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AN ASSESSMENT OF THE POTENTIAL FOR COAL BASED POWER GENERATION IN RURAL ALASKA

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AN ASSESSMENT OF THE POTENTIAL FOR COAL BASED POWER GENERATION IN RURAL ALASKA

A

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TITLE OF THESIS

AN ASSESSMENT OF THE POTENTIAL FOR COAL BASED POWER GENERATION IN RURAL ALASKA

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A. ABSTRACT

Most villages in rural Alaska generate their electrical power from diesel-electric generators which are becoming increasingly expensive to operate. Some of these villages have moderate-sized veins of coal coming to the surface of the ground near the village or are located on rivers or on the ocean shore where coal could be barged. Because of the high cost for diesel generated electricity and the availability of low cost coal, there has been an interest in using this coal for electrical power generation.

The economics of a number of systems using locally available coal for electrical generation were evaluated to determine the system with the lowest life-cycle cost. These costs were then compared to the life-cycle cost of a diesel-electric system. An external combustion gas turbine system proved to be cost competitive with the diesel-electric system.

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C. ACKNOWLEDGEMENTS

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1.0 INTRODUCTION

Most villages in rural Alaska generate their electrical power from diesel-electric generators (generally in the 50-200kw range), which are becoming increasingly expensive to operate. In bulk purchase, number one fuel oil used in the diesel generators is priced at $1.89 per gallon in 55 gallon barrels in Fairbanks, Union Oil(1981). By the time it is flown into the rural villages and transported into place it can be up to twice that price. The resulting utility rates usually exceed $.40/kwh, and sometimes reach as high as $.75/kwh, Teitzel(1981). Several of these villages have moderate-sized veins of coal coming to the surface of the ground near the village or are located on rivers or on the ocean shore where coal could be barged. Examples of this are: (1) coal from the Meade River could be used at Barrow or Atkasuk; (2) coal from Wainwright could be used at Wainwright or Point Lay; (3) coal from Cape Dyer could be used at Point Hope, Kavalina, or Kotzebue; (4) coal from Unalakleet could be used at Unalakleet, Nome, or Teller; (5) coal from Herendeen Bay could be used at Goodnews Bay, Togiak, or Dillingham; and (6) coal from Nulato could be used at Anaktuvak Pass, Conwell and Triplehorn(1980). Other options include using the Tanana and Yukon Rivers to transport Healy coal to additional villages which lie along these rivers. Given the high cost for diesel generated electricity and the availability of coal, there has been an interest in using this coal for electrical power generation to decrease the dependency on oil, possibly with an equal or even decreased operating cost.

A number of systems have been recommended as options for using locally available coal for electrical power generation in rural Alaska. These options include: (1) a conventional coal fired boiler-steam turbine (or steam engine) system; (2) a coal gasification system for combustion in a modified version (spark ignited) of a diesel engine; (3) a Stirling-cycle heat engine as a prime mover to generate the power; (4) an Organic Rankine Cycle Turbine; and (5) an external combustion gas turbine system. Each of these systems was examined to determine its lowest life-cycle cost and whether or not it could be built using commercially available components. Because of the remote location of the villages and the importance of the system to it, utmost importance was placed on using commercially available and reliable equipment requiring minimum support and technical know-how to operate.

The level of development of each system was researched to provide information on the degree of proven reliability and dependability, rate of increasing technology, and the amount of support equipment needed with the system as well as the level of development of support equipment. While researching the options, the names of companies at present or in the past which have done development on the generating equipment or have manufactured the equipment were noted.

The next step was to contact the companies noted above to determine if the equipment they manufacture could be used in such applications. If a particular company was not engaged in the manufacture of this equipment, they were questioned to determine if they knew of any companies that were.

From this information, potential systems were developed using the components located. An economic analysis was then performed to determine the system with the lowest life-cycle cost, which was then compared to the life-cycle cost for a diesel-electric generator.

