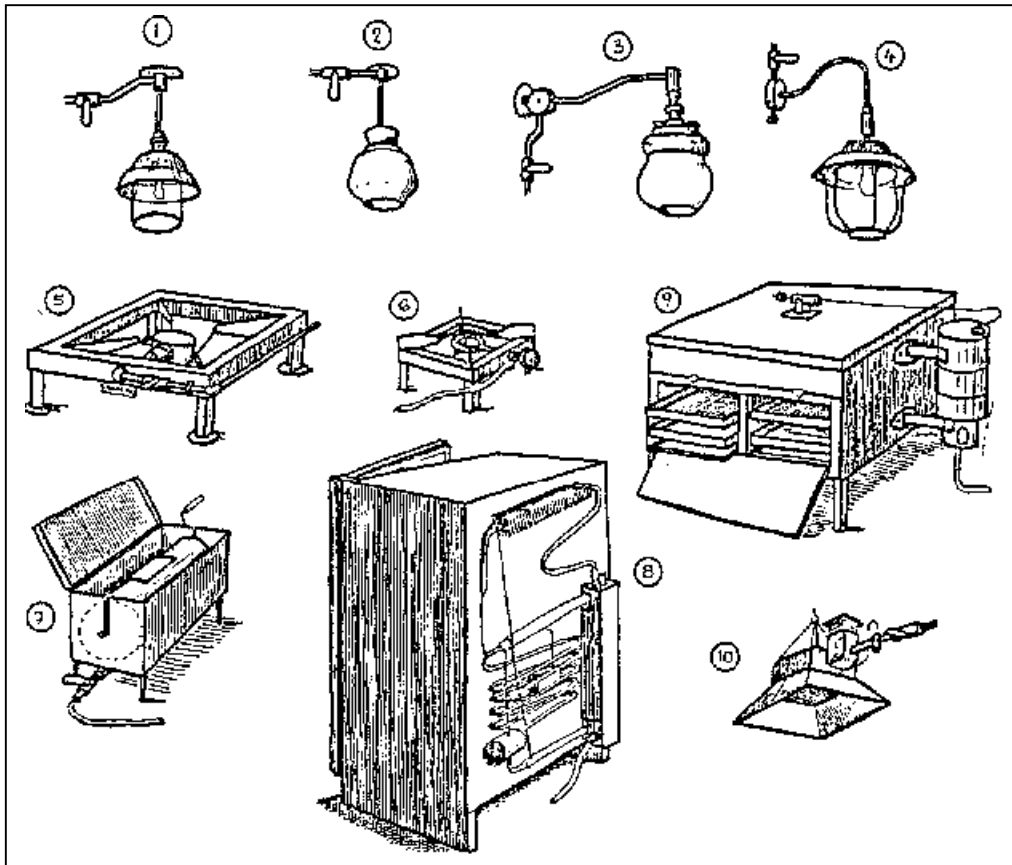
serving model. It has an air mixing chamber where outside air gets pre-heated before combustion.

#### Modification of Kerosene Pressure Lamps

Kerosene pressure lamps (petromax, anchor, butterfly and others) are available in most countries. They can be modified and there is no need to import special biogas lamps. Instead of 0,09 l kerosene 0,186 m<sup>3</sup> biogas is consumed per hour. To modify a pressure lamp the workshop must be equipped with a lathe. In principal, the jet is widened and a new mixing pipe is mounted. The gas is connected via the original pump opening.

#### Other Appliances

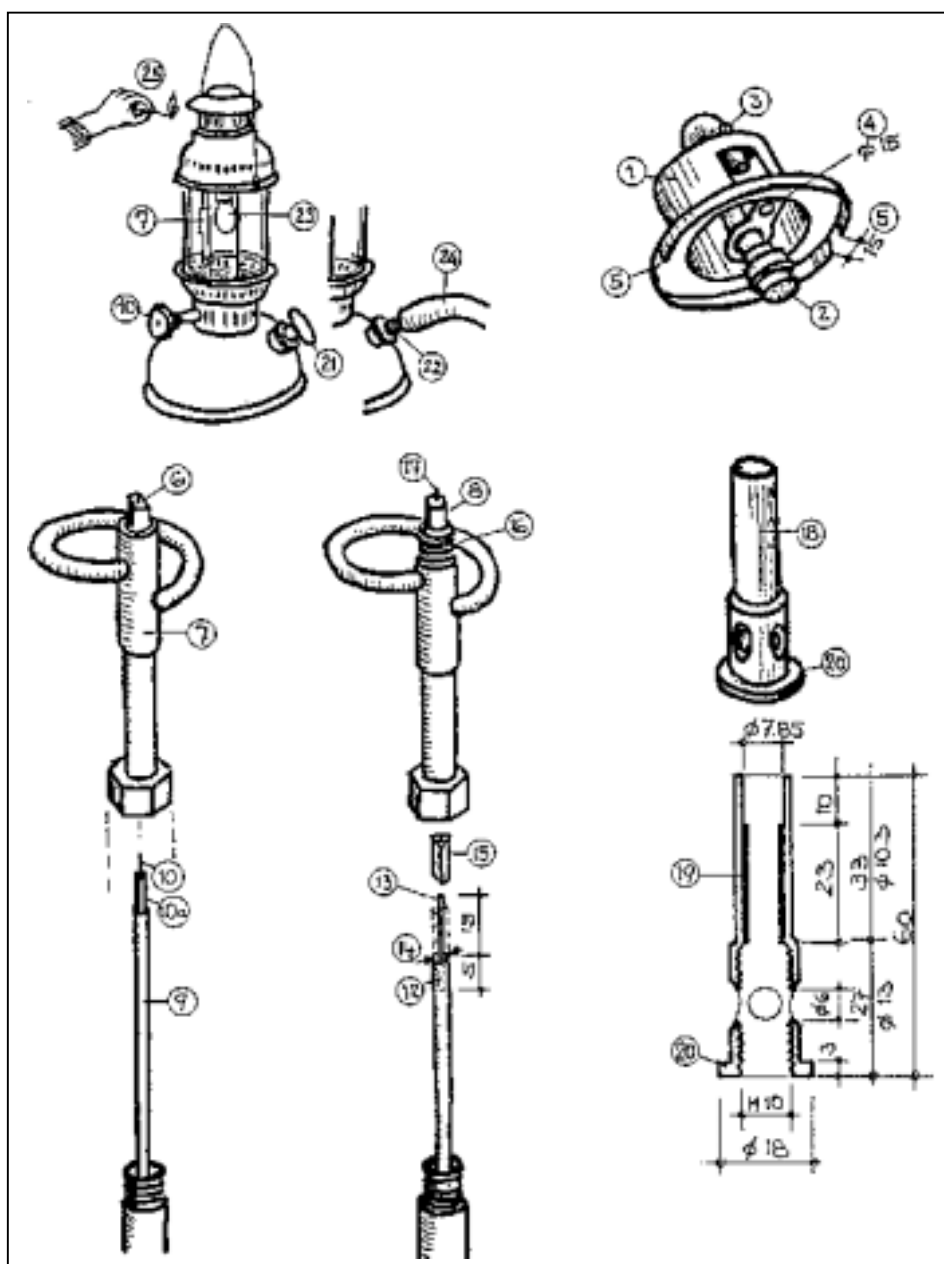
Biogas can be used for various activities and requirements common in the project region. Refrigerators and chicken heaters are the most common. There are individual cases of using biogas for coffee roasting, bread baking or sterilization of instruments. If the properties of biogas are observed, there is no limitation to its utilization.



**Fig.38:** Biogas appliances

(1) Gaslamp made by CAMARTEC from aluminium vessels and a glass mantle from a kerosene lamp. The lamp worked well but was never mass produced. (2) Gaslamp from Italy, (3) from Germany and (4) from Brazil. (5) Big cookstove for institutions, schools etc., developed, built and exported by CAMARTEC. There should always be a smaller stand-by stove in institutional kitchens (6) Household stove from KIE, Kenya (7) Coffee roaster for 1-3 kg of coffee placed on a tube burner or ordinary kitchen stove. (8) Gas refrigerator modified for biogas by changing the jet and the air-intake holes. (9) The "Detroit" chicken heater with temperature regulation with a floppy cap (a). (10) A room heating radiator, mainly used in chicken houses or piglet sties. A ceramic plate causes heat radiation.





**Fig.39:** Modification of pressure lamps

For modification, the head of the lamp ( 1 ) is to be taken off after removing the wig. Because the flame port (2) might break, unscrew it and save it. Remove the kerosene adjustment screw (3) from the U-pipe in' the head Either close the hole by hard soldering or cut the screw so short that it only closes the hole but does not disturb the gas-flow inside the U-pipe.

Look at the head from below and widen the hole (4) beside the flame port socket to  $\varnothing 15$  mm in order to receive the new mixing pipe. Then enlarge the two notches at the rim (5) of the head from each side to 15 mm width. This will help to replace and remove the head easily. The head is now modified.

For modification of the gas intake system, unscrew the brass jet (6) which is fixed at the top of the standpipe (7). The jet's opening could be widened to  $\varnothing 1$  mm but a stainless steel jet (8) is much more durable when using biogas. This will be made from a massive rod of  $\varnothing 8$  mm and should have

a thread of M7 · 1. Now unscrew the standpipe and you will find a long needle (9) with a tiny pin (10) at the top. The pin moves up and down, cleaning the jet when the handle of the main valve is turned (11). Unscrew the pin holder (10a) from the needle and widen the thread at the head of the needle with a drill of Ø 0.9 mm to 5 mm depth (12). Insert a steel pin Ø 0.9 mm in there (13) or cut the drill in half and use the drill itself as the new pin for cleaning the new 0.1 mm-jet. Press the head of the needle with pliers to fix the pin (14). Take the old pin holder and cut its thread and the pin off and place the remaining shaft over the new pin (15) in order to give better guidance to the needle when it moves up and down inside the jet.

The top of the standpipe will be provided with a thread M10·1 (16) to receive the new mixing pipe which will extend the existing standpipe by 60 mm. Fix the jet to the standpipe and screw the standpipe in its former position. Make sure that the cleaning pin is turned up when replacing the jet with the standpipe (17).

The new mixing pipe (18) is made from Ø 18 mm brass rod. The lower part is turned to Ø 13 mm with an inner thread of M10·1. Four air holes of Ø 6 mm cross the pipe. Their rims are bevelled. The upper part is turned to Ø 10.3 mm outside and 7.85 mm inside, where a stainless steel pipe (19) of Ø 8 mm outside and Ø 6 mm inside is pressed in. At the lower end of the mixing pipe there is a 3 mm flange to prevent uncontrolled air supply to the flame (20). After screwing the mixing pipe to the standpipe the inner parts are modified.

Remove the pump at the kerosene tank (21) and remove the inner valve with a screw driver. Either produce a new cap with hose connection nozzle and thread M20·0.8 mm or fix a hose connection to the existing cover cap (22). Make the joint gas-tight by soldering. Use teflon sealing tape for placing the cap on the nipple.

Assemble all parts, fix a new mantle (23), connect the gas (24) and light the lamp (25).

## 12. Operation and maintenance

### Operation of the Biogas Plant

If operational short-comings are often reported, the set up of the system is not appropriate to the farmer. The main task of a biogas engineer is to design and construct a user-friendly biogas unit. Operation and necessary maintenance must be logical to the user and should not be a burden to the ones attending the plant. A well designed biogas unit is easy to maintain. The ease of maintenance ensures constant attention by the farmer. Nevertheless, even with a perfect design, a minimum of daily care is needed to receive a proper service from the unit.

The clay sealing of the lid must stay moist. Therefore, the lid must be covered with water all the time. In order to reduce evaporation and prevent mosquito breeding, machine oil can be added on the surface of the water. Mineral oil pollutes ground water and should only be used in small quantities and with care. From time to time the water above the lid must be checked and refilled when necessary. A small control opening in the topmost cover makes control much easier and therefore more likely. When water is controlled, possible leakages at the lid are also detected.

Once in a while the expansion chamber should be cleaned In order to avoid solids assembling in the corners and thus, reducing the gas storage capacity.

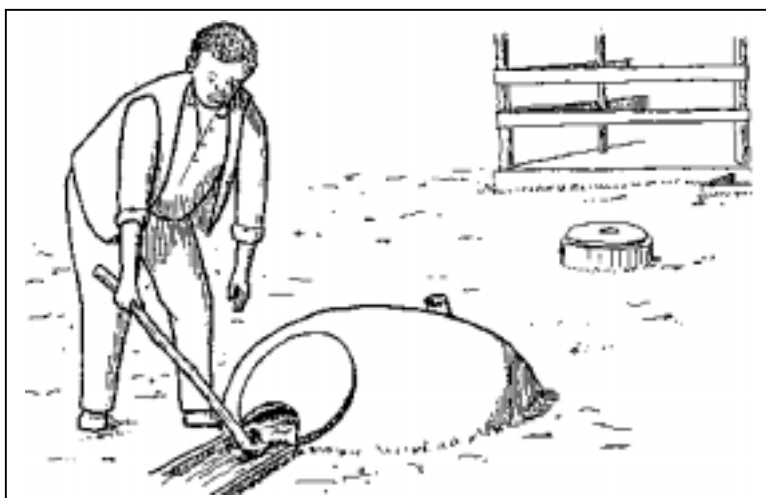
The plant must be fed regularly in order to achieve regular gas production. The substrate should be free of stalks and other impurities in order to avoid scum formation and blockage of the inlet and outlet pipes. After removing straw and waste fodder from the dung, it should be mixed sufficiently with urine or water to avoid separation of solid and liquid material inside the digester. Every day the liquid from the urine chamber must be transferred into the mixing chamber. How much liquid, i.e. how often the urine chamber needs to be emptied per day, depends on the amount of dung. As a rule of thumb 1 kg of dung requires 1 l of liquid. The user is to be advised by the BES-staff.

Chopping of the fodder into pieces of 3-5 cm length saves fodder grass and reduces the amount of stalk mixing with the dung on the floor.

In dry environments the amount of urine might not be enough to obtain the required mixing rate. Water must then be added. However, It is better to give more water to the cows instead of adding water to the plant. Beside producing more urine the cows will be in better health and produce more milk.

The overflowing slurry should move away from the outlet. Otherwise It can block the overflow and the gas pressure might increase until it escapes through the inlet pipe or blows off the water trap. Therefore, the outlet and the slurry canal must be cleaned. This must be part of the daily routine of cleaning the stable and feeding the plant. The problem becomes less, if a proper slope is maintained and the slurry canal is shaded off from direct sunshine.

The slurry distribution system must be cleaned and slurry directed towards the plants for fertilization. If this is not done, the biogas plant does not suffer, but the farmer will waste valuable manure.



**Fig.40:** Cleaning the overflow point at the expansion chamber

### Maintenance of Toilets

Well designed toilets do not require any maintenance except for cleaning the inlet and the floor of the cubical. Once a toilet is soiled and starts smelling badly, It is very difficult to again achieve cleanliness. Clean water should be used without disinfectants so as not to kill the methane bacteria in the plant. Soap water, from time to time, can be tolerated.

### Regular Maintenance of Appliances

Psychologically, the stove should be regarded as a kitchen ware and not as a fire place. There is no maintenance needed besides keeping it clean like other kitchen vessels and utensils.

The lamp needs cleaning of the glass screen in order to have bright light all the time. Cleaning should be done only if necessary to avoid shocks on the lamp that can destroy the gas mantle. Gas mantles of lamps only have a certain life time and ought to be replaced frequently. They are fixed with a string to the nozzle and the replacement is easy and does not require any skill. Used mantles are radioactive. Therefore, dust or pieces of the broken mantle should not come in contact with foodstuff. Children should be protected from inhaling the dust when they are around. Hands and working place should be cleaned with water after replacement of the mantle.

### Disturbance of the System

Trouble shooting becomes necessary if the customer, this is the owner or the user of the gasplant, complains about insufficient service or any nuisance caused by the plant. There are three sources for possible complains:

- Insufficient gasplant performance
- inadequate amount or kind of feeding material
- too high expectations on the service of a biogas unit

The latter is very difficult to deal with, because the fault was done when persuading the farmer with wrong promises. Serious information about possibilities and limitations of a biogas plant are the only way to have content customers. On the other hand, the farmer might have exaggerated the amount of feed material available to him. This can be the case when the animals are taken out for grazing when zero-grazing was expected. The actual amount of dung must be checked in order to

distinguish between short-comings in gasplant performance or underfeeding of the gasplant. A well functioning plant produces between 35 to 40 litres of biogas per kg of fresh cattle dung, depending on fodder, temperature and retention time. In rainy or colder seasons the gas production may drop to 60-70% of the normal rate.

### Interruption of Gas Production

"There is not enough gas" is by far the most common problem mentioned by the user. When the cause is found, normally the remedy is easy, except for scum problems. The following steps will help to find the reason for the gas shortage quickly:

Ask the user if gas supply is only less or if it stopped completely. Check the information given by the user concerning the appliances complained about. Ask if the problem occurred suddenly or gradual and when it was noticed first. If the problem occurred suddenly, a technical fault is very likely. If gas supply dropped gradually, one may guess that there is something wrong with the performance of the plant. This might be caused either by unsuitable properties of the feeding material or by inadequate feeding practices.

Check If there is gas in the plant. If the slurry level In the outlet chamber is high and slurry at the overflow is fresh, there is gas production. If the gas pressure is high but no gas reaches the point of use, there must be a blockage somewhere.

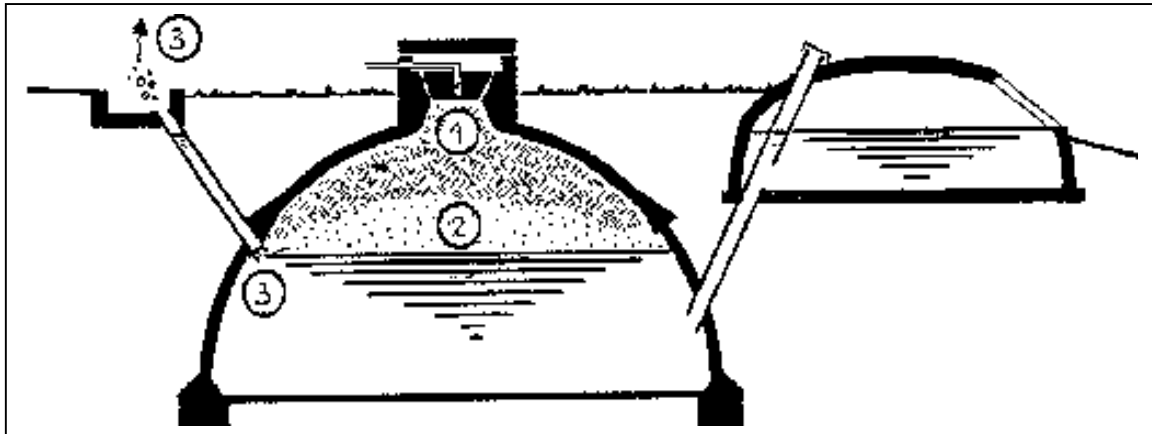
If there was no discharge of slurry because of not enough pressure inside the plant, there might be a leakage. Ask or observe if there is smell of gas in the kitchen. Check the lid for bubbles. Check the valves and then the Joints for leakages by applying soaped water to it. If no leakage is found, close the main valve and wait one day for gas pressure building up. If gas is produced, which can be seen if bubbles come up at the outlet or inlet pipe, but pressure does not build up, there must be either a leakage which opens up by increased pressure or a crack in the dome below a certain slurry level. A crack in the dome is the worst of all cases. The plant must be emptied and cracks must be repaired.

If there is no gas production at the plant, observe the smell of the slurry. If it smells sour, the fermentation process has been disturbed. Wait some time (maximum 4 weeks) without feeding the plant or feed with material from an other stable. If gas production does not start by itself again, the plant must be emptied and refilled with fresh material. Such a break down of fermentation is very rare and rarely happens with cattle dung, except in case of animal diseases treated with high doses of antibiotics. In most of the cases, gas is produced but can not arrive at the place of consumption.

If gas is produced but not available at only some of the stoves, lamps or other appliances, there is a blockage in the piping system or the Jet. If Jets are clean, there might be a water blockage in the piping system just before the appliances. Ask the customer, if gas was flickering before it finally went off. In this case, check If there is a water trap at the lowest point of the piping system. If not, change the pipe line or place a water trap. If there is once water in the pipe, there will be always water in the pipe. Reconstruction is the only solution.

### The Problem of Scum

If there is heavy gas release from the inlet but not enough gas available for use, scum is most likely the reason. Often the gas pressure does not build up because of the continuous release through the inlet. Slurry does not overflow for weeks. There is the danger of blocking the gas pipe by rising scum because of daily feeding without equivalent discharge. The lid must be opened and scum is to be taken out by hand.



**Fig.41:** Scum formation in a fixed dome plant

The scum may prevent the gas from reaching the gas outlet pipe (1). Instead, the gas will form large bubbles below the scum (2) from where the gas escapes through the inlet pipe (3). If the gas cannot escape, it might also burst the brickwork structure. Therefore, unsuitable dung should not enter the plant. Suitable dung should be filled in fresh. Stalks and other fibrous material should be sorted out and be stored directly on the compost heap. Dried dung should be thoroughly mixed with urine or water before entering the plant.

Straw, grass, stalks and even already dried dung tends to float to the surface. Solid and mineral material tends to sink to the bottom and, in the course of time, may block the outlet pipe or reduce the active digester volume. In proper mixed substrate there is no such separation because of sufficient friction within the paste-like substance.

With pure and fresh cattle dung there is no scum problem. Floating layers will become a problem when husks are part of the fodder. This is often the case in pig breeding. Before installing a gasplant at a piggery, the kind of fodder and consequently the kind of dung, must be checked to ensure if it is suitable for a biogas plant. It might be necessary to grind the fodder into fine powder. The user must be aware of this and the occurring costs before deciding on a biogas unit. The problem is even bigger with poultry droppings. The kind of fodder, the sand the chicken pick up, and the feathers falling to the ground make poultry dung the most difficult substrate. In case of doubt, no gasplant should be build.

Scum can be avoided by stirring, but....

Stirring must be done for 5 minutes every hour, throughout day and night to avoid scum formation. This can only be assured by automatic mechanisms and should not be expected from workers attending the stable. For simple gasplants, stirring is not a viable solution against scum formation.

Scum can be broken by stirrers, but....

Scum is not brittle but very filthy and tough. Scum can become so solid after only a short time, that it needs heavy equipment to break it. It remains at the surface after being broken up. To destroy it by fermentation, it must be kept wet. Either the scum must be watered from the top or pushed down into the liquid. Both operations demand costly apparatus. For simple gasplants, stirring is not a viable solution for breaking the scum.

The only solution for simple biogas plants to avoid scum is by selecting suitable feed material and by sufficient mixing of the dung with liquid before entering the plant.

### Trouble with Feeding the Plant

When there is a problem of charging dung and urine to the plant, there is a blockage at the inlet pipe. The problem might be caused by straw or grass and could be solved by thorough poking. If this happens more often, there might as well be scum blocking the inlet pipe from below. By entering a stick or a pipe into the inlet one may find out where and of which nature the blockage will be. Don't be surprised to find stones or other trash in the pipe which had been placed there by playing children. If it feels sandy, there is a heavy accumulation of soil below the inlet pipe. In this case, open the lid and scrap the sand off With a dipper or steel shovel. Only in serious cases the plant needs to be emptied.

### Faults at Appliances

It is surprising to see, how much complaints arise because equipment was not kept clean. Often food has dropped into the- burner head but sometimes dust or cinders block the Jets of burners or lamps. Normally, blockage of the jet is removed with help of a fine wire or needle. Only when blockage occurs in short intervals, the jet must be dismantled and cleaned. The rubber tube is to be disconnected and freed from dust by blowing through.

If a lamp starts to loose its brightness, it is very likely that dust particles have blocked the nozzle. Again, the nozzle must be unscrewed and cleaned.

### **13. Pending technical issues**

Several tests have been made by CAMARTEC. The results of these tests have not yet been put into practice, but might already be of interest to the reader.

#### **Position of the Outlet**

As reported above, the slurry is found in layers of different TS-content. Until now, the outlet pipe has been placed near the bottom, because it is known that digested slurry is heavier than the fresh substrate. At the same time, liquid slurry which hardly produces any gas remains for a long time in the plant. On the other hand, active sludge is driven out from the plant relatively early. Hence, the retention time of the viscous slurry is reduced. When the outlet pipe is placed higher up in the liquid zone, unproductive liquid overflows and active sludge remains longer in the plant. CAMARTEC has not yet decided if the volume of the plant could be reduced when the outlet pipe will be higher or if two alternative outlet pipes would be provided. For the time being, the present models remain valid.

#### **Standpipe for Gas Release in Case of Scum**

In one case, where pigs have been fed with husks, a heavy layer of scum had been developed. Most of the gas escaped through the inlet pipe because it could not penetrate the scum. It has now been proposed to place a perforated plastic pipe vertical in the centre of the digester, to allow the gas to pass the scum. It might still be necessary to take out the scum from time to time. For easier opening and closing of the lid, a rubber sealing and wedges of steel would be advisable.

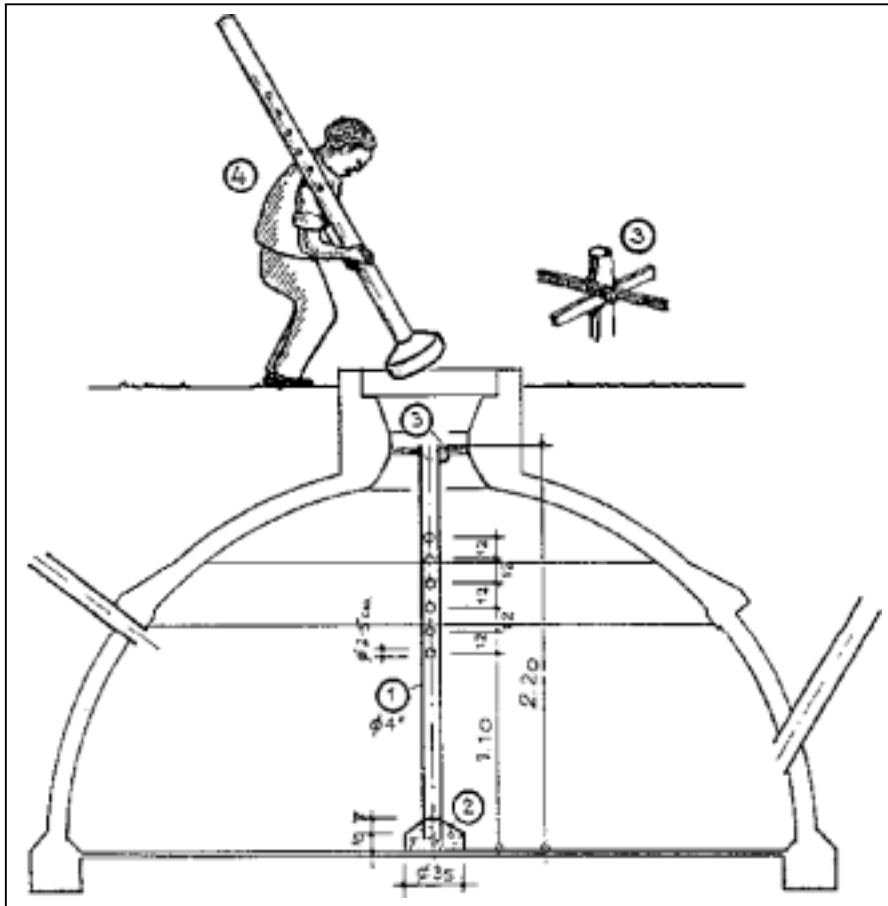
#### **Pre-Heater for Water**

In institutions, or when there is a surplus of gas, pre-heating of water might be a reasonable way of utilizing the gas. The gas burns continuously and heats the water to 30-400C. This water is used for washing or for boiling. A long-lasting and reliable apparatus has not yet been developed.

#### **Slurry Lifting Device (Pressure Booster)**

In case of an insufficient natural slope, the slurry could be lifted up with the help of water pressure from a main. Slurry flows in a pressure tank which is connected to a water pipe with sufficient pressure. The slurry inlet valve will be closed when the tank is filled. Then the water cock will be opened. The hydraulic pressure transports the slurry to a higher level from where it flows by gravity to the field. When the slurry becomes watery, the water cock will be closed and water from the pressure tank will be drained off. Then the slurry valve is opened again for re-filling. The system is valid when water is supplied free or at a low price from the main. The volume of the pressure tank depends on the intervals of distributing the slurry.





**Fig.42:** Stand-pipe for gas release

In case of heavy scum formation, a perforated 4"-plastic pipe ( 1 ) is placed in the centre of the digester to allow the gas to pass through the scum. Thus, removing of scum will be only necessary in longer intervals. It is held at the bottom in a concrete foot (2) and fixed at the top with a timber cross (3). The pipe can be inserted, when necessary, even after the plant is in operation (4).

#### Gas Pressure Equalizer

When there are several biogas plants scattered over the compound of an institution or a bigger farm, the pressure will be different because of the friction losses and different gasplant designs. A standardized instrument is to be developed which can be installed in such places.

## 14. Appendix

CHARACTERISTICS OF PROJECT AREA WHERE THE BIOGAS EXTENSION SERVICE IS ACTIVE.

Country: Tanzania: Population 25 Mill. inhabitants, area: 1,25 Mill square Km, GNP 235 US\$ per capita, deriving from Industries 10%, agriculture 59%, services 31%, inflation rate in 1985-1990 25%, local currency 1000 Tsh = 5,30 US\$ (May 1990).

Price relations: 1 adult milking cow 75.000 Tshs, 1 Biogas Plant of 16 m<sup>3</sup> VD costs 170.000 Tshs, or 2-3 in-calf cows, 1 daily wage of unskilled labourer is 200-300 Tshs, 1 bag of cement costs 1.150 Tshs, 1 kg of maize (producer price) gains 15 Tshs, 1 l of kerosene costs 51 Tshs.

Project area: Coffee-banana-belt around Mt. Meru with Arusha being the commercial and cultural centre. Population density: 195 inhabitants/km<sup>2</sup>, altitude: 1200-1500 m above NN, rainfall: 2500 mm p.a., semi-dry season: three months, min-max temperature: 10-30°C.

Theoretical Biogas Potential: 10% of households = 4 biogas plants/ km<sup>2</sup>.

### LIST OF FORMS

The following list of forms is a proposal for any private or public Biogas Extension Service. It has proven useful in practice for:

- giving the customer a reliable overview over the costs,
- not forgetting any details
- coming to clear arrangements with the customer and
- having a guideline for quantity and cost calculation.

#### FORM 1

Letter to potential Customers, asks the customer to send a formal request letter including details about his farm set-up. The data mentioned can be used as a reference for later evaluations, e.g. to compare the number of cows at application and after several years.

The first site-visit and the planning starts only after having received the formal request, in order not to waste any time on unserious applicants.

#### FORM 2

Calculation Sheet for Unit construction

#### FORM 3

Quantity survey form are forms to easily calculate the needed building materials for Biogas Plant, cowshed, pigsty, toilet, etc.. They are meant for internal use.

#### FORM 4

Letter to the customer explains all the details being necessary for a satisfactory functioning BGU on his farm: BGP, stable(s), modifications, gas consumption appliances etc..

It clears communication flow, but is not always necessary, as customer is mainly asking for costs, which can be only discussed after Form 5.

#### FORM 5

Delivery decision and cost calculation is an agreement between the Biogas Extension Service and the customer on who is delivering what. Often it is cheaper for a farmer to have his own workers digging the pit or he has e.g. a cheaper source of sand or his own means of transport. The farmer should have the chance to help make his BGU as cheap as possible, but of course this should be based on a clear arrangement.

The form informs about total value of construction, supervision costs and how much is to be paid to the contractor.

#### FORM 6

Contract is delivered personally and signed by both customer and constructor, after quantities and costs have been agreed on. While signing the contract, the first installment of 50% of the total costs has to be paid. As soon as the first installment is received, material delivery and construction work can start.

#### FORM 7

Material to be delivered by the customer is a form to agree on a certain time, when the building materials supplied by the farmer have to be at the site. If the farmer delays his delivery, B.E.S. or the contractor has the right to supply missing materials in order to avoid delay of construction work.

#### FORM 8

Slurry Utilisation Agreement is a form with which B.E.S. tries to explain to farmers their duties and B.E.S. inputs in order to establish a sustainable slurry distribution system.

#### FORM 9

After Sales Service is a contract in which the customer and B.E.S. come to an agreement about sharing the costs for the check-up and necessary modifications of the plant after an operational period of several years.

The above given list of forms should be taken as an example. It depends very much on regional conditions, on the number of BGU's built annually and on the diversity of regularly occurring problems, to which extent a "Form-System" is established.

Forms are created mainly to make a job easier. Things are made clear by writing them down.

EXAMPLE: FORM 2 CALCULATION SWEET FOR UNIT CONSTRUCTION

	(for internal use)		
<b>Name of Customer</b>			
Village			
Date			
It is-required for	phase 1	phase 2	phase 3
Size of plant	m <sup>3</sup>	m <sup>3</sup>	m <sup>3</sup>
additional inlet			
toilet complete		toilet connection	
stable Z		pigsty R	
stable modification:			
Item	unit	amount	
cement	bag		
sand	ton		
murrum	ton	..	
stones	ton	..	
bricks	piece	..	
pillars Ø 15 cm	piece	..	
purlins 2" x 2"	piece	..	
boards 2" x 4"	piece	..	
nails 4"	kg	..	
roofing nails	kg	..	
roof gutter	m	..	
gutter holder	piece	..	
iron sheets	piece	..	
slabs 15 x 15 cm	piece	..	
slabs 15 x 30 cm	piece	..	
slabs 30 x 30 cm	piece	..	
small items		..	
labour		..	
		..	
		..	
		..	
piping Ø 3/4"	m	..	
		gas consumption	
household stoves	piece	..	
canteen stoves, type ..	..	.	
canteen stoves ins.pot	.	.	
lamps piece	..	.	
signature of planner		signature of site engineer	

EXAMPLE: FORM 5 COST CALCULATION

Copy to customer)

Name of customer.....Village.....Date.....

Phase.....

Item	amount	will be provided by		additional items provided by BES for the price
		customer	BES	
bricks	.....	.....	.....	.....
cement	.....	.....	.....	.....
lime	.....	.....	.....	.....
sand	.....	.....	.....	.....
murrum	.....	.....	.....	.....
stones	.....	.....	.....	.....
chippings	.....	.....	.....	.....
PVC pipe 4"	.....	.....	.....	.....
PVC pipe 6"	.....	.....	.....	.....
plain wire	.....	.....	.....	.....
chick wire	.....	.....	.....	.....
small items	.....	.....	.....	.....
galv.pipe Ø 3/4"	.....	.....	.....	.....
h. h.stove	.....	.....	.....	.....
cant.stove	.....	.....	.....	.....
stove modif.	.....	.....	.....	.....
lamp	.....	.....	.....	.....
pillars	.....	.....	.....	.....
boards	.....	.....	.....	.....
gutter	.....	.....	.....	.....
metal piec.	.....	.....	.....	.....
nails	.....	.....	.....	.....
iron sheets	.....	.....	.....	.....
small Items	.....	.....	.....	.....
labour	.....	.....	.....	.....
digging	.....	.....	.....	.....
.....	.....	.....	.....	.....
.....	.....	.....	.....	.....

Total Tshs

.....

.....

Total value of construction

supervision.....%

.....

Grand Total

.....

Value of customers contribution

.....

Payment to BES

date:.....

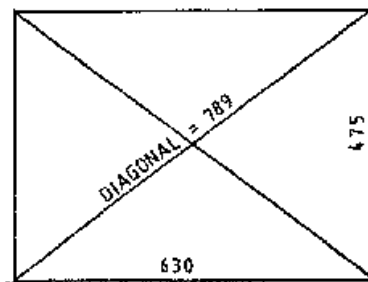
signature customer.....

signature BES.....

This detailed floor plan illustrates the layout of a dairy building, including the following features and dimensions:

- Top Section:** A row of five troughs labeled "Feeding Trough", "Water Trough", "Feeding Trough", "W.T.", and "F.T.".
- Central Area:** A large "Exersing Area" (Exercise Area) with a "2% Slope" indicated by an arrow pointing downwards.
- Right Section:** A designated area for "Calves" with a "2% Slope" indicated by an arrow pointing downwards.
- Left Section:** A "Mixing Chamber" and a "Urine Chamber" are located adjacent to the exercise area.
- Bottom Section:** A row of "Sleeping Boxes" with a "2% Slope" indicated by an arrow pointing downwards. A "Milking Stand" is located in the bottom right corner.
- Dimensions:**
  - Horizontal Dimensions (Top):** 12, 140, 12, 100, 12, 174, 12, 45, 12, 114, 12.
  - Horizontal Dimensions (Bottom):** 15, 95, 15, 95, 15, 105, 15, 105, 15, 135.
  - Vertical Dimensions (Right):** 10, 15, 82, 50, 15, 165, 15, 74, 15, 185, 15.
  - Vertical Dimensions (Left):** 601, 601.
  - Overall Dimensions:** 655 (Total Width), 579 (Total Depth).
- Orientation:** A North arrow is located at the top center, pointing upwards.

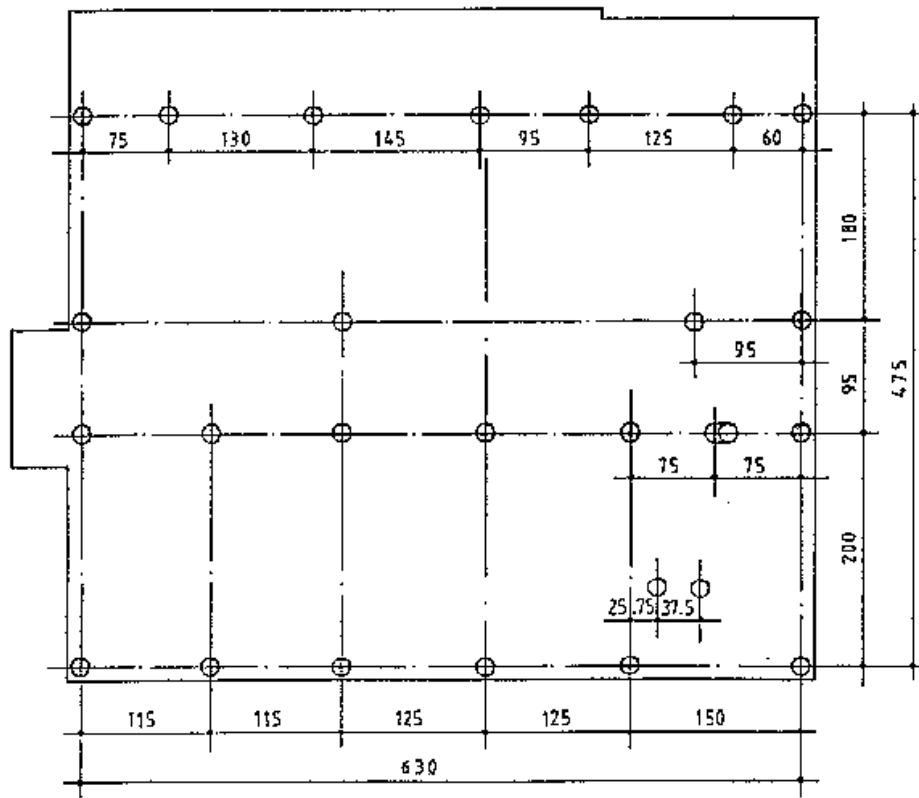
CAMARTEC Z4		JOB TITLE:  Zero Grazing Unit for Four Cows
DRAWN:	CHECKED:	
SCALE: 1:50	DATE: NOV. 1989	



Rectangular check

NOTE:

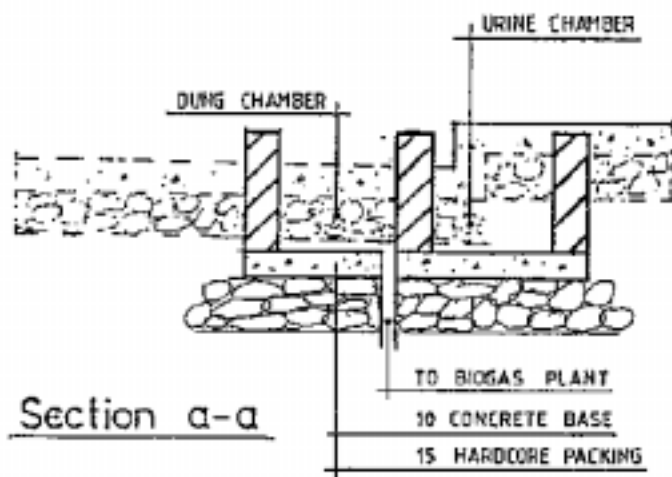
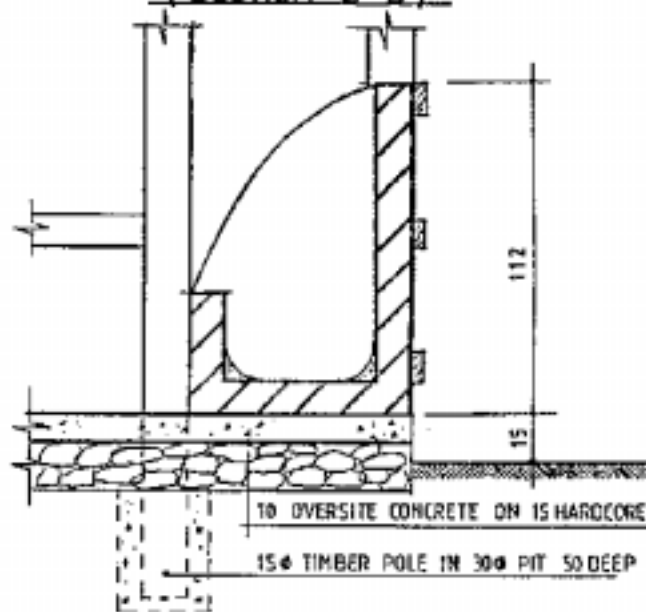
All dimensions are given for centers of pillars



Foundation plan

<b>CAMARTEC Z4</b>		JOB TITLE: <b>Zero Grazing Unit for Four Cows</b>
DRAWN:	CHECKED:	
SCALES: 1:50, 1:100	DATE: NOV. 1989	

# Feeding Trough at Milking Stand (Section b-b)

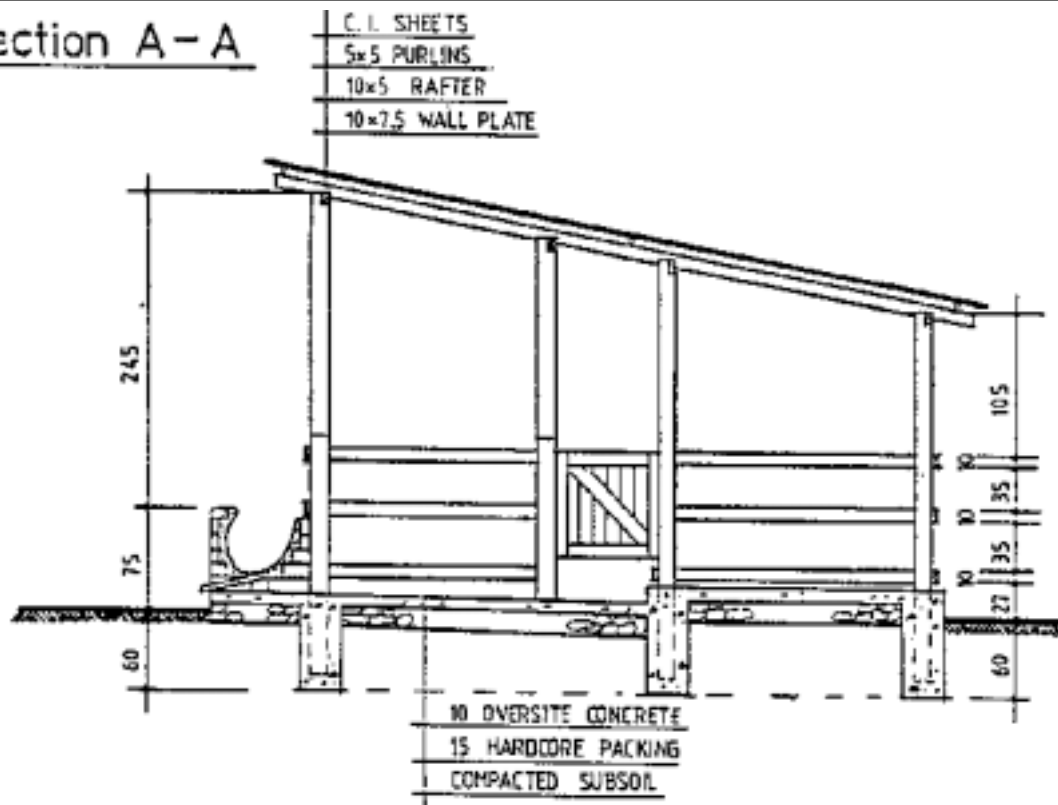


Section a-a

<b>CAMARTEC Z4</b>		JOB TITLE:	
DRAWN:	CHECKED:	Zero Grazing Unit for Four Cows	
SCALE: 1:20	DATE: NOV. 1989		



## Section A - A



**CAMARTEC Z<sub>4</sub>**

DRAWN:

CHECKED:

SCALE:

1:50

DATE:

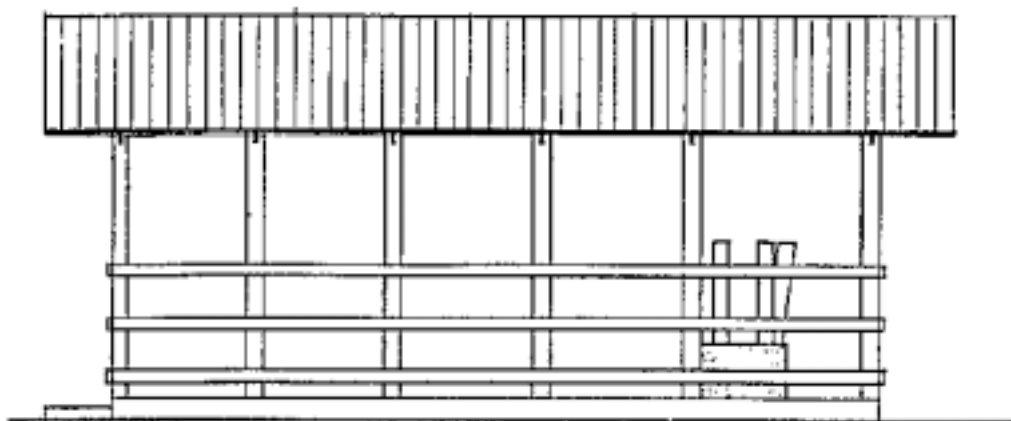
NOV. 1989

JOB TITLE:

Zero Grazing Unit for  
Four Cows

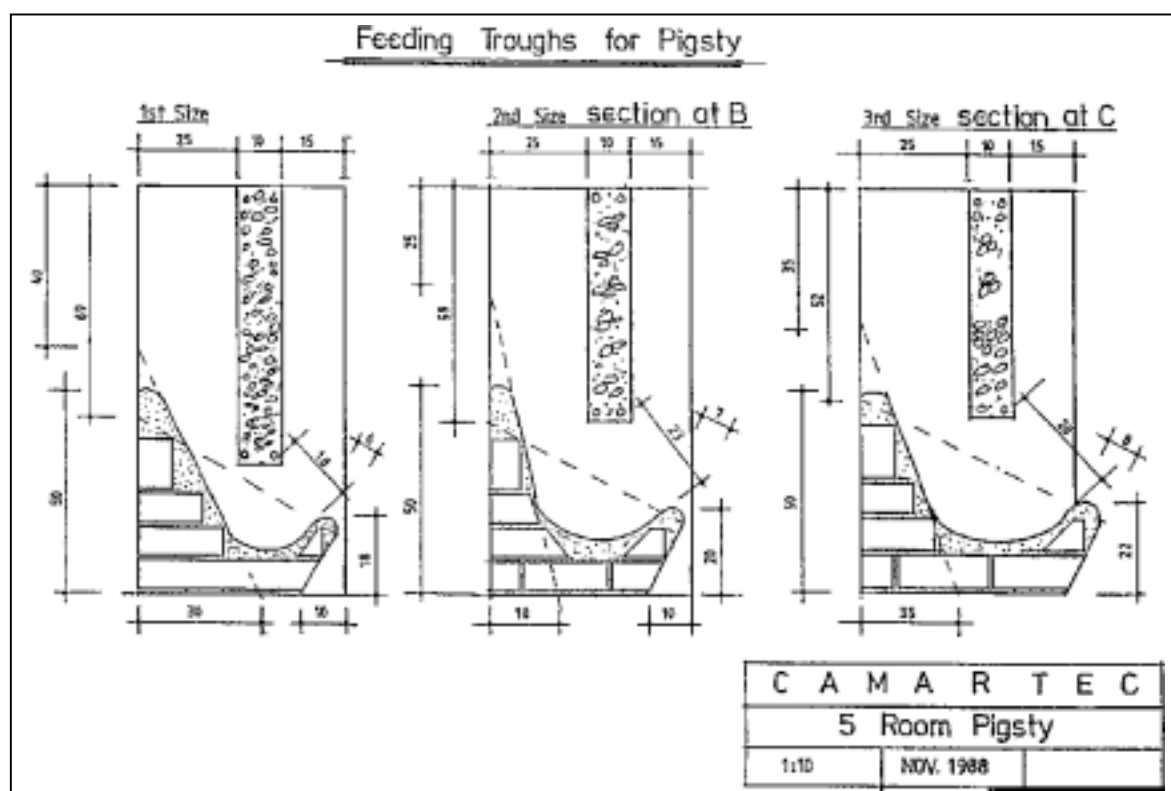
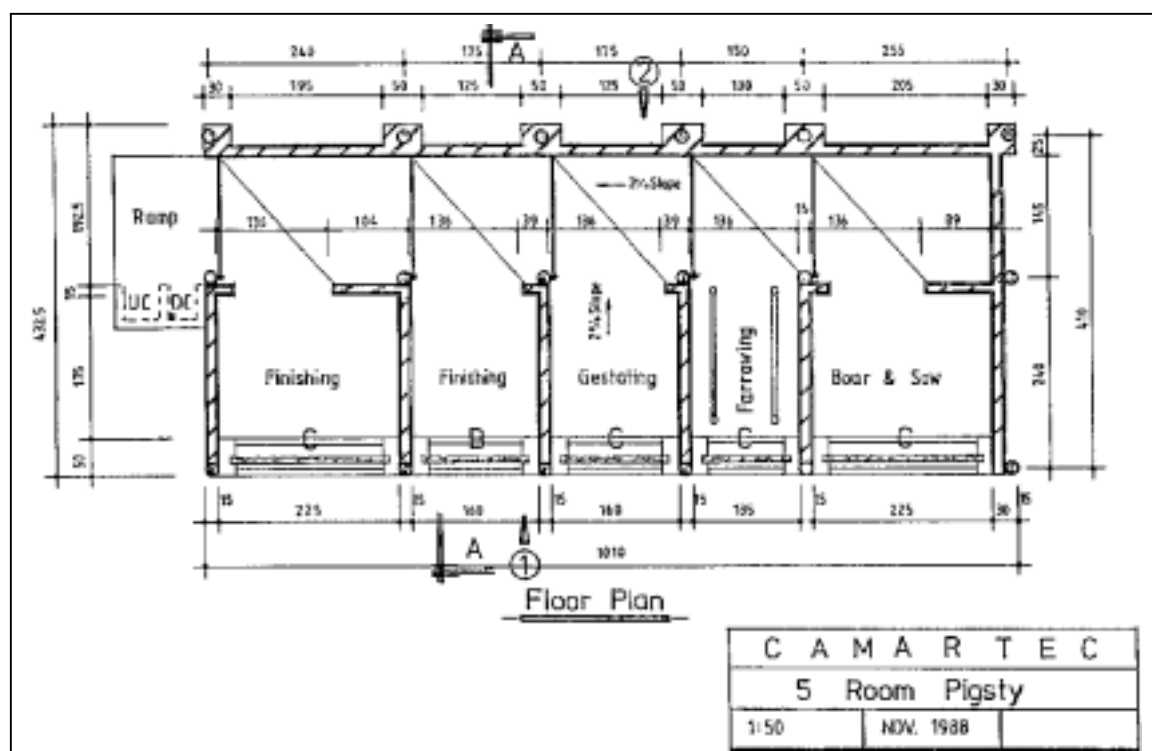


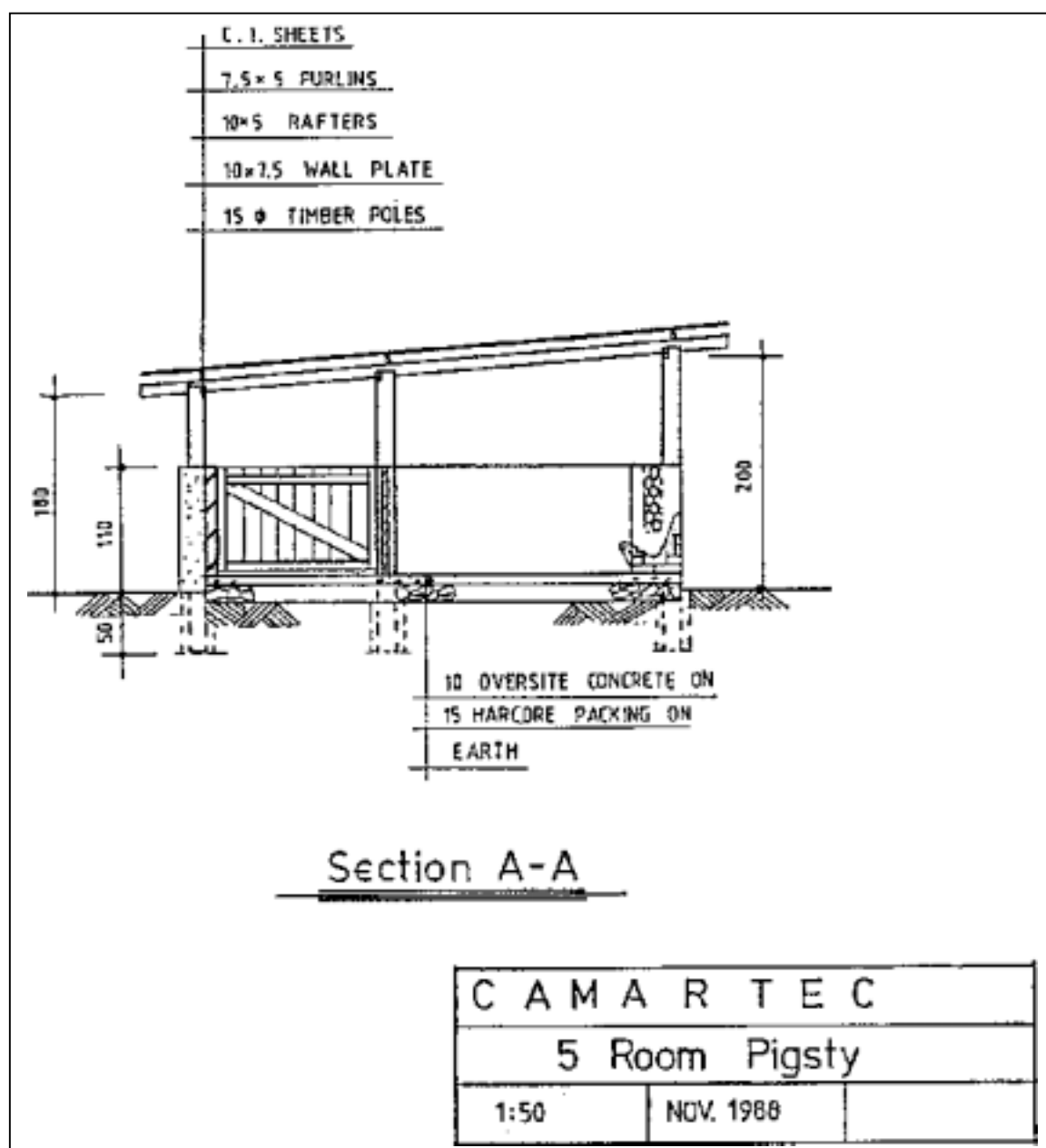
Front elevation

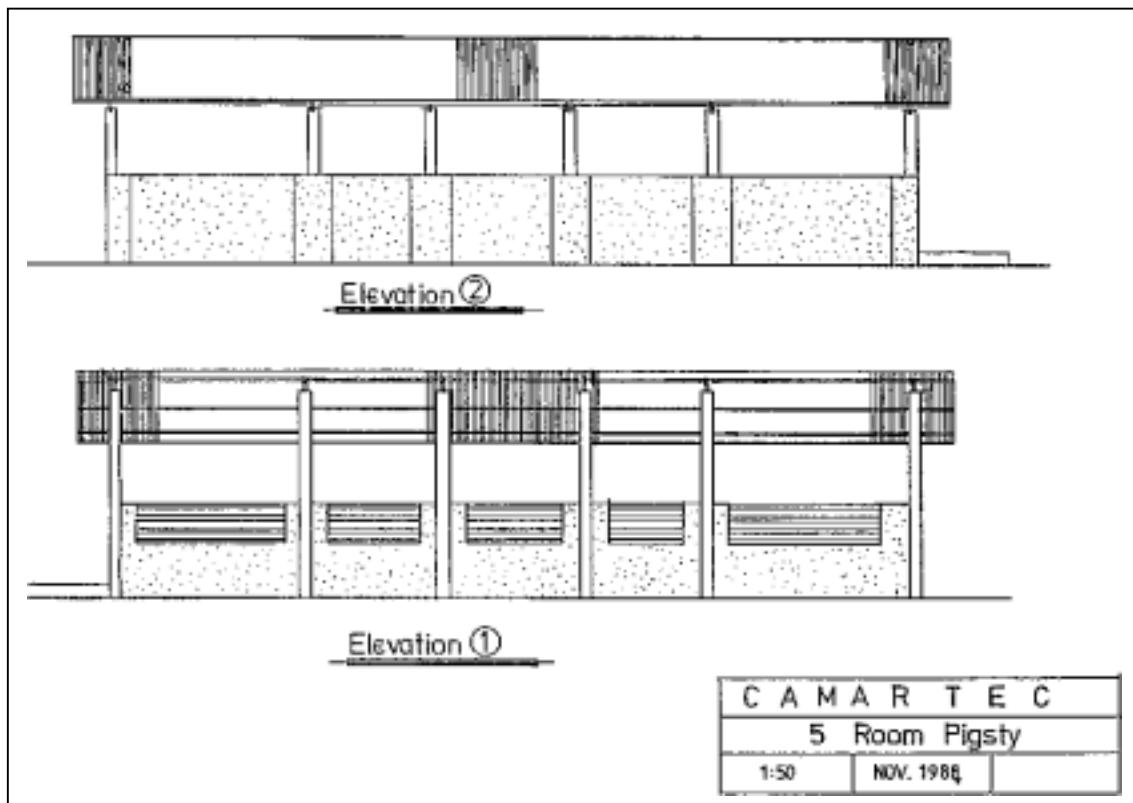


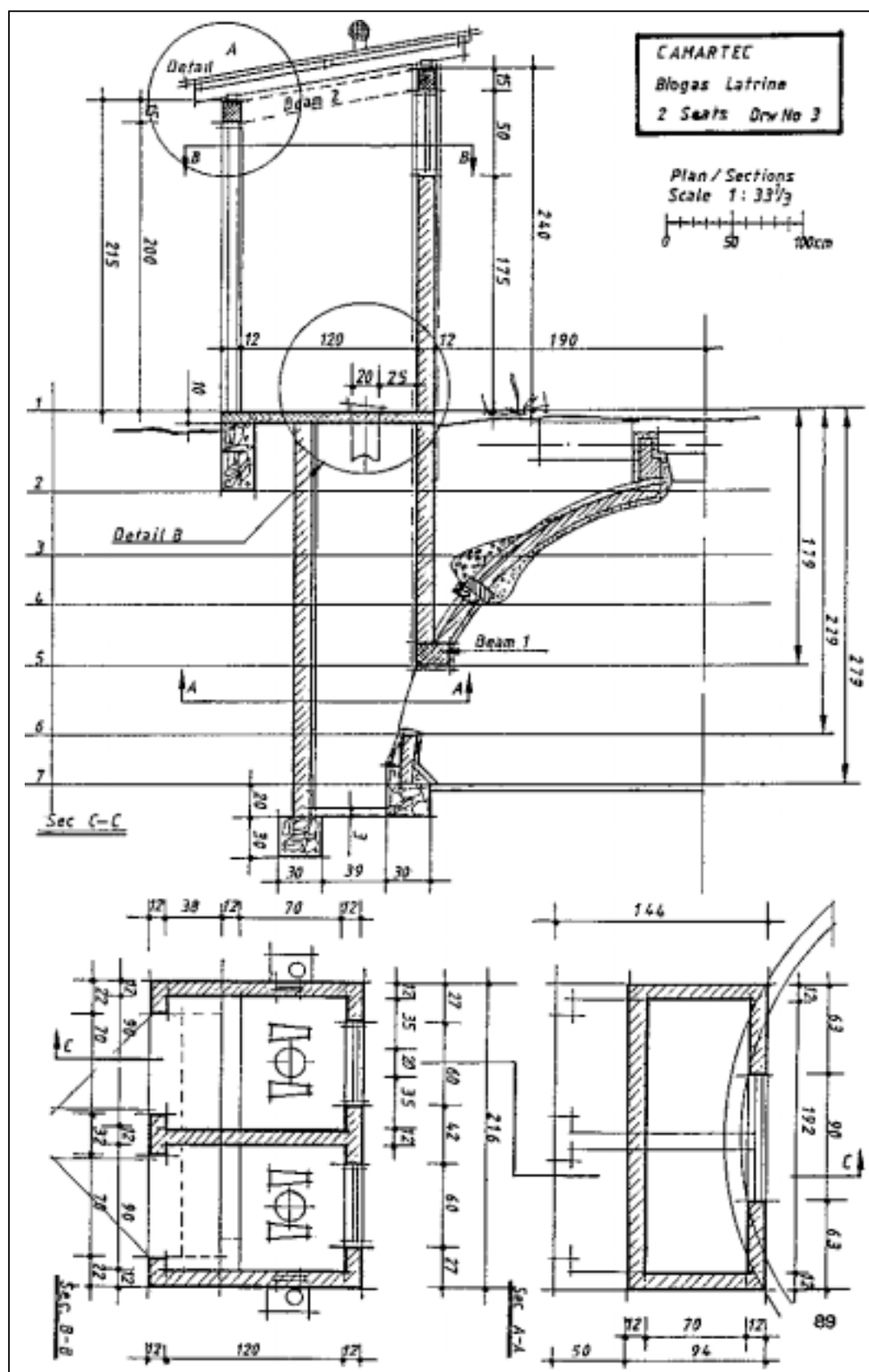
Rear elevation

<b>CAMARTEC Z4</b>		JOB TITLE:	
DRAWN:	CHECKED:	Zero Grazing Unit for	
SCALE:	DATE:	Four Cows	
1: 50	NOV. 1989		

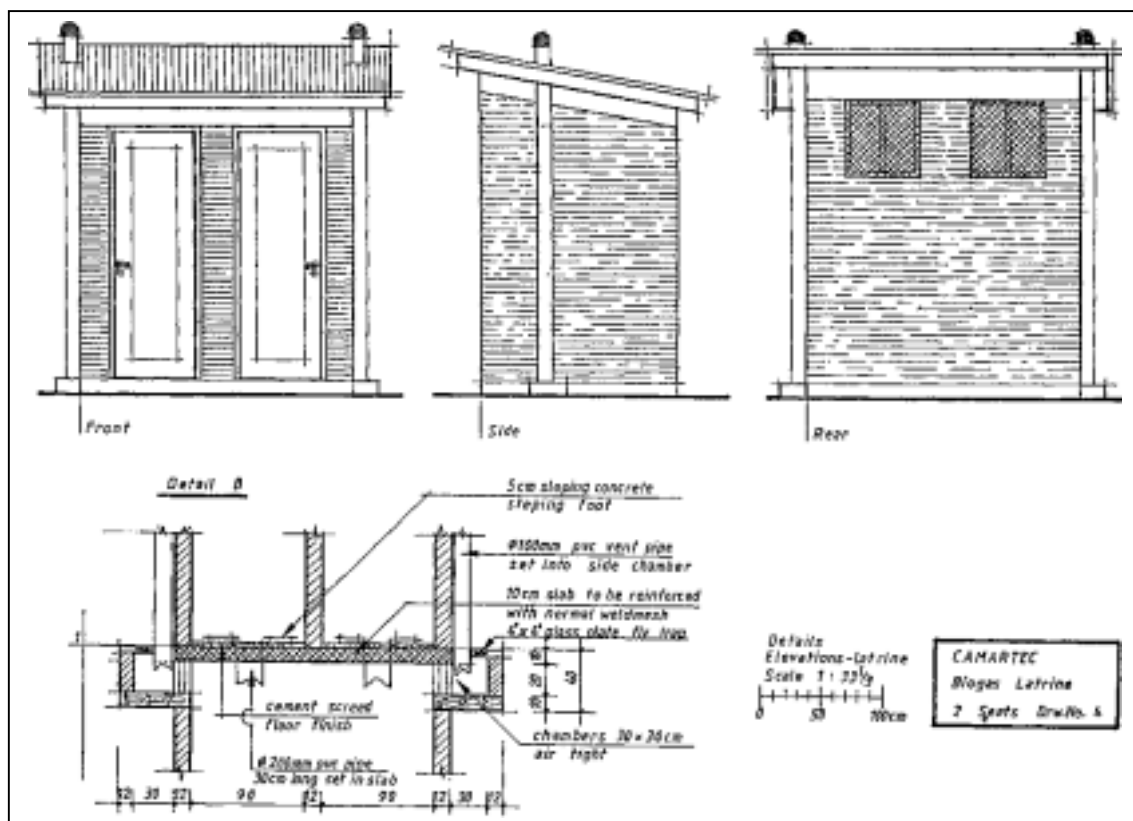
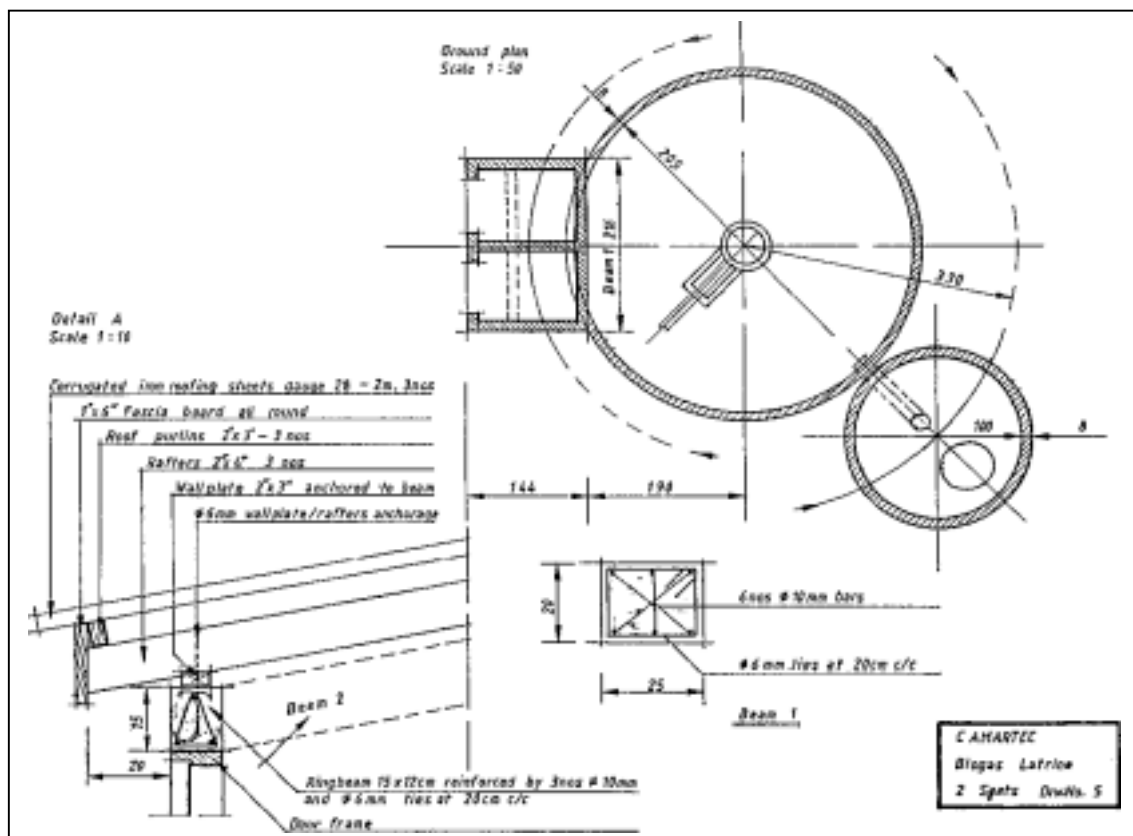








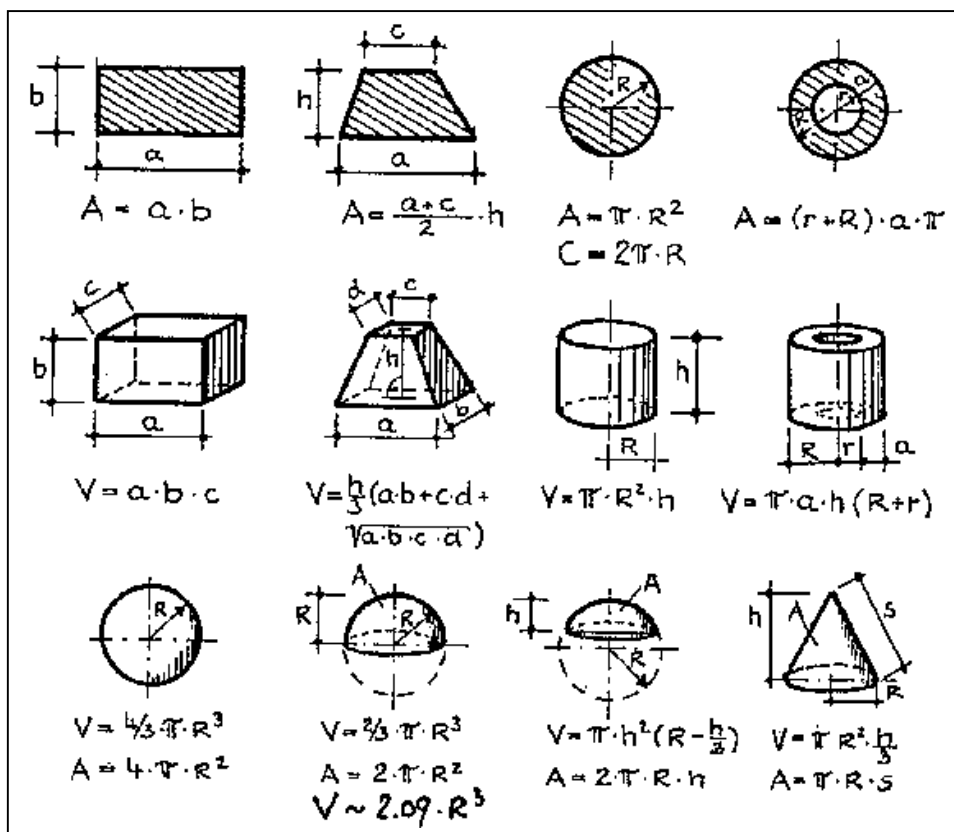




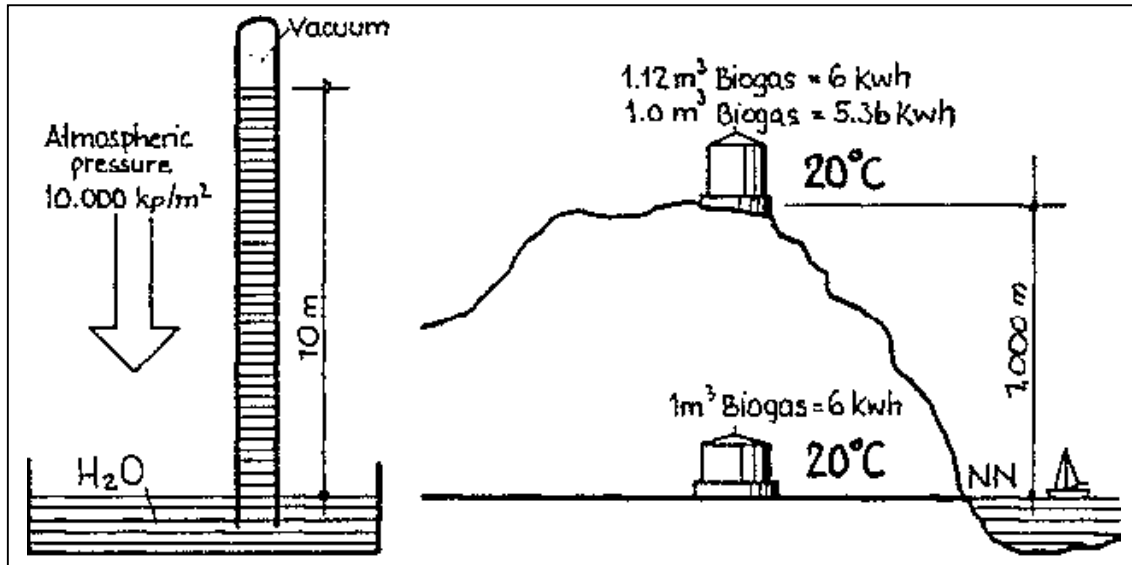


SQUARE AND CUBIC NUMBERS, GEOMETRICAL FORMULAE

n	n <sup>2</sup>	n <sup>3</sup>	n	n <sup>2</sup>	n <sup>3</sup>	n	n <sup>2</sup>	n <sup>3</sup>
1,00	1,00	1,00	2,00	4,00	8,00	3,00	9,00	27,00
1,05	1,10	1,18	2,05	4,20	8,62	3,05	9,30	28,37
1,10	1,21	1,33	2,10	4,41	9,26	3,10	9,61	29,79
1,15	1,32	1,52	2,15	4,62	9,94	3,15	9,92	31,28
1,20	1,44	1,73	2,20	4,84	10,85	3,20	10,24	32,77
1,25	1,56	1,95	2,25	5,06	11,39	3,25	10,56	34,33
1,30	1,69	2,20	2,30	5,29	12,17	3,30	10,89	35,94
1,35	1,82	2,48	2,35	5,52	12,98	3,35	11,22	37,60
1,40	1,96	2,74	2,40	5,76	13,92	3,40	11,56	39,30
1,45	2,10	3,05	2,45	6,00	14,71	3,45	11,90	41,06
1,50	2,25	3,38	2,50	6,25	15,63	3,50	12,25	42,88
1,55	2,40	3,72	2,55	6,50	16,58	3,55	12,60	44,74
1,60	2,56	4,10	2,80	6,76	17,58	3,60	12,98	46,66
1,85	2,72	4,49	2,65	7,02	18,81	3,65	13,32	48,63
1,70	2,89	4,91	2,70	7,29	19,68	3,70	13,89	50,85
1,75	3,06	5,38	2,75	7,56	20,80	3,75	14,06	52,73
1,80	3,24	5,83	2,80	7,84	21,95	3,80	14,44	54,87
1,85	3,42	6,33	2,85	8,12	23,15	3,85	14,82	57,07
1,90	3,51	6,86	2,90	8,41	24,39	3,90	15,21	59,32
1,95	3,80	7,41	2,95	8,70	25,67	3,95	15,60	61,63



## INFLUENCE OF ALTITUDE AND TEMPERATURE ON BIOGAS



Examples:

The calorific value of biogas at sea level and 20°C is about 6 kwh/m³

Calorific value of biogas at sea level and 40°C:

$$= (6 \text{ kwh/m}^3 \cdot 273^\circ\text{C}) / (273^\circ\text{C} + (40^\circ\text{C} - 20^\circ\text{C})) = 5.59 \text{ kwh/m}^3$$

where: 273°C = absolute zero point of temperature

Calorific value of biogas 1,000 m above sea level and 20°C:

$$= (6 \text{ kwh/m}^3 \cdot 10,000 \text{ kp/m}^2) / (10,000 \text{ kp/m}^2 + (1,000 \text{ m} \cdot 1,2 \text{ kp/m}^3)) = 5.36 \text{ kwh/m}^3$$

where: 10,000 kp/m² = atmospheric pressure at sea level,  
1,2 kp/m³ = density of air

Calorific value of biogas at 1,000 m above sea level and 40°C:

$$= (6 \text{ kwh/m}^3 \cdot 10,000 \text{ kp/m}^2 \cdot 273^\circ\text{C}) / [(273^\circ\text{C} + (40^\circ\text{C} - 20^\circ\text{C})) \cdot 10,000 \text{ kp/m}^2 + (1,000 \text{ m} \cdot 1,2 \text{ kp/m}^3)] = 4.99 \text{ kwh/m}^3$$

# GAS PROPERTIES, CALORIFIC VALUES AND GAS CONSUMPTION

<b>Properties of combustible gases</b>						
<b>Gas</b>	<b>Constituent value</b>	<b>Composition to air kwh/m<sup>3</sup></b>	<b>Calorific speed= 1</b>	<b>Density requirement cm/sec.</b>	<b>Combustion m<sup>3</sup>/m<sup>3</sup></b>	<b>Air</b>
Methane	CH <sub>4</sub>	100	9.94	0.554	43	9.5
Propane	C <sub>3</sub> H <sub>8</sub>	100	25.96	1.560	57	23.8
Butane	C <sub>4</sub> H <sub>10</sub>	100	34.02	2.077	45	30.9
Natural Gas	CH <sub>4</sub> ; H <sub>2</sub>	65;35	7.52	0.384	60	7.0
City Gas	H <sub>2</sub> ; CH <sub>4</sub> ; N <sub>2</sub>	50;26;24	4.07	0.411	82	3.7
Biogas	CH <sub>4</sub> ; CO <sub>2</sub>	80 40	5.98	0.940	40	5.7

Biogas compared with other fuels

<b>Fuel</b>	<b>Unit u</b>	<b>Calorific value kwh/u</b>	<b>Applicat ion</b>	<b>Efficiency %</b>	<b>Biogas equivalent m<sup>3</sup>/u</b>	<b>u/m<sup>3</sup> biogae</b>
Cow dung	kg	2.5	cooking	12	0.09	11.11
Wood	kg	5.0	cooking	12	0.18	5.56
Charcoal	kg	8.0	cooking	25	0.81	1.64
Hard coal	kg	9.0	cooking	25	0.59	1.45
Butane	kg	13.6	cooking	60	2.49	0.40
Propane	kg	13.9	cooking	60	2.54	0.39
Diesel	kg	12.0	cooking	50	1.83	0.55
Diesel	kg	12.0	engine	30	2.80	0.36
Electricity	kwh	1.0	motor	80	0.56	1.79
Biogas	m <sup>3</sup>	6.0	cooking	55	1	1
Biogas	m <sup>3</sup>	8.0	engine	24	1	1

Examples of Biogas consumption

Household burner: 200 - 500 l/h

Some figures of gas consumption from India: Boiling 1 l of water: 40 l; boiling 5 l of water 165 l; cooking 500 grice: 140 l; cooking 1000 g rice: 175 l; cooking 350 g pulses: 270 l; cooking 700 g pulses: 315 l

Industrial burner: 1000 - 3000 l/h

Refrigerator (100 l volume): 30 - 80 l/h

Gas lamp: 120 - 180 l/h

Generation of 1 kwh electricity: 700 l

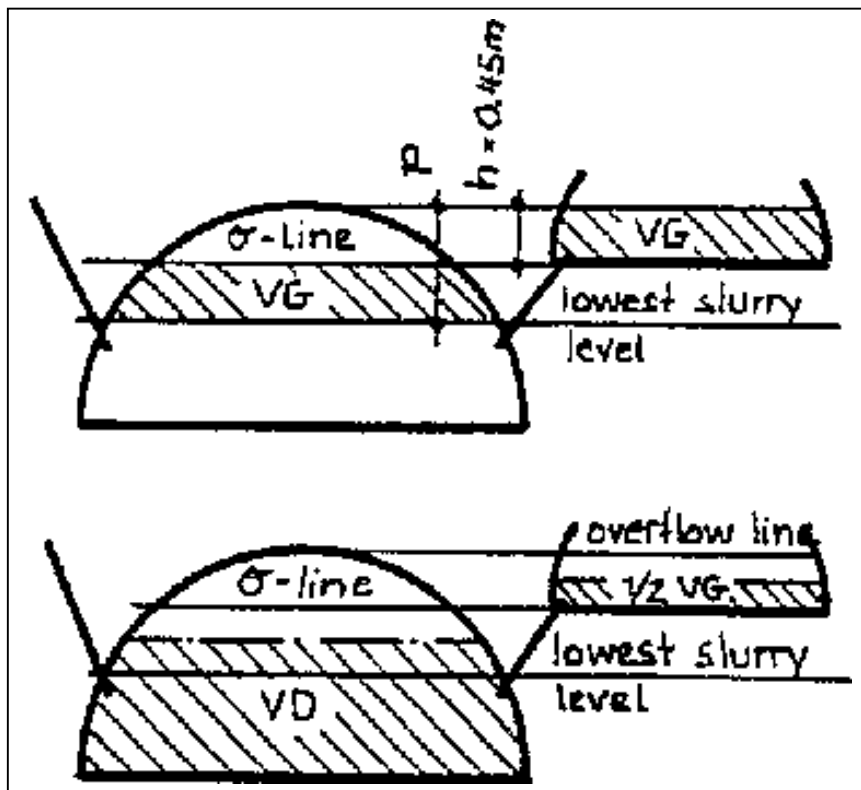
Biogas/Diesel engine per bhp: 420 l/h

## FORMULAE FOR THE DIMENSIONS OF FIXED DOME PLANTS

Vs	[l/day]	volume of feed material
RT	[days]	wanted retention time
h	[m]	depth of expansion chamber = 0.45 m the overflow is in level with the peak of the sphere of the digester
V	[m³]	wanted gas storage space
G		
	VG	$= r^3 \cdot 2.09 - (r - 0.45)^2 \cdot p(r - 0.15)$
V	[m³]	required digester volume
D		
	VD	$= (Vs \cdot RT)/1000$
	VD	$= (R^3 \cdot 2.09) - (VG/2) - 0.45^2 \cdot p(R - 0.45)$
p	[m]	maximum gas pressure (= lowest slurry level)
p		$= a(0.45^2 \cdot p(R - 0.15) + VG)/(p \cdot (R - 0.30))$

The real and active volume of the digester in fixed dome plants depends on the gas storage space actually utilized. This is normally not exactly known. Therefore, an approximate calculation of dimensions is sufficient. In the table below, the average digester volume VD is given which occurs with a chosen radius R. The relation between radius r and the volume of the expansion chamber (which is equal to the volume of the gas storage space) is based on a depth of the expansion chamber of 0.45 m. In order to keep the gas pressure below 1 m of W.C., the gas storage capacity should not exceed max VG.

Dimensions of Fixed Dome Plants				
R m	Digester avg. VD m³	max VG m³	Expansion r m	chamber VG m³
1,50	5,10	2,50	0,90	1,05
1,80	5,30	3,00	1,00	1,31
1,70	8,00	3,00	1,10	1,61
1,80	10,00	3,50	1,20	1,93
1,90	12,00	3,50	1,30	2,29
2,00	14,00	4,00	1,40	2,66
2,10	17,00	4,00	1,50	3,07
2,20	19,00	4,50	(1.60)	(3.51)
2,30	22,00	4,50	(1.70)	(3.97)
2,40	25,00	5,00	(1.80)	(4.46)
2,50	29,00	5,00	(1.90)	(4.98)
2,60	32,00	5,50	(2.00)	(5.53)
2,70	37,00	6,00		
2,80	41,00	6,00	For VD >3.00 m³ it is advisable to construct several chambers or expansion channels instead of spherical chambers	
2,90	46,00	6,00		
3,00	51,50	6,50		
3,10	57,00	7,00		
3,20	63,00	7,00		
3,30	69,00	7,50		
3,40	76,00	7,50		
3,50	83,00	8,00		



## FORMULAE FOR THE DESIGN OF BIOGAS BURNERS

### Starting Values

QR	[kcal/h]	prescribed heat requirement
VF	[m <sup>3</sup> /h]	fuel flow rate
h	[m W.C.]	prescribed gas pressure

### Geometrical data

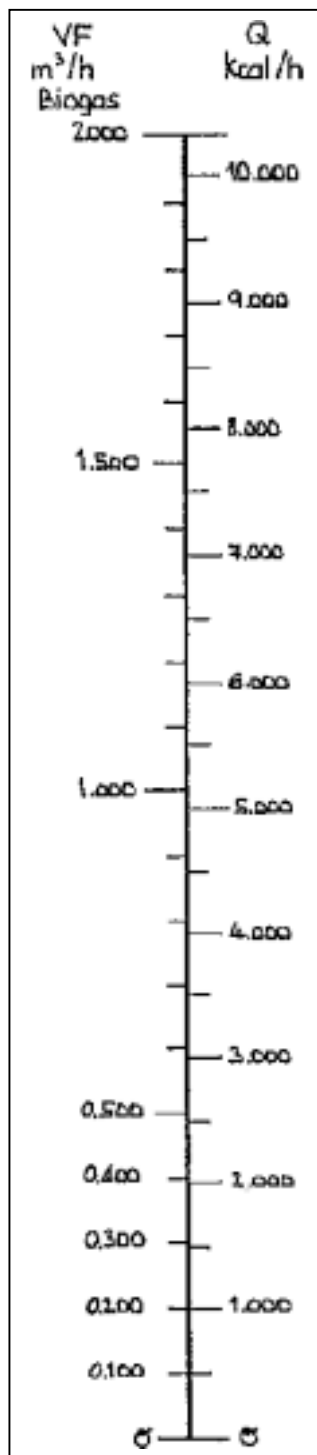
do	[mm]	= 2.1 (VF/h)
d	[mm]	= 6 · do
l max	[mm]	= 7 · d
l min	[mm]	= 1.35 · d

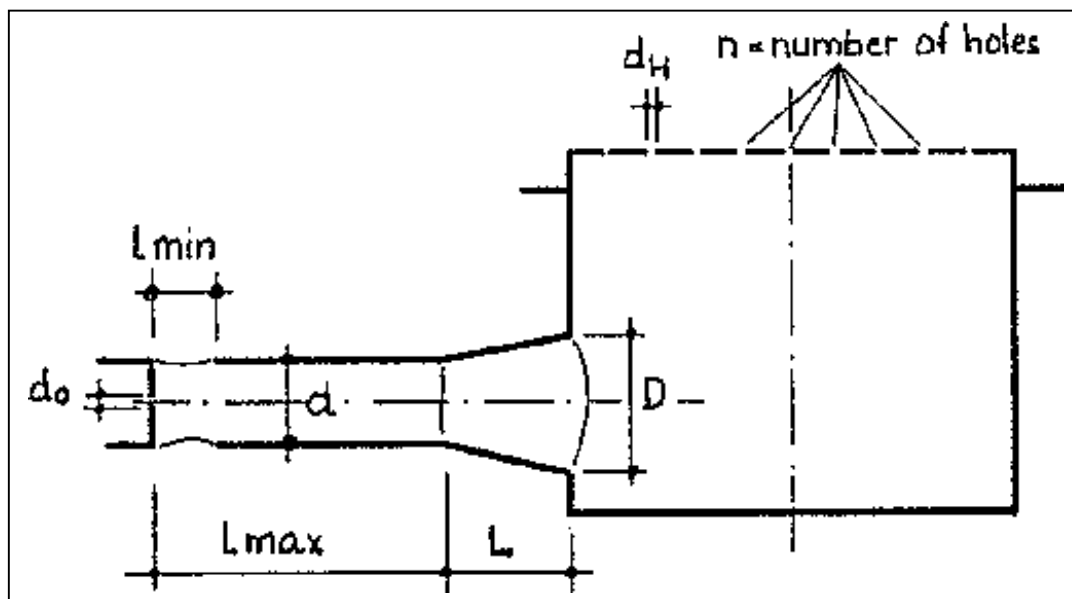
### Gas pressure 0.60 m W.C. (fixed dome plants)

D	[mm]	= 1.25 · d
L	[mm]	= 1.20 · d
n	[number]	= 50 · do <sup>2</sup> (dH = 2.5 mm)

### Gas pressure 0.10 m W.C. (floating drum plants)

D	[mm]	= 1.30 · d
L	[mm]	= 1.50 · d
n	[number]	= 20 · do <sup>2</sup> (dH = 2.5 mm)





**PROMOTION OF RENEWABLE ENERGY, ENERGY EFFICIENCY AND  
GREENHOUSE GAS ABATEMENT (PREGA)**

**Lao PDR**

**Biogas Production at Vanith Farm**

A Pre-feasibility Study Report<sup>1</sup>

**July 2006**

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<sup>1</sup> Prepared by the PREGA National Technical Experts from National Consulting Company: Vongtayfa Sisouvong, Syamphone Phommalyvong and Linsamouth Vilayvong.



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## List of Abbreviations

AD	Anaerobic Digestion
ADB	Asian Development Bank
BOOT	Build, Operate, Own and Transfer
BOT	Build, operate and transfer
BTF	Build, transfer and finance
CCEAP	Climate Change Enabling Activity Project
CDM	Clean Development Mechanism
CH <sub>4</sub>	Methane
CO	Carbon Monoxide
CO <sub>2</sub>	Carbon Dioxide
COD	Chemical Oxygen Demand
CPC	Committee for Planning and Cooperation
CTTE:	Canada-Thailand Tri-bilateral on Environment
DNA	Designated National Agency
DOE / DoE	Department of Electricity
EDL/EdL	Electricité du Laos
EE	Energy Efficiency
EIAs	Environmental Impact Assessments
EM	Extensive Microorganism
EMP	Environmental Management Plan
EMMUs	Environmental Management and Monitoring Units
ESCOs	Energy Service Companies
FAO	Food and Agricultural Organization (of United Nations)
GDP	Gross Domestic Product
GEF	Global Environment Facility
GIS	Geographical Information System
GHG	Greenhouse Gas
GMS	Greater Mekong Sub-region
GNP	Gross National Product
GOL/GoL	Government of Lao PDR
HDR	Global Human Development Report
Lao PDR	Lao People's Democratic Republic
LDC	Least-Developed Country
LPG	Liquefied Petroleum Gas
LRMC	Long Run Marginal Cost
MAF	Ministry of Agriculture and Forestry
MDG	Millennium Development Goals
MHP	Micro-Hydropower
MIH	Ministry of Industry and Handicrafts
MOC	Ministry of Commerce
MRC	Mekong River Commission
MSW	Municipal Solid Wastes
MUB	Multi-nutrient Urea Block
N <sub>2</sub> O	Nitrous Oxide
NGO	Non-governmental Organization
NO <sub>x</sub>	Nitrogen Oxide
NPEP	National Poverty Eradication Programme
NREL	US National Renewable Energy Laboratory
PDIH	Provincial Department(s) of Industry and Handicrafts

PEA	Provincial Electricity Authority of Thailand
PPA	Power Purchase Agreement
PPAg	Power Purchase Agreement
PPP	Purchasing Power Parity
PREGA	Promotion of Renewable Energy, Energy Efficiency and Greenhouse Gas Abatement
PRC	People's Republic of China
PV	Photovoltaic
R&D	Research and Development
RE	Renewable Energy
REGA	Renewable Energy, Energy Efficiency and Greenhouse Gas Abatement
RESDALAO	The Renewable Energy for Sustainable Development Association
RET(s)	Renewable Energy Technology (ies)
RETC	Renewable Energy Technology Centre
SHP	Small Scale Hydropower Potential
SHS	Solar Home System
SIDA:	Swedish International Development Agency
SPRE	Southern Provinces Rural Electrification Project
STEA	Science, Technology and Environment Agency
SNV	The Netherlands Development Organization
SWH	Solar Water Heater
TCD	Tons of Crushing per Day
TRI	Technology Research Institute
UNCED	United Nations Conference on Environment and Development
UNDP	United Nations Development Programme
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
Vientiane Cpt.	Vientiane Capital
WB	The World Bank

### Currency Unit

Unless otherwise specified, the term “dollar” refers to US\$

Currency	=	Kip (KN)
\$1	=	KN10,820
KN1	=	\$0.000092

### Units

km	Kilometers
ha	Hectares
GJ	Giga Joule
GWh	Gigawatt hour
ktoe	Kiloton of Oil Equivalent
kW	Kilowatt
kWh	Kilowatt hour
kWhe/kW	Kilowatt-hour per Kilowatt
m <sup>2</sup>	Square meter
m <sup>3</sup>	Cubic Meter

MW	Megawatt
toe	Ton of Oil Equivalent
kWh/m <sup>2</sup>	kilowatt-hours per square meter
kWp	kilowatt-peak
m/s	Metre per second

## 1. EXECUTIVE SUMMARY

1. Lao People's Democratic Republic (Lao PDR) is a landlocked country in the heart of Southeast Asia at the centre of the Indochinese peninsula between latitude 13-23 degrees north and 100-108 degrees east. Lao PDR has eastern border of 1,957 kilometres (km) with the Socialist Republic of Vietnam, a western border of 1,730 km with the Kingdom of Thailand, a southern border of 492 km with the Kingdom of Cambodia, a northern border of 416 km with the People's Republic of China and a north-western border of 230 km with the Union of Myanmar.

2. The climate is monsoonal, bringing rain from May to September and a dry season from November to February. In 2004, Lao PDR had a population of approximately 5.6 million people with a population growth rate of 2.7% per year. Buddhism is the dominant religion with more than 85% of the population as believers. The official language of the Lao PDR is Lao. The population density is 23 persons per square kilometre (km<sup>2</sup>) and roughly 85% of the population lives in rural areas.

3. Lao PDR is one of the 13 least developed countries (LDC) in the Asia-Pacific region; it is ranked 135 out of 175 countries in the Global Human Development Report (HDR) 2004. The narrowly based economy is one of the least developed in Asia with an approximate per capita Gross National Product (GNP) of around US\$ 370 annum. Real GDP growth over the last few years has been in the range of 5.5 – 6.5 % / year. Lao PDR is the recipient of about US\$ 200 million annually in international grant support, which is largely targeted at social and environmental projects designed to alleviate poverty in the country.

4. The National Poverty Eradication Programme (NPEP) is central to the national development agenda. The NPEP encapsulates the essence of the Lao PDR's approach towards achieving the goal set in 1996 by the 6th Party Congress, namely, exiting the group of LDCs by 2020. The Lao PDR's long-term national development goal is to be achieved through sustained equitable economic growth and social development, while safeguarding the country's social, cultural, economic and political identity. The foundations for reaching this goal have been laid during the past 28 years of peace and development in the country by:

- Moving consistently towards a market-oriented economy;
- Building-up the needed infrastructure throughout the country; and
- Improving the well being of the people through greater food security, extension of social services and environment conservation, while enhancing the spiritual and cultural life of the Lao multi-ethnic population.

5. Lao PDR is endowed with significant indigenous energy resources, in particular for electricity generation. Hydropower is the most abundant and cost-effective resource for electricity generation. The energy resources range from traditional energy sources such as fuel-wood to coal and hydropower. The forest areas, which cover over 47 % of the total land area as potential source for substantial traditional energy supplies. The total exploitable hydropower potential of Lao PDR is around 23,000 MW with major Mekong tributaries estimated at around 56%, followed by 35% of mainstream Mekong and 9% of the rest of the country. The Lao PDR's hydropower potential is very considerable and its development offers extensive benefits for the country. Hydropower is a major contributor both direct and indirect to economic output, government revenues and export earnings. However, only 623 Megawatts (MW) has so far been developed.

6. The Government of Lao PDR's goal is to increase the electrification ratio for the whole country from 41% to 90% by 2020, with intermediate targets of 45% in 2005 and 70% in 2010. This goal will be achieved through:

- On-grid household electrification – involving main transmission / distribution grid extensions to meet the 90% target, after deduction of off-grid installations.
- Off-grid household electrification – an embryonic but successful program of electrification of off-grid households employing state, donor and private resources is underway in Lao PDR and targets electrification of 150,000 households by 2020. However this program will need to be substantially scaled-up, if this target is to be achieved by 2020. Current projections of village and household electrification are as follows:

<b>Year</b>	<b>2004</b>	<b>2005</b>	<b>2010</b>	<b>2013</b>	<b>2015</b>	<b>2020</b>
No. of Villages Electrified	3,464	3,574	5,584	6,433	7,024	8,906
% of Villages Electrified	31%	32%	50%	58%	63%	80%
No. of Households Electrified	395,598	423,122	733,926	858,794	914,894	1,140,396
% of Households Electrified	41%	45%	70%	76%	79%	90%

7. Lao PDR ratified the United Nations Framework Convention on Climate Change (UNFCCC) on 4 April 1995. Awareness on climate change however, has been stirred in Lao PDR since it participated in the 1992 Rio Earth Summit. The first major climate change activity in the country was the Lao National Greenhouse Gas (GHG) Inventory Project (GEF Climate Change Enabling Activity (CCEAP) project and the capacity building project of GEF implemented through UNDP. The GOL has ratified the Kyoto Protocol on Clean Development Mechanism on February 6, 2003 and the Designated National Agency (DNA) has been established as the Science Technology and Environment Agency. The GOL has ratified the Kyoto Protocol on Clean Development Mechanism by February 6, 2003 and the DNA has been established as the Science Technology and Environment Agency.

8. Renewable energy resources will most likely be developed under the direction of the Ministry of Industry and Handicrafts (MIH) and/or Electricité du Laos (EDL), coordination with renewable energy sector organizations is recommended so that their data, experience and expertise can be accessed for the future projects. As well, staff of these organizations may be able to contribute practical experience on appropriate technologies, implementation approaches and pilot projects. The Science, Technology and Environment Agency (STEA) and/or the Technology Research Institute (TRI) of STEA is an important institution for any renewable energy related work, and their staff should be consulted particularly in respect of the biomass energy assessment, but also in respect of mini / micro hydropower, wind power assessments and solar PV energy technologies.

9. It can be said that the financial aspect is one of the most important issues that will contribute towards the success of the planning and implementation process in Lao PDR, but the Government has constraints in finance. Based on previous developments, it is indicated that most of the funding sources for energy/renewable energy sectors will come from the loans and



grants of multilateral financial organizations and international and local participants into this sector, although these are still limited.

10. There is a lack of energy efficiency/renewable energy (EE/RE) Promotion Funds, Lending conditions and procedures are complicated and often changed, Bank/financial organizations lack the necessary capacity to evaluate EE&RE projects, Banks also face high transaction costs due to the smallness of potential EE/RE projects, Credit institutions are hesitant to lend to EE/RE projects due to perceived high risks and long time to recover the investment cost. Renewable energy/efficiency energy financing is feasible but there are risks and barriers that need to be resolved. It requires detailed analyses to be carried out by both the electric service company (ESCO) and the financier. Performance contracts, insurance, owners' commitments & other safety measures are key elements that enhance its attractiveness over other investment opportunities.

11. There is limitation of manpower with the know-how, experience and skills in strategic planning and those of implementing the plans. On the contrary, distributing manpower from ministerial to provincial workplaces is not balanced. In addition, responsibilities among agencies, which are in charge of the energy sector are not clearly defined and coordinated. The separate energy organizations also mean reduction of efficiency in planning, implementing and managing energy resources. At present, there is only the hydropower sub-sector becoming the main priority for the energy sector; however other energy type sub-sectors are not well determined and not a single responsibility of any one organization.

12. Policy options and strategies for increasing the scale and application of energy/efficiency energy sources must take account of the diversity of national circumstances, as well as of technology options. It requires reliable support from the government in the form of incentives. The creation of an enabling policy environment, with appropriate institutional arrangements at the national level, would accelerate the development and wider scale application of new and renewable sources of energy. Available policies in Lao PDR include the following:

- (i) Linking new and renewable energy policies to sustainable development policies and to actions consistent with international agreements;
- (ii) Legal and regulatory policies and frameworks for attracting investment;
- (iii) Providing a clear policy message to mobilize all key actors and catalyze them into action.

13. As for the Lao PDR, the socio-economic development must be implemented with efficiency, continuation and stability so as to guarantee the balance between the economic growth and the social and cultural development as well as the eternally sustainable environmental protection. Consequently, the utilization of advanced technology is considered, which needs to be developed and resolved to suit the real situation of each field of work.

14. In order to achieve the above-mentioned issues for supporting the additional technical know-how, capacity and expertise of the technocrats, the staff must be supported and promoted. For example, it is essential to make use of all-existing technocrats' competency so as to systematically train them in the environmental field as well as carefully set plans of human resource development within this field of work. It is urgently necessary to guarantee providing the fund for environmental protection. Thus, one of the most important things is to raise money for the contribution for the National Environmental Fund simultaneously in an attempt to not only

search for the financial assistance from the friendly international agencies, but also to better promote the bilateral and multilateral cooperation.

15. The purpose of this study is to evaluate the feasibility of implementing biogas production from pig farm for generating electricity, particularly in the Vanith Pig Farm Company, in particular Farm No. F3, which is polluting the air and affecting the neighbours surrounding this farm. Primarily, this study is going to review the literature of anaerobic digestion (AD) technology and the process of the AD fermentation for producing biogas, after consideration of seven examples of AD plant from various locations in estimating biogas production through the size of co-generator or gas turbine. Installed system costs of AD + co-generator are also included.

16. Based on the actual data survey and literature review:

**For currently available data**, it is found that the gas production per day, at farm no F1+F2 is about 1099 m<sup>3</sup>/day with size of gas turbine 120 kW, with cost of investment from 368,880 US\$ up to 443,040 US\$ and at farm No F3 is 298 m<sup>3</sup>/day, 35 kW, with cost of investment from 107,590 US\$ up to 129,220 US\$.

**For future estimation plan**, it is found that the gas production per day, at farm no F1+F2 is about 1651 m<sup>3</sup>/day with size of gas turbine 195 kW of and the investment cost is 599,430 US\$ and at farm No F3 is 447 m<sup>3</sup>/day, 50 kW with investment cost from 153,700 US\$ up to 184,600 US\$ (2 Units × 25 kW).

## 2. MAP SHOWING THE LOCATION OF THE PROJECT

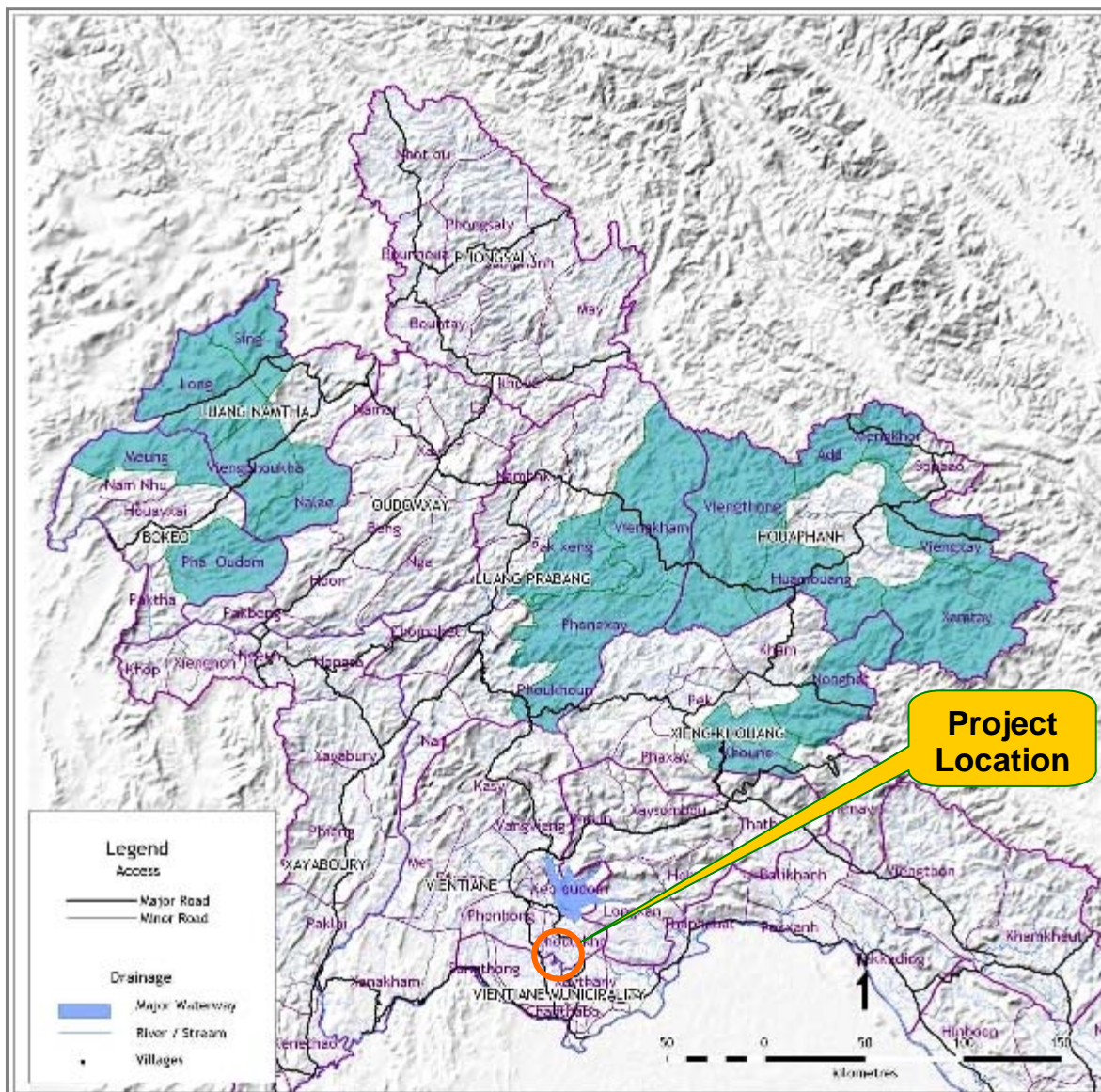
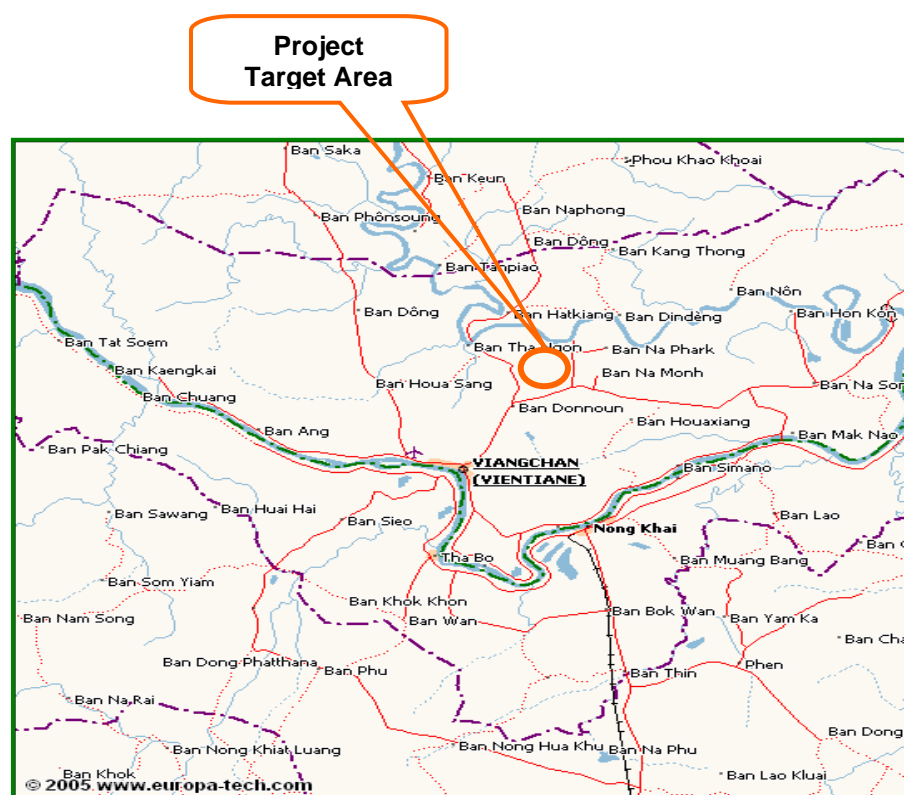


Figure 1: Map Showing the Location of the Project

### 3. INTRODUCTION

The Lao PDR economy has reported steady growth since 2000 with average GDP growth (in real terms) of over 5% per annum, the most recent figure being 5.8% in 2003 over the previous year. Annual inflation continues to rise from 7.7% in 2001 to 10.7% in 2002 and 15.5% in 2003 (mainly in response to a decline in the value of the Kip) although there were signs towards the end of 2003 that inflation was decreasing. The structure of the economy is changing gradually as dependence on the agricultural sector decreases and industry and services become increasingly important. While agricultural GDP (in current terms) continues to increase, its annual growth rate (in real terms) has declined from a peak in 1999 of 8.2% to 2.2% in 2003 in spite of a relatively strong performance of the forestry sector. As a consequence, the agricultural contribution to overall GDP has declined from 53.7% in 1999 to 48.6% in 2003, a trend that is expected to continue under the influence of growing industrial and services sectors that reported annual growth rates of 11.5% and 5.8% respectively in 2003.

ADB has significantly providing financial assistance in the development of Lao PDR, particularly in (i) industry and power sector, (ii) agriculture and natural resources, (iii) education and primary health care, (iii) infrastructure including energy, transport and communications, water supply, sanitation and waste management, and (iv) law reform and public sector management. ADB chairs the infrastructure-working group for the coordination of external funding in the sector and is the co-chair of the industry, agriculture, environment and natural resources working group.



**Figure 2: Map Showing the Project Target Area**

Biogas technology was introduced in Lao PDR in 1983 through the assistance of the Food and Agricultural Organization (FAO). The implementation of biogas technologies is expected in Lao



PDR in reducing environmental problems and in helping reduce importation of gas. In the energy sector, biogas could enable the farmers to supply themselves with heat and electricity and to supply the excess electricity to the national grid. It could significantly increase the income of a farm. All animal waste products contain organic and inorganic nutrients with potential to decompose in the environment with high Chemical Oxygen Demand (COD), methane and ammonia emissions and the release of excess nutrients and pathogens. Concerns have been expressed in recent years on the effects of pollution of the air and water from municipal, industrial and agricultural operations and such concerns continue to grow around the world. The emission of CO<sub>2</sub> and other greenhouse gases (GHG) has become an important issue, particularly since the governments of most Asian countries are signatories to the Kyoto Protocol.

Vanith Pig Farm Company is the biggest farm in Vientiane Capital with a total herd of about 9,705 heads of pig. This farm was established in 1992 under the cooperation investment between Mr. Vanith, a Lao private enterprise and a French Investor, and upgraded the company to become a Joint Venture Company. This project is sustainable under the policy of Lao government intended to reduce and eradicate poverty of Lao population. The Vanith Pig Farm Company separates into two locations, including Farm 1 and Farm 2 (F1+F2) are located at the first site, and Farm 3 (F3) is located at the second site. The first location of the farm is in Latkhouay village, Xaythany district, which is about 23 km from Vientiane Capital; it has a total area about 34 ha. The second location of Pig Farm is about 19 kilometres from Vientiane Capital, along the Road No. 10, with an area of 27 ha.

The initial investment registered cost is US\$ 200,000. At that time, there were only 100 sows growing at the farms # F1+F2; two years later the breeding sow population has increased to 600 heads. The Capital Agriculture and Forestry Department of Vientiane Capital, Lao Development Bank and Agricultural Promotion Bank have recognized the importance and the need of the pig farm. They provided a loan of US\$ 155,000 with an interest rate of 5% to enable the Vanith Pig Farm Company to increase the capacity to produce piglets to respond to the farmer demand in Vientiane Capital.

It appears that this proposed project would be possible if there would be a grant from NGO or other international organization as a pilot or demonstrative project for Lao PDR. One of the possible approaches for financing this proposed project is by a private investment.

The Vanith Pig Farm Company perceives the advantages and benefits in the long term from using AD technology. However when the PREGA team of Lao P.D.R tried to explain to the owner the process of “biogas production from their farm for electricity generation”, the owner of the company remains concerned that the investment cost is very high, and this is compounded because the company has financial problems related to their competitiveness in the Lao pork market, and the company is still reliant on the government grant assistance to stay in business.

## 4. BACKGROUND

### 4.1 Description

Renewable energy is power that comes from renewable resources such as the sun, wind and organic matter. These resources are constantly replenished by nature and are a cleaner source of energy.

Large municipal or industrial landfills produce gas that can be tapped to generate electricity. Microorganisms that live in organic materials such as food wastes, paper or yard clippings cause these materials to decompose. This produces landfill gas, typically comprised of roughly 60 percent methane ( $\text{CH}_4$ ) and 40 percent carbon dioxide (or " $\text{CO}_2$ ").

Landfills are the largest human related source of methane. Methane is a powerful GHG, more than 21 times more potent than carbon dioxide emissions. Landfill gas is collected by drilling "wells" into the landfills, and collecting the gases through pipes. Once the landfill gas is processed, it can be combined with natural gas to supplement the natural gas supply or can be burned in an internal combustion engine or micro turbine coupled to a generator to create electricity.

There is a wealth of energy to harness because of the abundance of plants and animals around us. Power generated using organic matter is called biomass energy or bioenergy. One form of bioenergy is a gas called methane. It's a naturally occurring byproduct of decaying plant and animal material. It is often found in bogs, wetlands and even landfills. The process can be duplicated in biogas generators using bacteria to break down organic material such as agricultural waste. The resulting methane gas is burned to produce electricity. It's a remarkable process that turns waste into energy.

For Lao PDR, livestock plays an important role in an agriculture-dependent country, where there has been little experience in biogas systems. Animal and human excreta is generally available within rural areas, and there is a potential for larger biogas digester program for cooking, lighting and other purposes within the country (RETC has set up five demonstrative units, and completed a feasibility study of a support program for domestic biogas plants in rural households in Lao PDR). There are 1.1 million cattle, 1.2 million buffaloes and 1.5 million pigs in Laos, though widely dispersed. Experience in other countries has shown that families



with enough animals to run a biogas digester are probably rich enough to use kerosene or LPG anyway, but recent increases in fuel costs may begin to negate this point. Pig excreta are a good energy resource, and if housed in pens, this makes dung collection easy, again reducing barriers to household scale development.

Large-scale biogas digesters using pig farm wastes could be established and be used to generate electricity. It is understood that there are no cultural inhibitions towards using biomass digesters based on human and animal excreta.

Biogas obtained by anaerobic fermentation of cow/pig dung and other organic matters can be used as energy source for cooking, lighting and other purposes. Biogas technology was introduced in Lao PDR in 1983 through the assistance of the Food and Agricultural Organization (FAO). Initially, three family-size biogas units were set up by the Ministry of Agriculture and Forestry with the cooperation of FAO. Since 1983, STEA has been involved in the development of pilot biogas plants. At present 14 biogas plants with capacity ranging from 12 to 16 m<sup>3</sup> each have been installed in the country.

Pig waste in large pig farms is a potential source of methane gas and most pig farms (35 in total) are concentrated around Vientiane Capital City. The data on large pig farms within Vientiane Capital City are shown in Annex 1.

## **4.2 Opportunities, Constraints and Issues Related**

Lao PDR does not have its own fossil fuel resources with the exception of some small amounts of lignite. All of the needed fuel and gas is imported from abroad. From this point of view, it may motivate the Lao community to develop biogas from animal dung in the future. The current issue is whether the development of biogas could contribute to reduce costs of imported fuel and gas. The overall expansion of renewable energy technologies (RETs) so far has relied upon government and donor agency assistance in the form of subsidies and grants. This does not mean that these technologies are financially unattractive. Beyond doubt, RETs can compete with other conventional alternatives. The proper design and implementation of these technologies can boost socio-economic development and address environmental concerns. Based on their implementation in the past, these technologies have not always been successful in rural electrification. For RETs to reach the goal, more attention must be paid not only to technical issues but also to social, cultural and management issues. Otherwise, even though, there are good RET applications, they are likely to be unsuccessfully implemented. To date, the contribution of RETs in meeting overall energy needs has been very small in Lao PDR, and the success of these technologies varies widely. Biogas is a well-established fuel for cooking and lighting in a number of developing countries, and it is also an environmentally friendly source of energy because biogas typically contains small (around 0.2%) hydrogen sulphide, which needs to be removed before combustion in most small generators. It produces electricity and heat but still keeps carbon dioxide emissions neutral and emits no sulphur. Biogas plant technology for generating energy from manure is an ancient method, but it is still useful for developing countries, especially for Lao PDR, a country where fossil fuel resources are scarce.

## **4.3 Sustainable Development Objectives**

The main objective of this study is to utilize renewable energy in a sustainable manner, to reduce electricity expense and encourage the owner of the pig farm that could run his business smoothly, without any objections from the people, who live surrounding the pig farm.

Even though the electric power produced from the pig farm is small scale, the implementation of this project may contribute in addressing environmental impacts such as unpleasant nuisance odour, proliferation of flies and the contamination of wastewater and land. The pig farm owner can generate additional revenue by selling the by-product that could be used as fertilizer.

Recently, the demand of pork is increasing; pig farms seem to be a good sustainable business. Bird flu scares may be contributing to the growing demand for pork. Consequently, this proposed project could have a high degree of sustainability. This project may also enable pig farm to be more competitive. The electricity required in the farm can be completely covered and the surplus could also be sold directly to the EDL. There is a great potential for efficient energy production for both individual producers and large-scale livestock operations.

#### **4.4 Government Policies and Strategies Relevant to the Project Sector**

##### **4.4.1 Electricity Law of Lao PDR**

The Electricity Law which became effective on 29 August 1997, sets out the regime for the administration, production, transmission and distribution of electricity, including export and import, through the use of productive natural resources, and potentially contributes to the implementation of the national socio-economic development plan and to upgrade the living standards of the people (Article 1). Amongst other things, it provides a suitable framework for the promotion and implementation of rural electrification.

With respect to concessions for electricity activities, it is stipulated that investment is solely by the State or with foreign partners. Cooperative investments are allowed. Modalities may be:

- Build, operate, own and transfer (BOOT),
- Build, operate and transfer (BOT),
- Build, transfer and finance (BTF),
- Operation by the State Electricity Company,
- Some other form.

However, in the section relating to concessions, the law stipulates that small-scale hydro generators under 2 MW, and thermal electricity generators under 500 kW, are exceptions to concession applications. As the majority of rural electrification projects will be under 2 MW (or under 500 kW in the case of diesel generators), concessions for such projects will not generally be required.

The law stipulates that MIH, the provincial and district authorities and the village administrative authorities have coordinating and supervisory duties and rights. Electrification projects between capacities of 100 kW and 2 MW are handled by the respective PDIH (Provincial Department(s) of Industry and Handicrafts, with approval from MIH), and projects under 100 kW are handled at the district authority level (with approval from PDIH / MIH).

In village schemes (generally less than about 10 kW), the village chief has the right and duty to facilitate parties who are undertaking electricity enterprises. This represents current practice, in that small entrepreneurs use solar PV, thermal and micro hydro generators for very small commercial distribution networks, operated as private investments, presumably with district authorization through the village chief. These systems assign operational control and ownership to customers and to village scheme managers.



The law stipulates that an off-grid fund may be established by the State, financed from various sources, including the State, entrepreneurs, consumer, and foreign or domestic assistance. The State may have a policy of reducing or exempting equipment, operation, and vehicles, from taxes and duties in order to facilitate off-grid development.

#### **4.4.2 Power Sector Policy**

Power sector policy is outlined in the Government's Power Sector Policy Statement, September 2000 (revision 4). The main power sector priorities are to:

- (i) Maintain and expand an affordable, reliable and sustainable electricity supply in Lao PDR to promote economic and social development.
- (ii) Promote power generation for export to provide revenues to meet the Government's development objectives.
- (iii) Develop and enhance the legal and regulatory framework to effectively direct and facilitate power sector development.
- (iv) Reform institutions and institutional structures to clarify responsibilities, strengthen commercial functions and streamline administration.

#### **4.4.3 Other Relevant Laws, Policies and Regulations**

A program of legislative reform has been in progress in Lao PDR for more than a decade, aimed at creating amongst other things a legal environment that encourages investment in the country. In addition to the Electricity Law (1997) already discussed, relevant legislation includes the:

- Law on Foreign Investment (1988)
- Contract Law (1990)
- Commercial Bank and Financial Institutions Act (1992)
- Customs Law (1994)
- Labor Law (1994)
- Business Law (1994)
- Law on the Promotion and Management of Foreign Investment (1994)
- Secured Transaction Law (1994)
- Water & Water Resources Law (1996)
- Environmental Protection Law (1999) and the
- Rules for Consideration and Approval of Foreign Investment Projects in Lao PDR (2002).

Institutional Arrangement for Energy Planning-the energy sub-sector in Lao PDR managed by relevant line ministries and organizations are:

- The petroleum and gas under Ministry of Commerce (MOC),
- Electric Power including New and Renewable Energy and Coal under Ministry of Industry and Handicrafts,
- Fuel-wood under Ministry of Agriculture and Forestry (MAF),

At the energy sub-sector:

- The Ministry of Commerce is responsible for entire petroleum and gas sector planning for commercial aspects.
- The Department of Electricity, Ministry of Industry and Handicrafts is in charge of the power sector strategic planning which includes hydropower, and the Ministry's Department of Geology and Mining is responsible for coal.
- The Department of Forestry, Ministry of Agriculture and forestry is responsible for overall supervision of the fuel-wood sector planning, in addition to its main forest sector planning.
- The Science, Technology and Environment Agency, Technology Research Institute is responsible for research on sustainable utilization of natural resources (New and Renewable Energy).

#### **4.5 Overlap of Government and ADB objectives**

ADB supported the government projects in terms of grant or soft long-term loan with low interests. It assists the government in achieving its policies (Poverty reduction and eradication, clean water, community health, reduce child mortality, AIDS /HIV prevention etc).

### **5. DESCRIPTION OF THE PROPOSED PROJECT**

#### **5.1 Project Goal and Objective**

The main goal of this proposed project is to produce electricity utilizing AD biogas from a pig farm. It also aims to reduce net environmental impacts, disseminate the use of renewable energy in the country and compensate the consumption of energy at the farm. To achieve the goal and objectives the following activities were undertaken: literature review, study of the existing AD technology of different sizes, estimation of the possible production of biogas based on the actual pig farms and animal diets, and consideration of the existing plants in foreign countries as examples for the selection of AD plant.

The project will reduce the odour problem and flies from the pig farm, which could affect areas of more than one and half kilometres surrounding the farm. The project will also reduce the problem of the wastewater and land contaminants in the area and will encourage the farm owner to reduce his expense on energy consumption especially in Vanith Pig Farm F1+F2 and Farm F3, located at Latkhouay Village, Xaythany district, Vientiane Capital, Lao PDR.

#### **5.2 Poverty Reduction and other MDG (Millennium Development Goal) Impacts**

The National Poverty Eradication Program of Lao PDR is central to the national development agenda. The NPEP encapsulates the essence of the Lao PDR's approach towards achieving the goal set in 1996 by the 6th Party Congress: that is, exiting from the group of Least-developed countries (LDCs) by 2020. Lao PDR's long-term national development goal is to be achieved through sustained equitable economic growth and social development, while safeguarding the country's social, cultural, economic and political identity. The foundations for reaching this goal have been laid during the past 28 years of peace and development in the country by:

- i. Moving consistently towards a market - oriented economy;
- ii. Building-up the needed infrastructure throughout the country, and;

- iii. Improving the well being of the people through greater food security, extension of social services and environment conservation, while enhancing the spiritual and cultural life of the multi-ethnic population.

The 7th Party Congress (March 2001) defined the following guidelines for poverty eradication and sustainable economic growth:

- The socio-economic development of the country must be balanced between the three pillars of economic growth, socio-cultural development and environmental preservation.
- Socio-economic development must be based on sound macro-economic management and institutional strengthening and must be harmoniously distributed between sector and regional development, and between urban and rural development, so as to fully and efficiently utilize human and natural resources.
- The national development potential and strengths must be combined with regional and global opportunities to enable Lao PDR's participation in regional and international economic integration.
- Socio-economic development must be closely linked with national security and stability.

Within these guidelines, the main objectives of the long-term development strategy include:

- a) Sustaining economic growth at an average rate of about 7 per cent (to triple the per-capita income of the multi-ethnic Lao population by 2020);
- b) Halving poverty levels by 2005 and eradicating mass poverty by 2010, and;
- c) Eliminating opium production by 2005 and phasing-out shifting cultivation by 2010.

### **5.3 Potential of the Vanith Pig Farm Company**

Vanith Pig Farm Company is the biggest pig farm in Vientiane Capital with a total herd numbering about 9,705 heads. This farm was established in 1992 under the cooperation investment between Lao private enterprise and a French Investor. This project is sustainable under the policy of Lao government intended to reduce and eradicate poverty of Lao population. The Vanith Pig Farm Company separates into two locations, including Farm 1 and Farm 2 (F1+F2) are located at the first site, and Farm 3 (F3) is located at the second site. The first location of the farm is in Latkhouay village, Xaythany district, which is about 23 km from Vientiane Capital; it has a total area about 34 ha. The second location of Pig Farm is about 19 kilometres from Vientiane Capital, along the Road No. 10, with an area of 27 ha.

The initial investment registered cost is US\$ 200,000. At that time there were only 100 sows growing at the farms # F1+F2; two years later the breeding sow population has increased to 600 heads. The Agriculture and Forestry Department of Vientiane Capital, Lao Development Bank and Agricultural Promotion Bank have recognised the importance and the need of the pig farm. They provided a loan of US\$ 155,000 with the interest rate of 5% to enable the Vanith Pig Farm Company to increase the capacity to produce piglets to respond to the farmer demand in Vientiane Capital.

In the year 1999 to 2000, Vanith Pig Farm Company increased the breeding sow population up to 1200 heads and at the end of the year Vanith Pig Farm Company achieved a capacity of 1800 piglets/month. Finally, Vanith Pig Farm Company had faced a significant problem with the smuggling of piglets into Vientiane Capital from neighbouring countries with the objective of

breaking the local market, due to all the raw materials, which are used in the pig farms being imported. Consequently, the Vanith Farm could not distribute their piglets and then the farm owner has to spread into three farms as Farm 3 (F3) by conceding the Pig Farm No 3 from the government farm which is constructed by the grant of Czechoslovakia to Laos Government.

This farm produces the slaughter pigs (fattening pigs) only for distribution and sale to the local market. To date, the Vanith Pig Farm Company has a capital cost up to US\$ 3,500,000 and the total of the pig population is 9705 heads on late October 2005.

#### 5.4 Description of the Subsystems in the Farm

Pig Production Subsystem. Recently, Vanith Pig Farm Company has a total number of 31 pens: 10 pens in Farm F1, 12 pens in Farm F2 and 9 pens in Farm F3. Pig dung slurry is disposed of in pond; there are 3 ponds at F1+F2 and 5 ponds at F3 (2 ponds at F3 are utilized for fish culture).

Pig Farms F1+F2 have a total of 7636 heads while Pig Farm F3 has 2069 heads of pigs for slaughter. This subsystem has a total of 9705 pigs that is grouped as follows: 63 father pigs (120 - 300 kg), 1138 breeding sows (100-180 kg), 1143 lactating pigs (less than 30 kg), 3433 piglet (30 to 45 kg) and 3928 fattening (slaughter) pigs (50 to 80 kg). These animals are distributed to five groups: father pigs, breeding (lactating) sows, suckling piglets (baby pigs), growing pigs and fattening pigs (slaughter pigs), the data of the population of pigs in Vanith pig farm is shown in the table below (showing data to the end of October, 2005).

Animals are mainly fed with a ration based on maize and soybean meal prepared at the farm, 75% of the meal is locally sourced and 25% of the meal is imported from Thailand such as: soybean 15 %, powder fish 7%, powder milk and vitamin complex 3%. Base on the 2004 Annual Report, Vanith Pig Farm has produced 19,000 piglets/year, distributed 13,939 heads/year of slaughter pigs, and sold 1,500 heads/year of young pigs to the farmer for growing.

**Table 1: Data of the Pig Population at Vanith Pig Farm Company**

Description	Farm: F1 (Pigs)	Farm: F2 (Pigs)	Farm: F1+F2 (Pigs)	Farm: F3 (Pigs)	Total (Pigs)
Father pigs	34	29	63		63
Breeding sows	594	544	1138		1138
Lactating pigs	473	670	1143		1143
Piglet pigs	1831	1602	3433		3433
Slaughter pigs (Hog)	1100	759	1859	2069	3928
<b>Total</b>	<b>4032</b>	<b>3604</b>	<b>7636</b>	<b>2069</b>	<b>9705</b>

The amount of food for feeding the pigs in these three farms is 4,000 tons per year and the total population of pig supplied by the company at the end of 2004 was 8811 heads. Based on the actual available data, the average amount of food given to a pig per day is about 1.25 kg.

Based on our interview with an employee who is responsible for the pigpen and the actual data collected from the Vanith Pig Farm, it was noted that the water consumption for drinking and washing away the pig manure is approximately 14 litres/pig/day. The chemical for reducing the odour (EM=Extensive Microorganish) is about 444 ml/day/pen mixed with 200 litres water. The

total needed EM per day is approximately 14 litres (1 litre cost 14,500 Kips) mixed with 6400 litres of water. This solution is sprayed onto the floor for eliminating odour in those pens.

The data of electrical energy consumption in Vanith Farm has been collected from EDL for two years and ten months back, from January 2003 to October 2005. It could be seen that the average consumption in Farm F1&F2 was about 44,789 kWh/month with average load of 62.21 kW, Farm F3 is 7,752 kWh/month with average load of 10.77 kW. The details are illustrated in the table below.

**Table 2: Summary of Electric Energy Consumption and Water Used**

Farm	Average Load Connected	Average Electric Energy Consumption	Electric Energy Payment per Month		Water Used	EM Used	
			Kips/month	US\$/month		litre/day	Kips/day
	<b>kW</b>	<b>kWh/month</b>			<b>m<sup>3</sup>/day</b>		
F1&F2	62.21	44,789	12,474,266	1,211.094	3.818	9.768	141,636
F3	10.77	7,752	2,207,800	214.350	1.035	3.996	43,442
<b>Total</b>	<b>72.98</b>	<b>52,541</b>	<b>14,682,066</b>	<b>1,425.444</b>	<b>4.852</b>	<b>13.764</b>	<b>185,078</b>

## 5.5 Current Main Problem

Nowadays, Vanith Pig Farm Company is faced with the big problem from people who live around these farms. They wish that the owner would stop the business of pig farming because the odour from pig farm is a significant nuisance to the neighbours. The worst problem is occurring at Farm F3, where the people living around the farm want the owner to find solutions for restricting the bad odour from this farm. The situation is worse at this farm as the farm is located at a slightly higher elevation than the village.

Based on the collected data from Vanith Pig Farm, the daily average pig dung production rate is as follows: father pigs and breeding sows is about 2 kg per head, slaughter pig is 1.5 kg per head, piglets are about 0,5 kg per head and for the suckling pigs is about 0,25 kg per head. It may be estimated that the total daily quantity of pig dung in Vanith Farm is approximately 10.3 tons.

**Table 3: Estimation of the Pig Dung in the Farms**

Description	Farm: F1 & F2	Dung	Farm: F3	Dung	Total	Dung
	Pigs	kg/day	Pigs	kg/day	Pigs	kg/day
Father pigs	63	126			63	126
Breeding sows	1138	2276			1138	2276
Lactating pigs	1143	285,75			1143	285,75
Piglet pigs	3433	1716,5			3433	1716,5
Slaughter pigs (Hog)	1859	2788,5	2069	3103.5	3928	5892
<b>Total</b>	<b>7636</b>	<b>7192,75</b>	<b>2069</b>	<b>3103.5</b>	<b>9705</b>	<b>10296.25</b>

## 5.6 Future Plan of the Vanith Pig Farm Company

**Table 4: Estimation of the Pig Dung in Vanith Farm including Future Plans**

Description	Farm: F1&F2	Dung kg/day	Farm: F3	Dung kg/day	Total Pigs	Dung kg/day
Father pigs	106	212			106	212
Breeding sows	1,707	3,414			1,707	3,414
Lactating pigs	1,715	428.75			1,715	428.75
Piglet pigs	5,150	2,575			5,150	2,575
Slaughter pigs (Hog)	2,789	4,183.5	3,104	4,656	5,893	8,839.5
<b>Total</b>	<b>11,467</b>	<b>10,813.25</b>	<b>3,104</b>	<b>4,656</b>	<b>14,571</b>	<b>15,469.25</b>

Based on our interview with the Vanith Company owner, there is a need for expansion in order to respond to the government's policy of eradicating poverty and prevent the export of money out of the country, and to respond to the local demand for flattened pigs. Vanith Company has to expand by more than 15 pens in three farms (it is needed to build an additional 5 pens, 6 pens and 4 pens at Farms F1, F2 and F3 respectively). Farm F3 is for slaughter pig. This future plan can only be realized if the impact to the environment can be completely solved. The estimate of pig production in the future after expansion of the farm is shown in the table above.

## 5.7 Benefits Resulting from the Use of Anaerobic Digestion Technology

The benefits resulting from this proposed project might be categorized as follows:

### Waste Treatment Benefits:

- Natural waste treatment process,
- Requires less land than aerobic composting,
- Reduces disposed waste volume and weight to be land filled applications,
- Reduces concentrations of leachates.

### Energy Benefits:

- Net energy producing process,
- Generates high quality renewable fuel,
- Biogas proven in numerous end-uses,
- Reduce monthly energy purchases from electricity and gas suppliers.

### Environmental Benefits:

- Significantly reduces greenhouse gas (CO<sub>2</sub>, CH<sub>4</sub>),
- Reduction of hydrogen sulphide, which is partly responsible for bad odour. It can be reduced with a simple iron oxide filter prior to combustion
- Produces a sanitised compost and nutrient-rich liquid fertiliser,
- Maximises recycling benefits,

### Economic Benefits:

- Is more cost-effective than other treatment options from a life-cycle perspective.
- Bringing the community into the project will assist them to share in the economic benefits, particularly at Farm #3. Villagers can possibly act as fertilizer sales reps, or can be offered employment at the new facility.
- The liquid fertilizer can be used to the advantage of the local villagers, since it is difficult to transport and sell compared with the solid fertilizer.

## **6 BIOGAS TECHNOLOGY**

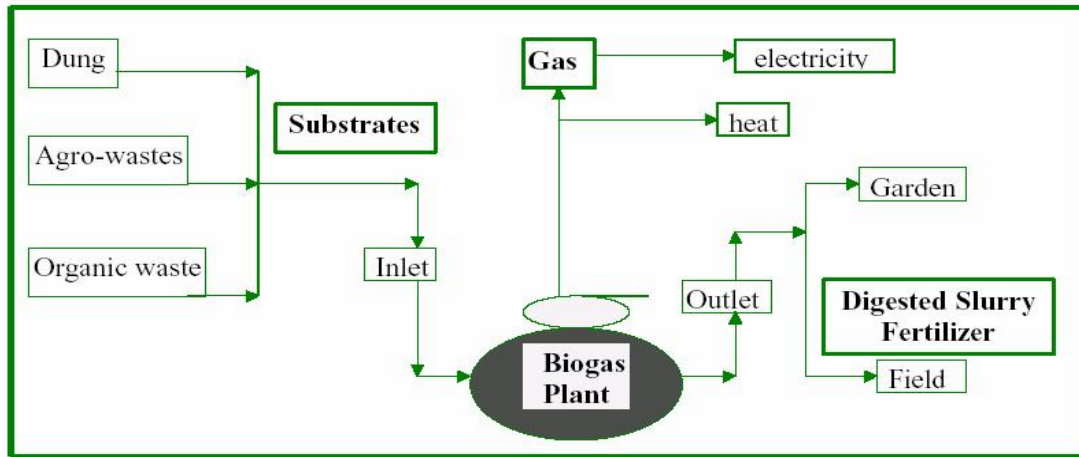
### **6.1 Role of Renewable Energy Technology**

The overall expansion of renewable energy technologies (RETs) so far has relied upon government and donor agency assistance in the form of subsidies and grants. This does not imply that these technologies are financially unattractive. Beyond doubt, RETs can compete with other conventional alternatives. The proper design and implementation of these technologies can boost socio-economic development and address environmental concerns. Wherever implemented, these technologies have been successful in rural electrification in developing many countries. However, its contribution to meeting overall energy needs has been very small, and the success of these technologies varies widely. Biogas is a well-established fuel for cooking and lighting in a number of developing countries, and it is also an environmentally friendly source of energy because it produces electricity and heat but still keeps carbon dioxide emissions neutral and emits no sulphur (Hydrogen Sulphide ( $H_2S$ ) is emitted but can be removed via a filter). Biogas plant technology for generating energy from manure is widely used as a renewable energy technology around the world.

### **6.2 Biogas Technology**

The implementation of biogas technologies in Lao PDR could reduce environmental problems and help reduce gas imports. In the energy sector, biogas could enable the farmers to supply themselves with heat and electricity and to supply the excess electricity to the national grid. It could significantly increase the income of a farm. All animal waste products contain organic and inorganic nutrients with potential to decompose in the environment with high Chemical Oxygen Demand (COD), methane and ammonia emissions and the release of excess nutrients and pathogens. Concerns have been expressed in recent years on the effects of air and water pollution from municipal, industrial and agricultural operations and such concerns continue to grow around the world.  $CO_2$  and other GHG emission has become an important concern, particularly since the governments of most Asian countries are signatories to the Kyoto Protocol. The implementation of biogas technologies would be profitable for commercial pig producers in terms of sale of carbon credits. Likewise, fertilizer can have a monetary value as well as the energy produced, with the present system of waste disposal. The concept of the 'four R's', which stands for Reduce, Reuse, Recycle, and Renewable energy, has generally been accepted as a useful principle for waste handling.

**Figure 4: Basics of Biogas Digesters**



Source: <http://gate.gtz.de/biogas/basics/basics.html>

One of the most generally available sources of renewable energy is biogas. Biogas digesters have been used extensively (But not always successfully on a small scale) in developing countries as sources of pollution-free heat and electricity, enriched fertilizer, and waste-management, but the success of digesters in colder climates in the past has been mixed. Biogas digesters have been proven to control odour, stabilize waste volatility, and convert methane emissions to usable energy. There is a great potential for efficient energy production for both individual producers and large-scale livestock operations. Not only would biogas digesters provide these operators with a waste-management system and emissions reduction tool, but also a source of pollution-free heat and electricity. The surplus energy produced by biogas digestion could also be sold for public consumption. As the technology involved in biogas digestion has improved since its inception thirty years ago, so has the need for such measures. How the basics of biogas digester for hog operations is illustrated in Saskatchewan. With the conditions of Saskatchewan including winter temperatures of -20 to -40 degrees Celsius, it would require all piping to be insulated and a heat exchange system for the digester. A biogas hot water boiler is an effective means of maintaining the digester's ambient temperature requirements through a coil heat exchanger. Heated water can be pumped through pipes within the digester; at the most 20% of the biogas will be expended to maintain the required reactor temperature. The saving accrued through building a smaller digestion tank can mitigate this loss. Through this system, it is possible to maintain a stable temperature with a variance of only 2-8 degrees Celsius in a northern climate<sup>2</sup>.

### 6.3 Technical Review of of Biogas Production

Biogas is a technology, which turns biological wastes into renewable energy and more stable organic matter and even enhances the value of the manure as a fertilizer by mineralization of organic bound nitrogen. Biogas is produced through an anaerobic fermentation process by a complex bacteria culture. In order to optimise the production, the process must be stable with only gradual changes in the supply of organic material and temperature to ensure an optimal adaptation of the bacteria culture. In fact, the bacteria should be regarded as domestic animals and treated with the same care as cows, pigs, and fish in fish farms.

<sup>2</sup> Source: "The Economics of Biogas in the Hog Industry", by the Canadian Agricultural Energy End Use Data and Analysis Centre (CAEEDAC), 1999, <http://www.usask.ca/agriculture/caedac/PDF/HOGS.pdf>



Biogas is produced by means of a process known as anaerobic digestion (AD). It is a process whereby organic matter is broken down by microbiological activity and, as the name suggests, it is a process, which takes place in the absence of air. It is a phenomenon that occurs naturally at the bottom of ponds and marshes and gives rise to marsh gas or methane, which is a combustible gas. Biogas or methane is produced when organic matter is made to decay under anaerobic (without oxygen) conditions. This is usually done in a digester, which can be a fairly simple and relatively small apparatus. Almost any kind of organic matter including kitchen garbage, animal and chicken manure, vegetable crops, and paper may be used. The methane gas ( $\text{CH}_4$ ) is produced along with about 30% carbon dioxide ( $\text{CO}_2$ ) by the biological processes involved in anaerobic digestion. The waste material from a biogas digester makes a useful fertilizer.

In most literature on the subject, the term “biogas” refers to the raw gas produced, which includes  $\text{CO}_2$  and other gases. The term “methane” is used for the pure  $\text{CH}_4$  gas. Each  $10 \text{ m}^3$  of biogas is equal in calorific value to about  $6.2 \text{ m}^3$  of methane,  $5.5 \text{ m}^3$  of natural gas, 7.0 litres of gasoline (petrol) and 6.2 litres of diesel.

Several precautions should be taken if one attempts to produce methane for the first time. Operators must learn how to use a starter brew to generate the biological activity, how to dilute and agitate the mixture, and how to control the pH level. The first batch of gas produced must not be used as the original air in the tank can form an explosive mixture. Otherwise the generation of biogas involves few technical or safety problems<sup>3</sup>

Most questions on biogas by possible users relate to the amount of fuel that they can expect from a given amount of organic material. The following table might provide some indication. The figures are based on the production rates of efficient digesters.

Depending on the raw material and the digester efficiency, we can obtain 300-to 600- $\text{m}^3$  biogas for each ton of organic matter. Grass and foliage can be used and some groups are experimenting with large plantations of water hyacinth, kelp and algae.

**Table 5: Biogas Production: Volumes Obtainable from Waste Matter**

Type of Waste	Water Dilution	Volume of Gas per Wt. Material	Gas Produced per Animal per Day
Pigs	× 3	$0.4 - 0.5 \text{ m}^3 / \text{kg}$	$0.24 \text{ m}^3$
Cattle	× 2	$0.1 - 0.3 \text{ m}^3 / \text{kg}$	$0.22 \text{ m}^3$
Poultry	× 4	$0.3 - 0.6 \text{ m}^3 / \text{kg}$	$0.014 \text{ m}^3$
Human & kitchen wastes	variable	$0.3 - 0.7 \text{ m}^3 / \text{kg}$	$0.028 \text{ m}^3$

Source: <http://www.fao.org/docrep/fiel/003/AB742E/AB742E02.htm>

Comparing it to other fuels, Cheshire<sup>4</sup> states that a continuous gas production rate of  $14 \text{ m}^3$  per day will generate 1.0 kW of electricity continuously given an engine efficiency of 25 per cent. Remember that the digesters require some heat for operation in cooler climates and this may be taken from the gas produced. Biogas has a variety of applications. The Table below shows some typical applications and outputs for one cubic metre of biogas. Small-scale biogas digesters usually provide fuel for domestic lighting and cooking.

<sup>3</sup> Clarke, R. Technological Self-Sufficiency. Faber, London, 1976.

<sup>4</sup> Cheshire, M. Methane on the Farm in How to Use Natural Energy. NEC, London, 1978.

**Table 6: The application of biogas in several forms**

No	Application	1 m <sup>3</sup> biogas equivalent
1	Lighting	Equal to 60-100 Watt bulb for 6 hours
2	Cooking	Can cook 3 meals for a family of 5-6
3	Fuel replacement	0.7 kg of petrol
4	Shaft power	Can run a one horse power motor for 2 hours
5	Electricity generation	Can generate 1.25 kilowatt hours of electricity

Source: [http://www.itdg.org/docs/technical\\_information\\_service/biogas\\_liquid\\_fuels.pdf](http://www.itdg.org/docs/technical_information_service/biogas_liquid_fuels.pdf)

There are two common man-made technologies for obtaining biogas: the first (which is more widespread) is the fermentation of human and/or animal waste in specially designed digesters. The second is a more recently developed technology for capturing methane from municipal waste landfill sites. The scale of simple biogas plants can vary from a small household system to large commercial plants of several thousand cubic metres. In the preliminary, two popular simple designs of digester have been developed, the first is fixed dome digester developed by China in 1936, and the second is floating cover biogas digester developed by India in 1937, both digesters are the same digestion process but the gas collection method is different in each. In the floating cover type, the water sealed cover of the digester is capable of rising as gas is produced and acts as a storage chamber, whereas the fixed dome type has a lower gas storage capacity and requires good sealing if gas leakage is to be prevented. Both have been designed for use with animal waste or dung.

## **7. OVERVIEW of ANAEROBIC DIGESTION TECHNOLOGY**

Anaerobic Digestion equipment consists, in simple terms, of a heated or well-insulated digester tank, a gasholder to store the biogas, and a gas-burning engine/generator set, if electricity is to be produced. The organic waste is broken down in the tank and up to 60% of this waste is converted into biogas; the rate of breakdown depends on the nature of the waste and the operating temperature. The biogas has a calorific value typically between 50% and 70% that of natural gas and can be combusted directly, but the hydrogen sulphide should be scrubbed out first to reduce corrosion in modified natural gas boilers or when used to run internal combustion engines. Apart from biogas, the process also produces a digestate, which may be separated into liquid and solid components. The liquid element can be used as a fertilizer and the solid element may be used as a soil conditioner or further processed to produce higher value organic compost.<sup>5</sup>

### **7.1 Anaerobic Digestion Process**

Anaerobic digestion is a biological process in which bacteria break down organic matter in an airless environment, with biogas as the end product. Biogas derived from dairy manure comprises approximately 60% methane (CH<sub>4</sub>), 40% carbon dioxide (CO<sub>2</sub>), and trace amounts of other gases, including hydrogen sulphide (H<sub>2</sub>S). Due to its high methane content, biogas can be used as a fuel for energy conversion devices. Alternatively, it can simply be flared, as the resulting carbon dioxide makes a lesser impact on global climate than the methane. Depending on the system design, biogas can be combusted to run a generator producing electricity and heat, or it can be burned as a fuel in a boiler or other burner. Several different types of bacteria work together to break down complex organic wastes in stages, resulting in the production of "biogas".

<sup>5</sup> Source: [http://europa.eu.int/comm/energy\\_transport/atlas/htmlu/adotech.html](http://europa.eu.int/comm/energy_transport/atlas/htmlu/adotech.html)

Symbiotic groups of bacteria perform different functions at different stages of the digestion process. There are four basic types of micro organisms involved. Hydrolytic bacteria break down complex organic wastes into sugars and amino acids. Fermentative bacteria then convert those products into organic acids. Acidogenic micro organisms convert the acids into hydrogen, carbon dioxide and acetate. Finally, the methanogenic bacteria produce biogas from acetic acid, hydrogen and carbon dioxide.

Digester temperature is an important factor in maintaining the bacteria necessary for digestion. Gas production is dependent upon controlling anaerobic digester temperature, fermentation or retention time and the feedstock material. The gas production from the manure is dependent on the feeding of the animals, and the age of the manure when it is fed into the digester. The produced biogas is by co-generation converted into electricity and heat, and the solid residue is by the anaerobic digestion converted into a "more ready to use" fertiliser.

## **7.2 Potential Operating Digester**

The potential output of an operating digester is dependent on the control of the anaerobic digestion conditions. To promote bacterial activity, the digester must be maintained at a temperature of at least 15°C up to 60°C depending on the type of anaerobic bacteria. There are more species of anaerobic bacteria that thrive in the temperature range of a standard design such as Psychrophilic bacteria, mesophilic bacteria and thermophilic bacteria. Thermophilic is a specie bacteria of three that thrive at higher temperatures. The potential operating digester can occur within three different temperature ranges:

- Psychrophilic range is between 15°C–25°C and is usually associated with systems that operate at ground temperature. These systems are very stable and easy to manage but it has the lowest biogas production rate and pathogen removal than for other systems of the three temperature ranges.
- The mesophilic range is between 30°C–38°C, these systems need a longer storage time (retention times of 15–20 days or more) in order for the lower temperature micro-organisms to break down organic matter. In general, these systems are reported to be more robust when considering temperature upsets. Smaller agricultural systems will operate in this temperature range. Digesters operating in the mesophilic range require constant heating in order to maintain a temperature of 38°C.
- The thermophylic range is between 50°C–60°C. It operates at a high temperature that allows for the highest rate of biogas production and the lowest hydraulic retention time (HRT), average retention times in the range of 3–5 days. Greater insulation is necessary to maintain the optimum temperature range and more energy needs to be consumed in heating the system. These systems may be more sensitive to upsets due to temperature variations. However, these systems are more effective in pathogen removal. To avoid operating errors, they require closer monitoring and maintenance. Another drawback is that their effluent is not odour free.

## **7.3 Types of Anaerobic Digesters**

This study will present only three basic digester designs, namely covered lagoon, complete mix and plug-flow digester. All of them can trap methane and reduce faecal coliform

bacteria, but they differ in cost, climate suitability and the concentration of manure solids they can digest. In less developed countries, direct AD is the only treatment of wastewater. If the digester is adequately designed and the retention time of the water is long enough, the quality of the treated water can be excellent.

### **7.3.1 Cover Lagoon Digester**

A covered lagoon digester, as the name suggests, consists of a manure storage lagoon with a cover. The cover traps gas produced during decomposition of the manure. This type of digester is the least expensive of the three. Covering a manure storage lagoon is a simple form of digester technology suitable for liquid manure with less than 3-percent solids. For this type of digester, an impermeable floating cover of industrial fabric covers all or part of the lagoon. A concrete footing along the edge of the lagoon holds the cover in place with an airtight seal. Methane produced in the lagoon collects under the cover. A suction pipe extracts the gas for use. Covered lagoon digesters require large lagoon volumes and a warm climate. Covered lagoons have low capital cost, but these systems are not suitable for locations in cooler climates or locations where a high water table exists. Regarding AD systems used on U.S. dairy farms with a covered lagoons design, it is found that they operate at approximately ground temperature in the psychrophilic range, and have the lowest biogas production rate.

### **7.3.2 Complete Mix Digester**

A complete mix digester converts organic waste to biogas in a heated tank above or below ground. A mechanical or gas mixer keeps the solids in suspension. Complete mix digesters are expensive to construct and cost more than plug-flow digesters to operate and maintain. Complete mix digesters are suitable for larger manure volumes having solids concentration of 3 percent to 10 percent. The reactor is a circular steel or poured concrete container. During the digestion process, the manure slurry is continuously mixed to keep the solids in suspension. Biogas accumulates at the top of the digester. The biogas can be used as fuel for an engine-generator to produce electricity or as boiler fuel to produce steam. Using waste heat from the engine or boiler to warm the slurry in the digester reduces retention time to less than 20 days. It is often operated in the thermophylic range, thereby generating biogas at a high rate, it consist of a large tank where fresh material is mixed with partially digested material. These systems are suitable for manure with lower dry matter content (4%–12%).

### **7.3.3 Plug-Flow Digesters**

Plug-flow digesters are suitable for ruminant animal manure that has a solids concentration of 11 percent to 13 percent. A typical design for a plug-flow system includes a manure collection system, a mixing pit and the digester itself. In the mixing pit, the addition of water adjusts the proportion of solids in the manure slurry to the optimal consistency. The digester is a long, rectangular container or tubular tank, usually built below ground, with an airtight, expandable cover. New material added to the tank at one end pushes older material to the opposite end. Coarse solids in ruminant manure form a viscous material as they are digested, limiting solids separation in the digester tank. As a result, the material flows through the tank in a "plug" For optimal digestion, the average retention time (the time a manure "plug" remains in the digester), should take about 15 to 20 days for a plug to pass completely through the digester. Anaerobic digestion of the manure slurry releases biogas as the material flows through the digester. A flexible, impermeable cover on the digester traps the gas. Pipes beneath the cover carry the biogas from the digester to an engine-generator set.

A plug-flow digester requires minimal maintenance and it is more suitable for manure with lower solids concentrations, such as swine manure. Waste heat from the engine-generator can be used to heat the digester. Inside the digester, suspended heating pipes allow hot water to circulate. The hot water heats the digester to keep the slurry at 25°C to 40°C (77°F to 104°F), a temperature range suitable for methane-producing bacteria. The hot water can come from recovered waste heat from an engine generator fuelled with digester gas or from burning digester gas directly in a boiler. Plug flow systems rely on external recycling of a proportion of the outgoing digestate to inoculate the incoming raw feedstock. There are systems with vertical plug-flow and horizontal plug-flow.

**Table 7: Summary Characteristics of Digester Technology**

Characteristics	Covered Lagoon	Compleat Mix Digester	Plug-Flow Digester
Digestion Vessel	Deep lagoon	Round/Square In/Above-Ground	Tubular/Rectangular In/Above-Ground Tank
Level of Technology	Low	Medium	In the past low, nowadays uncertain
Supplemental Heat	No	Yes	Yes
Total Solids	0,5-3%	3-10%	11-13%
Solids Characteristics	Fine	Coarse	Coarse
HTR *(days)	40-60		
Farm Type	Dairy, Hog	Dairy, Hog	Dairy, Hog
Optimum Location	Temperature and Warm climate	All climate	All climate

Source: <http://www.epa.gov/agstar/pdf/handbook/chapter1.pdf>

## 7.4 Other Digester Types

Besides the three digester types discussed above, there are many other anaerobic digester designs that have been used for processing municipal sewage as well as industrial waste<sup>6</sup>. Most of them treat waste streams with a low solids content, and thus have found various ways to speed up the digestion process or increase the solids content in order to reduce the volume required for digesting, thereby reducing costs. Without providing details of how they work, other digester designs include:

1. Batch-fed reactor, such as the anaerobic sequential batch reactor (ASBR);
2. Temperature-phased anaerobic digester (TPAD);
3. Suspended particle reactor;
4. Anaerobic filter reactor;
5. Upflow solids reactor;
6. Continuously stirred tank reactor with solids recycle;
7. Up flow anaerobic sludge blanket reactor;
8. Anaerobic pump digester;

<sup>6</sup> Industries that use anaerobic digestion to treat their wastes include: food processing (milk and milk products, starch products and sugar confectionery, brewing, and distilling and fermentation are some of the largest), and the paper industry. The treatment of the industrial waste, as well as municipal sewage, is often driven by regulations.

9. Fluidized- and expanded-bed reactors,<sup>7</sup> and
10. Fixed-film anaerobic digester.<sup>8</sup>

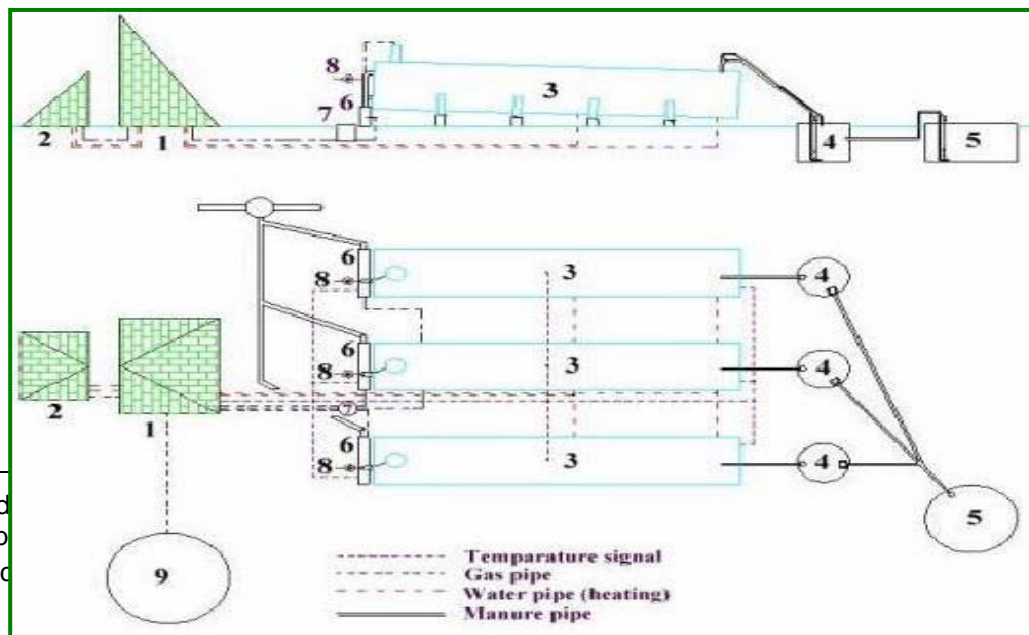
## 8. REVIEW OF BIOGAS PLANT TECHNOLOGY

The gas production from manure is dependent on the diet of the animals, and the age of the manure when it is fed into the digester. The produced biogas is by co-generation converted into electricity and heat, is by the anaerobic digestion converted into a "more ready to use" fertiliser.

### 8.1 First Case Overview (Lithuania)

An example of biogas technology exists in Lithuania – at the Rokai Pig Farm Demonstration Biogas Plant Kaunas using Danish Folkecenter's Renewable Energy Technology. The Anaerobic Digestion design is an inclined tubular digester (a modified form of the horizontal displacement digester). The digestion vessel is tubular, but inclined at an acute angle to the horizontal. Thus, the main advantages of a horizontal displacement digester are retained, while the exposed surface area of the digester contents, where scum and crusts can form, is minimized. It is also mechanically simpler to remove any scum and crust. The main applications of this design are likely to be for treating particulate waste of 8% total solids concentration, where some settling will occur. The biogas plant is designed based on the daily 60 m<sup>3</sup> of manure from the 11,000 pigs, is by the anaerobic digestion process where waste is converted into a "more ready to use" fertiliser. The produced biogas is converted into electricity and heat by co-generation, which will reduce the farms expenses for energy significantly. The technology gives possibility for much higher production with surplus of electric energy, which will be sold to the public grid. There are two gas turbine units, 1×75 kW + 1×110 kW, and electricity production is 2400 kWh/day. Installation system cost is equivalent to 3,692.31 USD per 1 kW. Electricity production or cogeneration can be run with a biogas boiler followed by a vapour turbine. The following figures show the layout and schematics drawing of the biogas plant of the Rokai plant.

**Figure 5: Schematic Drawing of the Biogas Plant (Decline Plug-flow Digester Type)**



<sup>7</sup> For a d  
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<sup>8</sup> "Reduc

son,  
00.

Source: <http://www.folkecenter.dk/en/rokai/rokai.html>

- 1) Technical building, control room, shows room, laboratory, and boilers.  
2) Technical building, co-generation. 3) Digesters. 4) 30 m<sup>3</sup> mixing tank. 5) 60 m<sup>3</sup> Pre-tank.  
6) Sulphur cleaning system. 7) Condensate separation. 8) Air pump. 9) Gas holder

Note: The sulphur cleaning system is needed to study for installation at Vanith Farm.

The biogas plant consists of 3 horizontal digesters in a parallel configuration - fed by the same raw material - the manure. Each 300m<sup>3</sup> digester receives daily 20m<sup>3</sup> manure in the 30m<sup>3</sup> individual mixing tanks. Waste additives are added and mixed in the same tank. The manure is pumped into the digester in intervals every 2 hours through a 24- hour period. An equivalent volume of manure is displaced at the outlet end of the digester. The process mix is heated to a temperature between 35°C and 50°C. Heating is obtained by an integrated heat exchanger, and heat losses are minimised by a 200 mm insulation covered by weatherproof steel plate coating. To keep the manure homogeneous and to avoid scum layer, the manure is mixed at intervals by a slowly rotating axial agitating system.

The agitator also transports the sediments to the sand outlet, where it can be removed. The biogas leaves from the top of the digester at a low pressure, sufficient to overcome the losses in pipes and the counter pressure from the floating gasholder.

The gasholder delivers pressure enough to operate gas burner and co-generation motor without any compressor to raise pressure. If the system pressure exceeds 45 mbar, the gas is released from the digester by a siphon trap.

## **8.2 Second Case Overview (Korea)**

In the case of biogas production from slurry for generating electricity in Korea, an Integrated Biogas Energy System (IBES) was developed in 1999. The biogas plants have been designed to process pigs' slurry of 10 m<sup>3</sup>/day, and the anaerobic digester tank is 200 m<sup>3</sup> used for 2000 pigs with the rate of biogas production 138 m<sup>3</sup>/day. The installed electricity generator is rated at continuous 33 kW, 380/220 V, 3-Phase, 0.8 power factor, and 60 hertz. This system showed that renewable energy production was 216 000 kWh/yr. The biogas produced by the digester was collected, and sent to a spark ignition engine or a dual-fuel engine-generator (this method was developed a few years ago). The electricity generator was rated at a continuous 33 kW (kilowatt), 380/220 volt, 3-phase, 0.8 power factor, and 60 hertz. This system consists of three parts: an anaerobic digester for reduction of organic matter and the production of biogas; an electricity generator for generating energy; and electrochemical oxidation process for waste water treatment containing bio refractory pollutants. Digestion takes place in a semi-continuous, single-stage, continuously stirring anaerobic digester, under 35°C of mesophilic temperature.

### 8.3 Third Case Overview (Zebulon)

In the case of Barham Farm of Zebulon<sup>9</sup> (this project is located on the Julian Barham Farm near Zebulon, North Carolina), 4000 sows to weaner pig farm with pit recharge are studied. This farm applied the covered lagoon type of digester. The construction process began in July 1996. The lagoon cover, a 400,000 Btu boiler and a 120 kW generator were installed in December 1996. Biogas use for heating water began in January 1997. Lagoon cover manufacturing problems limited biogas recovery and the production of electricity, however the boiler has operated almost continuously, providing hot water for pig mats under farrowed pigs. The owner recovered his money and has since purchased a new 40-mil HDPE cover. Preliminary results from July 1998 showed a recovery of 792 m<sup>3</sup>/d. of biogas while operating 12 hours of 90 kW daytime generator operations and 12 hours of nighttime boiler operation. Odour is virtually non-existent, the effluent is stable and nutrient content of the second lagoon has been reduced substantially.

### 8.4 Seven Farms Case Overview

This study is overview merely seven pig farms which has different scale, location and also AD type for being sample of pilot project study for Vanith Pig Farm, its have been part of a research project over the last ten-years. From the sample calculation of gas production samples per day per pig head in the table 9 are very different. If we observe biogas production per day per pig head, it can be seen that the data reported for Colorado Pork LLC is very high compared to the others; one pig gives biogas production about 0.3139 m<sup>3</sup> per day. For this reason, it might be dependent on the content of the stock feed used. And the other hand, when we are considering energy electric production per day for different types of AD, we supposed that, the Go-generator (Gas turbine) operates 12 hour & 24 hour per day, and we have noticed that Arex Pork Farm is one of seven farm, is highly productive when compared to the big scale farm at Hang Zhou which has a larger population of swine (nearly 30 times), more than, Shynyi (nearly 7 times), and Rokai biogas plant of Lithuania (more than 1.2 times). At the Arex farm for the Ratio 1 equivalent to 4.891 and, for the Ratio 2 equivalent to 2.446 the power electric of gas turbine of 1 kW can be produced electric energy of 4.891 kWh.

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<sup>9</sup> "Development of Environmentally Superior Technologies", Waste Management Programs, College of Agriculture and life sciences, [http://www.cals.ncsu.edu/waste\\_mgt](http://www.cals.ncsu.edu/waste_mgt).  
<http://www.epa.gov/agstar/resources/ben.html>



**Table 8: Comparisons of 7 Different Manure Digestion Systems, and Capacity of Gas Production and Size of Gas Turbine. (Estimated the Quality of Gas turbine Operate 12 hour/day)**

Example: Determination of the quality of gas turbine, the sample 1 total of energy production is 1448 kWh/day.

**We estimated that the system is operated 24 h/day, therefore:**

**Ratio** = (Total Energy Production per day) / (Hour Used per day X Gas Turbine Capacity)  
 = 1448 kWh.day/(24 h/day\*85 kW) = 0.710

**Average Ratio** = (Sum of Total Ratio of Gas Turbine) / (Number of Gas Turbine)

**Total of Energy Production per day** = Average Ratio X Hour Used per day X Gas Turbine Capacity

Sample size study	Farm Name And Type of AD	Head of Pigs	Gas Production per day	Size of Gas Turbine	1m <sup>3</sup> of gas produce electric (3/2)	One pig produce gas per day (2/1)	Energy Production per day	Quality of AD (6/1)	Quality of Gas Turbine
			M <sup>3</sup>	kW	kW	m <sup>3</sup>			
		1	2	3	4	5	6	7	8
1	Colorado Pork LLC Complete Mix	5,500	1,726	85	0,0493	0.3139	1448	0.2633	0.710
2	Barham Hog, Cover Lagoon	4,000	792.4	90	0,1136	0.1981	1080	0.2700	0.500
3	Hang Zhou, Zgehang Province <sup>a</sup>	200,000	8,500	230	0,0271	0.0425	13,500	1.5168	2.446
4	Shynyi, Beijing Municipality <sup>b</sup>	60,000	2,500	100	0,04	0.0417	4000	0.0666	1.667
5	Arex Pork Complete Mix	8,900	1,018.8	230	0,2258	0.1145	13,500	1.5168	2.446
6	Rokai, Lithuania, Plug-flow	11,000	1,200	185	0.1542	0.1091	2400	0.2182	0.541
7	Pig Slurry in Korea, Plug-flow	2,000	138	33	0,2391	0.0690	592	0.3000	0.747

<sup>a</sup> Project Activity Brief No.4: Biogas (didn't mention AD type)

<sup>b</sup> Project Activity Brief No.4: Biogas (didn't mention AD type)

It is noticed that in the seventh sample size study, one pig produced 0.069 m<sup>3</sup>/day of biogas per day; this result is very close to the value of 0.07 m<sup>3</sup>/day, which is mentioned in the RAP BULLETIN, 1995

## 8.5 Installed System Costs of Digester + Generator Review

In order to calculate the installation system cost of Digester + Generator of Vanith Pig Farm Company, information is taken the installation system cost of Rokai Pig Farm (Lithuania) which is mentioned in the previous page, and Colorado Pork LLC (USA) for sample study as is shown in table below

**Table 9: Anaerobic Digester System Costs of Colorado Pork LLC (USA)**

System Type	Installation cost US\$	O & M costs US\$/year	Installation system cost US\$/kW
Digester + Generator (5 systems)			
Low <sup>6</sup>	15,300	500	N/A
High <sup>6</sup>	32,200	2,500	N/A
Digester + Generator (7 systems)			
Low <sup>10</sup> (System size: 25 kW)	96,000	5,000	3,840
High <sup>11</sup> (System size: 120 kW)	368,880	10,000	3,074

Source: <http://www.westbioenergy.org/swine/six.html>

## 9. ESTIMATION OF VOLUME BIOGAS PRODUCTION AND CO-GENERATOR CAPACITY

### 9.1 Estimation of the Feasibility of Biogas Volume Production from Pig Farm

This study refers to the production rate of efficient digesters that includes pig effluent with a gas production of about 0.24 m<sup>3</sup>/day. Referring to Chesshire<sup>1</sup> that states that a gas production rate of 14 m<sup>3</sup>/day can generate 1 kW of electricity. Seven examples of different farm sizes from Asia, Europe and America have been studied, based on the actual pig population in the pig farm throughout Vientiane Capital City. The calculation of the gas production from pig farms in this study involved a statistical analysis to assist decision-making in the selection of the capacity of the co-generator. This study offers a current estimation of the amount of gas production per day through the selected co-generator capacity for eight pig farms. Beside these farms, it is noticed that the daily capacity of gas production is not enough for generating electricity. More details are given in Attachment 3.

Based on the study of the statistical analysis, the range of gas production measured is from 318 m<sup>3</sup>/day to 2,397 m<sup>3</sup>/day of the typical amounts from seven example farm sizes, but is noted to be only 87.9 m<sup>3</sup>/day to 298 m<sup>3</sup>/day have found at Vanith Farms F1+F2 and F3 respectively. It can be seen that the difference in gas production is quite large, and it is influenced by the different nutrient concentration in the food, and possibly the genetic quality of the pigs themselves. From this point, in order to improve the average value of gas production for the

<sup>10</sup> Lusk, Phil. (September 1998). Methane Recovery from Animal Manures: the Current Opportunities Casebook. NREL/SR-25145. NREL. Golden, CO. pp. 4-5: 4-69.

<sup>11</sup> Roos, Kurt. (May 2000). Colorado Pork LLC.

farm, F1+F2 should have an output from 969 m<sup>3</sup>/day to 1,229 m<sup>3</sup>/day and farm F3 from 263 m<sup>3</sup>/day to 333 m<sup>3</sup>/day. To achieve this target the specialist of Vanith Farm should consider the quality of pig food. The assessment of gas production per day in Vanith Farm will reach the medium standard value if the quality of food could be at standard level. It means that Vanith Farm is able to gain the average value of gas production as shown in the column thirteen which is the average value of column eleventh and twelve, the estimation of biogas production for farm F1+F2 is 1,099 m<sup>3</sup>/day and farm F3 is 332.9 m<sup>3</sup>/day.

**Table 10: The Current Estimation Plan of the Volume of Biogas and Methane Production by Comparing Within Different Sample Sizes of Study**

No.	Name of Pig Farm	No. of Pig	Theory 0.24 m <sup>3</sup> /day/pig	S1: 0.31389m <sup>3</sup> /day/pig	S2: 0.1981 m <sup>3</sup> /day/pig	S3: 0.0425 m <sup>3</sup> /day/pig	S4: 0.041667m <sup>3</sup> /day/day	S5: 0.1145 m <sup>3</sup> /day/pig	S6: 0.1091 m <sup>3</sup> /day/pig	S7: 0.069 m <sup>3</sup> /day/pig	Average of seven sample size	Average of five sample size (ignore S3 & S4)	Estimation of gas production
1	2	3	4	5	6	7	8	9	10	11	12	13	14
			m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	M <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d
1	Vanith Farm F1+F2	7,636	1,833	2,397	1,513	325	318	874	833	527	969	1,229	1,099
2	Vanith Farm F3	2,069	497	649	410	87.9	86.2	237	226	143	263	332.9	298
3	Total	9,705	2,330	3,046	1,913	413	404	1,111	1,059	670	1,232	1,562	1,397
The Volume of Methane Production by Comparing within Different Sample Sizes of Study													
			kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
1	Vanith Farm F1+F2	7,636	1,178	1,539	973	209	204	562	535	339	623	790	706
2	Vanith Farm F3	2,069	319	417	264	565	554	152	145	92	169	2140	191
3	Total	9,705	1,498	1,956	1,237	774	758	714	680	431	792	2,930	897

Where: Biogas production = 7,636 heads X 0.24 m<sup>3</sup>/day/head = 1,833 m<sup>3</sup>/day  
Methane production = (1,833 X 9)/14

## 9.2 Estimation of the Feasibility for Selecting the Capacity of Co-generator

Based on the table 10, the estimation of biogas production per day among several sample size studies, it can be calculated that the average size of co-generator for selecting the size of co-generator, and this is shown in the table below, in column 14.

**Table 11: The Current Estimation Plan of the Capacity of Co-generator by Comparing within Different Sample Sizes of Study**

No.	Name of Pig Farm	14 m <sup>3</sup> of biogas equivalent 1 kW	1 m <sup>3</sup> = 0.0493 kW	1 m <sup>3</sup> = 0.114 kW	1 m <sup>3</sup> = 0.027 kW	1 m <sup>3</sup> = 0.040 kW	1 m <sup>3</sup> = 0.226 kW	1 m <sup>3</sup> = 0.154 kW	1 m <sup>3</sup> = 0.239 kW	Average of seven sample	Average of five sample size (ignore S3 & S4)	Average of (1+12)/2	Select Capacity of co-generator
1	2	3	4	5	6	7	8	9	10	11	12	13	14
		kW	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW
1	Vanith Farm F1+F2	131	118	172	8,8	12.7	197	128	126	109	148	129	120
2	Vanith Farm F3	35.5	32	47	2.4	3.4	53	35	34	29.5	40	35	35
3	Total	166.5	150	219	11.2	16.4	250	163	157	139	188	164	155
The Conversion from Calorific value of Methane to kWh													
		kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	
1	Vanith Farm F1+F2	12,041	15,732	9,482	2,135	2,089	5,743	5,474	3,463	6,367	8,076	7,222	
2	Vanith Farm F3	3,266	4,264	2,698	5,785	5,663	1,553	1,482	940	1,727	21,875	1,962	
3	Total	15,307	19,996	12,181	7,921	7,752	7,297	6,956	4,403	8,095	29,951	9,184	

Where, example:

- Size of co-generator =  $1,833 \text{ m}^3 \times 1 \text{ kW}/14 \text{ m}^3 = 131 \text{ kW}$
- Size of co-generator =  $2,397 \text{ m}^3 \times 0.0493 \text{ kW}/\text{m}^3 = 118.17 \text{ kW}$

**Note:** 14 cubic meters of biogas to contain around 9 cubic meters of methane, which has a calorific

value of 315,000 BTU's, or 332 mega joules.

Based on the table 4, showing an estimation of the future pig population, the potential biogas production and the capacity of the co-generator can be calculated. This is shown in table 12 and 13.

**Table 12: The Future Plan Estimation of the Volume of Biogas Production**

No.	Name of Pig Farm	No. of Pig	Theory 0.24 m <sup>3</sup> /day/pig	S1: 0.31387m <sup>3</sup> /day/pig	S2: 0.1981 m <sup>3</sup> /day/pig	S3: 0.0425 m <sup>3</sup> /day/pig	S4: 0.041667m <sup>3</sup> /day/day	S5: 0,1145 m <sup>3</sup> /day/pig	S6: 0.1091 m <sup>3</sup> /day/pig	S7: 0.069 m <sup>3</sup> /day/pig	Average of seven sample size	Average of five sample size (ignore S3 & S4)	Estimation of gas production
1	2	3	4	5	6	7	8	9	10	11	12	13	14
		Heads	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d
1	Vanith Farm F1+F2	11467	2752	3599	2272	487	478	1313	1251	791	1456	1845	1651
2	Vanith Farm F3	3104	745	974	615	132	129	355	339	214	394	499,5	447
5	Total	14571	3497	4573	2887	619	607	1668	1590	1005	1850	2345	2098
The Conversion from Calorific value of Methane to kWh													
		Heads	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d
1	Vanith Farm F1+F2	11,467	1,769	2,314	1,461	313	307	844	804	509	936	1,186	1,061
2	Vanith Farm F3	3,104	479	626	395	85	83	228	218	138	253	321	287
3	Total	14,571	2,248	2,940	1,856	398	390	1,072	1022	646	1,189	1,507	1,349

**Table 13: The Future Estimation Plan for the Capacity of the Co-generator**

No.	Name of Pig Farm	14 m <sup>3</sup> of biogas equivalent 1 kW	1 m <sup>3</sup> = 0.0493 kW	1 m <sup>3</sup> = 0.114 kW	1 m <sup>3</sup> = 0.027 kW	1 m <sup>3</sup> = 0.040 kW	1 m <sup>3</sup> = 0.226 kW	1 m <sup>3</sup> = 0.154 kW	1 m <sup>3</sup> = 0.239 kW	Average of seven examples	Average of five sample size (ignore S3 & S4)	Average of (11+12)/2	Select Capacity of co-generator
1	2	3	4	5	6	7	8	9	10	11	12	13	14
		kW	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW
1	Vanith Farm F1+F2	197	177	258	13,2	19	296	193	189	164	223	193	195
2	Vanith Farm F3	53.2	48	69.8	3.57	5.2	80.2	52.2	51.2	44.3	60.3	52	50
3	Total	250	4573	2887	16.8	24	377	245	240	208	283	246	245
The Conversion from Calorific value of Methane to kWh													
		kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
1	Vanith Farm F1+F2	18,083	23,654	14,935	3,200	3,138	8,628	8,219	5,203	9,568	12,124	10,846	
2	Vanith Farm F3	4,896	6,399	4,038	869	848	2,331	2,228	1,411	2,586	3,281	2,934	
3	Total	22,980	30,053	18,972	4,068	3,986	10,958	10,447	6,613	12,154	15,405	13,779	

### 9.3 Conversion to Other Chemical Forms

Regarding Tables 10 and 12 under column 13, the energy can be converted to another form such as methane, natural gas, petrol and diesel, for present and in future as shown in table 14. Also in addition an estimation of biogas production from pig farms shown in table 5. See also the [Annex 4 & 5](#) whole pig farm through Vientiane Capital City.

**Table 14: Shows the Amount of Conversion Value of Gas to Methane, Natural Gas, Petrol and Diesel for Present Plan and for Future Plan**

No.	Name of Pig Farm	Gas Production	1 m3 of gas equivalent to 0.62 m3 of methane	1 m3 of gas equivalent to 0.55 m3 of natural gas	1 m3 of gas equivalent to 0.7 litre of petrol	1 m3 of gas equivalent to 0.62 litre of diesel
1	2	4	5	6	7	8
		M <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	Litres/d	Litres/d
<b>Present plan</b>						
1	Vanith Farm F1+F2	1099	681.45	604.51	769.38	681.45
2	Vanith Farm F3	298	184.641	163.79	208.47	184.641
3	<b>Total</b>	<b>1397</b>	<b>866.091</b>	<b>786.31</b>	<b>977.84</b>	<b>866.091</b>
<b>Future plan</b>						
1	Vanith Farm F1+F2	1651	1023.62	908.05	1155.7	1023.62
2	Vanith Farm F3	447	277.14	245.85	312.9	277.14
3	<b>Total</b>	<b>2098</b>	<b>1300.76</b>	<b>1153.9</b>	<b>1468.6</b>	<b>1300.76</b>

This project is intended to produce biogas by utilizing a by-product from the existing pig farm (pig dung) as raw material to feed an anaerobic digester. The biogas produced will be utilized as fuel to run a co-generator for generating electricity. The produced electrical energy will be utilized to cover the energy consumption of the farm and any surplus may be sold to the national grid. This is one inexpensive alternative form for the production of electrical energy. In addition biogas may be utilized for heating and cooking.

### 9.4 Estimation of Daily Energy Production

The principal objective of this study after selecting the capacity of the co-generator is the need to evaluate the possibility of electrical energy production per day, which takes into account the capacity of co-generator. From this point of view, it is necessary to consider table 3, in column 8, which shows the quality of the co-generator from the various scale pig farms. Some pig farms are very large scale such as Hang Zhou and Shynyi pig. This study is considering only small-scale farms and uses the average value of five small-scale farms to estimate the efficiency of co-generator at 1.977 kWhe/kW. This results in a daily production of electrical energy equivalent to 2610 kWhe/day. Considering the size of farm and taking the average value, our finding is in the margin. Finally, the average efficiency of the co-generator is equivalent to 1.254 kWhe/kW, with the electrical energy production per day equivalent to 1650 kWhe/day.

**Example:**

**Cases 1 is studied from a study of five similar sized examples from which the average is calculated:**

*For Farm F1+F2:*

Co-generator size of 110 kW, suppose the co-generator operates 12 h per day

Quality of Co-generator =  $(1.00+1.42 + 4.891 + 1.081 + 1.494)$  kWh/kW = 1.977 kWh/kW

Electrical Energy Production per day =  $110 \text{ kW} \times 1.977 \text{ kWh/kW} \times 12 \text{ h/day} = 2610 \text{ kWh/day}$

*For farm F3:*

Co-generator size 35 kW, suppose the co-generator operate 12 h per day

Electrical Energy Production per day =  $35 \text{ kW} \times 1.977 \text{ kWh/kW} \times 12 \text{ h/day} = 830 \text{ kWh/day}$

**Cases 2 is studied from four samples size study and calculates an average:**

*For farm F1+F2:*

Co-generator size 110 kW, suppose the co-generator operate 12 h per day

Quality of Co-generator =  $(1.00+1.42 + 1.081 + 1.494)$  kWh/kW = 1.25 kWh/kW

Electrical Energy Production per day =  $110 \text{ kW} \times 1.25 \text{ kWh/kW} \times 12 \text{ h/day} = 1650 \text{ kWh/day}$

*For farm F3:*

Co-generator size 35 kW, suppose the co-generator operate 12 h per day

Electrical Energy Production per day =  $35 \text{ kW} \times 1.25 \text{ kWh/kW} \times 12 \text{ h/day} = 527 \text{ kWh/day}$

**Table 15: Summary of the Evaluation for Daily Potential Electrical Energy Production**

No.	Name of Pig Farm	No. of Pigs	Size of Co-generator	Quality of Co-generator		Electric Production Per day	
				min	max	min	max
		Heads	kW	kWhe/kW	kWhe/kW	kWhe/kW	kWhe/kW
<b>Present plan</b>							
1	Vanith Farm F1+F2	7636	120	1.25	1.977	1800	2847
			110	1.25	1.977	1650	2610
2	Vanith Farm F3	2069	35	1.25	1.977	525	830
3	<b>Total</b>	<b>9705</b>	<b>155</b>			<b>2175 - 2325</b>	<b>3440 - 3677</b>
<b>Future Plan</b>							
1	Vanith Farm F1+F2	11467	195	1.25	1.977	2925	4626
2	Vanith Farm F3	3104	50	1.25	1.977	750	1186
3	<b>Total</b>	<b>14571</b>	<b>245</b>			<b>3675</b>	<b>5812</b>

Estimation of the current electrical energy production per day for Vanith Pig Farm and for future plans could be summarized in the table above.

## 9.5 Adopted Technology

This study learns from the experience of the Rokai Pig Farm concept using combined heat and power (CHP) and will mean that the plant is scaled according to the amount of resource available on the Vanith Farm. Presently, for F1+F2, the daily estimate of manure from the 7636 pigs is 40 m<sup>3</sup> and for F3 is 11 m<sup>3</sup> of manure from the 2069 pigs. By utilizing an anaerobic digestion process this can be converted from raw manure into biogas and "more ready to use" fertiliser. Biogas is utilized by co-generation and converted into electricity and heat, which will significantly reduce the farms expenditure on energy.

The technology provides the possibility for much higher production of electricity with the surplus being sold to the public grid. The technical estimation of the manure tank, the digester tank, the gas storage tank, pressure of the system and the capacity of co-generator will influence the expected output. The details of using a slurry heater in AD on different conditions are as follows:

### 1a. Technical estimation data for Vanith Digester Plant for Farm F1 and F2 for currently data

Manure	: 40 m <sup>3</sup> pig manure / day
Waste concentrated:	~ 7.19 t / day
Digester	: 2 x 300 m <sup>3</sup> horizontal steel digesters
Gas production	: 318 - 2397 m <sup>3</sup> /day (compare with the proportion of Rokai 850-2500 m <sup>3</sup> /day)
System pressure	: 25 Mbar, (max. 45 Mbar by safety siphon trap)
Gas storage	: 40 m <sup>3</sup>
Co-generation	: 110 kW or 120 kW
Boiler/burner	: 1 x 200 kW gas burner
Sulphur cleaning	: Aerobic external biological process
Control system	: PC based control -and data acquisition system

### 1b. Estimation technical data for Vanith Digester Plant for Farm F3 for currently data

Manure	: 11 m <sup>3</sup> pig manure / day
Waste concentrated	: ~ 3.1 t / day
Digester	: 1 x 300 m <sup>3</sup> horizontal steel digesters
Gas production	: 86.02 - 649 m <sup>3</sup> /day (compare with the proportion of Rokai 250-700 m <sup>3</sup> /day)
System pressure	: 25 Mbar, (max. 45 Mbar by safety siphon trap)
Gas storage	: 20 m <sup>3</sup>
Co-generation	: 25 kW or 35 kW
Boiler/burner	: 1 x 50 kW gas burner
Sulphur cleaning	: Aerobic external biological process
Control system	: PC based control - and data acquisition system

### 2a. Estimation technical data for Vanith Digester Plant for Farm F1 and F2 for future plan

Manure	: 63 m <sup>3</sup> pig manure / day
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Waste concentrated	: ~ 10.8 t / day
Digester	: 3 x 300 m <sup>3</sup> horizontal steel digesters
Gas production	: 478 – 3599 m <sup>3</sup> /day (compare with the proportion of Rokai 1200 - 3600 m <sup>3</sup> /day)
System pressure	: 25 Mbar, (max. 45 Mbar by safety siphon trap)
Gas storage	: 40 m <sup>3</sup>
Co-generation	: 1 x 75 kW + 1 x 120 kW
Boiler/burner	: 1 x 300 kW gas burner
Sulphur cleaning	: Aerobic external biological process
Control system	: PC based control- and data acquisition system

## 2b. Estimation technical data for Vanith Digester Plant for F3 for future plan

Manure	: 17 m <sup>3</sup> pig manure / day
Waste concentrated	: ~ 4.66 t / day
Digester	: 1 x 300 m <sup>3</sup> horizontal steel digesters
Gas production	: 129- 974 m <sup>3</sup> /day (compare with the proportion of Rokai 250 – 700 m <sup>3</sup> /day)
System pressure	: 25 Mbar, (max. 45 Mbar by safety siphon trap)
Gas storage	: 20 m <sup>3</sup>
Co-generation	: 2 x 25 kW
Boiler/burner	: 1 x 85 kW gas burner
Sulphur cleaning	: Aerobic external biological process
Control system	: PC based control and data acquisition system

## 9.6 Core Business of Vanith Farm is to Row and Supply of Pork to the Local Market.

The Vanith Pig Farm Company is a joint venture between Mr. Vanith and a private investor from France. The core business of this proposed project is to produce electricity by utilizing AD biogas produced at Vanith Pig farm to fuel a co-generator. Referring to the survey, financially Vanith Farm is not able to fund this proposed project. This is partly due to the farm not being the property of Vanith Company (This Pig Farm is the property of Ministry of Agriculture and Forestry, and now is become a concession project and run as a joint venture company). In addition, this proposed project may not be profitable for them. It seems that Vanith Company relies only on the Government authority to solve their problems.

It appears that this proposed project would be possible if there would be a grant from NGO or other international organization as a pilot or demonstrative project for Lao PDR. One of the possible approaches for financing this proposed project is by a private investment.

## 9.7 The product(s) or Service(s) Generated by the Project:

Electricity from biogas

- characteristics of energy produced (electricity, steam or hot water at specified temperature/pressure and daily, weekly and monthly quantities to match current and projected energy loads and profiles);

The installed capacity of the system is 35 kW under 0.4 kV will produce electrical energy of about 525 kWh per day.

- realistic expected annual production (GWh, GJ, TOE replaced, etc) to tie in with seasonal fuel supply/energy/production demand, using realistic annual hours of use - including provision for scheduled maintenance and major plant/generator overhauls;

The expected annual production is 191.6 MWh, the amount of 93.0 MWh will be utilized to run the farm; a surplus of 99.8 MWh will be sold to the grid.

- how any electricity/fuel/steam/hot water produced will be utilized in an efficient production process including specified current and future process temperature/pressures for steam/hot water/direct drying and so forth;

The amount of 93 MWh will be utilized to run the farm

- Why the stated annual production/activity level is reasonable for the plant concerned compared with other comparable plants/activities in the country and in relation to international practice
- Customer/process ability to pay for full cost of providing energy service (particularly relevant for small grid electricity to replace explicitly and more commonly implicitly subsidized/unrealistically low electricity prices where source of necessary ongoing subsidies is not identified, or source and likelihood of ongoing explicit or implicit subsidies continuing for project duration)

The electricity company will purchase the surplus at a lower rate. One of the alternatives to be more beneficial is to operate the plant during peak hours.

## 9.8 Assessment Installation Cost of the Gas Turbine for Vanith Pig Farm Company

This study refers to technology installed at the Rokai Pig farm and Colorado pig farm with the cost of digester system shown on table 3. This is then applied to the Vanith pig farm and, based on its present proportions for determining the construction size and design for present and future planning. It is then possible to assess the installation cost of a digester system as shown in the table below:

**Table 16: Estimation of Installation Cost of Anaerobic Digester System Costs**

Type of Technology	Installation Cost (US\$)	Operation and Maintenance Costs (O&M Costs) (US\$)	Installation System Cost (US\$)
<b>Estimation of Installation cost for currently data</b>			
<b>Transfer Rokai Technology</b>			
• F1&F2 (110 kW)	406,120		3,692
• F1&F2 (120 kW)	443,040		3,692
• F3 (35 kW)	129,220		3,692
• F3 (25 kW)	92,300		3,692
<b>Transfer USA Technology</b>			
• F1&F2 (120 kW)	368,880	10,000	3,074
• F3 (35 kW)	107,590	10,000	3,840
• F3 (25 kW)	96,000	5,000	3,840
<b>Estimation of Installation cost for future plan</b>			
<b>Transfer Rokai Technology</b>			

F1&F2 (75 kW + 110 kW)	683,020		3,692
F3 (50 kW)	184,600		3,692
<b>Transfer USA Technology</b>			
F1&F2 (75 kW + 120 kW)	599,430	10,000	3,074
F3 (50 kW)	153,700	5,000	3,074

## 9.9 Assessment of the Reduction of Environmental Impact

The reduction in methane emissions obtained by processing, based on the Rokai pig farm\*, the manure (or raw dung) is about 1000 kg/m<sup>3</sup>, the methane is 0.717 kg per m<sup>3</sup>, and the equivalent amount of CO<sub>2</sub> is 19-21 times greater, 68 kg CO<sub>2</sub> or 0.068 tCO<sub>2</sub>/m<sup>3</sup>. The estimation of reduction in methane emission for this study is separated in two conditions for present and future plan for two location of pig farm F1+F2 & F3.

### Present plan:

- In case of pig farm F1+F2, with 40 m<sup>3</sup> of manure per day:  
40 m<sup>3</sup> of dung is estimated to produce between 318 and 2397 m<sup>3</sup> of biogas, which is only 65% methane, so worst case this would yield (say) 200 m<sup>3</sup> of methane per day, which will weight 200 x 0.717 = 143 kg per day, or 52 tons CO<sub>2</sub> eq per annum. Then the 35% CO<sub>2</sub> must be subtracted too.
- In case of pig farm F3, with 20 m<sup>3</sup> of manure per day:  
20 m<sup>3</sup> of dung is estimated to produce between 159 and 1198.5 m<sup>3</sup> of biogas, which is only 65% methane, so worst case this would yield (say) 100 m<sup>3</sup> of methane per day, which will weight 100 x 0.717 = 717 kg per day, or 26 tons CO<sub>2</sub> equiv. per annum. Then the 35% CO<sub>2</sub> must be subtracted too.

### Future plan:

- In case of pig farm F1+F2, with 40 m<sup>3</sup> of manure per day:  
40 m<sup>3</sup> of dung is estimated to produce between 318 and 2397 m<sup>3</sup> of biogas, which is only 65% methane, so in better case this would yield (say) 300 m<sup>3</sup> of methane per day, which will weight 300 x 0.717 = 215.1kg per day, or 78 tons CO<sub>2</sub> equiv. per annum. Then the 35% CO<sub>2</sub> must be subtracted too.
- In case of pig farm F3, with 20 m<sup>3</sup> of manure per day:  
20 m<sup>3</sup> of dung is estimated to produce between 159 and 1198.5 m<sup>3</sup> of biogas, which is only 65% methane, so in better case this would yield (say) 150 m<sup>3</sup> of methane per day, which will weight 150 x 0.717 = 107.55 kg per day, or 39 tons CO<sub>2</sub> equiv. per annum. Then the 35% CO<sub>2</sub> must be subtracted too.

## 10. FINANCIAL ANALYSIS OF THE PROJECT

### 10.1 Financial Analysis and Commercial Viability

Effective financial models are powerful tools to most corporate finance transactions. Developers have to provide the lender a clear, comprehensive and accurate project model that shows project/shareholder's return and lender coverage ratio. The models should focus on the management of the continuing business and on project cash flow. The assumptions should be conservative and a sensitivity analysis should demonstrate the viability of the project and the financing structure under different scenarios. Financial advisers are often employed by the developers to produce financial models. These models monitor the success of long-term project

finance arrangement. Financial advisers provide monitoring services and model custody services that allow project finance to meet the requirements of their loan agreements. In particular, lenders will require periodic reports about lending ratios, sensitivity analysis and debt coverage ratios to allow them to monitor the risk of the developer's loan. Monitoring models are used at regular intervals during the life of the project financing to mitigate risks. Financial models are refined through the different stages of project development. As the project moves through the advance stage of development, a more precise model is possible to predict the viability and profitability of the project. The model does not only serve as a tool for analysis for the developer but more importantly it gives an overview of the project economics to potential participants such as investors and lenders. In the case of the Vanith Pig Farm proposed project, ADB has standard models available from their website to use

## 10.2 Structuring the Financial Model: Building and Securing the Project Cash Flow

The financial model should be designed to be an integrated spreadsheet-based program with several sheets linked to each other. The main features of the model should include:

- Separate but linked worksheets to allow the user to easily understand the different functions of the model and to navigate it with ease.
- Inclusion of technical analysis to determine the potential power and heat generation capacity of the chosen technology.
- Data entry is done on designated worksheets only, and changes in data can be accordingly done.
- An operation worksheet is included which captures the demand of the households served as well as the seasonality of the primary energy sources chosen.
- Sensitivity analyses on different parameters are included.
- The model should be customized to the specific project and to the technologies chosen, which increases the accuracy of the analysis

Once the technical option is determined, the most appropriate business model should be used for the financial modeling exercise. At this stage, the practical aspects of the business will be structured which will reflect matters related to the company's shareholding structure, financial plan, capital investment, and operational details. The financial model normally consists of different worksheets. Each worksheet has a different function and theme. Below are the descriptions of these worksheets and their functions in the model:

- **Results and summary:** This worksheet gives a summary of the assumptions used in the analysis and the corresponding results. The results presented include life-cycle performance such as the Internal Rate of Return (IRR) for the project and the equity, the Net Present Value (NPV) and payback period. The sheet can be printed in one page and is designed to give an overview of the business/project analyzed.
- **Inputs and assumptions:** In this worksheet, inputs on both technological and financial parameters are entered. Basic technical calculations and assumptions are included for each technology considered. Information on the electricity tariff and revenue structures is also included.
- **Costs data:** Information on the costing includes capital investment costs, operation and maintenance costs and financial costs. The major costs are further broken down into detailed items as far as possible.
- **Operation:** The Operation worksheet calculates, on a monthly basis, the electricity generation coming from the installed power generation plant, the losses incurred, the

consumption of the end-users or off-takers to be served considering their peak and off-peak electricity consumption, and the net electricity export to the grid, where appropriate.

- **Income statement:** The Income Statement shows the performance of the project. Data from the previous worksheets are captured to calculate the projected yearly income and expenses of the project analyzed. The Income Statement shows whether the project is generating net earnings, in which case giving wealth to the company, or net losses, which reduces the wealth of the company.
- **Cash flow:** The projected cash flow of the project is the main basis for the analysis of the life-cycle performance of the project. If financing is made on a project finance basis, the banks will look into the cash flow as the main source of debt service (i.e. repayment of principal and interests) for the loans extended to the project. The performance of the project for both operational and financing cash flows is determined. Its debt service performance is also determined.
- **Balance sheet:** The Balance Sheet gives a picture of what the company has – its wealth and how this wealth is financed. The model should provide the yearly projected values and shows key items such as cash and other current assets, fixed assets, as well as equity, loans and current liabilities that are required for the smooth operation of the company.
- **Sensitivity analysis:** As most of the figures considered in the analysis of a base case come from assumptions and estimates, the actual figures such as costs and revenues may vary. Thus, it is important to anticipate any uncertainty by considering the effect of different scenarios in the performance of the project. Sensitivity analyses on some parameters are conducted to determine which parameters, when changed affect the performance of the project significantly. The sensitivity analyses are carried out in the Cost Data worksheet.

The result of the financial modeling will show the viability of the project. Typically, a project that results in an IRR higher than the cost of capital of the company is a viable option. This cost of capital is reflected in the discount rate determined for the company and is used in the financial analysis. The financial model will also reveal the debt service coverage for the borrowing of the business. To be attractive for the financial institutions to provide financing to the project, the debt service coverage ratio should typically be equal to or over 1.2x in any given year during the tenor of the debt. Other information such as required subsidy levels in order for the business to be viable, whenever necessary, will also be determined as an output of the financial analysis.

When preparing a set of cash flow projections for a prospective project, it is important to give all the critical details. Prospective lenders and equity investors are particularly interested in the assumptions because the projections are meaningful only to the extent the assumptions have a sound basis. The projected operating cash flows form the basis for measuring the expected rates of return to the equity investors.

The Internal Rate of Return (IRR) is the expected rate of return of the investment into the project or business. The IRR is the discount rate when the net of the present values of all items in the cash flow is zero. The IRR is calculated from the net cash flow in the cash flow table using the following formula:

$$0 = CF_0 + \frac{CF_1}{(1+IRR)} + \frac{CF_2}{(1+IRR)^2} + \dots + \frac{CF_n}{(1+IRR)^n}$$

Where: CF = net cash flow at different periods

n = end of any period

The decision rule to apply when using the IRR method is to undertake the investment if the IRR exceeds the company's cost of capital.

Another measure of the viability of the investment that will be calculated is the Net Present Value (NPV). The NPV of a project is the difference between what the project costs and the value it has created (or destroyed) due to the investment made. It is determined by computing the present value of all relevant cash flows using the formula:

$$NPV = CF_0 + \frac{CF_1}{(1+r)} + \frac{CF_2}{(1+r)^2} + \dots + \frac{CF_n}{(1+r)^n}$$

Where: CF = net cash flow at different periods  
n = end of any period  
r = cost of capital or discount rate

According to Gupta and Bhandari (2000, p. 92-93), a country first needs to prioritize the type of projects it perceives as potential projects under the Clean Development Mechanism (CDM). These projects should meet the financial additionality criterion and should make a contribution to sustainable development. The concern of developing country governments that PREGA/CDM projects will trade away less expensive abatement options should be addressed at this stage. Several projects could qualify in meeting the environmental and financial additionality criteria. The Nepalese government and other developing countries can identify additional criteria other than carbon abatement depending upon the local needs and priority to evaluate the project. The following table lists four hypothetical projects and additional parameters that the project must address.

**Table 18: Hypothetical Projects and Additional Parameters**

<b>Project</b>	<b>CO<sub>2</sub> abatement Cost US\$/tCO<sub>2</sub></b>	<b>Positive Environment Impacts</b>	<b>Employment Generation</b>	<b>Access to the New Technology</b>
<b>A</b>	<b>3</b>	<b>Low</b>	<b>Low</b>	<b>Low</b>
<b>B</b>	<b>5</b>	<b>Medium</b>	<b>High</b>	<b>Low</b>
<b>C</b>	<b>8</b>	<b>Low</b>	<b>Low</b>	<b>High</b>
<b>D</b>	<b>21</b>	<b>High</b>	<b>Medium</b>	<b>High</b>

The additional parameters of the project are cost per ton of CO<sub>2</sub> abated (financial aspects), employment generation (social and developmental aspects), local environmental impacts (economic and environmental aspects) and access to technology (technological aspects). The host country may decide to exclude projects of type A as it fears that it is trading "low-hanging fruit" and the resultant additional benefits are not significant. On the other extreme, type D projects, for instance, with high CO<sub>2</sub> abatement costs but with favorable benefits could clearly be included in the list of desirable CDM/PREGA projects. It is for the government to decide whether to include projects of type B and C. The government should clearly prioritize identified projects and define rules of exclusion for potential CDM/PREGA projects.

Economic cost calculation is the ideal cost concept for use in GHG abatement assessment. Given the limitations in data and time for this country study review report, it will not be possible to employ full economic costs in the analysis. Life cycle cost (LCC) analysis has been carried out for all six potential REGA technologies in order to find out the abatement cost which has been used as the basis for prioritization. LCC is the total discounted cash flow for an investment during its economic life. In other words, it is the present value of all the costs associated with an investment which generally includes the initial cost, the sum of discounted annual maintenance and operating cost, and a credit for any residual value for the investment at the end of the project period.

The formula for LCC is:

$$\text{Lifecycle cost (LCC)} = C_c + \sum_{n=1}^t \frac{C_n}{(1+r)^n} - \frac{RV}{(1+r)^t}$$

Where:

$C_c$  = Initial capital cost (capital, labor, administration cost)

$C_n$  = Operating cost (operation, and maintenance cost, fuel, tax and interest) in year  $n$

$n$  = time period (year)

$r$  = discount rate

$t$  = total life of project

$RV$  = Residual Value

If the annual operating costs are constant, the simplified formula will be:

$$\text{LCC} = C_c + \frac{C_n}{\text{CRF}} - \frac{RV}{(1+r)^t}$$

$$\text{where: CRF (capital recovery factor)} = \frac{r}{1 - (1+r)^{-t}}$$

(Source: Spalding - Fecher, Clark, James, 1999, P. 23, 24)

The incremental cost thus obtained through the LCC analysis assuming constant O&M costs for REGA technologies and the conventional system is divided by the CO<sub>2</sub> abatement potential to get the incremental cost per ton of CO<sub>2</sub> abatement. An initial attempt has been made to calculate the incremental cost based on various assumptions. There is ample room to make the calculations more explicit once all the required empirical data are available

## **11. BARRIERS AND CONCLUSION**

### **11.1 Barriers for Development of Energy from Biogas**

A number of barriers, which impair the development of the energy from biogas, include: psychological, social, institutional, legal and economical factors.

#### **Legal and Financial Barriers:**

- lack of proper legal standards determining explicitly the programme and policy;
- insufficient economic mechanisms, in particular fiscal, to facilitate achieving the desirable profits related to the investment costs, installations and equipments;
- relatively high costs of technologies, labour (e.g. geological investigations).

#### **Information Barriers:**

- lack of easily available information on projects feasible for technical applications;
- lack of easy accessible information on procedures for projects implementation and realisation, standard costs, economic, social and ecological benefits;
- lack of information on installations producers, suppliers and contractors
- lack of information the certain of the design and construction of scale anaerobic digestion systems
- limited application of knowledge gained from the operation of existing plants in the design of plants
- lack of familiarity with biogas investments amongst the financial community

### **11.2 Conclusion**

The volume of daily biogas production from pig farm, generally, is dependent upon the type of anaerobic digester design that is concerned with the system of controlling anaerobic digester temperature, fermentation or retention time and the feedstock material.

The preferred type of digester is the complete mix digester, thereby generating biogas at a high rate and the lowest hydraulic retention time (HRT), It is often operated in the thermophylic range, at a high temperature (between 50°C–60°C), but the construction cost is very expensive, and the operation cost and the maintenance cost are also higher than the plug-flow type.

There are some difficulties in finding an accurate prediction for biogas production per head of pig (it is variable and depends on the design of the digester) and also the AD technology through the capacity of gas turbine.

It is noted that the selection of the capacity of a co-generator or gas turbine for the Vanith Pig Farm Company (which is shown in table 12), is reasonable when compared to the samples 6 and 7 (selected at 120 kW for F1+F2 and 35 kW or 33 kW for F3). And also, for the future estimated plan of the capacity of co-generator or gas turbine (in table 14), in it may be considered more viable to use a standard size of production turbine. Considering the Rokai case, it is possible to select two gas turbines (1×75 kW + 1×120 kW) instead of 1 x 195 kW for Farm F1+F2 and one unit 50 kW for farm F3 (if this size is available).



## Investment Cost of AD plant:

It is found that the investment cost of AD plant is very high.  
For current data

- Farm No F1+F2 is about 368,880 US\$ (transfer Colorado Pork LLC Complete Mix technology, case study of sample 1) up to 443,040 US\$ (transfer Rokai technology, case study of sample 6)
- Farm No F3 is about 107,590 US\$ (transfer USA technology, case study of sample 1) up to 129,220 US\$ (transfer Rokai technology, case study of sample 6).

For future estimation plan

- Farm No F1+F2 is about 599,430 US\$ (transfer USA technology, case study of sample 1)
- Farm No F3 is about 153,700 US\$ (transfer USA technology, case study of sample 1) up to 184,600 US\$ (transfer Rokai technology, case study of sample 6).

Based on the actual potential and background and the need of Vanith Pig Farm Company, if the gas production estimates based on the comparison farms are accurate, it can be perceived that there is high feasibility of implementation the pig farm waste to produce biogas for generating electricity:

Depending on the technology deployed and the level of gas filtering done, biogas systems can help the owner's of the Vanith pig farm on several fronts, such as:

- reducing their expense of electricity and energy consumption,
- resolving the problem of objection to the business of pig farm by neighbours,
- solving the problems of odours from the pig farm,
- continuously expanding the pigs pens as needed,
- reducing water pollution and ground contamination step by step,
- obtaining the extra benefit from selling the fertilizer from the pig manure,

The Vanith Pig Farm Company perceives the advantages and benefits in the long term from using AD technology. However when the PREGA team of Lao P.D.R tried to explain to the owner the process of “biogas production from their farm for electricity generation”, the owner of the company remains concerned that the investment cost is very high, and this is compounded because the company has financial problems related to their competitiveness in the Lao pork market, and the company is still reliant on the government grant assistance to stay in business.

## Recommendation

This study has only considered the generation of electrical energy by utilizing biogas produced from pig dung at the Vanith pig farm. Once the basic profitability of the Vanith Pig Farm Company is resolved, it may be worth studying further the alternative option of the direct sale of biogas, which consists of digester and biogas station. It may be expected that the investment cost of the former is higher than the latter. As Lao PDR does not have any known gas resources; consequently all of the gas needed is imported from neighbouring countries. This would add to the value of biogas, as it would be competing with expensive imported LPG and diesel, and not with lower cost reticulated natural gas.