2.0 PREVIOUS WORK

The first major move to electrify rural villages occured in October 1966 when officials from the Office of Economic Opportunity, the Rural Electrification Administration, and other Federal agencies met to discuss bringing electrical service to the unserved native villages of Alaska. As a result of this meeting, a proposal was made by Alaska Village Electrification Cooperative, Inc. to electrify 67 remote villages in Alaska. These villages were electrified with diesel-electric generators which are still used today.

Groups such as the Alaska Power Authority and A.V.E.C. (Alaska Village Electrification Cooperative) have done research on alternatives to diesel-electric power generation for a few specific villages. The majority of this work has either been done in the fields of wind and hydro-electric power generation, or in the case of coal, in the 1 to 5 MW range, either for large villages Marks(1981), Retherford(1980), Retherford(1981), or for centralized power generation using a central generating facility to generate power for a network of villages, Retherford(1975). That approach is opposite to the one taken in this study. They proposed inter-tying the villages to warrant a large generating facility, instead of developing a small generating facility. Although the central generation proposal has the advantage of using a conventional-sized system, the inherent problem associated with such generation is the high expense involved in providing a reliable power-line network.

In chapters 3, 4, and 5 is a discussion of the various components which were considered for use in the proposed systems for rural Alaska. Included in this discussion is an explanation of how they work, and how the components might be put together to generate power.

3.0 COAL GASIFICATION

Coal Gasification can be defined as the conversion of coal, a solid hydrocarbon, to a gaseous fuel. For use in rural Alaska, this gas could then be combusted in a spark-ignited engine to drive an electric generator. Generally, this gasification involves the controlled, partial oxidation of the coal to convert it into the desired gaseous product. The heating of this coal is usually by direct combustion, but other methods such as recirculated hot char or ash, nuclear waste heat, or the use of an electric current have been tried.

There are several types and configurations of reacting systems which may be used for this conversion. These include reactors (herein called gasifiers) which operate on a batch basis as well as those operating on a continuous or semi-continuous flow basis. Commercial systems nearly always utilize continuous flow reactors, although there is no intrinsic reason why a large number of batch reactors, operating on staggered cycles, could not work. In general, batch reactors are limited to experimental or research uses, as most commercial applications of a fuel gas require it on a continuous, or nearly continuous basis.

The disadvantages of batch reactors include: (a) it is usually more expensive to purchase many small units instead of a single large one, (b) the efficiencies of small units are almost always lower, (c) the maintenance of many gasifiers would be increased, and (d) it becomes an operationally complex system.

Coal gasification is a technique for converting coal to an environmentally acceptable gaseous fuel or to chemical feedstocks. The technology for it dates back to 1620, Miller(1980). Most research and development, and production of gasifiers was halted in the early 1950's when large quantities of cheaper natural gas became available.

There are three basic types of reaction systems used in coal gasification: the fixed/moving bed system, the fluidized bed system, and the entrained bed system. Although most gasifiers are classified by one of these three types, gasifiers of the same general type differ significantly in the heating values of the gas produced. There are three classifications of the produced gas, labeled high-, medium-, and low-Btu gas.

High-Btu gas is a substitute natural gas, with a high-heating value above 900 Btu/scf (38 MJ/m3) and a carbon monoxide content less than 0.1%. This gas can be mixed directly with natural gas or used as a substitute for it. Medium-Btu gas is a fuel gas with a high-heating value in the range of 200 to 500 Btu/scf, with an average of 300 Btu/scf (12 MJ/m3). Low-Btu gas is a fuel gas with a heating value of approximately 150 Btu/scf (6 MJ/m3). It is rarely economical to transport Low-Btu gas for anything but a very short distance because of the low heat output per volume of gas and the high cost of piping gaseous materials.

3.1 FIXED/MOVING BED GASIFIER

In a Fixed Bed Gasifier the coal feed is sized to between 0.25 and 1.5 in. (0.64 and 3.8 cm.) and fed into the gasifer through the top of the unit. The coal moves downward through the gasifier, devolitizing and then gasifying. Steam as well as air and/or oxygen is fed into the gasifier near the bottom of the unit, and flows counter-current to the coal, providing oxygen for the combustion of the coal char and steam for steam-carbon and water shift reactions, Stewart and Klett(1979).