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# Annex 1: The Statistics of Pig Farms in Vientiane Capital City

No.	Name of Pig Farm (*)	No. of Pig	Location	Latitude Degree	Longitude Degree	Remark
Large scale pig farm						
1	Vanit Farm F1+F2	7636	Vientiane Capital	18.08	102.42	
2	Vanit Farm F3	2069	Vientiane Capital	18.08	102.42	
3	Chanhpheng Douangphachanh	1,234	Vientiane Capital	17.59	102.31	
4	Khenphone Nongteng	1,112	Vientiane Capital	18.01	102.31	
Medium scale fig farm						
5	Keo Inthiphon	545	Vientiane Capital	18.11	102.38	
6	Phouvong Kolasak	535	Vientiane Capital	18.01	102.31	
7	Nang Vone	486	Vientiane Capital	17.53	102.45	
8	Nang Kham	357	Vientiane Capital	17.51	102.37	
9	Khamsing Sisoutham	224	Vientiane Capital	18.12	102.39	
10	Khamphay	223	Vientiane Capital	18.07	102.45	
11	Sivilay Hungheuang	180	Vientiane Capital	18.02	102.38	
12	Boun Gnanong	156	Vientiane Capital	18.09	102.38	
13	Liangkham	143	Vientiane Capital	17.58	102.52	
14	Champhonh	142	Vientiane Capital	17.56	102.43	
15	Nang Chanh	139	Vientiane Capital	17.55	102.39	
16	Khamsone Keamany	131	Vientiane Capital	18.03	102.37	
17	Phongsamouth	121	Vientiane Capital	18.05	102.43	
18	Nongphagna	111	Vientiane Capital	18.01	102.37	
19	Bounheng	104	Vientiane Capital	17.56	102.31	
Small scale pig farm						
20	Souay	85	Vientiane Capital	18.06	102.31	
21	Phan Sophamixay	77	Vientiane Capital	17.53	102.37	
22	Pancha	77	Vientiane Capital	18.07	102.39	
23	Chin	61	Vientiane Capital	17.59	102.41	
24	Bouaket	45	Vientiane Capital	17.59	102.29	
25	Damdouan Nonghai	45	Vientiane Capital	17.59	102.29	
26	Done Naxay	36	Vientiane Capital	17.59	102.39	
27	Loung Dom	35	Vientiane Capital	18.02	102.37	
28	Neuang	35	Vientiane Capital	18.02	102.37	
29	Khamla	33	Vientiane Capital	17.59	102.39	
30	Say	26	Vientiane Capital	18.03	102.32	
31	Phongphanh	21	Vientiane Capital	18.12	103.03	
32	Chanthone	21	Vientiane Capital	18.12	103.03	
33	Chommany	20	Vientiane Capital	18.01	102.38	
34	Sob Souanmone	18	Vientiane Capital	17.55	102.38	
35	That Sisoubath	15	Vientiane Capital	17.56	102.45	
36	Bounsou	15	Vientiane Capital	17.56	102.45	
	Total	16313				

Source: Department of Agriculture and Livestock, MAF. (\*) Estimate



**Annex 2: Assessment of Capacity of Gas Production from Thirty Seven Pig Farms in Vientiane Capital City by Considering Different Case from the Theory and Seven Sample Sizes**

No.	Name of Pig Farm (*)	No. of Pig	Gas production per pig 0.24 m <sup>3</sup> /day	Gas production per pig 0.31387m <sup>3</sup> /day	Gas production per pig 0.1981 m <sup>3</sup> /day	Gas production per pig 0.0425 m <sup>3</sup> /day	Gas production per pig 0.041667m <sup>3</sup> /day	Gas production per pig 0.1145 m <sup>3</sup> /day	Gas production per pig 0.1091 m <sup>3</sup> /day	Gas production per pig 0.069 m <sup>3</sup> /day	Gas production per pig Average of 7 sample sizes	Gas production per pig Average of 5 simple size	Gas production per pig (12+13)/2
			Theory	Sample 1	Sample 2	Sample 3	Sample 4	Sample 5	Sample 6	Sample 7	mean	mean	mean
1	2	3	4	5	6	7	8	9	10	11	12	13	14
		heads	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /day	m <sup>3</sup> /day	m <sup>3</sup> /day
1	Vanith Farm F1+F2	7,636	1832.6	2396.7	1512.7	324.53	318.17	874.32	833.09	526.88	969.485	1228.7	1099.112
2	Vanith Farm F3	2,069	496.56	649.4	409.87	87.933	86.208	236.9	225.73	142.76	262.685	332.93	297.8081
3	Chanhpheng Douangphachanh	1,234	296.16	387.32	244.46	52.445	51.417	141.29	134.63	85.146	156.672	198.57	177.6197
4	Khenphone Nongteng	1,112	266.88	349.02	220.29	47.26	46.333	127.32	121.32	76.728	141.182	178.94	160.0593
5	Keo Inthipon	545	130.8	171.06	107.96	23.163	22.708	62.403	59.46	37.605	69.1945	87.698	78.44632
6	Phouvong Kolasak	535	128.4	167.92	105.98	22.738	22.292	61.258	58.369	36.915	67.9249	86.089	77.00693
7	Nang Vone	486	116.64	152.54	96.277	20.655	20.25	55.647	53.023	33.534	61.7037	78.204	69.95396
8	Nang Kham	357	85.68	112.05	70.722	15.173	14.875	40.877	38.949	24.633	45.3256	57.446	51.38593
9	Khamsing Sisoutham	224	53.76	70.307	44.374	9.52	9.3333	25.648	24.438	15.456	28.4396	36.045	32.24216
10	Khamphay	223	53.52	69.993	44.176	9.4775	9.2917	25.534	24.329	15.387	28.3126	35.884	32.09822
11	Sivilay Hungheuang	180	43.2	56.497	35.658	7.65	7.5	20.61	19.638	12.42	22.8532	28.965	25.90887
12	Nang Chanh	139	33.36	43.628	27.536	5.9075	5.7917	15.916	15.165	9.591	17.6478	22.367	20.00741
13	Boun Gnanong	156	37.44	48.964	30.904	6.63	6.5	17.862	17.02	10.764	19.8061	25.103	22.45436

**Annex 2 (Con't): Assessment of Capacity of Gas Production from Thirty Seven Pig Farms in Vientiane Capital City by Considering Different Case from the Theory and Seven Sample Sizes**

No.	Name of Pig Farm (*)	No. of Pig	Gas production per pig 0.24 m <sup>3</sup> /day	Gas production per pig 0.31387m <sup>3</sup> /day	Gas production per pig 0.1981 m <sup>3</sup> /day	Gas production per pig 0.0425 m <sup>3</sup> /day	Gas production per pig 0.041667m <sup>3</sup> /day	Gas production per pig 0.1145 m <sup>3</sup> /day	Gas production per pig 0.1091 m <sup>3</sup> /day	Gas production per pig 0.069 m <sup>3</sup> /day	Gas production per pig Average of 7 sample sizes	Gas production per pig Average of 5 simple size	Gas production per pig (12+13)/2
			Theory	Sample 1	Sample 2	Sample 3	Sample 4	Sample 5	Sample 6	Sample 7	mean	mean	mean
1	2	3	4	5	6	7	8	9	10	11	12	13	14
		heads	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /day	m <sup>3</sup> /day	m <sup>3</sup> /day
14	Liangkham	143	34.32	44.883	28.328	6.0775	5.9583	16.374	15.601	9.867	18.1556	23.011	20.583
15	Champhonh	142	34.08	44.57	28.13	6.035	5.9167	16.259	15.492	9.798	18.0287	22.85	20.43922
16	Khamsone Keamany	131	31.44	41.117	25.951	5.5675	5.4583	15	14.292	9.039	16.6321	21.08	18.8559
17	Phongsamouth	121	29.04	37.978	23.97	5.1425	5.0417	13.855	13.201	8.349	15.3624	19.471	17.41652
18	Nongphagna	111	26.64	34.84	21.989	4.7175	4.625	12.71	12.11	7.659	14.0928	17.861	15.97714
19	Bounheng	104	24.96	32.642	20.602	4.42	4.3333	11.908	11.346	7.176	13.2041	16.735	14.96957
20	Souay	85	20.4	26.679	16.839	3.6125	3.5417	9.7325	9.2735	5.865	10.7918	13.678	12.23475
21	Phan Sophapmixay	77	18.48	24.168	15.254	3.2725	3.2083	8.8165	8.4007	5.313	9.7761	12.39	11.08324
22	Pancha	77	18.48	24.168	15.254	3.2725	3.2083	8.8165	8.4007	5.313	9.7761	12.39	11.08324
23	Chin	61	14.64	19.146	12.084	2.5925	2.5417	6.9845	6.6551	4.209	7.74471	9.8158	8.78023
24	Bouaket	45	10.8	14.124	8.9145	1.9125	1.875	5.1525	4.9095	3.105	5.71331	7.2411	6.477219
25	Damdouan Nonghai	45	10.8	14.124	8.9145	1.9125	1.875	5.1525	4.9095	3.105	5.71331	7.2411	6.477219
26	Done Naxay	36	8.64	11.299	7.1316	1.53	1.5	4.122	3.9276	2.484	4.57065	5.7929	5.181775

**Annex 2 (Con't): Assessment of Capacity of Gas Production from Thirty Seven Pig Farms in Vientiane Capital City by Considering Different Case from the Theory and Seven Sample Sizes**

No.	Name of Pig Farm (*)	No. of Pig	Gas production per pig 0.24 m <sup>3</sup> /day	Gas production per pig 0.31387m <sup>3</sup> /day	Gas production per pig 0.1981 m <sup>3</sup> /day	Gas production per pig 0.0425 m <sup>3</sup> /day	Gas production per pig 0.041667m <sup>3</sup> /day	Gas production per pig 0.1145 m <sup>3</sup> /day	Gas production per pig 0.1091 m <sup>3</sup> /day	Gas production per pig 0.069 m <sup>3</sup> /day	Gas production per pig Average of 7 sample sizes	Gas production per pig Average of 5 simple size	Gas production per pig (12+13)/2
			Theory	Sample 1	Sample 2	Sample 3	Sample 4	Sample 5	Sample 6	Sample 7	mean	mean	mean
1	2	3	4	5	6	7	8	9	10	11	12	13	14
		heads	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /d	m <sup>3</sup> /day	m <sup>3</sup> /day	m <sup>3</sup> /day
27	Loung Dom	35	8.4	10.85	6.9335	1.4875	1.4583	4.0075	3.8185	2.415	4.44368	5.632	5.037837
28	Neuang	35	8.4	10.985	6.9335	1.4875	1.4583	4.0075	3.8185	2.415	4.44368	5.632	5.037837
29	Khamla	33	7.92	10.358	6.5373	1.4025	1.375	3.7785	3.6003	2.277	4.18976	5.3102	4.74996
30	Say	26	6.24	8.1606	5.1506	1.105	1.0833	2.977	2.8366	1.794	3.30102	4.1838	3.742393
31	Phongphanh	21	5.04	6.5913	4.1601	0.8925	0.875	2.4045	2.2911	1.449	2.66621	3.3792	3.022702
32	Chanthone	21	5.04	6.5913	4.1601	0.8925	0.875	2.4045	2.2911	1.449	2.66621	3.3792	3.022702
33	Chommany	20	4.8	6.2774	3.962	0.85	0.8333	2.29	2.182	1.38	2.53925	3.2183	2.878764
34	Sob Souanmone	18	4.32	5.6497	3.5658	0.765	0.75	2.061	1.9638	1.242	2.28532	2.8965	2.590887
35	That Sisoubath	15	3.6	4.7081	2.9715	0.6375	0.625	1.7175	1.6365	1.035	1.90444	2.4137	2.159073
36	Bounsou	15	3.6	4.7081	2.9715	0.6375	0.625	1.7175	1.6365	1.035	1.90444	2.4137	2.159073
	<b>Total</b>	1,6319	3923.1	5130.2	3243.6	707.3	695.71	1885.8	1799.7	1147.6	2095.14	2651	2376.064



**Annex 3: Capacity of Power Generating from Thirty Seven Pig Farms in Vientiane Capital City by Considering Different Case from Seven Sample Size**

No.	Name of Pig Farm (*)	No. of Pigs	Capacity of Power generating based on theory	Capacity of Power generating based on sample 1	Capacity of Power generating based on sample 2	Capacity of Power generating based on sample 3	Capacity of Power generating based on sample 4	Capacity of Power generating based on sample 5	Capacity of Power generating based on sample 6	Capacity of Power generating based on sample 7	Capacity of Power generating Average for 7 case	Capacity of Power generating Average for necltes case 3 & 4	Capacity of Power generating Average (12+13)/2	Select Capacity of Co-Gen
		Heads	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	Vanith Farm F1+F2	7,636	130.903	118.03	171.81	8.7814	12.727	197.33	128.424	125.994	109.014	148.319	128.666	120
2	Vanith Farm F3	2,069	35.4686	31.9807	46.5525	2.37935	3.4483	53.469	34.7968	34.1385	29.5378	40.1874	34.8626	35
3	Chanhpheng Douangphachanh	1,234	21.1543	19.0741	27.765	1.4191	2.0567	31.89	20.7536	20.361	17.617	23.9687	20.7929	20
4	Khenphone Nongteng	1,112	19.0629	17.1883	25.02	1.2788	1.8533	28.737	18.7018	18.348	15.8753	21.599	18.7372	20
5	Keo Inthipon	545	9.34286	8.42412	12.2625	0.62675	0.9083	14.084	9.16591	8.9925	7.78063	10.5859	9.18324	10
6	Phouvong Kolasak	535	9.17143	8.26955	12.0375	0.61525	0.8917	13.826	8.99773	8.8275	7.63786	10.3916	9.01474	10
7	Nang Vone	486	8.33143	7.51215	10.935	0.5589	0.81	12.56	8.17364	8.019	6.93832	9.43987	8.18909	5
8	Nang Kham	357	6.12	5.51818	8.0325	0.41055	0.595	9.2258	6.00409	5.8905	5.09667	6.93422	6.01544	5
9	Khamsing Sisoutham	224	3.84	3.46239	5.04	0.2576	0.3733	5.7888	3.76727	3.696	3.19791	4.35089	3.7744	
10	Khamphay	223	3.82286	3.44693	5.0175	0.25645	0.3717	5.7629	3.75045	3.6795	3.18363	4.33146	3.75755	
11	Sivilay Hungheuang	180	3.08571	2.78228	4.05	0.207	0.3	4.6517	3.02727	2.97	2.56975	3.49625	3.033	
12	Boun Gnanong	156	2.67429	2.41131	3.51	0.1794	0.26	4.0315	2.62364	2.574	2.22711	3.03008	2.6286	
13	Liangkham	143	2.45143	2.21036	3.2175	0.16445	0.2383	3.6955	2.405	2.3595	2.04152	2.77757	2.40955	
14	Champhonh	142	2.43429	2.19491	3.195	0.1633	0.2367	3.6697	2.38818	2.343	2.02725	2.75815	2.3927	
15	Nang Chanh	139	2.38286	2.14854	3.1275	0.15985	0.2317	3.5921	2.33773	2.935	1.98442	2.9988	2.34215	
16	Phongsamouth	121	2.07429	1.87031	2.7225	0.13915	0.2017	3.127	2.035	1.9965	1.72744	2.35025	2.03885	

**Annex 3 (Con't): Capacity of Power Generating from Thirty Seven Pig Farms in Vientiane Capital City by Considering Different Case from Seven Sample Size**

No.	Name of Pig Farm (*)	No. of Pigs	Capacity of Power generating based on theory	Capacity of Power generating based on sample 1	Capacity of Power generating based on sample 2	Capacity of Power generating based on sample 3	Capacity of Power generating based on sample 4	Capacity of Power generating based on sample 5	Capacity of Power generating based on sample 6	Capacity of Power generating based on sample 7	Capacity of Power generating Average for 7 case	Capacity of Power generating Average for netcles case 3 & 4	Capacity of Power generating Average (12+13)/2	Select Capacity of Co-Gen
		Heads	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW
17	Nongphagna	111	1.90286	1.71574	2.4975	0.12765	0.185	2.8685	1.86682	1.8315	1.58468	2.15602	1.87035	
18	Bounheng	104	1.78286	1.60754	2.34	0.1196	0.1733	2.6876	1.74909	1.716	1.48474	2.02005	1.7524	
19	Souay	85	1.45714	1.31385	1.9125	0.09775	0.1417	2.1966	1.42955	1.4025	1.21349	1.65101	1.43225	
20	Phan Sophapmixay	77	1.32	1.1902	1.7325	0.08855	0.1283	1.9899	1.295	1.2705	1.09928	1.49562	1.29745	
21	Pancha	77	1.32	1.1902	1.7325	0.08855	0.1283	1.9899	1.295	1.2705	1.09928	1.49562	1.29745	
22	Chin	61	1.04571	0.94288	1.3725	0.07015	0.1017	1.5764	1.02591	1.0065	0.87086	1.18484	1.02785	
23	Bouaket	45	0.77143	0.69557	1.0125	0.05175	0.075	1.1629	0.75682	0.7425	0.64244	0.87406	0.75825	
24	Damdouan Nonghai	45	0.77143	0.69557	1.0125	0.05175	0.075	1.1629	0.75682	0.7425	0.64244	0.87406	0.75825	
25	Done Naxay	36	0.61714	0.55646	0.81	0.0414	0.06	0.9303	0.60545	0.594	0.51395	0.69925	0.6066	
26	Loung Dom	35	0.6	0.541	0.7875	0.04025	0.0583	0.9045	0.58864	0.5775	0.49967	0.67983	0.58975	
27	Neuang	35	0.6	0.541	0.7875	0.04025	0.0583	0.9045	0.58864	0.5775	0.49967	0.67983	0.58975	
28	Khamla	33	0.56571	0.51008	0.7425	0.03795	0.055	0.8528	0.555	0.5445	0.47112	0.64098	0.55605	
29	Say	26	0.44571	0.40188	0.585	0.0299	0.0433	0.6719	0.43727	0.429	0.37119	0.50501	0.4381	
30	Phongphanh	21	0.36	0.3246	0.4725	0.02415	0.035	0.5427	0.35318	0.3465	0.2998	0.4079	0.35385	
31	Chanthone	21	0.36	0.3246	0.4725	0.02415	0.035	0.5427	0.35318	0.3465	0.2998	0.4079	0.35385	
32	Chommany	20	0.34286	0.30914	0.45	0.023	0.0333	0.5169	0.33636	0.33	0.28553	0.38847	0.337	
33	Sob Souanmone	18	0.30857	0.27823	0.405	0.0207	0.03	0.4652	0.30273	0.297	0.25697	0.34962	0.3033	
34	That Sisoubath	15	0.25714	0.23186	0.3375	0.01725	0.025	0.3876	0.25227	0.2475	0.21415	0.29135	0.25275	
35	Bounsou	15	0.25714	0.23186	0.3375	0.01725	0.025	0.3876	0.25227	0.2475	0.21415	0.29135	0.25275	
<b>Total</b>		<b>16,313</b>	279.651	252.152	367.043	18.76	27.188	421.57	274.355	269.165	232.891	316.857	274.874	235

**Annex 4: Convert Gas Production from Pig Farm to Methane, Natural Gas, Petrol and Diesel**

No.	Name of Pig Farm (*)	No. of Pig	Gas Production	1 m <sup>3</sup> of gas equivalent to 0.62 m <sup>3</sup> of methane	1 m <sup>3</sup> of gas equivalent to 0.55 m <sup>3</sup> of natural gas	1 m <sup>3</sup> of gas equivalent to 0.7 litre of petrol	1 m <sup>3</sup> of gas equivalent to 0.62 litre of diesel
1	2	3	4	5	6	7	8
		heads	m <sup>3</sup> /day	m <sup>3</sup> /day	m <sup>3</sup> /day	Litres/day	Litres/day
1	Vanith Farm F1+F2	7,636	1,099.112	681.44944	604.5116	769.3784	681.44944
2	Vanith Farm F3	2,069	297.8081	184.641			
2	Vanith Farm F3	2,069	297.8081	184.64102	163.794455	208.46567	184.641022
3	Chanhpheng Douangphachanh	1,234	177.6197	110.12421	97.690835	124.33379	110.124214
4	Khenphone Nongteng	1,112	160.0593	99.236766	88.032615	112.04151	99.236766
5	Keo Inthipon	545	78.4463	48.636706	43.145465	54.91241	48.636706
6	Phouvong Kolasak	535	77.0069	47.744278	42.353795	53.90483	47.744278
7	Nang Vone	486	69.95396	43.371455	38.474678	48.967772	43.3714552
8	Nang Kham	357	51.38593	31.859277	28.2622615	35.970151	31.8592766
9	Khamsing Sisoutham	224	32.242	19.99004	17.7331	22.5694	19.99004
10	Khamphay	223	32.098	19.90076	17.6539	22.4686	19.90076
11	Sivilay Hungheuang	180	25.9088	16.063456	14.24984	18.13616	16.063456
12	Nang Chanh	139	20.007	12.40434	11.00385	14.0049	12.40434
13	Boun Gnanong	156	22.454	13.92148	12.3497	15.7178	13.92148
14	Liangkham	143	20.583	12.76146	11.32065	14.4081	12.76146
15	Champhonh	142	20.439	12.67218	11.24145	14.3073	12.67218
16	Khamsone Keamany	131	18.8559	11.690658	10.370745	13.19913	11.690658
17	Phongsamouth	121	17.165	10.79823	9.579075	12.19155	10.79823
18	Nongphagna	111	15.977	9.90574	8.78735	11.1839	9.90574
19	Bounheng	104	14.9657	9.278734	8.231135	10.47599	9.278734
20	Souay	85	12.2348	7.585576	6.72914	8.56436	7.585576
21	Phan Sophapmixay	77	11.0832	6.871584	6.09576	7.75824	6.871584
22	Pancha	77	11.0832	6.871584	6.09576	7.75824	6.871584
23	Chin	61	8.7802	5.443724	4.82911	6.14614	5.443724
24	Bouaket	45	6.4772	4.015864	3.56246	4.53404	4.015864
24	Bouaket	45	6.4772	4.015864	3.56246	4.53404	4.015864
25	Damdouan Nonghai	45	6.4772	4.015864	3.56246	4.53404	4.015864
26	Done Naxay	36	5.181775	3.2127005	2.84997625	3.6272425	3.2127005
27	Loung Dom	35	5.03784	3.1234608	2.770812	3.526488	3.1234608

**Annex 4 (Con't): Convert Gas Production from Pig Farm to Methane, Natural Gas, Petrol and Diesel**

No.	Name of Pig Farm (*)	No. of Pig	Gas Production	1 m3 of gas equivalent to 0.62 m3 of methane	1 m3 of gas equivalent to 0.55 m3 of natural gas	1 m3 of gas equivalent to 0.7 litre of petrol	1 m3 of gas equivalent to 0.62 litre of diesel
1	2	3	4	5	6	7	8
		heads	m <sup>3</sup> /day	M <sup>3</sup> /day	m <sup>3</sup> /day	Litres/day	Litres/day
28	Neuang	35	5.03784	3.1234608	2.770812	3.526488	3.1234608
29	Khamla	33	4.74996	2.9449752	2.612478	3.324972	2.9449752
30	Say	26	3.74239	2.3202818	2.0583145	2.619673	2.3202818
31	Phongphanh	21	3.0227	1.874074	1.662485	2.11589	1.874074
32	Chanthone	21	3.0227	1.874074	1.662485	2.11589	1.874074
33	Chommany	20	2.87876	1.7848312	1.583318	2.015132	1.7848312
34	Sob Souanmone	18	2.59089	1.6063518	1.4249895	1.813623	1.6063518
35	That Sisoubath	15	2.15907	1.3386234	1.1874885	1.511349	1.3386234
36	Bounsou	15	2.15907	1.3386234	1.1874885	1.511349	1.3386234
	<b>Total</b>	1,6319	2,348.0579	1,455.7959	1291.431837	1,643.64052	1,455.79589

## Annex 5: Convert the Biogas to Energy and the LPG

No.	Name of Pig Farm (*)	No. of Pigs	Gas production one pig gives 0.07m <sup>3</sup> /d	1 m <sup>3</sup> of gas equivalent to 1.25 kWh	1 m <sup>3</sup> of gas equivalent to 0.43 kg of LPG
		Heads	m <sup>3</sup> /day	kWh/day	kg/day
1	Vanith Farm F1+F2	7636	534.52	668.15	229.8436
2	Vanith Farm F3	2069	144.83	181.0375	62.2769
3	Chanhpheng Douangphachanh	1234	86.38	107.975	37.1434
4	Khenphone Nongteng	1112	77.84	97.3	33.4712
5	Keo Inthipon	545	38.15	47.6875	16.4045
6	Phouvong Kolasak	535	37.45	46.8125	16.1035
7	Nang Vone	486	34.02	42.525	14.6286
8	Nang Kham	357	24.99	31.2375	10.7457
9	Khamsing Sisoutham	224	15.68	19.6	6.7424
10	Khamphay	223	15.61	19.5125	6.7123
11	Sivilay Hungheuang	180	12.6	15.75	5.418
12	Boun Gnanong	156	10.92	13.65	4.6956
13	Liangkham	143	10.01	12.5125	4.3043
14	Champhonh	142	9.94	12.425	4.2742
15	Nang Chanh	139	9.73	12.1625	4.1839
16	Khamson Keamany	131	9.17	11.4625	3.9431
17	Phongsamouth	121	8.47	10.5875	3.6421
18	Nongphagna	111	7.77	9.7125	3.3411
19	Bounheng	104	7.28	9.1	3.1304
20	Souay	85	5.95	7.4375	2.5585
21	Phan sophapmixa	77	5.39	6.7375	2.3177
22	Pancha	77	5.39	6.7375	2.3177
23	Chin	61	4.27	5.3375	1.8361
24	Bouaket	45	3.15	3.9375	1.3545
25	Damdouan Nonghai	45	3.15	3.9375	1.3545
26	Done Naxay	36	2.52	3.15	1.0836
27	Loung Dom	35	2.45	3.0625	1.0535
28	Neuang	35	2.45	3.0625	1.0535
29	Khamla	33	2.31	2.8875	0.9933
30	Say	26	1.82	2.275	0.7826
31	Phongphanh	21	1.47	1.8375	0.6321
32	Chanthone	21	1.47	1.8375	0.6321
33	Chommany	20	1.4	1.75	0.602
34	Sob Souanmone	18	1.26	1.575	0.5418
35	That Sisoubath	15	1.05	1.3125	0.4515
36	Bounsou	15	1.05	1.3125	0.4515
	<b>Total</b>	<b>16,313</b>	<b>1,141.91</b>	<b>1,427.3875</b>	<b>491.0213</b>

## **Annex 6: Financial Analysis Calculation**

### **I. METHODOLOGY**

- Project life is 30 years.
- Values are expressed in constant 2005 prices so as to exclude inflation.
- The Lao PDR Kip is the unit of account. The exchange rate used is Kip 10,800 per U.S. dollar.

### **II. FINANCIAL ANALYSIS**

- Total Cost Estimated is US \$ 92,300.00 or 996.84 Million Kips.  
Operation and maintenance cost is US \$ 5,000.00 or 54.0 Million Kips.
- Project Financial Analyses
  - i. Without the benefits of CO<sub>2</sub> credits, the FIRR is 15% and NPV is 16,653.31 US \$
  - ii. With the inclusion of CO<sub>2</sub> credits:
    - a. price at 3 US \$/t of CO<sub>2</sub> the FIRR is 16% and NPV is 22,519.68 US \$
    - b. price at 5 US \$/t of CO<sub>2</sub> the FIRR is 16% and NPV is 26,430.60 US \$
    - c. price at 10 US \$/t of CO<sub>2</sub> the FIRR is 18% and NPV is 36,207.89 US \$
- Financing Plan  
Indicate the sources and proportions of finance for all foreign and local costs

### **III. ECONOMIC ANALYSES**

- Statement of poverty reduction impacts,
- Statement of social, gender and environment impacts,
  - Reduction of local pollutants, further findings and recommendations etc,
  - Land use impact: “ Vanith Pig Farm “ has the land allocated in its own (under the concession with the Government), so there is no impact to the others land ownerships around the farm,
  - Migration, resettlement, good governance, community infrastructure, community organization, etc
- **Project Economic Analyses**
  - i. Without the benefits of CO<sub>2</sub> credits, the EIRR is 19% and NPV is 33,135.45 US \$
  - ii. With the inclusion of CO<sub>2</sub> credits:
    - a. price at 5 US\$/t of CO<sub>2</sub> the EIRR is 20% and NPV is 42,912.74 US\$,
    - b. price at 3 US\$/t of CO<sub>2</sub> the EIRR is 20% and NPV is 39,001.83 US\$,
    - c. price at 10 US\$/t of CO<sub>2</sub> the EIRR is 22% and NPV is 52,690.04 US\$.

# Installation and performance of low-cost polyethylene tube biodigesters on small-scale farms

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## INSTALLATION DE BIODIGESTEURS TUBULAIRES EN POLYÉTHYLÈNE À FAIBLE COÛT DANS LES PETITES EXPLOITATIONS ET RÉSULTATS OBTENUS

*Les biodigesteurs peuvent apporter une importante contribution à l'agriculture à petite échelle, d'une part en limitant la pollution et, d'autre part, en valorisant les déjections animales à travers la production de biogaz et en améliorant la valeur fertilisante des effluents.*

*Le biodigester tubulaire en polyéthylène est intéressant pour les populations rurales en raison de son faible coût d'installation et de production de gaz. Il est utilisable aussi bien en milieu rural que dans les zones urbaines.*

*Divers facteurs conditionnent l'adoption de cette technologie et les résultats obtenus, à savoir notamment le site (disponibilité de combustibles traditionnels) et la façon dont la technologie est introduite et modifiée pour convenir aux conditions locales.*

*Cette technologie a été testée de façon suffisamment approfondie pour justifier son introduction à grande échelle dans les pays où les conditions socioéconomiques y étaient propices comme au Viet Nam et au Cambodge. Il convient, toutefois, de poursuivre les travaux de recherche avec la collaboration étroite des exploitants, afin que cette technologie puisse continuer à évoluer et à se perfectionner.*

## INSTALACION Y RENDIMIENTO DE BIODIGESTORES DE TUBOS DE POLIETILENO DE BAJO COSTO EN GRANJAS PEQUEÑAS

*Los biodigestores pueden contribuir de manera considerable a mejorar las explotaciones en pequeña escala, facilitando el control de la contaminación y añadiendo al mismo tiempo valor a la excreta del ganado mediante la producción de biogás y la mejora del valor como nutriente del efluente utilizado como fertilizante. El biodigester de película tubular de polietileno despierta atractivo entre la población rural debido al bajo costo de la instalación y la producción de gas. Se puede aplicar en zonas tanto rurales como urbanas. El éxito de la adopción de esta tecnología y los resultados conseguidos dependen de factores como el lugar (disponibilidad de combustible tradicional) y la manera de introducir y modificar la tecnología a fin de adaptarla a las condiciones locales. La tecnología se ha ensayado suficientemente para justificar su introducción en gran escala en países cuyas condiciones socioeconómicas son favorables a su aceptación, como por ejemplo Viet Nam y Camboya. No obstante, se debe proseguir la investigación con la participación directa de los agricultores, de manera que la tecnología pueda seguir evolucionando y mejorando.*

During the course of this century the global demand for power has increased sixteenfold. Today the industrial countries, with 32 percent of the world population, consume 82 percent of energy produced. On average, a person in an industrialized country uses 20 times more energy than someone living in Africa.

In many developing countries there is a serious shortage of fuel and the energy crisis is a daily reality for most families. Using renewable energy sources such as solar energy and low-cost biodigesters is advantageous to both the farmers and the environment (Rodríguez,

Preston and Dolberg, 1996).

Already many developing countries, such as Colombia, Ethiopia, the United Republic of Tanzania, Viet Nam and Cambodia, have adopted the low-cost biodigester technology with the aim of reducing production costs by using local materials and simplifying installation and operation (Solarte, 1995; Chater, 1986; Sarwatt, Lekule and Preston, 1995; Soeurn Than, 1994; Khan, 1996). The model used was a continuous-flow flexible tube biodigester based on the "red mud PVC" (Taiwan) bag design as described by Pound, Bordas and Preston (1981) and later simplified by Preston and co-workers, first in Ethiopia, then in Colombia (Botero and Preston, 1987) and later in Viet Nam (Bui Xuan An *et al.*, 1994). Within three years, more than 800 polyethylene digesters had been installed in Viet Nam, mainly paid for by the farmers (Bui Xuan An and Preston, 1995).

## TECHNOLOGY DEVELOPMENT

There are many designs of biogas plants but the most common are the floating canopy (Indian) and fixed dome (Chinese) models. The poor acceptability of many of these digesters has been due mainly to high costs, the difficulty of installation and problems in procuring spare parts.

### *Floating dome biodigester (Indian)*

This biodigester consists of a drum, originally made of mild steel but later replaced by fibreglass reinforced plastic (FRP) to overcome the problem of corrosion. The reactor wall and bottom are usually constructed of brick, although reinforced concrete is sometimes used. The gas produced is trapped under a floating cover which rises and falls on a central guide. The pressure of the gas available depends on the weight of the gas holder per unit area and usually varies between 4 to 8 cm of water pressure. The reactor is fed semi-continuously through an inlet pipe, and displaces an equal amount of slurry through an outlet pipe (Figure 1).

### *Fixed dome biodigester (Chinese)*

This reactor consists of a gas-tight chamber constructed of bricks, stone or poured concrete. Both the top and bottom are hemispherical and are joined together by straight sides. The inside surface is sealed by many thin layers of mortar to make it gas-tight. The inlet pipe is straight and ends at mid-level in the digester. There is an inspection plug at the top of the digester to facilitate cleaning, and the gas outlet pipe exits from the inspection cover. The gas produced during digestion is stored under the dome and displaces some of the digester contents into the effluent chamber, leading to gas pressures in the dome of between 1 and 1.5 m of water. This creates quite high structural forces and is the reason for the hemispherical top and bottom. High-quality materials and expensive human resources are needed to build this kind of digester (Figure 1). More than five million biodigesters have been built in China and are functioning well (FAO, 1992) but, unfortunately, the technology has not been so popular outside China.

### *Flexible structure biodigester*

The high investment required to construct biodigesters of fixed structure proved to be a major constraint for low-income small farmers. This motivated engineers in the Province of Taiwan in the 1960s (FAO, 1992) to make biodigesters from cheaper flexible materials. Initially



nylon and neoprene were used but they proved relatively costly. A major development in the 1970s was to combine PVC with the residue from aluminium refineries to produce the product named "red mud PVC". This was later replaced by less costly polyethylene which is now the most common material used in Latin America, Asia and Africa (Figure 2).

Since 1986, the Centre for Research in Sustainable Systems of Agricultural Production (CIPAV), a non-governmental organization in Colombia, has been recommending low-cost plastic biodigesters as the appropriate technology for making better use of livestock excreta, thus reducing the pressure on other natural resources.

## **ADVANTAGES OF LOW-COST PLASTIC BIODIGESTERS**

Biogas plants may offer several advantages to low-income rural communities, including:

- a reduction of the physical workload, especially of women;
- a reduction of the pressure on natural resources such as fuelwood and charcoal;
- cheap energy production, resulting in cash savings;
- improving the farming system by recycling manure through biodigesters to produce gas for cooking and effluent for fertilizer (once the manure has passed through a biodigester it becomes an excellent organic fertilizer [Figure 3]);
- making use of waste which would otherwise cause pollution, especially in urban areas.

## **MATERIALS**

Tubular polyethylene is produced in most countries. The choice of supplementary fittings and related materials has been limited to those available locally on farms or in rural markets; they are the basic components of sanitary installations which are similar all over the world. The materials required (Photo 1) for both the biodigester and the stove are listed below.

### *Biodigester*

- Transparent tubular polyethylene. The diameter will vary according to the capacity of the local producing plants, usually in the range of 80 to 125 cm (equivalent to a circumference of 2.5 to 4 m). The calibre (thickness) should be between 800 and 1 000 (200 to 250 microns). The length of the tube is determined by the size of the biodigester. The most appropriate material is that used for greenhouses since this usually contains an ultraviolet (UV) filter which helps to prolong the life of the plastic when it is fully exposed to the sun.
- Two ceramic tubes, 75 to 100 cm long with an internal diameter (id) of 15 cm.
- Plastic (PVC) hosepipe of 12.5 mm id (the length depends on the distance to the kitchen).
- Two PVC adapters (male and female) of 12.5 mm id.
- Two rubber washers (from inner tubes of cars) of 7 cm diameter and 1 mm thickness, with a 12.5 mm diameter central hole.
- Two rigid plastic (perspex) washers of 10 cm diameter and a central hole of 12.5 mm. Although perspex is best, they can also be cut from old plastic buckets or other items made from strong plastic.
- 2 m of PVC pipe of 12.5 mm id.
- Four used inner tubes (from bicycles, motorcycles or cars) cut into 5 cm wide strips.
- One transparent plastic bottle (capacity 1.5 litres).
- One PVC elbow of 12.5 mm id.
- Three PVC "T" pieces of 12.5 mm id.
- One tube of PVC cement.

### *Gas storage reservoir*

An important improvement to the biodigester technology was the installation of a reservoir, made of the same tubular plastic as the digester, for storing the gas in close proximity to the kitchen (Figure 2). This has overcome the problem of low rates of gas flow when the digester is located a long way from the kitchen and when the connecting gas tube has a narrow diameter.

### *Cooking stove*

The biodigester plant includes a simple stove with a galvanized pipe of 12.5 mm id, two burners using the same kind of pipe and two ball taps of the same diameter (Photo 2). Measurements of gas consumption show that it takes one hour to boil 6 litres of water and that, on average, 26 litres of gas are needed to boil 1 litre of water (Rodríguez, Preston and Dolberg, 1996). Users have developed many modifications to the basic design to combat wind effects and to suit personal needs. A lot of research has been put into improving more conventional stoves, but very little on stoves used with biodigesters (Rodríguez, Preston and Dolberg, 1996).

### *Cost of biodigester plant*

The cost of the plastic biodigester is relatively low, varying according to size and location. For instance, in Colombia the cost per m<sup>3</sup> of liquid volume is around \$US30, taking into account that this includes the container and its connection, cement boxes for the inlets and outlets, plastic gas reservoir, stove, labour to prepare the trench and installation of the biodigester. In Viet Nam the average cost per m<sup>3</sup> is only \$US7 (materials only), giving a total cost for one biodigester of 5.4 m<sup>3</sup> of US\$37.80, including two burners.

## **TECHNOLOGY DIFFUSION**

### *Colombia*

The first plastic biodigester was installed in Colombia in 1986 and continued to operate until 1995 when the plastic membrane/film was changed (the plastic had lasted for nine years!). Since 1986, about 30 biodigesters per year have been installed with the help of CIPAV. The most common size is 10 m in length (9 m<sup>3</sup> total volume). Over the last three years biodigesters of 3 and 5 m length (3 m<sup>3</sup> to 5.5 m<sup>3</sup> liquid volume) have also been installed with gas storage reservoirs of 3 m<sup>3</sup> (Luis Solarte, 1996, personal communication).

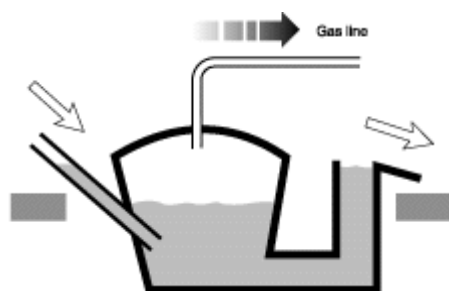
### *Viet Nam*

Many people from different countries have visited CIPAV in Colombia to learn about the low-cost biodigesters and related technologies for sustainable agriculture. In 1992, following a visit by a study group from a SAREC-sponsored project in Viet Nam, demonstration biodigesters were installed on small farms in Song Be and Dong Nai provinces around Ho Chi Minh City (Bui Xuan An and Preston, 1995). In April 1993, a local source of polyethylene was located in Ho Chi Minh City. The cost was only US\$1.25/kg, enabling the complete construction of a digester at a cost of US\$25 (materials only) plus two person days for preparing the trench and installation. This was much lower than in Colombia and encouraged farmers to accept the technology (Figure 4). After about three years, more than

800 units have been installed in Viet Nam, 90 percent of which in rural areas (Bui Xuan An, Preston and Dolberg, 1996).

### *Tanzania*

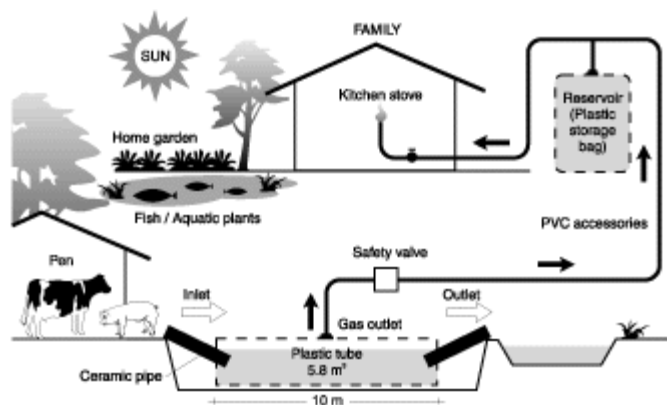
In mid-1993, the first low-cost plastic biodigesters were introduced into the United Republic of Tanzania as part of the FAO/TCP/URT/2255A project. So far, more than 100 biodigesters have been installed and the number is likely to increase owing to the high adoption rate by farmers. Experience has shown that the technology can be easily introduced in rural communities (Sarwatt, Lekule and Preston, 1995).



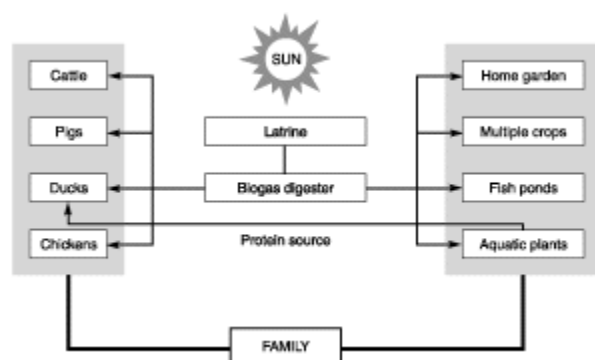
**FIGURE/FIGURA 1**  
**Fixed dome biodigester**  
**Biodigester à calotte fixe**  
**Biodigestor fijo de bóveda**



**PHOTO/FOTO 1**  
**Materials for the low-cost plastic biodigester**  
**Matériel pour l'installation du biodigester en plastique à faible coût**  
**Materiales para el biodigestor de plástico de bajo costo**  
**Photo/Foto: Lylian Rodríguez**



**FIGURE/FIGURA 2**  
**Low-cost plastic biodigester**  
*Biodigester en plastique à faible coût*  
*Biodigestor de plástico de bajo costo*



**FIGURE/FIGURA 3**  
**Integrated system**  
*Système intégré*  
*Sistema integrado*

## METHODOLOGY

### *Practical aspects*

When choosing a suitable location for a biodigester, a site close to the shed holding the livestock is preferable. The location of the kitchen is not usually an issue since the gas can be transported long distances using cheap, narrow-bore PVC tubing.

Next, a trench in which to place the biodigester must be dug. The walls must be firm and the floor flat or with only a minimum slope from entrance to exit (Figure 5). Any protruding matter such as sharp stones or roots must be removed from the walls and floor. On sloping land, the trench should be situated on the contour and a channel dug on the high side to deviate rainwater.

Trials are currently in progress to evaluate a modified design in which the bottom of the trench has a uniform slope of 1 percent from entrance to exit. The biodigester is then filled almost completely with substrate which forces the gas to accumulate in the upper part of the tube, close to the entrance where the gas pipe is located. In this way the maximum volume of the digester is used for fermentation, with the gas being stored in the reservoir.

The dimensions of the trench should be sized to accommodate the plastic tube. For example, in Colombia this is normally 1.25 m in diameter so the trench is 1.20 m wide at the top, 80 cm at the bottom and 1 m deep; the length may vary from 3 to 10 m according to the needs of the family and the availability of manure (Photo 3).

Two pieces of the tubular film are cut, each 1 m longer than the length of the biodigester. They are laid on smooth ground and one is inserted into the other.

For the gas outlet, a small hole is made in the two layers of the plastic tube, approximately 1.5 m from the entrance. One rigid PVC washer and one rubber washer are fitted on the flange of the male adapter which is then threaded through the hole from the inside to the outside. A second PVC washer and rubber washer are put on the male adapter from the outside of the tube and secured tightly with the female adapter. The exit of the female adapter is closed with a small square of plastic film and a rubber band (Figure 6).

A ceramic inlet pipe (concrete or PVC pipes can also be used but are more expensive) is inserted up to two-thirds of its length into one end of the plastic tube. The plastic film is folded around the pipe and secured with 5 cm rubber bands (made from the used inner tubes). The bands are wrapped in a continuous layer to cover completely the edges of the plastic film, finishing on the ceramic tube. The inlet tube is then closed with a square of plastic (or a plastic bag) and a rubber band (Photo 4).

The installation procedure in Viet Nam involves filling the polyethylene tube with air before placing it in the trench. From the open end, air is forced into the tube in waves formed by flapping the end of the tube. The tube is then tied with a rubber band about 3 m from the end so that the air does not escape (Photo 5). In Colombia, the most common way to install the biodigester is by folding the plastic in an organized way and then extending it along the floor of the trench (Figure 7).

The water tube is fitted following the same procedure as for the inlet tube.

The polyethylene tube must be placed in the trench with care. The ceramic tubes should be set at a 45° angle and fixed temporarily with clay.

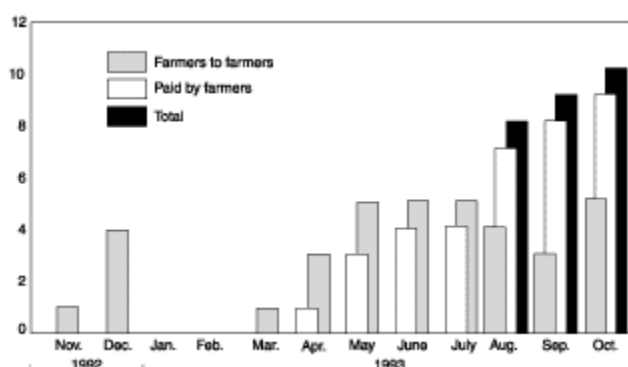
The safety valve is made from a transparent plastic bottle, a PVC "T" and three pieces of tubular PVC (one of 30 cm and the other two of 5 cm). Water is poured into the bottle and maintained at a depth of 5 cm above the mouth of the tube (Figure 8).

The biodigester tube is three-quarters filled with water or water and manure, moving up and down the outlet (as indicator of the water level inside the tube). The air trapped inside the tube escapes from the safety valve as the volume of water increases.

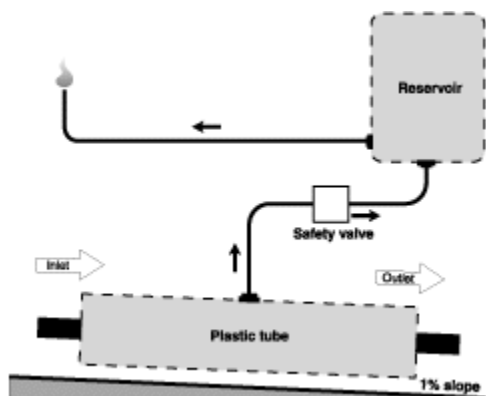
When fitting the gas pipe to the kitchen stove, it must not be placed underground because moisture will condense in the lowest part and may block the gas flow. The safety valve should be at the lowest point in the gas line.

The gas reservoir is made from a 3 to 4 m piece of the same polyethylene tube used for the biodigester and is joined to the gas line with a PVC "T". It can be suspended horizontally or vertically but should be shaded from the sun. To increase the pressure as the reservoir begins to empty, a weight (a brick or stone) is suspended from the bottom (vertical suspension) (Photo 6) or a cord is placed around the central part and tightened (horizontal suspension) (Photo 7).

It is important to handle the polyethylene tubular film with care, as it is easily punctured, and to cut the gas outlet neatly, taking care not to cut too large a hole in the tube.



**FIGURE/FIGURA 4**  
**Farmers' participation in the installation of biodigesters**  
**Participation des agriculteurs à l'installation de biodigesteurs**  
**Participación de los agricultores en la instalación de biodigestores**



**FIGURE/FIGURA 5**  
**Plastic biodigester**  
**Biodigesteur en plastique**  
**Biodigestor de plástico**



**PHOTO/FOTO 2**  
**Cooking stoves: (left) classical burner; (right) a burner made from a beer can**  
**Fourneaux: (à gauche) un brûleur de type traditionnel; (à droite) un brûleur réalisé au moyen d'une cannette métallique**  
**Estufas de cocinar: (izquierda) quemador clásico; (derecha) uno hecho con una lata de cerveza**  
**Photo/Foto: Lylian Rodríguez**



**PHOTO/FOTO 3**  
**The width of the trench varies according to the size of the tube**  
**La largeur de la tranchée varie selon les dimensions du tube**  
**El ancho de la zanja varía de acuerdo con las dimensiones de la tubería**  
**Photo/Foto: Lylian Rodríguez**



**PHOTO/FOTO 4**  
**Fitting the inlet pipe**  
*Installation du conduit d'admission*  
**Ajuste de la tubería de entrada**  
*Photo/Foto: Veronika Brezki*



**PHOTO/FOTO 5**  
**A plastic tube ready for installation**  
*Tube plastique prêt à être installé*  
**Tubo de plástico listo para su instalación**  
*Photo/Foto: Lylian Rodríguez*



**PHOTO/FOTO 6**  
**A vertical biogas storage bag**  
*Sac vertical de stockage du biogaz*  
**Bolsa vertical para almacenar el biogás**  
*Photo/Foto: Lylian Rodríguez*



**PHOTO/FOTO 7**

***A horizontal biogas storage bag***

***Sac horizontal de stockage du biogaz***

***Bolsa horizontal para almacenar el biogás***

***Photo/Foto: Lylian Rodríguez***

### *Floating digester*

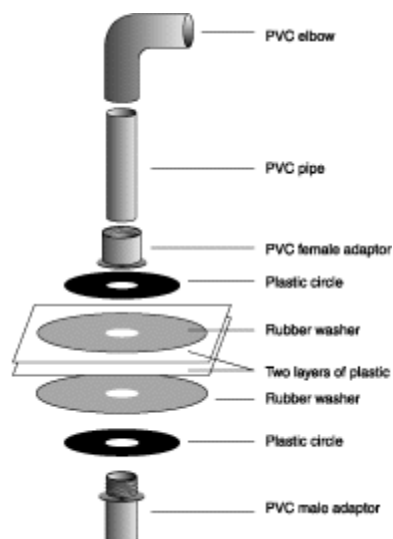
An innovative feature of using tubular polyethylene is that the biodigester can be located so as to float on any water surface. It floats half submerged, with only the inlet and outlet tubes being fixed to bamboo stakes. In places where the water level rises and falls, the inlet should be fixed firmly, with its mouth located above the highest water level, while the outlet should be fixed to a floating object, such as a dried coconut or a plastic container). In Viet Nam more than 5 percent of biodigesters float in ponds, which greatly facilitates their installation since space on farms is often very limited (Photo 8).

### *Digester operation*

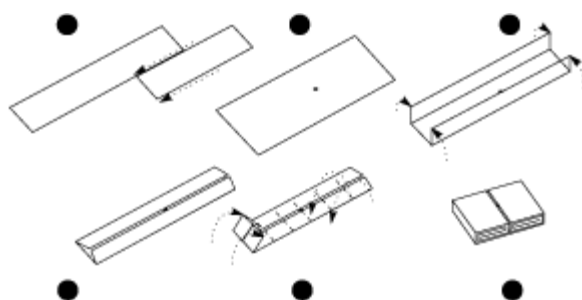
It is possible to use any type of excreta, but gas production is higher with pig manure and mixtures of poultry droppings and cattle manure. The amount required depends on the length of the digester, but is generally about 5 kg of fresh manure (1 kg solid matter) for every 1 m. To this should be added 15 litres of water so that the solids content represents approximately 5 percent. It is not advisable to use less water since this can lead to the formation of solid scum on the surface of the digesting material; there is no risk in adding more. As a rule of thumb, four to five pigs (assumed live weight of 70 kg) will provide enough manure to produce the gas required for a family of four to five people.

Linking latrines to the plastic biodigester was pioneered in Cambodia (Soeurn Than, 1994). It is also quite common in Viet Nam, while it is only a recent development in Colombia. Apart from the increase in gas production, recycling human excrement through biodigesters is an effective way of reducing disease transmission (Photo 9).

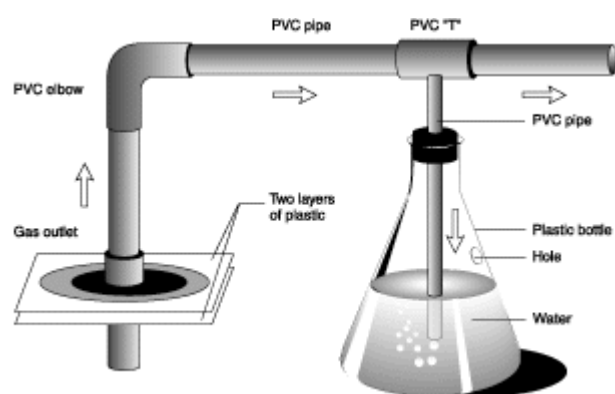




**FIGURE/FIGURA 6**  
**Fixing the gas outlet**  
*Installation de la sortie de gaz*  
*Ajuste de la salida del gas*



**FIGURE/FIGURA 7**  
**Colombian method of installing biodigester by folding the plastic**  
*Méthode de pliage du plastique utilisée en Colombie pour l'installation des biodigesteurs*  
*Sistema colombiano de instalación del biodigestor doblando el plástico*



**FIGURE/FIGURA 8**  
**Fitting the safety valve**  
*Installation de la valve de sécurité*  
*Ajuste de la válvula de seguridad*

## MAINTENANCE

- The digester should be fenced in; failure to do so is the main reason for the breakdown of the system.
- A roof should be provided to prevent damage to the plastic from ultraviolet radiation. Any type of roofing material traditionally used on the farm would be suitable.
- To increase the gas pressure when cooking, attach a heavy object (brick or rock) to the bottom of the reservoir or tighten a string around the middle.
- Make sure rain does not enter the digester, since it could cause excessive dilution.
- The water level in the safety valve should be checked weekly.
- Charge the digester daily and ensure that the exit tube is not blocked.

## FARMER PARTICIPATION

In Viet Nam, the cost of materials to construct a 5 m<sup>3</sup> biodigester was US\$37.00 and two person days were needed for digging the trench and installing the digester. The time from installing the first demonstration unit to the first unit paid for by a farmer was four months. During the past three years, more than 800 units have been installed by extensionists and farmers in Viet Nam. Less than 12 percent of the digesters have had technical problems, often because of damage caused by stray animals. Most of the repairs have been carried out by the farmers themselves.

## EFFECTS OF BIODIGESTERS ON CHEMICAL AND BIOLOGICAL ASPECTS OF WASTE WATERS

The process of fermentation in biodigesters results in the transformation of organically bound carbon into gaseous carbon dioxide and methane. The anaerobic environment and extended retention time inhibit the growth of most pathogenic organisms and prevent the survival of intestinal parasites. Both the chemical and biological parameters of livestock excreta are therefore improved by passage through biodigesters (Table 1).

1

**Differences between waste water and slurry of biodigesters**

**Différences entre les eaux usées et les effluents des biodigesteurs**

**Diferencias entre las aguas residuales y el estiércol líquido de los biodigestores**

	Input	Output
COD (mg/litre)	2 998	978
<i>Escherichia coli</i> (10 <sup>3</sup> /cell/ml)	52 890	75
Coliforms (10 <sup>3</sup> /cell/ml)	266 780	236
pH	6.8	7.2

*Note:* COD = chemical oxygen demand (the amount of oxygen consumed for the oxidation of the reductive substances contained in 1 litre sample of liquid waste by a strong oxidizer). ,

*Source:* Bui Xuan An and Preston (1995).

## GAS PRODUCTION

Bui Xuan An, Preston and Dolberg (1996) found that biodigestion decreased chemical oxygen demand (COD) from 35 610 mg/litre in the inlet to 13 470 mg/litre in the effluent, indicating a process efficiency of 62 percent (COD removal rate). The volume of gas per

caput per day, enough for cooking three meals, was about 200 litres. The loading rates were low and gas production could be improved by increasing the amount of manure fed to the digesters. However, five farmers reported that, in addition to cooking meals, they were also able to cook animal feeds; three farmers made wine; one made cakes; and two prepared tea and coffee in their cafeterias. This demonstrates that there is a high justification for adopting the technology, as discussed by Dolberg (1993) (Table 2).

## 2

**Input and output of 31 digesters working on small farms around Ho Chi Minh City, Viet Nam**

**Paramètres de production de 31 digesteurs utilisés dans de petites exploitations près de Hô Chi Minh-Ville, Viet Nam**

**Entrada y salida de 31 digestores que funcionan en pequeñas explotaciones alrededor de la Ciudad de Ho Chi Minh, Viet Nam**

	Mean	Range
Size of family	5.9	
Manure loading ( <i>kg/day</i> )	16	2-27
Water/manure ratio	5.1	2.9-8.1
Loading rates ( <i>kg DM/m<sup>3</sup></i> )	0.7	0.1-1.2
Temperature of loading (°C)	26.4	25.7-28.5
Temperature of effluent (°C)	27.0	26.0-29.1
pH of loading	6.7	6.4-7.1
pH of effluent	7.2	6.8-7.5
Gas production ( <i>litres/unit/day</i> )	1 235	689-2 237
Volume gas/caput ( <i>litres/person/day</i> )	223	68-377
Methane ratio (%) <sup>1</sup>	56	45-62
COD of loading ( <i>g/litre</i> )	35.6	22.4-46.0
COD of effluent ( <i>mg/litre</i> )	13.5	8.8-23.9
COD removal rate (%)	62	42-79

<sup>1</sup> From nine digesters.

*Note:* COD = chemical oxygen demand (the amount of oxygen consumed for the oxidation of the reductive substances contained in 1 litre sample of liquid waste by a strong oxidizer).

## PROBLEMS

The main problems identified in a farmers' survey (Bui Xuan An, Preston and Dolberg, 1996) were:

- inadequate management, using too much or too little manure;
- inadequate supervision, because the biodigester was installed far from the pig pen;
- lack of planning and design of the system (insufficient training);
- lack of protection and no fence or shade.

## CONCLUSIONS

Biodigesters can play a vital role in integrated farming systems by contributing to the control of pollution and at the same time adding value to livestock excreta.

The impact of the low-cost biodigester is variable. Adoption of the technique and successful results depend on aspects such as location (availability of traditional fuel) and the way in

which the technology is introduced, adapted and improved according to local conditions and technicians' attitudes.

The polyethylene tubular film biodigester technology is a cheap and simple way to produce gas. It is appealing to small farmers because of its low installation cost and also because of its environmental advantages. It can be applied in rural or urban areas.

The technology has been developed sufficiently to justify large-scale implementation in countries where socio-economic conditions facilitate its rapid adoption, such as in Viet Nam and Cambodia. Nevertheless, research should continue in close consultation with users so that the technology continues to improve.



**PHOTO/FOTO 8**

***A floating polyethylene biodigester  
Biodigester flottant en polyéthylène  
Biodigestor flotante de polietileno***



**PHOTO/FOTO 9**

***A latrine linked to the biodigester  
Latrines reliées au biodigester***

## RECOMMENDATIONS

In view of the high potential of the technology, the following recommendations can be made:

- research should continue to improve and perfect the technology;
- aid agencies and policy-makers involved in sustainable rural development should promote the use of low-cost, locally available materials for biodigesters;
- micro credit should be provided for resource-poor farmers to promote use of biodigesters where feasible;
- joint efforts should be made by all parties concerned in health, agriculture, housing, energy and sustainable use of natural resources to draw up long-term plans to enhance the adoption of the technology.

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# **Low-cost biodigesters as the epicenter of ecological farming systems**

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## **Abstract**

Much of the developmental work with biodigesters has been approached from the engineering viewpoint with emphasis on design and construction with the aim of maximizing gas production and efficiency of conversion of feedstock to biogas. There has been very little change in the basic designs of the floating canopy (as developed in India) and liquid displacement (developed in China) systems. The relatively high cost and need for skilled artisans in their construction have been major constraints to widespread adoption, which has had to be supported by subsidies from Government or Aid Agencies.

The introduction of the low-cost (< USD 50.00 for a family size unit) plastic biodigester, based on the use of tubular polythene film, put the technology within reach of a greater number of end users (more than 20,000 users in Vietnam are estimated to be using the technology). Subsidies were no longer needed for the purchase of the raw materials which can be found in most towns in developing countries. The simple means of installation has facilitated farmer to farmer extension of the technology. Recent developments have focused on integrating the biodigester within the farming system and have demonstrated that the biodigestion process leads to major improvements in the value of the livestock manure as fertilizer for crops and ponds growing water plants or fish.

Future needs are: to document the observed improvement in fertilizer value of the biodigester effluent compared with the raw manure; to understand the factors influencing this process; and to improve the design of the low-cost plastic biodigester so as to increase efficiency and rates of gas production.

*Key words: Biodigesters, farming system, effluent, fertilizer, design and construction*

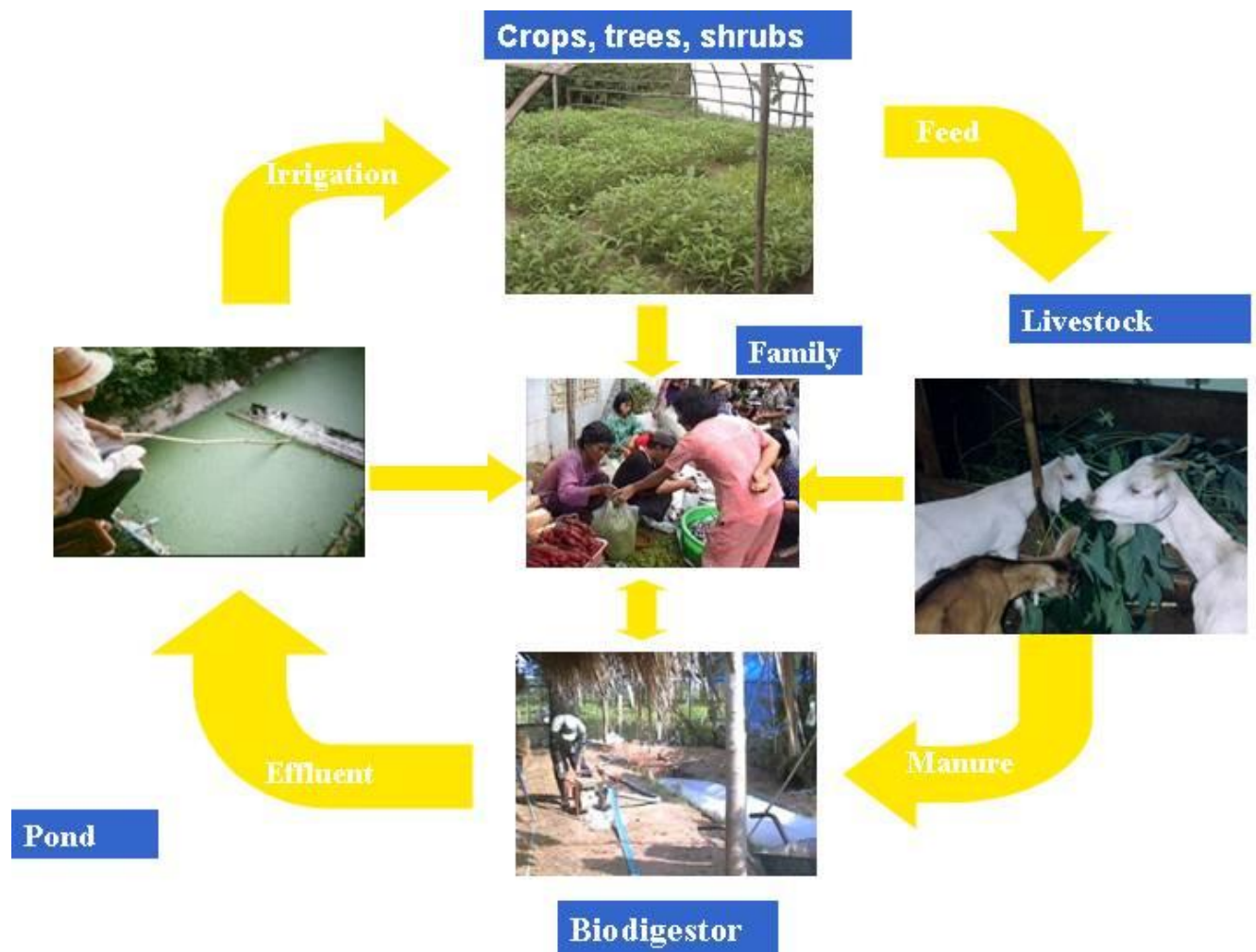
## **Introduction**

Biodigesters have been considered primarily as a means of producing a combustible gas from waste organic matter, derived from animals or people. In this respect, the developers of this technology have been mainly concerned with details of the design and construction of biodigesters, and of management strategies, which would lead to maximum rates of gas production. Less attention was given to the other output from the biodigester, namely the effluent resulting from the digestion process.

As a result of the increasing emphasis on the promotion of farming systems based on the sustainable use of natural resources, it is now appreciated that the biodigester should be considered in a much wider perspective and specifically in its potential role for the recycling of plant nutrients. This process has implications both as a means of reducing the dependence on inorganic fertilizers and for facilitating the production of foods and feeds of organic origin.

## **The biodigester in the farming system**

For farming systems to be sustainable there should be a close relationship among the different components that interact in the conversion of solar energy and soil nutrients into food of animal and plant origin for the benefit of both the consumer and the producer (Figure 1).



**Figure 1:** The integrated farming system

Seen in this context the biodigester plays several roles. It can be:

- A source of fuel for cooking
- A source of fertilizer for:
  - Crops
  - Water plants
  - Fish ponds
- A means of de-contaminating wastes rich in organic matter

The appropriate use of biodigesters can also give rise to a number of related socio-economic benefits that come about through improvements to:

- The quality of life for rural women and children due to:

- Reduced workload (less firewood has to be collected!!)
  - Cleaner kitchen and cooking utensils
- The fertilizer value of manure
  - Organic N is converted to  $\text{NH}_4\text{-N}$
- The environment
  - Reduced methane emissions
  - Less deforestation

Research on the biodigestion process should therefore proceed along a number of pathways, namely:

- Design and construction, with the aim of reducing installation costs and / or improving the efficiency of converting the input materials into usable end-products
- Changes that take place in the biological and chemical characteristics of the substrate during the process of biodigestion
- Use of the effluent as fertilizer for soil and water plants and for fish ponds

## **Design and construction of the biodigester**

Much of the developmental work with biodigesters has been approached from the engineering viewpoint with emphasis on design and construction with the aim of maximizing gas production and efficiency of conversion of feedstock to biogas. There has been very little change in the basic designs of the floating canopy (as developed in India) and liquid displacement (developed in China) systems. The relatively high cost and need for skilled artisans in their construction have been major constraints to widespread adoption, which has had to be supported by subsidies from Government or Aid Agencies.

The introduction of the low-cost (< USD 50.00 for a family size unit) plastic biodigester, based on the use of tubular polyethylene film (Botero and Preston 1985; Bui Xuan An et al 1997a,b), put the technology within reach of a greater number of end users. It has been estimated that there are more than 15,000 users of this technology in Vietnam (Nguyen Duong Khang 2002, this workshop). Subsidies were no longer needed for the purchase of the raw materials, which can be found in most towns in developing countries. The simple means of installation has facilitated farmer to farmer extension of the technology. The virtue of the tubular plastic biodigester is its low cost and simple installation and maintenance. It is recognized that the relatively fragile nature of the polyethylene film is a weak point in the system and that the “plug-flow” mode of operation is relatively inefficient compared with systems where the substrate can be agitated to facilitate mixing.

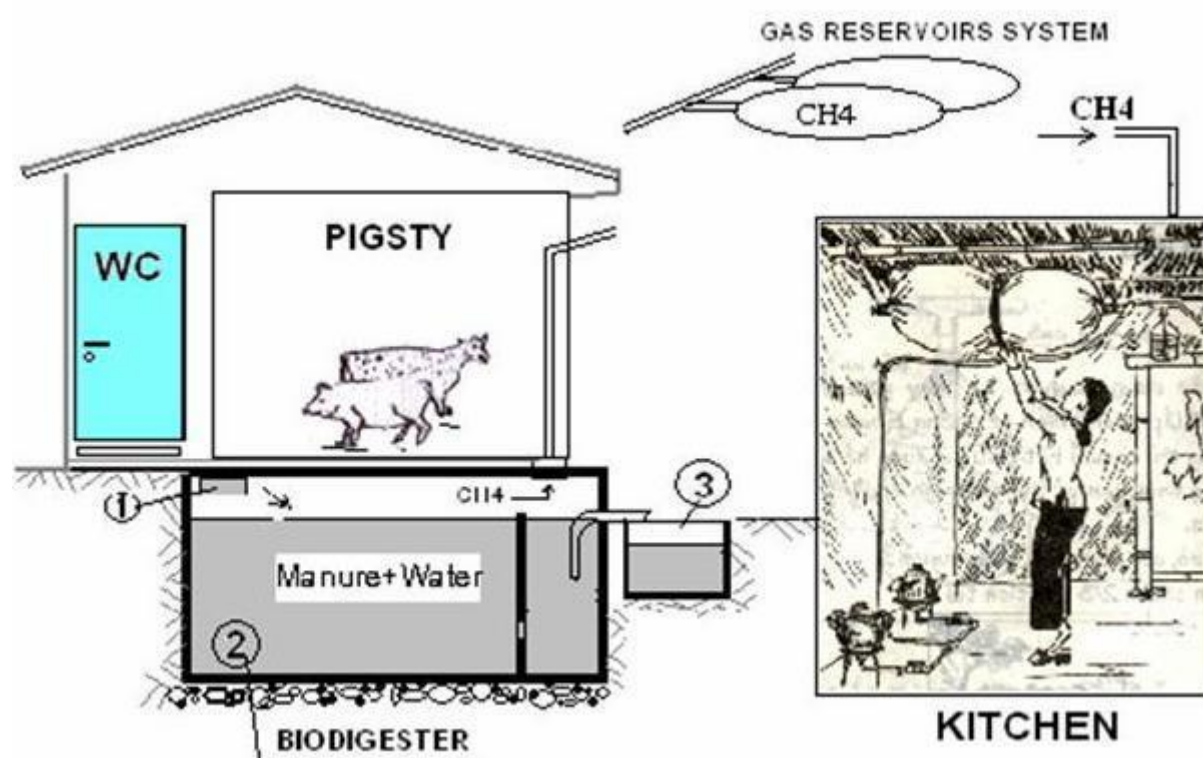
## **The Hybrid Technology Biodigester with Automatic Scum Control (HTASC)**

This modification of the low-cost plastic biodigester system (VACVINA 1998) was directed at improving the durability of the digestion chamber by constructing it from bricks and cement. The HTASC is a cross between an underground fixed dome (Chinese) model and a plastic-bag model. The main digestion chamber is a rectangular (flat-topped) low-depth underground cement tank. There is no pre-digestion / mixing chamber, but instead a siphon-type input with active and continuous scum-breaking action. The effluent is gravity fed to a secondary chamber. This design facilitates the integration of the livestock pen and household



latrine with the biodigester, thus saving space and reducing the overall costs of construction (Figure 2).

Positive results with this digester design have been reported from Vietnam (VACVINA 1998), however, it has been less successful in a pilot test in Cambodia, due apparently to gas leakage through the walls and /or roof of the digestion chamber, which was only resolved by connecting the input siphons to the traditional polyethylene model (<http://www.utafoundation.org/recdevel.htm> and Preston T R 2001, unpublished observations). The idea is an interesting one which merits further research and, specifically, the development of appropriate techniques to ensure the concrete surfaces are gas-tight.



**Figure 2:** The “hybrid” HASFC biodigester developed by VACVINA (1998) in North Vietnam

### The “Super-gas” mixing system

The objective behind the development of this model is to increase the rate and efficiency of the gas production from the substrate by using the gas pressure generated in the reactor to trigger the movement of the substrate between the reactor and the reservoir chambers. The digester is made from PVC sheets welded into a “balloon”. Two balloons are inter-connected to permit free movement of the substrate from one to the other and a simple “water” valve controls the build-up and release of the gas pressure (Figure 3).



**Figure 3:** The “super-gas” mixing biodigester installed in UTA, Cambodia

As the substrate ferments, pressure is built up in the reactor (in the foreground of Figure 3) and forces part of the substrate into the reservoir (background of Figure 3). When the pressure reaches 60 cm of water column the valve (left background in Figure 3) opens, thus equalizing the pressures in reactor and reservoir so that the substrate returns rapidly to the reactor producing a mixing reaction in the process. A pilot model of this system was installed in UTA, Cambodia in June 2001. Initial results were excellent with high and efficient gas production. However, the gas pressure reached at the peak moment eventually proved to be too much and the junction of the pipe at the base of the balloons was forced out of the reservoir balloon and the system collapsed. As with the “HAFSC” model, the idea behind the “super-gas” mixing system is a good one and should be further developed using alternative materials as welding of PVC sheets is a demanding technology required skilled craftsmen and sophisticated equipment.

## **The biodigestion process**

The changes that take place in the substrate during the digestion process have received less attention and have been concerned mainly with environmental and health issues. Thus the degree of reduction in the Biological Oxygen Demand (BOD) and in the concentration of pathogenic micro-organisms have been major areas of interest (Chara et al 1999; Vieyra 2000; Pedraza et al 2002).

Recently, attention has focused more on the fertilizer value of the effluent and specifically on comparisons of the effluent with the raw manure used to charge the digesters. Thus Le Ha Chau (1998a) showed that the biomass yield and the protein content of cassava foliage were significantly increased when biodigester effluent, derived from either pig or cow manure, was

used to fertilize the cassava as compared with the same amount of nitrogen applied in the form of the raw manure used to charge the biodigester. Similar findings were reported for duckweed grown in ponds fertilized with the effluent or the raw manure (Le Ha Chau 1998b). Kean Sophea and Preston (2001) recorded a linear response in biomass yield of water spinach (*Ipomoea acuatica*), which reached 2.4 tonnes dry matter /ha in a 28 day growing period with a level of effluent equivalent to 70 kg N/ha (details to be presented in this workshop).

Reports from China claimed higher productivity in fish ponds when biodigester effluent was used in comparison with raw manure (Ding Jieyi and Han Yujin 1984 ). A recent report from research in Cambodia (Pich Sophin and Preston 2001), details of which will be presented in this workshop, has confirmed the superior value of effluent from a biodigester charged with pig manure compared with the same manure applied directly to the pond at comparable levels of nitrogen.

## **Conclusions**

The increasing emphasis on the need to develop agricultural practices that are in harmony with the environment, and which make maximum use of local resources, is creating a favourable climate for promotion of biodigester technology. Future research in this area should focus on the role of the biodigester as an integral component of the farming system, with major emphasis on ways to optimize the fertilizer value of the effluent and its use on crops and in ponds for water plants and fish. There is opportunity for improvement in the design and management of low-cost plastic biodigesters in order to make them more productive and efficient.

# Methane – biogas – production guide

**VERSION 1.0**

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## Basic properties of methane

Methane is a colourless, odourless, flammable<sup>1</sup> gas and the main constituent, 85% to 90%, of the pipe natural gas that we use in our homes in the UK, Europe and the USA. Its chemical symbols are CH<sub>4</sub> and it is a hydrocarbon.

The theoretical methane yield can be shown to be 5.6 ft<sup>3</sup>/pound (lb) of chemical oxygen demand converted, but the exact recoverable yield depends on a number of environmental conditions. The ultimate yield of biogas depends on the composition and biodegradability of the organic feedstock, but its production rate will depend on the population of microorganisms, their growth conditions, and fermentation temperature.

Methane produced by the anaerobic digestion process is quite similar to natural gas<sup>2</sup> that is extracted from the wellhead and piped to our homes. However, natural gas contains a variety of hydrocarbons other than methane, such as ethane, propane, and butane. As a result, natural gas will always have a higher calorific value than pure methane. Depending on the digestion process, the methane content of biogas is generally between 55%-80%. The remaining composition is primarily carbon dioxide, with trace quantities (0-15,000 ppm) of corrosive hydrogen sulfide and water.

The average expected energy content of pure methane is 896-1069 Btu/ft<sup>3</sup>; natural gas has an energy content about 10% higher because of added gas liquids like butane. However, the particular characteristics of methane, the simplest of the hydrocarbons, make it an excellent fuel for certain uses. With some equipment modifications to account for its lower energy content and other constituent components, biogas can be used in all energy consuming applications designed for natural gas.

The gas made using the suggested ideas contained in this document will be made up of methane plus other gasses or 'diluters' and have a typical value of 600 BTUs per cubic foot.

Anecdotal evidence indicates that biogas was used for heating bath water in Assyria during the 10<sup>th</sup> century BC and in Persia during the 16<sup>th</sup> century. Jan Baptita Van Helmont first determined in 17<sup>th</sup> century that flammable gases could evolve from decaying organic matter. Count Alessandro Volta concluded in 1776 that there was a direct correlation between the amount of decaying organic matter and the amount of flammable gas produced. In 1808, Sir Humphry Davy determined that methane was present in the gases produced during the anaerobic digestion of cattle manure.

The first digestion plant was built at a leper colony in Bombay, India in 1859. Anaerobic digestion reached England in 1895 when biogas was recovered from a 'carefully designed' sewage treatment facility and used to fuel street lamps in Exeter. The development of microbiology as a science led to research by Buswells and others in the 1930s to identify anaerobic bacteria and the conditions that promote methane production.

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<sup>1</sup> Methane will not ignite and burn without the presence of oxygen

<sup>2</sup> The name natural gas was used to distinguish it from town gas made from coal or oil. Town gas was distributed around the UK until the discovery of natural gas in the North Sea. It comprised a whole range of gases including methane and carbon monoxide.

Methane gas also occurs naturally as swamp gas produced from murky stagnant water. Lightning could ignite this gas and has been said to be the origin of Willow the Wisp. Indeed the term swamp gas is often used as methane gas produced by anaerobic digestion. Landfill gas is also made up of a high proportion of methane and is a good example of the commercial use of methane production where the gas is often used to drive a gas engine and electric generators.

Gas made with a digester is also commonly called biogas.

## Anaerobic digestion

Anaerobic digestion is one of the most common chemical processes in nature. Anaerobic means the decay or breakdown in the absence of air or more specifically oxygen. The process is similar to fermentation as the transformation is brought about by micro-organisms (bacteria) called anaerobes. Like with the production of alcohol (ethanol) digestion takes place in two stages. First, in the medium of digestion certain micro-organisms break-down the materials into simple sugars, alcohol, glycerol and peptides. When these components are present in the correct amounts and the conditions are correct, a second group of micro-organisms converts these simpler molecules into methane gas. The micro-organisms are particularly sensitive to environmental conditions including temperature and acidity.

Anaerobic digestion occurs between 32° F and 150° F. However the optimum temperature which promotes activity of the micro-organisms and consequently produce more methane gas is between 85° and 95° F. In colder climates this is difficult to maintain but worthwhile trying to achieve. Below 60° F little gas is produced.

Acidity is also important with a desired pH of between 7 and 8. With a low acid content the - high pH - the fermenting slows down until the bacteria produce enough acid (acidic carbon dioxide) to restore the balance. Acidity can be measured using litmus paper.

Carbon and nitrogen are the other two components for a digester and are both required for the micro-organisms to live. However, the bacteria consume the carbon at about 30 times faster than the nitrogen. This 30:1 ratio produces the maximum amount of gas. If the ratio is not correct the bacteria will usually compensate creating the right balance within the digester.

As mentioned earlier the gas produced in a digester is not pure methane and is usually 75% methane and carbon dioxide (CO<sub>2</sub>) with trace amounts of hydrogen, nitrogen and other gases characteristic of the original materials used in the digester.

The slurry that is left after the digestion process is complete is mainly composed of organic humus, with small amounts of nitrogen and phosphates. This final product of gas production makes an excellent fertiliser and soil conditioner.

It should be noted that the time in starting the digester and producing gas can be as long as four weeks – but sometimes as short as two weeks. This is because the bacteria will first need time to breakdown the slurry into alcohols and sugars, before the second group of bacteria, the gas producing ones, can adjust the carbon/nitrogen mix and the acidity level for reasonable amounts of gas to be produced.

## Modest experiment in methane gas production

Having read the first part of this guide many readers may want to build a methane digestion plant now and power up their houses. However, while you are waiting to build a digester large enough to process your household waste and other peoples' waste from down the street into enough methane to heat the house, you may wish to try a simple, low cost experiment. This will help familiarise you with the fuel's production and some of its characteristics.

Here is how to put together one of the simplest and least expensive methane production experiments of all. You will need only a gallon cider jug, some sort of gas holder (a recycled, heavy-duty plastic bag) and, from the chemistry lab, some rubber tubing, a couple of tubing clamps, a two-hole rubber stopper, glass tubing and a glass "Y".

Your first step in constructing a mini-methane-generator will be to make a manometer. This is a U-shaped tube, partly filled with water, that will let you know when your little digester is producing gas, indicate the pressure of that gas and act as a safety valve (since excess pressure will blow the water out of the manometer). Any chemistry student should be able to show you the proper way to heat and form your glass tubing.

The four inch manometer dimension shown in the drawing should be considered a maximum for both practical and safety reasons. Filling the tube with water to such a depth will give you eight inches of pressure ( eight inches water gauge is about the same pressure as the gas in a UK home) and therefore more than sufficient. Gas appliances usually operate on pressures of less than eight inches and there is no reason for you to risk blowing your jug apart with gas compressed beyond this amount.

Once your manometer is completed, you should make a "burner tip" by drawing out a piece of glass tubing in the approved manner (again, any chemistry student should be able to help you if you have never formed glass tubing before). The tip should be quite long as a precaution against the possibility of a back flash. Then attach the stretched-out burner to one arm of your glass "Y" with a short piece of rubber tubing on which a clamp is placed to act as a valve.

The other branch of the "Y" feeds directly to your gas collector through a longer section of rubber tubing (also fitted with a clamp). The experiment that wrote this article<sup>3</sup> made a collector from a polyethylene milk bag taken from a cafeteria-type dispenser. The cardboard cartons that fit inside such dispensers are thrown out after one use and you will find that each box contains a bag-liner. Fully inflated, the bags are somewhat larger than a king-sized pillow. Wash one out, roll it up to expel the air inside and hook it to the "Y".

Now you are ready to place some manure in the jug. The best type appears to be a mixture of droppings and litter from chickens but, if you can not get that, try something else such as straight horse manure. As mentioned earlier in this guide the very most efficient formula is 30 parts of carbon to one part nitrogen.

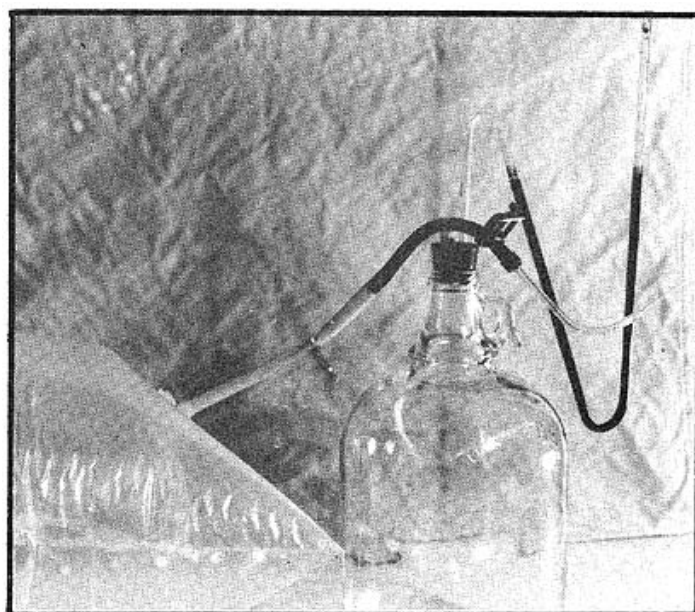
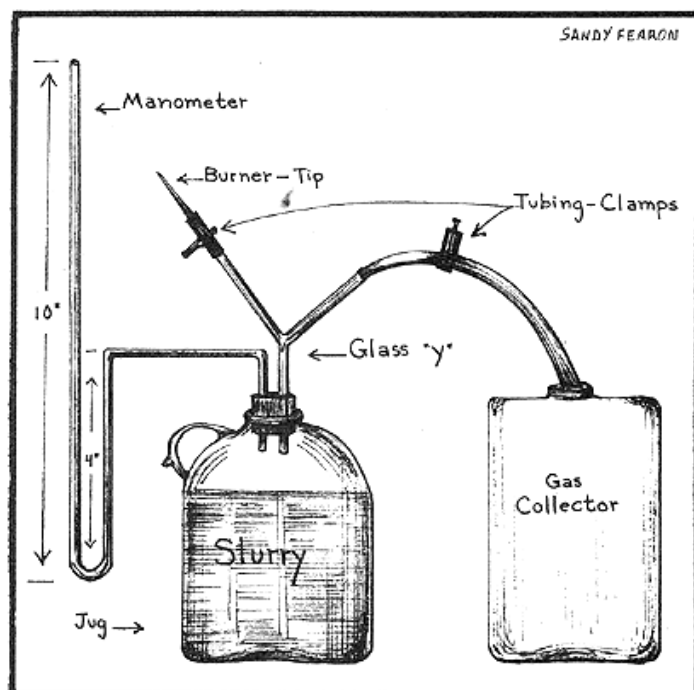
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<sup>3</sup> This section of the guide was taken from a Mother Earth publication written by Robert C. McMahon



Mix the manure with water to form slurry and pour it into the jug. Fill the jug to about four inches below the stopper (there will be some initial foaming and you want to keep it out of the tubing).

Once again the most efficient generation of methane takes place at 90 to 100°F and, if your slurry's temperature drops much below 80°, the gas production will be slow or non-existent. You will have to provide a sufficiently warm environment for your jug, then, if you want it to make gas. Bear in mind, though, that methane—carelessly handled—can explode so take suitable precautions in setting up your apparatus. Never place the experiment near a naked fire or burner. Never use a jar or tin to collect the gas in as it will contain air and therefore an explosive mixture will be made. Always use a bag or something similar from which all the air can be expelled.



Start your generator working with all its valves (clamps) closed and, after a couple of days, the water being "pushed" up the long arm of the manometer will indicate that

some pressure is beginning to build in the jug. This first production is mostly carbon dioxide, which will not burn. (Test the gas by holding an ignited match at the tip of the burner and opening its clamp. The amount of gas in the manometer is sufficient for such a trial, although—as stated—the carbon dioxide will not burn.)

Continue the tests until a match held at the burner tip does ignite the escaping gas. This may take a couple of weeks or more depending upon the acid conditions of the slurry in your jug.

Eventually, incorrect acidity levels will correct themselves and your model generator will begin to produce methane. When you are satisfied that such production is underway, open the clamp to the gas collector and you're in business. Methane production—depending on temperature—should last for from one to three months.

And what can you do with the gas? You can burn it off through the burner tip as a graphic demonstration that decomposed organic matter really does produce usable fuel. The quantity is too small for much else. To increase the pressure of the escaping gas (and, thereby, the spectacular nature of the resulting flame), place one or more weights on the collector bag. The manometer, of course, will faithfully indicate the pressure your gas reaches during such a demonstration.

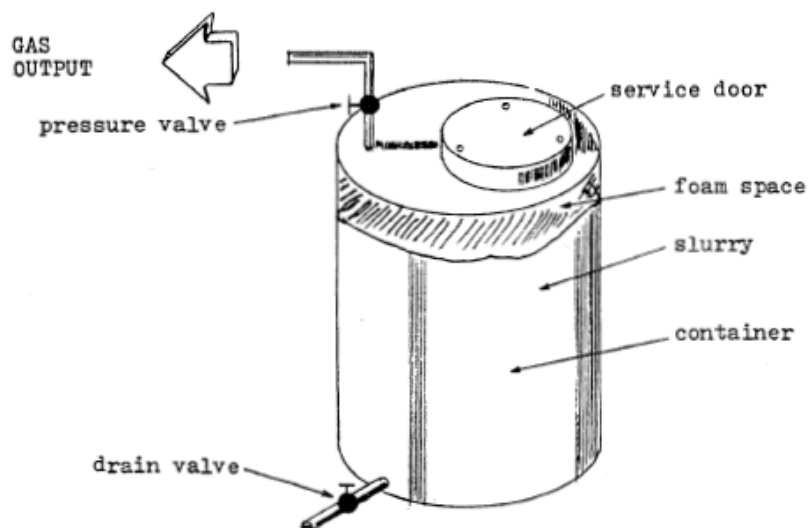
Once the thrill of watching the flame passes, disconnect the collector bag, take it outside and expel the remaining methane. Remember the residue left in the jug is an excellent fertiliser and you can use the liquid and some of the solids to seed your next batch of waste (and thereby hasten its production of gas).

The author also suggests a couple of untried refinements. If you have a fish aquarium heater available, you might try putting your jug in a bucket of water warmed by the element. This would be a significant improvement in maintaining the digesting slurry at optimum working temperature. You can also improve the burning qualities of the resulting methane by bubbling it through a lime water solution to remove carbon dioxide and passing it over ferric oxide (rust) to remove hydrogen sulphide.

Although the above experiment is imprecise and yields only a small quantity of methane, it will familiarise you with the digestion process and, possibly, encourage you to investigate the construction of larger-scale generators that will produce usable quantities of gas.

## Simple anaerobic digester

A larger digester can be made very simply. The main component required to make a simple digester is the vessel that will contain the slurry. The vessel must allow a method of filling as well as a way of extracting the gas. The diagram below is a simple digester show for demonstration purposes only, and is not meant for construction in its exact state as, although correct in concept it does not allow for the safe storage of the gas produced.



## Gas storage

Once the gas has been produced a practical and safe means of storing the gas is essential. As discussed earlier the storage container must not contain air and there must be no way for air to enter the storage vessel. Therefore the vessel must have absolutely no air in it before the gas is introduced. If not an explosive mixture will be reduced. It is never adequate to allow a gas air mixture to be formed and rely on there being no source of ignition. Sources of ignition can arise from static electricity, for example, and therefore there is always a potential source of ignition nearby.

This basic digester will produce a modest amount of methane gas. Once again it is a good model to try out in order to become familiarised with the process of methane production. This type of digester is known as a batch feed system, where slurry is introduced into the digester through a service door that is then sealed closed. After a few weeks once the conditions are right, fermentation begins. An airspace at the top of the vessel to allow the first group of bacteria some oxygen to breakdown the slurry into simple molecules and to help prevent foam produced during the digestion process to travel into the pipes. After a couple of months the batch will no longer produce gas. At this point the drain valve is opened and the decomposed matter removed. The vessel may be flushed through but a small amount of slurry should be kept to help start the next batch.

## Batch digester construction

This little digester will provide enough free gas to provide heat to cook one meal a day. Modest applications like lighting small rooms with gas lanterns and cooking are ideal for this system. It can also be a low cost build. A simple inner tube from a large tyre such as a tractor will make a perfect container for the gas as it:

- Is relatively inexpensive and easy to obtain
- May be purged of air relatively easily by rolling tightly
- Automatically creates pressure for feeding the appliance
- Is about the right volume for the size of the digester.

Purging the container or pipe means to remove all air from it. It cannot be emphasised enough that at no time must air be allowed to mix with the methane.

The container used in this system is a standard 44-gallon oil drum. Try and get one that is relatively clean with no rust whatsoever. Safely remove any residues in the tank with soap and water and then clean water. Oil drums are used to store a very wide range of chemicals and oils so find out what was stored in it before you flush out the contents. If in doubt look for another container that has been used for a safer product.

A stable and secure base can be made out of a few concrete bricks or slabs. The drum when full will be very heavy. The container should be kept off the ground to prevent rusting where possible. The drum should also be high enough to allow draining into a suitable container.

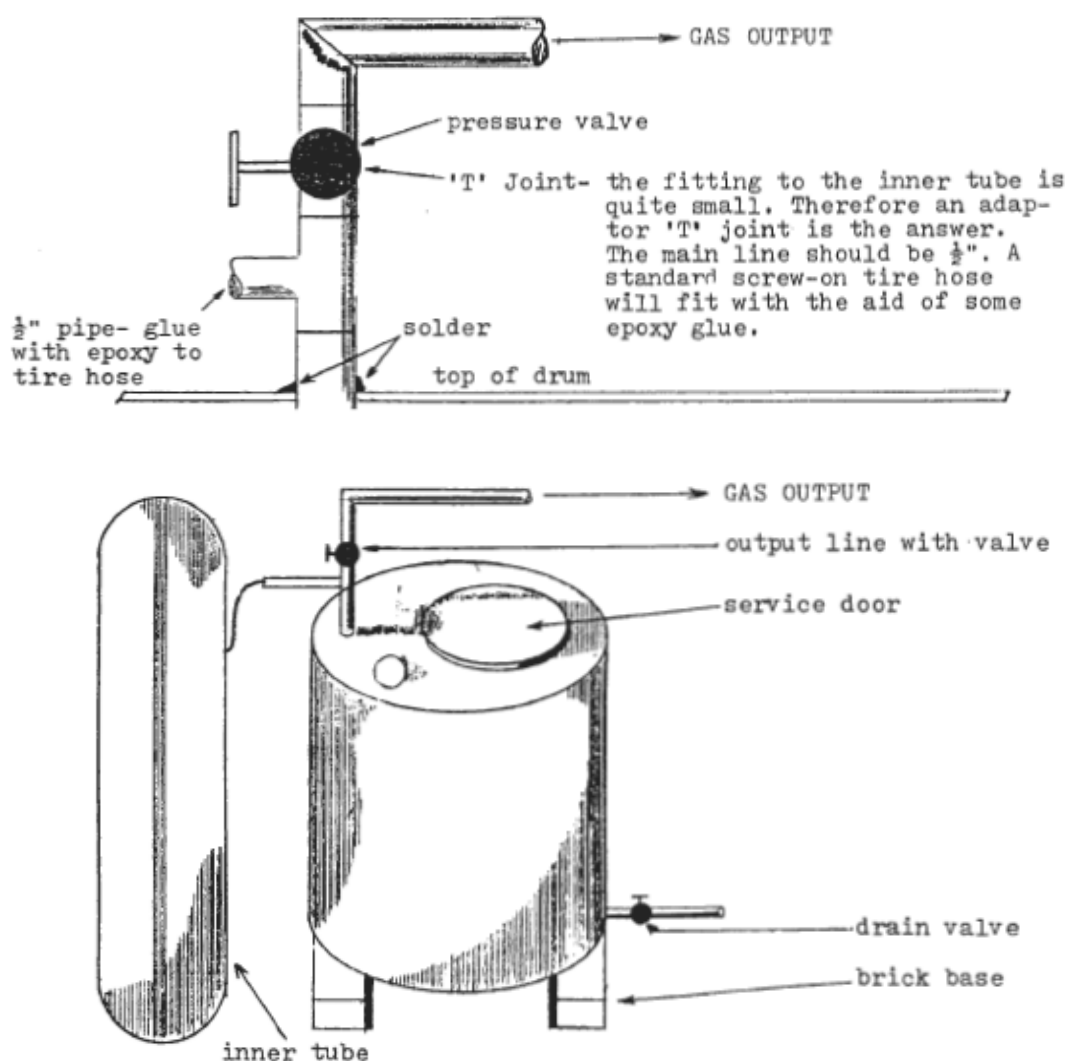
There are normally two vent holes at the top of the drum. It is best to try and use these to fill the vessel. They will need to be closed afterwards and be gas tight. If a larger access hole is required one suggestion is to use an air filter cover from an old car - some like Fords had large metal air filters with one or two bolts to secure them and a rubber gasket to provide an air tight seal. After cutting out the right size hole a cross bar could be fitted across the hole with bolts aligned to fit the air filter cover.

Last, drill a snug fitting  $\frac{3}{4}$ " hole into the top of the drum and install the gas outlet pipe. A further hole should be drilled near the bottom of the drum so that a drain can be fitted with a valve. The materials for these pipes can be iron or copper. Plastic pipe could be used for the drain. However some times this pipe can go brittle when exposed to sunlight.

For larger outputs two units can be constructed in series. Indeed as the units are simple and cheap to build you may wish to build even more

#### Suggested parts list

- 44 gallon oil drum
- air filter housing for service door- optional
- Concrete bricks for base
- $\frac{3}{4}$ " copper piping
- 'T' joint with  $\frac{1}{2}$ " copper reducer
- Valves
- Large tyre inner tube
- Tyre hose – screw on type
- Iron work for service door
- Copper fittings- compression fittings are not recommended
- PTFE tape, jointing compound, etc.
- Solder and propane blow torch.



## Digester operation

The composition of the slurry will to a large extent determine the success of your digester. To get the 30:1 ratio of carbon and nitrogen animal manure appears to be best. Adding grass cuttings and leaves maybe acceptable but they contain little or no nitrogen. But trial and error may help you find the right mix.

On a farm manure is readily available but in the city less so. It is then possible to mix leaves and grass clippings with organic waste from the kitchen. This can include fruit and vegetable peelings but not cooked food, meat, paper or cardboard.

Ideally the slurry that works best in the digester comprises:

- 3 to 4 gallons of liquefied manure
- 10 gallons of water
- Enough grass cuttings and leaves (50:50 ration) to fill the vessel within 1 foot of the top.

The mixture should be stirred well and should produce gas after about 2 weeks with peak production after about 8 weeks. There will be little production after 12 weeks.

When gas is being produced – try bubbling the output through some water rather than into the storage vessel - leave it to produce gas for several days until you are certain that all the air has been expelled. **DO NOT LIGHT THE GAS.** The vessel and pipe work may still contain air and therefore you might cause an explosion.

Then take the inner tube and remove the tyre valve. Roll the tube very tightly pushing all of the air out of the tube. When this is complete replace the valve and screw the valve onto the 'T' joint. The system should now be free of any air and ready to accept an appliance.

You must also purge all pipes that are added to the system at this point as they will have air in them until the gas passes through. You can let the appliance run for a few minutes before lighting when it is first connected. Do not do this in an enclosed area where the venting gas can build up.

## Digester performance

This type of batch feed system does offer some drawbacks as will probably need the gas each day rather than waiting for two weeks. One solution is to use two digesters and aim for one to reach peak performance whilst the other is fermenting and starting to produce gas.

## Continuous output digester

A fairly large digester can be built from two 275-gallon boiler oil tanks. One can be used for the digester and one for the holding tank.

A feed chamber can be placed at the end of the digester, with an airtight valve at the top and bottom of its column.

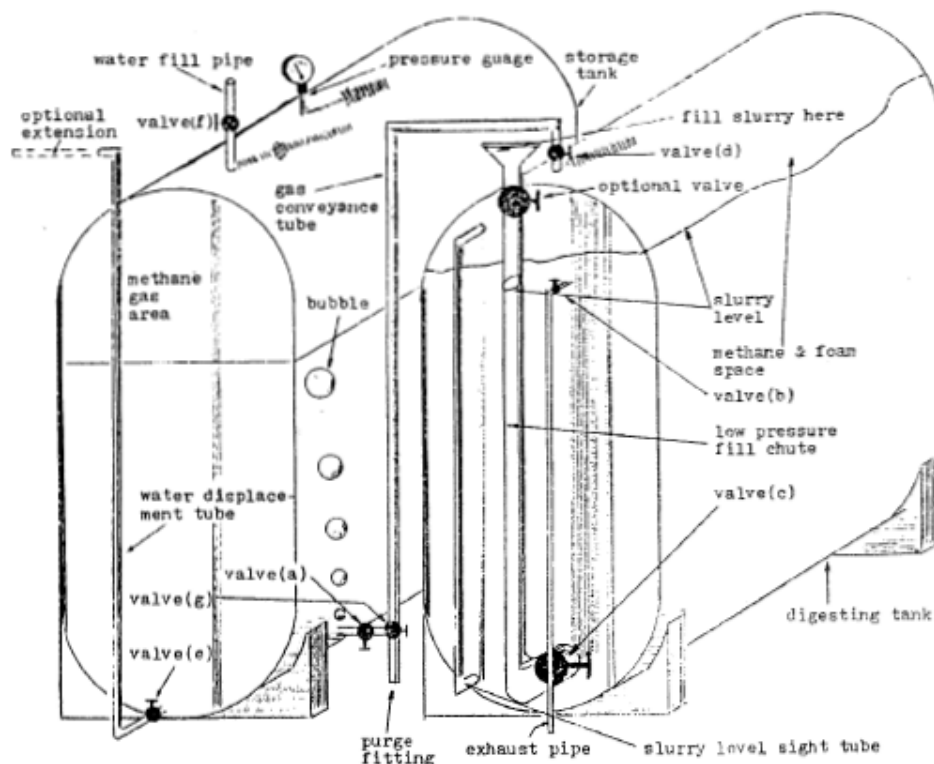
The exhaust tube can be placed up near the top of the tank, but low enough so that the level of the used slurry flows out of the digester (about 8 gallons) will come out. On the other hand a pipe too low will be exhausting slurry that is still digestible. A simple way of setting the correct height is to add exactly 8 gallons of liquid slurry when filling at the point when the slurry just starts to overflow out of the exhaust pipe. Close the valve and add 8 more gallons.

The holding tank should be equipped with a pressure valve measuring up to 50 pisp. The pressure of the gas should be monitored closely and any excess gas vented or consumed.

The holding tank cannot of course be collapsed. Therefore, a displacement method must be used to purge it of air. Filling the tank with water to the very top ensuring that there is no air present can do this. Once the feed line from the digester is purged – let it run for a few days after fermentation like the drum digester – it can be attached to the holding tank. The methane will then displace the water that will flow out of the exhaust tube. Once all the water is removed, the valve to the exhaust tube on the holding tank can be closed. The tank is now purged and ready for use.

### Parts

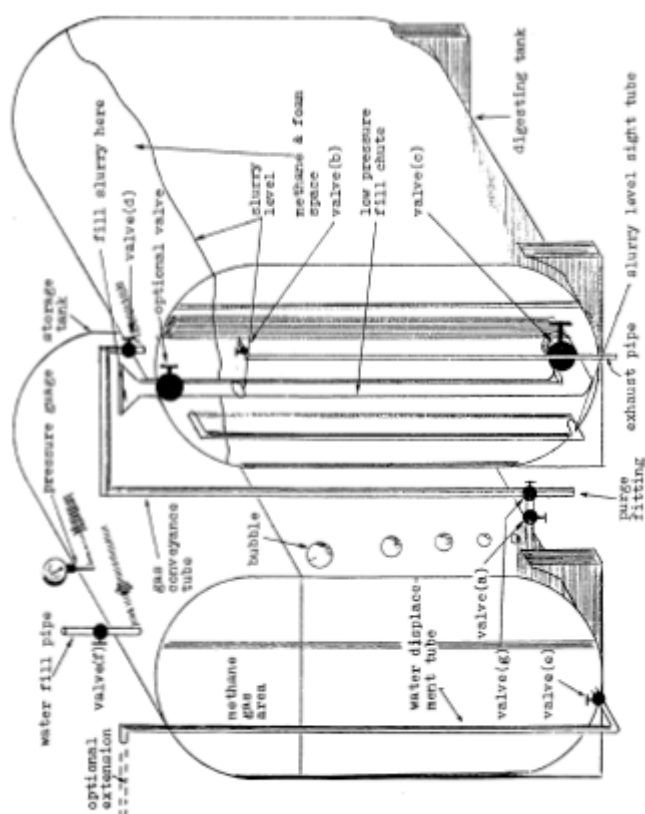
Two 275-gallon oil tanks  
3/4" copper tubing and fittings  
50psig pressure gauge  
Length of plastic hose for a site tube  
Hose clamps  
Valve to fit 4" copper pipe  
Length of 4" copper pipe for fill tube  
Funnel to aid filling



### Operation of continuous output digester

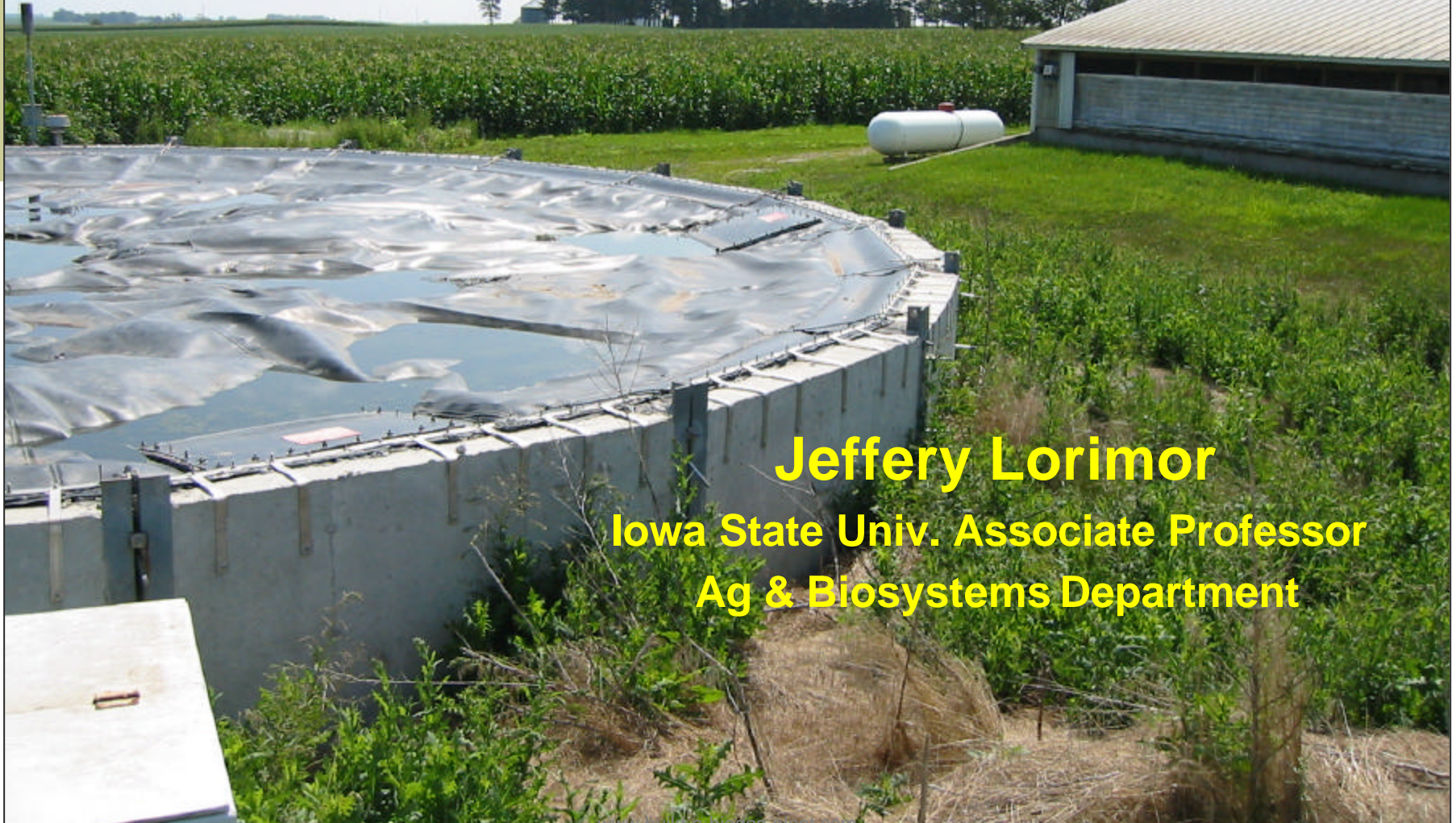
1. To start the digester close all valves
2. Open valves (g) (c) and (d)
3. Fill the low pressure chute with slurry until the sight level tube shows slurry near the top in the tank ( one foot space form the top). The slurry will seek its own level therefore there will still be slurry in the fill chute up to the level of the slurry in the digester. The slurry should be allowed to pre-ferment. A cover maybe fitted to the top of the chute if desired. Remember to close valve ( c) after initial filling and after daily filling.
4. As gas passes through valves (d) and (g) the system is purged and air is displaced. Fit a hose to the purge fitting and place the other end of the hose in water to check for bubbles of gas. Purge for a few days once the system is fermenting. Make sure no air is present in the line.
5. Open valve (f) fill the holding tank full with water making sure to expel all of the air. Then close valve (f).

6. Open valves (a) and (e) and let gas enter the holding tank and thus displace the water. It will be forced out of the water displacement tube. An optional extension may be placed on top of this tube, however make sure that the pipe passes above the top of the tank since the water will seek its own level.
7. A hose may be fitted to the water fill pipe, and the gas consumed by opening valve (f). Close valve (e) once all water is displaced.
8. Monitor the pressure gauge daily. If the pressure is high in the system gravity will not be enough to push the slurry down the fill chute. A circulation pump would then have to be installed. However if the pressure is within the specified range up to 50psig then there should be no problem. To refill daily, close all valves. Open valve (b) and let 1/30<sup>th</sup> of the slurry come out (this slurry is already digested). Then close valve (b) and replace the 1/30<sup>th</sup> of the slurry volume through the fill chute.





# MIXED DIGESTERS



**Jeffery Lorimor**

**Iowa State Univ. Associate Professor  
Ag & Biosystems Department**

# [ Mixed Digesters ]

- **Completely Stirred Tank Reactor (CSTR)**
  - Continuous flow/stir process
- **Sequencing Batch Reactor (SBR)**
  - Batch reactor
    - Feed
    - **Stir**
    - Settle
    - Decant

# [ Stirred Ag Reactors in the U.S. ]

- 15 mixed digesters\*
  - 10 dairy
  - 3 swine
  - 1 caged layers
  - 1 ducks



\*Per Agstar database Oct. 2002  
[www.build-a-biogas-plant.com](http://www.build-a-biogas-plant.com)



# [Mixed Digesters]

- **CSTR...HRT = SRT**

- **Generally design for long detention times**
  - 20-30 days
  - Means relatively large volume required...more \$\$
  - Theoretically fresh manure is discharged if mixing is thorough

- **SBR...HRT > SRT**

- **HRT may be very short...days or even hours**
- **SRT is very long...provides more thorough digestion**

# [ Mixed Digesters ]

- **Must have some type of mechanical system for agitating the manure**
  - **Mechanical propellers**
    - Submerged motors
    - Exposed motors with shafts extending into the manure
  - **Pumps**
    - Recirculate liquid
    - Recirculate gas



# [ Manure Thickness ]

- **Mixed reactors are good for manures too thin for plug flow and too thick for lagoons**
  - **Plug flow: 10 - 13% TS (dairy)**
  - **Lagoons: 0.1 – 2% TS (flush sys)**
  - **Mixed: 2 – 5% TS (swine)**

# [ Manure Thickness ]

- **Swine manure**

- **Farrowing/gestation: 3.0-5.0% TS**
- **Finishing houses: 4.0-9.0% TS**
  - **May have to be diluted if too thick**

- **Dairy manure**

- **Typically 10-13% undiluted**
  - **Bedding may thicken it**
  - **Works best undiluted in plug flow digester**
  - **Sand and digesters don't go together**

# [ Construction ]

- Mixed digesters may be either “hard top” or “soft top”
- Shape can be rectangular or circular
  - Round designs may be easier to mix
  - Rectangular don't need special length/width ratio like plug flows
- Concrete or steel
  - Must be insulated in cold climates



# [ Mixing ]

- **Ideally mixing would be continuous**
  - Keeps microbes into contact with nutrients
  - Requires a lot of energy
- **Periodic mixing**
  - Digesters respond quickly after mixing or feeding
  - Over-designed mixers provide safety factor against solids settling

# [ Primary Concerns ]

- **Additional mechanical equipment required for mixing**
  - More \$\$ to construct
  - More maintenance/management requirements
- **Solids accumulation if mixing or discharge designa are inadequate**
- **Struvite accumulations**
  - Foul pumps & pipes

# [ Heating ]

- **Uniform heat is necessary throughout digester volume**
  - Preheat not necessary or advantageous as it is for plug flow
  - Mixing while feeding is good management practice to rapidly warm incoming manure

# Iowa Mixed Digester



# [ Iowa Mixed Digester ]

- Iowa swine digester
  - Mixed morning and night for ~ 1 hour each time
  - Fed in the morning during the mixing cycle
  - Manually activated pumps to provide feed



# [ Performance ]

- Loading rate
  - Gal manure fed = 540,000 gal/mo.
    - 18,000 gal/day
    - 3.6 gal/sow-day
    - 1.5 kg VS/M<sup>3</sup>-day
      - 90 lb VS/1000 ft<sup>3</sup> (~10X lagoon loading rate)

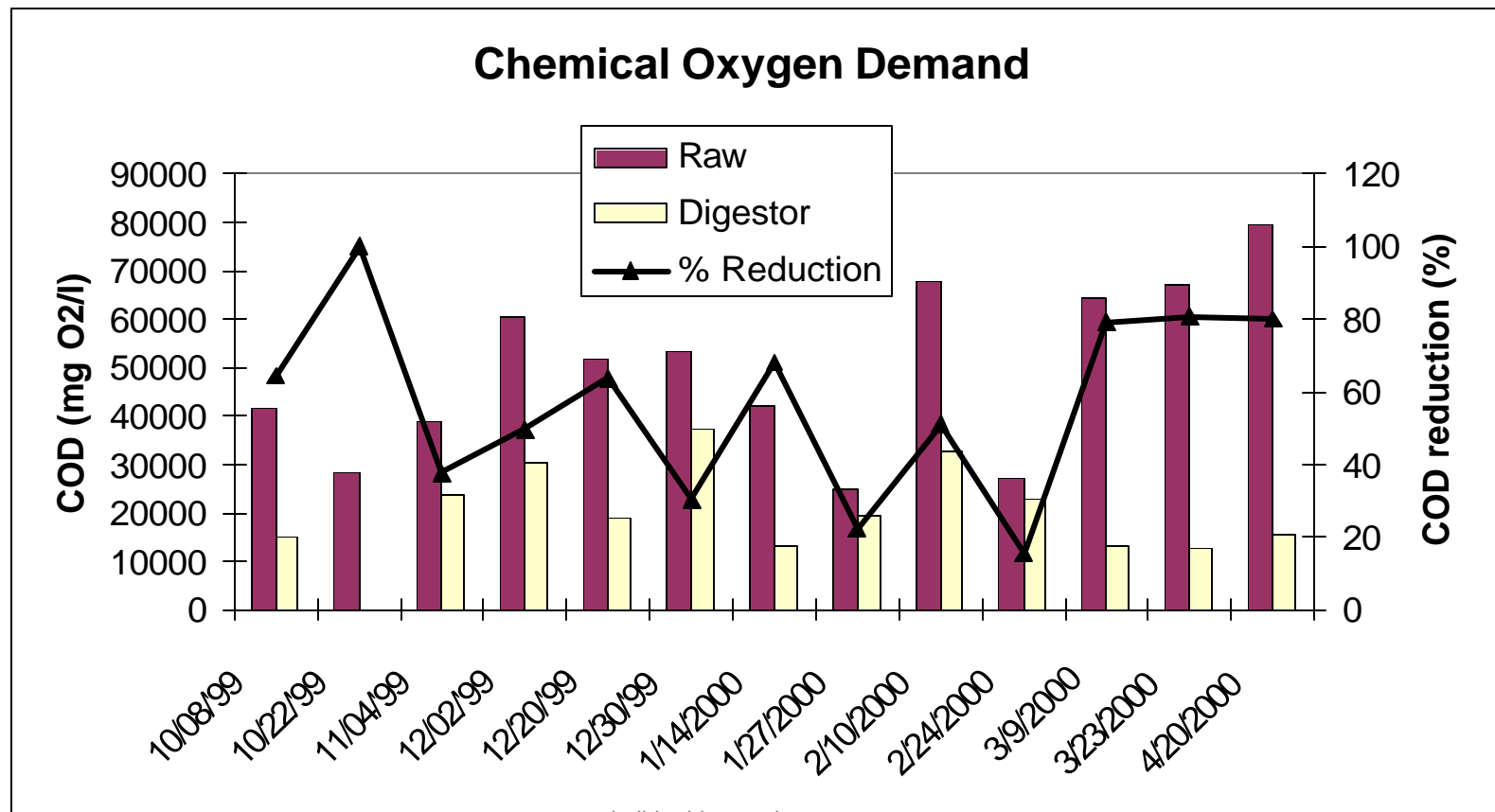
# [ Performance ]

- **Energy production**

- **Biogas generated = 588,000 cu ft/mo.**
  - 19,600 cu ft/day (70% methane)
  - 3.9 cu ft/sow-day
- **Electricity = 24,500 Kwh/mo.**
  - 816 kwh/day
  - 163 watt-hr/sow-day
  - 6.8 watts/sow
- **Generator run time 80% first 6 months**

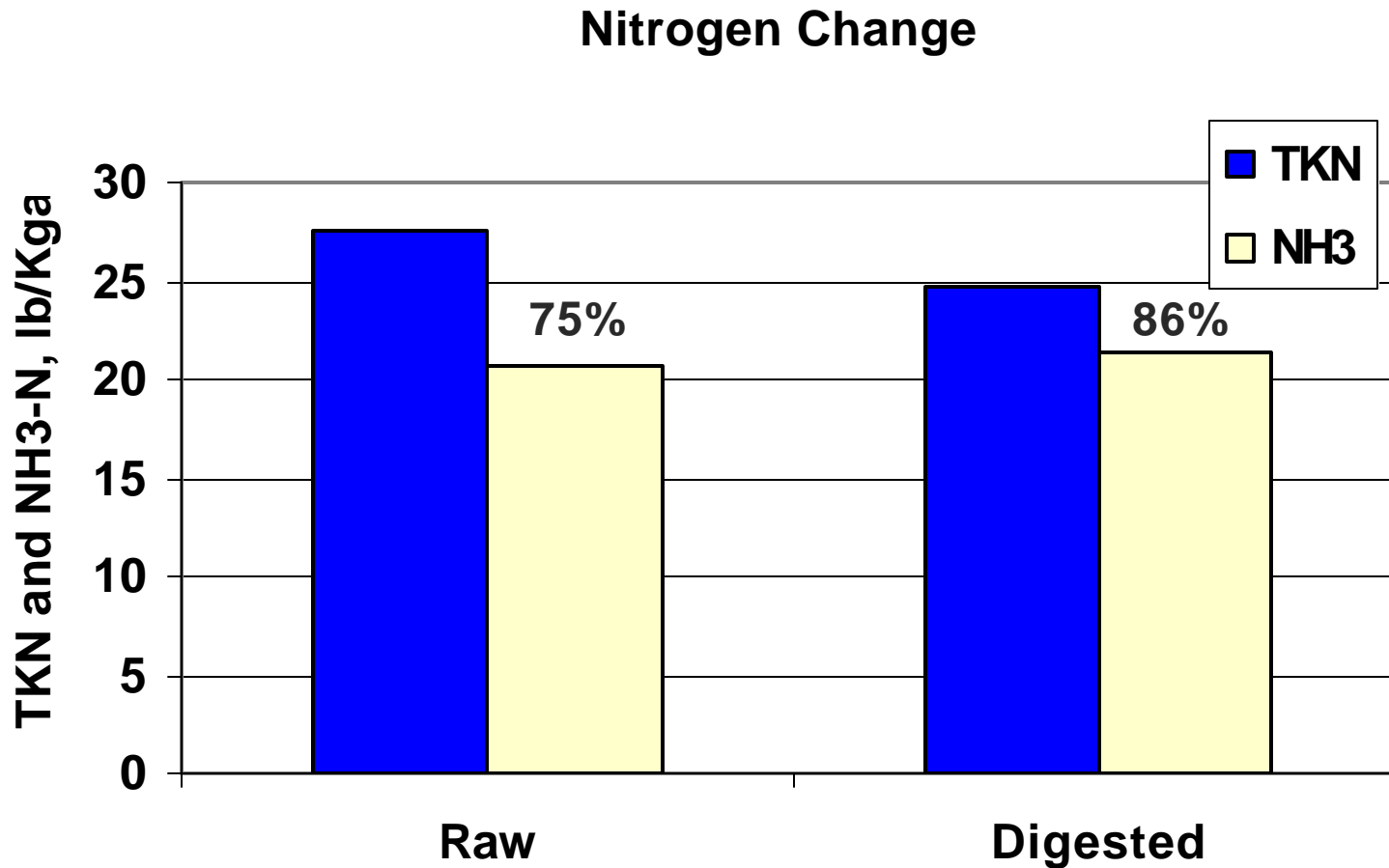
# Performance - COD

- Average COD reduction for Iowa CSTR = 60%



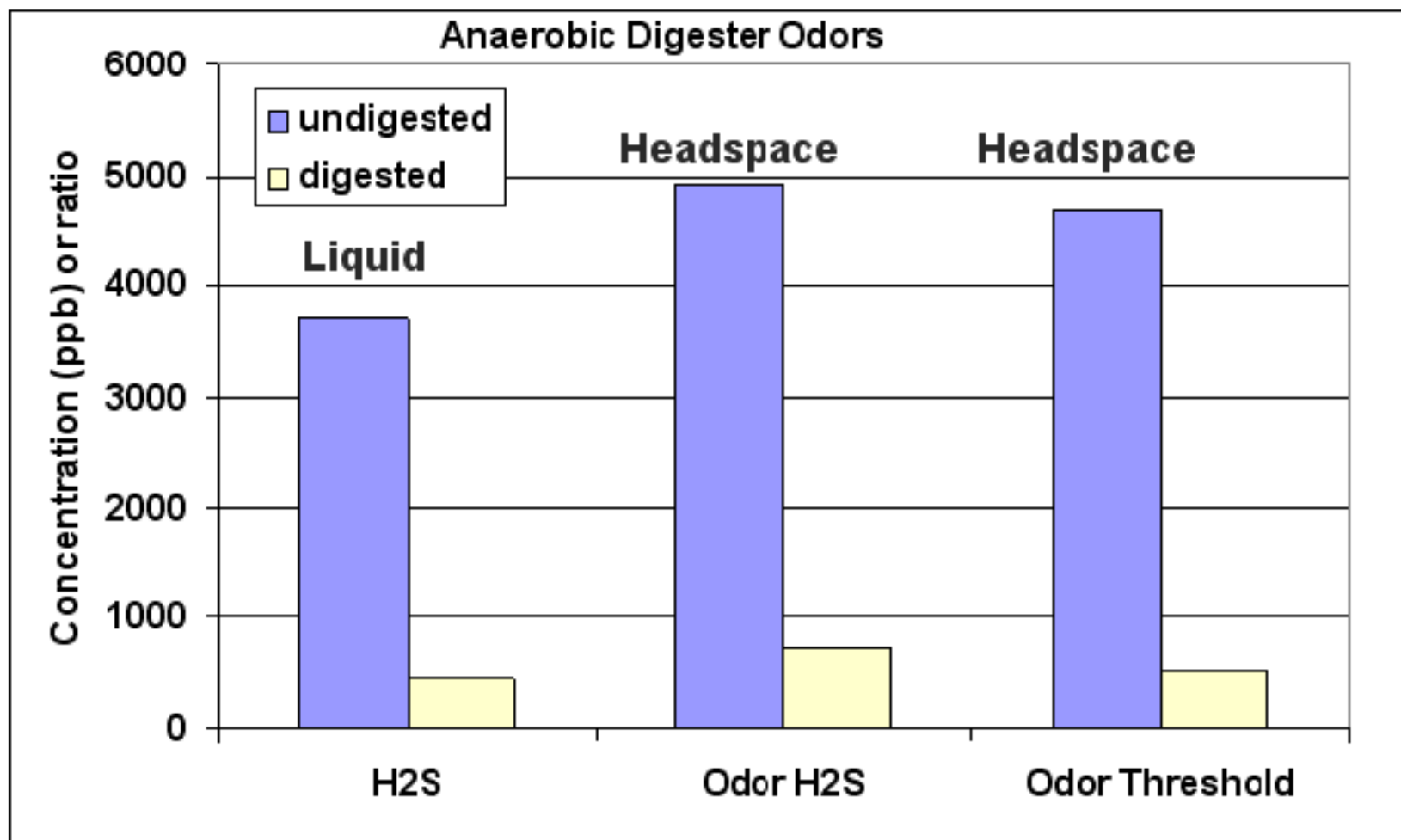


# Performance – N Change



# Performance – Odor Reduction

- Odors reduced ~ 90%



# [ Summary – Mixed Digesters ]

- **Useful for moderately thick manure**
  - Use if manure's not thick enough for plug flow
- **Additional mechanical requirements**
  - maintenance and good management very critical
  - Iowa unit has been challenging to maintain
- **Good COD & VS reductions**
- **Odor concentrations are reduced**
- **Manure is still not “releasable” quality**

# Plug Flow Digesters

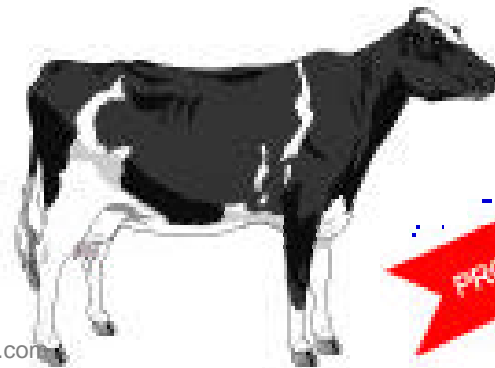
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**Peter Wright, Manure Treatment Specialist**

**Scott Inglis, Research Associate**

Department of Biological and Environmental  
Engineering

Cornell University



# Anaerobic Digestion Systems

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- ◆ Biological
- ◆ Manure and Effluent Handling  
Separation
- ◆ Gas Collection  
Conditioning
- ◆ Engine
- ◆ Electric
- ◆ Heat
- ◆ Management

# Benefits

---

- ◆ Energy production
- ◆ Odor Reduction
  - Nutrient Management
- ◆ Solid Sales
  - Bedding use
- ◆ Liquefy Manure
- ◆ Integration with other enterprises
- ◆ Profit Center

# Reasons to adopt Methane Generation in 1970s

---

- ◆ Energy prices went up and were expected to go higher
- ◆ Guaranteed price for electricity produced
- ◆ Technology was demonstrated successfully

## Problems in 1970s

- ◆ Biological systems management on farms was primitive
- ◆ Peak energy demands on farm
- ◆ Few large farms
- ◆ High capital costs
- ◆ High maintenance costs
- ◆ Cows on pasture







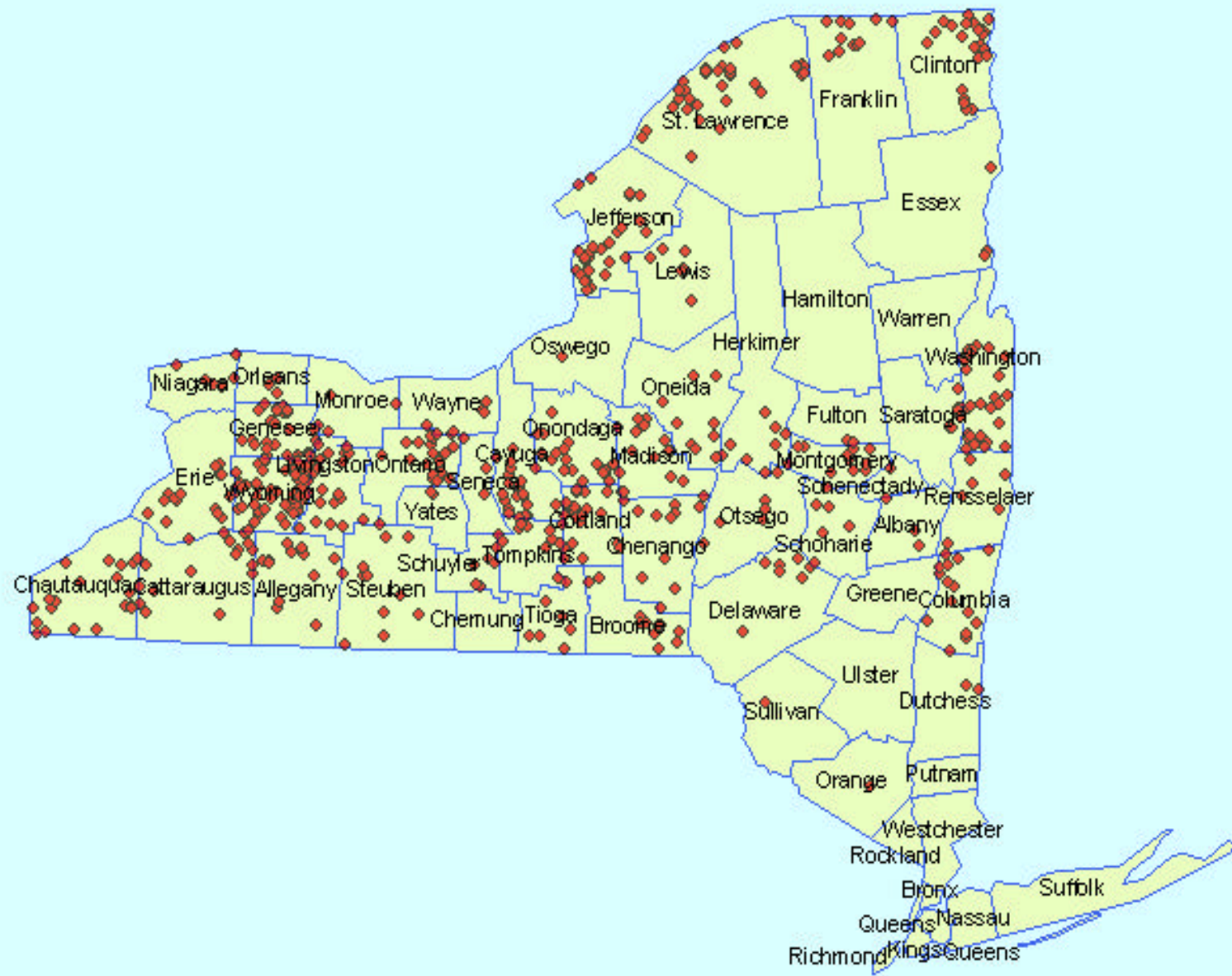
# Reasons to adopt Methane Digestion in 2004

---

- ◆ Odor control is a real need
- ◆ More larger farms with economies of sale
- ◆ Management ability of biological systems on farms has increased
- ◆ Electric demand on some farms is continuous
- ◆ Liquid manure handling systems are more advanced
- ◆ Solid separation

## ◆ Problems in 2004

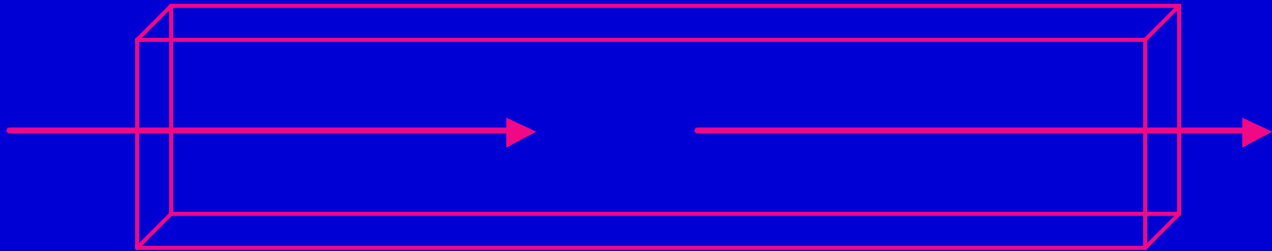
- ◆ High capital costs
- ◆ Support industry not developed
- ◆ Wholesale electric price is low



# Plug Flow

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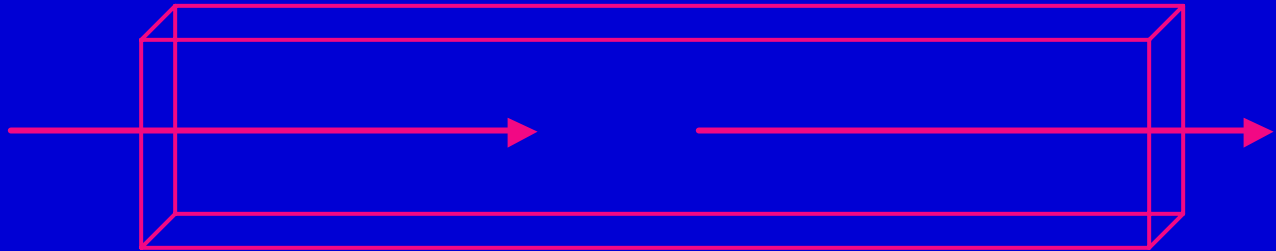
- ◆ No “Mixing”
- ◆ Inflow = Outflow,  $HRT=SRT$
- ◆ HRT 20-25 days



# Plug Flow advantages

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- ◆ Perfect for scraped dairy manure
- ◆ Many successful examples
- ◆ Slug loads?



# Plug Flow Disadvantages

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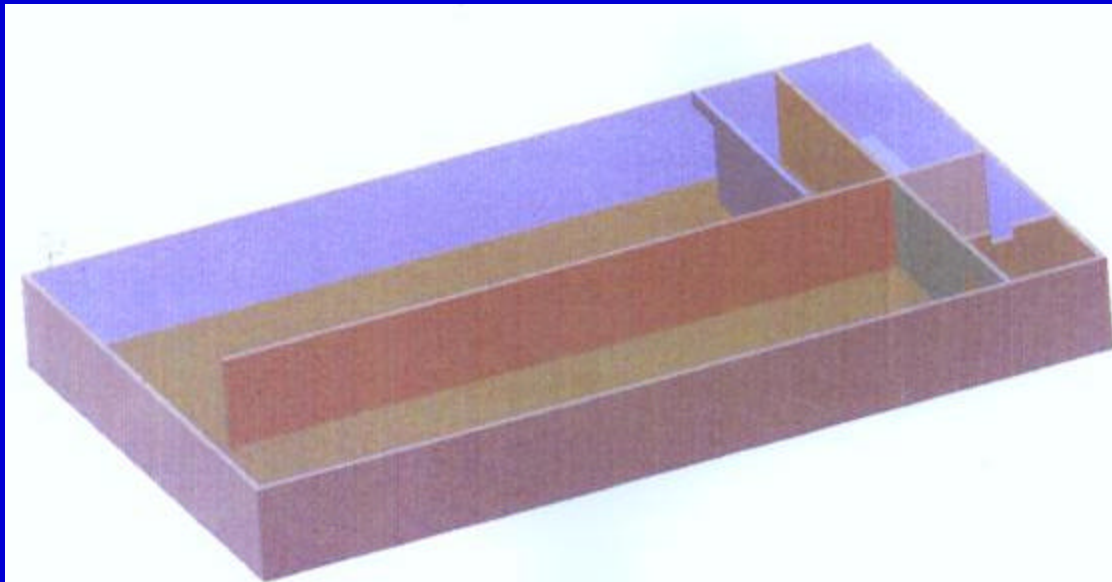
- ◆ Total solids need to be close to 12%
- ◆ Short Circuiting



# Plug flow

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- ◆ **Vertical**  
**With Conical Bottom**  
**Sand Laden Dairy Manure**
- ◆ **U shaped**



# Tops: Hard or Soft?

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- ◆ **Soft**

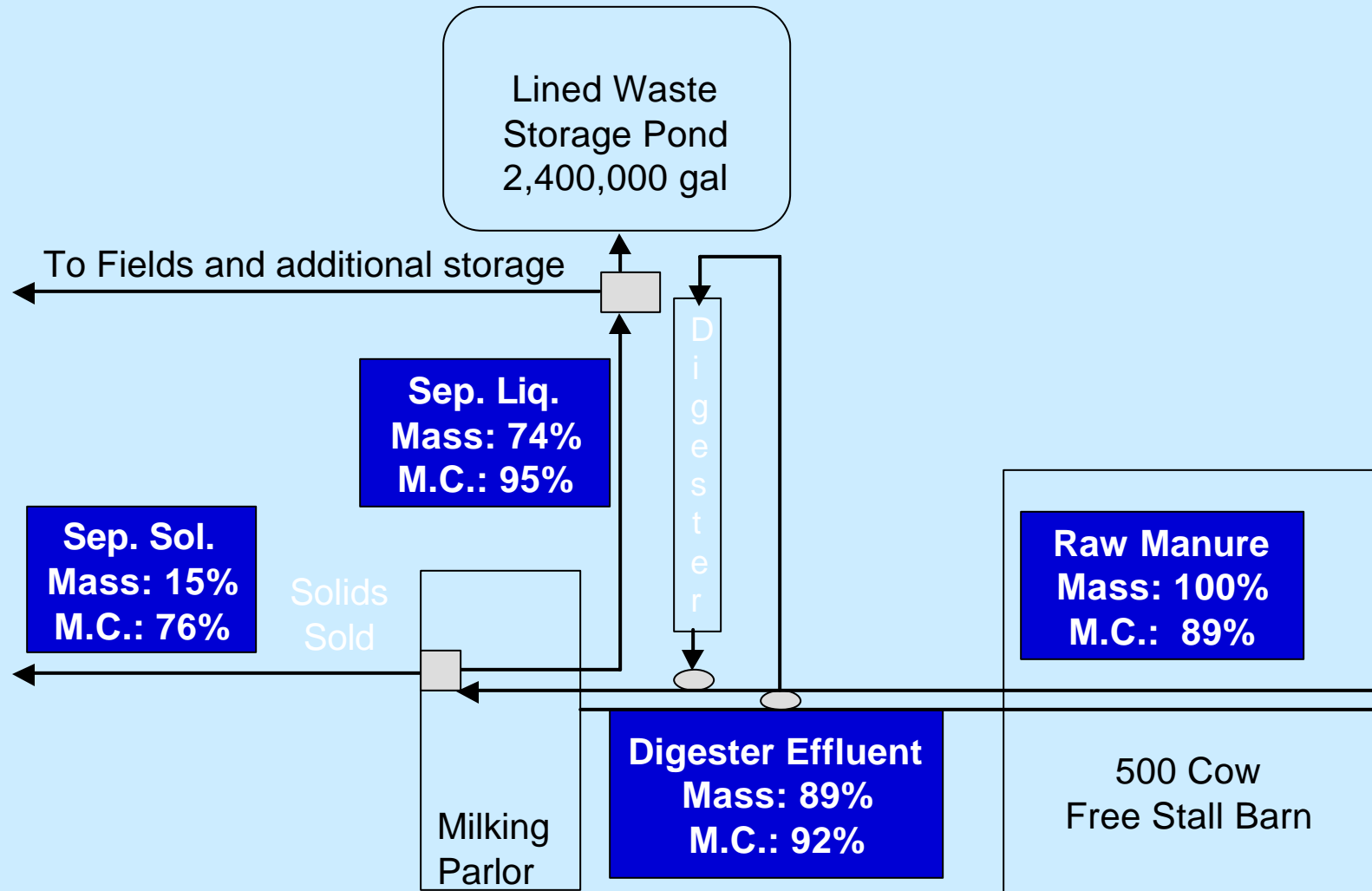
**Less cost, more storage, accessible  
Vandals, collapsable, life**

- ◆ **Hard**

**Long life, Insulated, Pressurized  
Cost, inaccessible, sealing**



# Farm A Anaerobic Digestion



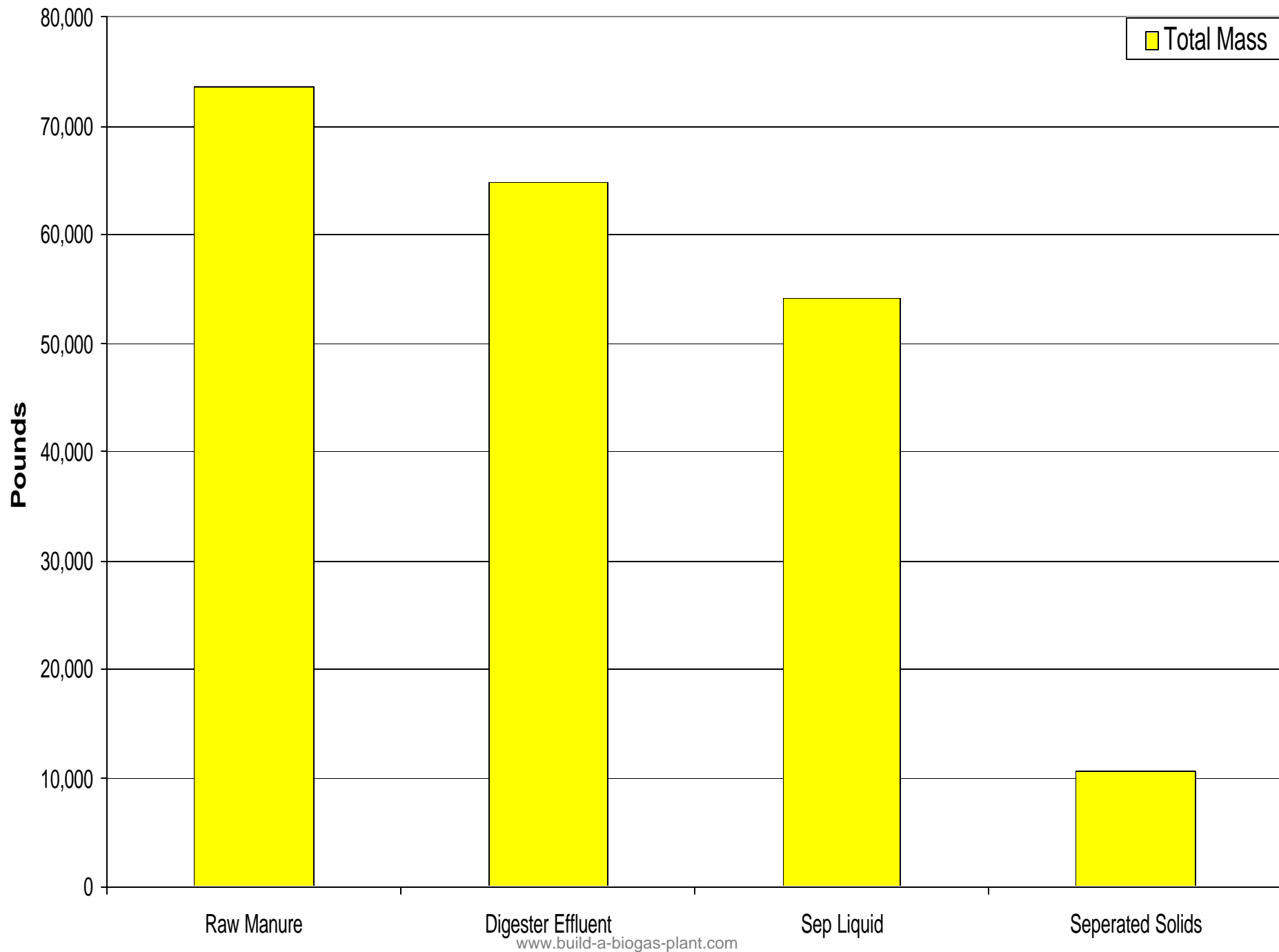


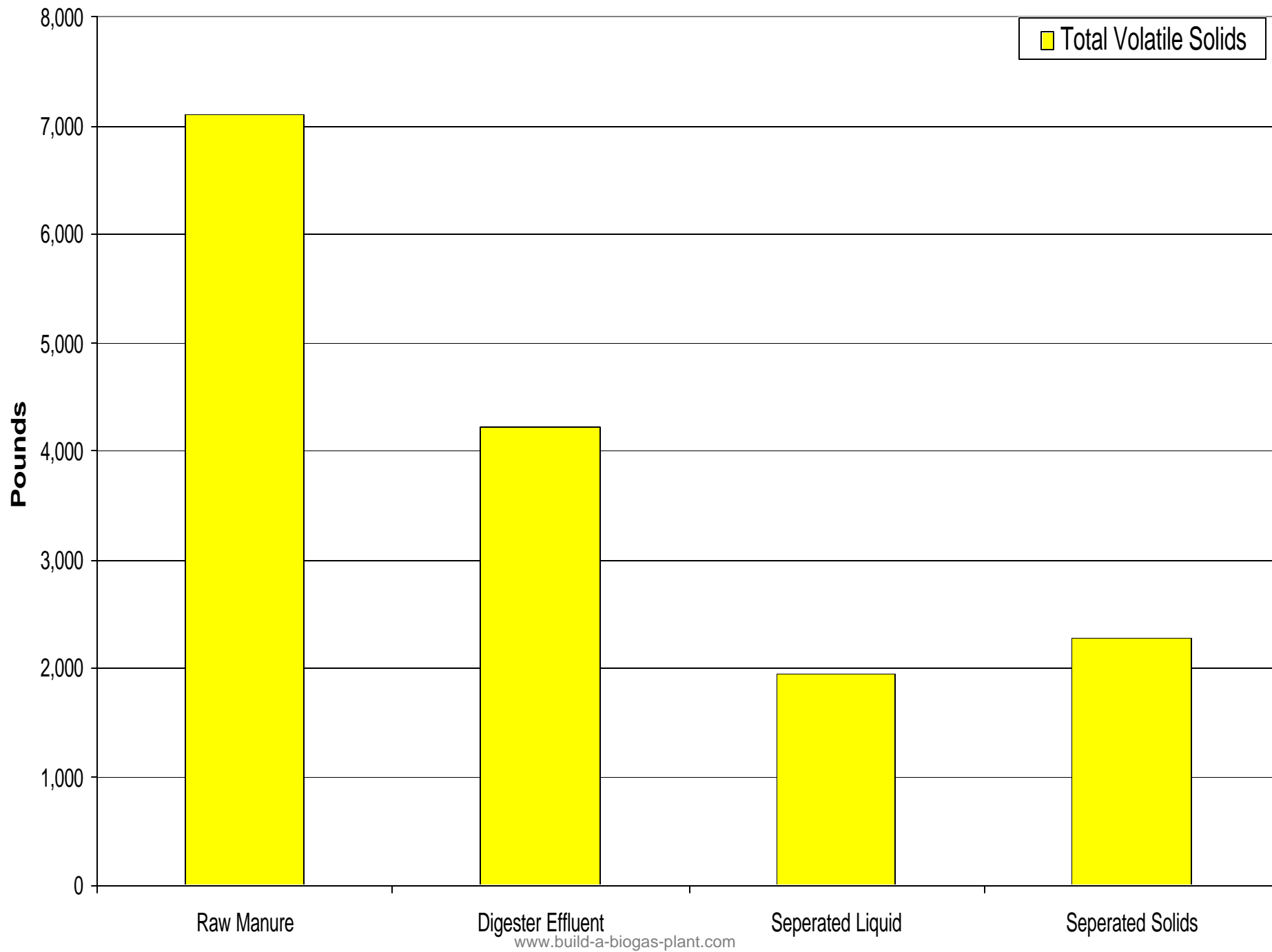




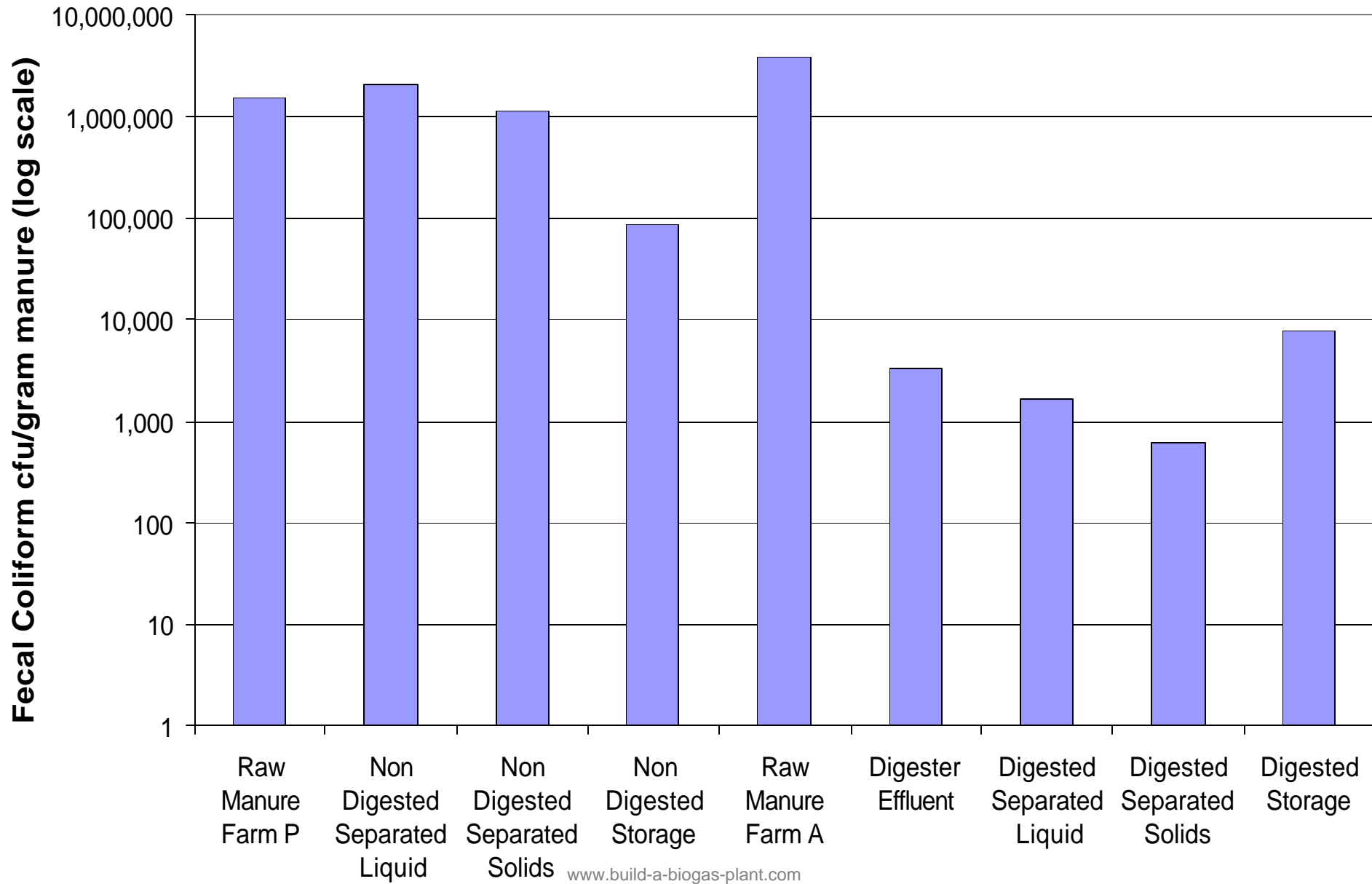








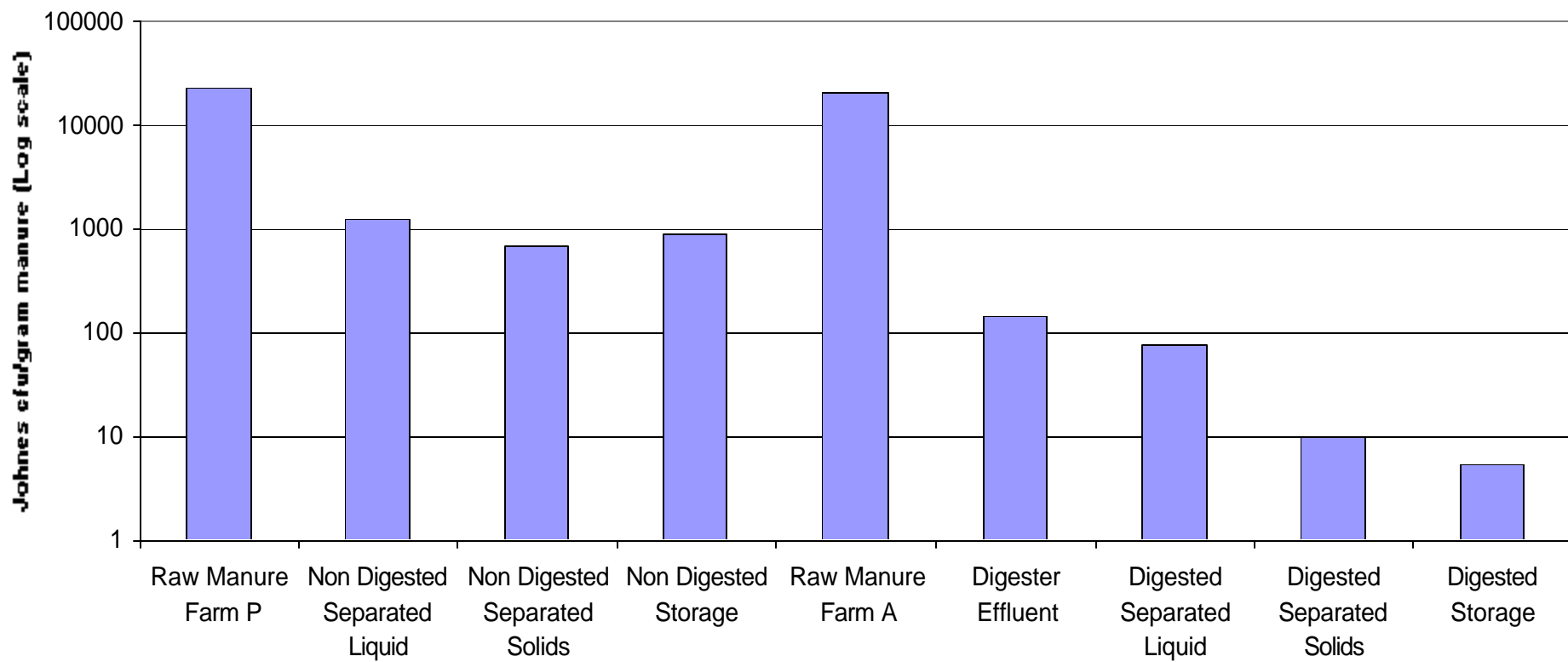
# Fecal Coliform data for digested and non-digested dairy manure





# Johnes

Johnes content in separated digested manure vs separated non-digested manure



Component	\$
<b>Digester</b>	
- manure pump (20 Hp)	9,000
- engineering design	20,000
- concrete digester (incl. floating insulation, gas containing cover, 2 hot water heating circuits)	160,000
<i>subtotal</i>	<b>189,000</b>
<b>Energy conversion</b>	
- engine generator (used) & switching equipment	15,000
- rebuild the engine	2,000
- rebuild the generator	9,000
- plumbing, electric, and mechanical systems	9,000
- run cable to utility hook-up	8,000
- electrical engineer consultant	18,000
<i>subtotal</i>	<b>61,000</b>
<b>Solids separation</b>	
- effluent pump (7.5 Hp) & variable speed drive	3,000
- separation equipment	25,000
- building for separator equipment	25,000
<i>subtotal</i>	<b>53,000</b>
<b>Liquid waste storage lagoon</b>	
- lagoon (excavation, fence, pipe, outlet structure)	18,000
- plastic liner	42,000
<i>subtotal</i>	<b>60,000</b>
<b>TOTAL</b>	<b>363,000</b>

# Contact Information

**P.O. Box 88**

**Homer, NY 13077**

**607-749-6500**

**607-749-5634 (FAX)**

**[ljones@farme.com](mailto:ljones@farme.com)**

**[www.milkproduction.com](http://www.milkproduction.com)**









MANURE DOESN'T SMELL  
IT STINKS  
MAR 9



PUT IT IN  
YOUR OWN  
BACKYARD





# Digesters Influence Barn Design

No Sand

No Flushing





**Limited Water Use is Paramount**

[www.build-a-biogas-plant.com](http://www.build-a-biogas-plant.com)



# Dairy Development International, LLC



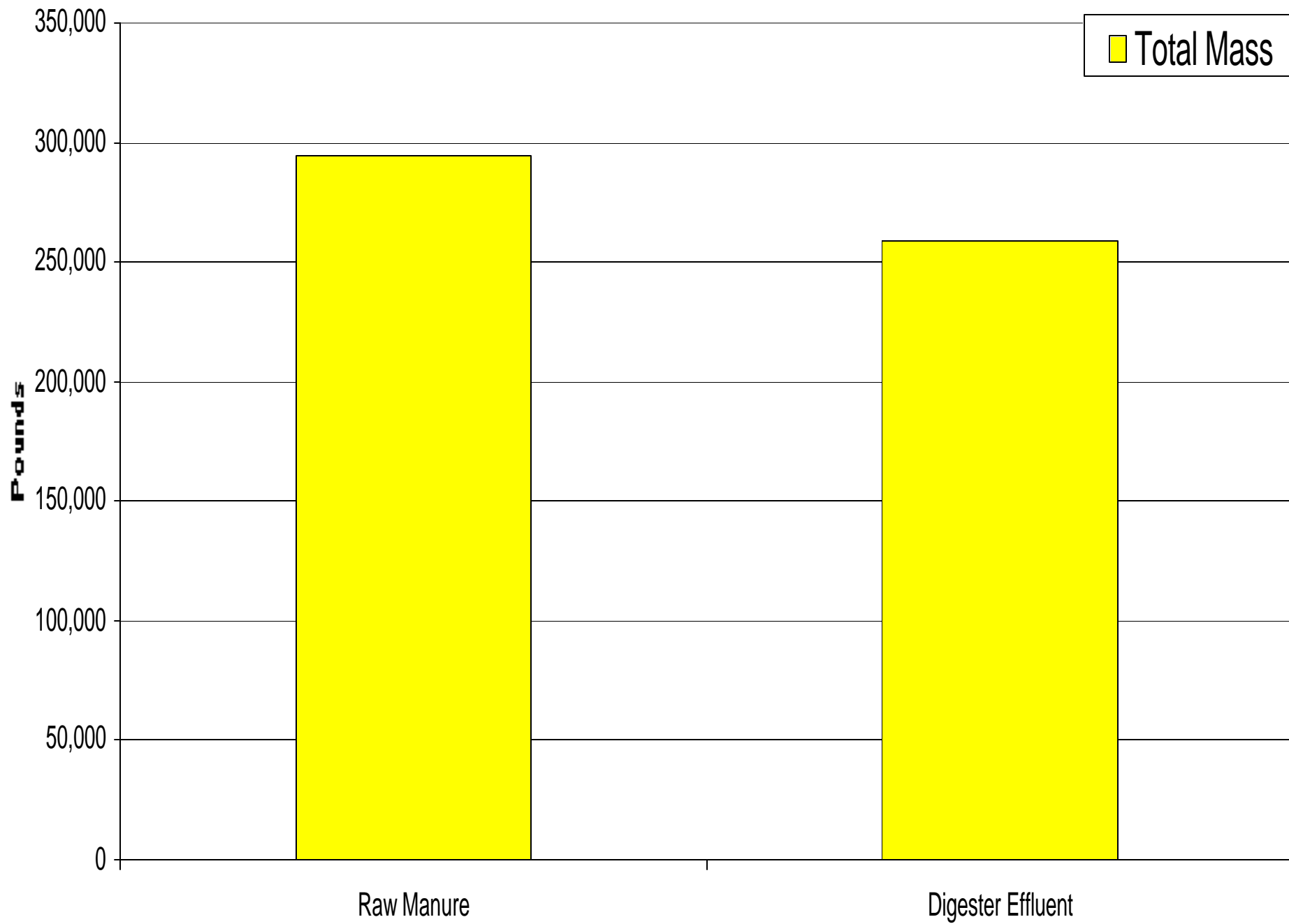
**Lawrence R. Jones, Ph.D.**  
**General/Farm Manager**

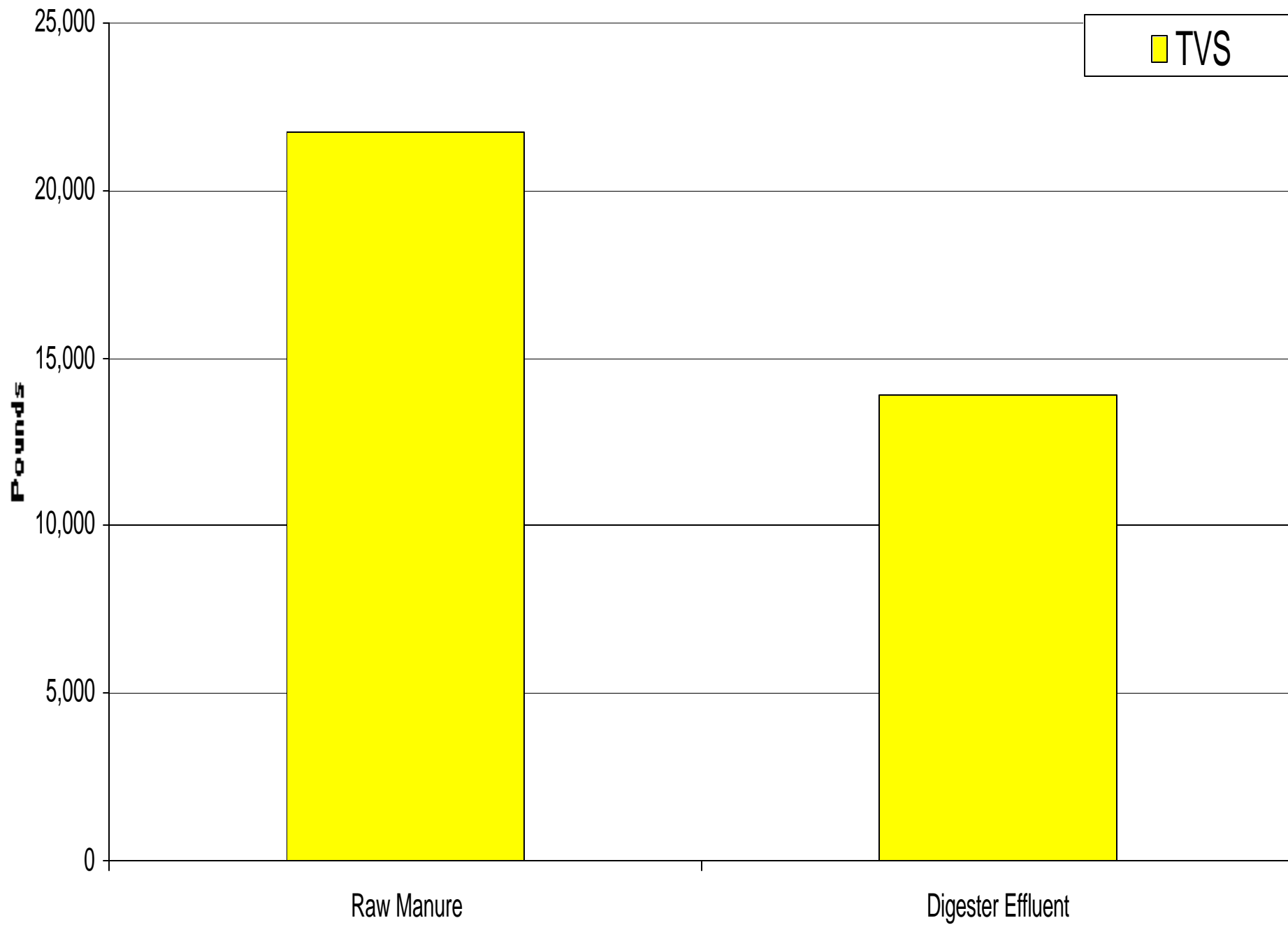
# Dairy Development International

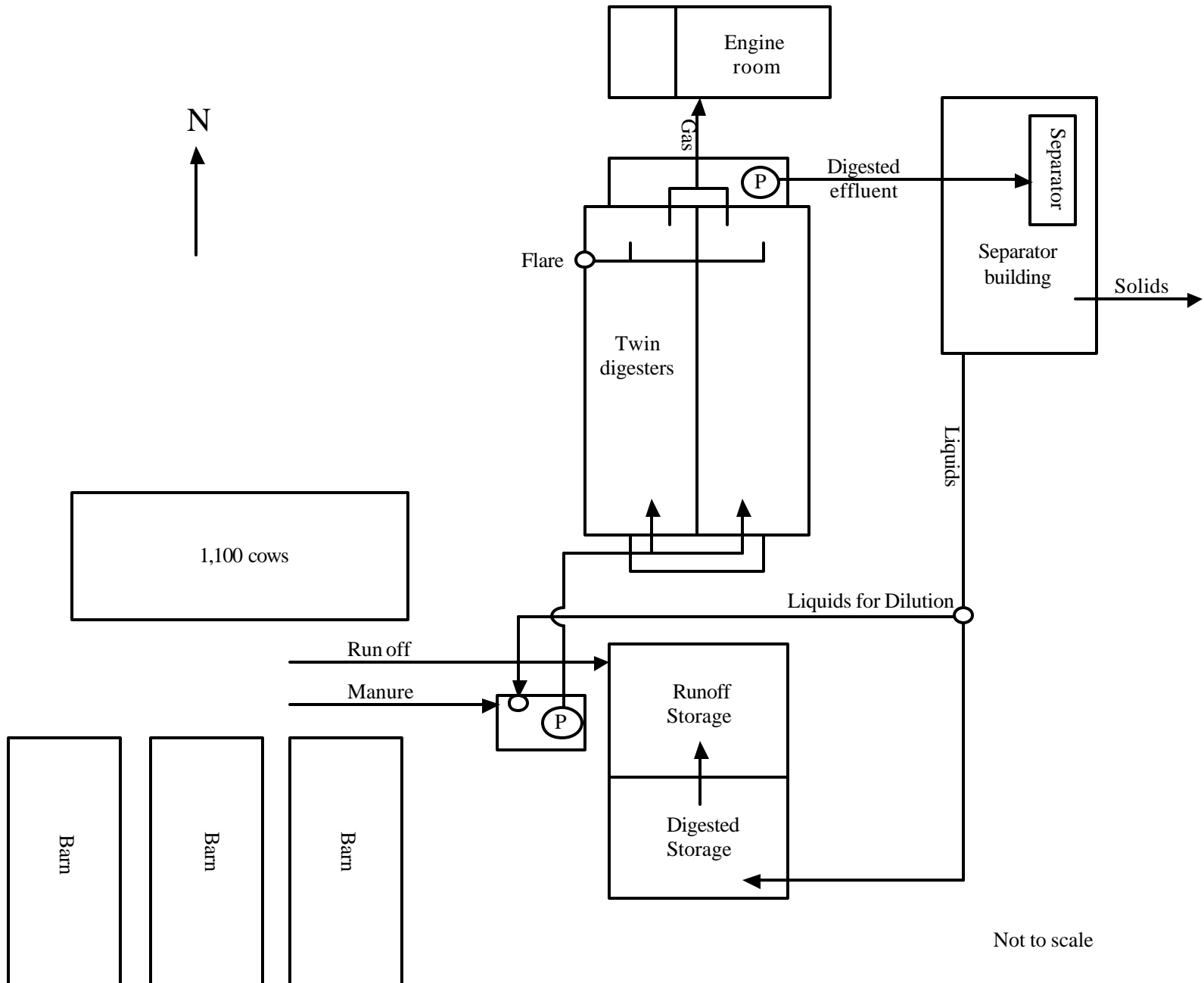
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- ◆ Low electric price
- ◆ Odor control needed
- ◆ Natural gas vs. bio gas microturbines
- ◆ Heated floor
- ◆ Excess liquids
- ◆ Heating system
- ◆ Temperature control
  - Groundwater
  - Thermometers off
  - Vapor lock
- ◆ Micro turbines for natural gas
- ◆ foam

	Items	Costs/Benefits
Capital Costs	Digester	\$350,000
	Electrical and Heating Systems	
	- Microturbines	\$185,000
	- Boiler and Piping	\$50,000
	Subtotal	\$235,000
	Solids and Liquids Separation	
	- Separator	\$46,613
	- Separator Building	\$42,387
	Subtotal	\$89,000
	Liquid Storage	\$315,000
	Others	\$43,800
	Total Capital Cost	<b>\$1,032,800</b>
	Total Annual Capital Cost	<b>\$71,895</b>
Annual Operating Costs	Maintenance, Repairs, Insurance	\$29,619
	Spreading	\$58,000
	Management	\$6,370
	Total Annual Operating Cost	<b>\$93,989</b>
Annual Benefits Including	Electric Savings	\$42,400
	Heat Savings	\$6,000
	Odor Control	\$15,000
	Solids	\$12,000
	Nutrients	\$45,000
	Total Annual Benefits	<b>\$120,400</b>
Annual Cost Per Cow (\$/cow/year)		<b>\$53.51</b>








Not to scale



# Noblehurst Digester Top Being Installed

24' X 4' Precast H.C. Planks



A wide-angle photograph of a large, flat concrete slab under construction. The slab is light gray and shows horizontal construction joints. A long, red, flexible hose or pipe runs diagonally across the left side of the slab. In the background, several workers in hard hats and work clothes are standing near the edge of the slab. To the left, a piece of construction equipment with a crane arm is visible. The background features a line of trees and a cloudy sky.

Later topped with 4" of structural concrete



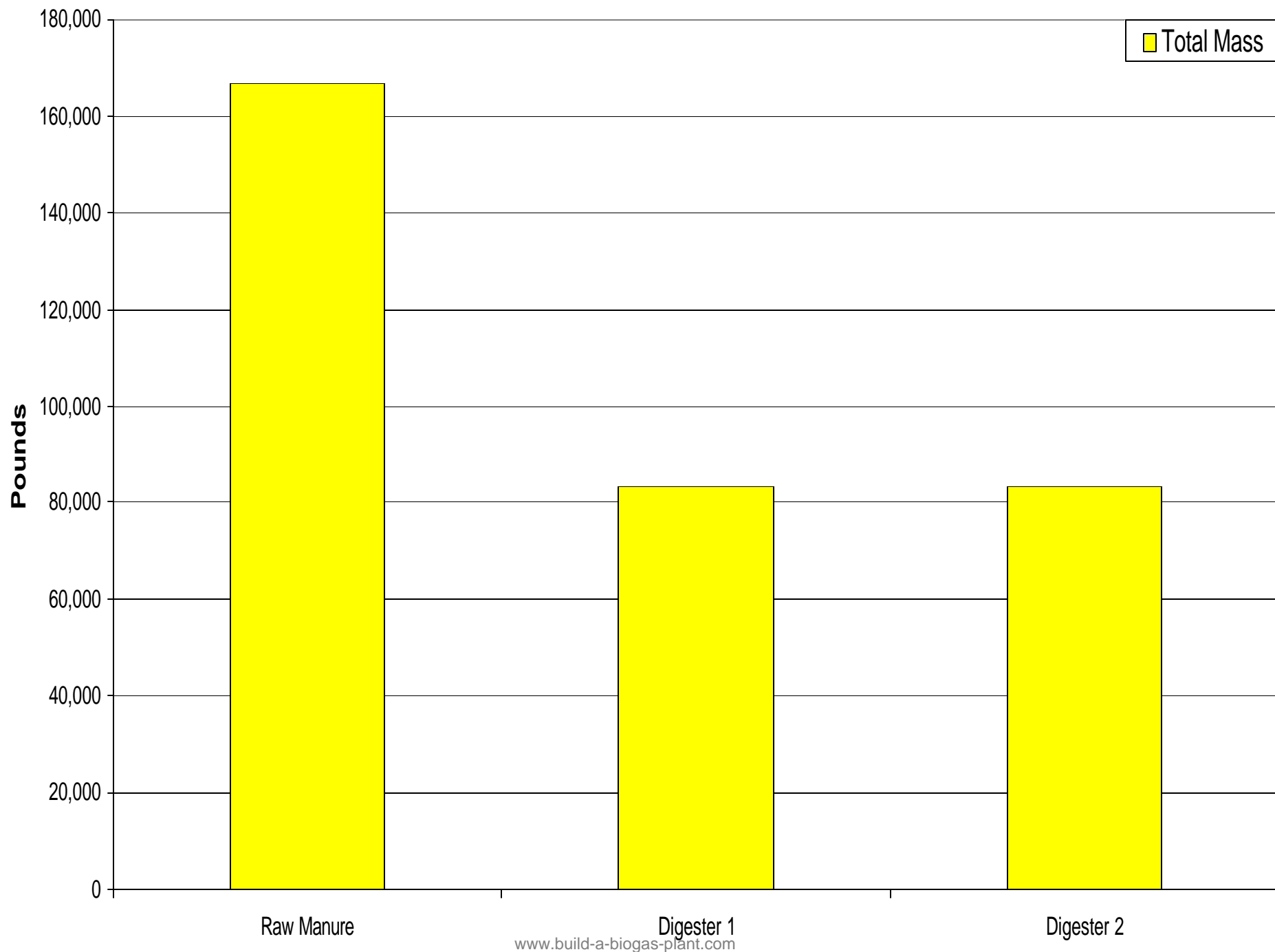
Note heat exchanger and grit-pit.







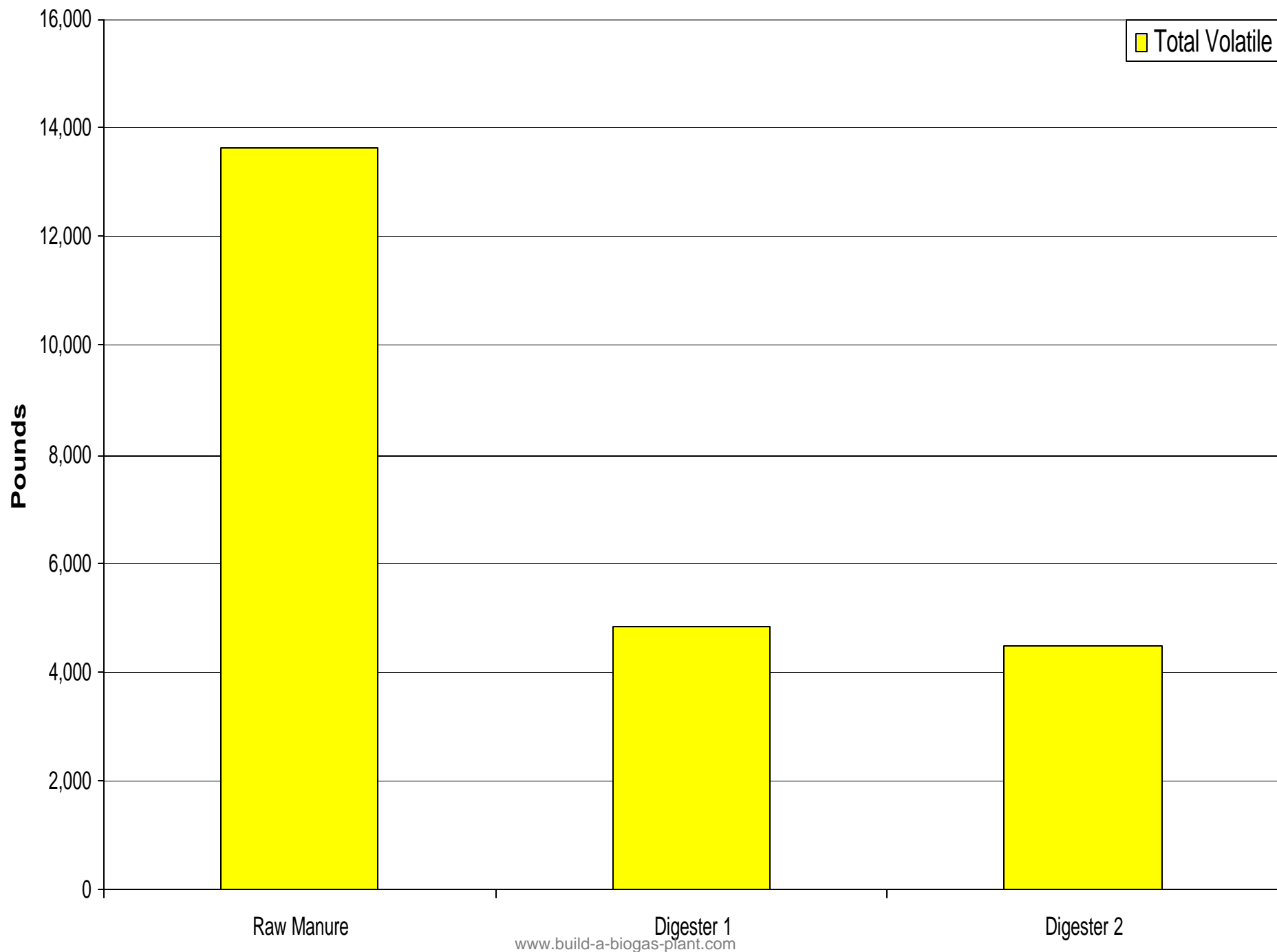


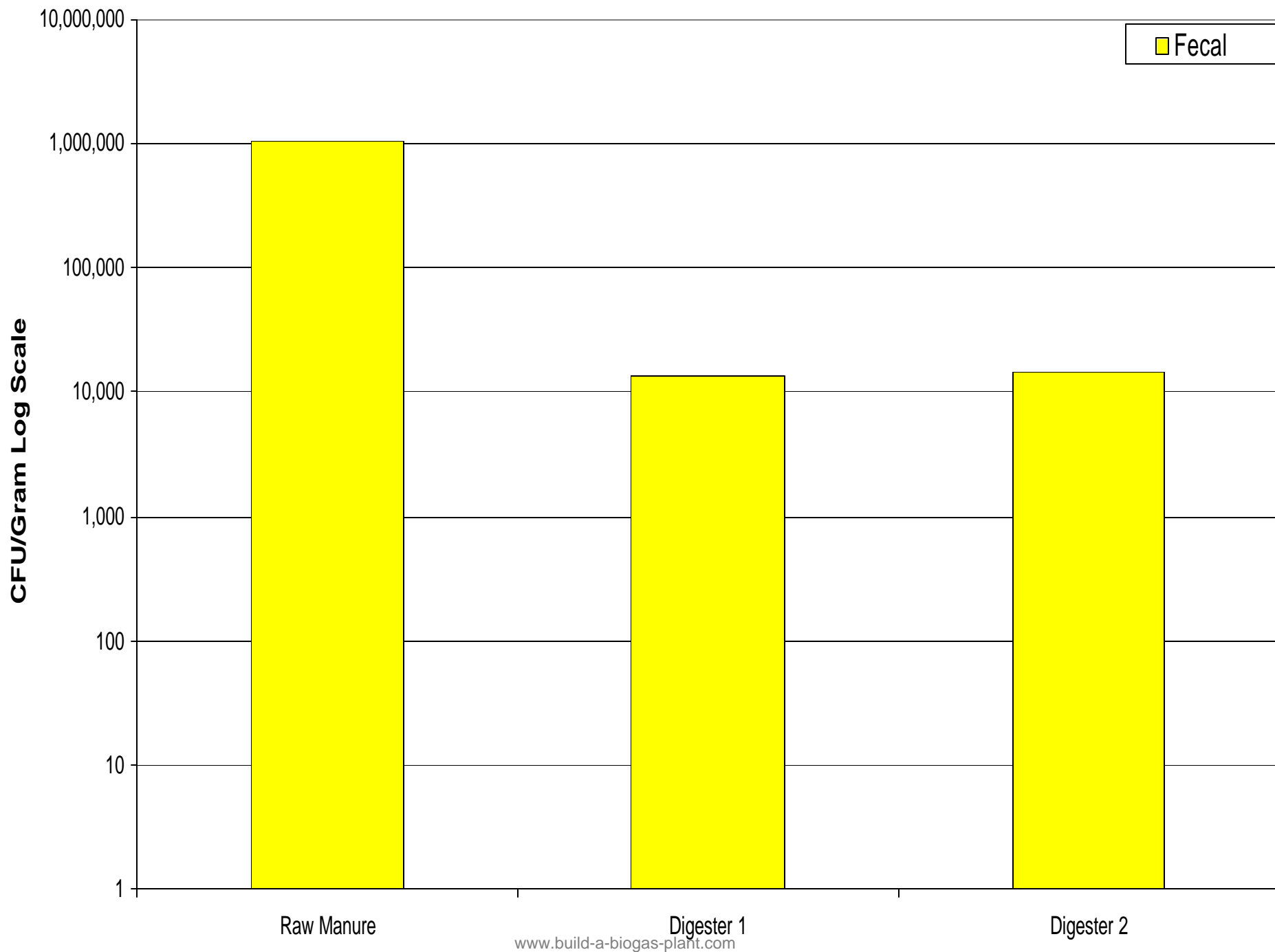




	Items	Cost/Benefit
	Digester	*
Capital Costs	- Digester Construction and Materials	\$250,000
	- Cover for digester	\$60,000
	Engine Generator Set	\$310,000
	- Engine Generator	\$241,000
	- Switching Equipment	\$18,000
	- Engine Building	\$43,500
	Subtotal	\$302,500
	Manure Storage	\$60,000
	Solids and Liquids Separation	
	- Separator	\$26,000
	- Separator Building	\$35,000
	Subtotal	\$61,000
	Others (flare, pumps)	\$14,200
	Total Capital Cost	\$747,700
	Total Capital Cost per cow	\$680
	Total Annual Capital Cost	\$68,522
Annual Operating Costs	Maintenance, Repairs, Labor, Fuel, Insurance, etc.	\$37,675
	Manure Spreading Cost (@0.005/gallon)	\$51,000
	Electricity Savings and Sales (projected)	-\$60,000
Annual Benefits	Heating Fuel Savings (projected)	-\$6,000
	Compost sale (projected sales @ net \$2/cubic yard)	-\$11,680
	Odor Control (@\$9/cow/year)	-\$9,900
	Total Annual Benefits	-\$77,680
Annual Net Cost Per Cow (\$/cow/year)		\$50 **
Note: * - The operating costs (maintenance and repairs) and revenues are projected numbers as of November 1, 2003. An updated analysis will be provided with real data once the system is operated for one year. ** - Manure management without digester and solids separator would cost \$50/cow.		







# Digester Reductions (%)

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Characteristic	AA	DDI	Nobles
Fecal Coliform	99.9	99.3	98.7
Johnes	99.3	98.7	

# Digester Reductions (%)

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Characteristic	AA	DDI	Nobles
Total Solids	27.5	23.5	24.5
Volatile Solids	32.3	23.5	31.7
Volatile Acids	85.7	56.3	85
COD	30.5	8.1	22.5

# Digester Reductions (%)

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Characteristic	AA	DDI	Nobles
NH <sub>3</sub>	-37	-28	-27
Ortho-P	-16.7	-14.4	-44

# Conclusions:

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- ◆ **Alternative Systems depend on farm situation**
- ◆ **Maximize By-Product Use**  
**Maximize Profits**
- ◆ **Integrate with other enterprises**
- ◆ **More Research is Needed**

# A Polyethylene Dome for Biogas Plants

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The majority of domestic biogas plants in the world are fixed dome models, the construction of which requires skilled labour and suitable quality materials. In rural India and many other parts of the world these requirements are often difficult to meet and as a result the quality of build suffers. To combat this problem a gas dome has been manufactured from Polyethylene that gives a 100% gas tightness as well as offering considerable time savings during construction and the ability to retrofit onto failed systems.

## What is a PE Dome?

The majority of domestic biogas plants in the world are fixed dome models with the dome section often needing skilled labour for construction. The quality of building materials plays a key role in the dome's gas tightness as any micro hole/crack will allow the gas to escape. In rural India and many other parts of the world the availability of affordable, suitable quality kiln fired bricks and raw materials is low and as a result build quality can suffer.

In evaluations of Indian biogas plants it has been found that the failure rate due to cracked/leaking domes is between 30-40%.

The PE Dome is a readymade 'off the shelf' plastic dome for the top of a domestic biogas plant and designed for use with the Indian Deenbandhu fixed dome type of two cubic metres capacity. The unit can be manufactured at any factory equipped with both plastic rotomoulding technology and a suitable mould, and then shipped to site for simple installation on the top

of the digester wall. The dome is made from Polyethylene (PE) with the resins blended to give good material strength, thermal properties etc. To date, three biogas digesters have been built with PE Domes and one defunct plant has been rehabilitated. After evaluating the performance of the four plants the Indian Ministry of New and Renewable Energy has approved it's dissemination under the National Programme for Biogas Development.

## The advantages of a PE Dome

The PE Dome offers numerous benefits such as:

Pre-tested	Unlike the concrete or brick version, the PE Dome can be pre-tested for 100% gas tightness
Time saving	It takes a single day for the PE Dome to be installed, compared to a minimum of four days (including inside plastering) for the Deenbandhu biogas plant's dome. There is also no time delay in waiting for brickwork or concrete to cure, saving a further 7 days. The whole construction process can take 6 days, substantially less than the three weeks of a conventional plant [1]
Simple	The PE Dome installation needs no specialised skill, other than those required to build the rest of the simple biogas plant. The technology allows for easy transfer to grass roots level organisations
Retrofit	The PE Dome can be used to renovate existing biogas plants with faulty domes



Figure 1. Digester wall construction (Photo: CV Krishna)



Figure 2. Finished Biogas plant with PE Dome (Photo: CV Krishna)

## Design Features

The dimensions of the PE Dome are essentially the same as for the conventional 2 cubic metre Deenbandhu Model plant:

Gas Volume	2 m <sup>3</sup>
Thickness	5 mm
Collar Width	50 mm
Weight	40 kg
Height	730 mm (Dome apex to centre chord)
Radius of Curvature	1275 mm
Internal Chord Length	2340 mm (identical to Deenbandhu model at the point where the initial slurry level is fixed and so assures 100% gas tightness)
Material properties	Polyethylene (PE) with resins blended to give material properties suitable for i) 100% gas tightness, ii) resisting buckling and impact loads, iii) a suitable heat deflection temperature and iv) a good resistance to UV degradation
Transportation	The shape of the PE Domes allows for approximately 28 units to be transported on a typical Indian truck
Cost	Varies according to local rates, production volumes and transportation costs. The marginally higher cost of the PE Dome will be offset in the long run by no leakage/failure of the dome

## The installation of a PE Dome

The biogas plant is constructed as per the Deenbandhu model; with the digester inlet tank and inner tank being constructed of brick and concrete (Figure 1). To fit the PE Dome the following steps are undertaken:

1. Holes are drilled for the apex gas pipe and collar bolts
2. Bolts are then inserted in to the drilled collar holes and the dome is placed up on bricks (5-7 around the circumference, 75mm high) before alignment with the digester wall. The bolts are placed head down with a piece of steel welded to the head to assure anchorage
3. The gap between the dome and digester wall is then filled with concrete (1:2:4 with medium sized gravel), ensuring that the bolts/steel pieces are firmly embedded. The bolts are then tightened
4. Fresh slurry can be loaded while the concrete is cured
5. The dome is then covered with alternate layers of rammed sand and clay (Figure 2)



Figure 3. Biogas plant during construction (Photo: CV Krishna)

## Notes and References

<sup>1</sup>For a comparative estimation of the conventional Deenbandhu and PE Dome biogas plants see [www.hedon.info/APolyethyleneDomeForBiogasPlants](http://www.hedon.info/APolyethyleneDomeForBiogasPlants)

## Profile of the author

*Mr C.V. Krishna is the Executive Director of the CREAT (Centre for Renewable Energy and Appropriate Technologies) in Bhubaneswar, India. He is both a Mechanical and Civil Engineer and has been working in the field of renewable energy and appropriate technologies for the last 26 years.*

[www.hedon.info/User:CVKrishna](http://www.hedon.info/User:CVKrishna)

[www.hedon.info/Creat](http://www.hedon.info/Creat)



# DEVELOPING SIMPLE PROCEDURES FOR SELECTING, SIZING, SCHEDULING OF MATERIALS AND COSTING OF SMALL BIO – GAS UNITS

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**Abstract** - The end users of biogas systems in most cases are farmers whose technical knowledge of the systems is limited. It is therefore important that material be availed to them which can assist them in making the decision whether to proceed with installation or not without having to hire professionals at a very early stage. The objectives of this study were to develop literature that could be used by laymen to assess the viability of installing biogas units and to size the biogas units with reference to a selected numbers of cows. A number of existing designs were analyzed and the floating drum design adopted based on a weighted-point approach that was developed in this study. Tables relating the number of cows to the size of a floating drum biogas unit and its cost of construction were developed.

**Index Terms** - Biogas, Floating Drum Digester, Methanogenic Bacteria, Slurry.

## NOMENCLATURE

$H$	Digester pit height	$N_s$	Number of stones
$V_d$	Digester pit volume	$N_{cs}$	Number of courses of stone
$t$	Thickness of concrete	$N_T$	Total Number if stones
$T$	Temperature	$D$	Digester pit diameter
$H$	Gas holder height	$d_i$	Diameter of influent chamber
$V_g$	Gas holder volume	$h_i$	Height of influent chamber
$v$	Slurry feed rate	$d_o$	Diameter of effluent chamber
$h_s$	Height of stone	$h_o$	Height of effluent chamber
$l$	Length of stone	$d_x$	Diameter of partition
$R$	Central radius of the digester	$h_x$	Height of partition
$R$	Central radius of the digester	$b$	Width of building stones

## INTRODUCTION

Like many other developing countries, Kenya faces a double energy crisis. Firstly, the country relies on imported petroleum for about 75% of its commercial energy needs and has no identified oil or gas reservoirs which could be used as a substitute for imported petroleum in the near future. The second energy crisis regards the increasing shortage of traditional

energy sources in the form of wood and charcoal<sup>1</sup>. The national energy consumption matrix is as follows<sup>2</sup>:

- 68% wood fuel and other biomass
- 22% petroleum
- 9% electricity
- 1% other

Use of wood and charcoal as a source of energy for the last fifteen years has resulted to a reduction of the country's forest cover by an average of 12,600 hectares of forest per year. This amounts to an average annual deforestation rate of 0.34%. In total, between 1990 and 2005, Kenya lost 5.0% of its forest cover, or around 186, 000 hectares. The forest cover in the country currently stands at 6.2% or 522, 000 hectares, which is less than the 10% minimum forest cover that is stipulated by the government<sup>3</sup>. Clearly, therefore, wood and charcoal can no longer be treated as a desirable energy source.

Therefore, there is an urgent need to seek alternative renewable energy sources such as biogas. The energy requirements of the average Kenyan family, particularly in the rural families that comprise about 70% of the population, are in the form of cooking and water heating fuel<sup>4</sup>. This is easily met by small scale biogas plants which can in addition be used to provide domestic lighting. It is also possible to provide large scale heating and cooking solutions within the urban setting using larger biogas plants.

About 10% of the total grid power comes from diesel power plants while 90% comes from hydro-power. Domestic consumption accounts for about 68.8% of the total power consumed in the country<sup>5</sup>. Also important to note is the fact that the grid power supply today currently reaches only about 15% of the Kenyan population<sup>6</sup>, where power needs are mainly for water heating and cooking<sup>7</sup>. Currently over 80% of the country's hydro-power potential has been exploited. This implies that with growing demand for power, both industrial and domestic, the country's reliance on fossil fuel power or on imported power will grow.

There is a clear and urgent need to develop alternative sources of power which not only release existing power for use on industries but also allow easy, flexible and on the spot renewable power solutions to reach the majority of the nation's population. Biogas technology can therefore play a vital role in reducing the country's reliance on imported petroleum fuels as well as facilitating easy, cheap and flexible access to energy by the Kenyan population. Biogas technology is now widely used all over the world, with over 17 million family-sized low-technology biogas digester installed in China by the year 2005 and over 3500 farm based biogas digesters in Europe and North America, over 2000 high-rate biogas digesters installed in the world today<sup>8</sup>. In Europe alone a total of 50TWh of biogas was produced in the year 2004 and is expected to grow to 210TWh by the year 2020<sup>9</sup>.

Biogas is produced from the breakdown of complex molecules of proteins, carbohydrates and fats found in feedstock, by microscopic organisms referred to as acidogenic and methanogenic bacteria, in a process that produces energy and chemicals required by the bacteria to grow, with biogas as a by-product<sup>10</sup>. The bacteria used in a biogas digester are similar to those found in the gut of ruminant animals such as cattle. The bacteria are adapted to conditions similar to those found in a cow that is, temperatures near 37°C, and the exclusion of air as well as light. The bacteria are therefore anaerobic. These conditions can be created by digging a hole into the ground and lining it with bricks and/or cement, to prevent the slurry mixture from leaking into the ground. A suitable cover is then provided to exclude light and air, and to collect the gas produced. In tropical and subtropical regions, the temperatures are usually conducive for biogas production during most of the year, while in cooler climates, some methods of insulating and heating the slurry must be provided<sup>11</sup>.

The objectives of this work are:

- To provide literature that can easily be used by laymen to assess the viability of installing biogas units.
- To analyze and compare existing designs of biogas units and develop a method of identifying the most appropriate one.
- To completely size the selected biogas plant with reference to the number of cows.
- To develop a bill of quantities for the selected biogas unit.

### THE PRODUCTION OF BIOGAS

Several bacteria are present in animal waste, compost and other feedstock each serving a specific function. The facultative bacteria in a digester break down complex feedstock molecules using oxygen in the feedstock and water through a process known as hydrolysis<sup>12</sup>. These bacteria function both in presence and absence of oxygen and require temperatures of about 37°C. This is followed by the formation of volatile fatty acids, carbon dioxide and hydrogen by the acidogenic bacteria in a process referred to as acidogenesis. These bacteria function only in the absence of oxygen. If there is any air/oxygen present during this process, the digestion of the feedstock stops and the digester gives off a distinctive smell of the acids present<sup>13</sup>. Finally the methanogenic bacteria break down the fatty acids in the feedstock into simpler molecules namely: carbon dioxide, water and methane in a process referred to as the methanogenesis<sup>14</sup>. These bacteria also function only in absence of oxygen. The composition of biogas depends heavily on the feedstock but mainly consists of 50- 70% methane, 30-40% carbon dioxide, 5-10% Hydrogen, 1-2% nitrogen, 0.3% water vapor and trace amounts hydrogen sulfide<sup>15 16 17</sup>. Figure 1 below shows the stages in biogas production, discussed above.

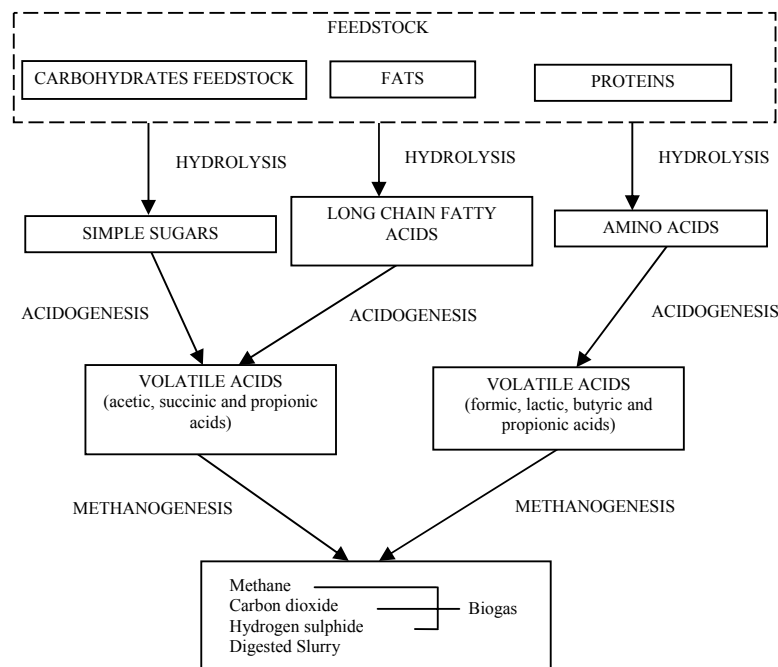


FIGURE 1  
STAGES IN THE PRODUCTION OF BIOGAS<sup>18</sup>

The main controlling factors in the production of biogas are the loading rate, retention time and temperature of the biogas digester<sup>19</sup>. The loading rate will vary with digester feedstock and types of digesters but is normally given in terms of the weight of the total volatile solids (TVS) per day per unit volume of the digester or the weight of TVS added per day per weight of TVS already in the digester<sup>20</sup>. Volatile solids define the amount of organic matter in a material or the organic component that is burnt off when a material is heated to 538 °C<sup>21 22</sup>. The higher the volatile solid content in a substrate, the higher the amount of biogas produced<sup>23</sup>. Over-loading leads to increased acidity of the digester and the attendant reduction in the production of methane, while under-loading gives rise to low gas production<sup>24</sup>. The retention time is a measure of the amount of time a substrate remains in the digester before being discharged and is normally equal to the volume of the digester divided by the daily inputs of substrate<sup>25 26</sup>. It is important to optimize the retention time in order to ensure, proper digestion of the slurry and extraction of as much biogas as possible before discharge of the slurry. The cellulose, hemicellulose and lignin components in fibre are difficult to bio-degrade, which contributes to a reduction in the production and content of methane in biogas from the high fibre content cow manure substrate. It is necessary therefore to introduce phase separation processes that separate the fibre from the rest of the substrate so that the fibre may be digested for longer periods apart from the rest of the substrate. The efficiency of phase separation processes however are dependent on a number of factors including, the type of substrate, organic loading rate (OLR), hydraulic retention time (HRT) and the configuration of digester reactors used<sup>27</sup>.

Biogas is one of the three most widely used fuel gases together with natural gas and Liquid petroleum gas (LPG)<sup>28</sup>. LPG is comprised of volatile fractions from petroleum refining principally; butane, propane, propylene and butylenes<sup>29</sup>. The characteristics of biogas lie between those of town gas and natural gas, the former which is obtained by cracking of cokes<sup>30</sup>. Methane, the flammable component of biogas, produces about a half of the carbon dioxide produced by other fuels for the same fuel value when burnt and does not emit carbon monoxide thus making it safe for domestic use. It has a comparatively slow burning flame velocity of 430mm s<sup>-1</sup>, which gives the fuel a high octane number thus making it good for use in internal combustion engines<sup>31</sup>. Biogas is mainly produced through the anaerobic digestion of animal and plant organic waste, primarily in simple and low technology systems. Bio-digestion is not solely attractive for the methane gas produced but also as it provides a means of converting organic waste that would otherwise be an environmental hazard into readily usable compost, reduction of pathogens in the organic waste, odor control, mineralization of organic nitrogen and weed seed destruction<sup>32 33 34</sup>.

The main by-products of bio-methane production, carbon dioxide and hydrogen sulfide, increase the storage and handling requirements of biogas, reduce the gas value of the biogas produced, in addition to which hydrogen sulfide is pungent. It is therefore advisable to remove these gases from the biogas before storage or use<sup>35</sup>. Efficient storage of methane, like natural gas, requires that it be compressed into an easily stored and transporter liquid. Methane unlike butane however, is not easily liquefied by pressure at normal temperatures and is only easily amendable to pressure-liquefaction at cryogenic temperatures<sup>36</sup>. Storage in Structure I (sI), Structure II (sII) or Structure H (sH) hydrates reduces the low temperature requirements for the liquefaction of methane and natural gas<sup>37</sup>. The formation pressure requirements in the storage of methane can be reduced by filling the large cages in sI and sII hydrates and stabilizing the largest cage in sH hydrates<sup>38</sup>. Experimental volume reductions of methane stored in sI, sII and sH hydrates of 56, 154 and 201, respectively, have been recorded, which compare well with the known Liquid Natural Gas (LNG) volume reduction of 600 at -162 °C<sup>39</sup>. The main constituent of natural gas, like biogas, is methane, with 5 - 16%

ethane and up to 8% hydrogen<sup>40</sup>. As the present study is concerned with simple ways of availing biogas technology to farmers in the country, it is expected that excess methane gas that cannot be used immediately would be stored in side collection tanks as is without being pressurized or without result to special storage treatment such as those described above.

### UNDESIRABLE GASES IN BIOGAS

The need to remove Carbon Dioxide, Hydrogen Sulphide and water vapour from biogas is done for various reasons including, use requirements, need to increase the heat content and for purposes of standardizing the gas. Table I below shows some use requirements for various gaseous components of biogas<sup>41 42</sup>.

TABLE I  
USE DEPENDENT NEED OF REMOVING VARIOUS GASEOUS COMPONENTS IN BIOGAS<sup>43 44</sup>

Use	H <sub>2</sub> S	CO <sub>2</sub>	H <sub>2</sub> O
Gas Heater (Boiler)	< 1000 ppm	no	no
Kitchen Stove	yes	no	no
Stationary Gas Engine	< 1000 ppm	no	No condensation
Vehicle Fuel	yes	Recommended	yes
Natural Gas Grid	yes	no	yes

Water vapor is present in biogas in proportions varying from 5% to saturation<sup>45</sup> and combines with hydrogen sulfide and carbon dioxide to form the very reactive sulfuric acid and the mild carbonic acid<sup>46</sup>. Hydrogen sulfide concentrations of less than 1% coupled with carbon dioxide concentrations above 2% are particularly corrosive<sup>47</sup>. Whilst increasing the flammability or explosion limits of biogas, water vapors causes the lowering of flame temperature, heat values and the stoichiometric or air-fuel ratios of biogas<sup>48</sup>. Removal of water vapor from biogas or dehydration of biogas therefore leads to a reduction in the possibility of corrosion of metallic components, an increase in the heat value of biogas by as much as 10%, as well as increases in both the flame temperature and air-fuel ratio of biogas<sup>49</sup>. Various dehydration methods exist including the use of tri-ethylene glycol (TEG) systems, silica gel and aluminium oxide, air cooling, heating, refrigerant cooling, molecular sieves, calcium chloride<sup>50 51 52</sup>. Water condenses out of the generated biogas due to natural cooling as the gas travels from the generation plant to the consumer. In order to ensure that this condensed water does not clog up the gas line, gas supply lines are designed with a 1% slope and have condensate traps and condensate drains installed along their length, which are in turn linked to a drainage tank. The condensate traps are designed with increased cross-sectional areas and baffle plates to in order to accelerate condensation<sup>53</sup>.

Incombustible carbon dioxide reduces the calorific value of biogas, increases its handling requirements and reduces its flame velocity<sup>54 55</sup>. The content of Carbon Dioxide, which varies as a function of conditions prevailing in a digester and the digester feed composition, introduces constraints on the efficient operation of appliances, such as gas burners<sup>56</sup>. Typical symptoms of carbon dioxide overexposure include dizziness, restlessness, headaches and sweating<sup>57</sup>. Exposure to carbon dioxide in concentrations above the Threshold Limit Value (TLV) time weighted average concentration (TWA) of 5,000 parts per million (ppm) for carbon dioxide that a person may be exposed to continuously for an 8-hour working day, 40-hours working week, and the Threshold Limit Value (TLV) Short Term Exposure Limit (STEL) of 30,000 ppm for carbon dioxide that a person may be exposed to continuously for not more than 15 minutes, even given satisfaction of the 8- hour working day, both cause asphyxiation<sup>58</sup>. It is necessary where possible therefore to remove the gas

from biogas before storage or use. This however, is only economically viable in cases of commercial production of biogas, due to the related high cost of carbon dioxide removal, as the low biogas production pressure lying between 0.5 - 2.0 Kpa and the normal operating pressures of appliances of about 0.6 – 0.7 Kpa, requires the use of pumping equipment to circulate the biogas through carbon dioxide scrubbing installations<sup>59</sup>.

Hydrogen sulphide levels in biogas range between 100 – 4000 ppm, with rare cases of 2 ppm and 8000 ppm being recorded now and then<sup>60 61</sup>. Hydrogen sulphide not only has an undesirable pungent, “rotten egg” odor in concentrations as low as 50 parts per billion by volume (PPBV) and is toxic in proportions above 10 ppm, but is also corrosive and will therefore reduce the life of metallic (copper, iron, steel and lead) pipes, gas holders and other metallic accessories if not removed from biogas<sup>62 63 64 65 66</sup>. The corrosive effects Hydrogen sulfide overexposure causes eye irritation and convulsions and is considered a poison in concentrations above 10 and 15 ppm TVL-TWA and TVL-STEL, respectively<sup>67</sup>. Continuous exposure to concentrations of hydrogen sulfide of between 10 – 50 ppm give rise to nausea, dizziness, headaches and irritation of mucous membranes, while exposure to concentrations of between 200 – 300 ppm will lead to respiratory arrest, comma or unconsciousness<sup>68</sup>. Exposure to concentrations of hydrogen sulfide in excess of 700 ppm, for periods longer than 30 minutes, is likely to result into pulmonary paralysis, sudden collapse and death<sup>69</sup>. When oxidized, hydrogen sulfide forms the sulfur oxides SO<sub>2</sub> and SO<sub>3</sub> both of which are even more poisonous than hydrogen sulfide. The two oxides form the very highly corrosive sulfuric acid, H<sub>2</sub>SO<sub>4</sub>, and sulfurous acid, H<sub>2</sub>SO<sub>3</sub>, respectively, when exposed to water and occur in the environment as acid rain<sup>70 71</sup>.

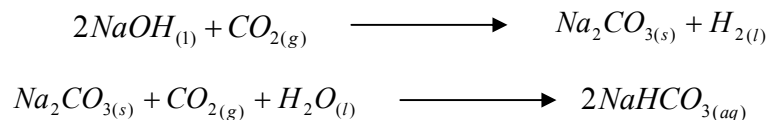
A number of processes exist for upgrading of biogas by removal of the undesirable constituents of biogas, hydrogen sulfide and carbon dioxide, including, physical and chemical scrubbing absorption using water or polyethylene glycol and aqueous solvents, respectively<sup>72 73 74 75 76 77 78</sup>, selective gas permeation through polymeric hollow-fibre membranes or microporous hydrophobic membranes for the high pressure gas separation and low pressure gas liquid absorption processes, respectively, biological desulphurization methods based on aerobic chemotrophic and anaerobic light requiring phototrophic bacteria, combined chemical and biological desulphurization methods, combined water and biological desulphurization methods, insitu methane enrichment, as well as adsorption through granular, large surface area materials such as zeolites, alumina, silica, and activated carbon or silicate molecular sieves<sup>79 80 81 82 83 84 85</sup>. The first three methods are poor in separating the two gases removed from methane, while the last method is very efficient and finds wide use in commercial gas upgrading processes. Other methods of separation do exist such as, cryogenic and chemical separation methods, which however are too expensive to be applied to biogas<sup>86 87</sup>. Only a few of these methods will be discussed in details and the interested reader is advised to refer to the reference material given here for details on the other methods.

### *Removal of Carbon Dioxide*

Carbon Dioxide may be removed from biogas by being diffused through water in the ratio of 91.6 L of water to 200 L of biogas at a pressure of 1 atmosphere (atm) i.e.  $1.015 \times 10^5 \text{ N/m}^2$  in a counter flow process such as is shown in Figure 2<sup>88 89</sup>. The counter flow water spray (or lime water) column method is a variation of this process, in which water with absorbed carbon dioxide from the first column is then sprayed into a desorption column, thus releasing the absorbed carbon dioxide, which is then vented into the atmosphere and the recovered water re-circulated back into the original column<sup>90 91 92 93</sup>. De-pressurisation or air stripping, of the used water from the first column also achieves the same result<sup>94 95 96</sup>. Variations of carbon dioxide absorption scrubbing using water include, multiple or single pressured water /

biogas counter flow processes, multiple or pressured water / biogas packed bed counter flow systems, each with different levels of efficiency depending on the composition of the raw biogas, water and biogas flow rates and water purity<sup>97</sup>.