Within the gasifier, a definite temperature profile exists, as shown in Fig. 1. In the bottom of the bed, in the combustion zone, the temperatures are the highest, with temperatures between 2000F and 2200F (1365K to 1475K). The temperatures become progressively cooler, passing through the gasification zone and into the devolitization zone. The gas, as it leaves the gasifier will range between 900F and 1200F (755K to 920K) depending upon the properties of the coal that is used and the conditions under which the gasifier is operated. In some gasifiers, a mechanically driven and possibly water cooled rotary grate is used to aid in the removal of ash from the gasifier. There are two classifications into which the gasifier can be further broken down. These are single-stage and two-stage gasifiers. In a single-stage gasifier, the product gas and devolitized gas exit through a single gas outlet, while in

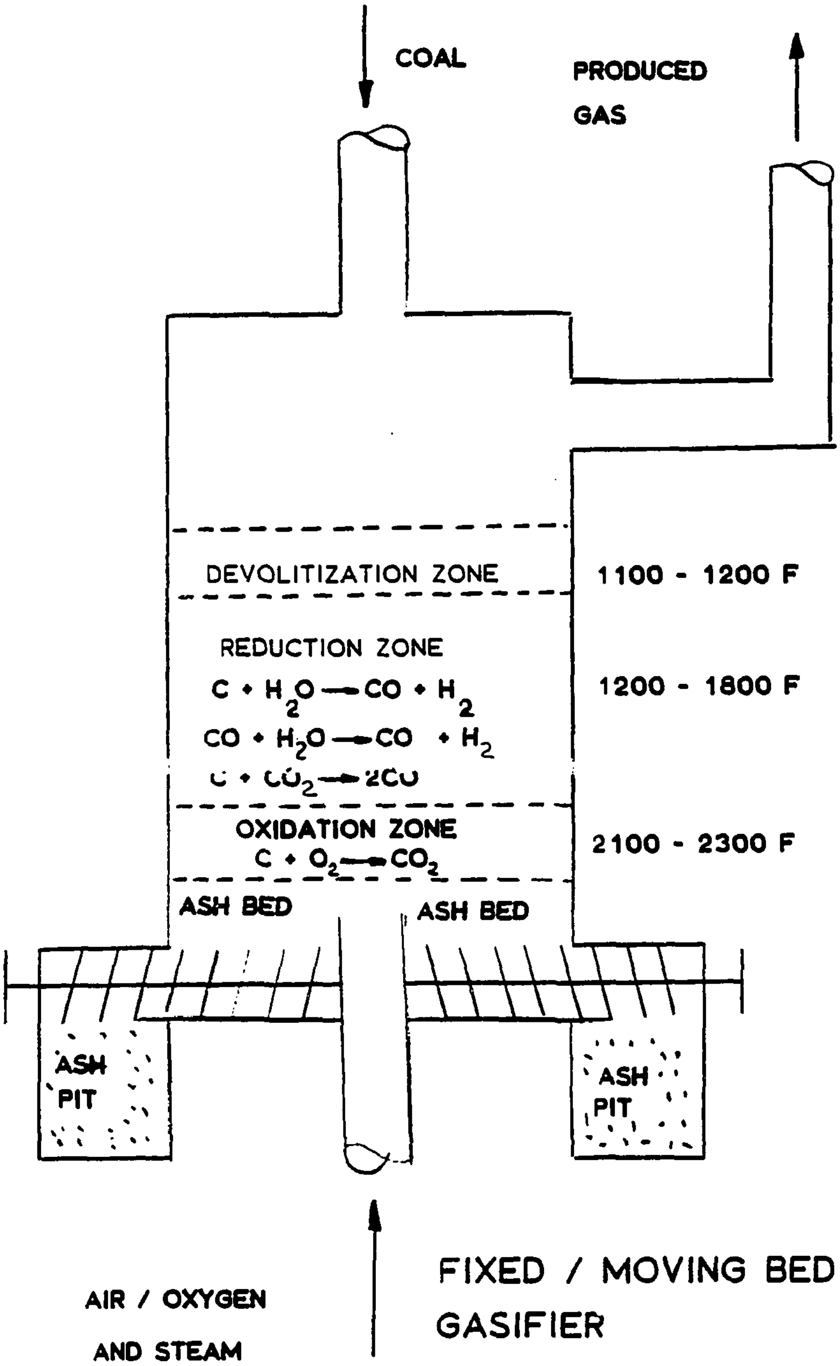

COAL
PRODUCED GAS
DEVOLITIZATION ZONE
1100 - 1200 F
REDUCTION ZONE
$C + H_2O \rightarrow CO + H_2$
$CO + H_2O \rightarrow CO + H_2$
$C + CO_2 \rightarrow 2CO$
1200 - 1800 F
OXIDATION ZONE
$C + O_2 \rightarrow CO_2$
2100 - 2300 F
ASH BED
ASH BED
ASH PIT
ASH PIT
AIR / OXYGEN AND STEAM
FIXED / MOVING BED GASIFIER

FIGURE 1

the two-stage gasifiers they exit through separate outlets.

The Fixed Bed gasifier (FBG) has several advantages compared with the other two systems. These include a high carbon conversion efficiency which leads to a large Btu-output per unit of coal consumed. This would reduce the fuel cost of the system. The system has the best turndown ratio and it is easier to operate than other types of gasifiers, Stewart and Klett(1979). Also, it has a low ash carryover from the gasifier to the fuel stream, Miller(1980). This results in a low cost for fuel gas scrubbing. The FBG has a relatively low operating temperature in comparison with the other gasifiers. This leads to less materials problems, less heat loss to surroundings, and less wasted heat in the producer gas (unless heat recovery is used in the high-temperature gasifiers), resulting in a higher thermal efficiency. A final advantage is the low air/oxygen requirement of the FBG system, which reduces the energy required to produce the oxygen and the size of the required oxygen plant (assuming oxygen is used). This also results in a reduced cost of compressing large volumes of gas for injection into the gasifier, Miller(1980).