Carbon Dioxide may also be removed using aqueous solutions of sodium, potassium and calcium hydroxide, in reactions such as<sup>98 99 100</sup>:

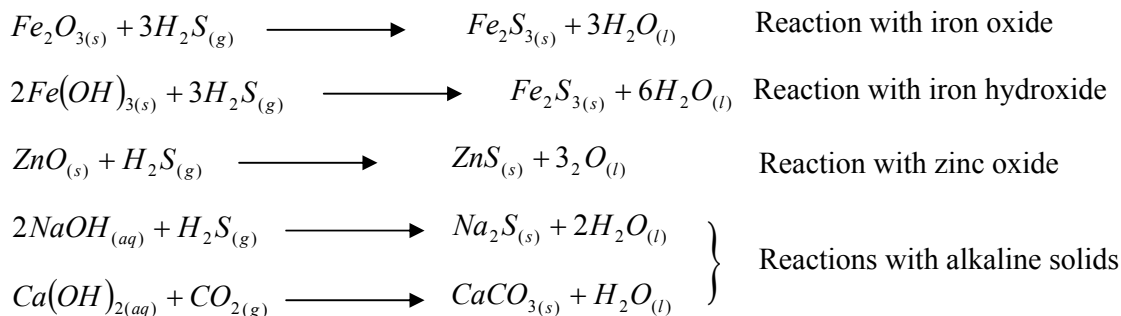


The hydrogen carbonate obtained, dissociates at temperatures above 150°C to give sodium carbonate, which can be used in the manufacture of soap powder or as a chemical reagent in laboratories<sup>101</sup>. Carbon dioxide may also be removed using aqueous solutions of amines such as mono-, di- or tri-ethanolamine. Used mono-, di- or tri-ethanolamine are easily recovered by boiling for about 5 minutes<sup>102</sup>.

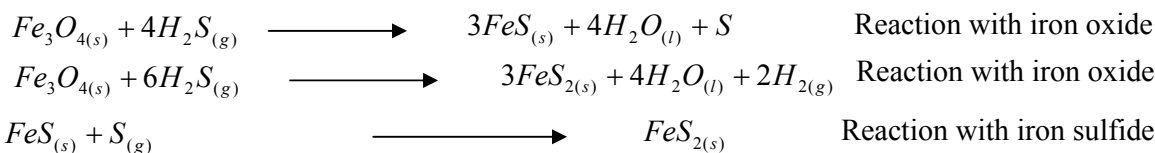
### Removal of Hydrogen Sulfide

Hydrogen sulfide is corrosive, poisonous and its combustion by product, sulfur dioxide, is environmentally hazardous<sup>103</sup>. The corrosiveness of hydrogen sulfide increases with increasing concentration, temperature and pressure, and is enhanced by the presence of water<sup>104</sup>. The methods used to remove hydrogen sulfide from gas streams fall into the three broad categories of dry oxidation, liquid phase oxidation and formation suppression processes<sup>105 106</sup>. Dry oxidation is either done by the direct introduction of 2-6% air into the gas stream or by dry adsorption also referred to as chemisorption processes, while liquid phase oxidation may be done either through liquid absorption processes or through the use of oxidizing liquid solutions<sup>107 108 109 110</sup>. It is important in all processes where biogas gas is mixed with air to ensure that the lower and upper explosive methane concentrations of 5 – 15% by volume in air<sup>111</sup>, also given as 6 – 12%<sup>112 113</sup> and 5 – 20%<sup>114</sup>, are never reached, otherwise the gas will self ignite without requiring any flame or spark on attainment of its auto-ignition temperature of 343 °C<sup>115</sup>.

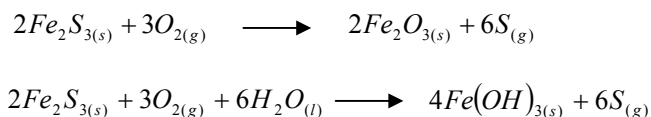
In dry oxidation processes, the sulfur in hydrogen sulfide is removed from gas through the separate reactions shown below, with iron oxide, iron hydroxide, zinc oxide or alkaline solid particles of different densities and varying degrees of porosity<sup>116 117 118 119</sup>. Iron oxide for this purpose is normally in the form of iron fillings, iron pellets, iron sponge or steel wool<sup>120 121 122 123 124</sup>. The sulfur removal capacities of iron oxide range from 0.20 – 0.716 kg of hydrogen sulfide for every one kg of iron oxide<sup>125 126</sup>, also given as 3.7 kg of sulfur/bushel (0.0352m<sup>3</sup> of iron oxide)<sup>127</sup>. Mixing of the iron fillings with wood shavings or sawdust increases the contact area to volume ratio and therefore enhances scrubbing<sup>128 129 130</sup>. The sulfur removal capacities of zinc oxide range from 0.3 – 0.4 kg of hydrogen sulfide per kg of zinc oxide<sup>131</sup>.



Apart from the reaction of iron oxide shown above, several other reactions do occur during scrubbing of biogas with iron oxide, including<sup>132</sup>:



Iron oxide and hydroxide are regenerated at rates that are lower than the rates of scrubbing by forcing air through the iron sulfide formed during scrubbing, in the reactions<sup>133 134 135</sup>:



The regenerated iron oxide and hydroxides are re-used, while the sulfur gas produced is normally released into the atmosphere or may be used as a reagent in laboratories<sup>136</sup>. The iron fillings or steel wool in a sulfur scrubbing column are normally changed once 75% of the scrubbing iron has been oxidized<sup>137 138</sup> giving between 3 – 5 cycles of use and regeneration<sup>139</sup>. Zinc oxide on the other hand cannot be regenerated and therefore comes with addition disposal costs<sup>140</sup>.

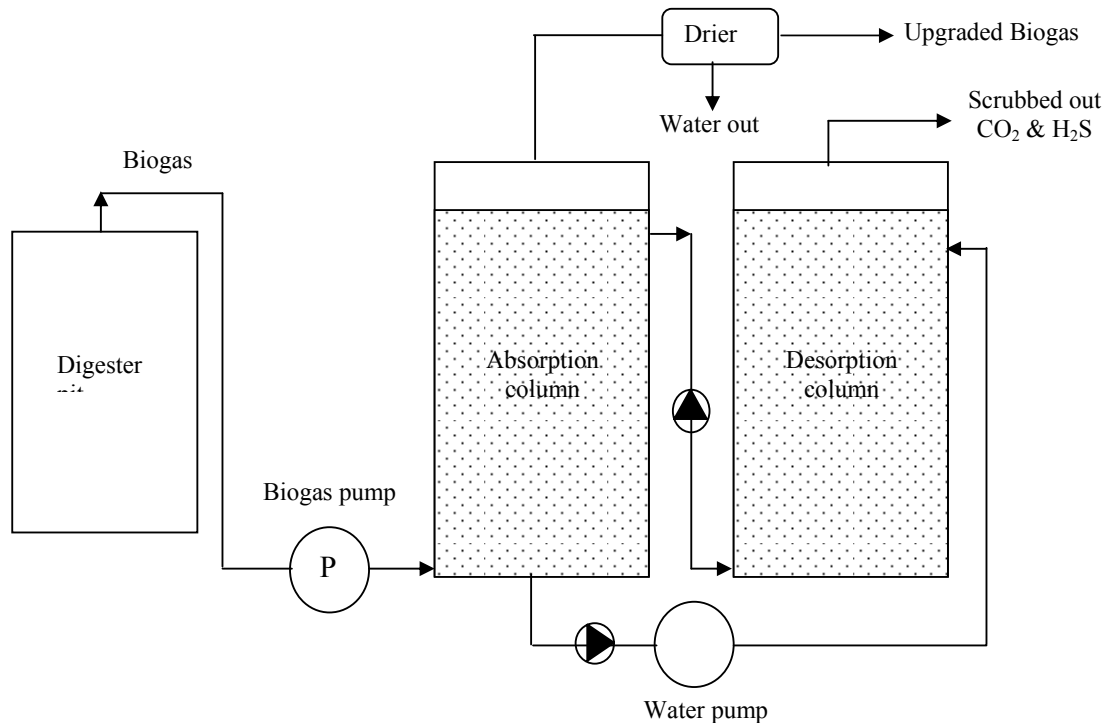


FIGURE 2  
WATER-BIOGAS COUNTERFLOW CARBON DIOXIDE AND HYDROGEN  
SULPHIDE DE-PRESSURIZATION SCRUBBING FLOW DIAGRAM



Figure 2 above shows Liquid scrubbing processes are categorized as being either physical or chemical. Physical liquid scrubbing of hydrogen sulfide is normally done by passing biogas through water, in a process such as is shown in Figure 2 above, with small amounts of sodium hydroxide added in sometimes in order to enhance absorption. The particular system shown here is that of a water-biogas counter flow carbon dioxide and hydrogen sulphide de-pressurization scrubbing plant<sup>141</sup>. The used scrubbing water is recovered using de-pressurization or air stripping processes<sup>142</sup>. Air stripping however does eventually lead to contamination of the scrubbing water with elementary sulfur and is therefore not a preferred method<sup>143</sup>. Chemical liquid absorption scrubbing processes use either iron oxide or zinc oxide slurry, while chemical liquid solution oxidization is based on caustic solution, iron chelate solution, or other iron salt solutions such as iron chloride. In situ hydrogen sulfide control methods include the introduction of chemicals such as ferric chloride and ferrous chloride into digesters, as well as the injection of air or oxygen into the space just above the slurry in a digester<sup>144 145 146</sup>.

#### FACTORS AFFECTING THE PRODUCTION OF BIOGAS AND ITS QUALITY

Biogas production and its quality are dependent on maintaining a delicate balance between the acid forming and methanogenic bacteria in a digester, which is done through control of several factors including, the type of substrate, the C/N ratio of the substrate, temperature, pH, organic loading rate and the concentration of solids in digester charge<sup>147 148</sup>.

##### *Effects of pH*

The pH is the negative logarithm to base 10 of the concentration of hydrogen ions. The pH in a working biogas plant normally lies between 7 and 8 and the optimum biogas production is achieved for digester inputs with a pH lying between 6 and 7<sup>149 150 151 152 153 154</sup>. The solids content in biogas digesters should lie between 2 – 12% by weight, the rest being water. Solids content lower than 2% gives rise to reduced production of biogas per unit solids due to a decrease in the active bacteria population in the digester, while solids content higher than 6% may lead to a drop in the quality of biogas produced as a result of increased acidity<sup>155 156 157 158</sup>.

Production of biogas in a well designed and properly seeded semi-continuous batch loaded feed unit should start within 24 hours, while a typical batch digester starts producing gas after 2 – 4 weeks and continues producing for between 3 – 4 months<sup>159 160</sup>. A maximum production rate after only two days of production from start up and a production of more than 90% of the total biogas-yield from a grass substrate have been reported after 9 to 11 days of operation of a batch type digester<sup>161</sup>. A continuous feed digester takes between 2 – 3 weeks to start producing biogas when started from scratch<sup>162</sup>. Continuous feed digesters may also be started and operated as batch systems till the production of biogas stabilizes in about a week's time<sup>163</sup>. Once production of biogas commences, 1/3 of the total biogas is produced in the first one week, another 1/4 in the second week and the rest in another 6 weeks<sup>164</sup>. Seeding a newly started batch type digester with active sewage waste whose volume is 15% of that of the digester, reduces the stabilization period of methanogenic bacteria to a point where optimum gas production is achieved, from between 2 – 3 months to 4 weeks<sup>165 166 167</sup>.

In a balanced digester, the action of methanogenic bacteria that feed on acids formed by acetogenic bacteria, helps maintain a neutral pH of slurry to 8<sup>168 169 170 171 172</sup>. Digestion of nitrogen by the methanogens produces ammonia, NH<sub>4</sub>, which increases the pH of slurry<sup>173</sup>. A

pH value that is higher than 8.5 is toxic to the methanogenic bacteria<sup>174</sup>. In a newly started digester however, the acid forming bacteria become active before the methanogens. This coupled with the fact that the reaction rate involving acid forming bacteria is faster than the one involving methanogens, normally leads to an initial reduction of the slurry pH to below 7<sup>175 176</sup>. Moreover, methanogenic bacteria take time to multiply to the numbers required to maintain a stable production of methane. It is necessary therefore to buffer a newly started digester using baking soda (sodium bicarbonate -  $\text{NaHCO}_3$ ), lime (calcium oxide -  $\text{CaO}$ ), or ammonium hydroxide ( $\text{NH}_4\text{OH}$ ) in order maintain the pH within a range that is conducive for methanogenic bacteria to operate<sup>177 178 179</sup>. The activity of methanogenic bacteria begins to become inhibited at a pH of 6.6<sup>180 181</sup> and pH values below 6 are clear indication that too much acid is being formed as a result of too few methanogenic bacteria. PH values above 5 though low can be corrected by the addition of lime or dilution of the digester feed<sup>182 183</sup>. PH values below 5 on the other hand, will almost certainly lead to a stoppage of digesters, which then requires a complete replacement of the slurry and a fresh restart<sup>184</sup>.

### *Effects of Toxins*

Toxic substances such as antibiotics, disinfectants and pesticides are designed to kill bacteria and will also stop the digester from functioning. Detergents have a similar effect, therefore if a cattle shed from which the feedstock is obtained, is washed with detergents, it must subsequently be rinsed thoroughly with clean water<sup>185</sup>.

### *Effects of Temperature*

Bacteria may be classified by their preferred operating temperatures:

- Cryophilic (Psychrophilic) bacteria work best at temperatures between 10°C and 20°C.
- Mesophilic bacteria work best at temperatures between 20°C and 40°C.
- Thermophilic bacteria work best at temperatures between 40°C and 60°C.

While anaerobic digestion is very efficient in thermophilic regions, digesters in the tropics may operate adequately in the mesophilic region. Gas production efficiency, which is the gas produced per unit kilogram of feedstock, generally increases with temperature, roughly doubling for every 10°C rise between 15°C and 35°C<sup>186</sup>. The quantity of ammonia, in a digester increases with increasing temperature, which because of its inhibitory effect on methanogenic bacteria as a result of increasing pH activity, leads to a decrease in the production of biogas<sup>187</sup>. High digester operating temperatures in digesters are therefore preferable, for so long as the production of ammonia is limited. Methanogenic bacteria are also known to be very sensitive to temperature changes, the degree of sensitivity being dependent on the range of temperature change. Changes in temperature of less than  $\pm 2^\circ\text{C/h}$ ,  $\pm 1^\circ\text{C/h}$  and  $\pm 0.5^\circ\text{C/h}$  in the cryophilic, mesophilic and thermophilic anaerobic temperature ranges, respectively, are considered to be un-inhibitive<sup>188</sup>. A sudden change of more than 5°C/day may cause a digester to stop working temporarily resulting in accumulation of volatile acids and eventual stalling of the digester. This phenomenon is less of a problem in large digesters where, the high heat capacity of the slurry ensures that the digester temperature changes slowly<sup>189</sup>. Figure 3 shows the various operating temperatures and production rates of biogas for various types of bacteria<sup>190</sup>.

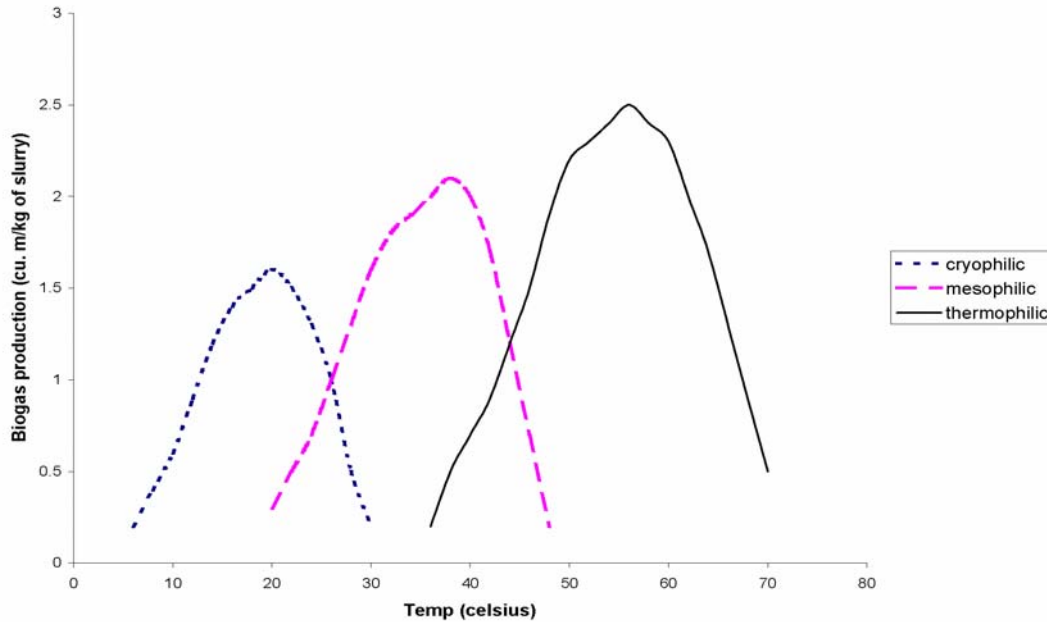


FIGURE 3  
OPERATING TEMPERATURES AND PRODUCTION RATES OF VARIOIUS TYPES OF BACTERIA<sup>191</sup>

### *Properties of Feedstock*

Any material containing food substances comprising of carbohydrates, proteins and fats, can be digested in a biogas plant. However, the rate and efficiency of digestion of the feedstock depends on their specific physical and chemical form, thus:

- Cattle dung is the easiest feedstock to use for a biogas plant as it already contains the right types of bacteria and is already broken down chemically by acids and enzymes in the animals gut<sup>192</sup>.
- Human, pig and chicken manure are also good but need a 'starter' such as slurry from a working biogas plant to initiate the digestion process.
- Goat and sheep dung are rich in nutrients but occur in the form of pellets and therefore need to be broken down mechanically to make them easily soluble in water and hence digestible by the bacteria.
- Raw vegetable must be broken down first before being used. This can be done physically through chopping or mincing<sup>193</sup>.

### *Carbon and Nitrogen (C/N) Ratio*

C/N ratio is an important parameter in biogas production since anaerobic bacteria need nitrogen for growth, however, if not properly controlled, it can inhibit methanogenic activity. The optimum C/N ratio for a digester lies in the range 20 - 30:1. C/N ratios that are too high inhibit the production of biogas as the nitrogen levels are too low for the production of new cell structures by the methanogenic bacterial required to replicate themselves. Low C/N ratios on the other hand inhibit methanogenic activity due to the production of excess amounts of ammonium that may lead to an increase in the alkalinity of a digester beyond the tolerable pH level of 8.5<sup>194 195 196 197 198 199</sup>. Where cattle or sewage slurry is used, this ratio is maintained naturally due to the composition of the feedstock. In case the ratio falls, it can be raised by

adding components with a high C/N ratio such as saw dust into the digester slurry. The dry weight of nitrogen as a percentage of the feedstock weight and C/N ratios of some selected feedstock are shown in Table II below.

TABLE II  
DRY WEIGHT OF NITROGEN AND C/N RATIOS OF SELECTED FEEDSTOCK<sup>200</sup>.

Material	N (%)	C/N Ratio
Animal		
Dung cow	1.8	19.9
horse	2.3	25
chicken	6.3	7.3
Household Waste		
night soil	7.1	6.72
kitchen waste	1.9	28.6
Crop Residual		
crop stalks	1.2	50.6
rice straw	0.7	51.0
corn cobs	1.0	49.9
Others		
saw dust	0.1	200-500
grass trimmings	2.5	15.7

#### TYPES OF BIOGAS DESIGNS

There are different types of biogas digester designs:

- Floating gas drum design.
- Fixed dome design.
- Flexible bag design.
- Slurry pit with flexible gas cover design.

A suitable Biogas design must be amendable to production in different sizes and be adaptable to the customer's specifications. In this paper, we shall consider three designs namely, the floating drum design, fixed dome design and the flexible bag design.

##### *Floating Gas Drum Biogas Design*

In this type of biogas design, the slurry is kept in a cylindrical pit in the ground. The pit is lined with bricks that are supported by the surrounding soil to ensure that the plant is able to withstand hydraulic pressure from the feed slurry. The gas is normally collected in a cylindrical steel gas drum that floats mouth downwards in the slurry. Figure 5 shows a typical floating drum digester design.

As the gas rises through the slurry, it carries some of the lighter slurry particles which settle at the top of the slurry to form scum that inhibits the biogas from passing through<sup>201</sup>. Problems of scum formation are particularly prevalent in digesters that are charged with vegetable waste and it is important though not necessary therefore to have a stirring and mixing mechanism installed in digesters, particularly for batch type of digester systems<sup>202</sup>.

Where the digester substrate consists primarily of solute substances, there is no formation of scum<sup>203</sup>. Continuous feed systems on the other hand experience automatic and continuous break up any scum formed as the new feed comes into the digester<sup>204</sup>. Thin layers of scum will not normally inhibit the release of biogas and in cases of substrates with high Total Solids (TS) content, no stratification occurs<sup>205</sup>. Stirrers and mixers will normally be used daily, in order to facilitate removal of the biogas produced, for purposes of inoculation of the fresh substrate with bacterial in the digester, break up scum and avoid sedimentation by keeping the heavy material distributed in the digester system and to ensure a uniform distribution of bacterial in the digester by avoiding the formation of areas of low bacterial activity due to local depletion of nutrients and concentration of metabolic products<sup>206 207 208 209 210</sup>. There is not hard and fast rule determining the regularity and degree of stirring, which varies from digester to digester and from substrate to substrate, and may if excessive inhibit the process of digestion<sup>211</sup>.

The gas collection drum usually has a steel bar framework fixed on its lower inner side, which serves to stir up and break up any scum that is formed, when the drum is rotated<sup>212</sup> using brackets that are fixed on its inclined outer surface. The gas drum is held in a vertical position by a central guide pipe running vertically through a second pipe at its center. This system allows the drum to move up and down and to rotate about its axis, without tipping<sup>213</sup>. The facility of the gas drum to move up and down regulates the pressure of the produced gas at a constant value, while its ability to rotate helps break up any scum formed on the surface of the digester slurry. The floating gas drum biogas system falls in the category of continuous biogas systems, in which the slurry in the digester is displaced into the effluent chamber by incoming slurry. There is need in such types of biogas systems, to ensure that slurry that is fed into digesters is well mixed and that it carries little or no inorganic material such as sand and stones, in order to avoid sedimentation and the related gradual reduction of the digester capacity<sup>214</sup>. In the event of large volumes of sand and stones accumulating at the bottom of the digester, it would be necessary to stop operation of the digester and then manually empty out the slurry, together with any deposited sand and stones.

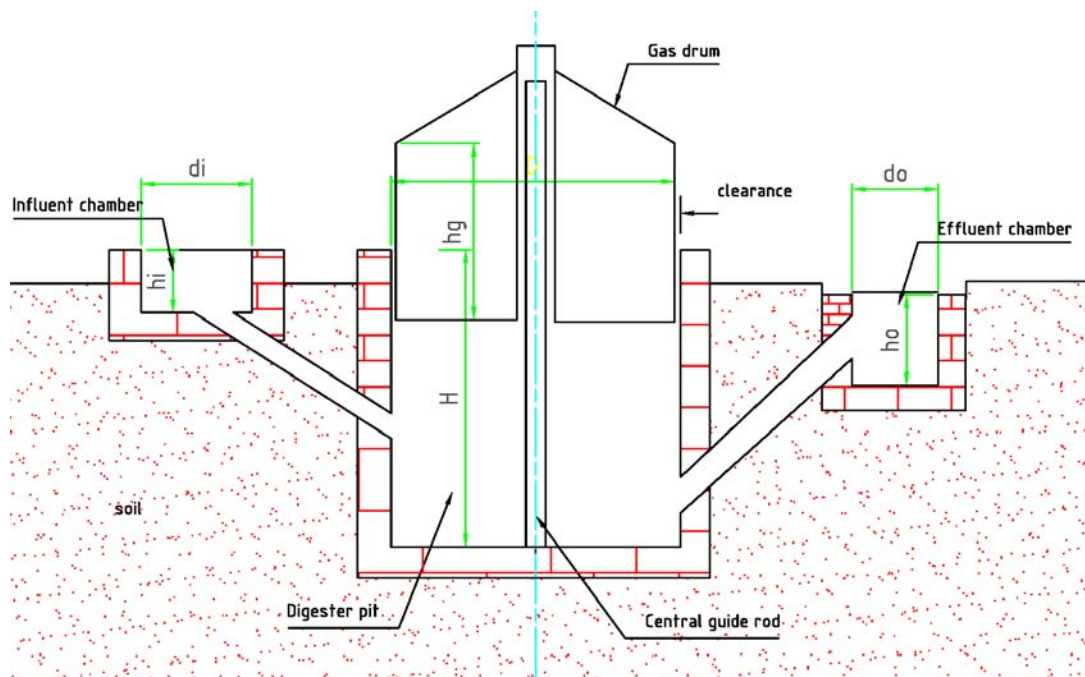


FIGURE 5  
FLOATING DRUM BIOGAS DIGESTER<sup>215</sup>

### *Fixed Dome Biogas Design*

This type of biogas design consists of a digester pit lined with bricks and a permanent concrete roof placed over it. Earth soil is piled on top of the roof in order to assist in containing the gas produced within it. As the gas is produced, it collects in the dome and displaces some of the slurry from the digester pit to the effluent chamber. The slurry flows from the influent chamber into the digester pit where it is used up in production of biogas. Access into the digester pit during part of the construction and cleaning is solely through the slurry influent and effluent chambers. This makes the fixed dome biogas design difficult to maintain and operate<sup>216</sup>. Figure 6 shows a typical fixed dome biogas design.

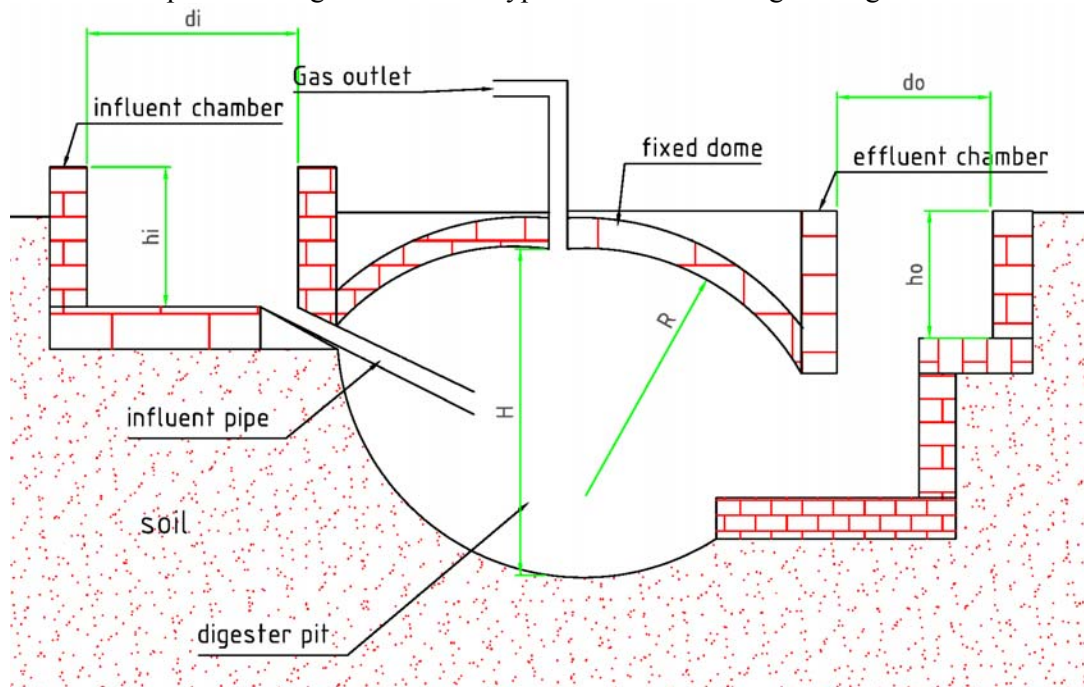


FIGURE 6  
FIXED DOME DIGESTER

### *Flexible Bag Biogas Design*

This type of biogas design consists of a long cylindrical bag, made of plastic material that is placed in a trench, which is lined with masonry, compacted sand or mud. The slurry fills the lower 2/3 of the bag and the gas collects above it. As the biogas is used up, the bag collapses behaving like a balloon. The edges of the roof are held down to the edges of the trench with clips or poles passing through loops in the plastic bag.

The major limitation with this design is the difficulty in tapping the gas produced. A flexible PVC pipe can be welded on the top of the bag for collection of the gas but it is not easy to ensure an air-tight seal between the pipe and the plastic bag. In addition, there is a risk of explosion in case of excess gas pressure<sup>217</sup>. Figure 7 shows a typical flexible bag biogas design.

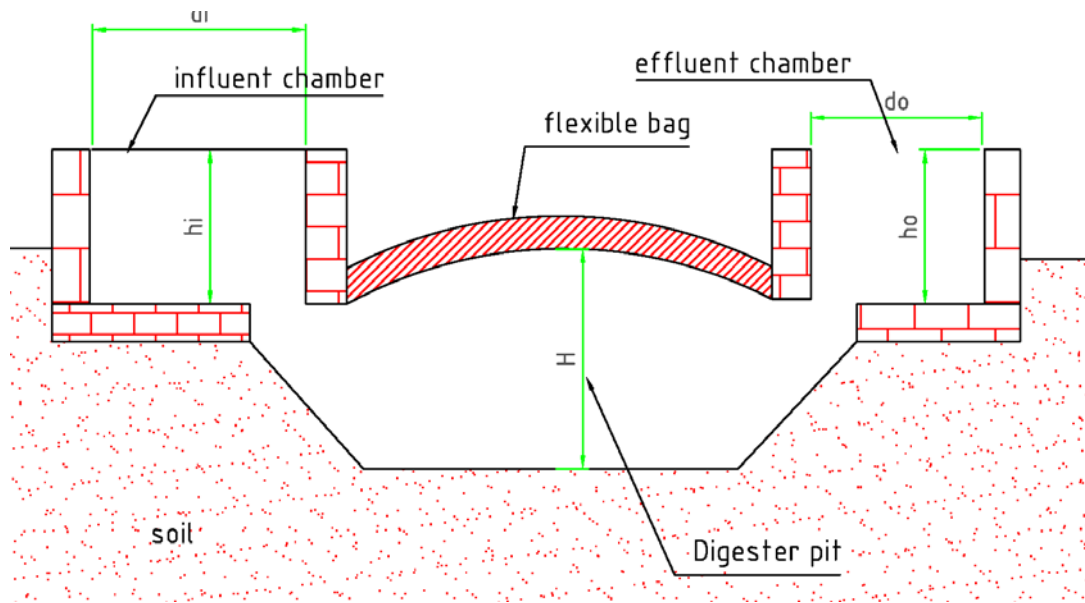


FIGURE 7  
 FLEXIBLE BAG DIGESTER

Effluence in the effluent tanks is very useful as a fertilizer as it provides a good source of organic material to help maintain or increase the humus content of soils, which in turn helps maintain or improve the soil structure<sup>218 219</sup>. Further usefulness of the effluence arises from the fact that it contains water soluble nitrogen, a plant nutrient, that can be readily taken in by plants<sup>220</sup>. The nitrogen in the effluence occurs in the form of ammonia and is highly volatile, which makes it necessary to be fed directly at plants bases, preferably by being transmitted under the soil surface in order to minimize loss through vaporization in the process<sup>221 222</sup>. The effluence may be fed through channels to a sloping filter bed on the ground that is covered with a layer of compacted dry or green leaves of about 15cm that acts to filter the solids off<sup>223</sup>. The solids can then be carried off for spreading on farms around plants, while the liquid can either be mixed with fresh digester charge solids to form slurry or is pumped directly to the bases of plants<sup>224 225</sup>. Effluent slurry may alternatively be channeled out to basins that are lined with plastic sheeting in order to prevent loss of the liquid by percolation through the soil and whose surface on filling with the effluence is then covered with a mixture of soil and leaves in order to minimize evaporation loss of nitrogen<sup>226 227</sup>. The mixture is then taken out and spread in the farm around plant material when needed<sup>228</sup>. Plants that have been treated with digester effluence have shown increases in yield of 5 – 20% compared to crops not treated this way<sup>229 230</sup>, thus emphasizing the importance of utilizing digester effluence on plants.

#### BASIS OF SELECTING A BIOGAS PLANT DESIGN

The choice of a particular biogas design must be guided by comparison of the various available options and based on criteria that weigh their respective strengths and weaknesses. In the present work, the choice of a particular type of biogas design was informed by comparing the following factors, each on a scale of 0 to 10.



- Strength - can the design withstand the gas pressure as well as the hydraulic pressure of the slurry?
- Cost of construction.
- Availability and cost of the materials.
- Ease of construction.
- Ease of operation.
- Ease of maintenance.
- Reliability - can it function as expected and with what regularity?
- Gas tight - can it accommodate the gas pressure without leakage?
- Safety - is it safe to operate the plant, is it safe from explosions?

Table III shows the rating of the three designs selected here for comparison against the above factors based on a 0-10 scale, 0-lowest and 10-highest.

TABLE III  
COMPARISON OF THREE SELECTED, BIOGAS DESIGNS.

	Floating gas drum biogas design	Fixed dome biogas design	Flexible bag biogas design
Strength	8	9	5
Cost of construction	6	7	8
Availability of materials	9	9	6
Ease of construction	8	5	6
Ease of operation	9	7	7
Ease of maintenance	8	4	5
Reliability	8	7	7
Safety	8	5	7
Gas tight	7	6	5
<b>Total</b>	<b>71</b>	<b>58</b>	<b>55</b>

The floating gas drum biogas design comes out with the highest total score in Table 2, thus making it the best of option of the three. The following factors further make the floating gas drum more attractive:

- Ease of maintenance - the gas holder can be removed easily thus giving easy access for inspection and repair of the digester and gas holder as well as repainting for the cache.
- In case of the plant stalling, the gas holder can be removed easily and the digester cleaned.
- It is easy to incorporate a slurry mixing mechanism in a floating gas holder system.
- Amongst the factors that make fixed dome and flexible plastic bag, biogas designs unattractive include:
  - Need for gas tight coatings or plastic liners, applied to the walls of the dome in order to prevent gas leakage through pores in the building materials.
  - Lack of direct access to the digester pit for the fixed dome design in the event of the plant stalling.
  - Possibility of collapse of concrete domes.



- Possibility of explosion of the concrete domes and flexible plastic bag due to excessive biogas pressure.
- Effective sealing between the flexible plastic bag and the gas outlet pipe is difficult to achieve.

### MODIFIED FLOATING DRUM BIOGAS UNIT

The ensuing work is all based on the floating gas drum biogas design. Various modifications can be made on the standard floating gas drum biogas design such as:

- Extension of the gas drum roof to cover the digester pit. This prevents rain water from entering the digester pit to avoid the diluting the slurry<sup>231</sup>.
- Protrusion of the effluent pipe into and at the top of the effluent chamber to prevent the effluent from flowing back into the digester pit<sup>232</sup>.
- Construction of a partition wall in the digester, which is raised above the influent pipe in order to ensure that the incoming slurry does not feed directly into the effluent pipe, thereby passing right through the digester without being digested<sup>233</sup>.
- In the absence of the partition wall, an angle of between  $90^0$  and  $135^0$  in plan view, between the digester inlet and outlet pipes must be maintained in order to minimize incidences of incoming slurry feeding directly into the effluent pipe, and therefore passing right through the digester without digestion<sup>234</sup>.
- The entry height of the influent pipe, above the digester floor and the effluent pipe intake, prevents the slurry already in the digester from blocking the influent pipe.

Figure 8 shows the modified floating drum biogas digester.

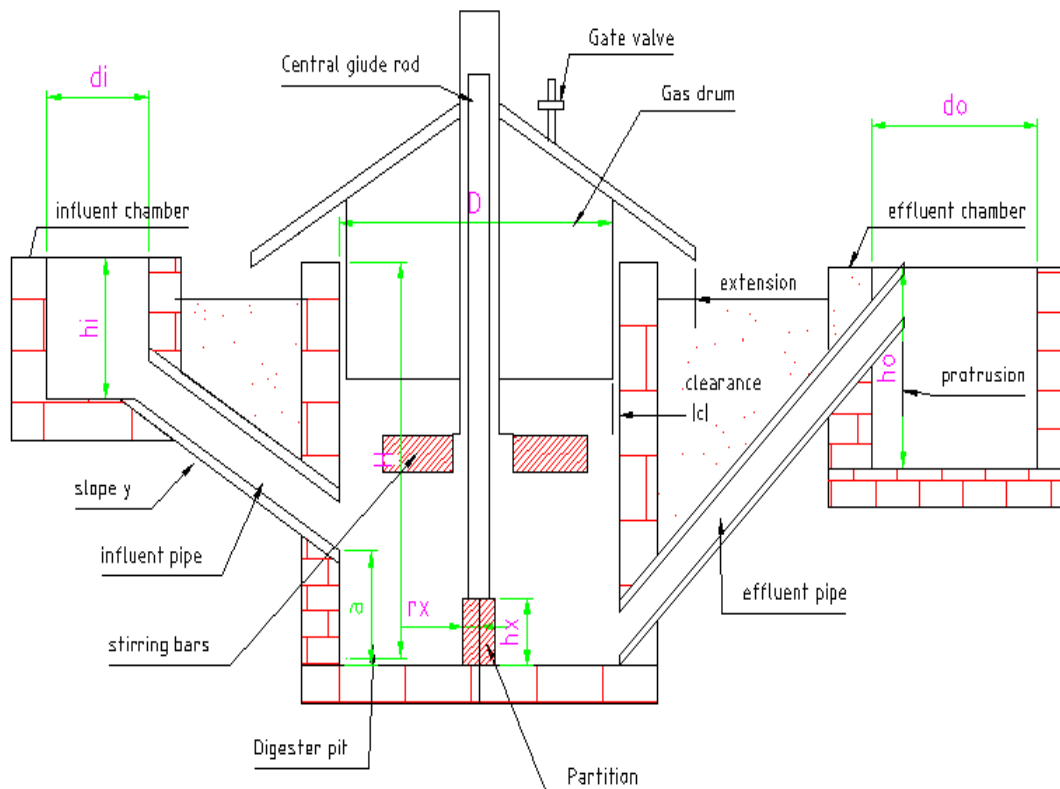


FIGURE 8

## MODIFIED FLOATING DRUM DIGESTER

### DIGESTER SIZING

The main variable that controls the design of a biogas unit is the internal volume of the digester, since the amount of the gas produced is a function of the volume of slurry in the digester pit. The digester volume is mainly dependent on the slurry feed rate and retention time and ultimately therefore, on the amount of slurry available. Slurry loading rates are easily converted into total volatile solids (TVS) per day per unit volume of the digester or the weight of TVS added per day per weight of TVS already in the digester from set ratios of dilution of solids with water that are dependent on the type and dryness or wetness status of a particular substrate<sup>235 236 237</sup>.

#### *Retention Time*

The retention time  $R$  is the time that the slurry requires to stay in the digester pit for complete digestion by bacteria. For continuous digester systems, the daily feed rate ( $v$ ) is arrived at by dividing the digester volume ( $V_d$ ) with the slurry retention time ( $R$ ), thus:

$$v = \frac{V_d}{R} \quad (1)$$

The retention time is dependent on the prevailing temperature in a digester and on the type of substrate used. Most biogas digesters in Kenya operate in the mesophilic temperature range ( $20^\circ < t < 40^\circ\text{C}$ ). For liquid manure undergoing fermentation in this temperature range, the following approximate retention times apply<sup>238</sup>:

- Liquid cow manure 20 - 30 days
- Liquid pig manure 15 - 25 days
- Liquid chicken droppings 20 - 40 days

Various experiments on the retention time that have been carried out on cow dung slurry show that biogas production starts dropping on the 40th day<sup>239</sup>. For the analysis presented here, a retention time of 50 days was chosen in order to allow for the complete digestion of cow dung slurry. The feed rate in such a case is easily calculated from equation 1.

The feed rate is of course dependent on the amount of manure available, which translates to the number of cows and volume of water available. The optimum water:cow manure volume ratio is 0.7 : 1.0<sup>240</sup>. Of course the wetter or drier manure is the less or more extra water is required to be added. The optimum solids content and effects of charging digesters with slurries whose solids contents are outside the optimum range have been discussed in the section entitled, "Effects of pH".

### SIZING OF DIGESTER PITS AND GAS HOLDERS

The following standard relationships were used in order to size the biogas units based on a zero grazed cow<sup>241</sup>:

- 1kg of cow dung is mixed into 1.8 L of slurry.
- 1 cow produces 10kg of cow dung per day.

- 1kg of cow dung produces 0.062m<sup>3</sup> of methane gas.
- 1 person requires (0.34 – 0.42) m<sup>3</sup> of methane gas per day.
- (0.34 – 0.42) m<sup>3</sup> of methane gas requires (5.48 – 6.77) kg of cow dung per day.

Table IV below shows the sizes of digesters and gas holders that are determined from these relationships.

TABLE IV  
SIZING OF DIGESTERS AND GAS HOLDERS

Cows	Amount of biogas	Amount of wet dung	Persons	Digester size	Gas holder size
(No.)	(m <sup>3</sup> )	(kg)	(No.)	(m <sup>3</sup> )	(m <sup>3</sup> )
1	0.57	5.48	1	0.49	0.25
3	2.83	27.40	5	2.45	1.25
6	5.67	54.80	10	4.9	2.50
8	8.50	82.25	15	7.35	3.75
11	11.33	109.6	20	9.80	5.00
14	14.17	137.00	25	12.25	6.25
17	17.00	164.00	30	14.70	7.50
20	20.67	200.00	35	18.00	9.00

### Dimensioning

In determining the dimensions of digesters, the simplifying assumption was made here that the diameter of the digester ( $D$ ) is equal to its height ( $H$ ). A clearance gap of 20mm between the digester pit and the gas drum was adopted as adequate to allow free rotation of the gas drum, without allowing too much leakage of the generated gas. The volume of such a digester pit is given by:

$$V_d = \frac{\pi D^2 H}{4} \quad (2)$$

which since  $H \approx D$  becomes:

$$V_d = \frac{\pi D^3}{4} \quad (3)$$

From which the diameter of the digester is obtained as:

$$D = \sqrt[3]{\frac{4V_d}{\pi}} \quad (4)$$

Taking the gas holder/digester radial clearance to be 20 mm, gives a diameter ( $d$ ) of the gas holder of:

$$d = (D - 0.04) = \left( \sqrt[3]{\frac{4V_d}{\pi}} - 0.04 \right) \text{ m} \quad (5)$$

Given a gas holder volume ( $V_g$ ), the height (h) of the gas holder is therefore be given by:

$$h = \frac{4V_g}{\pi d^2} = \frac{4V_g}{\pi} \left( \sqrt[3]{\frac{4V_d}{\pi}} - 0.04 \right)^{-2} \text{ m} \quad (6)$$

Table V below gives the dimensions of the digester pit and gas holder based on Equations 3-6<sup>242</sup>.

TABLE V  
DIMENSIONS OF DIGESTERS AND GAS DRUMS

Cows	$V_d$	D	H	$V_g$	D	H
(No.)	(m <sup>3</sup> )	(m)	(m)	(m <sup>3</sup> )	(m)	(m)
1	0.49	0.85	0.85	0.25	0.81	0.49
3	2.45	1.46	1.46	1.25	1.42	0.79
6	4.90	1.84	1.84	2.50	1.80	0.98
8	7.35	2.11	2.11	3.75	2.07	1.11
11	9.80	2.32	2.32	5.00	2.28	1.22
14	12.25	2.50	2.50	6.25	2.46	1.31
17	14.70	2.66	2.66	7.50	2.62	1.39

#### COSTING OF THE BUILDING MATERIALS AND LABOR

##### *Costs of materials for the digester pit*

Mortar, a mixture of sand, cement and water, to be used in joining stones and also for the digester inner wall plastering should be in the ratio of: 1 part of cement, 6 parts of sand, 7 parts of water. Concrete, a mixture of sand, cement, ballast and water, to be used in constructing the digester floor, should be in the ratio of: 1 part of cement, 2 parts of sand, 4 parts of ballast and 5 parts of water. A layer of stones is referred to here as a course, as is the norm.

The number of stones ( $N_s$ ) per course is given by:

$$N_c = \frac{H}{h_s} + 1 \quad (7)$$

Number of courses of stone required ( $N_{cs}$ ) is given by:

$$N_{cs} = \frac{2\pi R}{l}, \text{ where } R = \frac{(D+b)}{2} \quad (8)$$

The symbols  $H$ ,  $h_s$ ,  $R$ ,  $l$ ,  $D$  and  $b$  are as defined in the section on nomenclature.

The total number of stones ( $N_T$ ) required therefore is given by:

$$N_T = \frac{2\pi R}{l} \left( \frac{H}{h_s} + 1 \right) \quad (9)$$

The quantity of mortar ( $Q_m$ ) required is given by:

$$Q_m = (2\pi R \times b \times k \times N_c) + (N_s \times k \times b \times h_s) + (D \times H \times k) \quad (10)$$

The amount of concrete ( $Q_c$ ) required is given by:

$$Q_c = \frac{\pi}{4 \left[ (d_i + 2b)^2 t + (d_o = 2b)^2 t + (D + 2b)2t + d_x^2 h_x \right]} \quad (11)$$

Where the symbols  $d_i$ ,  $d_o$ ,  $d_x$ ,  $h_x$  and  $t$  are as defined in the section on nomenclature.

Since building materials are normally sold in weight, it was necessary to use the values of density given in Table VI below to compute the weight of these materials<sup>243</sup>.

TABLE VI  
MATERIAL DENSITIES (COURTESY OF CIVIL ENGINEERING DEPARTMENT, JKUAT)

Material	Density (kg/m <sup>3</sup> )
cement	1440
sand	1445
ballast	1450

In order to compute costs for the building materials, a quotation of the materials was obtained from a local hardware and building materials dealer (Tumaine Hardware, P.O. Box 288, Kalimoni, Kenya), as shown in Table VII below.

TABLE VII  
PRICE LIST FOR BUILDING MATERIALS

Item	Description	Units	Unit cost (Kshs)
mild steel rods	d = 25 mm	kgs	240
mild steel sheet ofsheet	gauge 14 (3mm)	sheet	1590
mild steel electrodes	d=2.5mm	packet	680
GI pipe	d = 1"	metres	240
PVC pipe	d = 6", l = 6m	metres	1850
dressed stones	standard	pieces	26

Sand		tons	1200
ballast		tons	1440
water trap	standard	pieces	220
gate valve	standard	pieces	300
primer coat	metallic antislaline	4 liters	500
Bituminous paint	red and black	4 liters	500

The sequence and times for constructing the digester pit were proposed as follows:

1. Building the concrete base - approximately one day.
2. Laying the stones and applying mortar - 1.5m per day
3. Plastering the walls - approximately one day.

The labor rates in force are:

- Excavation - Kshs 200/m<sup>3</sup>
- Hiring a mason - Kshs 300/day
- Hiring an assistant mason - Kshs 150/day

One mason and an assistant mason can build approximately 12m<sup>2</sup> of a wall in a day. Thus depending on the size of the digester and hence the surface area of the digester pit, it may be necessary to hire one mason and several assistant masons. Table VIII shows the material requirement and cost for building digester pits, as well as influent and effluent tanks.

TABLE VIII  
MATERIALS LIST AND THEIR RESPECTIVE COSTS (OBTAINED FROM TUMAINE HARDWARE, P.O.  
BOX 288, KALIMONI, KENYA) FOR CONSTRUCTION OF DIGESTER PITS

Cows (No.)	Persons (No.)	Stones (No.)	Cost of Stones (Kshs)	Bags of cement (No.)	Cost of cement (Kshs)	Quantity of sand (tons)	Cost of sand (Kshs)	Quantity of ballast (tons)	Cost of ballast (Kshs)	Cost of labour (Kshs)	Overall total cost (Kshs)
1	1	76	1976	7	3255	0.8	960	1.3	1872	1600	11983
3	5	176	4576	11	5115	1.3	1560	1.9	2736	1990	19647
6	10	265	6890	13	6045	1.7	2040	2.3	3312	3080	25937
8	15	334	8684	15	6975	1.9	2280	2.6	3744	3570	30423
11	20	391	10166	16	7440	2.3	2520	2.7	3888	4060	33694
14	25	453	11778	17	7905	2.4	2880	2.9	4176	4550	37359
17	30	511	13286	19	8835	2.5	3000	3	4320	4940	40926

#### *Cost of the Gas Holder Materials and Labor*

Plain mild steel sheets of gauge 14 (3mm thick) were recommended for the fabrication of gas holders since they are easy to cut and form. These mild steel sheets are available in standard sizes of (2.44 m × 1.22 m). The labor cost for hiring an artisan, welding equipment and electricity is normally taken as 0.2× materials cost (courtesy of Welding workshop, JKUAT). Welding one mild steel sheet will require approximately one packet of welding rods. One tin (4 L) of paint will paint a surface area of approximately 3m<sup>2</sup>. Table IX below shows the total cost of fabricating a gas holder<sup>244</sup>.

**TABLE IX**  
**MATERIAL REQUIREMENT AND THEIR RESPECTIVE COSTS (OBTAINED FROM TUMAINE**  
**HARDWARE, P.O. BOX 288, KALIMONI, KENYA) FOR FABRICATING THE GAS HOLDER.**

Cows	Persons	Sheets	Cost of sheets	Cost of welding rods	Cost of GI pipe	Cost of paint	Cost of labor	Overall total cost
(No.)	(No.)	(No.)	(kshs)	(kshs)	(kshs)	(kshs)	(kshs)	(kshs)
1	1	2	3180	340	685	1500	1141	6846
3	5	4	6360	510	913	1500	1856	11140
6	10	5	7950	680	1063	1500	2237	13432
8	15	5	7950	850	1165	1500	2293	13758
11	20	6	9540	1020	1262	1500	2662	15974
14	25	7	11130	1190	1323	1500	3029	18172
17	30	8	12720	1386	1386	1500	3393	20359

#### **AUXILIARY PARTS**

##### *The central guide mechanism.*

As the volume of gas that is generated increases it pushes the gas holder upwards which later retracts back into the digester pit as the gas is used up. This up and down movement of the gas holder requires a central guide mechanism to prevent the gas drum from jamming onto the sides of the digester. The central guide mechanism consists of a mild steel rod of 30mm coated with 1 layer of primer and 2 layers of oil paint onto which is applied a layer of grease to lubricate the system and also to protect the rod against corrosion.

##### *Water trap*

When the gas collected flows along the gas outlet pipe, some water condenses along the pipe necessitating the use of a water trap. Standard water traps are available and should be installed along the gas pipe and just before the consumer point. Water traps encourage condensation, subsequent retention and eventual discharge of water in the biogas.

##### *Gate valve*

A gate valve is required at the outlet of the gas drum to regulate the flow of the gas depending on the consumer requirements.

##### *Slurry influent and effluent pipes*

Standard pipes of polyvinyl chloride (PVC) should be used for slurry flowing into and out of the digester. PVC is recommended since it does not corrode in the alkaline conditions prevailing in the digester and is therefore more durable than galvanized iron pipes.

Material requirements and their respective cost (Obtained from Tumaine Hardware, P.O. Box 288, Kalimoni, Kenya) for the accessories discussed above are tabulated in Table X below.

TABLE X  
MATERIAL REQUIREMENTS AND THE RESPECTIVE COSTS FOR THE ACCESSORIES

Cows	Persons	Central guide rod		Inlet/outlet pipe		Gate valve	Water trap	Overall total
(No.)	(No.)	Length (m)	Cost (Kshs)	Length (m)	Cost (Kshs)	Cost (Kshs)	Cost (Kshs)	Cost (Kshs)
1	1	1.15	1800	4	1230	300	220	3550
3	5	1.76	3150	5	1533	300	220	4903
6	10	2.14	4050	6	1850	300	220	6420
8	15	2.41	4650	8	2467	300	220	7637
11	20	2.62	5100	9	2775	300	220	8395
14	25	2.8	5550	10	3083	300	220	9953
17	30	2.96	5925	12	3700	300	220	10145

Table XI below shows the total cost of installing biogas units of different sizes depending on the number of cows and therefore cow dung available. Since the costs given in this paper relate to the Kenyan market, the cost information provided can only act as a guide for external markets. Conversions of the Kenya shilling to some of the major international currencies in Kenya as on the 15<sup>th</sup> of January 2008 were; Kshs 68 to one US Dollar, Kshs 133 to one Sterling Pound, Kshs 101 to one Euro and Kshs 0.62 to one Japanese Yen.

TABLE XI  
TOTAL COST OF A BIOGAS PLANT

Cows	Persons	Cost of digester	Cost of gas holder	Cost of accessories	Overall total cost
(No.)	(No.)	(Kshs)	(Kshs.)	(Kshs)	(Kshs)
1	1	11983	6486	3550	20,059
3	5	19647	11140	4903	32,320
6	10	25937	13423	6420	41,219
8	15	30423	13758	7637	46,648
11	20	33694	15974	8395	52,443
14	25	37359	18172	9953	58,614
17	30	40926	20359	10145	64,985

## CONCLUSION



This report provides literature on the necessary requirements for installing a biogas unit. It presents information on how to develop a bill of quantities and complete costing of various size biogas units, based on available cow dung slurry (number of cows), for the floating drum biogas plant and includes an example of the sizing and costing of a digester in Kenya.

### RECOMMENDATIONS

- Standard designs for the piping network from the digester to the consumer should be developed for uses on institutional biogas units.
- A computer program should be developed to assist in determining the bill of quantities and costing of various size biogas units based on the available cow dung (number of cows).
- A means of sustaining thermophilic temperatures should be developed, as productivity of biogas is higher in this temperature region.
- Design for an integrated biogas system that includes scrubbing, charging and storage systems should be developed.
- Charging mechanisms, pressure regulators and flame arrestors should be developed and standardized for easy uptake by users.

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Tools required for welding plastic:  
Welder, small air compressor, HDPE  
welding rod.



Looking down into open tank, showing  
3/4" HDPE tube bent into hoop and  
welded into tank. Hoop acts as support  
blocking for baffle partitioning vertical  
tank into two chambers.



Closeup of hoop welded to wall of HDPE tank.



Assembled baffle plate, top view: Disk is cut from 1/4" HDPE sheet, holes/fittings in baffle are for 3/4" gas vent, 2" transfer pipe (center), 2" influent in.



Assembled baffle plate ready for installation in tank.

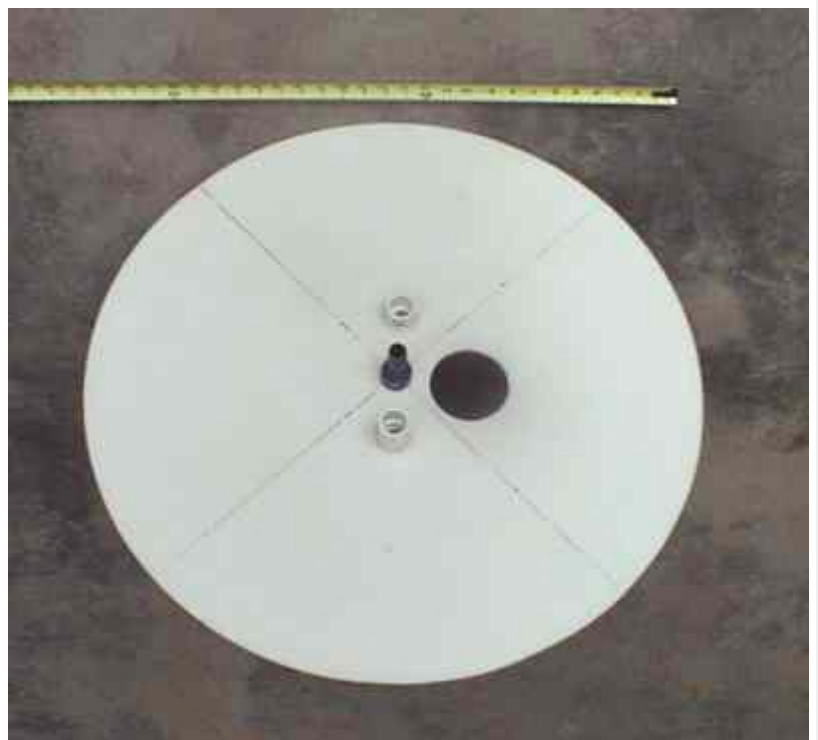


Looking down in tank with completed baffle plate in place. Baffle is attached to support blocking (3/4" tube hoop) with self-tapping stainless steel screws, sealed with silicone caulk. (Note: 3/4" hose connecting gas vent to lid is not shown.)



### Digester Lid Construction

Cut tank lid from 3/8" thick HDPE sheet to fit inside flange of open top HDPE tank. (Diameter varies depending on tank selected -- which will depend on amount of material to be digested. Use [design tool](#) to select tank.) Holes cut in tank are for influent/effluent heat exchanger assembly, biogas out, biogas recirculation, and gas vent from acid reactor. Top view.



Closeup view of underside of lid showing silicone caulk bead and fittings. Large hole is caulked in preparation for inserting 4" ABS heat exchanger assembly (see photos below).



Assembled lid with gas vent hose and gas recirculation conduit attached to fittings.



Influent/effluent heat exchanger, assembled from 4" ABS pipe with 2" PVC inside





Closeup of top of HX assembly showing 2" PVC bulkhead fitting inserted into hole drilled through 4" ABS cap.

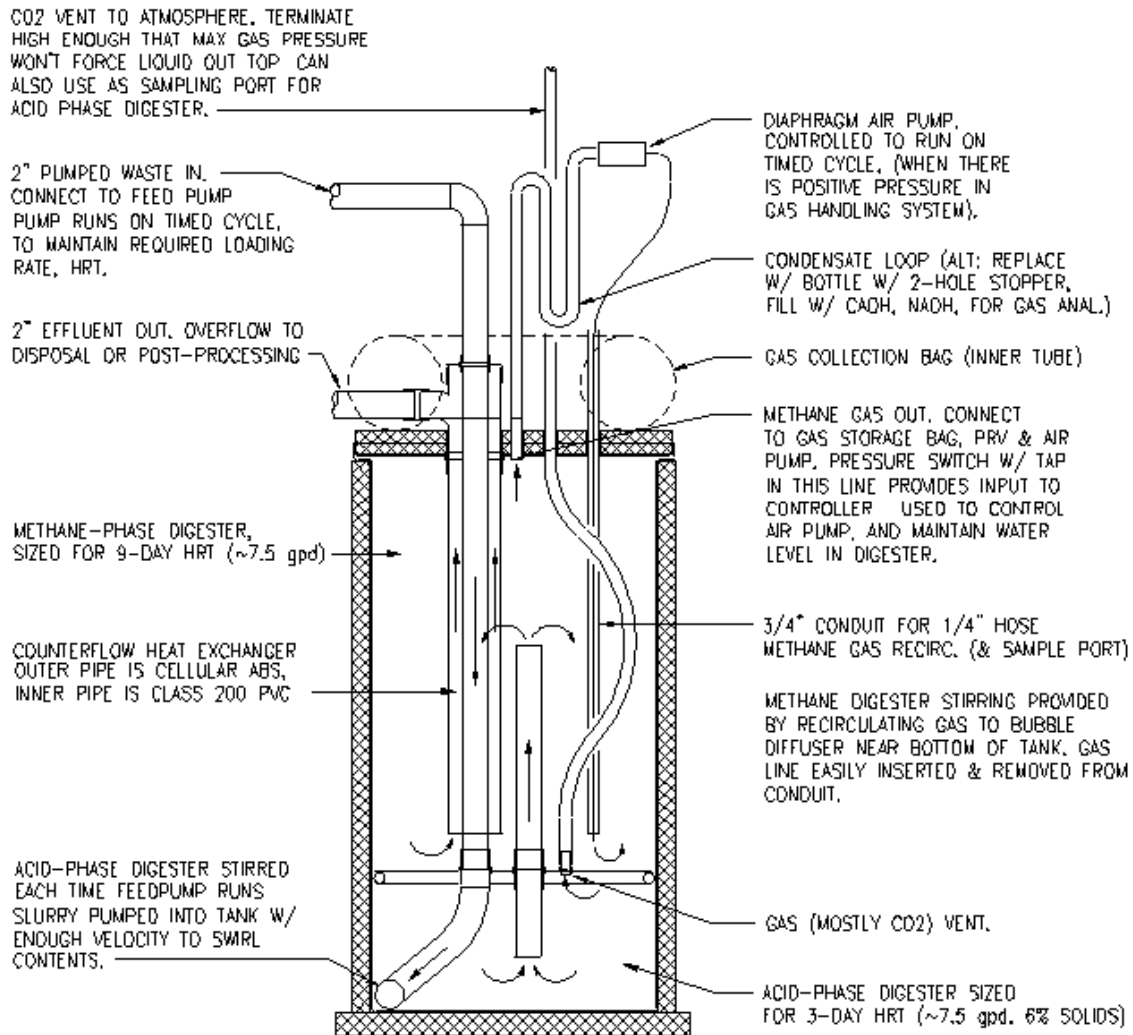


Completed digester prior to final installation of lid and wrapping with insulation. Heat tape is wrapped around tank and attached with aluminum tape.

(Note also an immersion well installed in lid, for temperature measurement -- not included in construction drawings.)



## OPERATION



### Incoming Waste

A system can be designed to digest a wide variety of organic wastes, from kitchen scraps to sewage, to livestock manure, to industrial wastes. The ideal feedstock is a 6-8% slurry with a Carbon to Nitrogen ratio of about 30:1. Incoming waste material should be macerated, and as close to the operating temperature (95 degF) of the digester as possible. The small scale system described below will handle the toilet wastes produced by a family of 6, each flushing a 1-1/2 Pint/flush toilet 5 times per day.

### Gas Handling:

Gas can be stored in low pressure gas bags (i.e. truck tire inner tubes, etc.), rigid tank(s) with floating cover and water seal, compressed and stored in pressure tank, and/or burned as it is produced, (minimizing storage requirements). For safety reasons, it is recommended that the gas be burned as soon as possible, avoiding the requirement to store and handle larger quantities of flammable gas.

The gas produced typically consists of about 30% CO<sub>2</sub> and about 60-65% methane, depending on the content of the wastes. Small amounts of hydrogen, hydrogen sulfide, and nitrogen gas will also be produced, as well as water vapor.



One use of this gas is to heat domestic hot water in a gas-fired tank-type water heater installed between the cold water inlet and the conventional (backup) water heater. A small, weighted inflatable gas bag will be used to collect up to an hour's worth of gas (i.e. about 5 cu ft at design conditions), and to provide required pressure for proper burner operation.

Gas burner should be as small as possible, with intermittent ignition with continuous retry and maximum lock-out time. Sufficient hot water storage capacity should be provided to make use of all available energy without having to store flammable gas. This may require addition of one or more insulated storage tanks piped together, and a small circulator pump and controls.

### **Digester Effluent:**

Effluent from the digester will be returned to the conventional backup sewer system. A hydraulic loading rate (total liquid throughput) of about 60 gallons/ day is assumed. Estimated solids loading will be about 35 lbs/day. Assuming that volatile solids will be reduced by about 60-70% in the digester, additional volatile solids entering the sewer system will be about  $35 - (35 \times .65) \sim 12\text{-}15$  lbs/day.

### **Digester Sludge:**

The volume of sludge solids accumulating in the digester will depend on the digestibility of the influent material and the extent to which digester contents are mixed (i.e. kept in suspension and discharged with effluent), or allowed to settle. Tanks are designed to facilitate sludge removal (e.g. quick disconnect fittings provided for connection to vacuum pump, etc.). To reduce solids loading on backup sewer system and recover sludge solids as a valuable soil amendment, a settling tank can be installed in the line between the effluent overflow and the sewer system

# UNDERSTANDING BIOGAS GENERATION

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## I. INTRODUCTION

### HISTORY

Biogas is a by-product of the biological breakdown--under oxygen-free conditions--of organic wastes such as plants, crop residues, wood and bark residues, and human and animal manure. Interest in biogas as a viable energy resource has spread throughout the globe in the past two decades. Biogas generators or digesters operate throughout Asia, for example, with more than 100,000 reported in India, about 30,000 in Korea, and several million in China. Many more are operating in the Middle East, Africa, Oceania, Europe, and the Americas.

Biogas is known by many names--swamp gas, marsh gas, "will o' the wisp," gobar gas. It contains about 50 to 60 percent methane, the primary constituent of natural gas. Biogas is produced naturally from the degradation of plants in such situations as rice paddies, ponds, or marshes. Because it can also be produced and collected under controlled conditions in an airtight container, it can be an important energy source.

Ancient Chinese experimented with burning the gas given off when vegetables and manures were left to rot in a closed vessel. More recently, Volto, Beachans, and Pasteur worked with biogas-producing organisms. At the turn of the 20th century, communities in England and Bombay, India, disposed of wastes in closed containers and collected the resulting gas for cooking and lighting. Germany, the United States, Australia, Algeria, France, and other nations constructed such methane digesters to supplement dwindling energy supplies during the two world wars.

### NEEDS SERVED BY THE TECHNOLOGY

Biogas generators or digesters yield two products: the biogas itself, and a semi-solid by-product called effluent or sludge.

Biogas systems are most popular for their ability to produce fuel from products that might otherwise be wasted--crop residues, manures, etc. The fuel is a flammable gas suitable for cooking, lighting, and fueling combustion engines.

The digested waste--sludge--is a high quality fertilizer. The digestion process converts the nitrogen in the organic materials to ammonium, a form that becomes more stable when plowed into the soil. Ammonium is readily "fixed" (bonded) in soil so that it can be absorbed by plants. In contrast, raw manure has its nitrogen oxidized into nitrates and nitrites, which do not "fix" well in soil and are readily washed away.

Moreover, biogas systems offer a means to sanitize wastes. Simply put, these systems are capable of destroying most bacteria and parasitic eggs in human and animal wastes, enabling the digested sludge to be applied safely to crops. Tests have shown that biogas systems can kill as much as 90 to 100 percent of hookworm eggs, 35 to 90 percent of ascarid (i.e., roundworms and pinworms), and 90 to 100 percent of blood flukes (i.e., schistosome flukes, which are found in water snails that commonly live in paddy fields and ponds).

Biogas systems are also capable of digesting municipal sewage, which is a major source of pollution. Using biogas systems in this way substantially reduces the potential for environmental pollution.

Finally, agricultural and animal wastes, the major raw materials for biogas production, are usually plentiful in rural areas. People living in rural communities, who are often subjected to the price and supply fluctuations of conventional fuels and fertilizers, can benefit directly from biogas systems.

It should be noted that, while this paper focuses on the production of biogas for fuel, in some applications the gas is considered to be the by-product of the process. Some digesters in China, for example, are used primarily for treating sewage and producing fertilizer, and only secondarily for producing fuel.

## II. OPERATING PRINCIPLES

### BASIS OF THE TECHNOLOGY

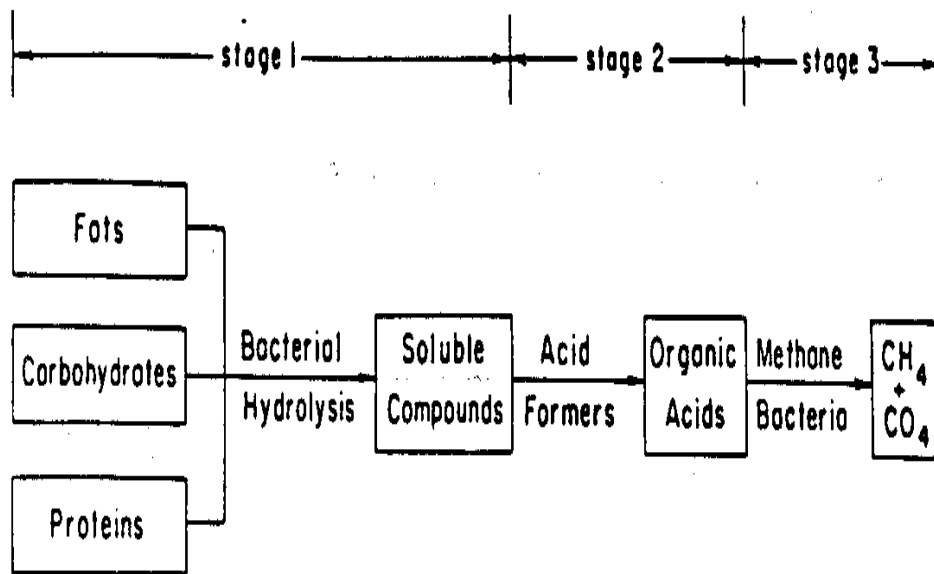
Biogas generation is a process that takes place in an oxygen-free environment. It uses anaerobic bacteria--bacteria that live only in the absence of oxygen--to break down complex organic compounds in fairly well-defined stages. The process is called anaerobic digestion. It produces biogas, a gas composed of approximately 50 to 60 percent methane, 40 to 50 percent carbon dioxide, as well as water vapor and a small quantity of nitrogen, sulfur, and other trace compounds. Biogas is flammable, which is what makes it useful, but it has a relatively low heat content, approximately 6.1 Calories per liter (around 600 BTU per cubic foot). Compare this with pure methane, which has a heat value of 995 BTU per cubic foot, or natural gas with over 1,000. Nevertheless, biogas can be an important fuel source for many applications.

A biogas digester is the device in which the digestion process occurs. The organic feedstock, which is called the substrate, may consist of night soil, manure, crop or kitchen residues, or similar materials. The substrate is usually diluted with water, and is thoroughly mixed into a slurry; crop residues and vegetation are usually cut or chopped into small, fairly uniform

pieces. It is then fed into the digester and permitted to undergo degradation in a sealed oxygen-free chamber. When digestion is completed, the material is discharged, or removed from the digester. The biogas is collected for direct usage or pressurized for subsequent use. The discharged material is called effluent, or sludge.

The actual breakdown of organic material inside the digester is a three-stage process that leads to the production of methane (Figure 1).

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**Figure 1. Microbial Stages in Methane Production**

Source: D.J. Hills and D.W. Roberts, Basic Fundamentals of Methane Generators from Agricultural Waste (Davis, California: University of California, August 1980), p. 4.

In the first stage, numerous organisms release enzymes that attack specific bonds in complex protein, carbohydrate, and lipid compounds in the incoming substrate. This stage of degradation converts the compounds into simpler molecules. Another set of organisms further degrades the molecules to form short-chain volatile fatty acids. At this point, various methane-producing

organisms (or methanogens) use carbon dioxide or volatile fatty acids to produce biogas (a mixture of methane and carbon dioxide).

The principles of anaerobic digestion are the same regardless of the digestion vessel. Organic material is loaded into a fairly warm, temperature-controlled, oxygen-free environment and methane is produced after acclimatization. The makeup or quality of incoming material to be digested, the vessel, and the surrounding environment influence the digester efficiencies. The production of gases is greater when the digester is operated at a relatively high temperature, when the substrate is stirred or otherwise agitated, and when system conditions are kept fairly constant. A more detailed discussion of these and other factors influencing digester efficiency follows. In general, however, the important objective to keep in mind when operating a biogas digester is the production of the greatest volume of biogas in the shortest possible time.

## FACTORS INFLUENCING PERFORMANCE AND SIZE OF BIOGAS DIGESTERS

Researchers are only now gaining a better understanding of the metabolic process in biogas digesters. They do know, however, that methane-producing organisms (called methanogens) "prefer" to channel energy, or calories (derived by breaking down incoming substrate), to methane rather than use the energy to construct or satisfy internal cellular needs. As such, methanogens do not adapt well to changes in their environment that may require them to increase their numbers or adjust their internal mechanisms. If the environmental changes are significant enough, the methanogens may slow or even stop their work.

Changes that may affect the behavior of the bacteria and thus the performance of the digester include variations in the substrate, presence of certain toxic chemicals, gas pressure, temperature, and the amount of time the material remains in the digester.

Other factors that could have a major impact on the operating performance of a biogas digester include biological balance/acidity, solids concentration, agitation, feedstock, pretreatment, and the carbon-to-nitrogen ratio.

The primary factors that could affect the size of a biogas digester include the type and amount of feedstock, the rate at which it is loaded, and hydraulic retention time.

### Factors Influencing Digester Operating Performance

#### Biological Balance/Acidity

Methanogens--methane-producing organisms--live in a syntrophic, or complementary, relationship with certain other microorganisms that consume the feedstock and produce simple acids as part of their metabolism. The simplest acids are essential to the metabolic processes of the methanogens. As acid-producing organisms tend to choke in their own acetic by-products, methanogens cooperate by consuming these by-products in the methane-producing process.

Given sufficient time to establish the proper ratio of methane-producing organisms to acid-producing organisms, a homeostasis,

or stability, will occur with a pH of about seven in a digester. A digester fed poultry or high nitrogen waste may stabilize at a pH of eight or greater.

The objective here is to create a stable working relationship among the microbial population in the digester. This implies the need for fairly constant operating temperatures and feedstock characteristics. Conversely, any rapid variations of these conditions will cause the microbial population to shift dramatically and possibly upset the overall system balance in the digester. For example, if the methane-producing organisms become dormant due to, say, temperature fluctuations, the pH will drop so low as to incapacitate them.

Maintaining a stable pH requires stabilizing the feedstock as well as the operating temperature in the digester. If this proves impractical, adding lime or other buffering compounds to the digester will prevent the pH from falling. Note that the correct amount and type of buffering compound can be determined only on a case-by-case basis.

Four additional factors that could affect the overall system balance in the digester are:

1. The concentration of the incoming solid waste could vary and either increase or decrease the amount of food to be consumed by the digester.
2. Removing the slurry (the mixture of water and substrate added to the digester) from the digester or replacing it altogether, each day, will change the average age of the organisms in the digester.
3. The average characteristics of the material being consumed by the microbial population in the digester will change in response to any fluctuations in the amount of feedstock material removed each day.
4. The temperature, as well as the contents of the water used to dilute the incoming waste, will alter the nature of the food to be consumed by the digester.

### Operating Temperature

Operating temperature is another factor influencing digester efficiency. A digester can operate in three temperature ranges: (1) the low temperature, psychrophilic bacteria range, which is less than 35[degrees]C (90[degrees]F); (2) the medium temperature, mesophilic bacteria range, which is 29 to 40[degrees]C (85 to 105[degrees]F); and (3) the high temperature, thermophilic bacteria range, which is 50 to 55[degrees]C (135 to 140[degrees]F). Organic material degrades more rapidly at higher temperatures because the full range of bacteria are at work. Thus, a digester operating at a higher temperature can be expected to produce greater quantities of biogas. The disadvantage of an elevated-temperature digester is that even minor changes in system conditions could offset digester efficiency or productivity. Moreover, an additional source of energy will likely be required to maintain the digester contents at a constant higher temperature.

Though operating temperature is critical, stabilizing the temperature and keeping it stabilized are even more important. Variations of plus or minus 1[degree]C in a day may force the methane-producing organisms into periods of dormancy. These organisms consume acids, and without them acids will accumulate and the pH will fall, impeding the effectiveness of the whole biogas system.

In northern latitudes or colder climates, the volume of methane will be substantially less unless specific provisions are made to preheat the incoming substrate and maintain the digester temperature. Thus, in colder climates, larger digesters will likely be required. Moreover, the amount of digester surface constructed above ground should be reduced when temperatures are low.

One way to overcome the problem of lower temperatures is to dilute the daily incoming waste material with preheated (solar-heated) water. Or you can construct a greenhouse or compost pile around the digester.

Note that the amount and type of waste to be degraded as well as the operating temperature are two important factors governing digester size.

#### Solids Concentration

The moisture content of the digestion liquor (waste that is diluted) should be in the range of 5 to 12 percent total solids. The percentage of total solids should include a minimum of inorganic sands and soils. Incoming waste products may have to be diluted to a consistency of slightly thick cream. A rule of thumb for diluting cattle waste is 2.5 parts water for every one part of relatively dry waste or one part water for every one part of fresh manure.

#### Stirring the Digester Contents

The microorganisms degrading the waste material are living, metabolizing creatures that produce their own metabolic by-products. To prevent the bacteria from stagnating in their own waste products, and thus to promote a more rapid digestion, stir or agitate the digester contents by paddle, Scraper, piston, or in more sophisticated settings, by gas recirculation.

Agitation also helps to minimize the build-up of internal fibrous scum on top of the digestion liquor. Failure to break the scum may result in excessive gas pressures forcing substrate out of the openings instead of permitting the gas to escape through gas transport lines. The scum may also plug the digester. Digesters that are fed higher volumes of fibrous waste may require special design considerations.

#### Feedstock Pretreatment

Feedstocks sometimes require pretreatment to increase the methane yield in the anaerobic digestion process. Pretreating the feedstock (with alkaline or acid treatments, for example) breaks down the complex organic structures into simpler molecules that are then more susceptible to microbial degradation.

Thus, you may want to pretreat any incoming substrate whose volatile solids are not readily degradable. Note that microorganisms do not readily act upon rice hulls or sawdust.

Fibrous wastes also require special handling. Wastes with long fibers such as straw should be chopped or broken. Any given waste will digest more rapidly, and possibly even more completely, when broken into bits. Thus, the finer the waste is shredded, ground, or pulped, the easier the digestion process will be.

Scientific research has determined that minimum levels of nickel, cobalt, and iron are required for methanogens to degrade organic wastes more efficiently. This is of little immediate consequence to most farmers, as chemical analysis is required to determine whether addition of these elements would be helpful.

### Carbon-to-Nitrogen Ratio

If the carbon-to-nitrogen ratio is either too high or too low, or fluctuates substantially, the digestion process will slow or even stop. To act efficiently on the substrate, microorganisms need a 20-30:1 ratio of carbon to nitrogen, with the largest percentage of the carbon being readily degradable. Digesters have efficiently operated on poultry waste with a 5-7:1 ratio. The key here is to keep the quantity as well as the characteristics of the incoming substrate constant.

One note of caution: some carbon compounds resist being broken down. Lignin, for example, which all land plants use to help stiffen and support themselves, is the least readily degradable carbon compound. The amount of lignin increases proportionally with plant age. Thus, old grass contains more lignin than new grass, and wood contains more of it than do leaves. Remember, any substrate that contains a high percentage of lignin will not readily decompose in the biogas digester as well or as completely as substrates that contain lesser amounts. Thus, horse dung and mature vegetative waste material are probably not good feedstocks, because they contain a high fraction of non-degradable lignin.

### Presence of Certain Toxins

Certain medications (e.g., antibiotics used in animal feeds or injected into animals), feed additives, pesticides, and herbicides may have adverse effects on anaerobic bacteria, particularly the methanogens. For example, lincomycin (frequently used in treating swine) and monensin (often used in treating cattle) are two antibiotics that will harm these bacteria and immediately halt methane production.

### Factors Influencing Digester Size

Digester design depends basically upon the availability and type of waste to be fed to the digester, as well as the amount of gas and/or fertilizer required. Large digesters are generally designed after establishing system operating conditions through laboratory analysis. Small digestion plants are generally designed based on past experiences with a particular substrate.

A distinct advantage of small digesters over large ones is that



their contents require less vigorous and less frequent stirring (only several times a day) to prevent scum buildup and thus increase the production of biogas. A principal disadvantage of these digesters, on the other hand, is that their operating temperatures tend to fluctuate more often and to a much greater degree.

Nevertheless, feeding a biogas digester--regardless of its size--any number of individual or combined feedstocks or organic materials will result in the production of biogas as long as the proper conditions exist and are kept fairly stable. These conditions were researched initially for sewage treatment plants and more recently are the subject of intense investigation toward meeting the waste management needs of various agricultural and specialized industries.

#### Type and Availability of Raw Waste Material

Husbandry practices can influence the quantities of manure available for use in the digester. For example, cattle in pasture will scatter their waste over a large grazing area, making waste collection difficult. Conversely, a herd that spends most of the day in a confined area (e.g., a corral) will deposit waste in a concentrated area, making it possible to collect waste more easily. Moreover, manure deposited directly in the field will likely contain a lot of soil or grit, which will eventually clog the digester, and thus not be suitable for the production of biogas.

The amount of manure produced per animal per day varies. For example, one may expect about six pounds per day from a 1,000 pound beef or dairy cattle and about nine or 10 pounds per day from 1,000 pounds of broiler chicken. Remember, increased gas production is directly proportional to the amount of volatile solids in the raw waste used.

Under optimum collection conditions (i.e., when animal is confined), you get:

4 lb of manure per 100-lb sheep  
80 lb of manure per 1,000-lb dairy cattle  
60 lb of manure per 1,000-lb beef cattle  
10 lb of manure per 200-lb pig  
45 lb of manure per 1,000-lb horse  
0.2 lb of manure per 4-lb poultry layer

The rule of thumb here is that the waste material from two adult cattle will usually supply the gas required for cooking food for a family of four. Comparable quantities of other waste may produce slightly more or slightly less gas.

If you are considering relying on the use of a significant amount of vegetable waste in your digester, you need to know when such material will be available in the greatest quantities. For example, water hyacinth may be available year round in some climates, while grain straw or other crop residues will be most plentiful only at harvest.

Wilted or semi-dried vegetation may require the addition of water in order to maintain optimum solids concentration. Freshly-cut

young vegetation may require less dilution than freshly cut older plant material.

### Organic Loading Rate

The organic loading rate refers to the number obtained when the weight of the volatile solids loaded each day into the digester is divided by the volume of the digester. ("Volatile solids" refers to the portion of organic material solids that can be digested. The remainder of the solids are fixed. The fixed solids and a portion of the volatile solids are non-degradable. Organic material may also contain a substantial amount of water.)

Loading rate is an important parameter, since it tells us the amount of volatile solids to be fed into the digester each day. At high loading rates, the feeding has to be more nearly continuous (perhaps hourly). At lower loading rates, the biogas digester needs to be fed only once a day.

Digesters are designed to receive and treat from 0.1 to 0.4 pounds of volatile solids per cubic foot of digester volume. Although the actual loading rate depends on the type of wastes fed to the digester, 0.2 pounds of volatile solids per cubic foot of digester volume (approximately 3 kg per cubic meter) is a frequently used design parameter. This means a digester used to process mainly manure should be designed to accommodate from 20 to 120 cubic feet of digester volume per 1,000 pounds of live animal. (The actual amount varies from species to species.) Here, it is important to remember that a digester must be designed on the basis of the amount of waste that can be collected and actually fed to the digester, not on the quantity of waste produced.

For illustration, the following estimates are useful:

1 lb of volatile solids per 200-lb pig per day  
1 lb of volatile solids per 1-lb sheep per day  
0.04 lb of volatile solids per 4-lb poultry layer per day  
6 lb of volatile solids per 1,000-lb beef or dairy cattle per day  
9 to 10 lb volatile solids per 1,000 pounds of poultry layer

The percentage of water in animal waste on a unit volume basis is around 75 to 95 percent. Of the solids in the waste, about 70 percent are volatile. Percentage of water in vegetable and plant wastes varies from 40 to 95 percent. Of that, the percentage of volatile solids varies from 50 to 95 percent. The amount of biogas produced from vegetable and plant waste varies because various crops have differing biomass production rates.

With time, constant temperature, and a uniform incoming substrate, a digester will stabilize. The rules of thumb for any digester include:

1. Incoming substrate 5 to 12 percent total solids;
2. 0.2 to 0.5 pounds volatile acids per cubic foot of digester volume;
3. 1 to 2 pounds raw manure per cubic foot of digester space per day; and

4. 0.2 to 1.0 unit volume of biogas produced per unit volume of digester.

The actual amount of biogas that will be produced can be determined by experimentation under conditions similar to those at the site. One should experiment with various types of waste, the amount of water used to dilute an incoming waste, operating temperature, and feeding (loading) frequency.

A source of potential confusion in determining digester size is the means to measure gas production. When reading literature on biogas digesters, make sure that the gas production under discussion is in comparable units. Gas produced in a digester is biogas, of which 50 to 60 percent is methane; the remainder is carbon dioxide and other gases. Biogas volumes are distinct from methane volumes. Other ways of quantifying gas include: gas volumes per volume of digester, gas volumes per 1,000 pounds of live weight of an animal species, gas volumes per pound of volatile solids added, and gas volumes per pound of volatile solids destroyed.

### Hydraulic Retention Time

Hydraulic retention time (HRT) is the average number of days a unit volume of substrate is to remain in the digester. Put another way, HRT is the volume of material already in the digester divided by the average amount of incoming daily feedstock, or the average age of the digester contents. The HRT will vary from 10 to 60 days, and is an important parameter because it influences the efficiency of the biogas digester.

Closely controlled digesters will average about 20 to 25 days retention time. Shorter retention times will create the risk of washout, a condition where active biogas bacteria are washed out of the digester at too young an age, making the population of bacteria unstable and potentially inactive. Daily conversion of organic material to methane will continue to increase per unit increase of weight (i.e., age) of bacteria up to a certain point. Thereafter, methane production will drop off per unit weight (or age) of bacteria.

Note that a longer retention time requires a larger digester and more capital for its construction. Recall, however, that the smaller the digestion vessel, the less time the methane-producing bacteria will have to act on the available substrate and thus the more likely the biogas system could malfunction. One should consider all these factors carefully before choosing a system.

### III. DESIGN VARIATIONS

There are two general design characteristics of digesters: batch feed and continuous feed. The batch digester is loaded, sealed, and after a period of gas collection, emptied. A batch digester can essentially be any suitably sized container or tank that can be sealed and fitted with a means to collect the biogas. The continuous feed digester receives substrate on a continuous or daily basis with a roughly equivalent amount of effluent removed. There are many possible design variations for continuous feed digesters.

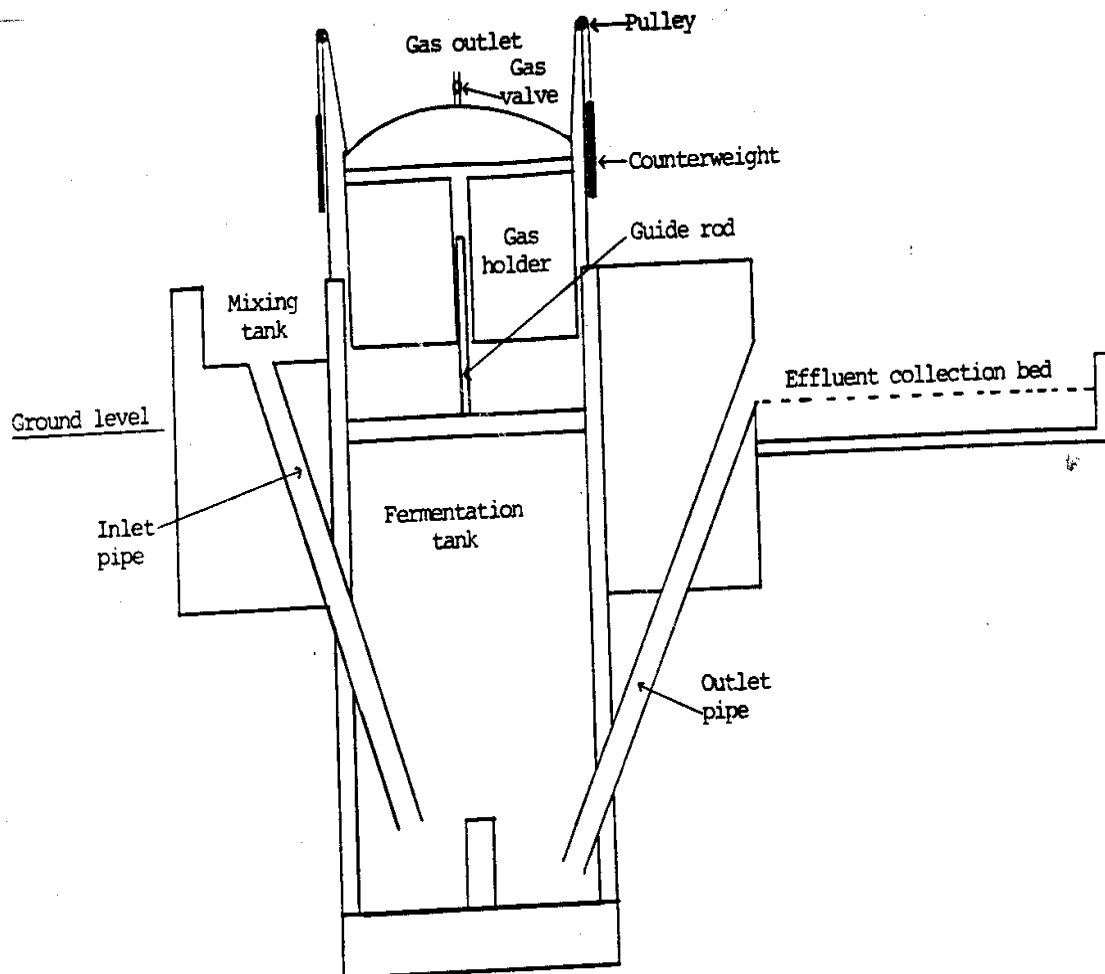
## CONTINUOUS FEED DIGESTERS

The design variations for continuous feed digesters can be divided into four distinct types: the Indian design, the Chinese design, the sewage treatment plant, and the hybrid design. Each of these types, along with cost and construction considerations, is described in the sections that follow.

### Indian Design

The Indian, or Khadi, design (Figure 2) is based on the principle

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**Figure 2. A Typical Indian Biogas Plant**

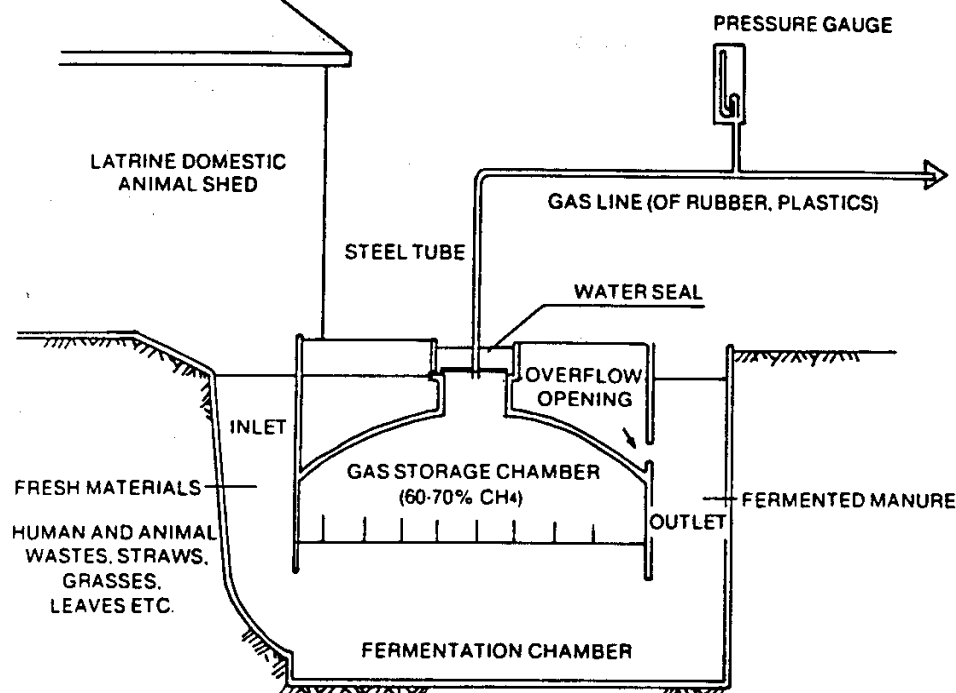
that gas produced will lift a bell-shaped dome located above the digestion vat. Substrate enters one side of the digester and displaces effluent out the other side. As gas is produced, it is collected under the dome, forcing it to rise. The dome descends as gas is forced out of the digester into the gas transport

lines.

### Chinese Design

The gas storage chamber in the Chinese design characteristically has a fixed top (Figure 3). Substrate enters one side; effluent

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**Figure 3. Idealized Chinese Design**

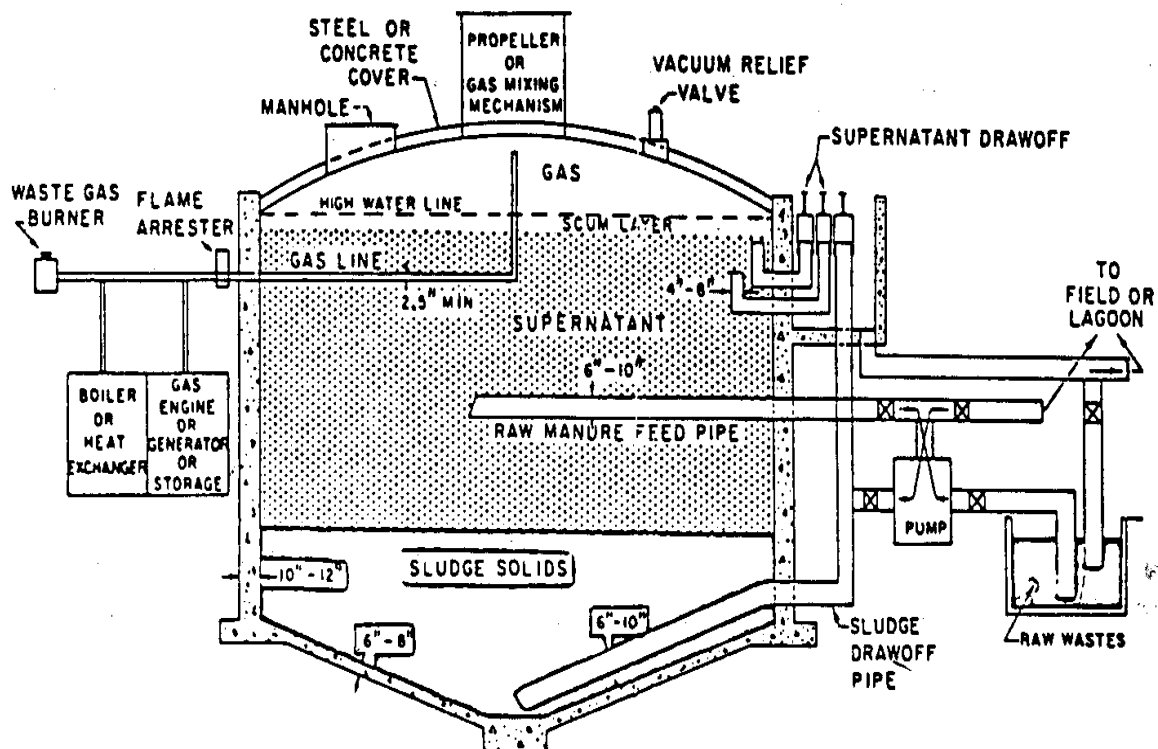
**Source:** A. Barnett, L. Pyle, and S.K. Subramanian, Biogas Technology in the Third World: A Multidisciplinary Review, (Ottawa, Canada: International Development Research Center, 1978), p. 42.

exits the other side. Gas produced accumulates under the dome and above the vessel contents. Increases in gas volume displace digester contents into the displacement, or overflow, chamber. The materials forced into the displacement chamber will, by virtue of gravity, attempt to flow back into the digester. The attempt by the displaced liquor to flow back into the digestion vessel creates the pressure to force the gas into the gas transport line. As the gas is used, materials displaced into the displacement chamber will flow back into the vessel.

Sewage Treatment Plant

Though the designs associated with treating sewage or industrial wastes follow the same basic principles of the Indian and Chinese designs, they are much more complex and more efficient. The digester content is stirred either by paddle or gas recirculation. Temperature controls are much more stringent and digester content may be heated. The effluent exits the plant and is thickened prior to final disposal. Gas is tapped from the digester, possibly pressurized, and used for heating purposes or flared; it may be used for process heat in the digester. The sewage treatment plant principles may be employed on a much smaller scale with lower levels of technology. Figure 4 shows a high-technology

ubg4x14.gif (600x600)



**Figure 4. A Typical Fixed Wall Sewage Treatment Plant**

Source: P. Targanides, "Anaerobic Digestion of Poultry Waste,"  
World Poultry Science Journal 19 (1962):252-61.

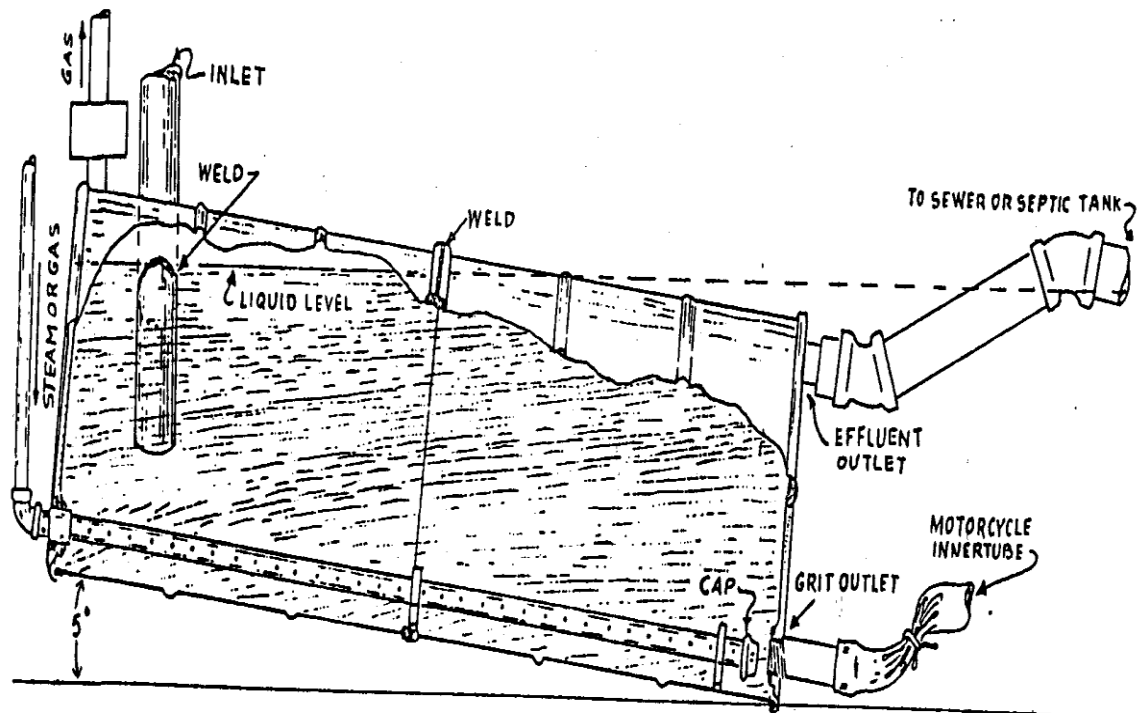
sewage treatment plant.

Hybrid Designs

Hybrid digesters imitate the principles employed in other designs,

except that digestion vessels conform to the least expensive, most readily available construction materials. They can be built from available scrap materials, plastic bags, or covered troughs. A very simple design is the end-to-end welding of 55-gallon oil drums to create a long, narrow, small-volume continuous feed digester. With hybrid digesters, care must be taken not to let construction economy offset digester efficiency or productivity. Figure 5 shows a low-technology hybrid digester.

ubg5x16.gif (600x600)



**Figure 5. A Low-Technology Hybrid Digester**

Source: D. House, The Compleat Biogas Handbook, Aurora, Oregon, 1980, p. 308.

#### Comparison of Continuous Feed Digesters

The more sophisticated biogas digesters require skilled people to build, operate, and maintain them. Such digesters will likely be more economically feasible if they are used to process large quantities of waste. Although a high-technology digester does produce considerably more gas than either the Indian or the Chinese design, it has higher capital and operating costs and

requires careful monitoring on a daily basis.

The Indian and Chinese designs are less expensive and easier to build and operate, but those benefits are countered by fairly inefficient gas production. Moreover, leakage may become a problem if the digesters are not maintained well. Although the Indian design produces slightly more gas than the Chinese design, it is slightly more expensive and has the added maintenance requirements associated with the floating dome.

## APPLICATIONS

Biogas can be burned directly as a fuel for cooking, lighting, heating, water pumping, or grain milling, and can also be used to fuel combustion engines. In larger applications where scale and skills warrant, biogas can be pressurized and stored, cleansed for sale to commercial gas suppliers, or converted to electricity and sold to power grids, to meet peak energy needs.

Gas transport lines are connected to the gas-collection chamber of the digester (the floating dome of the Indian style digester). The gas has a high moisture content. It is necessary to devise a way to remove the moisture before the gas is used. One way is to slope the transport line back toward the digester so that the moisture will flow down the line back into the tank. If this is not practical, it will be necessary to install a sump, or chamber, in the gas line to collect the moisture.

Biogas is also very corrosive. It may contain dangerous amounts of hydrogen sulfide, a poisonous flammable gas that produces a highly corrosive acid when mixed with water. For this reason, gas transport lines must be corrosion resistant. Polyvinyl chloride (PVC) plastic pipe is a good choice for gas lines because it is durable, corrosion resistant, and usually economical. Because the gas is so corrosive, it may have to be cleansed before it is used, particularly in engines.

While biogas is an excellent fuel, it does have a fairly low energy value for its volume--500-600 BTUs per cubic foot--and the pressure in the distribution lines may be low. Lamps, stoves, refrigerators, and other appliances require specially designed jets to offset the low energy value and the low gas pressure. To stabilize the flame on a cookstove, for example, the jet forcefully shoots the biogas up through and out of the burner. Jets can either be purchased or built easily from locally available materials.

The amount of methane required daily per household will vary. About 0.5 to 1.0 cubic meter of biogas is required per family member for food preparation alone, and roughly one cubic meter of biogas is produced per 1,000 pounds of animal. Meeting one family member's cooking requirements, then, requires two or three healthy dairy or beef cows, or eight to 10 pigs (weighing 150 to 250 pounds each), or over 500 chickens. The amount of waste material produced by these animals varies with their health and diet and will influence the number of animals required. Collecting more than 30 to 40 pounds of waste daily per 1,000 pounds of live weight per animal will increase the amount of gas produced per animal.



The effluent leaving the digester at the end of the digestion period is spread on farmland much as the undigested manure, etc., is used. Research has been performed on using the digester effluent to feed cattle or to promote algal growth in fish ponds, as is done in some Chinese aquaculture installations.

## CONSTRUCTION MATERIALS

The equipment and materials required for digester construction depend upon the level of technology employed. The basic Chinese design requires cement, sand, clay, lime, and bricks. Sulfate-resistant cement should be used if available due to the corrosive nature of the gas and slurry. The Indian design requires these same materials, plus some welding and iron works. The higher technology designs may require some specific machinery and electronics.

The following are generalized examples of the types and quantities of materials required to build similar sized Chinese- or Indian-style digesters.

A Brace Research Institute publication (1976) reports the following materials for an Indian-style, 3-cubic meter digester that should produce sufficient gas for the cooking needs of a family of six to eight members:

- \* 9 meters galvanized iron sheet
- \* 3,200 small construction bricks
- \* 25 50-kg bags of cement
- \* 12 cubic meters of sand
- \* various angle irons, iron pipes, etc.

The Khadhi and Village Industries Commission in Bombay, India, lists (in part) the following materials for a 3-cubic meter horizontal digester:

- \* 2,870 bricks
- \* 3.2 cubic meters of sand
- \* 1.9 cubic meters of 1/2" to 3/4" rock
- \* 24 bags of cement
- \* 7.5 meters of sheet steel
- \* various angle irons, pipes, reinforcing rods.

A masonry wall Chinese style digester of 8 cubic meters calls for:

- \* 400 kg of cement
- \* 1,000 kg of sand
- \* 1,000 bricks
- \* various plastic tubes for gas delivery.

Small-scale, nonpermanent digesters can be constructed of oil drums or uniformly-supported plastic bags.

The above materials are meant only for demonstration purposes. Actual type and quantity of materials required depend on design. Note, however, that smaller biogas digesters are generally built with readily available materials.

## SKILLS REQUIRED TO PRODUCE AND OPERATE A BIOGAS DIGESTER

The basics of a digester can be creatively adapted by competent, local craftspeople working with locally available materials.

The Chinese design requires the skills of a competent mason. The Indian design requires the skills of a competent mason as well as an iron worker and welder.

More sophisticated digesters for larger scale applications require plumbers and electricians. Careful planning is required prior to building such facilities.

Once constructed, the digester requires the daily attention of a semiskilled individual. Each day, the digester must be fed and agitated, and the effluent properly disposed of. Just as a caretaker tends to a herd of animals, the individual responsible for the digester must understand the operational procedures. This person must maintain not only the digester's physical plant, but also ensure that the gas transport line and gas utilization system are operative and in good repair.

## COSTS

Costs for construction are governed by the level of technology employed. They range from a few dollars for digesters built of readily available scrap to a few hundred dollars for a small family, Chinese-style digester, and from several hundreds of dollars for a small-scale Indian-style digester to several hundreds of thousands of dollars for a large-scale operation. A rule of thumb for comparable sized digesters is that the Chinese-style digester costs half that of a "drum"-style Indian digester. A more sophisticated digester will cost at least three times that of an Indian-style digester of comparable volume.

Actual costs depend upon the availability of resources. Large numbers of semi-skilled laborers, for example, suggest that construction of a Chinese-style digester would be more economical.

On the other hand, even though an Indian-style digester costs more initially to construct, it is nevertheless more efficient, requires less maintenance, and produces more gas than a Chinese-style digester. Larger, more sophisticated digesters require markedly higher initial capital costs than smaller, less complex units. However, they are more efficient in terms of the total volume of organic material that can be handled per unit volume of digester, and they produce more gas per unit of organic material handled. To do a thorough cost analysis one must take into account such factors as inflation, interest rates, operating costs, maintenance expenses, labor costs, and the value of replacing conventional fuels (e.g., oil, gas) with biogas.

## EFFICIENCY

The amount of biogas varies from 30 to nearly 100 cubic feet per 1,000 pounds of live body weight. Thus, there is no universal formula to determine biogas efficiency. To do so, one must consider many factors.

For example, biogas efficiency varies, depending upon how the biogas is used. Biogas plants use organic wastes, which, if not

fed to a digester, are at best spread over land or at worst directly burned. Although direct combustion of dung or grasses yields at best 10 percent of the available energy, the nutrient values of such wastes are severely reduced. Biogas systems yield 40 to 50 percent, or better, of the thermal potential of organic wastes and yield a fertilizer of superior quality. Composting provides excellent fertilizer with no gas. Other, much more sophisticated procedures are also available for more efficient removal of energy from waste.

Moreover, efficiency varies with the type of digester, the operating conditions, and the type of material loaded into the digester. All else equal, the Chinese-style digester produces about half as much gas as the Indian-style digester, which in turn yields less than half the gas of more sophisticated units. The Chinese design, the Indian design, and the high-technology designs, respectively, yield about 0.2 to 0.3, 0.5 to 0.7, and 1.0 to 2.0 volumes of biogas per volume of digester. And, in general, digesters produce more gas with poultry waste (about 100 or so cubic feet of biogas per 1,000 pounds of live poultry weight) than they do with cattle waste (25 to 30 cubic feet per 1,000 pounds of live cattle weight).

Apart from these factors, the key to maintaining efficiency is to feed the digester a uniform feedstock daily, to maintain a constant operating temperature, and to agitate the contents regularly.

## MAINTENANCE REQUIREMENTS

Biogas digesters require careful maintenance. Operators should be responsible for the following maintenance activities:

- \* **Daily Activities:** Collect and prepare the feedstock, and load it into the digester. Collect the liquid effluent from the digester. It may be spread over fields, used to fertilize fish ponds, or dried for later use.
- \* **Periodic (at regular intervals) Activities:** Remove the digester contents, including any solids that have accumulated at the bottom of the digester. Because of the potentially corrosive nature of the digester contents (slurry as well as gas), check all metal components of the digester to see whether they need to be resurfaced (e.g., the metal dome of the Indian-style digester).
- \* **Occasional (at irregular or infrequent intervals) Activities:** Check the digester, particularly Chinese-style digesters, for any gas leaks. Also, examine components in high-technology units such as pumps and mixers, which require occasional repair or replacement.

Finally, preventing sand, dirt, and gravel from mixing with dung as it is being collected, and protecting the dome of the digester with a metal or asphalt coating, will lengthen time between maintenance.

## IV. COMPARING THE ALTERNATIVES

### CURRENT RESEARCH AND DEVELOPMENT

#### Biogas Generation Technology

Extensive research continues with the various biogas generation plants operating worldwide. Various institutions throughout the world are conducting research toward making maximum use of the biogas produced. This involves matching energy needs to gas production, and using equipment that burns or converts the gas more efficiently. Additional research deals with digester designs and design parameters; here, heat losses and maintaining an adequate, stable temperature in the digester are of prime interest to researchers in their efforts to maximize methane production. Other research efforts focus on improvements in the use of digester effluent to promote maximum growth of algae, fish, aquatic vegetation, and farm animals.

#### Competing Technologies

More sophisticated and expensive biomass conversion technologies exist to convert organic material to charcoal, producer gas, crude oil, simple sugars, alcohol, plastics, or other chemicals. Pyrolysis, which may be used to produce crude oil, for example, or distillation, which yields ethyl alcohol, are examples of these technologies. These technologies have been introduced in many developing countries, but further research is required before they can be widely applied.

### COMPARISON OF TECHNOLOGIES

This paper focuses on biogasification as a means of producing fuel from material that might otherwise be wasted or that has only a single end use, for example, as fertilizer. The alternative biomass conversion technologies are burning raw waste to get rid of it, composting, distillation, burning raw waste to provide process or other heat, gasification, and pyrolysis. To compare all of these technologies, you must examine each technology separately, weighing its advantages and disadvantages and taking into account such factors as the availability and cost of capital, energy costs, the relative value of a particular raw waste and the end products it produces, the availability of human and material resources, and the impact of the technology on the environment. The discussion below presents some examples of the kinds of factors you need to consider in balancing one technology against another.

If the sole objective is to reduce waste, burning raw waste may be a good choice, provided it is sufficiently dry, air pollution is controlled, and there is a means to dispose of the ash. One disadvantage of burning raw waste for disposal is that it is a very inefficient use of energy. The energy produced by burning is wasted. In some situations, simply making the waste material available to people who can use it for cooking fuel may be a more effective means of disposal. And it does help assure that the heat energy will be put to use.

Composting is an excellent way to turn waste products into a commodity--fertilizer--simply and economically. One disadvantage

of composting is that some of the nutrients in the raw waste--particularly nitrogen, phosphorus, and potassium--convert to a gas, evaporate, and are lost to the atmosphere, or they leach out through the soil. Moreover, composting is limited to producing only fertilizer.

If you want to do more with raw waste than composting or just getting rid of it--that is, if you want to harness the energy from the raw waste material to produce fuels or other products--you will need to make additional investments in capital, materials, and labor. As we have seen in this paper, a biogas digester yields both a fuel gas and a high quality fertilizer. Unlike composting, the digestion process retains and even improves the nutrient value of the original feedstock. With biogasification, raw wastes can be digested, and returned to the environment in the form of fertilizer and fuel, without degrading the environment. Keep in mind, however, that the equipment (e.g., a digester, systems, pumps) necessary for biogasification will generally be more expensive than the equipment (e.g., a wagon equipped with a loader, a manure spreader) necessary for composting.

The remaining four biomass conversion technologies--distillation, controlled burning to provide process or other heat, gasification, and pyrolysis--collectively produce an even wider range of products than biogasification. Distillation of raw wastes produces sugar and alcohol, for example; controlled burning produces heat to, say, a boiler. Pyrolysis produces biofuels such as charcoal and crude oil; and gasification produces still other biofuels such as low- and medium-energy gas (often called producer gas). These four technologies differ chiefly in their equipment requirements (i.e., depending on the technology, the hardware can be as simple as a cookstove or retort or as intricate as a distillation plant), in their techniques (i.e., some techniques are more complex than others, resulting in higher product yields), and in costs.

In sum, comparing one biomass conversion technology with another must be based on what end products you want from the technology, end product user how much you are willing to spend, relative economies of scale, skill levels, availability of raw waste materials, environmental impact, and many other factors.

## V. CHOOSING THE TECHNOLOGY RIGHT FOR YOU

### ECONOMIC IMPACT

Economics are a major factor in deciding whether or not to introduce a biogas system. To determine the economics of such a system, you need to consider such factors as availability and cost of biogas (based on BTU), cost of equipment, capital costs, labor costs, energy availability/needs/cycles, material availability and costs, and anticipated returns. Remember, also, to factor into the cost analysis inflation and capitalization expenses. All cost factors and the resulting analysis will vary from country to country.

### SOCIAL/CULTURAL IMPACT

Certain social/cultural questions need to be addressed. For example, is daily waste handling acceptable or taboo? Moreover, to

succeed, a biogas technology must interface with existing practices: can existing waste management practices be adapted, for example, to include a digester and effluent disposal? What happens to the very poor who have traditionally collected cattle dung freely to use for fuel when the dung is used in a digester and the fuel is available only to those who can pay for it? Who controls the distribution of the gas in a community system?

## AVAILABILITY OF RESOURCES

Technical resource considerations include taking into account the availability of a constant, high-quality supply of organic material, the suitability of the ambient temperature, the availability of good-quality water with which to dilute the feedstock, whether the biogas produced can be used efficiently, and whether the space is sufficient for effluent disposal and usage. Moreover, keep in mind the need for a biogas plant, whose construction and operation depend upon the availability of capital, personnel (skilled and semiskilled), and materials.

## REGULATIONS

Consult local officials about any local regulations and laws that may prevent you from building or using a biogas generator. On the positive side, some laws might work in your favor. For example, the governments of some developing countries provide investment incentives, grants, or low-interest loans to people who want to introduce a biogas plant. Such governments are actively pursuing national policies that would reduce dependence on imported fuels and so encourage the production of biogas as an environmentally safe fuel source.

## LOCAL MANUFACTURE

Chinese- and Indian-style biogas generators can generally be built in-country, since plant components are usually available locally. Certain components, i.e., the dome and guide mechanism of an Indian digester, can be manufactured on a larger scale and sold to users.

## SCALE OF PRODUCTION AND POTENTIAL MARKET

Subsistence farmers who depend on firewood for cooking and heating comprise a substantial percentage of the world's population. Though biogas generation seems likely to at least supplement their current energy supplies, there are several reasons why biogas may not totally replace firewood:

- \* raw waste from the equivalent of several cows is required to meet a family's cooking needs;
- \* nearly all of the biomass conversion technologies require investments of capital usually available only to a few people in society;
- \* cultural norms may not permit waste handling or gas usage, or may limit availability of organic material if animals are pastured rather than confined; and

- \* biogas generation must be accepted and learned, a process dependent on motivated, knowledgeable extension agents or others who can point to successful applications of the technology, or who can demonstrate it effectively.

## SOURCES OF INFORMATION ON BIOGAS PLANTS

Director, Gobar Gas Scheme  
Khadi and Village Industries Commission  
Gramodaya  
Irla Road, Vile Parle (West)  
Bombay 400 056 INDIA

Head of the Division of Soils Science and Agricultural Chemistry  
Indian Agricultural Research Institute  
New Delhi 110 012 INDIA

Farm Information Unit  
Directorate of Extension  
Ministry of Agriculture and Irrigation  
New Delhi, INDIA

Gobar Gas Research Station  
Ajitmal, Etawah  
Uttar Pradesh, INDIA

Director, National Environmental Engineering Research Institute  
World Health Organization  
1211 Geneva 27, SWITZERLAND

Economic and Social Commission for Asia and the Pacific (ESCAP)  
Division of Industry, Housing, and Technology  
United Nations Building  
Bangkok 2, THAILAND

Bangladesh Academy for Rural Development  
Comilla, BANGLADESH

Appropriate Technology Development Organization  
Planning Commission  
Government of Pakistan  
Islamabad, PAKISTAN

CEMAT  
Apartado 1160  
Guatemala, GUATEMALA

OLADE  
Casilla 119  
Quito, ECUADOR

Volunteers in Technical Assistance (VITA)  
1815 North Lynn St., Suite 200  
Arlington, VA 22209 USA

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**MONTANA BIOMASS COGENERATION MANUAL:**  
**A WORKSHOP HANDBOOK**

*Prepared for*  
**MONTANA DEPARTMENT of NATURAL RESOURCES and CONSERVATION**

MONTANA BIOMASS COGENERATION MANUAL: A WORKSHOP HANDBOOK

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## I. INTRODUCTION

### A. BACKGROUND

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

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

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

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

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

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

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

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



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

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

#### **B. BIOMASS AS AN ENERGY RESOURCE**

Cogeneration systems can be fired with conventional as well as non-conventional fuels. Among the non-conventional fuels, biomass is an important energy source. The use of biomass as an energy resource is not

a new idea either. In the mid-1800's wood supplied over 90% of our energy needs; and as late as 1940, 20% of the homes in the U.S. used wood for space heating.

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

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

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

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

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



## II. COGENERATION TECHNOLOGIES

### A. INTRODUCTION

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

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

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

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

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

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

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

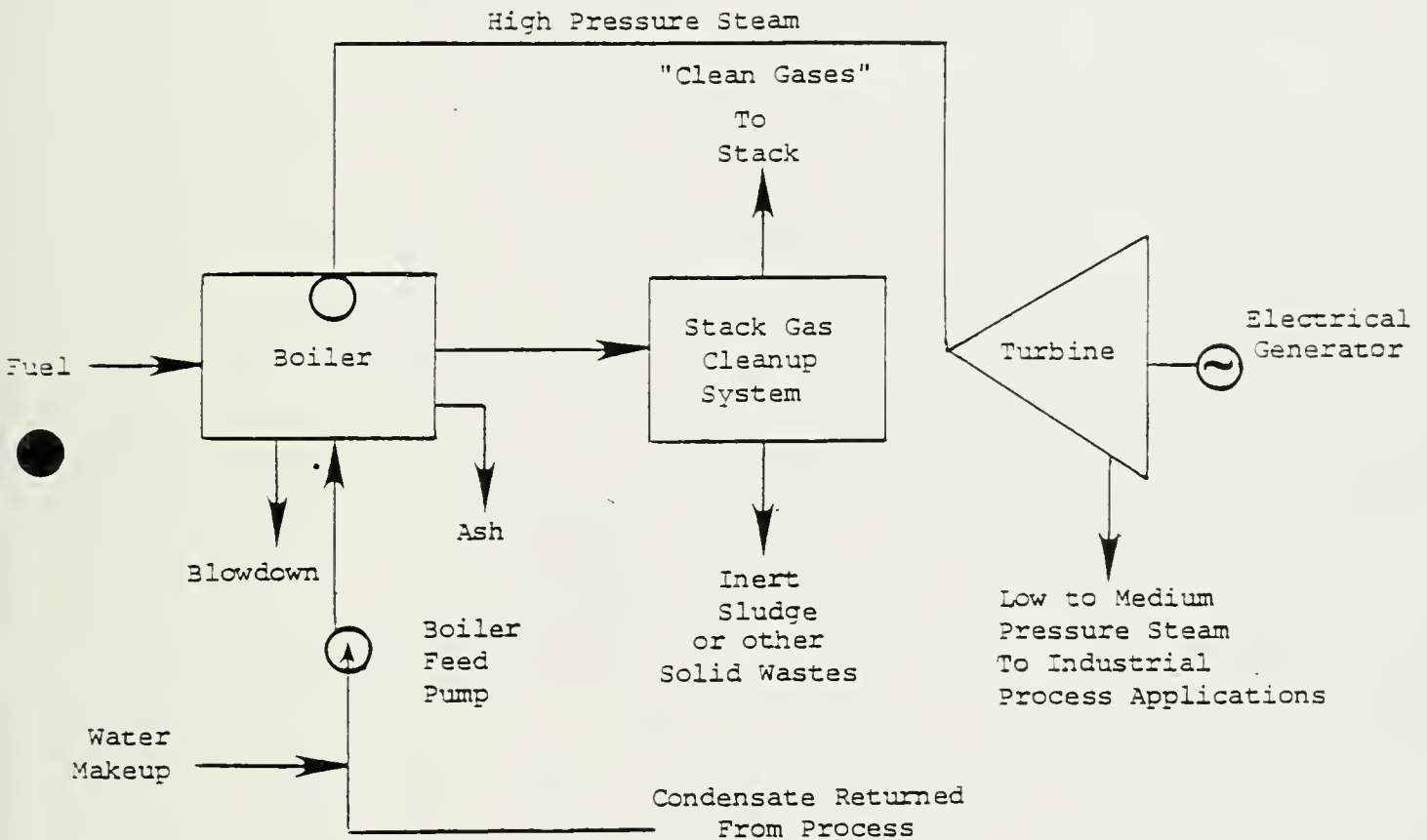
## B. SYSTEM DESCRIPTIONS

### 1. Steam Turbine Systems

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

Figure II-1

COGENERATION SYSTEM WITH A BACKPRESSURE STEAM TURBINE



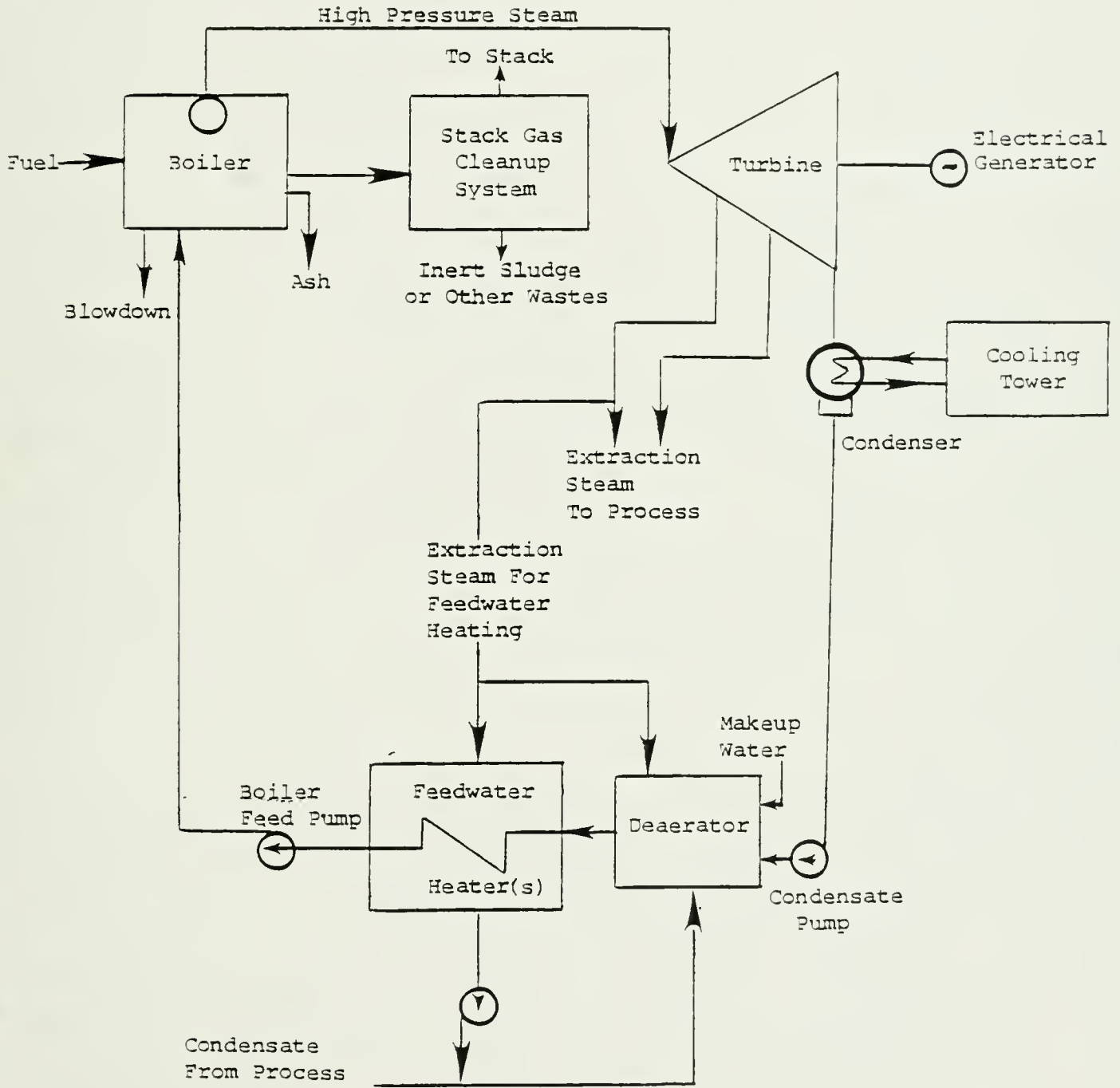
A schematic diagram of a cogeneration system using an extraction/condensing steam turbine is shown in Figure II-2. In this system, some of the steam exits the turbine at one or more intermediate points and supplies the process requirements while a large fraction of the steam is expanded in the turbine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

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

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

Figure II-2

COGENERATION SYSTEM WITH AN EXTRACTION CONDENSING STEAM TURBINE



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

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

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

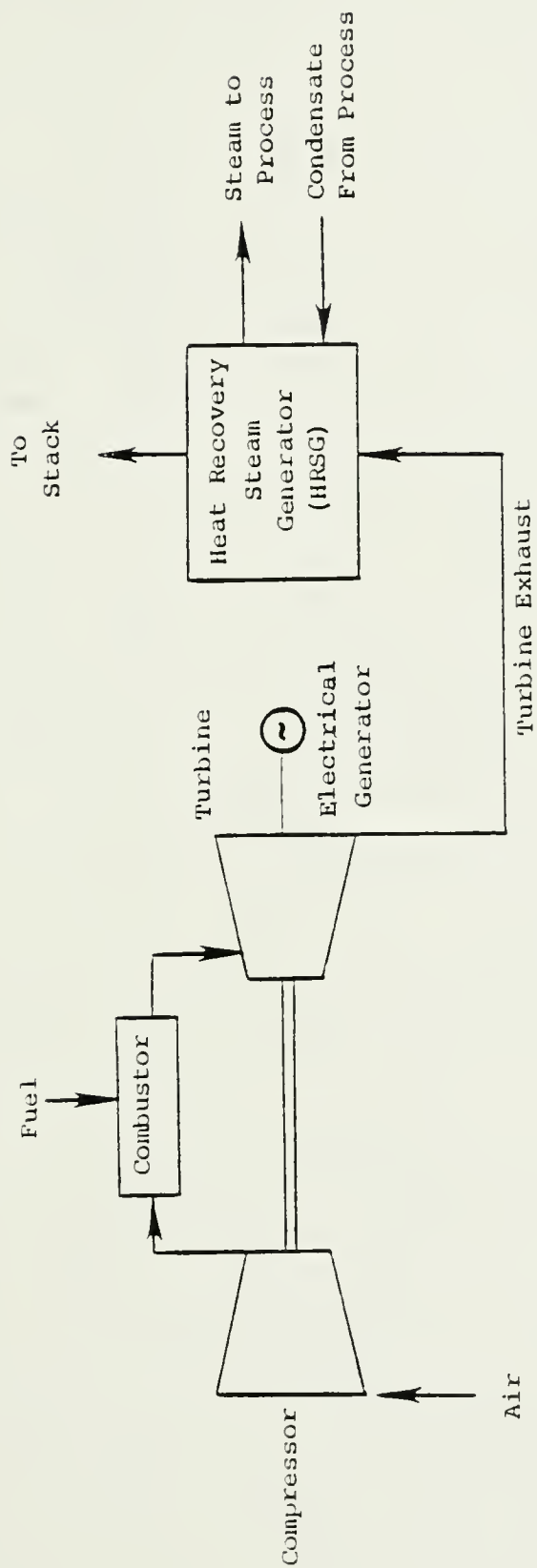
In a fluidized-bed combustion boiler, fuel is burned in a bed of inert particles suspended by air currents in the combustion zone. The bed is in constant motion, similar to a boiling liquid. This results in rapid heat transfer to the boiler tubes, located in the fluidized bed or the combustion chamber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

## 2. Combustion Turbine Systems

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

Figure 11-3

COMBUSTION TURBINE COGENERATION SYSTEM





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

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

### 3. Internal Combustion Engines

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

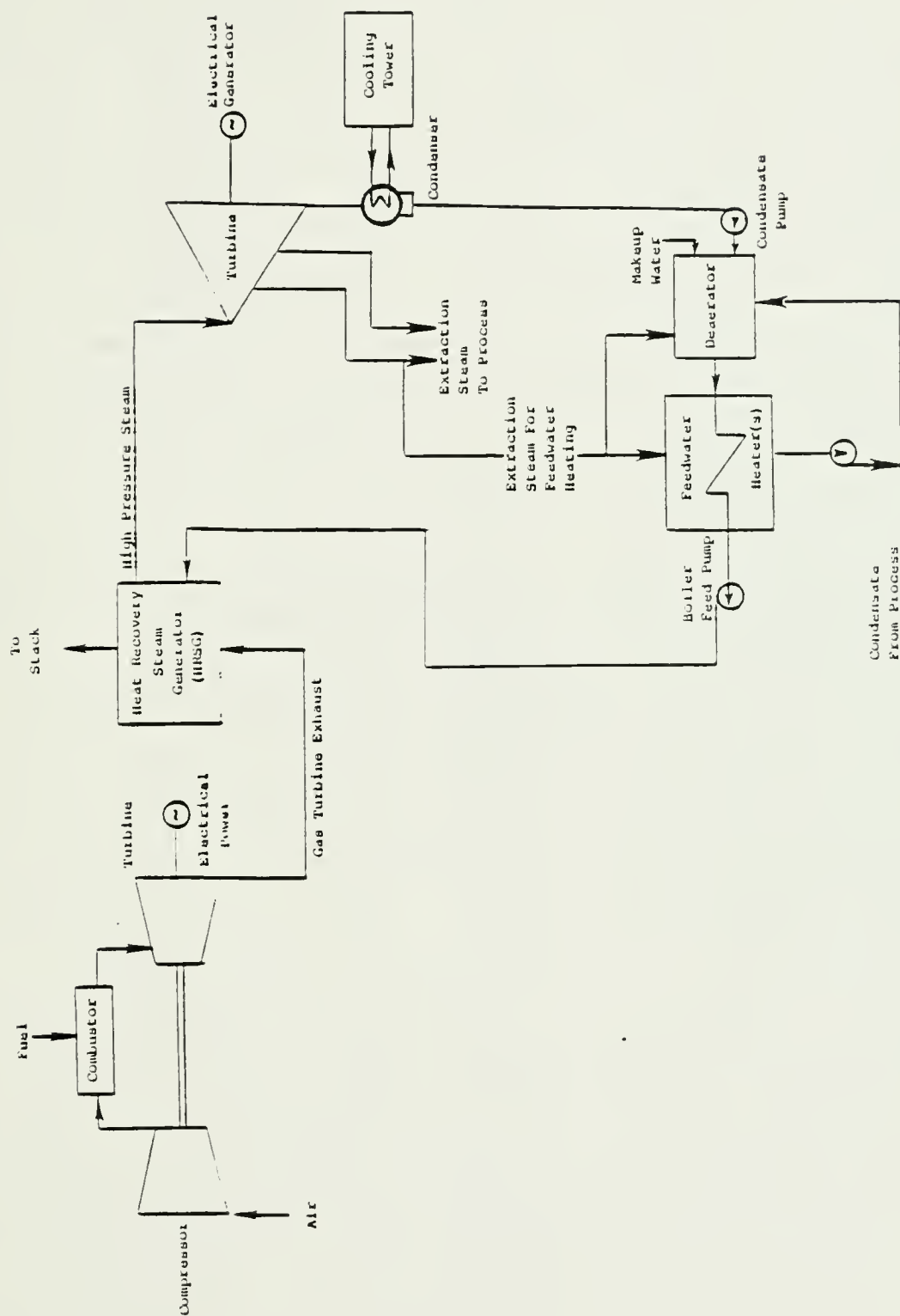
### 4. Combined-Cycle Cogeneration Systems

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



Figure II-4

COMBINED-CYCLE COGENERATION SYSTEM



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

## 5. Bottoming Cycle Systems

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

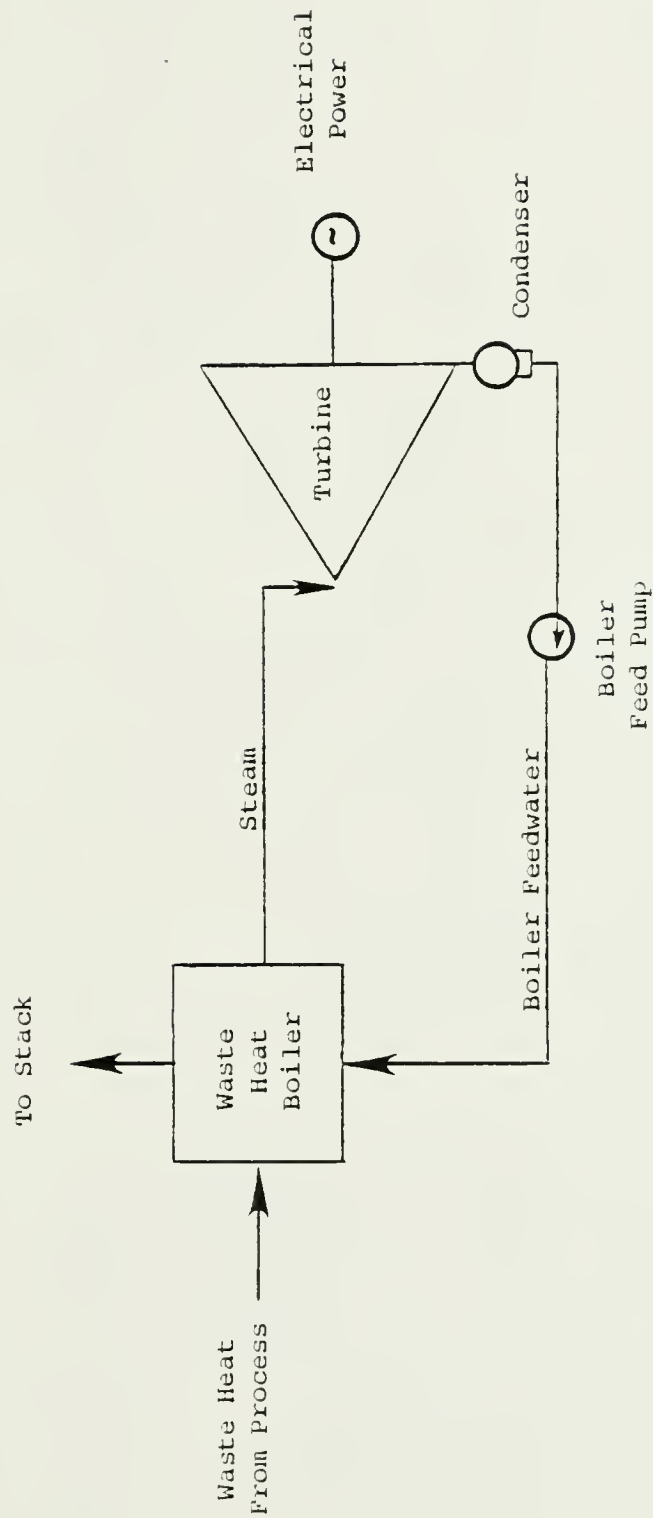
### • Steam Rankine Cycle

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

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

Figure II-5

STEAM RANKINE BOTTOMING CYCLE



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

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

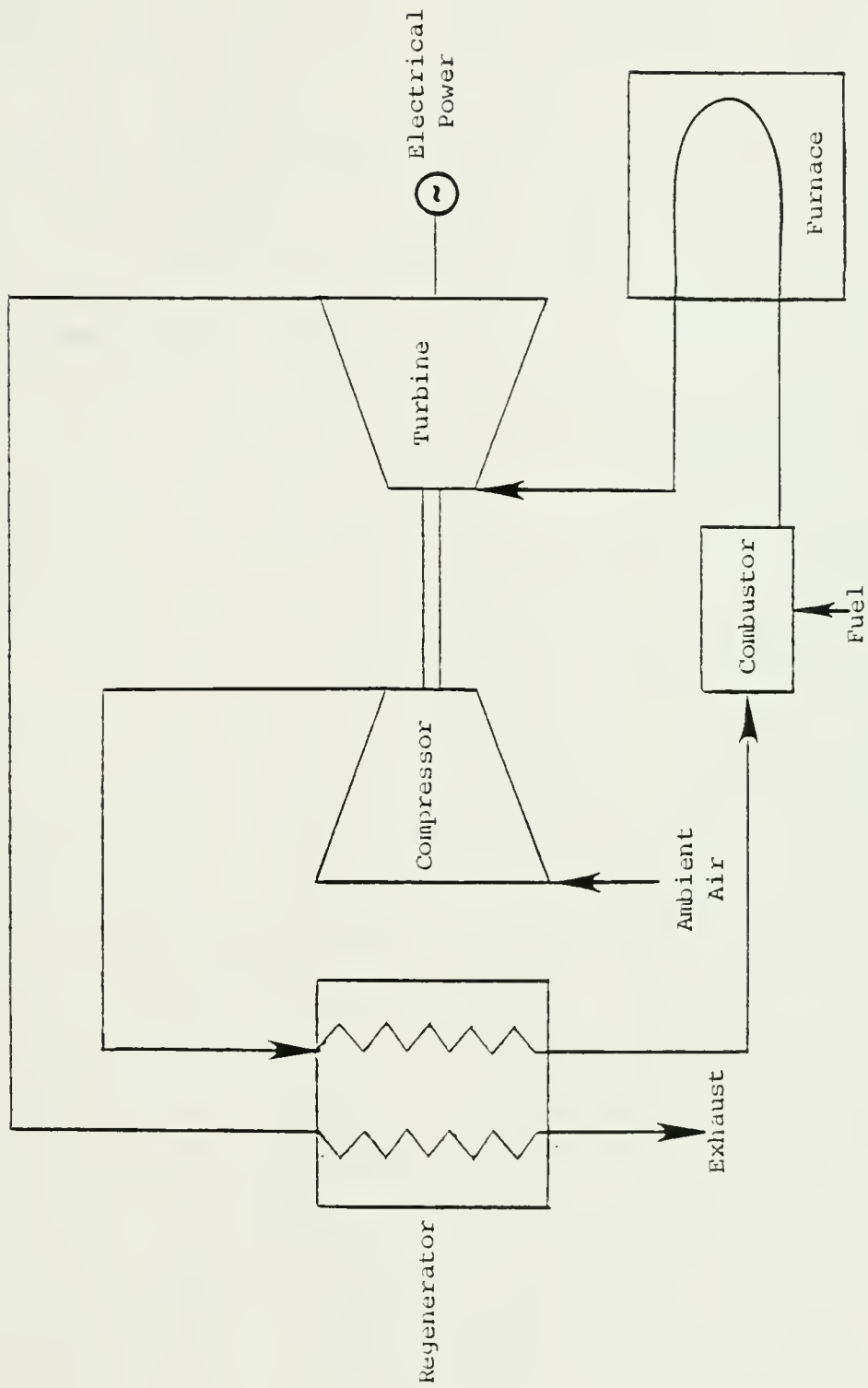
- Organic Rankine Cycle

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

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

Figure II-6

GAS TURBINE BOTTOMING CYCLE



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

- Gas Turbine (Brayton) Cycle

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

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

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

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

## 6. New Technologies

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

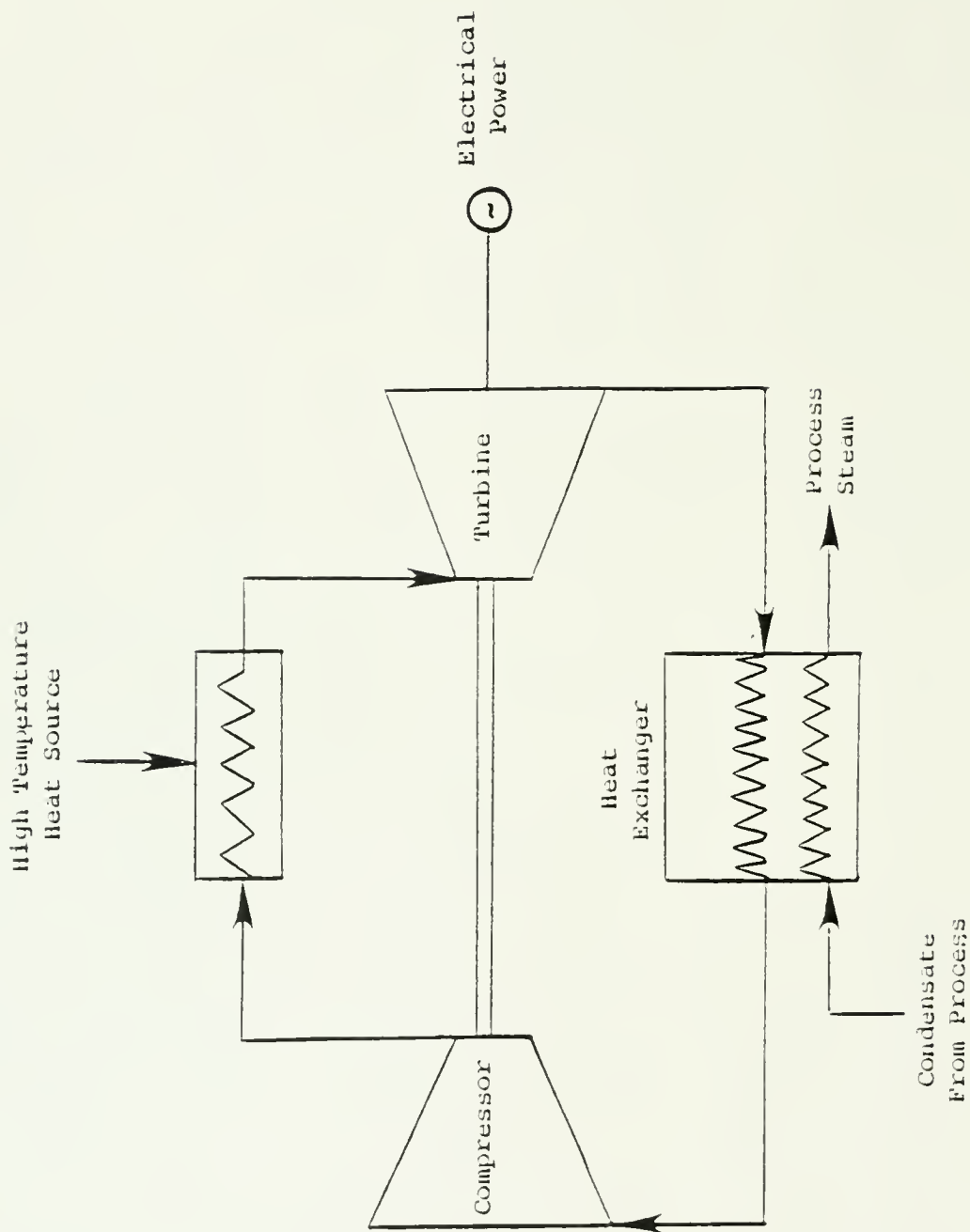
The gas turbine shown in Figure II-3 uses an open cycle, so named because the compressor inlet and turbine exhaust are at ambient pressure and are not directly connected. In a closed-cycle system, the compressor inlet and turbine exhaust pressures are greater than ambient. As a result, it is possible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

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



Figure II-7

CLOSED CYCLE GAS TURBINE COGENERATION SYSTEM





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

## C. COGENERATION SYSTEM CHARACTERISTICS

### 1. Total Installed Costs

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

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

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

Figure II-8

STEAM TURBINE COGENERATION SYSTEM INSTALLED COSTS

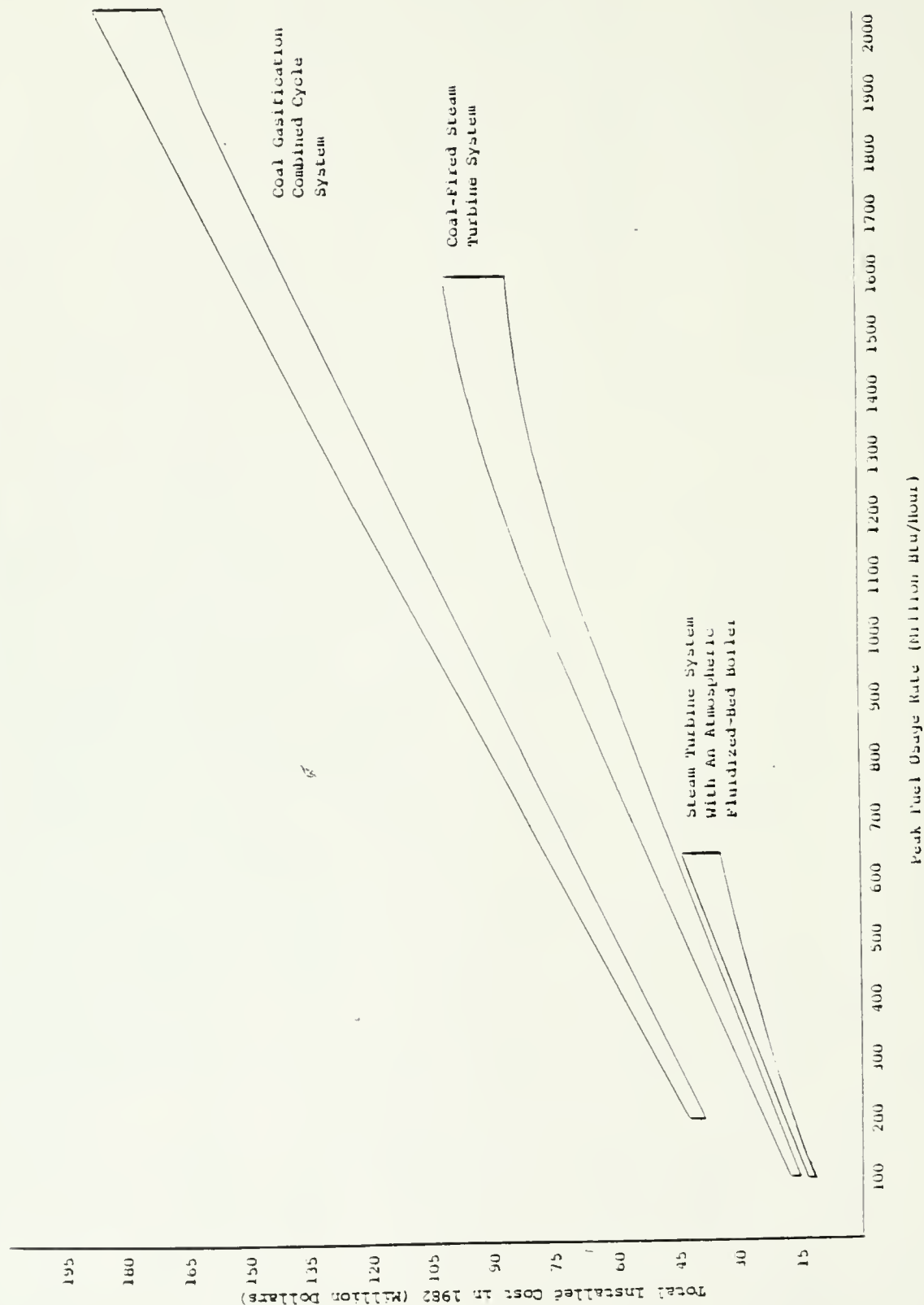


Figure II-9

COMBUSTION TURBINE AND COMBINED CYCLE COGENERATION SYSTEM INSTALLED COSTS

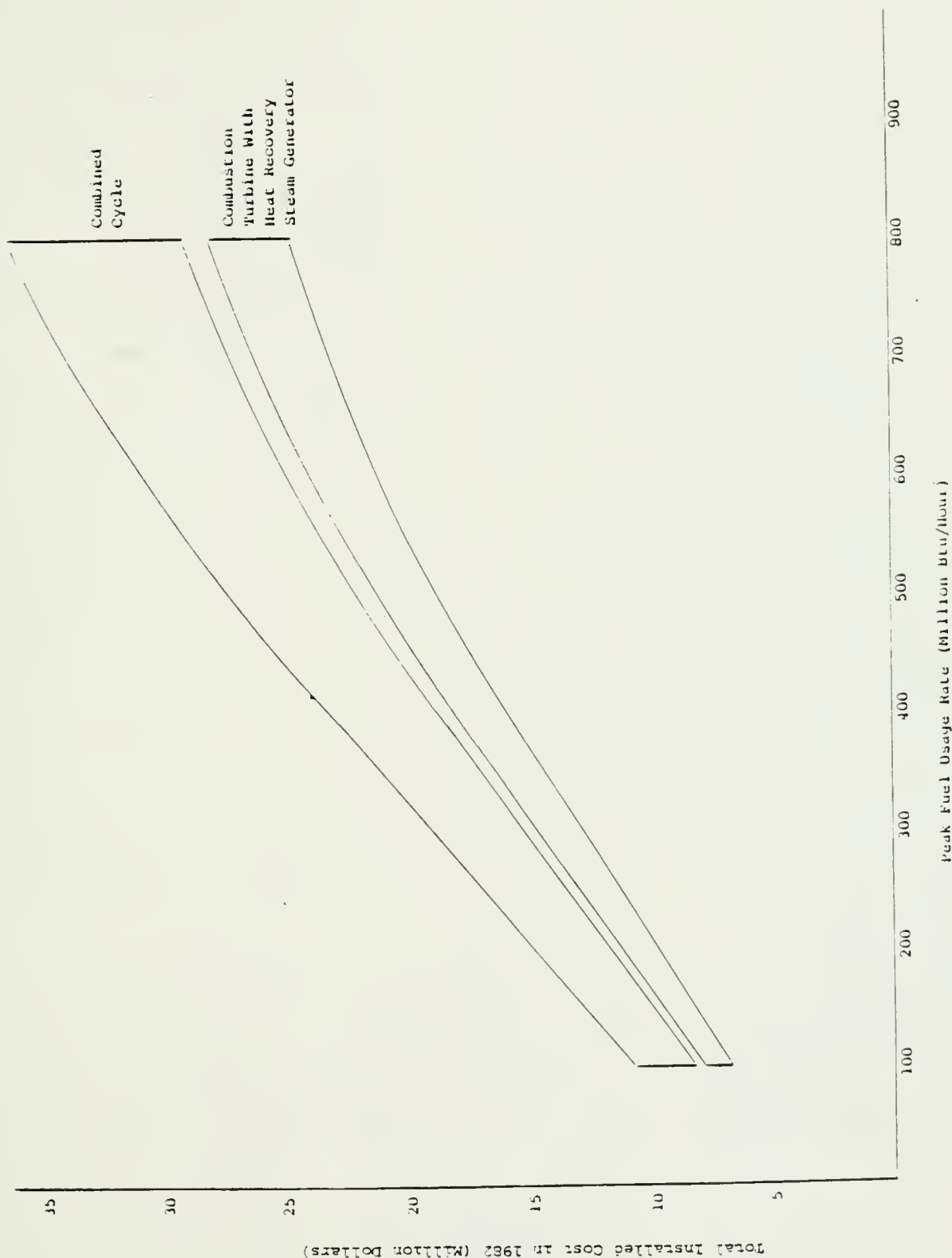


Figure II-8

STEAM TURBINE COGENERATION SYSTEM INSTALLED COSTS

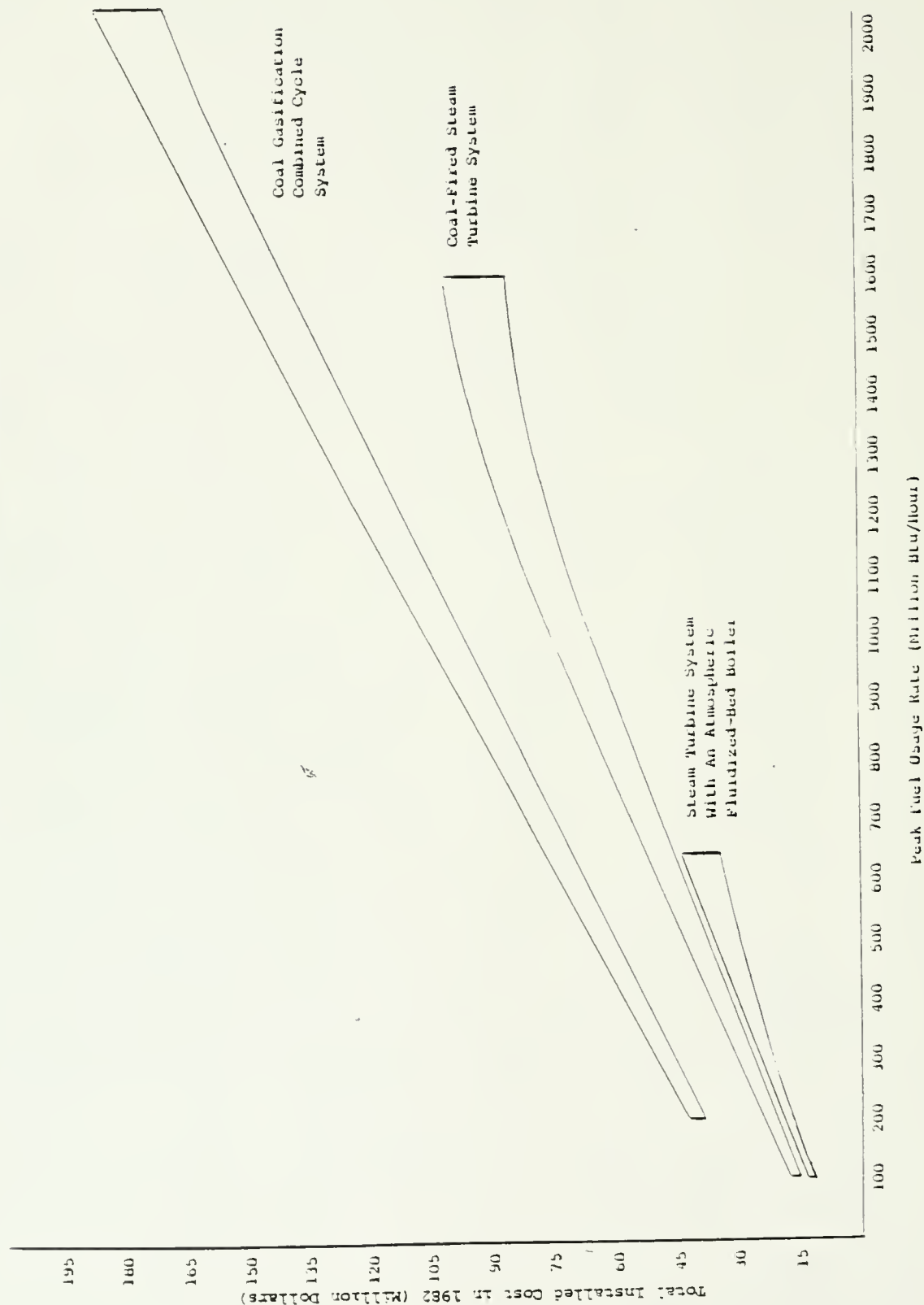


Figure II-9

COMBUSTION TURBINE AND COMBINED CYCLE COGENERATION SYSTEM INSTALLED COSTS

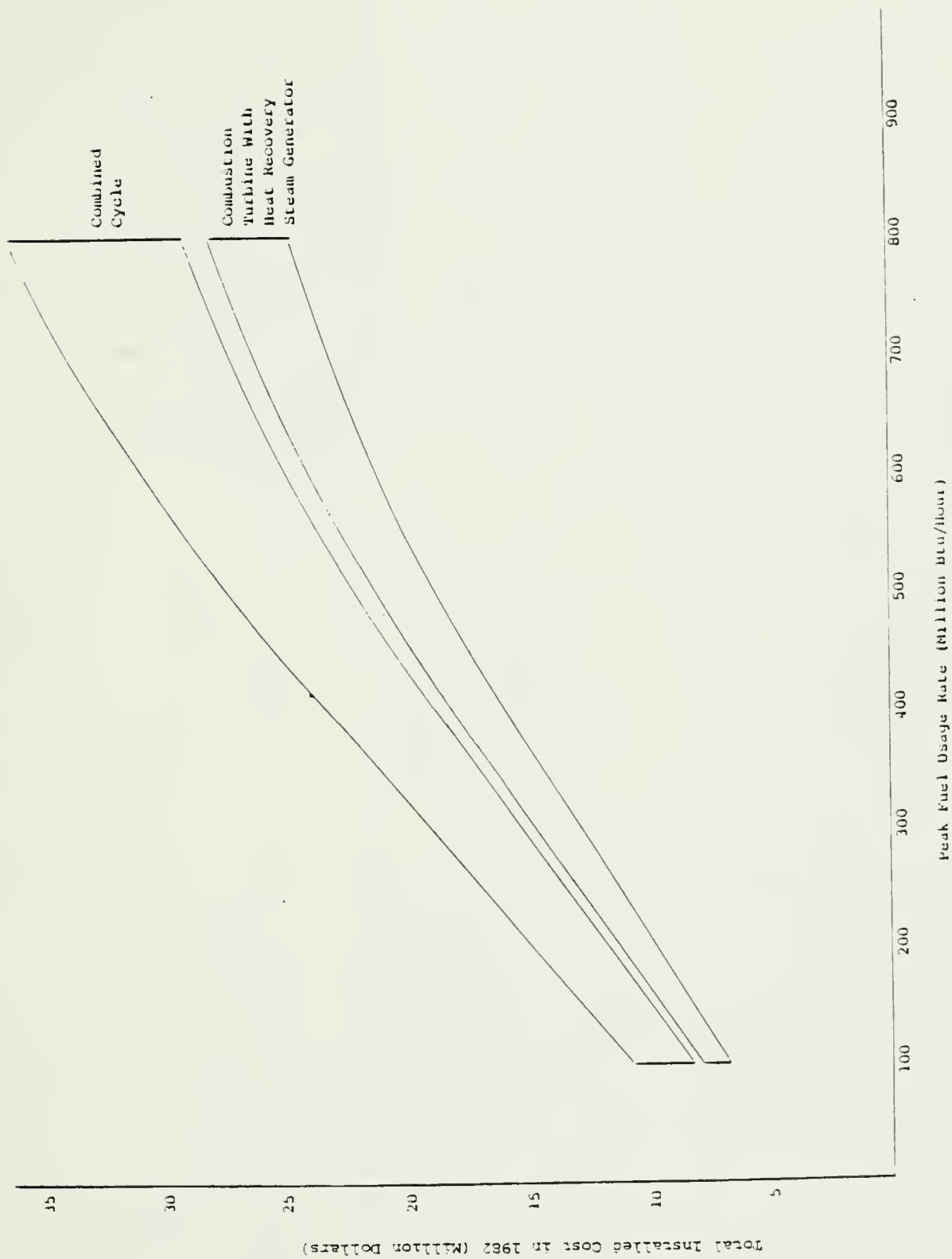
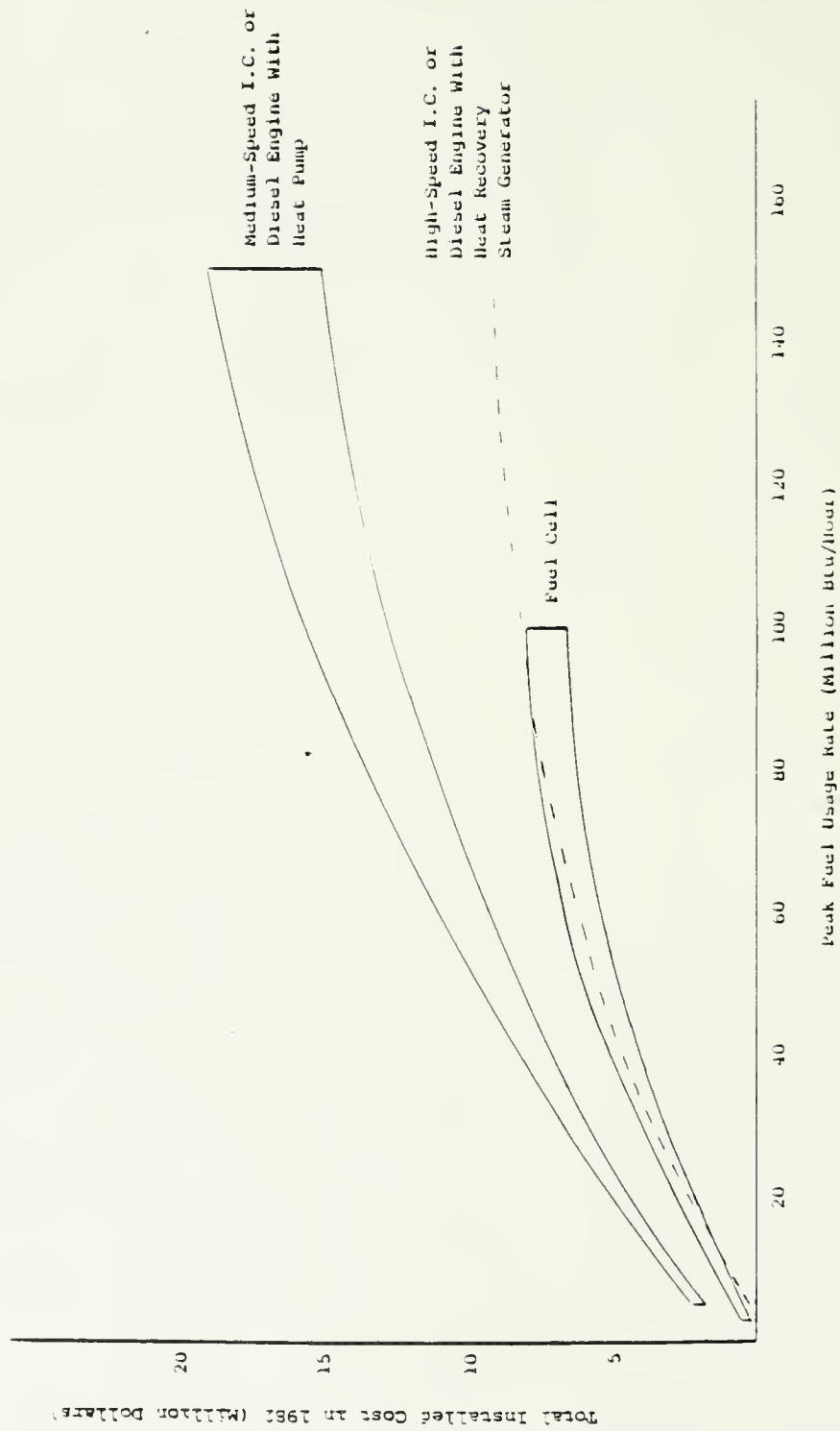


Figure II-10

INTERNAL COMBUSTION, DIESEL AND FUEL CELL COGENERATION SYSTEM INSTALLED COSTS



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

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

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

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

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

Table II-1

TOTAL INSTALLED COST FACTORS

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

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

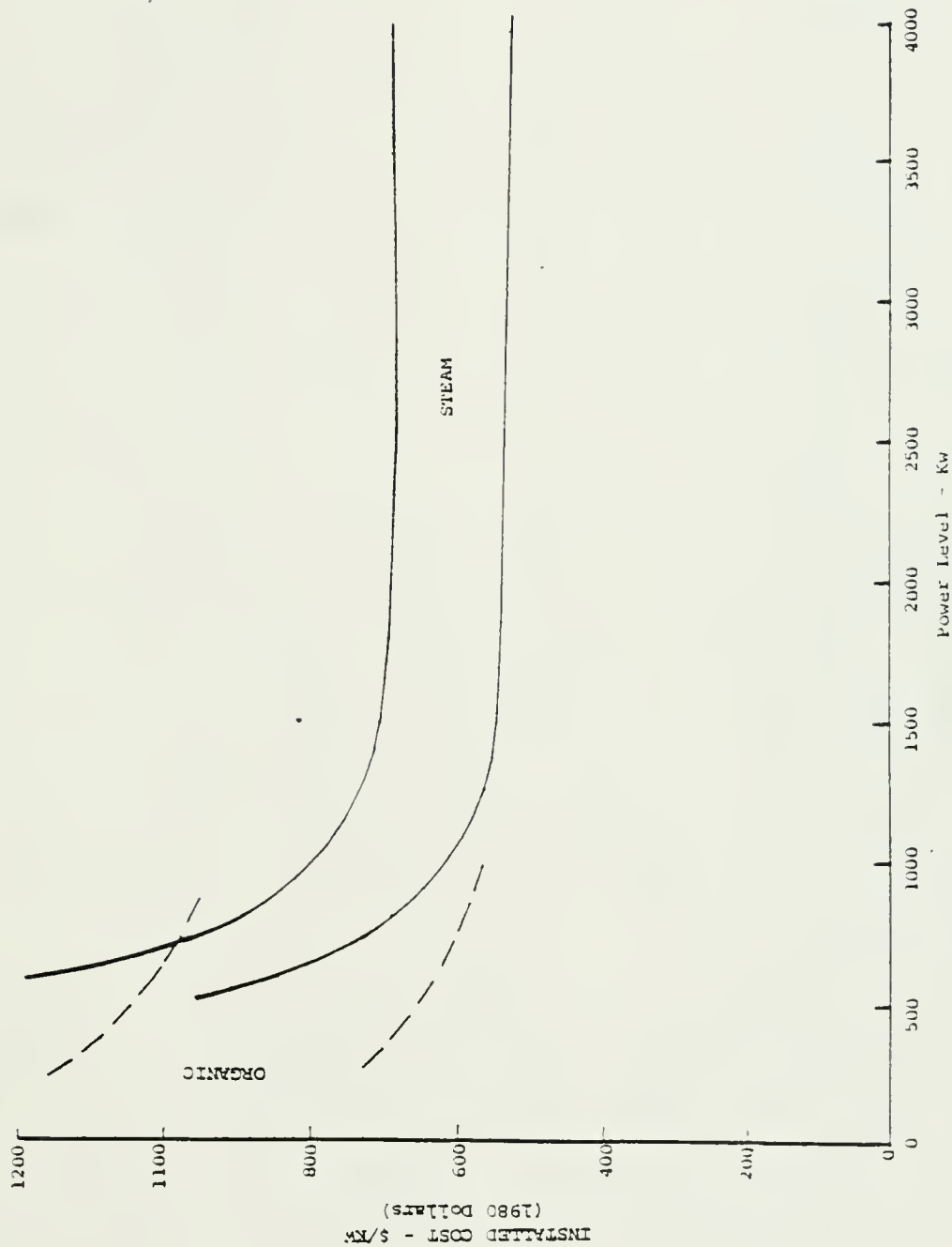
\*\*Applies to variants shown in Figure II-10, including coal-gasification/combined-cycle.



Figure II-11

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

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



## 2. System Performance

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

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

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

Table II-2

## COGENERATION SYSTEM PERFORMANCE FACTORS

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

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

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

### 3. Operation and Maintenance Costs

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

## D. INDUSTRIAL APPROACHES TO COGENERATION

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

Figure II-12

BOTTOMING CYCLE EFFICIENCY AS A FUNCTION OF PEAK CYCLE TEMPERATURE

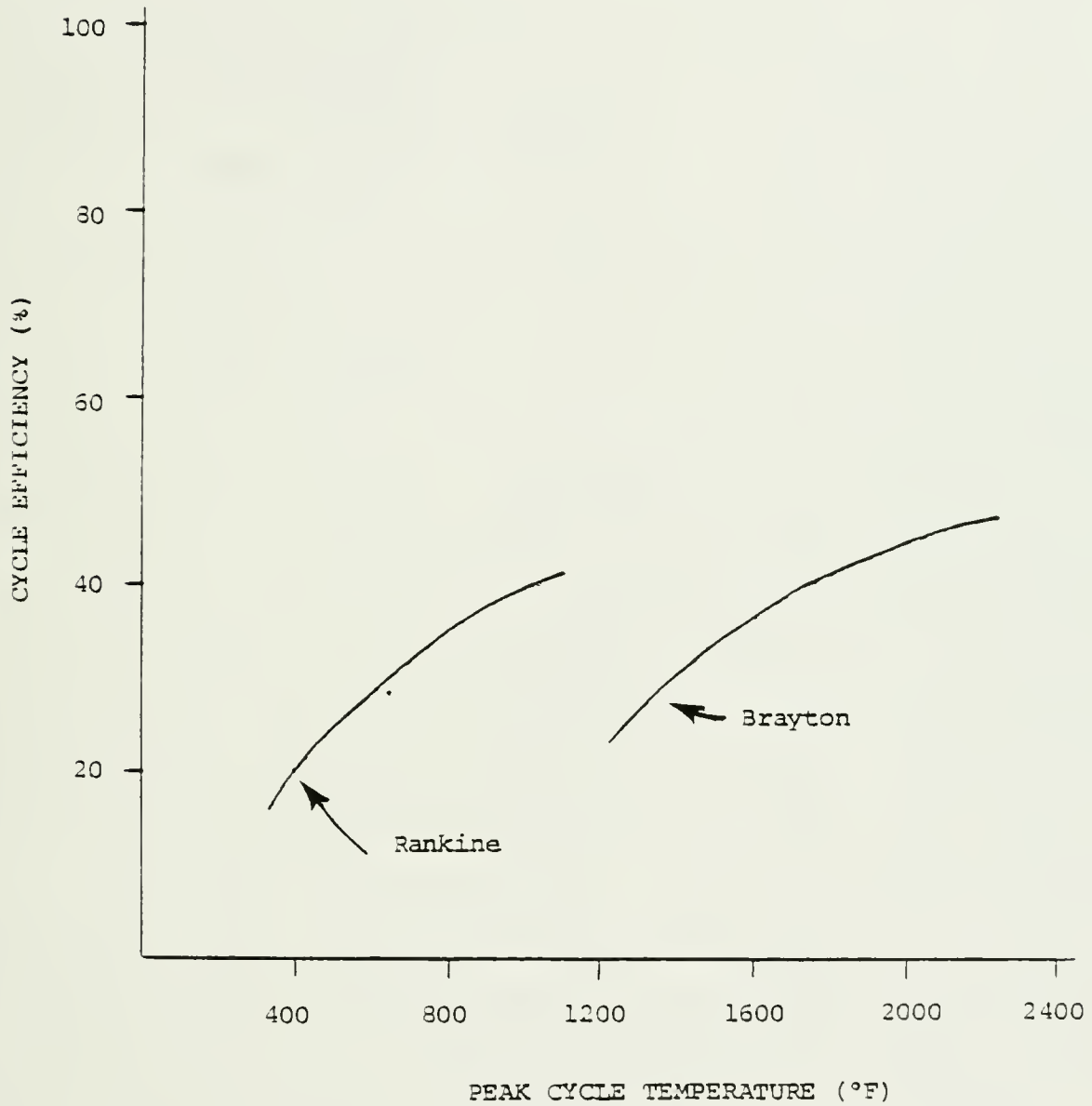


Table II-3

OPERATION AND MAINTENANCE COSTS FOR  
FIRST YEAR OF SYSTEM OPERATION

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

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

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

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

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



## E. FUELS FOR COGENERATION SYSTEMS

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



### III. BIOMASS ENERGY RESOURCES



### III. BIOMASS ENERGY RESOURCES

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

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

#### A. WOOD AND WOOD WASTES

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

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

Table III-1

FACTORS FOR  
ESTIMATING WOOD WASTE GENERATION

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

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

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

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

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

Table III-2

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

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

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\*DTE = Dry Ton Equivalent

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

## B. MUNICIPAL SOLID WASTES (MSW)

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

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

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

Table III-3  
COMPOSITION OF U.S. URBAN  
REFUSE, 1975

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

Source: New England Energy Congress

Table III-4  
PER CAPITA WASTE GENERATION IN  
MUNICIPALITIES OF VARIOUS SIZES

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

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



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

### C. AGRICULTURAL WASTES

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

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

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

Table III-5

CONVERSION FACTORS FOR ESTIMATING RESIDUE GENERATION

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

Table III-5

CONVERSION FACTORS FOR ESTIMATING RESIDUE GENERATION

(Continued)

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

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

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

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

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

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

#### D. ANIMAL WASTES

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

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

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

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

Table III-6

ANIMAL WASTE PRODUCTION PER DAY

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

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

Table III-7

SUMMARY OF ANIMAL WASTE CHARACTERISTICS<sup>a</sup>

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

<sup>a</sup>pounds of component per day per 1,000 live pounds of animal.

<sup>b</sup>Feces and urine with no litter or bedding.

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



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



#### IV. BIOMASS ENERGY RECOVERY TECHNOLOGIES



#### IV. BIOMASS ENERGY RECOVERY TECHNOLOGIES

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

- Thermochemical conversion
- Biological conversion.

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

- Direct Combustion
- Gasification
- Pyrolysis.

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

- Anaerobic digestion
- Fermentation.

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

##### A. DIRECT COMBUSTION

This is the simplest and best developed biomass conversion process. Forest and agricultural wastes and residues can be burned to

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

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

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

#### 1. Wood Combustion Technologies

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

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

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

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

Table IV-1

FUEL PROPERTIES OF BARK, WOOD AND COAL

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

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

<sup>1</sup>Logs Stored in Saltwater <sup>2</sup>Sanderdust <sup>3</sup>Texas Lignite <sup>4</sup>Wyoming Subbituminous B <sup>5</sup>Illinois Bituminous (high volatile A) <sup>6</sup>West Virginia Bituminous (low-volatile)

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

Table IV-2

HOW FUEL MOISTURE CONTENT AFFECTS EFFICIENCY

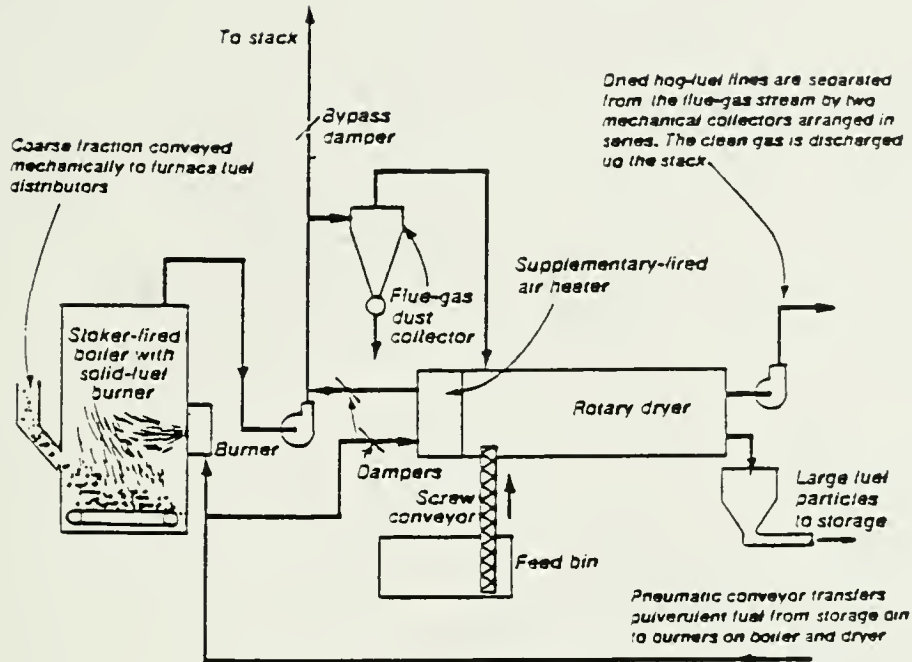
Moisture Content (as received, %)	Gross Heating Value (as-fired), Btu/lb <sup>1</sup>	Net Heating Value (heat available for steam production), Btu/lb <sup>2</sup>	Boiler Efficiency %
15	7440	5767	77
30	5125	4505	73
40	5250	3682	70
50	4375	2860	65
60	3500	2038	58

Source: North Carolina State University, School of Forest Resources.  
 1/Assumes a higher heating value of 3750 Btu/lb for wood and bark.  
 2/Assumes a stack temperature of 500° F and excess air (%) equal to the percentage of moisture contained in the fuel.  
 3/Overall efficiency is found by subtracting other losses - such as radiation, blowdown, etc.

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

Figure IV-1

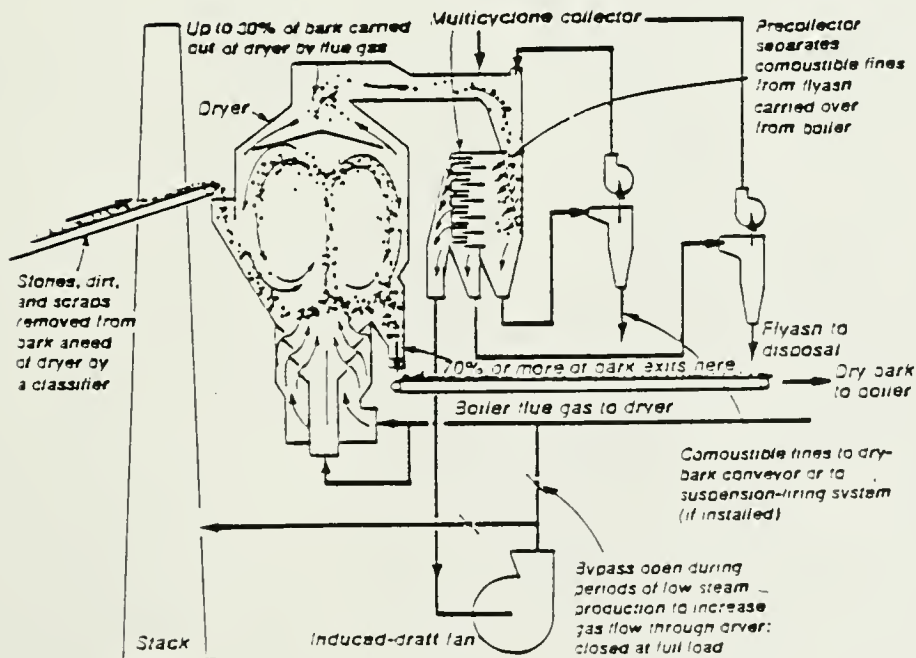
ROTARY DRUM DRYER



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

Figure IV-2

CASCADE DRYER



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



Table IV-3

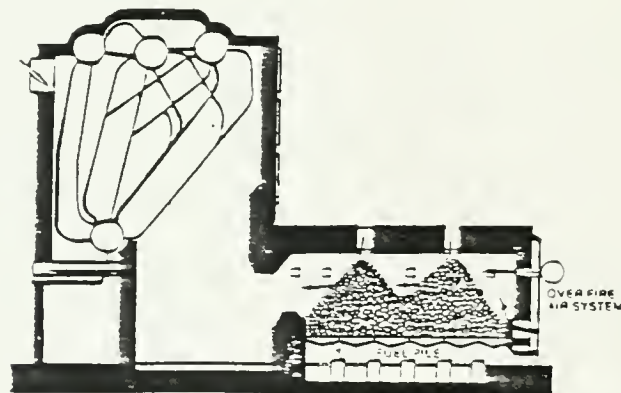
TYPES OF WOOD-FUELED COMBUSTION SYSTEMS

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

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

Figure IV-3

DUTCH OVEN



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



- Pile Combustion

- Dutch Ovens

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

- Cyclone Furnace

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

- Semi-pile Combustion

- Inclined Water-Cooled Pinhole Grate

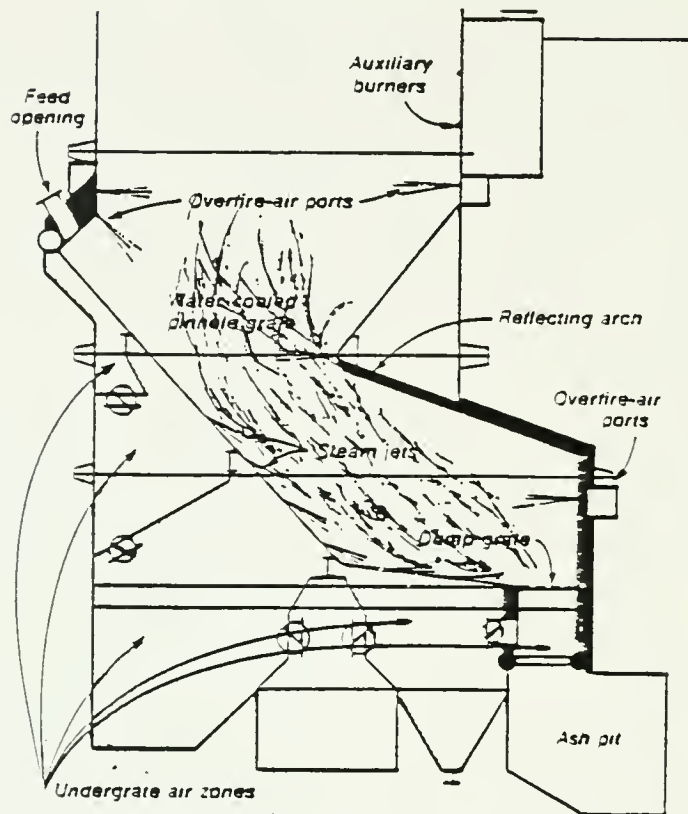
In these boilers, hogged or unhogged woodwaste is fed onto an inclined grate (angle of approximately 55°) where it slides toward the bottom with drying, vaporization and combustion occurring during this movement (see Figures IV-4 and IV-5). Air is fed from beneath the grate as well as above, and steam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

- Semi-suspension Firing

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

Figure IV-4

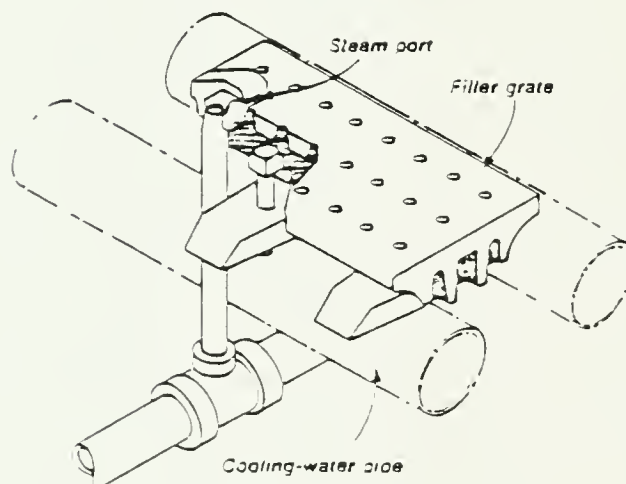
INCLINED WATER COOLED GRATE



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

Figure IV-5

PINHOLE GRATE DESIGN



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

- Flat Air-Cooled Grates

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

- Water-cooled Grates

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

- Traveling-grate Spreader Stokers

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

- Water-cooled Vibrating Grates

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

● Suspension Firing

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

- Scroll Feed Burners

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

- Suspension Burners

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

- Cyclonic Burners

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

● Regulatory Aspects

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

2. Technologies for Municipal Solid Wastes (MSW)

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

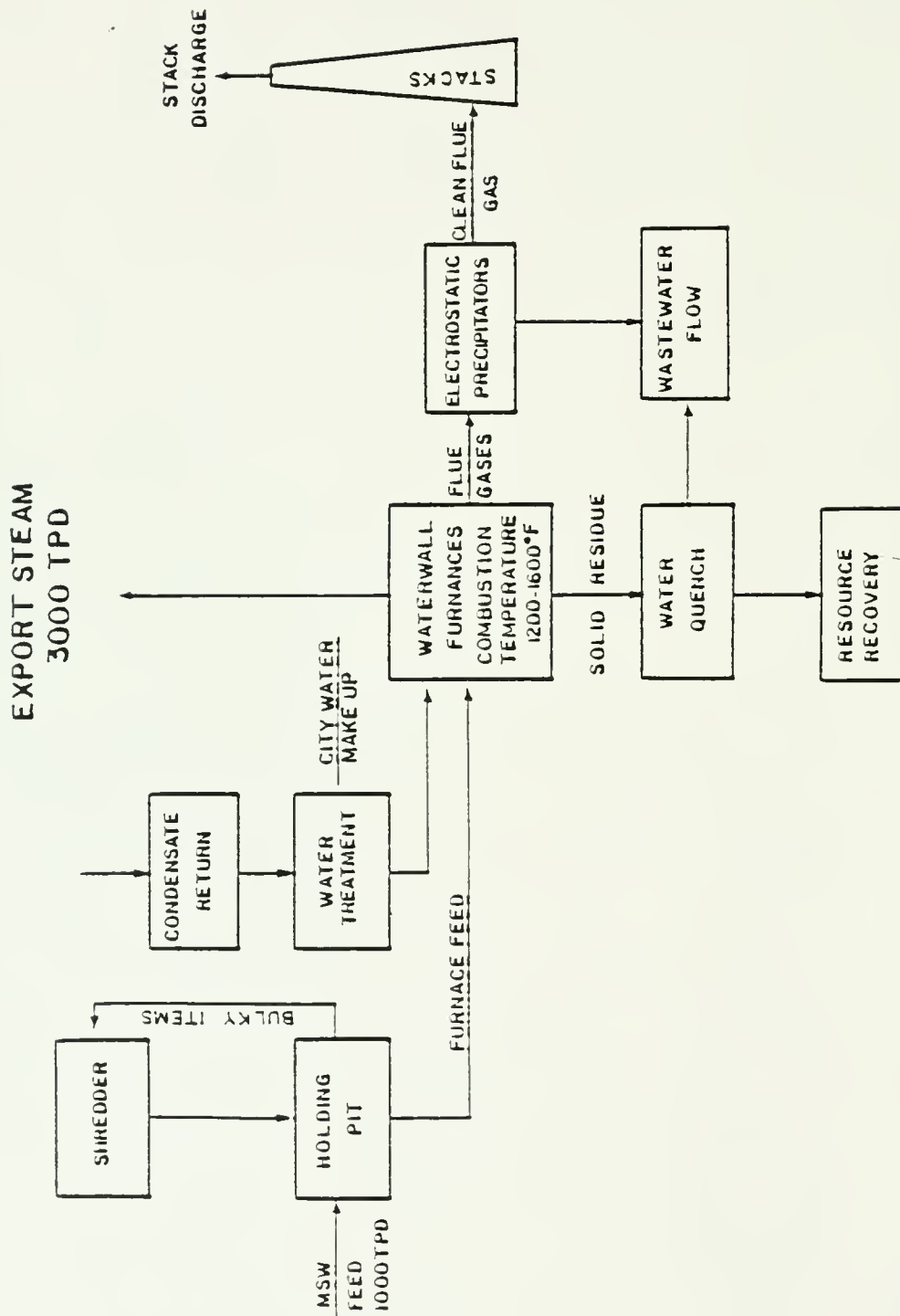
The only commercialized technology for energy recovery from solid wastes is incineration with heat recovery. The type of incineration technique depends on the quantity of refuse to be burned. Waterwall incinerators are often used for refuse quantities greater than 150 tons per day. Boiler efficiencies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

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



Figure IV-6

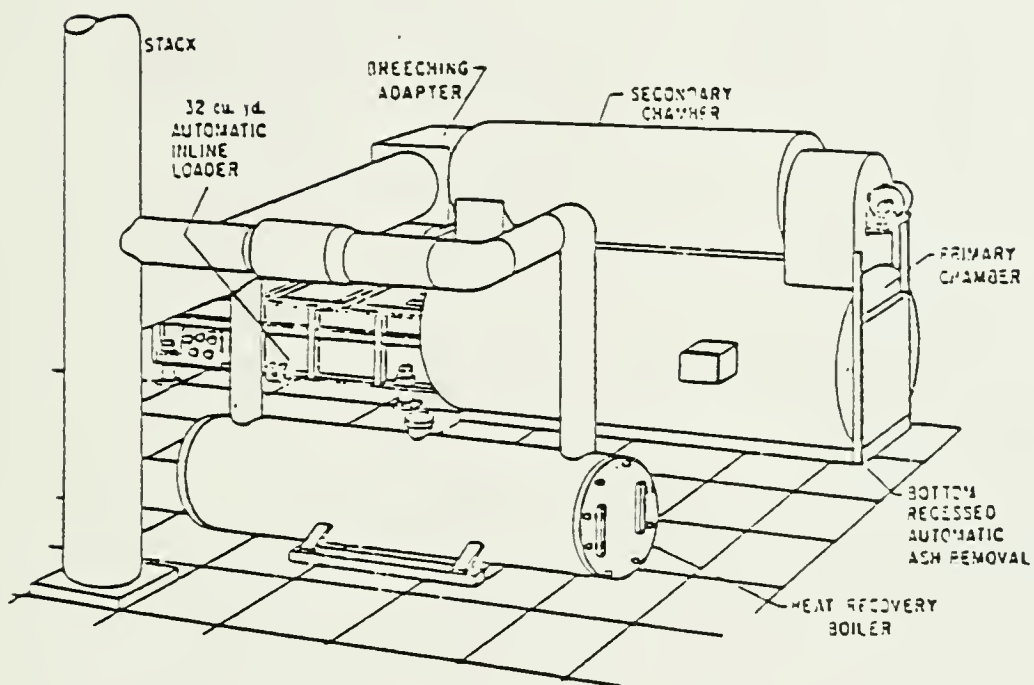
WATERWALL PROCESS FLOW DIAGRAM



XBL 7810-11668

Figure IV-7

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



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

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

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



Figure IV-8

DRY PROCESS RDF SYSTEM

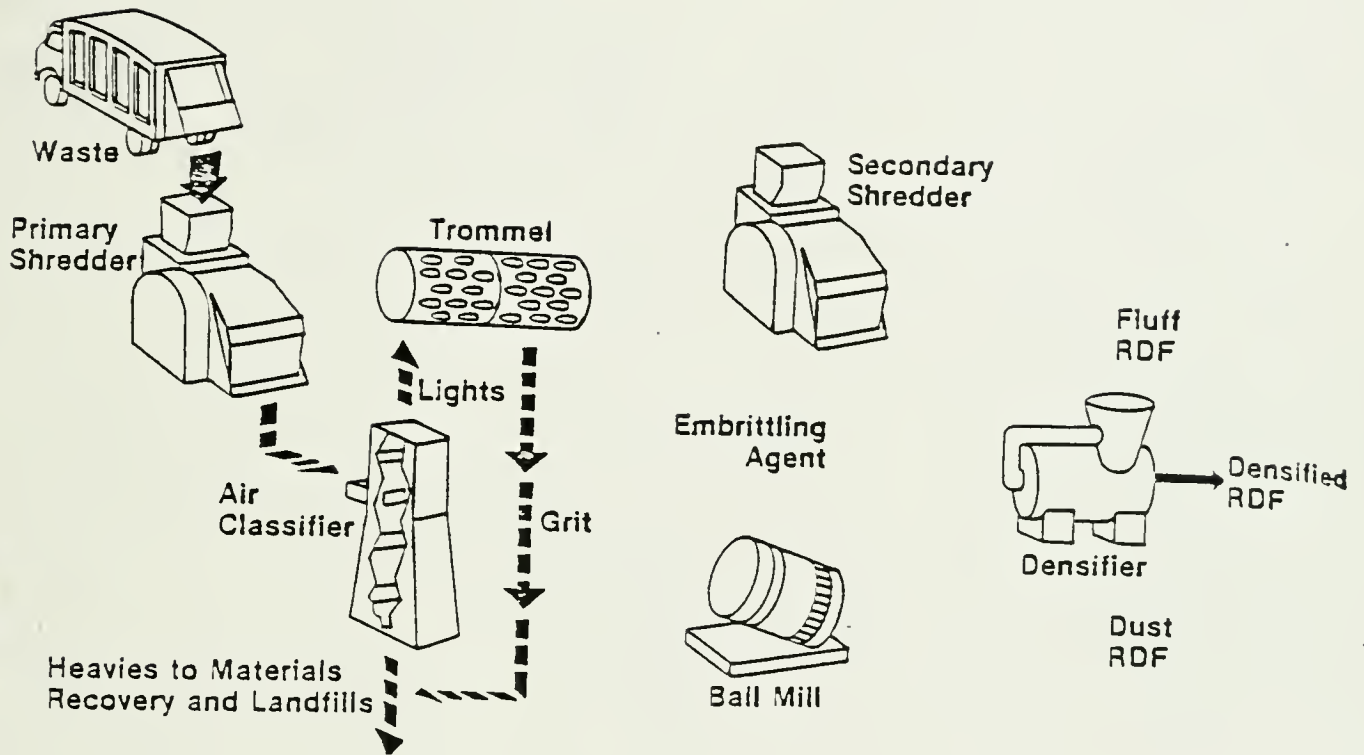
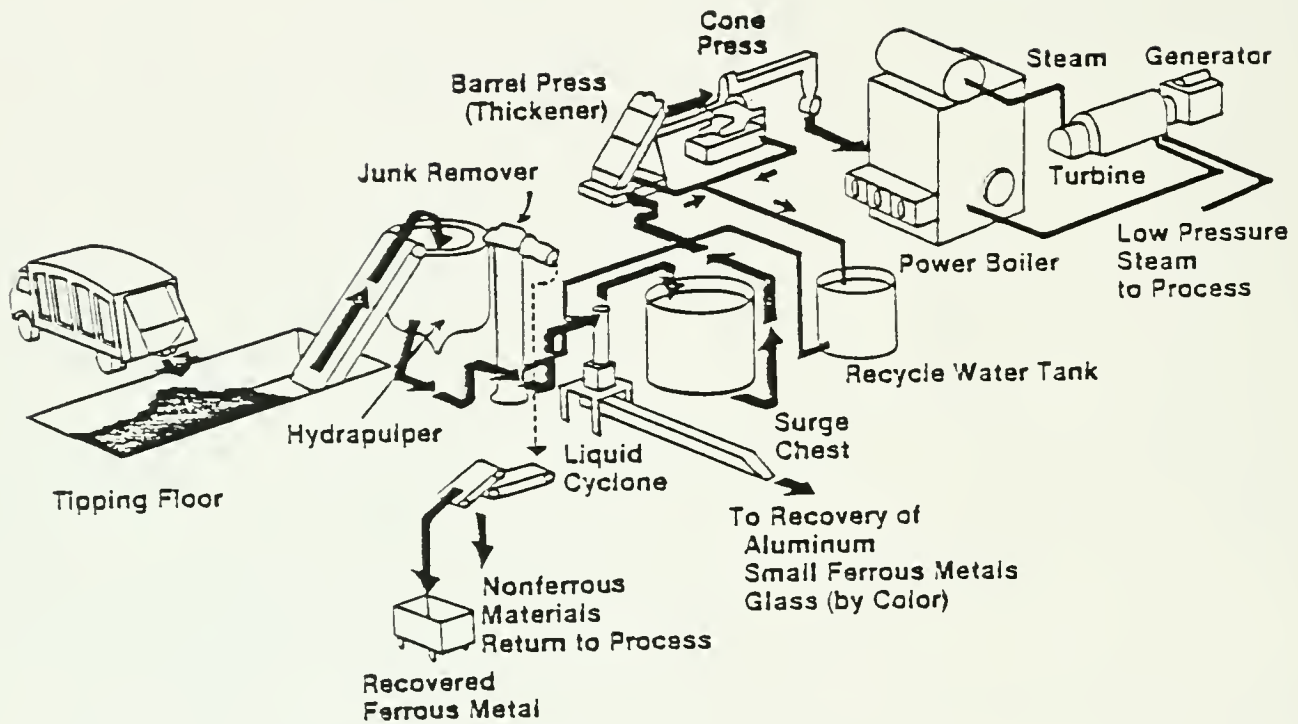


Figure IV-9

WET PROCESS RDF SYSTEM



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

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

### Institutional and Regulatory Issues

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

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

## B. GASIFICATION

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

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

Gasification can be simply explained as a special case of direct combustion. In direct combustion, three processes continuously occur: (1) heating and drying of feedstock as it is brought from ambient to reaction temperature, (2) evolution of hydrocarbon gas for subsequent combustion, and (3) combustion of fixed carbon char. In gasifiers, processes (1) and (3) occur in a vessel under conditions of controlled

temperature and oxygen starvation (pyrolysis). Most of the evolved gases in process (2) are not ignited. In addition, gases evolved from gasification of the char join the gases evolved in process (2) to form a low-energy gas. Various gasifier designs are briefly explained in the following pages.

## 1. Counter-Current Gasification

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

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

## 2. Co-Current Gasification

Two basic types of co-current gasifiers exist: downdraft and cross-flow, of which the downdraft is the more important. Downdraft gasifiers are designed specifically to eliminate the tars and oils from



the gases. After passing through a drying zone, the biomass feedstock undergoes pyrolysis. The gases, tars, and char produced contact incoming air and are oxidized under high temperatures. The remaining chars and gases then pass through a cooler reduction zone where most of the tars are broken down into gases. These gases can then be used with minimal filtering to fuel spark and diesel engines, the principal use of downdraft gasifiers. Downdraft gasifiers are highly sensitive to moisture and cannot tolerate content greater than 30 percent.

### 3. Fluidized Bed Gasification

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

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

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

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

### C. ANAEROBIC DIGESTION

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

#### 1. Digester Systems and Designs

Digester systems are of two basic types: batch process and continuous feed. The batch type digester is filled with a slurry of organic materials that is left to digest for a specified retention period, after which the digester is emptied and refilled. This system is advantageous where the materials are available only sporadically. Batch digesters require little daily attention. However, gas

production is variable in batch systems, starting out at a very low rate and increasing to a peak and then declining again. This is undesirable if a continuous user of the biogas is available. The disadvantage of uneven gas production can be reduced by use of additional digesters filled at regular intervals. However, investment in numerous batch digesters will usually be uneconomic on small farms.

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

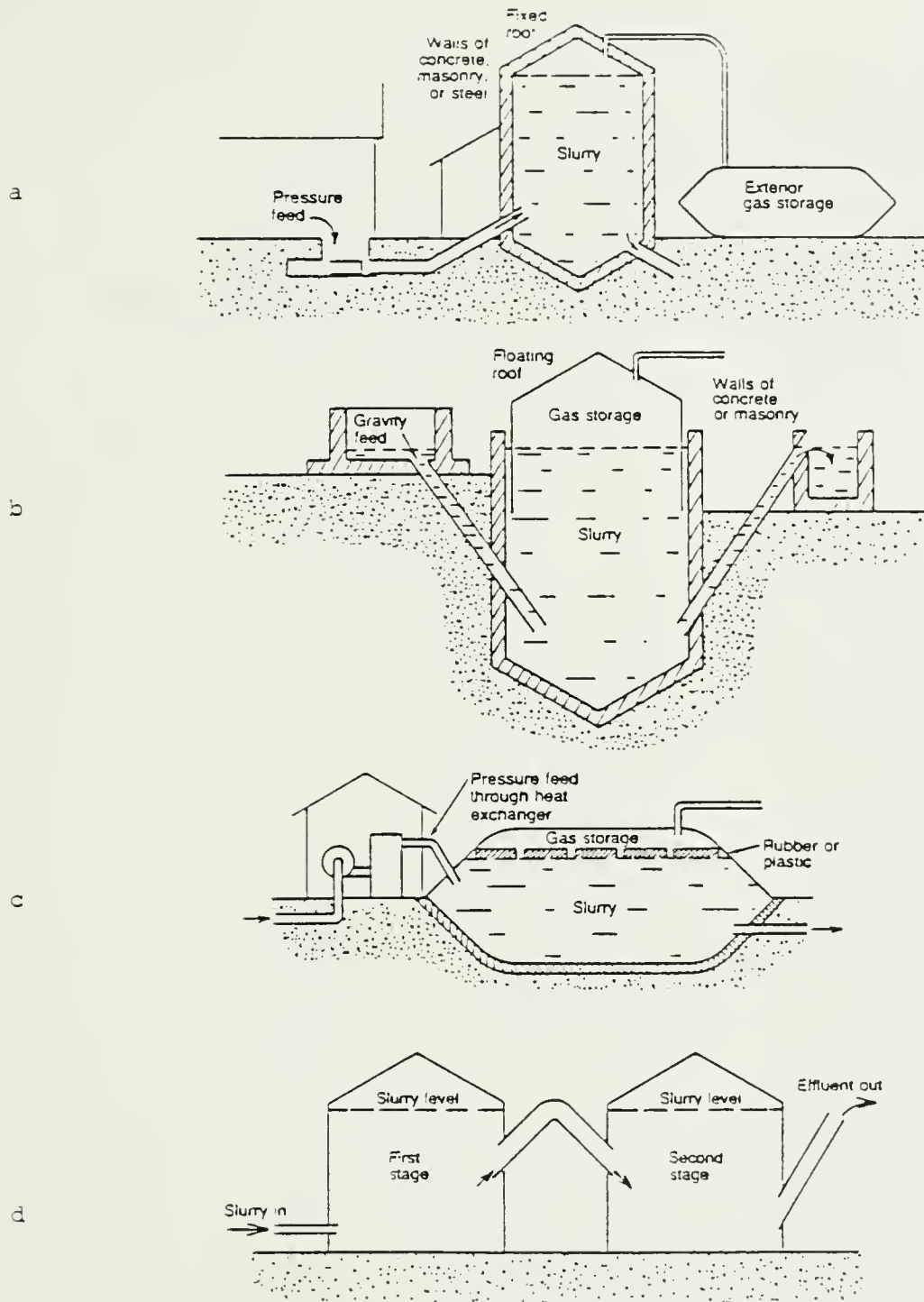
## **2. Structures and Structural Components**

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



Figure IV-10

TYPICAL DESIGNS OF AGRICULTURAL DIGESTERS



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

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

### 3. Slurry Preparation

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

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

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

#### 4. Storage of Digester Effluent

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

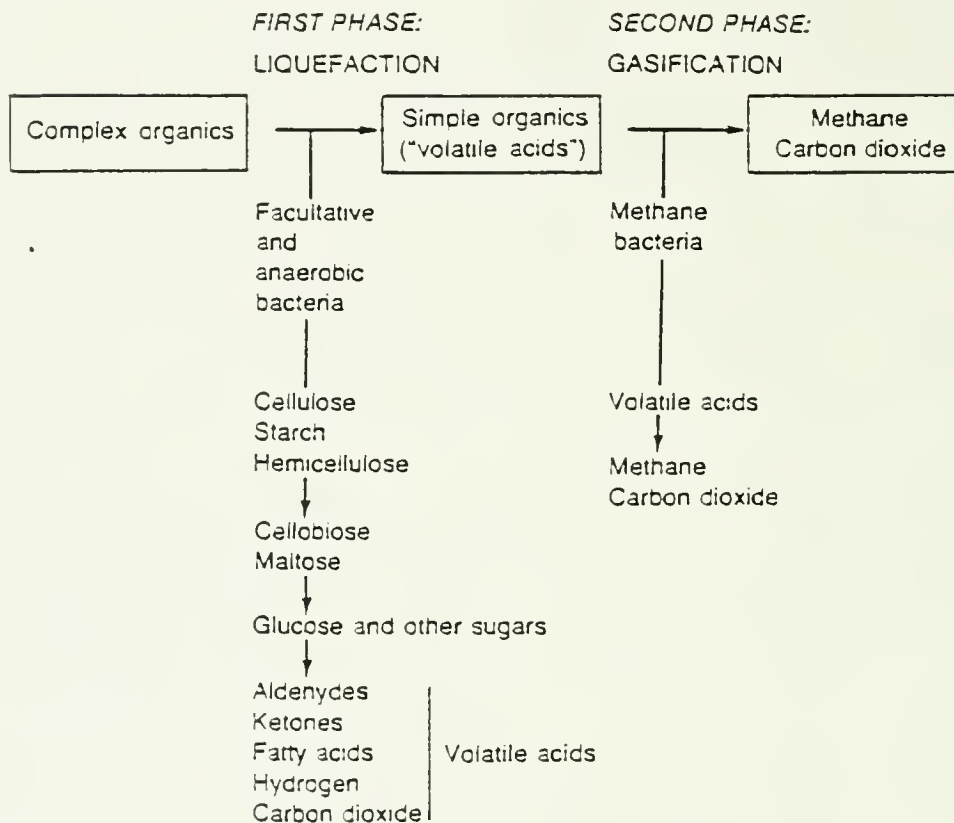
Separation of liquids and solids may be desirable so liquids could then be distributed as fertilizer by irrigation or other methods. More importantly, it may be possible to recycle some water back into the digester slurry, reducing storage requirements and water usage. Solids storage requires no special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

#### 5. Characteristics of Anaerobic Digestion

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

Figure IV-11

SIMPLIFIED DESCRIPTION OF ANAEROBIC DIGESTION PROCESS



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

## 6. Slurry Composition

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

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

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

The carbon content in dairy manure is slightly higher than that required for an efficient balance, and swine and poultry manures usually have excess nitrogen. Consequently, adding swine or poultry manure to the dairy manure will increase gas production and the

efficiency of solids reduction. However, this is not practical unless the two livestock species are housed on the same farm, or a cooperative venture is established that includes both species. Conversely, digestion of swine or poultry manure becomes more effective when material that contains excess carbon (in relation to nitrogen), such as bedding or litter, is added.

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

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

## 7. Landfill Biogas

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



Table IV-4

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

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

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

Source: Pennsylvania State University, Bulletin 827.

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

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

#### 8. Opportunities for Utilization of Biogas

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

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

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Source: Vause, 1980.



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

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

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

- Enlargement of burner nozzle orifices from the standard natural gas or LP designed orifices. The heating value of biogas is only 30 percent of LP gas and 60 percent of natural gas. LP gas burner orifices should be enlarged by about 70 percent.
- Air supply to the burner should be reduced. Air inlet ports on conventional boilers can be almost entirely closed.
- A separate fuel source, such as LP gas should be used for pilot fuel. This is primarily a precaution should the supply of biogas be interrupted.