One of the disadvantages of this gasifier is that either briquetting equipment is required, or coal fines less than about 0.08 in. (2mm) cannot be used. This is because they are not of sufficient mass to be carried downward, against the upflowing gasses, into the combustion zone and out as ash, but they are carried upwards and mixed with the product gas, which is undesireable.

Unwanted by-products of this system include phenols, tars and heavier hydrocarbons. These by-products must be removed from the gas prior to its use. In addition to these by-products, this system has a high steam consumption, which has a high energy cost and reduces efficiency. Also, unless the gasifier is operated at an elevated pressure, the capacity of this gasifier is relatively small.

3.2 FLUIDIZED BED GASIFIER

In a Fluidized Bed gasifier, as shown in Fig. 2, the coal is sized smaller than that which is used for the fixed or moving bed gasifiers. The size of coal fed into the gasifier in the range of 20 to 10 mesh, which is 0.03 to 0.07in. (0.8 to 1.7mm). A fluidized bed operates much like an air-popper popcorn popper. In the bed, the gas flows upward at a velocity slightly above that required to support the coal particles. At this velocity, the coal particles are kept in a constant state of agitation by the stream of hot gas passing upward through a grid plate in the bottom of the gasifier. The solids appear as a bubbling fluid, which justifies its name, "Fluidized Bed". Because of this mixing, the gasifier operates in a nearly isothermal state, in contrast with the fixed bed. The smaller sized coal feed results in a reaction rate for the fluidized bed which is much greater than that of the fixed bed. Thus, the capacity of a fluidized bed reactor is greater than an equivalent sized fixed bed unit.

The relatively short coal residence time within the bed, combined with a high solids entrainment by the effluent gas (20-30% of the carbon is lost by entrainment in the gas and the ash) results in a somewhat lower operating efficiency than for the fixed bed gasifier.