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

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

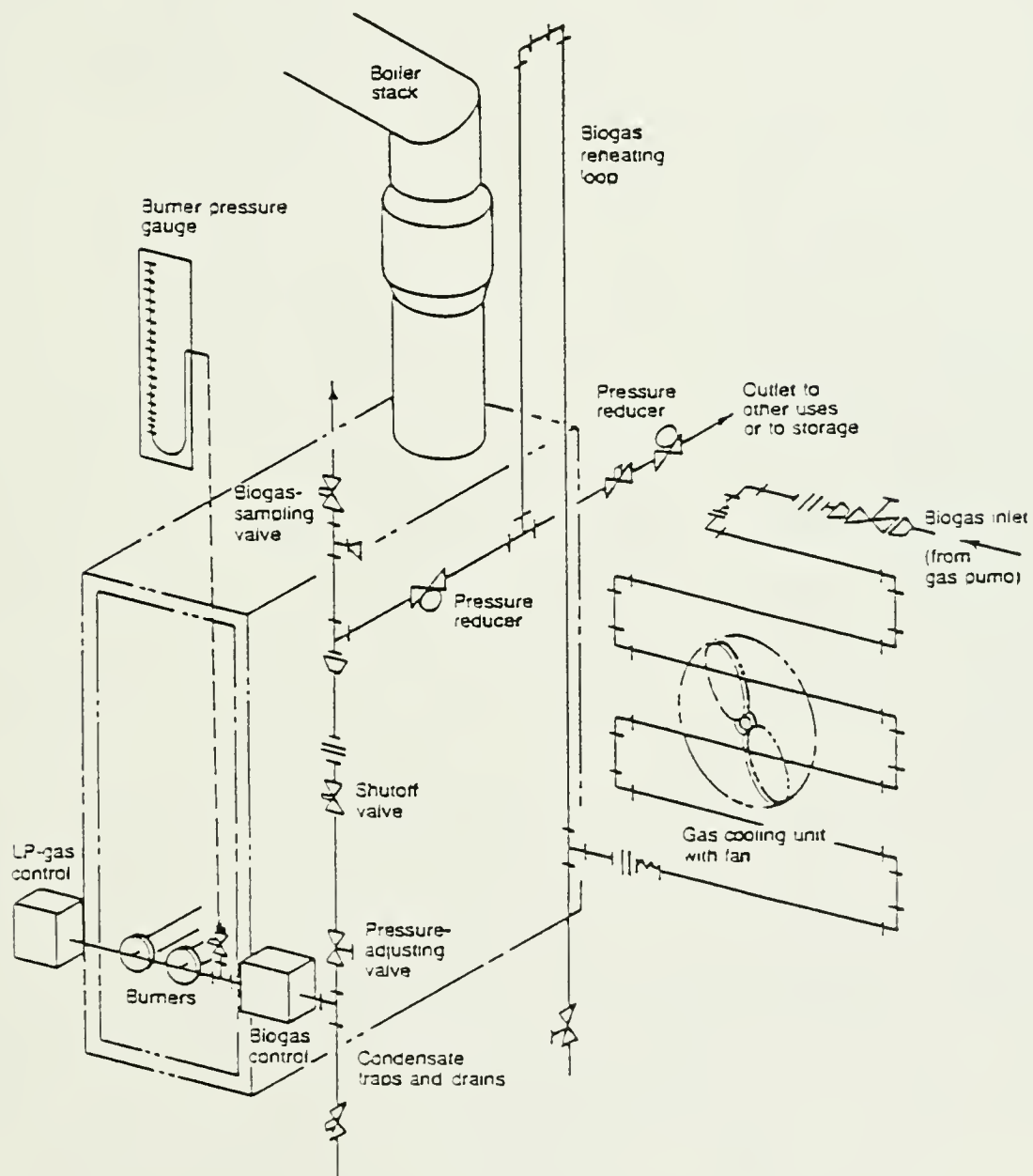
Biogas has a high (100 to 110) octane rating and consequently can be used in high compression engines. However, the high octane rating also means that the fuel mixture must be ignited by a spark or by some other fuel. In spark-ignition engines, biogas alone can be used as fuel. In diesel engines, however,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

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

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

Figure IV-12

SYSTEM FOR MOISTURE REMOVAL FROM BIOGAS  
BEFORE COMBUSTION



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

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

V. COGENERATION: ECONOMIC AND FINANCIAL CONSIDERATIONS



## V. COGENERATION: ECONOMIC AND FINANCIAL CONSIDERATIONS

### COGENERATION - OLD GAME, NEW RULES

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

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

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

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

In addition to PURPA, three other parts of the 1978 NEA also provide incentives for cogenerators. The Powerplant and Industrial Fuel Use Act (FUA) allows cogenerators to be exempted from prohibitions on the use of

oil and natural gas. The Natural Gas Policy Act (NGPA) provides an exemption from incremental pricing of natural gas to cogenerators. The Energy Tax Act (ETA) provides a 10% investment tax credit for certain property which may be used with cogeneration systems. Also, additional incentives were provided in subsequent legislation passed by the 96th Congress (8).

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

#### TECHNICAL OPTIONS FOR COGENERATION

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

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

- Extraction steam turbines
- Back-pressure steam turbines



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

Bottoming options include:

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

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

systems are generally economically feasible only in large sizes (over 10 MW). Gas turbines can be used to intermediate or large sizes -- there are many in the 1-10 MW range. Diesels can be as small as 100 KW.

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

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

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

#### THE ECONOMICS OF COGENERATION

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

Table V-1

## COGENERATION TOPPING CYCLE PERFORMANCE PARAMETERS

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

1 Hot water @ 250° F is available at 10 times the flow of the steam

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

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

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

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

### The EPRI Project

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

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

- Identify and assess utility options for participation in industrial cogeneration.
- Identify research, development and demonstration needs and priorities.

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

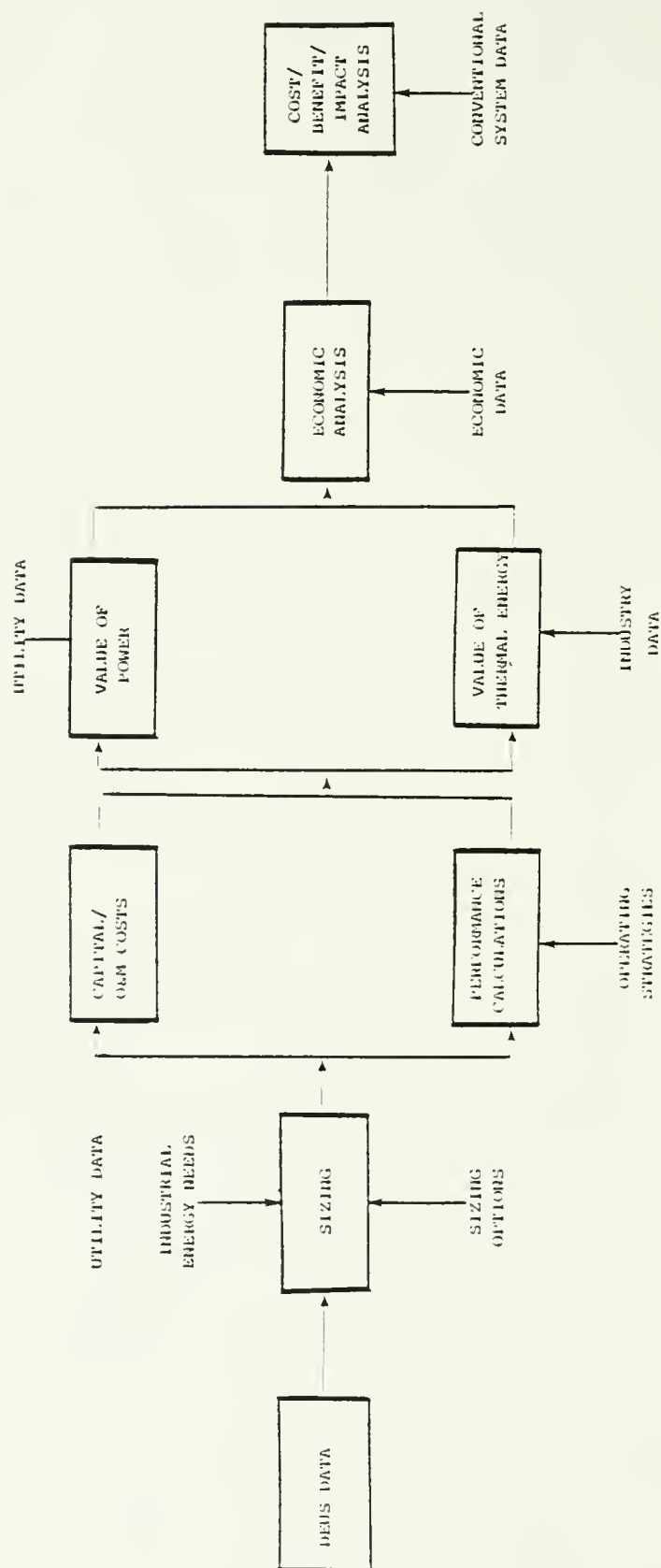
#### Methodology for Cogeneration Evaluation

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

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

Figure V-1

SUGGESTED APPROACH FOR EVALUATION OF DEUS OPTIONS  
STEP 1 - IDENTIFICATION OF ATTRACTIVE OPTIONS





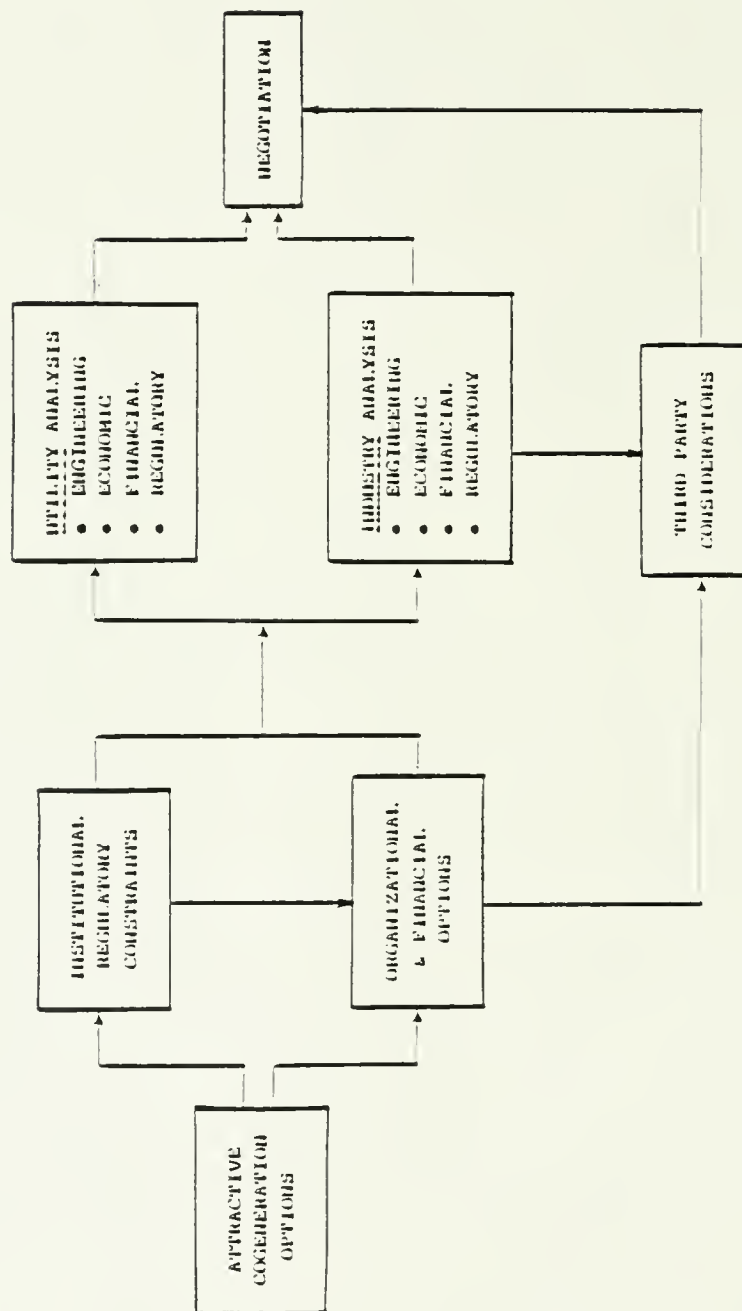
Calculations are then performed for the performance of the cogeneration system and its capital, operating and maintenance costs. The performance calculations provide information regarding the amount of thermal and electric energy generated by the cogeneration system under different operating strategies.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

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

Figure V-2

SUGGESTED APPROACH

STEP 2 - DETAILED ANALYSIS OF OPTIONS





## Value Of Thermal And Electric Energy

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

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

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

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

- The availability of the power to the utility - In order to realize credits for capacity, the power generated by the cogeneration system must displace utility capacity over some period of time. If the cogenerated power is not available when the utility needs it, then the utility will have to back up the cogeneration system with additional capacity. In such situations, the capacity credit would be very small, or non-existent. On the other hand, if the cogenerated power is available at all times when the utility needs it, then there should be some capacity credit given to the cogeneration system.
- Reliability - While no power generation facility is likely to be 100% reliable, experience with cogeneration facilities shows that they can accomplish a high degree of reliability with a small amount of unscheduled maintenance. In general, the higher the reliability of the system, the greater should be its capacity value. Some utilities have argued that they would have to back up cogeneration facilities with enough standby capacity and that there would be no avoided capacity costs. However, if the reliability of the cogeneration system is adequately accounted for in the utility's calculations of loss of load probability and reserve margin, then an appropriate method can be determined for developing the proper capacity value.
- Long-term availability of power - In many cases, the capacity value of a cogeneration system will have to be calculated based on displaced utility capacity over some future planning horizon. This requires some guarantees of the long-term availability of power from the cogenerator. In general, a cogenerator which is prepared to guarantee long-term availability through a long-term contract is likely to have a greater value for its capacity than one where there is some uncertainty regarding the long-term availability of power.
- Supply diversity - Given a number of cogenerators on a utility system, the supply diversity of the probability of outages of one or more cogenerators should be calculated in determining the appropriate capacity credits. This can be accomplished by treating each cogenerator as another unit in the utility system available to meet the utility's loads. The characteristics of power output, forced outage rates and maintenance schedules for each cogenerator can be analyzed using the utility's evaluation methodologies. The greater the diversity of supply, the greater the capacity value of the cogenerator.

- Short-term versus long-term considerations - Many utilities with excess generation capacity have argued that they should not provide any capacity value to potential cogenerators. Their arguments are probably valid in the short-run. If utilities do not save any capacity costs by having cogenerated power available, then the short-term capacity credit should be zero. Short-term capacity credits are relevant only for utilities with low current reserve margins, or utilities with substantial purchased capacity. In the long-run, however, the situation is different. If a utility has excess capacity now, but is experiencing some load growth, it may have to add capacity in the future. The availability of the cogenerator will allow such capacity additions to be either deferred or cancelled, leading to some savings in investment costs. Such savings should be reflected in the development of the capacity value of the cogenerator.
- Other factors affecting generation capacity credits - Other factors which influence the capacity value of a cogenerator include the quality of the power generated, the degree of operating control that the utility has over a cogeneration system, the size of the cogenerator and the possible value of the cogenerator for spinning reserve.
- Transmission and distribution capacity credits - It is possible that a cogeneration system would reduce the need for transmission and distribution capacity additions. The calculation of avoided transmission and distribution capacity has to be site-specific and is extremely difficult. It requires the analysis of the reliability of supply at the customer level, which includes an assessment of the reliability of the T&D network. If the cogenerator is sufficiently large and is located near a load center, it is possible that it could lead to the deferral or elimination of some future T&D investments by the utility. In such cases, the cogenerator should be given an appropriate capacity credit.

### Computer Evaluation of Dual Energy Use Systems (DEUS)

In order to perform the sizing and performance calculations, and to screen and evaluate the costs and benefits of cogeneration options relative to a conventional systems, an analytical model called DEUS - Computer Evaluation of Dual Energy Use Systems, has been developed. This model accomplishes step 1 of the evaluation methodology. An overview of

this model is provided in Figure V-3. The model can evaluate up to twelve systems, (including a no-cogeneration base case) taking into account industrial requirements for heat and power, fuel types, utility rate schedules, (including industrial and PURPA rates), economic data, operational ground rules, and various ownership types.

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

#### COPE - Cogeneration Options Evaluation

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

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

Figure V-3

OVERALL STRUCTURE OF DEUS PROGRAM

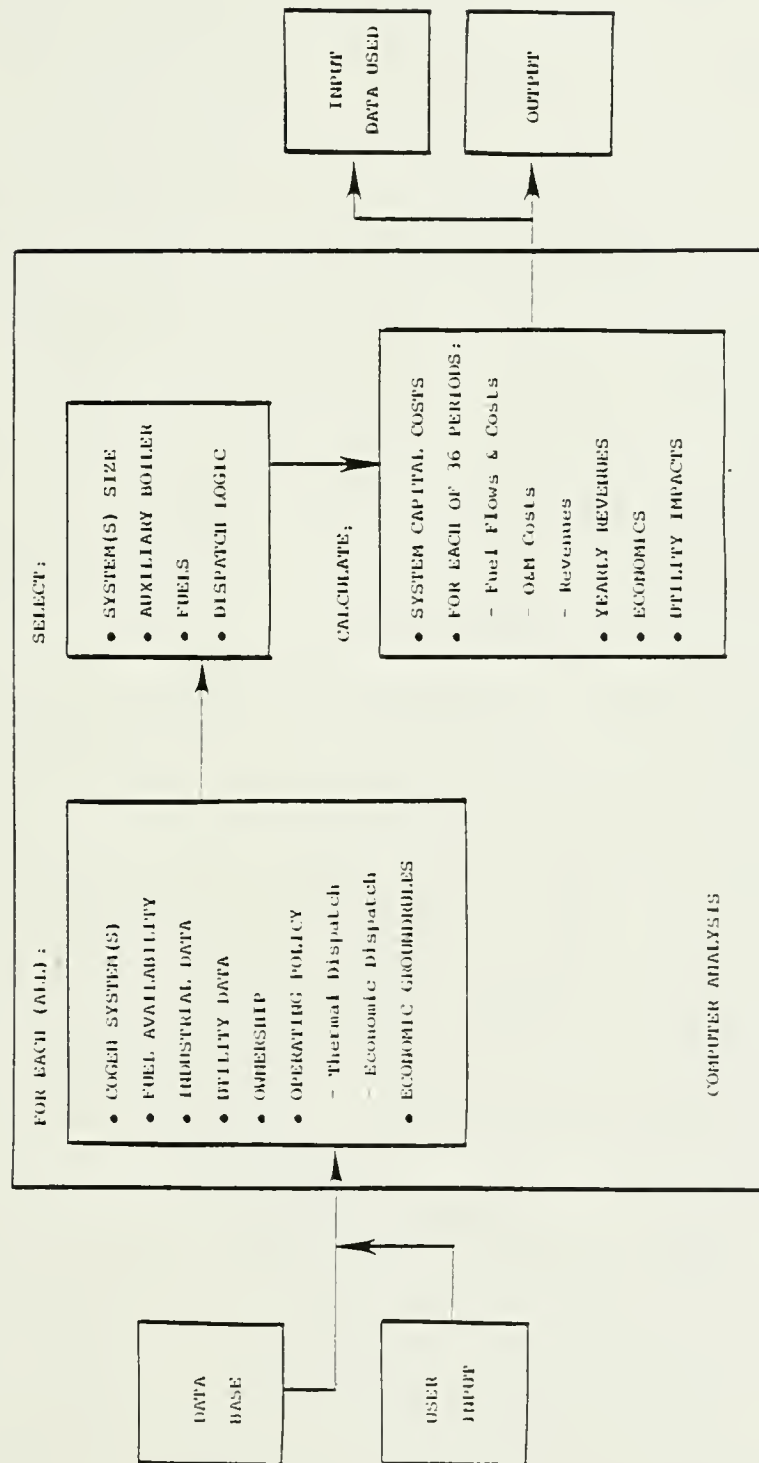
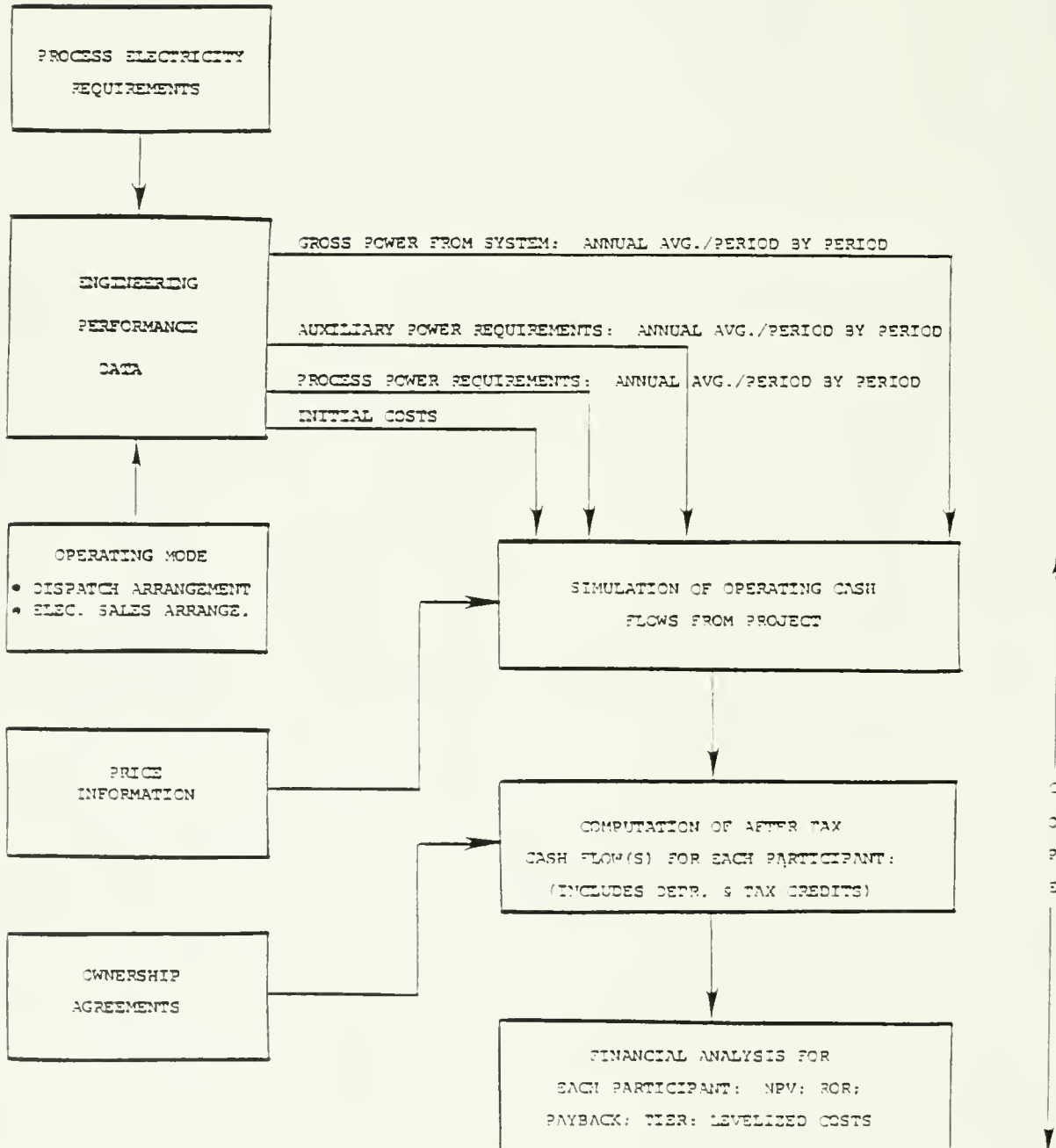




Figure V-4

OVERVIEW OF COPE COGENERATION OPTION EVALUATION



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

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

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

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

- Partnership - Utility/Third Party
- Partnership - Industry/Third Party
- Partnership - Utility/Industry/Third Party.
- Leasing Arrangements
  - Lessor/Lessee - Third Party/Utility
  - Lessor/Lessee - Third Party/Industry.

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

### Illustrative Results

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

### FINANCING COGENERATION PROJECTS

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

The reasons for considering such cooperative efforts are:

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



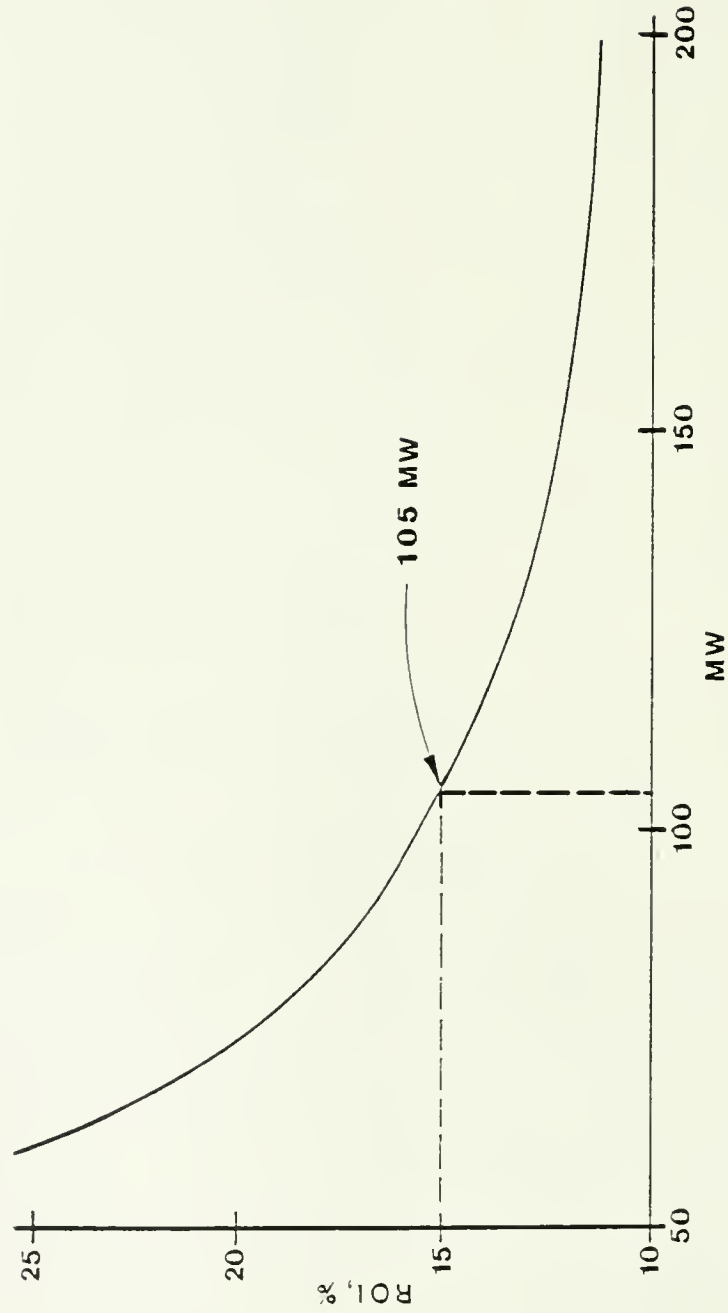
Figure V-5

ILLUSTRATION OF COGENERATION ECONOMICSPULP MILL EXAMPLE

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

Figure V-6

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



VI. FEDERAL REGULATION OF COGENERATION



- The industry may not have the skilled staff needed to operate and maintain a power generation system.
- Industry may not consider power generation a natural extension of its primary business, even when such generation is economically attractive.
- Utilities are generally willing to accept a lower rate of return than industry.
- Industrial plant managers may be hesitant to face the problems related to the handling, storage and use of coal and the associated environmental requirements.
- Utilities can offer the necessary expertise in the construction, operation and maintenance of cogeneration systems.

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

#### Options For Industry/Utility Cooperation

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

- Sole utility ownership of the cogeneration plant with sale of thermal energy by the utility to industry
- Joint venture between industry and utility (with utility owning 50% or less to qualify the cogeneration facility for PURPA benefits).
- Third party ownership with contracts for thermal energy and electricity sales to industry and utility respectively.
- Partial ownership with the utility owning the power generation equipment and industry owning the remaining plant
- Sole industry ownership but operating control (dispatch) by utility.

## Multi-Party Approaches For Financing

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

### Types of Joint Ventures

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

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

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

ADVANTAGES AND DISADVANTAGES OF JOINT VENTURE FINANCING  
OF A COGENERATION PROJECT

ADVANTAGES

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

DISADVANTAGES

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

IMPLICATIONS FOR UTILITIES

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

JOINT VENTURE FINANCING FOR COGENERATION FACILITIES  
SCHEMATIC FLOW DIAGRAM





- Utility gets 75% of the profit and losses and cash flows until the difference in their initial equity contribution is paid back. Thereafter, profits/losses and cash flows are split equally
- If or when the partnership is terminated/liquidated, the utility and industry agree to split the value equally.

### Cogeneration Financing Structures

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

#### Undivided Interest

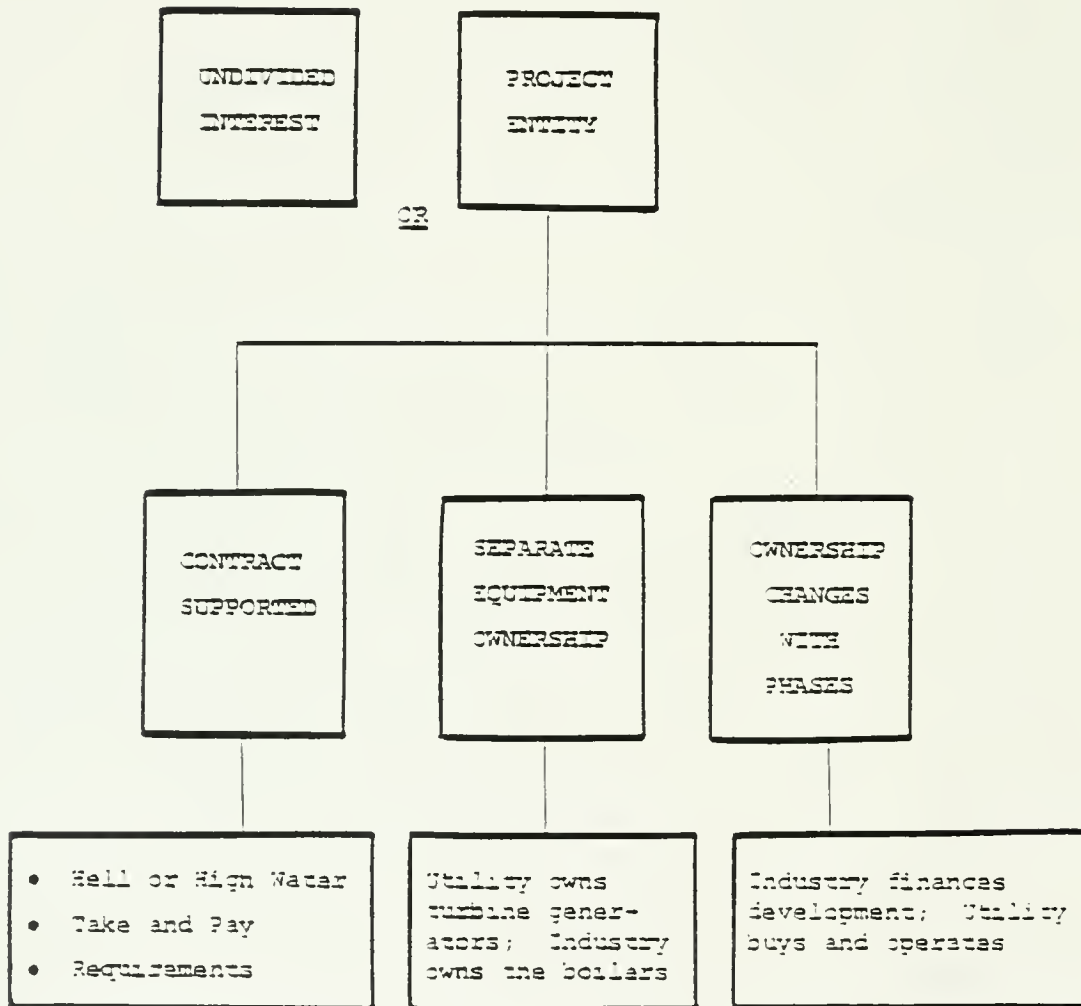
The undivided interest structure may be used by a sole owner or a joint venture. The owner(s) of an undivided interest in a project contributes capital in proportion with his ownership and receives profits in the same proportion. Any funds borrowed to capitalize the project would be shown on the participant's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

#### Project Entity

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

Figure V-9

COGENERATION FINANCING STRUCTURES



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

There are three basic variations on the project entity structure:

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

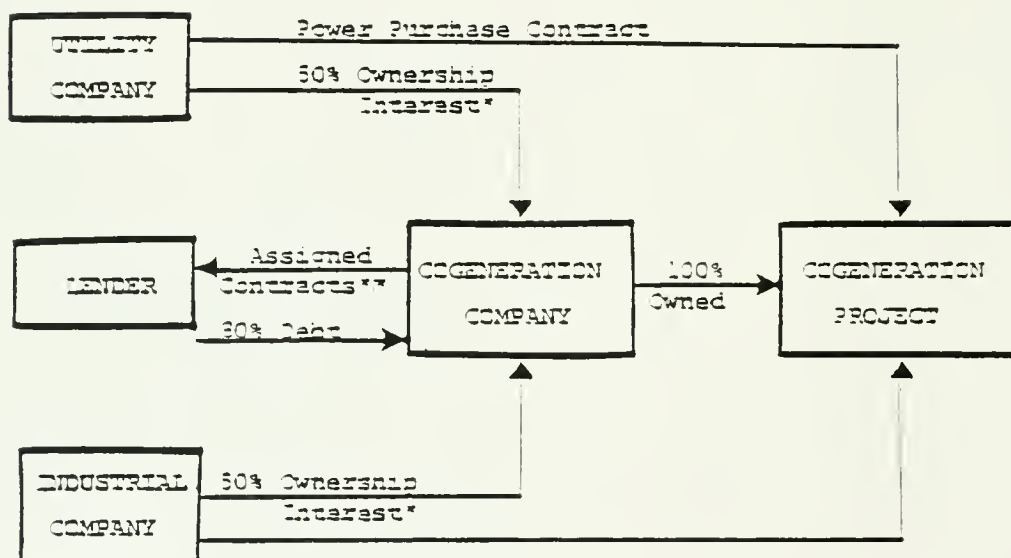
#### Contract-Supported Project Financing

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

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

Figure V-10

CONTRACT-SUPPORTED FINANCING OF A COGENERATION FACILITY



### Different Methods for Different Equipment

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

### Different Methods for Different Phases of the Project

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

### Summary of Project Financing Structures

The most common project financing structure is contract supported. Other project financing structures include: separate equipment ownership and ownership that changes with project phases. The foregoing structures may properly be considered the basic building blocks of project financing. One of the keys to successful project financing, however, is the ability to arrange the structural components in such a

manner as to meet the specific objectives and requirements of the participants. Each utility must evaluate the appropriate theoretical and practical considerations in order to select the most desirable financing arrangement.

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

## VI. FEDERAL REGULATION OF COGENERATION

### INTRODUCTION

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

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

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



## PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

### General Description

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

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

Section 210 also required electric utilities to provide retail electric service to qualifying cogeneration facilities at just, reasonable and non-discriminatory rates. Finally, Section 210(e) of PURPA exempted all qualifying cogeneration and certain qualifying small power production facilities from state regulation regarding utility rates and financial organization, and from most Federal regulations under the Federal Power Act and the Public Utility Holding Company Act. Licensing and permitting under Part 1 of the Federal Power Act and Sections 210, 211 and 212 of the Federal Power Act still apply to qualifying facilities.



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

### Specific Provisions of PURPA Implementation

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

### Rates for Utility Purchase of Power

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

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

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

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

### Wheeling

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

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

### Simultaneous Buy-Sell Provision

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

### Rates for Standby/Backup Power

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

### Exemption from Utility Regulation

The FERC exercised its exemption authority to the full extent authorized by Section 210(e) of PURPA. It exempted all qualifying cogeneration facilities from utility regulation under the Public Utility Holding Company Act, the Federal Power Act, and state law. As a result of these exemptions, cogeneration facilities which sell electric power to utilities will not be subject to rate regulation by the Commission under Sections 205 and 206 of the Federal Power Act. Their books and records will not be scrutinized by FERC, and they will not be subject to many of the prohibitions and requirements imposed on electric utility companies by the Securities and Exchange Commission under the Holding Company Act.

The exemption from state law applies only insofar as State law would regulate sales to utilities; a cogeneration or small power producer which sells power at retail may still be subjected to state utility regulation. The exemptions provided are only from laws and regulations concerning rates and financial organization. Cogeneration facilities are still subject to applicable state and Federal laws concerning siting and environmental restrictions.

## **QUALIFICATION CRITERIA FOR COGENERATION AND SMALL POWER PRODUCTION FACILITIES**

### **Definition of Cogeneration Facility**

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

One type of topping-cycle cogeneration facility, the new diesel and dual fuel cogeneration facility, had been temporarily excluded from qualifying under the FERC rules, pending the completion of a final

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

#### Definition of Small Power Production Facility

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

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

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\*Energy User News, June 1, 1981.

\*\*Edison Electric Institute, Dispersed Energy Update.



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

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

### Fuel Use Restrictions

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

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

### Operating Standard (Bona Fide Test)

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

### Efficiency Standards

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

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

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

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

### Ownership

Section 201 of PURPA provides that in order to qualify, a cogeneration or small power production facility must be owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities). However, the Conference Report of the House and Senate managers of the PURPA legislation specifically stated that electric utilities may participate in joint ventures that own qualifying facilities. To implement this provision, the FERC adopted a rule providing that electric utilities may own no more than 50 percent of the equity of a qualifying facility. This rule has been modified to allow



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

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

#### Summary of PURPA

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

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

The key provisions of Section 201 of PURPA include definition of a qualifying cogeneration facility as:

- One which produces electricity and other form(s) of useful energy through the sequential use of energy.
- One which is not more than 50% owned by electric utilities.
- Unlimited in size and unrestricted as to fuel used.
- One which meets minimum operating efficiency standards and produces at least 5% useful thermal output.

### Modifications to PURPA

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

The final rule:

- extends "qualifying facility" status to geothermal energy projects.
- exempts geothermal facilities up to 80 MW from certain obligations under the Federal Power Act, state rate and financial regulation and the Public Utility Holding Company Act (PUHCA).

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

In another change in final rule making for cogeneration and small power production facilities, the FERC lifted the 50% ownership limit on cogeneration facilities for certain electric utilities including combined gas and electric utilities. The amendment (Docket Number RM 79-54) allows electric utilities that are declared not to be electric

utilities under certain provisions of the PUHCA to own 100% equity in a qualifying facility. Thus, a combination gas and electric utility company which earns most of its revenues from its gas utility operations may be allowed to own all the equity in a qualifying facility.

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

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

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

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

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

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

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

##### Introduction

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

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\*Edison Electric Institute, Dispersed Energy Update.

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

#### Definition of Fuels Covered

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

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

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



## Definition of Cogeneration Facilities

ERA issued final rules on June 6, 1980, which (1) define MFBI, electric powerplant, and cogeneration facility; (2) describe the prohibitions applicable to new powerplants and MFBI's as well as exemptions available; and (3) provide administrative procedures for applying for exemptions. ERA also published on May 15, 1979 and July 23, 1979 interim rules relating to the prohibitions against oil and gas use in existing facilities and exemptions available, as well as rules relating to exemptions for cogeneration facilities.

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

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

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

## Fuel Use Restrictions

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

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

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

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

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

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

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

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

#### Summary of FUA

In summary, the Fuel Use Act defines cogeneration differently from PURPA. Sections 212(c) and 312(c) of the FUA allow oil and gas for cogeneration if the benefits of cogeneration are unattainable without using oil or gas. Many classes of petroleum and natural gas are exempt from the FUA and if used would not be subject to regulation. A



cogeneration facility as defined by the FUA could be classified as either a major fuel burning installation (MFBI) or as a powerplant. A cogeneration facility falling into the powerplant category but selling less than half of its annual electric generation would be covered as an MFBI. The fuel restrictions are different for new or existing facilities.

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

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

#### Proposed Regulations Revising The FUA

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

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

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

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

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

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

## NATURAL GAS POLICY ACT OF 1978 (NGPA)

### Introduction

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

### Efficiency Standards

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

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\*18 CFR S 282.203(a).

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

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

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

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

## Curtailement Priorities

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

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

## Summary of NGPA

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

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\*45 Federal Register 71787, October 30, 1980.

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



## **ADDENDUM**

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

### **D.C. Court of Appeals**

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

The appeal presented four issues:

- Whether the rates utilities pay for purchases from qualifying cogeneration and small power production facilities ("QFs") should be based on full avoided cost
- Whether FERC has authority to require, by rule, utilities to make all interconnections necessary to sell to or purchase from a QF
- Whether QFs could make simultaneous sales to utilities at avoided cost and purchases from utilities at system average cost
- Whether FERC is required to impose fuel use restrictions on qualifying cogeneration facilities.

The Court vacated FERC's rule requiring utilities to pay full avoided cost for electricity purchased from QFs. This decision was based on the conclusion that PURPA requires FERC to strike a balance among three criteria - the public interest, the interests of QFs and the interest of electric consumers - in determining a rate for power purchased from QFs. The Court stated that while PURPA identifies avoided

cost as the upper limit for such rates, it does not mandate that the purchase rate be at the avoided cost level. The Court held that FERC had failed to explain adequately how the avoided cost formula is consistent with PURPA's mandate. As a result of the Court's action, FERC must promulgate a new rule to establish rates for purchases from QFs.

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

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

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

#### FERC v. Mississippi

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

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

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

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

#### Powerplant and Industrial Fuel Use Act

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



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

## Chapter V

1. U.S. General Accounting Office, Industrial Cogeneration - What it is, How it works, Its potential, EMD-80-7, April 29, 1980.
2. Fred J. Sissine, "Energy Conservation: Prospects for Cogeneration Technology," Issue Brief No. IB81006, Library of Congress, Washington, D.C., February 1982.
3. Frederick H. Pickel, Cogeneration in the U.S.: An Economic and Technical Analysis, M.I.T. Energy Laboratory Report, MIT-EL-78-039, Boston, Massachusetts 1978.
4. Synergic Resources Corporation, Cogeneration Data Base, Draft report submitted to Electric Power Research Institute, September 1981.
5. Synergic Resources Corporation, Industrial Cogeneration Case Studies, EPRI EM-1531, Electric Power Research Institute, September 1980.
6. Thomas C. Hough and Dilip R. Limaye, Utility Participation in DEUS Projects: Regulatory and Financial Aspects, Draft Final Report, submitted to Electric Power Research Institute, April 1981.
7. For further details, see Final Rules Implementing Sections 201 and 210 of PURPA, 45 Federal Register, 12214 and 17949.
8. The legislation providing additional incentives to cogeneration includes the Crude Oil Windfall Profits Tax Act, the Energy Security Act and the Housing and Community Development Act of 1980.
9. Synergic Resources Corporation, Evaluation of Dual Energy Use Systems: Volume I, Executive Summary, Draft Report, March 1981.
10. Synergic Resources Corporation, Evaluation of Dual Energy Use Systems (DEUS) Applications: Project Overview, RP1276, prepared for Electric Power Research Institute, August 1980.
11. Dilip R. Limaye, Methodology for Evaluation of Cogeneration Projects, paper presented at the National Fuel Cell Seminar, Norfolk, Virginia, June 1981.
12. B. Venkateswara, Technical Documentation of COPE-Cogeneration Options Evaluation, unpublished draft report, Synergic Resources Corporation, Bala Cynwyd, PA, April 1982.

APPENDIX A

CASE STUDIES



CHAMPION PACKAGING  
MISSOULA, MONTANA

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

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

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



WEYERHAEUSER  
SPRINGFIELD, OREGON

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

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

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

- A single engineering firm completed the design for the entire project, thereby reducing interface problems.
- The price paid by the utility for steam is based on the kilowatt hours produced and indexed to the market price of petroleum.
- Weyerhaeuser controls the rate of steam production, and thus exerts indirect control over the rate of electrical production.

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

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

DIAMOND WALNUT GROWERS, INC.

STOCKTON, CALIFORNIA

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

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

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

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

PUBLISHERS PAPER  
OREGON CITY, OREGON

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

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

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

MANITOBA FORESTRY RESOURCES  
THE PAS, MANITOBA, CANADA

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

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

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

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

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

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

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



**APPENDIX B**  
**COGENERATION SYSTEMS SUPPLIES, CONSULTANTS,**  
**AND INFORMATION CONTACTS**





## COGENERATION SYSTEMS SUPPLIERS

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

The list of suppliers was compiled from two primary sources:

- The Cogeneration Equipment Compendium - published by the California Energy Commission
- Major Suppliers of Cogeneration Systems - published in the July 12, 1982 issue of Energy User News.

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

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

- Manager, Cogeneration Program  
California Energy Commission  
1111 Howe Avenue  
Sacramento, CA 95825  
(916) 924-2496
- Energy User News  
7 E. 12th St.  
New York, N.Y. 10003  
(212) 741-4485

## MAJOR SUPPLIERS

Air Products & Chemicals, Inc.  
Allentown, PA 18105

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

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

Alturdyne  
8050 Armour St.  
San Diego, CA 92111

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

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

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

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

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

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

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

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

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

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

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

Dravo Corp.  
One Oliver Plaza  
Pittsburgh, PA 15222

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

O'Brien Machinery  
Dowington, PA 19335

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

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

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

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

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

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

Sundstrand Energy Systems  
4747 Harrison Ave.  
Rockford, ILL 61101

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

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

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

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

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

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

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

APPENDIX C

MONTANA FACILITIES SITING ACT AND CURRENT  
BUY BACK RATES AS ESTABLISHED BY THE  
MONTANA PUBLIC SERVICE COMMISSION



TITLE 75  
ENVIRONMENTAL PROTECTION

CHAPTER 20  
MAJOR FACILITY SITING

Part 1

Policy and General Provisions

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

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

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

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

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

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

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

75-20-104. Definitions. In this chapter, unless the



context requires otherwise, the following definitions apply:

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

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

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

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

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

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

(7) "Commence to construct" means:

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

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

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

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

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

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

(10) "Facility" means:

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

1981 Change



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

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

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

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

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

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

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

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

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

(e) any underground in situ gasification of coal.

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

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

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

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

Compiler's Comments

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

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

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

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

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

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

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

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

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

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

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

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

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

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

History: En. Sec. 22, Ch. 327, L. 1973; amd. Sec. 22,

Ch. 494, L. 1975; R.C.M. 1947, 70-822.

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

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

## Part 2

### Certification Proceedings

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

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

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

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

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

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

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

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

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

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

(ii) utilizes coal, wood, biomass, grain, wind, or sun as a fuel source and the technology of which will result in

greater efficiency, promote energy conservation, and promote greater system reliability than the existing facility.

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

#### Compiler's Comments

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(2) An application may consist of an application for



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

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

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

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

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

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

#### Compiler's Comments

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

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

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

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

(2) The following functions of the department of

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

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

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

Composite Section: This section was amended by Ch. 553 and Ch. 676, L. 1979, and a composite section was prepared by the Code Commissioner, 1979. Subsection (3) regarding persons and agencies to be served with a copy of an application was amended by both of the above chapters. Ch. 675 deleted "chief executive officer of each" but the Code Commissioner reinserted this phrase to incorporate the change by Ch. 553 from "municipality" to "unit of local government".

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

History: En. Sec. 6, Ch. 327, L. 1973; amd. Sec. 1, Ch. 115, L. 1974; amd. Sec. 2, Ch. 268, L. 1974; amd. Sec. 1, Ch. 270, L. 1975; amd. Sec. 6, Ch. 494, L. 1975; amd. Sec. 1, Ch. 179, L. 1977; R.C.M. 1947, 70-306(part).

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

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

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

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

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

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

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

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

- (i) 2% of any estimated cost up to \$1 million; plus
- (ii) 1% of any estimated cost over \$1 million and up to \$20 million; plus
- (iii) 0.5% of any estimated cost over \$20 million and up to \$100 million; plus
- (iv) 0.25% of any amount of estimated cost over \$100 million and up to \$300 million; plus
- (v) .125% of any amount of estimated cost over \$300 million.

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



notice to the applicant, this credit may at any time be reduced if the department determines that it is necessary to carry out its responsibilities under this chapter.

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

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

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

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

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

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

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

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

(a) the application is in compliance and is accepted



as complete; or

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

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

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

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

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

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

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

#### Compiler's Comments

~~1991 Amendments:~~ Chapter 274 substituted "department of commerce" for "department of community affairs" in (5).

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

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

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

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

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

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

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

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

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

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

History: En. Sec. 18, Ch. 327, L. 1973; amd. Sec. 18, Ch. 494, L. 1975; R.C.M. 1947, 70-918(2); amd. Sec. 9, Ch. 676, L. 1979.

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

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

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



health.

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

#### Compiler's Comments

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

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

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

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

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

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

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

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

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

#### Compiler's Comments

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

#### 75-20-220. Hearing examiner -- restrictions -- duties.

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

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

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

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

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

allow the introduction of new evidence at any time.

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

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

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

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

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

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

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

#### Compiler's Comments

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

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

75-20-221. Parties to certification proceeding. --  
waiver. -- statement of intent to participate. (1) The



parties to a certification proceeding or to a proceeding involving the issuance of a decision, opinion, order, certification, or permit by the board of health under this chapter may include as active parties:

(a) the applicant;

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

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

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

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

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

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

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

(5) Each unit of local government entitled to receive service of a copy of the application under 75-20-211(3) shall file with the board a statement showing whether the unit of local government intends to participate in the certification proceeding. If the unit of local government does not intend to participate, it shall list in this statement its reasons for failing to do so. This statement of intent shall be published before the proceeding begins in a newspaper of general circulation within the jurisdiction of the applicable unit of local government.

History: En. Sec. 8, Ch. 327, L. 1973; amd. Sec. 8, Ch. 494, L. 1975; R.C.M. 1947, 70-808; amd. Sec. 2, Ch. 553, L. 1979; amd. Sec. 13, Ch. 676, L. 1979.

75-20-222. Record of hearing -- procedure -- rules of evidence -- burden of proof. (1) Any studies, investigations, reports, or other documentary evidence, including those prepared by the department, which any party wishes the board to consider or which the board itself expects to utilize or rely upon shall be made a part of the record.

(2) A record shall be made of the hearing and of all testimony taken.

(3) In a certification proceeding held under this chapter, the applicant has the burden of showing by clear

and convincing evidence that the application should be granted and that the criteria of 75-20-301 are met.

(4) All proceedings under this chapter are governed by the procedures set forth in this chapter, the procedural rules adopted by the board, and the Montana Rules of Evidence unless one or more rules of evidence are waived by the hearing examiner upon a showing of good cause by one or more of the parties to the hearing. No other rules of procedure or evidence shall apply except that the contested case procedures of the Montana Administrative Procedure Act shall apply if not in conflict with the procedures set forth in this chapter or the procedural rules adopted by the board.

History: En. Sec. 9, Ch. 327, L. 1973; amd. Sec. 9, Ch. 494, L. 1975; R.C.M. 1947, 70-809(1), (2); amd. Sec. 14, Ch. 676, L. 1979.

### Part 3

#### Decisions

75-20-301. Decision of board -- findings necessary for certification. (1) Within 60 days after submission of the recommended decision by the hearing examiner, the board shall make complete findings, issue an opinion, and render a decision upon the record, either granting or denying the application as filed or granting it upon such terms, conditions, or modifications of the construction, operation, or maintenance of the facility as the board considers appropriate.

(2) The board may not grant a certificate either as proposed by the applicant or as modified by the board unless it shall find and determine:

- (a) the basis of the need for the facility;
- (b) the nature of the probable environmental impact;
- (c) that the facility represents the minimum adverse environmental impact, considering the state of available technology and the nature and economics of the various alternatives;
- (d) each of the criteria listed in 75-20-503;
- (e) in the case of an electric, gas, or liquid transmission line or aqueduct:
  - (i) what part, if any, of the line or aqueduct shall be located underground;
  - (ii) that the facility is consistent with regional plans for expansion of the appropriate grid of the utility systems serving the state and interconnected utility systems; and
  - (iii) that the facility will serve the interests of utility system economy and reliability;
- (f) that the location of the facility as proposed conforms to applicable state and local laws and regulations issued thereunder, except that the board may refuse to apply any local law or regulation if it finds that, as applied to the proposed facility, the law or regulation is unreasonably



restrictive in view of the existing technology, of factors of cost or economics, or of the needs of consumers, whether located inside or outside of the directly affected government subdivisions;

(g) that the facility will serve the public interest, convenience, and necessity;

(h) that the department of health or board of health have issued a decision, opinion, order, certification, or permit as required by 75-20-216(3); and

(i) that the use of public lands for location of the facility was evaluated and public lands were selected whenever their use is as economically practicable as the use of private lands and compatible with the environmental criteria listed in 75-20-503.

(3) In determining that the facility will serve the public interest, convenience, and necessity under subsection (2)(g) of this section, the board shall consider:

(a) the items listed in subsections (2)(a) and (2)(b) of this section;

(b) the benefits to the applicant and the state resulting from the proposed facility;

(c) the effects of the economic activity resulting from the proposed facility;

(d) the effects of the proposed facility on the public health, welfare, and safety;

(e) any other factors that it considers relevant.

(4) Considerations of need, public need, or public convenience and necessity and demonstration thereof by the applicant shall apply only to utility facilities.

History: En. Sec. 10, Ch. 327, L. 1973; amd. Sec. 10, Ch. 494, L. 1975; R.C.M. 1947, 70-810(1), (3), (4); amd. Sec. 1, Ch. 69, L. 1979; amd. Sec. 15, Ch. 676, L. 1979.

75-20-302. Conditions imposed. If the board determines that the location of all or a part of the proposed facility should be modified, it may condition its certificate upon such modification, provided that the persons residing in the area affected by the modification have been given reasonable notice of the modification.

History: En. Sec. 10, Ch. 327, L. 1973; amd. Sec. 10, Ch. 494, L. 1975; R.C.M. 1947, 70-810(2); amd. Sec. 16, Ch. 676, L. 1979.

75-20-303. Opinion issued with decision -- contents.

(1) In rendering a decision on an application for a certificate, the board shall issue an opinion stating its reasons for the action taken.

(2) If the board has found that any regional or local law or regulation which would be otherwise applicable is unreasonably restrictive pursuant to 75-20-301(2)(f), it shall state in its opinion the reasons therefor.

(3) Any certificate issued by the board shall include the following:

(a) an environmental evaluation statement related to

the facility being certified. The statement shall include but not be limited to analysis of the following information:

- (i) the environmental impact of the proposed facility;
- (ii) any adverse environmental effects which cannot be avoided by issuance of the certificate;
- (iii) problems and objections raised by other federal and state agencies and interested groups;
- (iv) alternatives to the proposed facility;
- (v) a plan for monitoring environmental effects of the proposed facility; and
- (vi) a time limit as provided in subsection (4), during which construction of the facility must be completed;

(b) a statement signed by the applicant showing agreement to comply with the requirements of this chapter and the conditions of the certificate.

(4) The board shall issue as part of the certificate the following time limits during which construction of a facility must be completed:

(a) For a facility as defined in (b) or (c) of 75-20-104(7) that is more than 30 miles in length, the time limit is 10 years.

(b) For a facility as defined in (b) or (c) of 75-20-104(7) that is 30 miles or less in length, the time limit is 5 years.

(c) The time limit shall be extended for periods of 2 years each upon a showing by the applicant to the board that a good faith effort is being undertaken to complete construction. Under this subsection, a good faith effort to complete construction includes the process of acquiring any necessary state or federal permit or certificate for the facility and the process of judicial review of any such permit or certificate.

(5) The provisions of subsection (4) apply to any facility for which a certificate has not been issued or for which construction is yet to be commenced.

History: En. Sec. 11, Ch. 327, L. 1973; amd. Sec. 11, Ch. 494, L. 1975; R.C.M. 1947, 70-811(1), (2); amd. Sec. 1, Ch. 120, L. 1979.

#### Compiler's Comments

Effective date. Sec. 2, Ch. 120, L. 1979, provided: "This act is effective on passage and approval." Approved March 19, 1979."

75-20-304. Waiver of provisions of certification proceedings. (1) The board may waive compliance with any of the provisions of 75-20-216 through 75-20-222, 75-20-501, and this part if the applicant makes a clear and convincing showing to the board at a public hearing that an immediate, urgent need for a facility exists and that the applicant did not have knowledge that the need for the facility existed sufficiently in advance to fully comply with the provisions of 75-20-216 through 75-20-222, 75-20-501, and this part.

(2) The board may waive compliance with any of the provisions of this chapter upon receipt of notice by a

utility or person subject to this chapter that a facility or associated facility has been damaged or destroyed as a result of fire, flood, or other natural disaster or as the result of insurrection, war, or other civil disorder and there exists an immediate need for construction of a new facility or associated facility or the relocation of a previously existing facility or associated facility in order to promote the public welfare.

(3) The board shall waive compliance with the requirements of subsections (2)(c), (3)(b), and (3)(c) of 75-20-301 and 75-20-501(5) and the requirements of subsections (1)(a)(iv) and (v) of 75-20-211, 75-20-216(3), and 75-20-303(3)(a)(iv) relating to consideration of alternative sites if the applicant makes a clear and convincing showing to the board at a public hearing that:

(a) a proposed facility will be constructed in a county where a single employer within the county has permanently curtailed or ceased operations causing a loss of 250 or more permanent jobs within 2 years at the employer's operations within the preceding 10-year period;

(b) the county and municipal governing bodies in whose jurisdiction the facility is proposed to be located support by resolution such a waiver;

(c) the proposed facility will be constructed within a 15-mile radius of the operations that have ceased or been curtailed; and

(d) the proposed facility will have a beneficial effect on the economy of the county in which the facility is proposed to be located.

(4) The waiver provided for in subsection (3) applies only to permanent job losses by a single employer. The waiver provided for in subsection (3) does not apply to jobs of a temporary or seasonal nature, including but not limited to construction jobs or job losses during labor disputes.

(5) The waiver provided for in subsection (3) does not apply to consideration of alternatives or minimum adverse environmental impact for a facility defined in subsections (10)(b), (c), (d), or (e) of 75-20-104, for an associated facility defined in subsection (3) of 75-20-104, or for any portion of or process in a facility defined in subsection (10)(a) of 75-20-104 to the extent that the process or portion of the facility is not subject to a permit issued by the department of health or board of health.

(6) The applicant shall pay all expenses required to process and conduct a hearing on a waiver request under subsection (3). However, any payments made under this subsection shall be credited toward the fee paid under 75-20-215 to the extent the data or evidence presented at the hearing or the decision of the board under subsection (3) can be used in making a certification decision under this chapter.

(7) The board may grant only one waiver under subsections (3) and (4) for each permanent loss of jobs as defined in subsection (3)(a).

History: En. Sec. 11, Ch. 327, L. 1973; amd. Sec. 11,



Ch. 494, L. 1975; R.C.M. 1947, 70-811(3), (4); amd. Sec. 17, Ch. 676, L. 1979; amd. Sec. 7, Ch. 539, L. 1981.

#### Compiler's Comments

1981 Amendment: Added subsections (3) through (7).

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

### Part 4

#### Postcertification and Legal Responsibilities

75-20-401. Additional requirements by other governmental agencies not permitted after issuance of certificate -- exceptions. (1) Notwithstanding any other law, no state or regional agency or municipality or other local government may require any approval, consent, permit, certificate, or other condition for the construction, operation, or maintenance of a facility authorized by a certificate issued pursuant to this chapter, except that the state air and water quality agency or agencies shall retain authority which they have or may be granted to determine compliance of the proposed facility with state and federal standards and implementation plans for air and water quality and to enforce those standards.

(2) This chapter does not prevent the application of state laws for the protection of employees engaged in the construction, operation, or maintenance of a facility.

History: En. Sec. 17, Ch. 327, L. 1973; amd. Sec. 17, Ch. 494, L. 1975; R.C.M. 1947, 70-817; amd. Sec. 18, Ch. 676, L. 1979.

75-20-402. Monitoring. The board, the department, the department of health, and the board of health shall monitor the operations of all certificated facilities for assuring continuing compliance with this chapter and certificates issued hereunder and for discovering and preventing noncompliance with this chapter and the certificates. The applicant shall pay all expenses related to the monitoring plan established in subsection (3)(a)(v) of 75-20-303 to the extent federal funds available for the facility, as determined by the department of health, have not been provided for such purposes.

History: En. Sec. 20, Ch. 327, L. 1973; amd. Sec. 4, Ch. 268, L. 1974; amd. Sec. 20, Ch. 494, L. 1975; R.C.M. 1947, 70-820(2); amd. Sec. 19, Ch. 676, L. 1979.

75-20-403. Revocation or suspension of certificate. A certificate may be revoked or suspended by the board:

(1) for any material false statement in the application or in accompanying statements or studies required of the applicant if a true statement would have warranted the board's refusal to grant a certificate;

(2) for failure to maintain safety standards or to comply with the terms or conditions of the certificate; or  
(3) for violation of any provision of this chapter, the rules issued thereunder, or orders of the board or department.

History: En. Sec. 19, Ch. 327, L. 1973; amd. Sec. 18, Ch. 494, L. 1975; R.C.M. 1947, 70-813(1).

75-20-404. Enforcement of chapter by residents. (1) A resident of this state with knowledge that a requirement of this chapter or a rule adopted under it is not being enforced by a public officer or employee whose duty it is to enforce the requirement or rule may bring the failure to enforce to the attention of the public officer or employee by a written statement under oath that shall state the specific facts of the failure to enforce the requirement or rule. Knowingly making false statements or charges in the affidavit subjects the affiant to penalties prescribed under the law of perjury.

(2) If the public officer or employee neglects or refuses for an unreasonable time after receipt of the statement to enforce the requirement or rule, the resident may bring an action of mandamus in the district court of the first judicial district of this state, in and for the county of Lewis and Clark. If the court finds that a requirement of this chapter or a rule adopted under it is not being enforced, the court may order the public officer or employee whose duty it is to enforce the requirement or rule to perform his duties. If he fails to do so, the public officer or employee shall be held in contempt of court and is subject to the penalties provided by law.

History: En. Sec. 19, Ch. 327, L. 1973; amd. Sec. 19, Ch. 494, L. 1975; R.C.M. 1947, 70-819(1), (2).

75-20-405. Action to recover damages to water supply. An owner of an interest in real property who obtains all or part of his supply of water for domestic, agricultural, industrial, or other legitimate use from a surface or underground source may sue a person to recover damages for contamination, diminution, or interruption of the water supply proximately resulting from the operation of a facility. The remedies enumerated in this section do not exclude the use of any other remedy which may be available under the laws of the state.

History: En. Sec. 19, Ch. 327, L. 1973; amd. Sec. 19, Ch. 494, L. 1975; R.C.M. 1947, 70-819(3).

75-20-406. Judicial review of board, board of health, and department of health decisions. (1) Any active party as defined in 75-20-221 aggrieved by the final decision of the board on an application for a certificate may obtain judicial review of that decision by the filing of a petition in a state district court of competent jurisdiction.

(2) The judicial review procedure shall be the same as that for contested cases under the Montana Administrative Procedure Act.

(3) When the board of health or department of health conducts hearings pursuant to 75-20-216(3) and 75-20-218 and the applicant is granted a permit or certification, with or without conditions, pursuant to the laws administered by the department of health and the board of health and this chapter, the decision may only be appealed in conjunction with the final decision of the board as provided in subsections (1) and (2). If a permit or certification is denied by the department of health or the board of health, the applicant may:

(a) appeal the denial under the appellate review procedures provided in the laws administered by the department of health and the board of health; or

(b) reserve the right to appeal the denial by the department of health or the board of health until after the board has issued a final decision.

(4) Nothing in this section may be construed to prohibit the board from holding a hearing as herein provided on all matters that are not the subject of a pending appeal by the applicant under subsection (3)(a).

History: En. Sec. 12, Ch. 327, L. 1973; amd. Sec. 12, Ch. 494, L. 1975; R.C.M. 1947, 70-312; amd. Sec. 20, Ch. 676, L. 1979; amd. Sec. 8, Ch. 539, L. 1981.

#### Compiler's Comments

1981 Amendment: Added subsections (3) and (4).

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

75-20-407. Jurisdiction of courts restricted. Except as expressly set forth in 75-20-401, 75-20-406, and 75-20-408, no court of this state has jurisdiction to hear or determine any issue, case, or controversy concerning any matter which was or could have been determined in a proceeding before the board under this chapter or to stop or delay the construction, operation, or maintenance of a facility, except to enforce compliance with this chapter or the provisions of a certificate issued hereunder pursuant to 75-20-404 and 75-20-405 or 75-20-408.

History: En. Sec. 13, Ch. 327, L. 1973; amd. Sec. 13, Ch. 494, L. 1975; R.C.M. 1947, 70-813.

75-20-408. Penalties for violation of chapter -- civil action by attorney general. (1) (a) Whoever commences to construct or operate a facility without first obtaining a certificate required under 75-20-201 or a waiver thereof under 75-20-304(2) or having first obtained a certificate, constructs, operates, or maintains a facility other than in compliance with the certificate or violates any other provision of this chapter or any rule or order adopted



thereunder or knowingly submits false information in any report, 10-year plan, or application required by this chapter or rule or order adopted thereunder or causes any of the aforementioned acts to occur is liable for a civil penalty of not more than \$10,000 for each violation.

(b) Each day of a continuing violation constitutes a separate offense.

(c) The penalty is recoverable in a civil suit brought by the attorney general on behalf of the state in the district court of the first judicial district of Montana.

(2) Whoever knowingly and willfully violates subsection (1) shall be fined not more than \$10,000 for each violation or imprisoned for not more than 1 year, or both. Each day of a continuing violation constitutes a separate offense.

(3) In addition to any penalty provided in subsections (1) or (2), whenever the department determines that a person is violating or is about to violate any of the provisions of this section, it may refer the matter to the attorney general who may bring a civil action on behalf of the state in the district court of the first judicial district of Montana for injunctive or other appropriate relief against the violation and to enforce this chapter or a certificate issued hereunder. Upon a proper showing, a permanent or preliminary injunction or temporary restraining order shall be granted without bond.

(4) The department shall also enforce this chapter and bring legal actions to accomplish the enforcement through its own legal counsel.

(5) All fines and penalties collected shall be deposited in the earmarked revenue fund for the use of the department in administering this chapter.

History: En. Sec. 21, Ch. 327, L. 1973; amd. Sec. 2, Ch. 270 L. 1975; amd. Sec. 21, Ch. 494, L. 1975; R.C.M. 1947, 70-821; amd. Sec. 16, Ch. 68, L. 1979; amd. Sec. 21, Ch. 676, L. 1979.

~~15-20-409. Optional annual installments for location of facility on landowner's property.~~ A landowner upon whose land a facility is proposed to be located shall have the option of receiving any negotiated settlement for use of his land, if and when the land is used for a facility, by easement, right-of-way, or other legal conveyance in either a lump sum or in not more than five consecutive annual installments.

History: En. Sec. 1, Ch. 71, L. 1979.

~~15-20-410. Order not stayed by appeal -- stay or suspension by court -- limitations.~~ Notwithstanding any contrary provision in the law, the pendency of an appeal from a board order does not automatically stay or suspend the operation of the order. During the pendency of the appeal, the court may upon motion by one of the parties stay or suspend, in whole or in part, the operation of the

board's orders on terms the court considers just. The court's action must be in accordance with the practice of courts exercising equity jurisdiction, subject to the following limitations:

(1) No stay may be granted without notice to the parties and an opportunity to be heard by the court.

(2) No board order may be stayed or suspended without finding that irreparable damage would otherwise result to the party seeking the stay or suspension, and any other stay or suspension of a board order must specify the nature of the damage.

History: En. Sec. 24, Ch. 676, L. 1979.

#### Compiler's Comments

Codification. Sec. 27, Ch. 676, L. 1979, provided: "It is the intent of the legislature that sections 24 and 25 become an integral part of Title 75, chapter 20, MCA, and that the provisions of that chapter apply to sections 24 and 25." Sections 24 and 25 are codified as 75-20-410 and 75-20-411.

75-20-411. Surety bond -- other security. If an order of the board is stayed or suspended, the court may require a bond with good and sufficient surety conditioned that the party petitioning for review answer for all damages caused by the delay in enforcing the order of the board; except that the cost of the bond is not chargeable to the applicant as part of the fee. If the party petitioning for review prevails upon final resolution of an appeal, he does not forfeit bond nor is he responsible for damages caused by delay.

History: En. Sec. 25, Ch. 676, L. 1979.

#### Compiler's Comments

Codification. Sec. 27, Ch. 676, L. 1979, provided: "It is the intent of the legislature that sections 24 and 25 become an integral part of Title 75, chapter 20, MCA, and that the provisions of that chapter apply to sections 24 and 25." Sections 24 and 25 are codified as 75-20-410 and 75-20-411.

### Part 5

#### Long-Range Plans

75-20-201. Annual long-range plan submitted -- contents -- available to public. (1) Each utility and each person contemplating the construction of a facility within this state in the ensuing 10 years shall furnish annually to the department for its review a long-range plan for the construction and operation of facilities.

(2) The plan shall be submitted by April 1 of each year and must include the following:

(a) the general location, size, and type of all



facilities to be owned and operated by the utility or person whose construction is projected to commence during the ensuing 10 years, as well as those facilities to be removed from service during the planning period;

(b) in the case of utility facilities, a description of efforts by the utility or person to coordinate the plan with other utilities or persons so as to provide a coordinated regional plan for meeting the energy needs of the region;

(c) a description of the efforts to involve environmental protection and land use planning agencies in the planning process, as well as other efforts to identify and minimize environmental problems at the earliest possible stage in the planning process;

(d) projections of the demand for the service rendered by the utility or person and explanation of the basis for those projections and a description of the manner and extent to which the proposed facilities will meet the projected demand; and

(e) additional information that the board by rule or the department on its own initiative or upon the advice of interested state agencies might request in order to carry out the purposes of this chapter.

(3) The plan shall be furnished to the governing body of each county in which any facility included in the plan under (2)(a) of this section is proposed to be located and made available to the public by the department. The utility or person shall give public notice throughout the state of its plan by filing the plan with the environmental quality council, the department of health and environmental sciences, the department of highways, the department of public service regulation, the department of state lands, the department of fish, wildlife, and parks, and the department of commerce. Citizen environmental protection and resource planning groups and other interested persons may obtain a plan by written request and payment therefor to the department.

(4) A rural electric cooperative may furnish the department with a copy of the long-range plan and 2-year work plan required to be completed under federal rural electrification requirements in lieu of the long-range plan required in subsection (1).

(5) No person may file an application for a facility unless the facility had been adequately identified in a long-range plan at least 2 years prior to acceptance of an application by the department.

History: En. Sec. 14, Ch. 327, L. 1973; amd. Sec. 40, Ch. 213, L. 1975; amd. Sec. 14, Ch. 494, L. 1975; R.C.M. 1947, 70-814; amd. Sec. 17, Ch. 68, L. 1979; amd. Sec. 3, Ch. 553, L. 1979; amd. Sec. 22, Ch. 676, L. 1979; amd. Sec. 6, Ch. 274, L. 1981.

#### Compiler's Comments

~~1981 Amendment:~~ Substituted "department of commerce" for "department of community affairs" in (3).

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

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

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

75-20-502. Study of included facilities. If a utility or person lists and identifies a proposed facility in its plan, submitted pursuant to 75-20-501, as one on which construction is proposed to be commenced within the 5-year period following submission of the plan, the department shall commence examination and evaluation of the proposed site to determine whether construction of the proposed facility would unduly impair the environmental values in 75-20-503. This study may be continued until such time as a person files an application for a certificate under 75-20-211. Information gathered under this section may be used to support findings and recommendations required for issuance of a certificate.

History: En. Sec. 15, Ch. 327, L. 1973; amd. Sec. 15, Ch. 494, L. 1975; R.C.M. 1947, 70-815.

75-20-503. Environmental factors evaluated. In evaluating long-range plans, conducting 5-year site reviews, and evaluating applications for certificates, the board and department shall give consideration to the following list of environmental factors, where applicable, and may by rule add to the categories of this section:

- (1) energy needs:
  - (a) growth in demand and projections of need;
  - (b) availability and desirability of alternative sources of energy;
  - (c) availability and desirability of alternative sources of energy in lieu of the proposed facility;
  - (d) promotional activities of the utility which may have given rise to the need for this facility;
  - (e) socially beneficial uses of the output of this facility, including its uses to protect or enhance environmental quality;
  - (f) conservation activities which could reduce the need for more energy;
  - (g) research activities of the utility of new technology available to it which might minimize environmental impact;
- (2) land use impacts:
  - (a) area of land required and ultimate use;
  - (b) consistency with areawide state and regional land use plans;
  - (c) consistency with existing and projected nearby land use;
  - (d) alternative uses of the site;

(e) impact on population already in the area, population attracted by construction or operation of the facility itself;

(f) impact of availability of energy from this facility on growth patterns and population dispersal;

(g) geologic suitability of the site or route;

(h) seismologic characteristics;

(i) construction practices;

(j) extent of erosion, scouring, wasting of land, both at site and as a result of fossil fuel demands of the facility;

(k) corridor design and construction precautions for transmission lines or aqueducts;

(l) scenic impacts;

(m) effects on natural systems, wildlife, plant life;

(n) impacts on important historic architectural, archeological, and cultural areas and features;

(o) extent of recreation opportunities and related compatible uses;

(p) public recreation plan for the project;

(q) public facilities and accommodation;

(r) opportunities for joint use with energy-intensive industries or other activities to utilize the waste heat from facilities;

(s) opportunities for using public lands for location of facilities whenever as economically practicable as the use of private lands and compatible with the requirements of this section;

(3) water resources impacts:

(a) hydrologic studies of adequacy of water supply and impact of facility on streamflow, lakes, and reservoirs;

(b) hydrologic studies of impact of facilities on groundwater;

(c) cooling system evaluation, including consideration of alternatives;

(d) inventory of effluents, including physical, chemical, biological, and radiological characteristics;

(e) hydrologic studies of effects of effluents on receiving waters, including mixing characteristics of receiving waters, changed evaporation due to temperature differentials, and effect of discharge on bottom sediments;

(f) relationship to water quality standards;

(g) effects of changes in quantity and quality on water use by others, including both withdrawal and in situ uses;

(h) relationship to projected uses;

(i) relationship to water rights;

(j) effects on plant and animal life, including algae, macroinvertebrates, and fish population;

(k) effects on unique or otherwise significant ecosystems, e.g., wetlands;

(l) monitoring programs;

(4) air quality impacts:

(a) meteorology--wind direction and velocity, ambient temperature ranges, precipitation values, inversion occurrence, other effects on dispersion;

- (b) topography--factors affecting dispersion;
- (c) standards in effect and projected for emissions;
- (d) design capability to meet standards;
- (e) emissions and controls:
  - (i) stack design;
  - (ii) particulates;
  - (iii) sulfur oxides;
  - (iv) oxides of nitrogen; and
  - (v) heavy metals, trace elements, radioactive materials, and other toxic substances;
- (f) relationship to present and projected air quality of the area;
- (g) monitoring program;
- (5) solid wastes impacts:
  - (a) solid waste inventory;
  - (b) disposal program;
  - (c) relationship of disposal practices to environmental quality criteria;
  - (d) capacity of disposal sites to accept projected waste loadings;
- (6) radiation impacts:
  - (a) land use controls over development and population;
  - (b) wastes and associated disposal program for solid, liquid, radioactive, and gaseous wastes;
  - (c) analyses and studies of the adequacy of engineering safeguards and operating procedures;
  - (d) monitoring--adequacy of devices and sampling techniques;
- (7) noise impacts:
  - (a) construction period levels;
  - (b) operational levels;
  - (c) relationship of present and projected noise levels to existing and potential stricter noise standards;
  - (d) monitoring--adequacy of devices and methods.

History: En. Sec. 16, Ch. 327, L. 1973; amd. Sec. 16, Ch. 494, L. 1975; R.C.M. 1947, 70-816; amd. Sec. 2, Ch. 69, L. 1979; amd. Sec. 23, Ch. 676, L. 1979.

Parts 6 through 9 reserved

## Part 10

### Geothermal Exploration

15-20-1001. Geothermal exploration--notification of department. The board shall adopt rules requiring every person who proposes to gather geological data by boring of test holes or other underground exploration, investigation, or experimentation related to the possible future development of a facility employing geothermal resources to comply with the following requirements:

- (1) notify the department of the proposed action;
- (2) submit to the department a description of the area involved;
- (3) submit to the department a statement of the



proposed activities to be conducted and the methods to be utilized;

(4) submit to the department geological data reports at such times as may be required by the rules; and

(5) submit such other information as the board may require in the rules.

History: En. Sec. 20, Ch. 327, L. 1973; amd. Sec. 4, Ch. 268, L. 1974; amd. Sec. 20, Ch. 494, L. 1975; R.C.M. 1947, 70-820(3).

## Part 11

### Energy Conversion Facility

(Repealed. Sec. 28, Ch. 676, L. 1979)

#### Part Compiler's Comments

##### Histories of Repealed Sections:

75-20-1101 through 75-20-1105. En. 70-825 through 70-829 by Sec. 1 through 5, Ch. 517, L. 1975; R.C.M. 1947, 70-825 through 70-829.

## Part 12

### Nuclear Energy Conversion

75-20-1201. Purpose -- findings as to nuclear safety -- reservation of nuclear facility approval powers to the people. (1) The people of Montana find that substantial public concern exists regarding nuclear reactors and other major nuclear facilities, including the following unresolved issues:

(a) the generation of waste from nuclear facilities, which remains a severe radiological hazard for many thousands of years and to which no means of containment assuring the protection of future generations exists;

(b) the spending of scarce capital to pay the rapidly increasing costs of nuclear facilities, preventing the use of that capital to finance renewable energy sources which hold more promise for supplying useful energy, providing jobs, and holding down energy costs;

(c) the liability of nuclear facilities to sudden catastrophic accidents which can affect large areas of the state, thousands of people, and countless future generations;

(d) the refusal of utilities, industry, and government to assume normal financial responsibility for compensating victims of such nuclear accidents;

(e) the impact of nuclear facilities on the proliferation of nuclear bombs and terrorism;

(f) the increasing pattern of abandonment of used nuclear facilities by their owners, resulting in radiological dangers to present and future societies as well as higher public costs for perpetual management; and

(g) the detrimental effect of the large uranium import program necessary to the expansion of nuclear power on

American energy independence, defense policy, and economic well being.

(2) Therefore, the people of Montana reserve to themselves the exclusive right to determine whether major nuclear facilities are built and operated in this state.

-History: En. Sec. 1, I.M. 80, app. Nov. 7, 1978.

#### Compiler's Comments

Severability. Section 7 of Initiative 80 was a severability clause.

Effective date. Initiative 80 was approved at the general election held November 7, 1978, and was effective July 1, 1979.

75-20-1202. Definitions. As used in this part and 75-20-201 through 75-20-203, the following definitions apply:

(1) (a) "Nuclear facility" means each plant, unit, or other facility designed for, or capable of,

(i) generating 50 megawatts of electricity or more by means of nuclear fission,

(ii) converting, enriching, fabricating, or reprocessing uranium minerals or nuclear fuels, or

(iii) storing or disposing of radioactive wastes or materials from a nuclear facility;

(b) "nuclear facility" does not include any small-scale facility used solely for educational, research, or medical purposes not connected with the commercial generation of energy.

(2) "Facility," as defined in 75-20-104(7) is further defined to include any nuclear facility as defined in subsection (1)(a) of this section.

History: En. Sec. 2, I.M. 80, app. Nov. 7, 1978.

75-20-1203. Additional requirements for issuance of a certificate for the siting of a nuclear facility. (1) The board may not issue a certificate to construct a nuclear facility unless it finds that:

(a) no legal limits exist regarding the rights of a person or group of persons to bring suit for and recover full and just compensation from the designers, manufacturers, distributors, owners, and/or operators of a nuclear facility for damages resulting from the existence or operation of the facility; and further, that no legal limits exist regarding the total compensation which may be required from the designers, manufacturers, distributors, owners, and/or operators of a nuclear facility for damages resulting from the existence or operation of such facility;

(b) the effectiveness of all safety systems, including but not limited to the emergency core cooling systems, of such nuclear facility has been demonstrated, to the satisfaction of the board, by the comprehensive laboratory testing of substantially similar physical systems in actual

operation;

(c) the radioactive materials from such nuclear facilities can be contained with no reasonable chance, as determined by the board, of intentional or unintentional escape or diversion of such materials into the natural environment in such manner as to cause substantial or long-term harm or hazard to present or future generations due to imperfect storage technologies, earthquakes or other acts of God, theft, sabotage, acts of war or other social instabilities, or whatever other causes the board may deem to be reasonably possible, at any time during which such materials remain a radiological hazard; and

(d) the owner of such nuclear facility has posted with the board a bond totalling not less than 30% of the total capital cost of the facility, as estimated by the board, to pay for the decommissioning of the facility and the decontamination of any area contaminated with radioactive materials due to the existence or operation of the facility in the event the owner fails to pay the full costs of such decommissioning and decontamination. Excess bond, if any, shall be refunded to the owner upon demonstration, to the satisfaction of the board, that the site and environs of the facility pose no radiological danger to present or future generations and that whatever other conditions the board may deem reasonable have been met.

(2) Nothing in this section shall be construed as relieving the owner of a nuclear facility from full financial responsibility for the decommissioning of such facility and decontamination of any area contaminated with radioactive materials as a result of the existence or operation of such facility at any time during which such materials remain a radiological hazard.

History: En. Sec. 4, I.M. 80, app. Nov. 7, 1978.

75-20-1204. Annual review of evacuation and emergency medical aid plans. (1) The governor shall annually publish, publicize, and release to the news media and to the appropriate officials of affected communities, in a manner designed to inform residents of the affected communities, the entire evacuation plan specified in the licensing of each certified nuclear facility within this state. Copies of such plan shall be made available to the public upon request at no more than the cost of reproduction.

(2) The governor shall establish procedures for annual review by state and local officials of established evacuation and emergency medical aid plans with regard for, but not limited to, such factors as the adequacy of such plans, changes in traffic patterns, population densities, the locations of schools, hospitals, and industrial developments, and other factors as requested by locally elected representatives.

History: En. Sec. 5, I.M. 80, app. Nov. 7, 1978.

75-20-1205. Emergency approval authority invalid for

nuclear\_\_\_facilities. Notwithstanding the provisions of subsections (2) and (3) of 75-20-304, the board may not waive compliance with any of the provisions of this part or 75-20-201 through 75-20-203 relating to certification of a nuclear facility.

History: En. Sec. 6, I.M. 80, app. Nov. 7, 1977.



## Public Service Commission of Montana

The Montana Power Company

Sheet No. STPP-82 Supp. #

Cancelling Sheet No. STPP-82

Page 1 of 2

Name of Company)

## Schedule STPP-82 Supp. #1

## Short-Term Power Purchase

## Service

**AVAILABILITY:** To any Seller who operates facilities for the purpose of generating short-term electric energy in parallel with the Company's system. This schedule is applicable to Cogeneration and Small Power Production (COG/SPP) facilities that are Qualifying Facilities under the Rules of the MPSC.

**DEFINITIONS:** "Seller," for purposes of this schedule, is any individual, partnership, corporation, association, government agency, political subdivision, municipality, or other entity that:

1. Operates a qualifying COG/SPP facility;
2. Has signed the standard written contract with the Company, stipulating the terms and conditions of the interconnection and sale of electricity to the Company;
3. Has agreed in the standard contract to provide electricity to the Company on a short-term basis as defined in the contract.

"Company" means The Montana Power Company.

"MPSC" means The Montana Public Service Commission.

"Contract Year" means twelve months beginning on July 1.

**RATE:** \$0.0234/kWh

SPECIAL TERMS AND CONDITIONS:

1. Change of Rate: This schedule will be reviewed annually for each Contract Year and revised upon MPSC approval.
2. Net Billing Option: If the Seller opts for Short-Term Net Billing in the standard contract and the Seller's consumption kWh exceeds the production kWh, the Seller will be billed for only the consumption kWh in excess of production kWh according to the Company's applicable Retail Sales Rate Schedule. If the Seller's consumption kWh is less than the production kWh, the Seller will receive payment for only the production kWh in excess of consumption kWh according to the energy rate in this schedule. A Seller under this Option will receive no separate payment for capacity, and all metered consumption kW (if applicable) will be billed to

Issued July 30, 1982  
(Date)

By [Signature]  
(Signature of Officer of Utility)

Approved August 3, 1982  
(Date)

Effective For electric service rendered on and after (Date) August 3, 1982

Docket No. 81-2-15  
Order No. 4865b & 4865c  
(Space for Stamp or Seal of Commission)

PUBLIC SERVICE COMMISSION OF MONTANA.

[Signature]  
Secretary.

\*Space below these lines for use of Commission only.

## Public Service Commission of Montana

The Montana Power Company

Sheet No. STPP-82 Supp. #1

Cancelling Sheet No. STPP-82  
Page 2 of 2

Name of Company)

Schedule STPP-82 Supp. #1

Short-Term Power Purchase

Service

the Seller according to the Company's applicable Retail Sales Rate Schedule. If the Seller is demand-metered for consumption, the Seller will be required to install a kW/kWh meter to separately measure production.

3. All service provided by the Company under this and all other schedules is governed by the rules and regulations approved by the MPSC.

331474

Issued July 30, 1982

(Date)

By

(Signature of Officer of Utility)

August 3, 1982

Approved

Effective

For electric service rendered

on and after

(Date) August 3, 1982

PUBLIC SERVICE COMMISSION OF MONTANA.

Docket No. 81.2.15 (Date)

Order No. 4865b &amp; 4865c

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## Public Service Commission of Montana

The Montana Power Company

Sheet No. LTPP-82 Supp. #

Cancelling Sheet No. LTPP-82

Name of Company)

Page 1 of 3

## Schedule LTPP-82 Supp. #1

Long-Term Power Purchase Service

**AVAILABILITY:** To any Seller who operates facilities for the purpose of generating long-term electric energy in parallel with the Company's system. This schedule is applicable to Cogeneration and Small Power Production (COG/SPP) facilities that are Qualifying Facilities under the Rules of the MPSC.

**DEFINITIONS:** "Seller," for purposes of this schedule, is any individual, partnership, corporation, association, government agency, political subdivision, municipality, or other entity that:

1. Operates a qualifying COG/SPP facility;
2. Has signed the standard written contract with the Company stipulating the terms and conditions of the interconnection and sale of electricity to the Company;
3. Has agreed in the standard contract to provide electricity to the Company on a long-term basis as defined in the contract.

"Company" means The Montana Power Company.

"MPSC" means The Montana Public Service Commission.

"Contract Year" means twelve months beginning on July 1.

**RATE:** Energy: \$0.0533/kWh

**Capacity:** The Seller will be compensated monthly for capacity according to the following formula:

$$\$/\text{Annual Contract kW/month} = \frac{\$6.74 \times \text{ACCF}}{.85}$$

where: ACCF = Annual Contract Capacity Factor

**Annual Capacity Payment Adjustment:** At the end of each Contract Year, a reconciliation of the accumulated monthly capacity payments made to the Seller for the Contract Year and actual capacity value to the Company for the Contract Year will be made utilizing the following formula:

Issued July 30, 1982  
(Date)

By: Steven Paul Lark  
(Signature of Officer of Utility)

August 3, 1982

Approved: 81 2.15 (Date)

Docket # 48655 & 48656

(Space for Stamp or Seal of Commission)

Effective for electric service rendered on and after (Date) August 3, 1982

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## Public Service Commission of Montana

The Montana Power Company

Sheet No. LTPP-82 Supp. #1

Cancelling Sheet No. LTPP-82

Name of Company)

Page 2 of 3

## Schedule LTPP-82 Supp. #1

Long-Term Power Purchase

Service

$$$/AAKW = \frac{(80.92 \times ACCF)}{(.85)} \times \frac{(AACF)}{(ACCF)} \times \frac{(AAKW)}{(ACKW)}$$

Refund to Company = (Dollars Paid to Seller) - (\$/AAKW) (AAKW)

Where AAKW = Annual Actual kW (for Contract Year)  
 ACCF = Annual Contract Capacity Factor  
 AACF = Annual Actual Capacity Factor (for Contract Year)  
 ACKW = Annual Contract kW  
 If AAKW is greater than ACKW then AAKW = ACKW

## SPECIAL TERMS AND CONDITIONS:

1. Change of Rate: This schedule will be reviewed annually for each Contract Year and revised upon MPSC approval.
2. Net Billing Option: (A) If the Seller opts for Long-Term Net Billing in the standard contract and the Seller's consumption kWh exceeds the production kWh, the Seller will be billed for only the consumption kWh in excess of production kWh according to the Company's applicable Retail Sales Rate Schedule. If the Seller's consumption kWh is less than the production kWh, the Seller will receive payment for only the production kWh in excess of consumption kWh according to the energy rate in this schedule.

(B) To meet the conditions of this Option and to receive a separate capacity payment, the Seller's consumption must be measured and billed on a demand basis and a separate kW/kWh meter to measure production is required. Under this Option, the Seller will be billed at the Company's applicable Retail Sales Rate Schedule for only the consumption kW in excess of the production kW. If the Seller's production kW exceeds the consumption kW, the Seller will be compensated for only the production kW in excess of the consumption kW according to the Production Capacity Payment Procedure detailed in this Schedule. The calculation of monthly capacity payments for the expected excess production kW will utilize the expected annual net production capacity factor. The Annual Capacity Payment Adjustment is to be applied to the actual excess production kW for the Contract Year. The procedure will utilize the annual contracted and annual gross production kW and gross capacity factor information for payment reconciliation.

Issued July 30, 1982  
 (Date)

By Steven Paul Cook  
 (Signature of Officer of Utility)

Approved August 3, 1982  
 Docket # 81.1.1 (Date)  
 Order 4865B & 4865C  
 (Space for Stamp or  
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Effective for electric service rendered  
 on and after August 3, 1982 (Date)

PUBLIC SERVICE COMMISSION OF MONTANA.

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Secretary.

## Public Service Commission of Montana

The Montana Power Company

Sheet No. LTPP-82 Supp.

Cancelling Sheet No. LTPP-82

Name of Company)

Page 3 of 3

Schedule LTPP-82 Supp. #1

Long-Term Power Purchase

Service

3. All service provided by the Company under this and all other schedules is governed by the rules and regulations approved by the MPSC.

330378

Issued July 30, 1982

(Date)

By

(Signature of Officer of Utility)

August 3, 1982

Approved

Effective

for electric service rendered

on and after (Date) August 3, 1982

Docket # 81.2.15 (Date)

Order No. 4865b &amp; 4865c

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PUBLIC SERVICE COMMISSION OF MONTANA.

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Secretary.

STATE OF MONTANA  
ELECTRIC RATE SCHEDULE

MONTANA DAKOTA UTILITIES CO.  
400 NORTH FOURTH STREET  
BISMARCK, NORTH DAKOTA 58501

	MPSC	Volume	1
	1st Revised	Sheet No.	25
Cancelling	Original	Sheet No.	25

SHORT TERM POWER PURCHASE - RATE STPP-92

AVAILABILITY:

To any qualifying cogeneration and small power production (COG/SPP) operating facilities for the purpose of generating short-term electric energy in parallel with the company's system. This schedule is applicable to cogeneration facilities and other facilities of qualifying facilities at the discretion of the Montana Public Service Commission.

RATE:

Energy: 2.16¢/Kwh

TERMS AND CONDITIONS:

1. Change of Rates: This schedule will be reviewed annually for each Contract Year and revised upon the Commission's approval.
2. The rates and terms and conditions set forth herein are subject to the provisions of the "Net Billing Option," and "Interconnection Cost Amortization Option" set forth in Rates 94 and 95, respectively.
3. The company shall install appropriate metering facilities to record all flows of energy necessary to bill and pay in accordance with the charges and payments contained in this rate schedule.
4. The customer shall, with prior written consent of the company, furnish, install and wire the necessary service entrance equipment, meter sockets, meter enclosure cabinets, or meter connection cabinets that may be required by the company to properly meter usage and sales to the company.
5. The term of the contract hereunder shall be at least twelve months but less than four years.
6. A standard written contract with the company has been signed stipulating the terms and conditions of the interconnection and sale of the electricity to the company.
7. All services provided by the company under this and all other schedules are governed by the rules and regulations approved by the Montana Public Service Commission.

Issued July 7, 1982

(Date)

By C. Wayne Felt  
Assistant Vice President

(SPACE BELOW THESE LINES FOR USE OF COMMISSION ONLY.)

Approved July 16, 1982

(Date)

Effective for electric service rendered

(Date)

Docket No. 81.2.15; Order No. 4865b

on and after July 16, 1982  
PUBLIC SERVICE COMMISSION OF MONTANA

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Madeline L. Corrie

STATE OF MONTANA  
ELECTRIC RATE SCHEDULE

MONTANA-DAKOTA UTILITIES CO.  
400 NORTH FOURTH STREET  
BISMARCK, NORTH DAKOTA 58501

	MPSC	Volume	1
	1st Revised	Sheet No.	26
Cancelling	Original	Sheet No.	26

Page 1 of 2

LONG TERM POWER PURCHASE - RATE LTPP-93

AVAILABILITY:

To any qualifying cogeneration and small power production (COG/SPP) facilities for the purpose of generating long-term electric energy in parallel with the company's system. This schedule is applicable to cogeneration and small power production facilities that are Qualifying Facilities under the Rules of the Montana Public Service Commission.

RATE:

Energy: 5.23¢/Kwh

Capacity: The Seller will be compensated monthly for Capacity according to the following formula:

$$$/\text{Annual Contract Kw/month} = \frac{\$5.33 \times \text{ACCF}}{.85}$$

where: ACCF = Annual Contract Capacity Factor

Annual Capacity Payment Adjustment: At the end of each Contract Year, a reconciliation of the accumulated monthly Capacity payments made to the Seller for the Contract Year and actual Capacity value to the company for the Contract Year will be made utilizing the following formula:

$$S/\text{AAKW} = \frac{(\$63.96 \times \text{ACCF}) \times (\text{AACF}) \times (\text{AAKW})}{(.85) \times (\text{ACCF}) \times (\text{ACKW})}$$

$$\text{Refund to Company} = (\text{Dollars Paid to Seller}) - (S/\text{AAKW}) (\text{AAKW})$$

where: AAKW = Annual Actual Kw (for Contract Year)

ACCF = Annual Contract Capacity Factor

AACF = Annual Actual Capacity Factor (for Contract Year)

ACKW = Annual Contract Kw

If AAKW is greater than ACKW then AAKW = ACKW

Issued July 7, 1982

(Date)

By E. Wayne Fall  
Assistant Vice President

(SPACE BELOW THESE LINES FOR USE OF COMMISSION ONLY.)

Approved July 16, 1982

Docket No. 81.2.15; Order No. 4865b

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Madeline L. Cottrell  
(Secretary)



STATE OF MONTANA  
ELECTRIC RATE SCHEDULE

MONTANA-DAKOTA UTILITIES CO.  
400 NORTH FOURTH STREET  
BISMARCK, NORTH DAKOTA 58501

MPSC Volume 1  
1st Revised Sheet No. 25.1  
Cancelling Original Sheet No. 26.1

Page 2 of 2

TERMS AND CONDITIONS:

1. Change of Rates: This schedule will be reviewed annually for each Contract Year and revised upon the Commission's approval.
2. The rates and terms and conditions set forth herein are subject to the provisions of the "Net Billing Option," and "Interconnection Cost Amortization Option" set forth in Rates 94 and 95, respectively.
3. The company shall install appropriate metering facilities to record all flows of energy necessary to bill and pay in accordance with the charges and payments contained in this rate schedule.
4. The customer shall, with prior written consent of the company, furnish, install and wire the necessary service entrance equipment, meter sockets, meter enclosure cabinets, or meter connection cabinets that may be required by the company to properly meter usage and sales to the company.
5. The term of the contract hereunder shall be four years or more.
6. A standard written contract with the company has been signed stipulating the terms and conditions of the interconnection and sale of the electricity to the company.
7. All services provided by the company under this and all other schedules are governed by the rules and regulations approved by the Montana Public Service Commission.

Issued July 7, 1982

(Date)

By C. Wayne Lee  
Assistant Vice President

(SPACE BELOW THESE LINES FOR USE OF COMMISSION ONLY.)

Approved July 16, 1982

(Date)

Docket No. 81.2.15; Order No. 4865b

Effective for electric service rendered  
on and after July 16, 1982

PUBLIC SERVICE COMMISSION OF MONTANA

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Seal of Commission)

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Madeline L. Otwell



## SCHEDULE NO. 87

## PURCHASES FROM COGENERATORS AND SMALL POWER PRODUCERS

APPLICABLE:

For qualifying facilities located in the territory served by Company in Montana.

APPLICABLE:

To all non-utility owners or operators of qualifying facilities (Sellers) who are willing and able to enter into a written contract.

DEFINITIONS:

Qualifying Facility means either a cogeneration facility or small power production facility not greater than 50 megawatts capacity as defined hereunder:

- (a) Cogeneration Facility means a facility which produces electric energy together with steam or other forms of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes through the sequential use of energy.
- (b) Small Power Production Facility means a facility which produces electric energy using as a primary energy source biomass, waste, renewable resources, or any combination thereof.

CONDITIONS OF SERVICE:

All purchases shall be accomplished according to the terms and conditions of a written contract.

RATES FOR SALES:

All sales by Company to Sellers shall be in accordance with standard rate schedules filed by Company with the Commission.

RATES FOR PURCHASES:

The rates for purchases by Company hereunder shall be either 1) the Short-Term Rate or 2) the Long-Term Rate, at the option of the Seller exercised at the time of execution of a written contract at:

## 1) Short-Term Rate

- a) All energy purchased is to be priced, at the option of the Seller, exercised at the time of execution of a written contract at i) the Average Rate or ii) the Time Differentiated Rate.

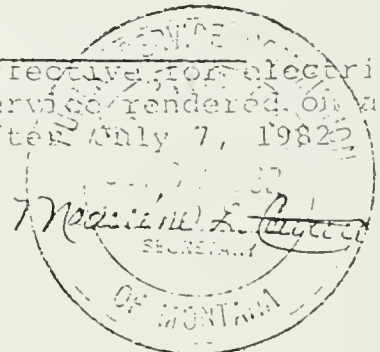
(Continued)

Issued 6/29/82

*Fredric D. Reed*

Effective on and after

Approved: January 4, 1982/March 16, 1982 Issued by PACIFIC POWER & LIGHT COMPANY Effective for electric service rendered on and after July 7, 1982  
Fredric D. Reed, Vice President and Treasurer  
Public Service Building, Portland, Oregon  
Order No. 81.2.15 Order No. 4865 & 4865a



PACIFIC POWER & LIGHT COMPANY

## SCHEDULE NO. 87

## PURCHASES FROM COGENERATORS AND SMALL POWER PRODUCERS

RATES FOR PURCHASES: (Continued)

## i) Average Rate

2.28¢ per kwh

## ii) Time Differentiated Rate

On-Peak: 6 a.m. to 10 p.m. Monday through Friday  
2.76¢ per kwh for all kwh purchased during the On-Peak period.

Off-Peak: All other times.  
1.84¢ per kwh for all kwh sold during the Off-Peak period.

## b) Term of Contract: Not less than one (1) year.

## 2) Long-Term Rate

## a) Availability: Available to all Sellers willing to sign a written contract with a term of not less than four years.

## b) All energy and contracted capacity is to be priced, at the option of the Seller, exercised at the time of execution of the contract, at i) the Average Rate or ii) the Time Differentiated Rate.

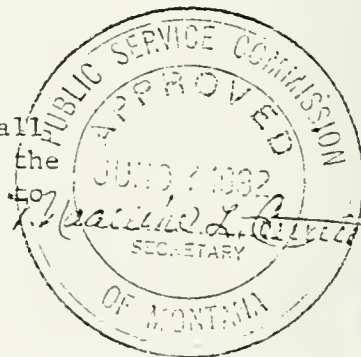
## i) Average Rate

## A) Energy Payment

4.99¢ per kwh

## B) Capacity Payment

(\$7.21 per kw per month) x (dcf) for all contracted kw, where (dcf) represents the Demonstrated Capacity Factor pursuant to the terms and conditions of a written contract.



(Continued)

Issued 6/29/82

*Fredric D Reed*

Effective on and after

over: January 4, Issued by PACIFIC POWER & LIGHT COMPANY Effective for electric  
02/March 16, 1982 Fredric D. Reed, Vice President and Treasurerservice rendered on a  
cket No. 81.2.15 Public Service Building, Portland, Oregon after July 7, 1982  
er No. 4865 & 4865a

PACIFIC POWER & LIGHT COMPANY

## SCHEDULE NO. 87

## PURCHASES FROM COGENERATORS AND SMALL POWER PRODUCERS

RATES FOR PURCHASES: (Continued)

## ii) Time Differentiated Rate

## A) Energy Payment

On-Peak: 6 a.m. to 10 p.m. Monday through Friday.  
6.05¢ per kwh for all kwh sold during On-Peak periods.

Off-Peak: All other times.  
4.03¢ per kwh for all kwh sold during Off-Peak periods.

## B) Capacity Payment

All times  
(\$7.21 per kw per month) x (dcf) for all contracted kw, where (dcf) represents the Demonstrated Capacity Factor pursuant to the terms and conditions of a written contract.

RULES AND REGULATIONS:

Service hereunder is subject to the General Rules and Regulations contained in the Company's regularly filed and published tariff and to those prescribed by regulatory authorities.



Issued 6/29/82

*Fredric D. Reed*

Effective on and after

Issued by PACIFIC POWER & LIGHT COMPANY Effective for electric service rendered on and after July 7, 1982  
Fredric D. Reed, Vice President and Treasurer  
Public Service Building, Portland, Oregon  
No. 81.2.15  
No. 4865 & 4865a



Service Date: JAN 4 1982

DEPARTMENT OF PUBLIC SERVICE REGULATION  
BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF MONTANA

\* \* \* \* \*

In the Matter of Avoided Cost Based )  
Rates for Public Utility Purchases )  
from Qualifying Cogenerators and )  
Small Power Producers. )

UTILITY DIVISION  
DOCKET NO. 81.2.15  
ORDER NO. 4865

\* \* \* \* \*



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DEPARTMENT OF PUBLIC SERVICE REGULATION  
BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF MONTANA

\* \* \* \* \*

In the Matter of Avoided Cost Based )	
Rates for Public Utility Purchases )	UTILITY DIVISION
from Qualifying Cogenerators and )	DOCKET NO. 81.2.15
Small Power Producers. )	ORDER NO. 4865

\* \* \* \* \*

APPEARANCES

Appearing on behalf of Montana-Dakota Utilities Co.:

John L. Alke, Hughes, Bennett, Kellner and Sullivan, 406  
Fuller Avenue, Helena, Montana 59601.

Appearing on behalf of Pacific Power & Light Co.:

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P.O. Box 759, 1 Main Building, Kalispell, Montana 59901.

Thomas H. Nelson, Stoel, Rives, Boley, Fraser & Wyse, 900  
South West Fifth Avenue, Portland, Oregon 97207.

Appearing on behalf of Montana Power Company:

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Helena, Montana 59624.

Michael E. Zimmerman, Legal Department of the Montana Power  
Company, 40 East Broadway, Butte, Montana 59701.

Appearing on behalf of Montana Consumer Counsel:

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Appearing on behalf of PSC Advocacy Staff:

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Robert Olson, Energy Law Institute, 2 White Street, Concord,  
New Hampshire 03301.

Appearing on behalf of PSC Advisory Staff:

Brenda Nordlund, Staff Attorney, Public Service Commission,  
1227 11th Avenue, Helena, Montana 59620.

BEFORE THE MONTANA PUBLIC SERVICE COMMISSION:

GORDON E. BOLLINGER, Chairman  
JOHN B. DRISCOLL, Commissioner  
HOWARD L. ELLIS, Commissioner  
CLYDE JARVIS, Commissioner  
THOMAS J. SCHNEIDER, Commissioner

#### FINDINGS OF FACT

##### BACKGROUND

1. Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) required the Federal Energy Regulatory Commission (FERC), as well as state regulatory authorities, to prescribe rules to encourage cogeneration and small power production (COG/SPP) including rules requiring electric utilities to purchase electric power from cogeneration and small power production facilities. Among other things, the rules were to insure that rates for purchases of electric energy from qualifying facilities (QF) "be just and reasonable to the electric consumers of the electric utility and in the public interest" and that the rates would not exceed the "incremental cost to the electric utility of alternative electric energy."

2. On May 4, 1981 the Commission adopted final rules governing purchases and sales between public utilities and qualifying small power production facilities. The Commission rules are

modeled after FERC regulations implementing Section 201 and 210 of PURPA. The rulemaking procedure featured a public comment period commencing with the issuance of draft rules on September 2, 1980 and extending through October 23, 1980. The draft rules, with proper notice, went to public hearing on October 23, 1980 in Helena, Montana. Testimony and/or comments were received from the Montana Power Company (MPC), Pacific Power and Light (PP&L), Montana-Dakota Utilities (MDU), the City of Livingston, the Department of Natural Resources and Conservation (DNRC), and several individuals. A second, revised draft of the rules was issued on March 16, 1981 with public comment extending through April 27, 1981. Comments were received from MPC, PP&L, the Alternative Energy Resource Organization, the Energy Law Institute, and several individuals. The rulemaking proceeding ended with adoption of final rules on May 4, 1981.

3. The Commission's rules (ARM 38.5.1901 through 38.5.1908), pursuant to FERC regulations, provide the general obligations of the COG/SPP and the regulated electric utilities. The rules, however, left to a contested case proceeding the development of tariffs providing specific rates, terms, and conditions for service.

4. The Commission initiated this proceeding on February 24, 1981 when it requested that MDU, PP&L, and MPC file testimony regarding avoided cost methodologies, avoided cost-based rates, and tariffs and standard contracts for purchases of electricity from COG/SPP.

5. When the Montana Consumer Counsel declined to present a case in this docket, the Commission created the Commission Advocacy Staff for the purpose of providing testimony concerning the instant issues independent of each utility's case. Ms. Eileen Shore, Chief Counsel, was assigned to head the Advocacy Staff, and Drs. Thomas M. Power and John Fox were hired to provide expert testimony. Additionally, Mr. Robert Olson assisted Ms. Shore in the presentation and preparation of Advocacy Staff's case.

6. Pursuant to the procedural order dated April 13, 1981, Rural Energy Development Foundation (REDF) and Alpha Engineers, Incorporated were granted intervention status. REDF participated to a limited extent throughout the proceeding; Alpha Engineers, Inc. withdrew their intervention status immediately before the hearing.

7. Public hearings were held on September 29 and 30, 1981 in the district courtroom of the Federal Building in Helena, Montana. Parties were given an opportunity to cross-examine one another and other interested persons, including engineer James Barber of JUB Engineering, Inc. of Boise, Idaho and economist Dr. Lawrence Nordell of the Montana Department of Natural Resources and Conservation, presented statements to the Commission.

8. For explicatory purposes, and commensurate with the Commission's rules, the major issues have been divided into two categories: standard tariff rates and tariff and standard contract terms and conditions. Analysis of each issue will include

a brief summary of the parties' testimony and pertinent Commission rule when necessary, followed by the Commission's determinations on a general basis. Any utility-specific matters will be resolved at the end of each section.

### STANDARD TARIFF RATES

#### Policy

9. ARM 38.5.1903(2) reads, in part, that "...each utility shall purchase any energy and capacity made available by a qualifying facility: (a) At a standard rate for such purchases which is based on avoided costs to the utility as determined by the Commission; or (b) If the qualifying facility agrees, at a rate which is a negotiated term of the contract between the utility and the facility..." ARM 38.5.1901(2)(j) defines standard rates as "those rates calculated by a means approved by the Commission which ...are based on avoided costs to the utility, are computed annually and made available to the public, are reviewed by the Commission, and are applicable to all contracts with qualifying facilities which do not choose to negotiate a different rate...". Thus, the Commission's intent, in respect to tariff rates, is to establish regulated rates to which all qualifying facilities (QFs) are entitled in exchange for the sale of power to the utilities. The tariff is only an option--an alternative to negotiation.

10. Prior to a discussion of the relative merits of each proposal and the resulting findings, the Commission wishes to set forth several critical policy findings.



11. The Commission recognizes that any deviation from full or complete avoided costs, either on the high side or low side, results in an adverse affect on ratepayers. Thus the primary objective in developing rate calculation methods is to allow rates which most accurately reflect full avoided costs. "Full avoided costs" is interpreted here to represent 1) exhaustiveness in cost components and, when appropriate, 2) long-run incremental costs.

12. A second goal in the Commission's deliberation is moderation, or gradualism. The Commission has found several substantial unknowns and thus has attempted to find some middle ground balancing the unknowns between the low side and high side of the true avoided costs. The Commission intends to encourage the progressive refinement of the methods and will entertain constructive criticism and evidence at each annual filing of proposed tariffs. If conclusive evidence is submitted suggesting the methods developed herein need refinement, then the Commission will revise the methods with grandfathering provisions as deemed necessary.

13. Both MDU and PP&L argued that the methods they proposed represent methods suited to their unique systems, are accepted by other state Commissions, and that any deviation from those methods would cause the incurrance of needless additional administrative costs. Although the Commission has neither gone out of its way to develop uniformity nor to maintain the PP&L and MDU proposals, it finds that it is the utilities, not the Commission,

who are best equipped to deal with the increased costs of differing methods. The Commission is establishing only an option available to all QFs and the companies are free to negotiate rates utilizing their proposals. Furthermore, the Commission has found portions of their proposals unacceptable for purposes of a standard tariff and has found that the utilities are similar in that they are all experiencing load growth with similar generation expansion plans.

#### Energy

14. In structuring energy payments all three utilities make some type of distinction between firm and nonfirm QF. Nonfirm energy rates, in all three cases, reflect short run incremental running costs via some form of production modeling, e.g. system lambda. The utilities diverge however in structuring firm energy rates. MPC uses the same production modeling effort but provides a 5 mill bonus for firm performance. MDU goes to the running cost of a baseload plant with the fixed costs added to reflect capacity. PP&L further distinguishes long-term firm from short-term firm. Short-term firm is, on an interim basis, treated as nonfirm while long-term firm is paid energy depending on specific resource(s) avoidable and ability to follow load.

15. The Advocacy Staff proposes a calculation of avoided energy costs which does not distinguish between nonfirm and firm energy and which does not utilize production modeling, or short

run marginal costs, but focuses on the energy function of base load plants.

16. The key to evaluating the alternative calculations of avoided energy costs lies in the purported relationship between short run incremental energy costs (e.g. system lambda) and the incremental energy costs of bringing on line a coal-fired base-load steam plant.

17. The Commission has been presented testimony in this proceeding as in several other proceedings, suggesting that the concept of fuel savings and optimal system planning necessarily, or at least theoretically, equate a rolling average system lambda with the energy-related cost of baseload expansion. In the case of MPC, Dr. Power (Exh. M, p.20-22) provides calculations which suggest that the theorem is correct -- at least for the period July, 1981 to June, 1982.

18. The Commission, however, is not convinced that the system-lambda-equal-energy-related-baseload-generation-costs theorem is correct when applied to systems characterized by load growth, hydro resources, and limited thermal peaking and/or cycling capacity. The Commission feels that a system with peak shaving hydro storage capability or a system with a relatively high load factor, in both cases resulting in little or no thermal peaking or cycling capability, lambda will be dominated by the running costs of baseload plants. An example exemplifies this situation. MPC's forecast of system lambda (Exh. B, Exh. TAL-2 p.1) projects a 56 percent real decrease in the load weighted



average system lambda between 1980 and 1990 (4.5 percent annual average). Despite the projected decrease in system lambda, or marginal energy costs, over the same time period the company projects (The Montana Power Company, 1981-2000 Projection of Loads and Resources February, 1981 and the Montana Power Company Forecast of Electricity and Natural Gas Prices 1981-1990, March, 1981), real total or average costs to escalate 81.6 percent (6.1 percent annual average). The latter figure represents annual real increases (over and above inflated operating expenses) of 18.78 percent in 1984, 15.02 percent in 1985, and 15.07 percent in 1990; reflecting Colstrip #3, Colstrip #4, and Resource 89, respectively. Evident is some substantial divergence between system lambda and long-run incremental energy costs. The long-range plans of all three utilities include no less than nine baseload plants prior to 1990.

19. In the short run, for example, one contract year or one test year, system lambda (or its equivalent short run production modeling) does represent the time differentiated costs the utilities will avoid by purchasing QF production. However, it is not system lambda, but coal-fired steam plants that the utilities have recently brought (Coyote #1, Jim Bridger) or will soon be bringing (Colstrip #3) to the Commission in search of additional revenues. It is these plants, not system lambda, that has and will result in substantial (perhaps drastic) increases in the utilities' costs and consumers' rates. Thus the Commission finds

that energy rates must reflect both system lambda in the short run and the baseload alternative in the long-run.

20. The avoided energy cost discussion to this point has addressed only avoided generation costs. The record in this proceeding has not provided the Commission a sound basis for establishing avoided energy-related line loss and transmission costs. Whereas the existence of a net avoidance of transmission costs, although logical, is not clearly established, the record indicates (e.g. Jordan Exh. O, p. 4, Barber Tr. p. 49) that some unknown amount of line losses will be avoided. Marginal line losses are substantial. MPC witness Bruce Ambrose calculates (Exh. 13, Sch. 1) a secondary energy loss factor of 30.5 percent and 26.1 percent for the winter and summer periods, respectively. Electric rate case proceedings for MDU and PP&L have indicated marginal line losses of similar magnitude. The Commission finds unacceptable the utilities and Advocacy Staff's proposed rates which simply ignore line losses. The proper approach is to establish some nominal energy loss factor subject to refinement with utility-specific analysis. For purposes of the initial tariffs, the Commission finds appropriate an energy loss factor of 8.3 percent. This factor represents the approximate load weighted average of transmission level energy losses calculated by Mr. Ambrose for the MPC system.

Capacity

21. The Commission has been presented four distinct proposals for structuring capacity payments. The three utilities' proposals are similar in that they reflect the possible deferral or avoidance of a specific avoidable generating plant. In the case of PP&L, 22 percent of the Wyodak #2 baseload plant (1986 recently deferred to 1988) is used to calculate avoided capacity. MDU also uses baseload expansion plans (1985) but proposes the entire fixed costs as potential capacity payments. MPC uses a 1985 gas-fired combustion turbine which was in their 1980 long-range plan but has since been deleted from the Company's expansion plans.

22. The capacity payments to QFs in each case are a function of the beginning year of the contract (1982-1988), length of the contract (5-35 years), industry construction inflation indices (generally, 6 percent to 10 percent), discount rates for discounting future cost avoidance (4 percent to 6 percent), and a qualifying performance criteria (capacity factor of 65 percent - 75 percent). The utilities' proposals do not recognize partial or aggregate capacity payments to QFs who do not meet the performance criteria and grant full payment to those above the criteria level with a full length contract beginning the year the avoidable plant is scheduled to come on line. All three utilities' offer some level of prepayments for capacity provided prior to the 1985-1988 period, but it is not clear whether these discounted prepayments in any way reflect expected avoidance of

system planning (engineering studies, siting, etc.) efforts. Payments for capacity contracts of less than full duration are discounted to reflect the inflated costs of building the plant beyond the deferral period (or length of contract).

23. The Advocacy Staff's proposal differs primarily in how the payments are calculated and to whom the payments are made, and not necessarily in the calculation of avoided capacity. The Advocacy Staff's proposal utilizes a combustion turbine to estimate the exclusively capacity-related value of baseload expansion. Whereas the utilities discount pre-on line capacity (1982-1985 or 1988), the Advocacy Staff's proposal features full prepayment of capacity. The Advocacy Staff, rather than levelizing the discounted sum of inflated costs over the life of the contract, annualize capital costs in terms of constant contract year dollars. A third area of major difference lies in the concept of partial capacity payments. The Advocacy Staff, as opposed to a make-or-break performance criteria, proposes partial capacity payments based on the QF's expected reliability relative to that expected of a combustion turbine.

24. The Commission in reviewing the capacity rate proposals of each utility found unnecessary complexity a predominant characteristic. For purposes of a standard tariff, updated at least annually, the Commission finds persuasive the Advocacy Staff's proposal to simply annualize the cost of a combustion turbine in constant contract year dollars. The Commission also finds merit in the concept of partial capacity credits and the recognition of

aggregate QF capacity. The Commission is less sure in respect to the merits of full prepayment. However, in light of the fact that 1) the magnitude of a full capacity payment is only in the area of four to seven mills, 2) the utilities do incur system planning costs (engineering studies, siting, etc.) prior to the on line dates, and primarily 3) the fact that several "full avoided cost" components (e.g. remote siting transmission, line losses, etc.) are not fully accounted for, leads the Commission to believe that full prepayment will not error on the high side of truly avoidable costs. The Advocacy Staff's capacity proposal accepted by the Commission is essentially that practiced by the utilities in recovering capacity-related revenues.

#### Rates

25. Commensurate with these findings, the Commission directs the utilities to develop a tariff providing rate schedules for two classes of QFs -- short-term and long-term. One class is to be comprised of QFs unwilling or unable to commit themselves to a performance contract of at least four years. The second class is to consist of all QFs who are willing and able to sign a contract of at least four years duration. It should be pointed out that there is no explicit distinction here between firm and nonfirm -- the pricing provisions of each schedule will dictate an implicit distinction. The short-term/long-term distinction is made in anticipation that the system planners, in the initial start up period only, will require four year con-



tracts with appropriate penalty provisions for incorporating QF loads into projections of system resources for purposes of designing system expansion plans.

#### Short-Term Rates

26. The short-term QF's energy rate schedule shall reflect short run incremental energy costs as determined from the utilities' production modeling efforts. The rate shall reflect a one contract year projection of annual load weighted average system lambda (or equivalent measure of short run incremental energy costs) and shall include the appropriate calculations of variable O&M, revenue requirement associated with working capital, and the nominal energy loss factor.

27. The Commission, initially, leaves to the utilities the option of establishing a short-term time differentiated rate schedule reflecting the companies' short run cost variation. The utilities are encouraged to structure time differentiated rates featuring seasonal, monthly, and/or daily rating periods. The relatively higher general level of sophistication on the part of QFs presents a challenge to structure rates most accurately reflecting costs. The companies' proposals will be scrutinized and adjustments made on an as needed basis. It should be pointed out that only MPC's proposal does not feature optional time differentiation, even with evidence of substantial seasonal cost variation.

28. In addition to the energy rate, the short-term option -- both annual average or time differentiated -- shall include a nominal aggregate capacity credit. For purposes of the initial tariffs and until convincing evidence is provided to suggest otherwise, the aggregate capacity payment shall be calculated by assuming a 42.5 percent availability level relative to an assumed 85 percent combustion turbine availability. That is, short-term QFs will receive one-half of a full capacity payment added to the energy payment using the assumed 85 percent load factor for converting the annualized capital costs into a Kwh payment.

29. The Commission again leaves to the utilities the option of time differentiation with respect to the nominal aggregate capacity payment. The utilities, should they desire to develop time differentiation in the initial tariffs, or the 1982 tariffs, must use hourly loss of load data for structuring the differentiation. That is, while the annual average aggregate capacity payment is spread over all hours, the time differentiated option would spread the same aggregate capacity payment over those hours, as indicated by loss of load probability, where the utility is most likely to be capacity short.

#### Long-Term Rates

30. The second class of QFs are those who are willing and able to commit themselves to a contract of at least four years with appropriate penalty provisions for failure to deliver con-

tracted capacity. These long-term QFs shall be paid an energy rate reflecting the energy-related generation costs associated with baseload expansion and a capacity payment reflecting the remaining capacity-related baseload expansion costs.

31. The utilities are directed to develop a long-term rate featuring an energy component based on the cost (current contract year constant dollars) of the projected running costs of the next baseload plant. Added to the running costs are the fixed costs associated with bringing on line a base load plant less the capital costs associated with bringing on line a combustion turbine. In addition to the energy payment, a separate annualized capacity payment based on the costs of a combustion turbine paid in proportion (above, as well as below) to a 85 percent availability factor is to be developed. The capacity payment can be structured on a monthly or annual basis.

32. As with the short-term option, the Commission encourages the utilities to structure a time differentiated suboption featuring time differentiated energy and capacity rates based on system lambda and hourly loss of load probability, respectively. The time differentiated energy rate shall feature the same base-load plant costs, but allocated to rating periods commensurate with system lambda. The separate time differentiated capacity payment, however, provides an opportunistic alternative to the nontime differentiated partial capacity payment. Rather than partial capacity payments reflecting the QF's probability of providing capacity as needed, the time differentiation can allow



for full capacity payments in exchange for QFs capacity provided in the hours most likely to correspond with capacity shortage. Depending on the level of differentiation, hours with less probability of capacity shortage should feature something less than full capacity. The Commission has left the time differentiation, at least initially, an option to the utilities. The utilities are encouraged to develop time differentiation (seasonal, monthly, and/or daily) in its offerings of long-term capacity payments.

33. The long-term costs shall be calculated and rates structured such that long-term energy and full capacity rates fully account for the annualized costs of owning and operating baseload plants. In the case of MPC, those costs shall reflect the costs of Colstrip #3 and #4, averaged. This overcomes the problem of relating common facilities to individual plants. MDU shall use Antelope Valley #2 and PP&L, Wyodak #2. The calculation of costs is to be exhaustive including coal, fuel inventory, taxes, insurance, administrative and general, O&M, as well as the nominal line loss factor of 8.3 percent. The costs of the combustion turbine used as a proxy to determine the portion of baseload expansion related solely to the capacity function, must be equally exhaustive and based on reasonable combustion turbine alternatives to QF's capacity and must reflect costs consistent with actual costing experience or industry estimates. All costs are to be stated in constant contract year dollars, to be updated each June 1, for the contract year beginning July 1st, to reflect

1) refined resource plans, 2) more accurate and/or complete cost information, and 3) inflation, according to standard industry practice.

34. Capital costs are to be annualized by applying the companies' overall incremental cost of capital including tax effect -- not embedded cost of capital -- and shall be updated annually to reflect the contract year capital market. Finally, for purposes of converting baseload capital costs into energy rates, each utility shall use an assumed baseload capacity factor of 70 percent. The 70 percent reflects the Commission's attempt at some middle ground, but is certainly an item open to future refinement and utility specific experience if it exceeds average industry or regional performance.

#### Procedure

35. Appendix A provides a summary of the rate schedules to be developed in compliance with this Order and Appendix B provides specific direction in costing to be followed in arriving at costs pursuant to this Order.

36. In submitting initial tariffs in compliance with this Order, and proposed revised tariffs each June 1st thereafter, each utility is directed to provide 1) the proposed tariffs, 2) the calculated avoided costs used in arriving at the tariffed rate schedules, and 3) detailed working papers. The tariffs are to include, in addition to the rate schedules, the terms and conditions for service and the standard contract, in compliance

with this Order. The avoided costs must include, at least, five year projections (beginning with the contract year) of: 1) the average annual system lambda (or equivalent short run production modeling), 2) time differentiated system lambda and/or loss of load probability supporting the time differentiation, 3) baseload running cost and capital cost calculations detailed by component, 4) detailed combustion turbine calculations, and 5) the estimate of overall marginal cost of capital. These five year projections must be presented in both constant contract year dollars and in nominal terms. These avoided cost data satisfy and supplement the requirements of ARM 38.5.1905(1). The working papers must provide the source and derivation of the costs, including incremental cost of capital, and provide the transformation of costs into rates. In the case of the baseload costs, the working papers must include the most recent version of the actual engineering cost study, revealing projections of costs by component by time of incurrence from the time of initial planning to on line production. If available, the actual engineering cost studies supporting the estimated combustion turbine avoided costs must also be provided.

37. As all parties become experienced in QFs production, the Commission encourages further pursuit of a progressively refined treatment of structuring QFs rates. Several obvious items requiring refinement are the 42.5 percent availability assumption in calculating aggregate capacity payments, the 70 percent baseload and 85 percent combustion turbine production

factors, the 8.3 percent line loss factor, and appropriate inflation factors. The utilities are directed to investigate avoided line losses, avoided transmission costs, and avoided reserve requirements. The Commission intends to expand the role of these factors in the calculation of the 1982 standard rates. The utilities are directed to provide evidence in their June 1, 1982 filing detailing appropriate transmission, line loss, and reserve requirement values to be included in the calculation of each rate schedule.

38. The tariff providing rates as found appropriate by the Commission precludes the use of "opportunity cost," "performance incentive," "levelized," "time of delivery," "retail rates," fixed capacity/variable energy," etc. payment schemes for purposes of a tariff, only. The Commission has merely established a payment option available to all QFs. The utilities and the QFs are encouraged to negotiate at will in a business-like atmosphere. For example, if PP&L finds that its tariffed short-term energy rate is too low and that it can offer its "opportunity cost" rate with no effect on ratepayers, then the Commission in no way intends to restrict that offering. The Commission, in its rules, did not require wheeling under the assumption that the utilities would, in good faith, utilize opportunity cost concepts in providing QFs access to lucrative regional markets with no effect on ratepayers. If the Commission finds its "good faith" assumption in respect to opportunity cost and wheeling, as well as other options provided herein, was in error, then it will

readdress these provisions. Likewise, the offering of levelized or front loading contracts as required by ARM 38.5.1903(2)(b), fixed capacity/variable energy contracts, and performance incentives is in no way restricted by this Order. The innovative contracts resulting from negotiation should be the prime mover in the purchase of QF's energy.

39. Lastly, the Commission wishes to remind the utilities that ARM 38.5.1903(8) requires each utility to "upon initial contact with a potential qualifying facility, provide the potential qualifying facility with one (1) copy of: a) these rules, b) the Commission's approved standard provisions tariff, and c) the Commission's standard complaint procedure." ARM 38.5.1908 requires each utility to provide the Commission with one copy of the utility's initial written response to the potential qualifying facility. In addition to these provisions of information, the Commission contemplates a utility sponsored working conference to be held in each utilities service area for purposes of providing information to potential QFs.

#### TARIFF AND STANDARD CONTRACT TERMS AND CONDITIONS

40. ARM 38.5.1902(5) reads, in part, that "All purchases... shall be accomplished according to the terms of a written contract between the parties or in accordance with the standard tariff provisions as approved by the Commission. The contract shall specify:



- (a) The nature of the purchase and sales;
- (b) The applicable rate schedule or negotiated rates for the purchases and sales;
- (c) The amount and manner of payment of interconnection costs;
- (d) The means for measurement of the energy or capacity purchased or sold by the utility;
- (e) The method of payment by the utility for purchases, and the method of payment by the facility for utility sales;
- (f) Any installation and performance incentives to be provided by the utility to the qualifying facility;
- (g) The services to be provided or discontinued by either party during system emergencies;
- (h) The term of the contract;
- (i) Applicable operating safety and reliability standards with which the qualifying facility must comply;
- (j) Appropriate insurance indemnity and liability provisions."

Commensurate with the rules, the Commission's intent here is to resolve contested issues with respect to the specific terms and conditions for service under the standard tariff.

41. The utilities propose that all QFs be required to execute a written contract prior to interconnection. Accordingly utility-sponsored testimony contains tariff and standard contract proposals in varying degrees of length and complexity.

42. To promote understanding of party responsibilities and to minimize uncertainty as to allocation of risks, for the present, the Commission finds that all QFs should be required to sign a standard contract, containing the terms and conditions of service, for a minimum term of one year. The standard contract is to be a component of the QF's tariff -- approved, regulated, and maintained by the Commission. The standard contract should concisely set forth the options available to QFs regarding short and long-term purchase rates and terms and billing and payment

alternatives, and the QF's choice should be clearly specified therein. To the extent practicable, definitions, technical specifications, and computations and/or formulas for payment determinations should be confined to appendices to the standard contract. Terms and conditions made redundant by Commission rules should be excluded from the QF tariff and standard contract.

#### BILLING ALTERNATIVES

43. Contrary to Commission rules, (ARM 38.5.1903(5)(c) and 38.5.1905(6)), each of the utilities confined their standard billing proposals to simultaneous sale and purchase arrangements. Their exclusion of any net billing option was premised on two contentions: (1) that the reliability of meters, not specifically designed to run backward and forward, was suspect; and (2) that valuable information concerning the production characteristics of QFs, individually and in the aggregate, could not be captured by a single meter.

44. Dr. Power maintained that the net billing option should be available to small QFs as such an option would minimize transaction and metering costs. On cross-examination, Dr. Power agreed that there was value to gathering information on the actual generating characteristics of small QFs but he questioned the cost-effectiveness of mandating dual meters for every QF when a sampling technique might provide the same information at a lower cost.

45. The fact the utilities are united in opposition to net billing, in combination with some of Dr. Power's statements regarding the concept, indicate to the Commission that there is a general lack of understanding, concerning the net billing option per the Commission's rules.

46. Dr. Power stated that in his opinion only very small QFs would opt for net billing, and that their motivation would be to avoid additional metering charges. In addition, he testified that the concept of net billing presumes that a utility's avoided costs and its retail rates are roughly approximate. Dr. Power then concluded that "[a]nybody who was in the range displacing all of their consumption certainly would be better off opting for some other arrangement than net billing." (Tr. B-115).

47. The Commission would clarify that net billing was premised on two assumptions: first, that the state of the art of metering is such that a single meter, whether currently in place in Montana or not, can accurately record net consumption or production within a given billing period, thus avoiding the cost of the second meter; and second, that up until the point a QF becomes a net producer, the QF is logically entitled to be billed for his/her net consumption at the retail rate.

48. Once during a billing period, a QF becomes a net producer, the costs the utility avoids in purchasing the QF's energy are accurately reflected in avoided cost, not retail, rates. The Commission wishes to dispel any notion that a QF who opts for net billing would receive any rate other than the



utility's avoided cost rate for its net production. This finding confirms what is explicitly stated in ARM 38.5.1905(6).

49. PP&L's proposed tariff implicitly recognizes the attractiveness of net billing wherein they give large QFs the option of offsetting their local load and then delivering any excess energy to the company at avoided cost rates. Likewise, PP&L's revised contract appears to endorse, to the exclusion of any simultaneous sale and purchase arrangements, a modified net billing approach via their definition of "Net Metered Output." In both instances, however, the amount subject to net billing is determined not by one but two meters.

50. The Commission finds merit in collecting QF production data, but it believes that there are means to accomplish such without abrogating the Commission rule that gives a QF the option of operating in parallel on a net billing basis. The utilities were given two hearing and public comment opportunities in the Fall of 1980 and the Spring of 1981. The Commission finds that the issue was resolved in those proceedings as reflected in ARM 38.1905(6). Should the utilities find a second meter necessary, then the utility shall provide the second meter (as PP&L has proposed) and make QF payments, upon request, under the net billing option. The Commission would note that by placing the cost of the second meter on the utilities, to the extent that meters currently in use cannot reliably track net consumption or production, the utilities will have incentive to stay abreast of

development regarding single meters that were specifically designed to operate on a net basis.

51. PP&L's definition of 'Net Metered Output' should be amended because it necessarily forecloses QF selection of a simultaneous sale and purchase arrangement.

52. These findings should serve to explicitly clear the air with respect to standard billing options. In summary, the QF has the option, upon request, of 1) simultaneous purchase and sale whereby all QF production is measured via a second meter, at the expense of the QF, and is purchased at the appropriate tariff schedule; and 2) operating in parallel with a single meter measuring net consumption or production. Net consumption is billed at the appropriate retail tariff schedule and net production is purchased at the appropriate QF's tariff schedule. If the utility deems a second meter necessary for either billing integrity or data collection then it remains the utilities' prerogative to install a second meter at no cost to the QF.

53. In a related matter the Commission finds MPC's and PP&L's billing procedures, as set forth in Appendix A and Articles IV and V of their respective contracts, to be unnecessarily convoluted. Mr. Jordan's suggested alternative should suffice to adequately meet the needs of QFs and utility alike, without excessive rigmarole: within 15 to 20 days after the billing period had ended, the utility should make payment to the QF. A statement showing the amount of energy delivered to the

utility's system during the billing period and the computation of the payment amount should be included with each payment.

54. The Commission finds MDU's 600 KWH per month ceiling on energy purchases from QFs of 100 KW or less to be inconsistent with Commission rules and MDU's policy to purchase all energy available from QFs. That restriction should be deleted from MDU's tariffs.

#### Interconnection Payments

55. ARM 38.5.1904(2)(c) provides that, if the utility installs interconnection facilities for the QF, the QF must reimburse the utility but "[the] reimbursement may be accomplished by means of amortization over a reasonable period of time within the term of the contract." ARM 38.5.1902 (5)(c) specifies that "the amount and manner of payment of interconnection costs" be set forth in the contract.

56. The Commission would reiterate that the issue of payment of interconnection costs was settled in the rules. MDU and PP&L are directed to amend their standard contracts to provide some method using reasonable financing charges for QFs to amortize such costs. The Commission is aware that instances may arise where a QF has as ready access to financing as do the utilities, however, absent guidelines as to how to distinguish which QFs need help financing interconnection costs, the amortization rule will be available to all QFs.

57. The Commission also determines that, once intertie has been accomplished between the utility and QF, the utility, not the QF, should be financially responsible for any alterations or modifications that are necessitated by a change in the utility's system voltage.

#### Insurance

58. The utilities proposed that the QFs be required to maintain liability and, if a capacity supplier, property damage or destruction insurance. Suggested floors for liability limits ranged from \$500,000 to \$1,000,000 per single occurrence, and property insurance provisions required that the utility be named insured as well as receive any proceeds, pending QF replacement of destroyed or damaged facilities. In addition, liability insurance proposals from MPC and PP&L give the utility unilateral power to require the QF to purchase additional coverage.

59. The Commission is reluctant to mandate comprehensive liability insurance coverage that would include explosion, collapse and underground hazards and contractual liability, without more information as to the cost of such insurance and a better justification as to why such insurance is essential to purchasing electricity from a QF. For the time being, the Commission will require only general liability insurance provisions in standard contracts. The Commission will permit the utilities to increase liability limits, whenever they see fit,

only if such requests are made in good faith and upon reasonable justification.

60. The Commission finds the record to be insufficient to justify distinguishing liability insurance limits on the basis of QF size, therefore, the Commission leaves to the initiative of insurance companies to differentiate premiums that reflect adequate liability coverage given a particular QF's size and operating characteristics.

61. The Commission finds the utilities' proposals for property insurance to be particularly lopsided. The combination of named insured treatment, and receipt and retention of proceeds in anticipation of proof of replacement expenditure, could necessitate duplication of policies by the QF. The Commission understands the utilities desire to have access to a source of funds should the QF be destroyed and performance be discontinued, however, there is not necessarily any direct relationship between the cost of replacing a QF and the damages the utility will face as a result of the disruption. Absent a better explanation for the need for such requirements, the Commission finds the standard contracts need only contain a provision requiring capacity suppliers to obtain and maintain adequate property insurance; named insured and proceeds requirements should be deleted.

62. In light of the Commission's decision to allow all QFs, irrespective of size, to contract to provide capacity, the utilities may want to amend their proposals to distinguish between smaller and larger QFs. Such proposals should be



accompanied by sufficient justification, based on system planning needs, for distinguishing property insurance treatment on the basis of QF size.

63. Following Advocacy Staff suggestion, the utilities are directed to investigate the possibilities of obtaining group insurance for smaller QFs.

#### Force Majeure

64. Both MPC and PP&L proposed force majeure clauses in their standard contract which specifically excluded nonavailability of fuel or lack of motive force to operate QF's facility. PP&L exempted small hydro projects from this exclusion on the rationale that, like PP&L, such projects are susceptible to dry water years that are beyond the control of the operator.

The Commission finds that it is unreasonable to give small hydro development deferential treatment when other types of small power production or cogeneration might suffer from similar circumstances. The utilities are directed to include nonavailability of fuel or motive force in their force majeure clauses. Lack of foreseeability or reasonable control will still be the major determinants as to whether performance will be excused. This provision should not be interpreted to give QFs carte blanche to enter into contractual obligations without reasonable engineering, meteorological, or hydrological studies or economic forecasts.

Capacity Adjustments

65. The utilities argued that if during any contract year a QF fails to deliver sufficient capacity some adjustment to its total annual capacity payment should be made. The Commission agrees. Failure to meet contractual capacity commitments should not be casually disregarded.

66. MPC proposes that if a QF fails to meet its capacity commitment during any 12 hour contract capacity review the QF should lose its right to receive any capacity payments for that entire year; this "all or nothing" approach clearly is inconsistent with the proposition that a QF should be paid for any capacity it actually delivers to a utility. MDU's proposal has the same "all or nothing" effect even though its impact is less drastic -- MDU would only require forfeiture of the QF's right to capacity payments for the month in which the deficiency occurred.

66. Because PP&L's proposal accommodates the notion of paying QFs for the capacity they actually deliver, yet it recognizes that some reasonable adjustment should be made for failure to fulfill contractual obligations, the Commission finds that if a QF fails to deliver capacity according to its commitment it would be appropriate for the utilities to adjust either their annual or monthly capacity payment by a factor of delivered capacity to contracted capacity. The QF will still be paid for each kilowatt it delivers, but the reduced per unit payment will force the QF to realize a loss beyond that which results from the

loss of anticipated revenue associated with its decreased capacity production.

67. Additionally the Commission recommends that MPC and MDU incorporate PP&L's idea of using an estimate of capacity capabilities for the initial contract year and then adjusting the second and remaining years according to the QF's demonstrated capacity. MPC and MDU are directed to incorporate this finding into their standard contract.

#### Payment Options

68. A considerable amount of testimony was provided to the Commission pro and con variations in innovative payment schemes. Dr. Power urged that the utilities provide a variety of payment options to any QF contracting to supply energy and capacity over a four to five year contract term. He specifically addressed payments which were based upon (1) levelized annual payments for energy and capacity as derived from projected avoided costs, (2) a fixed capacity component, increased annually by the general inflation rate, and a variable energy component, based on either the preceding or succeeding years' actual or projected avoided energy costs, and (3) variable capacity and energy payments, based on the current contract year's avoided costs.

69. Mr. Barber too stressed the need for flexibility in payment options, particularly noting the desirability of front loaded contracts. In order to further facilitate QF financing, he also suggested that the utilities be required to sign a con-



tract with a QF for a firm amount, projected over the term of the contract, a number of years before the QF would actually deliver any energy; then when the QF comes on-line, he suggested that payments commence at the higher of the contracted rate (a projection) or the-then prevailing avoided cost rate (valuation at time-of-delivery). The Commission finds this proposal to be particularly noteworthy because it would not only give the QF greater flexibility in financing but it would give system planners considerable lead time to integrate QF production into their resource planning efforts.

70. Of the three utilities, only PP&L presented any alternative method of payment. Their proposal consisted of payments that have been levelized over the term of the contract, based on prices as projected at the time the contract was executed. PP&L's levelized payment option was available only to QFs willing to provide capacity for a period of years. At hearing PP&L withdrew its levelized payment option and justified its action in light of a recent decision by the Oregon Public Utilities Commissioner that required all QFs opting for a levelized payment plan to provide a performance bond. In its rebuttal brief, however, PP&L requested that its initial levelized payment proposal and supporting testimony be reinstated because, on October 29, 1981, the Oregon Public Utilities Commissioner modified his position on performance bonds. Rather than requiring bonds for all QFs opting for levelized payments, the Oregon Commissioner may

require, upon utility petition and with good cause shown, QF performance bonds in particular instances.

71. With respect to the offering of levelized and/or front loaded contracts, the Commission merely wishes to remind the parties that this particular issue was, after considerable debate, resolved in rulemaking. ARM 38.5.1903(2)(b) explicitly requires the utilities to offer long-term levelized or front-loading contracts: "...the utility shall offer long-term contracts with qualifying facilities which permit a rate higher than avoided costs in the early years of the contract and a lower rate in the latter years."

72. When the Commission adopted this rule it recognized that front-loaded, or levelized, contracts, would initially aid the QF by covering debt service and ultimately benefit the utility and/or ratepayers by providing power below avoided costs during the second half of the contract. Neither the Commission rule, nor its policy, has changed in the interim.

73. The Commission reinstates and accepts PP&L's levelized payment proposal, with the admonition that Commission rules must not be disregarded merely because another state's regulatory body has taken a different approach to the same issue. MPC and MDU should expand their payment options to comply with Commission rules; their payment options need not mirror PP&L's proposal. As long as the payment option incorporated into the tariff and standard contract embodies the purposes of ARM 38.5.1903(2), MPC

and MDU will have discharged their obligation under the rule. The Commission wishes to emphasize, however, that all QFs signing long-term contracts, per Commission rule, are entitled to levelized or front-loaded contracts.

74. Because of the risk associated with nonperformance of front-loaded or levelized contracts PP&L has indicated in its rebuttal brief, that as a matter of corporate policy, all QF contracts of four megawatts or more which contain a levelized payment provision will be submitted to the Commission and that, should PP&L perceive that there is sufficient risk of nonperformance by the QF, PP&L will submit such a contract to the Commission for advance review.

75. The Commission rules do not contemplate advance review and Commission approval of questionable contracts. Although the Commission concedes that PP&L's suggestions may be practical and well conceived, they necessarily place the Commission in a position to set aside a rule when there are no rules or guidelines for doing so. In declining to act as arbitrator regarding prospects of QF nonperformance [dubious QF contracts containing a levelization of payments provision], the Commission assures the utilities that, should a QF default on a front-loaded or levelized contract and subsequently the QF is discovered to be judgment proof, any losses the utility incurred as a result of complying with this rule will be given appropriate treatment in ratemaking proceedings.

### Liquidated Damages

76. The Commission finds that each utility should include a liquidated damages provision in their standard contract. The formulae for calculating the appropriate damages should account for two contingencies: (1) early termination or default on a front-loaded or "levelization of payments" long-term contract and (2) premature termination or default on a nonlevelized long-term contract. The particulars of how to compute these damages will be addressed below; first the Commission wishes to discuss the policy rationale for requiring such a provision.

77. The Commission requires this provision to encourage QFs to accurately assess energy and capacity production capabilities when it commits, and the utility integrates, its production into utility system resource planning under a long-term power contract. As well, the Commission recognizes that it may be very difficult to ascertain the losses either party has experienced as a result of termination or default, however, if a reasonable estimate of those losses can be agreed upon at the time the contract is executed, an additional element of uncertainty can be eliminated from the contract.

78. Although none of the utilities proposed a liquidated damages provision that specifically addressed default or termination of a levelized contract, because MPC's standard contract provided for per unit capacity payments that varied with the term of the contract, that liquidated damages clause can be used for a frame of reference in this instance. Overcollection

of payments during the actual term of the contract vis a vis the original term and the impact of unexpired term on system planning were handled separately under MPC's proposal. Differences in the amount of losses estimated due to overcollection were supposedly justified by the nature of the termination. System planning losses were recognized only in the eventuality that minimum notice requirements were not met.

79. Dr. Power suggested that the Commission adopt a repayment (liquidated damages) provision similar to that ordered by the Idaho Public Utilities Commission. There, rather than constructing what could be perceived as serious disincentives to QF development, the Idaho PUC forgave small QFs (less than 1 MW in size) all but a nominal proportion of the damages that could flow from early termination or default and only required larger QFs to repay one-half of what was lost.

80. The Commission rejects the notion that policy considerations warrant encouragement of cogeneration and small power production at any cost: QF accountability for early termination or default-related losses should not be a function of QF size, or implicitly, the magnitude of the possible loss to the utility and/or ratepayers. As of the date of notice of termination or termination, the QF should return the entire difference between the total payments received under the front-loaded contract and the total payments that would have been received had payments been based upon the QF's actual term of performance and avoided capacity and energy rates as projected at the time the contract



was executed. The Commission finds this repayment formula not only logical but eminently fair to QFs, utility and ratepayer alike.

81. Because the Commission determined above that, for system planning purposes, a minimum term of four years is required to actually avoid or defer capacity expansion, it follows that the utility will incur minimal, if any, damages should a QF, upon four or more years advance notice, terminate a long-term contract. However, if a utility relies on the continuation of QF capacity in its system planning and a QF prematurely terminates its minimum four year contract or gives less than 48 months notice of its termination, the utility will incur system planning related losses, and the QF should reimburse the utility for the value of the system planning latitude the utility has necessarily forfeited. An amount equal to the average monthly capacity payment times the difference between the lesser of 48 months or the unexpired term of the contract (in months) and the number of months notice given regarding the termination should roughly approximate these losses. The approach the Commission has adopted is a modification of similar proposals from MPC and MDU.

#### Governmental Regulation and Termination

82. Burdensome governmental regulation was proffered by the utilities as a suitable justification for almost immediate termination of a QF contract. Irrespective of the fact that they

could not envision a utility invoking this provision, the utilities suggested that inclusion of such a provision was primarily to the benefit of the QF.

83. The Commission is not persuaded. The fact that there is no mutuality involved making such a determination suggests that such a clause begs contention and promotes uncertainty as to party responsibilities. The utilities are requested to delete such provisions from their contracts.

#### CONCLUSIONS OF LAW

1. Montana-Dakota Utilities Company, Montana Power Company and Pacific Light & Power Company are public utilities within the meaning of Montana law, Sections 69-3-101, 69-3-601(3), MCA.

2. The Commission properly exercises jurisdiction over the rates and terms and conditions for the purchase of electricity by public utilities from qualified cogenerators and small power producers. Sections 69-3-102, 69-3-103 and 69-3-603, MCA.

3. The rates the Commission has directed the utilities to file are just and reasonable to Montana ratepayers as they reflect each utility's avoided energy and capacity costs.

4. The objective of encouraging cogeneration and small power production is promoted by the rates and terms and conditions established by this order.

ORDER

1. MDU, MPC and PP&L shall develop rates which are consistent with the Findings of Fact entered by the Commission in this order. These rates shall be developed as summarized below.

a) avoided energy rates shall be based on (1) for short-term contracts (one year), a one year projection of each utility's short run incremental running costs, and (2) for long-term contracts (four or more years), the annualized costs (per directions set forth in Appendix B) of owning and operating a baseload plant, converted to ¢/KWH by using an assumed capacity factor of 70 percent.

b) avoided capacity rates shall be based on the annualized capital costs of a combustion turbine; payments can be structured on either an annual or monthly basis. A factor relating a QF's capacity factor to a 85 percent availability factor of a combustion turbine shall be used to determine the capacity payment which a QF is entitled; for short-term energy, an aggregate capacity payment, equal to one-half of the avoided capacity rate, shall be added to the short-term energy rate.

c) detailed working papers shall be submitted in support of aforementioned rate calculations.

2. MDU, MPC and PP&L shall revise their proposed standard contracts in a manner that is consistent with the Findings of Fact herein.

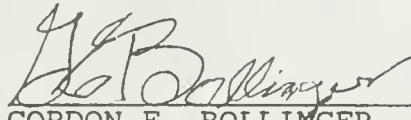
3. Proposed tariffs, including avoided energy and capacity rates and standard contract, shall be filed with this Commission



within forty-five (45) days from the date of this order is issued.

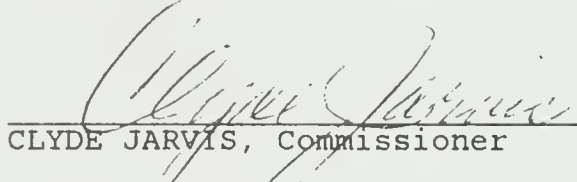
Done and Dated this 4th day of January, 1982.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION.

  
GORDON E. BOLLINGER, Chairman

  
JOHN B. DRISCOLL, Commissioner

  
HOWARD L. ELLIS, Commissioner

  
CLYDE JARVIS, Commissioner

  
THOMAS J. SCHNEIDER, Commissioner

ATTEST:

Madeline L. Cottrill  
Secretary

(SEAL)

By:  Acting Secretary

NOTE: You may be entitled to judicial review of the final decision in this matter. If no Motion for Reconsideration is filed, judicial review may be obtained by filing a petition for review within thirty (30) days from the service of this order. If a Motion for Reconsideration is filed, a Commission order is final for purpose of appeal upon the entry of a ruling on that motion, or upon the passage of ten (10) days following the filing of that motion. cf. the Montana Administrative Procedure Act, esp. Sec. 2-4-702, MCA; and Commission Rules of Practice and Procedure, esp. 38.2.4806, ARM.

## APPENDIX A

### SUMMARY OF STANDARD TARIFF RATE SCHEDULES

At the option of the QF, energy and capacity is to be purchased at either 1) the Short-Term Schedule or 2) the Long-Term Schedule.

#### 1) The Short-Term Schedule

- Availability: available to all QFs willing and able to sign the standard contract.
- Rates: all energy and capacity purchased is to be priced, at the option of the QF, at a) the Annual Average Rate or b) the Time Differentiated Rate.
  - a) Annual Average Rate
    - $X$  ¢/KWH for all KWH purchased, where  $X$  equals the annual average projection of short run incremental energy costs plus the aggregate capacity payment.
  - b) Time Differentiated Rate (initially, at the option of the utility)
    - $X_t$  ¢/KWH for all KWH purchased during time period  $t$ , where  $X$  equals the projection of short run incremental energy costs during each time period  $t$  plus the aggregate capacity payment allocated to each time period  $t$  based on hourly loss of load probability.

#### 2) The Long-Term Schedule

- Availability: available to all QFs willing and able to sign the standard contract and a performance contract of duration not less than four years.
- Rates: all energy and contracted capacity is to be priced, at the option of the QF, at a) the Annual Average Rate or b) the Time Differentiated Rate.
  - a) Annual Average Rate

i) Energy Payment

- $X$  ¢/KWH for all KWH purchased, where  $X$  equals the annualized unit cost of owning and operating a baseload plant, less the annualized unit cost of owning a combustion turbine.

ii) Capacity Payment

- $Y$  \$/KW(cf) for all contracted KW, where  $Y$  equals the annualized unit cost of a combustion turbine (from 2ai, above) and CF represents the negotiated expected or demonstrated QF plant capacity factor.

b) Time Differentiated Rate (initially, at the option of the utility)

i) Energy Payment

- $X_t$  ¢/KWH for all KWH purchased during each time period  $t$  where  $X$  represents the annualized unit cost of owning and operating a baseload plant less the annualized unit cost of a combustion turbine, differentiated by time period  $t$  to reflect short run incremental energy cost variation.

ii) Capacity Payment

- $Y_t$  \$/KW for all contracted KW delivered during each time period  $t$ , where  $Y$  equals the annualized unit cost of combustion turbine (from 2bi, above) differentiated by time period  $t$  to reflect the relative probability of capacity shortage in time period  $t$ .

## APPENDIX B

### SUMMARY OF SPECIFIC DIRECTION IN COSTING

- All values are to be inflated/discounted to reflect constant contract year dollars.
- Inflation is to reflect industry specific, regionalized real cost indices.
- Discounting is to reflect standard (e.g. DRI) projections of national general inflation.
- Variables and formulae are defined and an example provided, below.

#### Definition of Variables

$\lambda$  = system lambda<sup>1</sup> (¢/KWH)  
a = baseload capital cost<sup>2</sup> (\$/KW)  
b = combustion turbine capital cost<sup>3</sup> (\$/KW)  
c = baseload annual carrying charge<sup>4</sup> (%)  
d = combustion turbine carrying charge<sup>4</sup> (%)  
e = baseload fixed O&M<sup>5</sup> (\$/KW)  
f = combustion turbine fixed O&M<sup>5</sup> (\$/KW)  
g = line loss factor<sup>6</sup> (%)  
h = coal cost<sup>7</sup> (\$/ton)  
i = coal fuel content<sup>7</sup> (BTU/lb)  
j = baseload plant heat rate<sup>8</sup> (BTU/KWH)  
k = baseload variable O&M<sup>5</sup> (¢/KWH)  
cf = QF capacity factor<sup>9</sup> (KWH/KW)

1 Short run incremental energy cost via production modeling of economic dispatch. To include variable O&M and revenue requirement associated with working capital and fuel inventory.

2 Actual baseload capital cost estimates to be supported by actual engineering cost study. The capital cost estimates are to be exhaustive and detailed by component. Rather than list the components, the Commission refers you to Appendix A

of EPRI's "Coal-Fired Power Plant Capital Cost Estimates" (Bechtel Power Corporation, May, 1981, report #EPRI PE-1865). Cost estimates will be reviewed with necessary adjustment made as deemed appropriate.

- 3 Actual combustion turbine capital cost estimate supported by actual engineering cost study, if available, or consistent with industry estimates. Treatment must be equally exhaustive and detailed by component.
- 4 Annual carrying charges supported by calculations of incremental cost of capital; 35 year book life assigned to base-load plants, 25 for combustion turbines.
- 5 Appendix A of the EPRI report cited above provides the minimum components to be considered. Includes working capital and variable costs associated with SO<sub>2</sub> removal.
- 6 Initially, equal to 8.3% applied to all energy. Eventually, shall reflect utility specific actual analysis and, in the case of time differentiation, allocated to rating periods commensurate with analysis results.
- 7 Coal cost and fuel content are to reflect actual contract year purchase contracts. Coal cost is to include a separate component reflecting transportation costs.
- 8 Plant heat rate is to reflect actual plant heat rate at expected operating load.
- 9 QF capacity factor is to represent expected performance, initially, and demonstrated performance after first contract year.

#### Rate Schedule Formulae

short-term energy =

$$\lambda g + \frac{(bd + f).425}{(8760)(.85).85}$$

long-term energy =

$$\frac{((ac + e) - (bd + f))g}{(8760).70} + \frac{hj}{i} + k$$

long-term capacity =

$$\frac{(bd + f)cf}{.85}$$

### Example Rate Calculation<sup>10</sup>

$$\begin{aligned}\lambda &= 2.50 \text{ ¢/KWH} \\ a &= 1200 \text{ \$/KW} \\ b &= 300 \text{ \$/KW} \\ c &= 16\% \\ d &= 17\% \\ e &= 20 \text{ \$/KW} \\ f &= 10 \text{ \$/KW}\end{aligned}$$

$$\begin{aligned}g &= 8.3\% \\ h &= 10.0 \text{ \$/ton} \\ i &= 9,000 \text{ BTU/lb} \\ j &= 11,000 \text{ BTU/KWH} \\ k &= .3 \text{ ¢/KWH} \\ cf &= .65 \text{ KWH/KW}\end{aligned}$$

$$\begin{aligned}\therefore \text{ short-term energy} &= .0250 (1.083) + \frac{(300(.17) + 10).425}{8760(.85)(.85)} \\ &= .0271 + .0041 \\ &= .0312 \text{ \$/KWH}\end{aligned}$$

long-term energy =

$$\begin{aligned}&\frac{((1200(.16) + 20) - (300(.17) + 10))}{8760(.70)} 1.083 + \frac{(10(11,000))}{(2000(9000))} + .003 \\ &= .0266 + .0091 \\ &= .0357 \text{ \$/KWH}\end{aligned}$$

$$\begin{aligned}\text{long-term capacity} &= \frac{(300(.17) + 10)(.65)}{(.85)} \\ &= 46.65 \text{ \$/KW-YR}\end{aligned}$$

10

These values are generally representative of those submitted by intervening parties in this proceeding. Although they are provided for illustrative purposes, they also serve as indicators of what the Commission has found to be reasonable.



Service Date: June 25, 1982

DEPARTMENT OF PUBLIC SERVICE REGULATION  
BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF MONTANA

\* \* \* \* \*

IN THE MATTER of Avoided Cost Based )  
Rates for Public Utility Purchases )  
from Qualifying Cogenerators and )  
Small Power Producers. )

UTILITY DIVISION  
DOCKET NO. 81.2.15  
ORDER NO. 4865b

\* \* \* \* \*

FINDINGS OF FACT

BACKGROUND

1. Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) required the Federal Energy Regulatory Commission (FERC), as well as state regulatory authorities, to prescribe rules to encourage cogeneration and small power production (COG/SPP) including rules requiring electric utilities to purchase electric power from cogeneration and small power production facilities. Among other things, the rules were to insure that rates for purchases of electric energy from qualifying facilities (QF) "be just and reasonable to the electric consumers of the electric utility and in the public interest" and that the rates would not exceed the "incremental cost to the electric utility of alternative electric energy."

2. On May 4, 1981 the Commission adopted final rules governing purchases and sales between public utilities and

qualifying small power production facilities. The Commission rules are modeled after FERC regulations implementing Section 201 and 210 of PURPA. The rulemaking procedure featured a public comment period commencing with the issuance of draft rules on September 2, 1980 and extending through October 23, 1980. A second revised draft of the rules was issued on March 16, 1981 with public comment extending through April 27, 1981. The rule-making proceeding ended with adoption of final rules on May 4, 1981.

3. The Commission's rules (ARM 38.5.1901 through 38.5.1908), pursuant to FERC regulations, provide the general obligations of the COG/SPP and the regulated electric utilities.

4. The Commission initiated Docket No. 81.2.15 on February 24, 1981 when it requested that MDU, PP&L, and MPC file testimony regarding avoided cost methodologies, avoided cost-based rates, and tariffs and standard contracts for purchases of electricity from COG/SPP. On January 4, 1982, the Commission issued Order No. 4865 setting forth the Commission's initial findings in this Docket.

5. On January 22, 1982, MDU, MPC and PP&L each filed Petitions for Reconsideration and/or Clarification and, on February 10, 1982, the Commission issued Order No. 4865a which addressed the Petitions.



6. By March 5, 1982 the utilities had submitted their original compliance tariffs. On March 12, 1982 the Commission had a working session where it (1) approved on an interim basis MPC's and MDU's tariffs (2) directed PP&L to resubmit new tariffs based on Colstrip 3 and 4 and (3) requested each utility to provide rebuttal to the Commission's concerns within 45 days.

7. The Commission has two objectives to achieve in this order regarding the avoided cost tariffs submitted by the three electric utilities.

8. First, the Commission seeks to approve, after correcting for apparent conceptual problems (detailed below) the utilities have with the avoided cost methodology, the interim tariffs for MDU and MPC and to address existing problems with PP&L's proposed tariffs; the resulting final tariffs will be updated June 1, 1983 for the contract year July 1, 1983 - June 30, 1984 (Order No. 4865, Finding of Fact No. 33).

9. Second, the Commission indicates negotiated payment options (e.g., fixed minimum payments and levelized) which it finds acceptable.

#### FINAL AVOIDED COST TARIFFS

10. This section reviews each Company's initial tariff filings, inherent problems the Commission perceives with these tariff filings, the Commission's corrective measures, and the final avoided cost tariffs.

MDU did not submit any cost stream information with regards to the Antelope Valley project. Montana Power had a cost stream extending almost fourteen years for their Colstrip units #3 and #4, and were directed to take a time series calculation into account in order to equate that cost stream into present day dollars. MDU is not faced with that situation with regards to Antelope Valley since our letter of intent with Basin Electric states that we will not put forth any capital until 1984 should we choose to execute our option then. As a result, MDU will have one large capital expenditure in 1984, with another expenditure coming in 1985. Since the 1985 expenditure will undoubtedly be significantly less than the 1984 expenditure, MDU chose not to make a cost stream calculation but rather lumped all expenditures into one and then brought that value back to 1982 dollars.

15. While the Company's 1985 expenditure, relative to its 1984 expenditure, is small, the Commission finds no grounds for deviating from the direction of Orders 4865 and 4865a. In Schedule A, the Commission provides a corrected baseload capital cost calculation and resulting long-term energy rate.

Montana Power Company.

16. MPC's calculation of annual capital costs for the baseload electric generating plant suffers from the same analytic problems as MDU's. However, unlike MDU, MPC not only chose to not follow the direction of Order's 4865 and 4865a but further argues that the Commission's direction (Findings of Fact No. 33, Order No. 4865, and Finding of Fact No. 37, Order No. 4865a) is theoretically flawed.

17. In its March 17, 1982 correspondence to MPC, the Commission stated the following:

The primary problem involves the Company's calculation of the capital cost associated with Colstrip Units #3 and 4. The cost stream (Cost Calculations, Table VI, Page 7 of 7) begins with a \$489,000 expenditure in 1973, and culminates with \$166,000 budgeted for 1987. Order No. 4865 (page 1 of Appendix B) contemplates converting this cost stream to 1982 dollars via real cost and inflation indices. The Company, however, has chosen not to follow this procedure and instead sums the actual cost stream with an AFUDC component. My discussions with Jim Cullier indicate that the Company's position is that the Company's treatment of the cost stream results in a calculation which reflects the ratepayers cost of Colstrip Units #3 and 4. While there is merit in the argument, the proffered fact is simply false.

18. In its "rebuttal comments" the Company (Mr. Jack Haffey, April 26, 1982) had the following remarks:

The Company disagrees with that interpretation of the Order. No where in Appendix B or anywhere else in the Order is there any mention whatsoever of "cost streams." What is requested in Appendix B are the "actual baseload capital cost estimates." Those estimates or "values" have indeed been placed in 1982 dollars in the Company's calculation of capital costs.

The Staff's letter of March 17, 1982 is the first indication in Docket 81.2.15 that the appropriate manner of calculating avoided costs is to inflate or deflate a stream of capital expenditures.

Mr. Haffey's letter goes on to add:

The Staff's assertion that Order No. 4865 "contemplated" the conversion of the "cost stream" to 1982 dollars finds no support in the Order. In fact, such a procedure would not be consistent with the Order since a fictitious number bearing no resemblance to avoided costs would be the result. What this approach would yield is the cost of Colstrip #3 and 4 if it were built entirely in 1982. Such a calculation was not suggested by any of the witnesses in Docket No. 81.2.15 nor in Order No. 4865. Furthermore, by using the word "contemplated," it appears as though the Staff is admitting that the Order did not explicitly state what was required of the utilities. [Footnote deleted].

19. As stated in Finding of Fact No. 18, the Company claims to have converted its 1973 through 1987 baseload capital cost expenditures, including AFUDC, to 1982 dollars. The Company's analytic treatment involved simply summing all expenditures -- 1973 through 1987 -- in nominal or current year's dollars and then discounting this sum back from 1984 to 1982 dollars by multiplying the sum by a factor of 0.8629 (this factor equals the inverse of the product of 1.079 and 1.074 from page 7 of 7 of the Company's compliance work papers dated February 25, 1982).

20. It is the Commission's finding that this methodology is logically unsound, indicating only the cost of Colstrip #3 and 4 to Montana ratepayers on an accounting basis. This cost does not accurately reflect the time value of money which stems from two factors 1) price inflation -- a rise in the general price level -- and 2) the real earning potential of investments; this latter

definition representing economic cost. The following example rectifies for the Company the meaning of "avoided costs."

21. In Order No. 69, issued in February of 1980, the Federal Energy Regulatory Commission defined "avoided costs" as:

"Avoided costs" means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source. (§292.101(b)6).

That is, avoided costs are to be based on the costs a utility would avoid incurring as a result of a QF's supplying energy and/or capacity.

22. For example, if the Company's forecasts indicate a one kw deficit in capacity in year 1990, the question could be posed as to what exactly the cost would be to the Company of obtaining an incremental kw of capacity. A literal interpretation of the Company's logic (Finding of Fact Nos. 18 and 19) would lead one to believe it would be capital costs that in part occurred in year 1973 and in 1973 dollars. Clearly the Company recognizes that prices for materials, capital, labor, etc., have not remained constant since year 1973. That is, costs in 1973 dollars are not best estimates of what it would cost the Company today to install an incremental kw of capacity; a best estimate is reflected by use of constant contract year dollars.



23. Regarding the treatment of costs incurred overtime, the advocacy staff's expert witness Dr. Tom Power made the following statements:

... I certainly do not recommend -- and that is crystal clear in my testimony -- that we take estimates in 1989 dollars and add them to estimates in 1986 dollars and add those to estimates in 1981 dollars. I know of nobody who would make that suggestion. (Tr. p. B-101)

24. The Commission finds the Company's baseload capital cost calculation of \$1245.0 to underestimate a constant contract year estimate by \$353.0. The Commission derived a constant contract year estimate of \$1598.0/kw, described below, using the Company's cash flow with AFUDC and PP&L's escalation/de-escalation factors.

#### Pacific Power and Light

25. In its March 29, 1982 correspondence with PP&L, the Commission requested the following:

In my discussions with Jerry Rust he indicated a preliminary Colstrip 3 and 4 cost of \$1596/kw resulting in a modified long-term energy rate of 5.18¢/kwh. This calculation appears to properly follow the intent of Order No. 4865 (page 1 of Appendix B) in its treatment of the historical cost stream. It is requested that the Company provide, as soon as possible, two copies of signed tariff pages reflecting this calculation.

26. Evident from the Company's May 14, 1982 response is the Company's decision to deviate from its own finding regarding a

\$1596/kw capital cost estimate for Colstrip #3 and 4; rather than use this estimate the Company simply adopted certain parameters including the \$1245/kw estimate, from MPC. In a later finding in this Order, the Company is directed to adopt certain previously submitted values for parameters used in deriving short and long-term energy and capacity payments.

#### Resulting Tariffs.

27. In MDU's work papers complying with Order No. 4865, the Company did not separately discount 1984 and 1985 baseload capital cost expenditures. The Company has since corrected this problem and is reflected in the baseload \$/kw estimate and the long-term energy rates in Schedule A.

28. MPC is to resubmit final avoided cost tariffs as computed by this Commission and summarized in Schedule A. These tariffs differ from the Company's in the value of the long-term energy rates, which reflects the Commission's baseload capital cost of \$1598/kw. Schedule B details the assumptions used to arrive at \$1598/kw for a baseload plant. As indicated below (Schedule A) this value of \$1598/kw approximates PP&L's correctly computed baseload capital cost estimate of \$1596/kw.

29. PP&L is to resubmit final avoided cost tariffs as summarized in Schedule A. The parameters and resulting tariffs

SCHEDULE A

Input Parameters and Resulting Avoided Cost Energy and Capacity Tariffs.

<u>Variable/Utility</u>	<u>MDU</u>	<u>MPC</u>	<u>PP&amp;L</u>
¢/Kwh	1.6	1.66	1.65
a \$/kw	1480	1598	1596
b \$/kw	318	367	347
c %	19.047	20.04	18.31
d %	19.69	21.87	19.76
e \$/kw	5.79	12.34	12.59
f \$/kw	1.4	0.66	5.0
g %	8.3	8.3	8.3
h \$/ton	13.5	10.03	10.03
i BTU/LB	6600	8500	8500
j BTU/Kwh	11280	10819	10819
k ¢/Kwh	0.128	0.26	0.27
STE <sup>1</sup> \$/Kwh	0.0216	0.0234	0.0228
LTE <sup>1</sup> \$/Kwh	0.0523	0.0534	0.0518
LTC <sup>2</sup> \$/kw/yr	63.96	80.88	73.54

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1 Short Term Energy (STE) and Long Term Energy (LTE).

2 Long Term Capacity (LTC).



SCHEDULE B

## Calculation of Variable "a" For MPC

	<u>Cash Flow<sup>1</sup></u> <u>W/AFUDC</u>	<u>Escalation</u> <u>De-Escalation<sup>2</sup></u> <u>Factor</u>	<u>December<sup>3</sup></u> <u>1981 \$</u>
1973	509	2.439	1,242
1974	1,214	2.267	2,752
1975	1,354	1.806	2,445
1976	2,287	1.642	3,488
1977	13,431	1.525	20,482
1978	8,915	1.424	12,694
1979	8,003	1.291	10,332
1980	46,365	1.17	54,247
1981	108,879	1.07	116,501
1982	164,304	1.0	164,304
1983	140,427	0.9174	128,828
1984	74,859	0.8495	63,593
1985	35,094	0.7865	27,601
1986	213	0.7351	157
1987	166	0.687	114
			<u>610,000</u> X (1.1) <sup>4</sup>
			= \$671,000 (December 1982 Dollars)

$$671,000 \div 420 \text{ MW} = 1,598/\text{kw.}$$

- 
- 1 Cash Flow with AFUDC was obtained from MPC's Order No. 4865 compliance work papers. Table IV Page 7 of 7 dated February 25, 1982.
  - 2 Escalation and De-escalation factors are from PP&L's 1982 Montana Electric Long Run Incremental Cost Study, Docket No. 82.4.28, (Workbook No. 8)
  - 3 December 31, 1981 dollars.
  - 4 The factor 1.1 indicates 10% inflation from the beginning of 1982 to year ending. (Workbook No. 8, Docket No. 82.4.28).

in this Schedule reflect PP&L's cost information for Colstrip #3 and 4 in constant contract year dollars.

30. All utilities are to resubmit their respective final avoided cost tariff pages within five days. These tariffs will become effective upon approval.

#### PAYMENT OPTIONS

31. With regard to payment options, Order No. 4865 allows a QF the option to adopt 1) either of the short-term or long-term standard tariffs, or 2) negotiate with their respective utility an alternate avoided cost energy and capacity rate. From recent communication with both utilities and prospective QF's, it is evident to this Commission that much concern has emerged over some sort of tariffed alternate payment option. From the QF's perspective, the concern is for more concrete information on future energy/capacity payments in order to acquire loans from financial institutions.

32. Some payment options that QF's and utilities are free to arrange via negotiation were summarized by Dr. Thomas Power:

#### Payment Arrangements

- Q. What options for payment arrangements should be provided to QFs?
- A. I would recommend that three options be provided by each of the utilities.
  - i. Rates based upon levelized annual payments for both energy and capacity based

upon projected avoided costs. The levelized annual payments would have the same present value as the estimated avoided investment cost and operation costs over the life of the contract. All payments would be fixed in real terms for the life of the contract. An annual adjustment for the overall inflation rate in the economy would be made to protect the purchasing power of these payments.

- ii. Rates which had a fixed and variable component for the life of the contract. The capacity payment would be fixed in real terms but the energy payment would be based upon the marginal energy costs actually experienced in the previous year or projected for the coming year. The capacity payment would be increased each year by the general rate of inflation to protect its value.
- iii. Rates which were based entirely on current marginal energy and capacity costs. They would vary from year to year. (Exh. M, Page 47).

The first two of Dr. Power's proposed payment options (i and ii) are examples that QF's and utilities are free to negotiate and which the Commission finds acceptable. Dr. Power's third proposal is currently a standard tariff option.

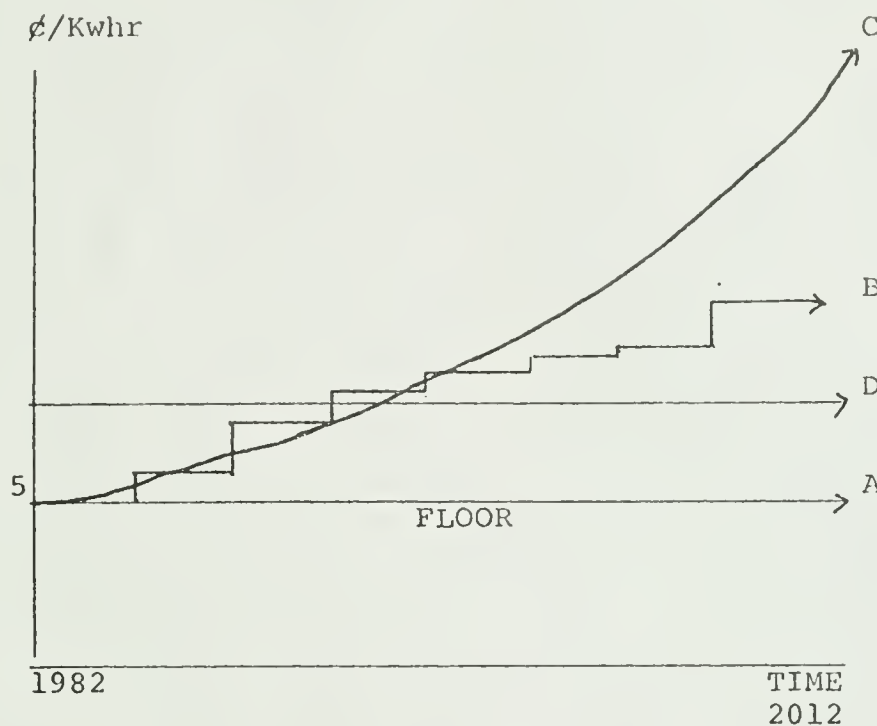
33. To the above proposals which address the market failure problems QF's face in obtaining financing, the Commission offers the following elaborations.

34. First, QF's may negotiate a fixed minimum rate with a utility. This proposal has two variants: (1) A fixed minimum

rate may be established that equals the initial year's standard tariff for long-term energy. Under no circumstances would the rate ever fall below the initial fixed minimum. (2) A fixed minimum rate may be negotiated that is annually adjusted for the previous years rise (fall) in the general price level, as indicated by the Consumer Price Index (CPI). As the U.S. Department of Labor's indices are initial estimates, the final or "revised" index may be used later, when published, to refine the initial estimate. As with (1) above, a latter year's avoided cost tariff may never fall below the initial floor.

35. A QF may also negotiate a levelized or front-loaded, contract with a utility. Such a contract would make use of standard capital recovery methods in levelizing capital costs. In fact this is just one procedure a utility may use to derive a fixed minimum rate. In turn, an annual inflation adjustment may be used with a levelized tariff as suggested by Dr. Power:

I'm proposing that one estimate long-run incremental costs in current 1981 dollar terms and base the avoided cost rates on that, and I also suggest an option similar to what Pacific and Montana Power have both proposed, a levelizing arrangement that would load more the payments at the front end or something that I think has some attractive features, setting that avoided cost rate on a levelized basis in real purchasing power terms and then increasing it at whatever the actual experienced rate of inflation was each year. (Tr. p. B-139).

SCHEDULE C

36. Schedule C provides a graphical summary of payment options discussed above. In summary, the Commission has indicated five payment options which it finds acceptable:

1) The standard rate, where, over the life of the contract, the QF is paid the standard rate which varies from year to year [assuming no real inflation in the cost components used to compute standard rates, Curve B would represent this option].

2) A fixed minimum, where, over the life of the contract, the QF is paid the greater of the initial year's standard rate [Curve A] and the actual standard rate.

3) A fixed payment, where, over the life of the contract, the QF is paid the initial year standard rate plus the previous year's inflation [Curve B].

4) A fixed payment, where, over the life of the contract, the QF is paid the initial year standard rate plus a negotiated level of projected inflation [Curve C].

5) A levelized payment, where, the present value of the projected inflation [Curve C minus Curve A] is levelized over the life of the contract and added to the initial year standard rate [Curve A] resulting in Curve D.

37. Lastly, the Commission wishes to point out that the process of establishing final tariffs complying with the methodology set forth in this proceeding has been frustrating. The Commission finds the working session efforts initiated by all three utilities commendable. Further it finds that MDU has been relatively cooperative in addressing the compliance concerns of the Commission.

38. It is with PP&L's letter of May 14, 1982 and MPC's letter of April 26, 1982, that this Commission finds a possible lack of good faith. The Idaho Public Utilities Commission has taken the same problem into consideration when setting rates of return and approving issuances of security used to finance the construction of conventional thermal units.

39. The Montana Commission holds that utility failure to actively pursue QF contributions to their resource base, via negotiated terms of contract -- as discussed in Finding Nos. 33 through 36 -- to constitute failure to provide cost effective service. To the extent the evidence in future proceedings does not demonstrate that the utilities have in fact vigorously pursued such contracts, the Commission will use such evidence in considering whether utilities are providing adequate service at just and reasonable rates. Initially, it is the "conservation adder" recently granted in the equity returns of both MPC (Order No. 4775b, Finding No. 45) and PP&L (Order No. 4881a, Finding No. 33) which is at stake.



40. The Companies are reminded of their obligation to provide information to the Commission regarding their initial written response to each prospective QF [ARM 38.5.1908(1)]. In addition to reporting each contact made, the Commission directs the Companies to submit one copy of the completed contractual agreement with each QF. The Commission welcomes additional information that will aid the Commission in analyzing the individual efforts of each utility in encouraging QF contributions to a utility's resource base.

#### CONCLUSIONS OF LAW

1. Montana-Dakota Utilities Company, Montana Power Company and Pacific Power & Light Company are public utilities within the meaning of Montana law, Sections 69-3-101 and 69-3-601(3), MCA.

2. The Commission properly exercises jurisdiction over the rates and terms and conditions for the purchase of electricity by public utilities from qualified cogenerators and small power producers. Sections 69-3-102, 69-3-103 and 69-3-603, MCA. Section 210, Pub. L. 97-617, 92 Stat. 3119 (1978).

3. The rates the Commission has directed the utilities to file are just and reasonable to Montana ratepayers as they reflect each utility's avoided energy and capacity costs.

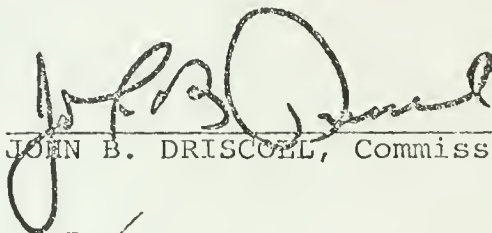
4. The objective of encouraging cogeneration and small power production is promoted by the rates and terms and conditions established by this order.

ORDER

Each utility is to submit their respective tariffs as listed in Schedule A within 5 days; these tariffs will become effective upon approval.

DONE IN OPEN SESSION this 21st day of June, 1982, by a vote of 3 - 0.

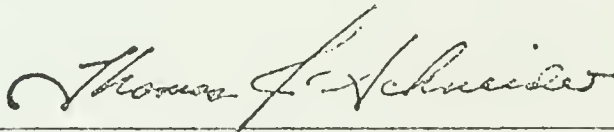
BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION.



JOHN B. DRISCOLL, Commissioner

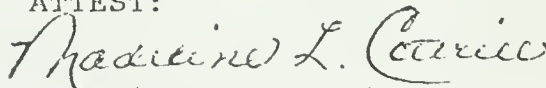


HOWARD L. ELLIS, Commissioner



THOMAS J. SCHNEIDER, Commissioner

ATTEST:



Madeline L. Cottrill  
Commission Secretary

(SEAL)

NOTE: You may be entitled to judicial review of the final decision in this matter. If no Motion for Reconsideration is filed, judicial review may be obtained by filing a petition for review within thirty (30) days from the service of this order. If a Motion for Reconsideration is filed, a Commission order is final for purpose of appeal upon the entry of a ruling on that motion, or upon the passage of ten (10) days following the filing of that motion. cf. the Montana Administrative Procedure Act, esp. Sec. 2-4-702, MCA; and Commission Rules of Practice and Procedure, esp. 38.2.4806 ARM.



APPENDIX D

MONTANA GRAIN CROP RESIDUES



MONTANA GRAIN CROP RESIDUES

<u>CROP</u>	<u>UNIT WEIGHT (lb/bu)</u>	<u>STRAW/GRAIN WEIGHT RATIO</u>	<u>STRAW WEIGHT (lb/bu of grain)</u>	<u>AVAILABILITY</u>
Winter Wheat	60	1.3	78	95%
Spring Wheat	48	1.3	71.2	95%
Barley	58	1.1	52.8	95%
Oats	34	1.6	54.4	95%



APPENDIX E

BTU CONTENT OF NATURAL GAS

IN MONTANA



\*\*\*\*\*  
 \* NATURAL GAS CONVERSION FACTORS FOR MONTANA SITES. BTU/MCF \*  
 \*\*\*\*\*

*SITE	*CONV BTU/MCF	*PRESS PSIA		*SITE	*CONV BTU/MCF	*PRESS PSIA
ABSDROKEE.....	908238	12.70	>>***<<	HINGHAM.....	941903	13.18
ALHAMBRA.....	900523	12.59	>>***<<	HUNGRY HORSE....	939799	13.15
AMSTERDAM.....	892809	12.48	>>***<<	INVERNESS.....	932785	13.05
ANACONDA.....	870366	12.16	>>***<<	JEFFERSON CITY..	890705	12.45
AUGUSTA.....	906836	12.68	>>***<<	JOPLIN.....	932785	13.05
BELGRADE.....	893510	12.49	>>***<<	JUDITH GAP.....	889302	12.43
BIG SANDY.....	953124	13.34	>>***<<	KALISFELL.....	944708	13.22
BIG TIMBER.....	904030	12.64	>>***<<	KREMLIN.....	948916	13.28
BILLINGS.....	925070	12.94	>>***<<	LEWISTOWN.....	911745	12.75
BOULDER.....	878081	12.27	>>***<<	LIVINGSTON.....	884393	12.36
BOZEMAN.....	885795	12.38	>>***<<	LOGAN.....	904732	12.65
BROWNING.....	893510	12.49	>>***<<	LOMA.....	958034	13.41
BUTTE.....	857040	11.97	>>***<<	MANHATTAN.....	900523	12.59
CHESTER.....	938396	13.13	>>***<<	MARTIN CITY.....	939799	13.15
CHINOOK.....	963644	13.49	>>***<<	MAXVILLE.....	880886	12.31
CHOTEAU.....	915252	12.80	>>***<<	MILES CITY.....	956631	13.39
CLANCY.....	901926	12.61	>>***<<	MILLTOWN.....	933487	13.06
CLINTON.....	927876	12.98	>>***<<	MISSOULA.....	929980	13.01
COLUMBIA FALLS..	942604	13.19	>>***<<	MOUNT ELLIS.....	878081	12.27
COLUMBUS.....	922966	12.91	>>***<<	NISSLER.....	864755	12.08
CONRAD.....	925772	12.95	>>***<<	OPPORTUNITY.....	876678	12.25
CORAM.....	937695	13.12	>>***<<	PHILIPSBURG.....	866859	12.11
CORVALLIS.....	926473	12.96	>>***<<	PINE GROVE.....	933487	13.06
CUT BANK.....	913148	12.77	>>***<<	RAMSAY.....	865456	12.09
DEER LODGE.....	890705	12.45	>>***<<	RED LODGE.....	860547	12.02
DILLON.....	873171	12.20	>>***<<	ROBERTS.....	889302	12.43
DRUMMOND.....	911044	12.74	>>***<<	ROCKER.....	864054	12.07
EAST GLACIER....	882990	12.34	>>***<<	RUDYARD.....	939097	13.14
EAST HELENA.....	913148	12.77	>>***<<	SHAWMUT.....	913849	12.78
ELLISTON.....	875275	12.23	>>***<<	SHERIDAN.....	874574	12.22
FAIRFIELD.....	909641	12.72	>>***<<	SIMMS.....	924369	12.93
FORT BELKNAP....	964346	13.50	>>***<<	SILVER BOW.....	865456	12.09
FORT BENTON.....	955930	13.38	>>***<<	SILVER STAR.....	892107	12.47
FORT SHAW.....	925772	12.95	>>***<<	STEVENSVILLE...	930681	13.02
GALEN.....	884393	12.36	>>***<<	SUN RIVER.....	929279	13.00
GARRISON.....	898419	12.56	>>***<<	THREE FORKS.....	906836	12.68
GILDFORD.....	948916	13.28	>>***<<	TWIN BRIDGES....	888601	12.42
GLASGOW.....	967852	13.55	>>***<<	VALIER.....	915953	12.81
GREAT FALLS.....	922265	12.90	>>***<<	VAUGHN.....	930681	13.02
GREYCLIFF.....	911044	12.74	>>***<<	VICTOR.....	930681	13.02
HALL.....	902628	12.62	>>***<<	WARM SPRINGS....	881587	12.32
HAMILTON.....	923668	12.92	>>***<<	WEST GLACIER....	935591	13.09
HARLEM.....	965047	13.51	>>***<<	WHITEFISH.....	941903	13.18
HARLOWTON.....	903329	12.63	>>***<<	WHITEHALL.....	897017	12.54
HAVRE.....	960839	13.45	>>***<<	WOLF CREEK.....	922265	12.90
HELENA.....	912446	12.76	>>***<<			

\*\*\*\*\*  
 \*SOURCE: MEMORANDUM FROM MONTANA POWER, JANUARY, 1981:  
 HEAT CONTENT OF GAS GIVEN BY THE FORMULA:  
 $HV, BTU/MCF = 1045 * (PRESS + .25) * 1000 / 14.9$   
 \*\*\*\*\*





**APPENDIX F**  
**WORKSHOP PRESENTATIONS**



WOOD FOR FIBER PRODUCTS AND FUEL

A DIMINISHING SUPPLY?

By:

Charles E. Keegan  
and  
Mary L. Lenihan

The wood products industry is the backbone of western Montana's economy. It provides jobs for thousands of Montanans. It is the only sizable basic industry in some counties west of the Divide. And despite the industry's depressed condition during the recent recession, it will continue to provide a very large part of western Montana's economic base.

Over the past few years, both the industry and the general public have increased their use of wood fiber. This increased use has greatly increased the demand for dead and waste timber.

Until very recently the forest products industry's needs have been supplied almost entirely by harvesting sawtimber, timber suitable for high value products such as lumber and plywood. Residue from their manufacture (mill residue) was used for wood fiber products and fuel. In the immediate future the industry will use increasingly substantial volumes of lower quality dead and waste timber -- usually referred to as forest residue -- for wood fiber products such as pulp and paper, and for industrial fuel.

At the same time, the general public is using more dead and waste timber as a source of fuelwood. Energy costs have escalated rapidly in recent years. Many people are returning to wood for home heating, a fuel source that had been more or less abandoned by the early 1960s.

These shifts are leading to a potential conflict among users of dead and waste timber from Montana's forests. Ten years ago there was

virtually no competition between home fuelwood and industrial users. Now Montana residents and industrial firms that rely on wood for heat, steam generation, and the manufacture of wood fiber products may find their supply dwindling and prices increasing.

The Bureau of Business and Economic Research at the University of Montana recently assessed both the industrial and home firewood user demand for wood fiber in Montana. Measured against the available supply of dead and waste wood, it is clear that there may be a shortage that could affect both types of users.

### Industrial Demand for Wood Fiber

The wood products industry in western Montana changed considerably over the past ten years. New fiberboard and particleboard plants were built, and a pulp and paper mill greatly expanded its production capacity. In addition, increasing energy costs forced most major primary wood products manufacturers to shift to wood fiber as a fuel source. All these developments greatly increased industrial demand for wood fiber.

Until now, the preferred and virtually the only source of wood fiber for these users has been residue from lumber and plywood production. This manufacturing or mill residue will continue to provide the major source for industrial wood fiber users, both for fiber products and fuel. However, very recent increases have caused the projected demand for mill residue to exceed the anticipated supply substantially.

This mill residue shortfall, if it is to be satisfied, will have to come from increased harvesting of forest residue. Conflict may occur as both industrial and home users attempt to harvest the most readily accessible components.

To assess the potential shortage, we have projected industrial demand for wood fiber and considered the probable demand for home use. First we examined the estimated wood fiber demand for uses other than plywood and lumber production. Then we looked at the portion that will have to come from forest residue.<sup>1</sup>

We used three major sources. One is an industry-wide census sponsored jointly by the Bureau of Business and Economic Research and the Forest Service. That survey asked each forest products manufacturer to note its annual use of wood fiber residue from sawmills and plywood plants. Another source is the cooperative research work in forest residue utilization conducted jointly by the Bureau and the Forest Service.<sup>2</sup> Discussions with industry and Forest Service personnel comprise the third source.

These projections cover the years 1983 through 1990. All wood fiber volumes have been translated into cords. A cord is a stack of logs 4 feet by 4 feet by 8 feet, which is equivalent to approximately 2,150 pounds of wood fiber (oven dry weight).

Using these sources, we estimate that the annual industrial wood fiber needs for the manufacture of pulp, paper, particleboard, fiberboard, and industrial fuel in Montana will be just under 2.4 million cords for the remainder of the 1980s. Based on projected lumber and plywood production levels, approximately 2.1 million cords will be available in the form of mill residue.<sup>3</sup> This means that 300 thousand cords will have to be supplied by other sources.

#### Home Fuelwood Demand

Projecting demand for home fuelwood is more difficult because of the very large numbers of small users. The U.S. Department of Energy estimated that in 1981 Montanans used 380 thousand cords of home

fuelwood. These estimates are similar to some the Bureau made earlier, based on user surveys and data from the 1980 Census of Population. We feel they are reasonably good estimates.<sup>4</sup>

Among those people we contacted there were mixed opinions concerning future home fuelwood use. We feel such use is peaking now due to the increasing competition for wood fiber. We will use the 1981 figure of 380 thousand cords as the annual demand for the years 1983 through 1990. Adding this to the 300 thousand cords for industrial use that will not be supplied by mill residue, we have a total annual demand for 680 thousand cords of dead and waste timber.

To provide some perspective, let us compare this projected demand to Montana's commercial sawtimber harvest for the ten-year period 1972-1981. The harvest in Montana for that period was just under 1.1 billion board feet per year, or approximately 2.9 million cords. To meet the projected industrial and home fuelwood demand for dead and waste timber it will be necessary to harvest an additional volume equal to 20 to 25 percent of the last ten years' annual sawtimber harvest. This is a considerable volume.

### Supply

Is there wood available to meet this need? The demand for all or some of the 680 thousand cords will be supplied by forest residue. This includes any wood fiber material in commercial forests that is not of high enough quality to be sawtimber. It also includes small trees that will not be of sawtimber quality when mature.

Forest residue can be broken down into the following components, based on availability and removal costs:

- o Logging residue--dead wood or low quality green wood left over after logging operations

- o Small, live trees in overstocked stands
- o Untreated slash from previous logging operations
- o Dead or other "cull" (low value) material on sites not scheduled for logging or stand improvement.

If one looks at the total estimated volume of this dead and waste timber in Montana, the potential supply is enormous and greatly exceeds the demand for nonsawtimber wood fiber. But when we begin to examine such factors as accessibility and cost, a seemingly infinite supply becomes much more limited. In fact, given conventional harvesting methods, there may not be enough wood fiber available to meet the demand in fairly large areas of the state.

Dead and waste timber material from current logging sites--logging residue--is the first choice of industrial users and one of the top choices of home firewood users. Let's examine the supply available from that component and see if this supply is sufficient to meet statewide demand.

The Bureau of Business and Economic Research has made some rather detailed estimates of the volume of logging residue that might be available annually, at various costs, through conventional sawtimber harvesting techniques. Based on projected harvest levels, we estimated that nearly 840 thousand cords of logging residue, sound enough and large enough to be handled by conventional techniques, should be available annually in Montana.<sup>5</sup>

Some of this would be too expensive to recover, but it appears that the statewide supply might be sufficient to meet statewide demand. There is one catch: unfortunately, the demand is not distributed geographically in the same fashion as supply.

Industrial demand for nonsawtimber wood fiber is centered in west central Montana. In fact, we estimate that approximately half the



expected demand for forest residue in the state is in Missoula County and its surrounding area (Figure 1). We estimate this demand to be 340 thousand cords annually, compared with the total statewide annual demand of 680 thousand cords. Of the 340 thousand cords, approximately two-thirds will be needed by industrial users, with one-third by home fuelwood users.<sup>6</sup>

Missoula area users, both industrial and home, will require a larger share of the total wood fiber supply than users in most other timber-producing parts of the state. As a result, there is greater potential for conflict between users in western Montana. To satisfy their demand, Missoula area users will be forced to incur higher removal and delivery costs since they'll have to use those components of the forest residue resource that are more difficult to obtain.

Our estimates indicate that approximately 170 thousand cords of logging residue will be available annually, at a reasonable price, within a 100-mile haul distance of the major processors in Missoula County. In this case, we used \$65 per cord as a cutoff price, a relatively high price considering the uses.

Expanding the haul distance might raise the total available to almost 240 thousand cords. This is barely what industrial users expect to need, assuming they could get it all (which is unlikely). This leaves a shortfall of 100 to 120 thousand cords. Evidently, then, in west central Montana the future demand for nonsawtimber wood fiber for industrial and home fuelwood use may exceed the readily accessible supply by a large amount.

In some other parts of the state the situation is similar, though on a smaller scale. For example, a number of forests located east of the Continental Divide have estimated firewood cuts well in excess of the commercial timber harvest. This may cause supply problems in the near future.



One way to solve this shortfall problem is to begin utilizing components of forest residue other than those currently available in the course of conventional logging operations. This would entail using harvesting techniques that, while not new to the forest industry, have not been commonly used in the northern Rocky Mountain area.

In Montana, the tendency lately has been to use more small stems from overstocked or improperly stocked stands. Champion International is already utilizing relatively large volumes of small timber from thinning and stand conversion operations to meet industrial fuelwood needs at its pulp and paper mill.

### Implications for Users and Land Managers

If it is not economically feasible to harvest small stems and other previously unutilized components of forest residue for fiber products and fuelwood, there may be some problems. The supply/demand relationship will mean conflicting demand for a limited supply of wood fiber.

Home fuelwood users. First of all, what might happen on the home fuelwood side? No matter what is done to develop new harvesting technology, we expect that there will be a great deal more commercialization of home fuelwood harvesting.

Most of the firewood currently used is gathered with free use permits. Were landowners and managers operating strictly to maximize dollar returns, they would attempt to recoup as much of their lands fuelwood value as they could. And we think this will happen, to a degree. However, the general feeling is that public relations and political factors will slow the rate of fuelwood commercialization on both public and industrial private lands. Free use or low-cost permit use, such as the recently announced \$10 fee in certain sections of Northern Region National Forests, will probably continue for some time.

Physical constraints may also lead to increased commercialization of home fuelwood. The supply of timber physically available to the home firewooder with only a chainsaw and pickup will become greatly reduced in some areas. As the firewooder finds that wood is becoming more difficult to gather, he will become more willing to pay for it. Whatever the reason, more and more commercialization is coming and home fuelwood is going to become more expensive, especially in heavy use areas.

Industrial users. We expect that within the industry wood fiber costs will increase both for use as fiber and fuel. This will happen because more expensive components of roundwood, such as small steams, will have to be utilized and because increased competition for mill residue will cause prices to increase. A benefit, though, is that sawmills will receive more revenue for their wood fiber residue.

The present structure and normal operating levels of Montana's forest products industry will probably be maintained if successful techniques are developed to harvest additional wood fiber economically. If little or only limited success is achieved, we foresee various competition for nonsawtimber roundwood.

This competition could lead to a shortage of raw materials and resulting reduced operating levels in the pulp, paper, fiberboard, and particleboard sectors. In addition, the sawmills and houselog sectors of the industry might suffer as the pulp and paper industry and home fuelwood users compete for the lower quality sawtimber supply.

It is possible that we could see plant closures if new wood supplies are not developed. There are fiber product plants in the state with relatively low value use for wood fiber. These plants probably cannot afford to use any roundwood at all and may not be able to compete as mill residue prices increase. It's possible, then, that one or more of these plants could close as their current wood fiber contracts expire.

An additional ramification of the supply/demand relationship concerns energy use. If the price of dead and waste timber increases, industrial users may find other fuels becoming more competitive, despite recent price increases.

Land managers. Both public and private land managers should benefit from the upcoming demand for nonsawtimber roundwood. In Montana we have never had a consistent pulpwood market, let alone a home or industrial fuelwood market. Pulpwood has been harvested only in recession years. Commercial fuelwood harvesting has been low volume and sporadic. Now, in much of the state's timber-producing region, we will have a substantial and consistent market for dead timber and small stems. This should allow many stand treatments that were not economically feasible in the past.

Despite some of these rather negative concerns, we are optimistic about the potential for more fully utilizing our forest residue resource. The wood fiber is there. The land management agencies, the forest products industry, and universities in this region have all given the problem high priority. We do want to point out, though, that in many parts of Montana increased utilization of forest residue is no longer just a matter of a wood fiber resource that is unutilized. Rather it is a matter of an increasing demand of wood fiber that will require new harvesting techniques to satisfy.

### FOOTNOTES

<sup>1</sup>Industrial demand is based on projected plant capacity. Price was not considered in this analysis.

<sup>2</sup>Both of these projects were completed under the sponsorship of the Forest Service Intermountain Forest and Range Experiment Station in Ogden, Utah. The cooperative research work on forest residue utilization was handled through the Intermountain Station's Forestry Sciences Lab in Missoula. The cooperative research on mill residue was handled through the Forest Survey Unit of the Intermountain Station.

<sup>3</sup>The demand and supply figures are based on estimates presented in Charles E. Keegan III and Randle V. White, "Forest and Mill Residue in Montana and the Potential for Major Manufacturing Plants," Montana Business Quarterly 17 (Winter 1979): 10-18. These estimates have been updated based on a 1981 census of the industry and discussions with industry personnel.

<sup>4</sup>U.S. Department of Energy, "Estimates of Wood Consumption from 1949 to 1981," (Washington, D.C.), August 1980. Throughout this report, home fuelwood demand is an estimate of expected consumption.

<sup>5</sup>Charles E. Keegan III, The Cost and Availability of Forest Residue in the Northern Rocky Mountains (Missoula, Montana: University of Montana, Bureau of Business and Economic Research, 1981).

<sup>6</sup>The localized industrial demand was estimated from the Bureau's Montana Forest Industries Data Collection System (unpublished data, 1982). Localized home fuelwood demand is based on 1980 U.S. Census of Population data and user survey data obtained from the Montana Power Company.

## COST OF COLLECTING AND TRANSPORTING WOOD RESIDUES

By John A. Combes

A. Introduction: Wood residue consists of that portion of the woody biomass which will not be manufactured into a primary forest product such as lumber, plywood, poles, piling, or similar products. This does not mean that residues are not used in the marketplace. Paper products are a prime example of a product manufactured from residues. Firewood, roundwood for wafer and flake-board manufacture, planer shavings for animal bedding, and barkdust for flower gardens are other examples of uses for wood residues.

Wood residues are broken down into three categories:

1. Residues (mill residues) from the manufacture of primary products.
2. Logging residues consisting primarily of tops, limbs and unmerchantable logs or pieces from trees harvested for primary forest products.
3. Forest residues consisting of pole size timber which need to be removed to improve the growth of residual crop trees. In addition, both live and dead unmerchantable trees, and downed material are included.

The discussion in this paper will deal with the collecting and transportation costs of logging and forest residues. The major obstacle to the use of logging and forest residues for energy purposes is its availability and cost of gathering and transportation.



B. Availability: Logging and forest residues as a potential resource for use in the generation of steam and electrical energy from the forests of Montana is first discussed:

1. Logging residues: An average of 1,150 million board feet of timber is harvested annually of which half is logged from National Forest lands. The total volume of logging residue generated from the harvest of timber is nearly 700,000 cunits of material annually.

One cunit equals 100 cubic feet of solid wood. For the species of Montana, 1 cunit equals approximately 2,400 pounds of wood on a bone dry basis or 1.2 bone dry tones (bdt).

The availability of logging residues is dependent upon several factors including the demand for primary forest products which dictates how much timber is harvested and residues generated annually. Other factors include the accessibility of residues to the log landing or road. Gathering residues with ground lead or skyline cable machines on steep terrain results in the logging residue becoming more economically inaccessible than when it is found on favorable terrain where skidders and log forwarders can readily operate. Other factors which affect the availability of logging residues are whether the tops and branches, while still attached to the merchantable log, are skidded to the log landing such as commonly done when harvesting is done with mechanical faller-bunchers and grapple skidders. Another important factor is the distance the logging area is from the area of potential use of the residues.

There is a tendency for residues in the form of roundwood to find its way into the pulp and paper market when the demand for lumber and plywood products is depressed. For example, during the years 1980 - 1982, many cull logs were harvested, hauled and chipped for pulp manufacture. However, the demand for such material in 1983 is nearly nonexistent since the market for primary wood products has markedly improved, resulting in a greater production of mill residues for use in the pulp and paper industry.

This brings us to the point of competition for wood residues. The demand for firewood, small timber and logs for tree stakes, posts, rails, corral poles, hog fuel for pulp mills, and pulpwood places residues from both logging and forest thinning operations on a competitive basis.

In conclusion from an economical standpoint, for use as a commercial fuel, there would be approximately 230,000 oven dry tons of logging residue generated in Montana annually of which 200,000 tons comes from Western Montana.

2. Forest residues: Forest residues are the most expensive and therefore, the least economically available residue for bio-energy or other uses. The major cost of making logging residues available is borne by the value generated by the primary product. However, the costs of making forest residues available is usually borne by the end product value of the residue itself. Sometimes under thinning contracts, part

of the cost in delivering the residue is offset by the funds received for performance of the contract from the contracting agency or company.

The total forest residue available for bio-energy or other products from the commercial forest land of the National Forests in Montana is estimated as follows:

Million Cubic Feet

Pole timber	1,940
Cull trees	420
Sound dead trees	2,450
Down trees	<u>5,500</u>
Total	10,310

This, on the average, equals a little over 12.5 cunits of forest residues per acre. In areas of insect killed timber and thickets of suppressed lodgepole pine, as an example, the forest residues would be above the average per acre, whereas the residues would most likely be least in stands of sawtimber.

The most significant factor concerning the availability of forest residues is access. Forest residues must be located relatively near, probably no further than 500 feet, to existing roads in order to be economically available. At the present time, only about 45 percent of the commercial forest lands in the National Forests of Montana are accessible. Of the areas that are accessed, most likely less than



half of the forest land is economically available for collecting forest residues. Therefore, of the 10,310 million cubic feet of forest residues available on commercial forest lands, approximately 2,500 million cubic feet would be economically available, providing suitable markets exist.

The question arises whether removing logging or forest residues removes the nutrients from the forest floor. The majority of the forest nutrients reside in the needles, twigs, and the smaller portions of the limbs. In general, the residues having commercial applications would be material with a small end diameter of 3 inches and larger.

Another question arising is whether a user of wood residues could contract for logging or forest residues on a long term basis. The answer to this question is generally no. The Forest Service, and most other public land owners do not sell forest products using long term contracts. The prime reasons for this are twofold. First, the competitive nature for forest products preclude the tying up the resource for only one user. Second, the ever changing economic, resource and environmental standards result in contractual stipulations being outdated in relatively short periods of time.

- C. Cost of Collecting and Transporting: The major cost factors affecting the removal of residues is the falling and bunching, skidding or yarding and transportation.

1. Falling and bunching: This process would be associated with the gathering of forest residues if such residues have not been readied through a timber stand improvement contract. Mechanical faller-bunchers are the most efficient means for felling and bunching forest residues although the use of power saws with bunching done with winches is also quite efficient. The latter method is adaptable for handling small trees on steep terrain.
2. Skidding and yarding: The cost of skidding or yarding varies in accordance with many factors. Skidding refers to the gathering of woody material and transporting it to the landing or concentration area using rubber tired or tracked skidders. Yarding refers to the gathering of the material using cable systems. The latter is usually done on slopes over 35 percent and swampy terrain.

Skidding techniques used in harvesting timber for primary forest products varies significantly. In the lodgepole pine and second growth forests, the use of faller-bunchers in conjunction with grapple skidding or forewarders results in most of the logging residues being taken to the landing attached to the sawtimber or trees to be manufactured into primary forest products. Conventional skidding techniques using chokers usually results in most of the residue being left in the woods. New techniques in prebunching trees using small radio controlled winches can materially reduce the cost of gathering or bunching trees for later transportation to the landing by use of grapple skidders on the more gentle terrain or cable yarders on steeper terrain.

Cable yarding, consisting of using ground lead yarders or skyline machines usually results in most residues being left in the woods. Many times, particularly on public lands, the logging contractor may be required to skid or yard the larger pieces of residue to the landing for the reduction of heavy fuels on the forest floor. This substantially reduces the cost of acquiring logging residue from the residue user's standpoint.

In summary, the most economical way to gather forest residues would be by using small faller-bunchers or prebuncher winches in conjunction with grapple skidders and forwarders. On steeper terrain, the use of prebuncher winches to bunch material into skyline corridors would be the most cost effective way.

3. Handling and chipping: The transportation of residues from the landing or concentration yard would be most efficiently done by chipping and blowing the residues into chip vans. The handling part of the operation primarily consists of feeding the residues into the mobile chipper. Large material consisting of dead and cull logs would normally be hauled on log trucks and processed through "in plant" chipping plants.
4. Transportation: Wood residues are bulky and from the fuel standpoint have low BTU values per unit of weight as compared to other conventional fuels. In addition, the residues normally average 50 percent moisture content. Therefore, a great deal of water is needlessly transported. The transportation cost per BTU for logging or forest residues varies with the moisture content, amount of compaction in the van, density of

the wood (varies by species), and inorganic contaminants mixed in with the residue. This would be in addition to the variation of cost due to haul distances and types and grades of roads on which the residues are hauled. A constraint to hauling residues from many points in the forest relates to the ability of chip vans to negotiate the forest roads. Many of the access roads to landings and potential sites for concentrating forest residues are not designed to handle commercial chip vans.

As a rule of thumb, 75 miles should be considered as the maximum haul for logging and forest residues. Economically, the average haul should be no more than 40-50 miles.

Costs can vary quite dramatically as demonstrated from the above discussion. To give some idea of the cost of delivering wood residues to a point of use for energy purposes, the following scenario is developed using costs on a 1981 dollar basis:

Dollars per Oven Dry Ton

	<u>Forest Residues</u>		<u>Logging Residues</u>	
	<u>Skidding</u>	<u>Yarding</u>	<u>Skidding</u>	<u>Yarding</u>
Felling and Bunching	\$32.00	\$35.00	-	-
Skidding or yarding	17.00	28.00	\$10.00 <sup>1/</sup>	\$16.00 <sup>1/</sup>
Handling and chipping	20.00	20.00	16.00 <sup>2/</sup>	16.00 <sup>2/</sup>
Transportation (50 miles)	<u>13.00</u>	<u>13.00</u>	<u>15.00</u>	<u>15.00</u>
	\$82.00	\$92.00	\$41.00	\$47.00

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<sup>1/</sup> Assumes that a certain amount of the material to be skidded or yarded to the landing is attached to saw logs or peeler logs.

<sup>2/</sup> Assumes larger pieces of cull or dead material is hauled intact to the delivery point for chipping with an "in plant" chipper.

The cost per BTU can readily be figured using 8,500 BTU's per oven dry pound or 17 million BTU's per oven dry ton. If costs are developed on a green weight basis, the energy derived is approximately 6,400 BTU's per pound.

The Wood Residue Utilization Act of 1980 (Public Law 96-554) was enacted to help offset the cost of delivering logging residues to a point of use for energy purposes. This is accomplished by giving the purchaser of National Forest timber a credit against stumpage payments for gathering and transporting the residues. The credits to the purchaser cannot exceed the value received for the residues plus the value of the slash reduction benefits to the Forest Service. Unfortunately, no monies have been appropriated through fiscal year 1983 to implement the provisions of this act.

- D. Conclusion: The cost of collecting and transporting logging residues is dependent upon its availability, characteristics of the area from which it is harvested, and the characteristics of the residues itself. The cost of delivering residues is higher than the delivery of conventional fuels in Montana and most other western States. Mill residues, although not discussed in this paper, are the least costly to deliver although they may be the least available of the residues because of competing uses and market fluctuation of the primary products. If mill residues are available, a mix of mill residues with logging and forest residues can significantly lower the delivery cost of the fuel. The major advantage of wood residues for energy purposes over conventional fuels is that it is renewable.

APPENDIX G

BIBLIOGRAPHY OF COGENERATION

LITERATURE





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