The advantages of a fluidized bed include an excellent solid/gas contact because of the thorough mixing and

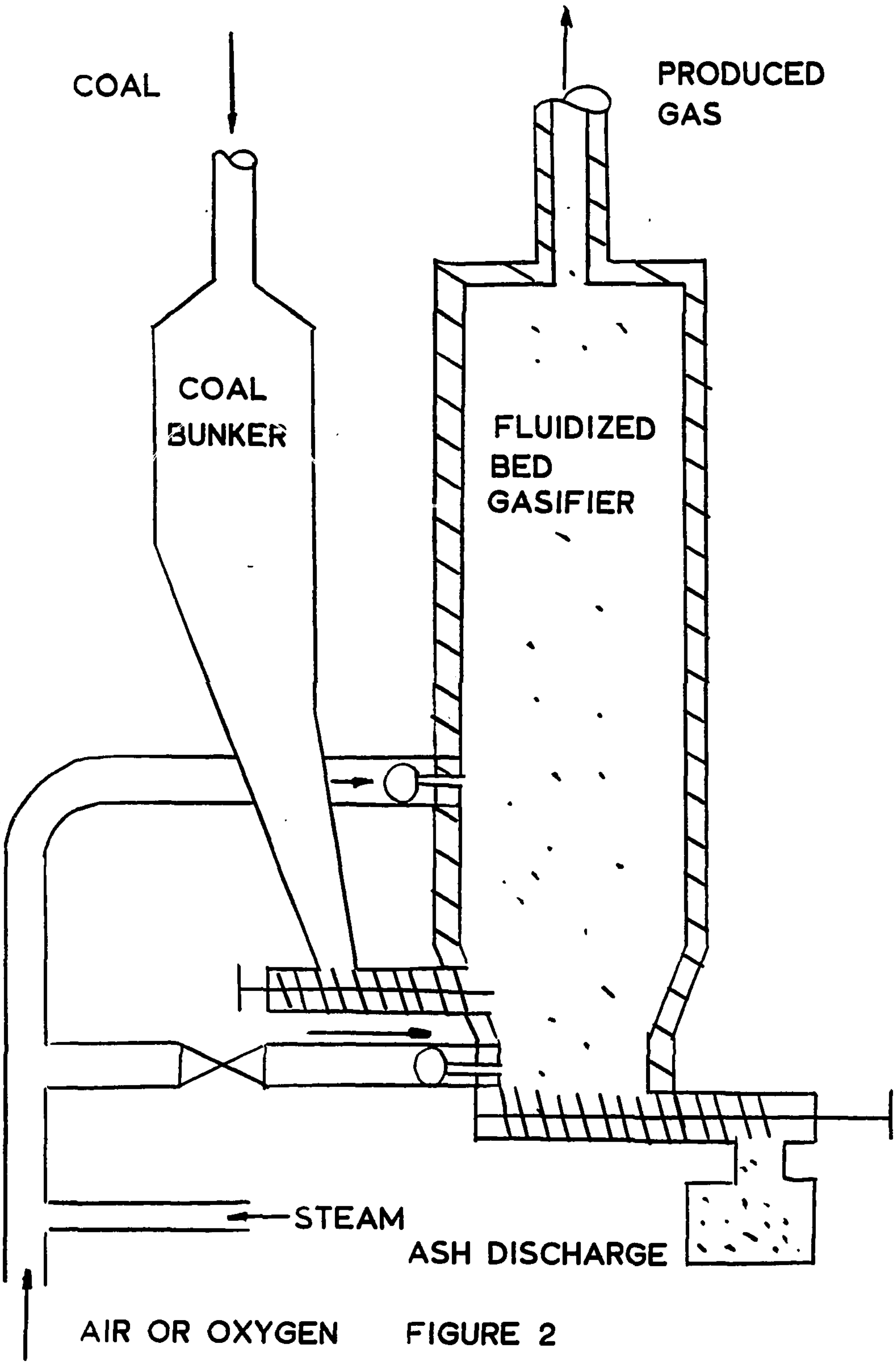

COAL
PRODUCED GAS
COAL BUNKER
FLUIDIZED BED GASIFIER
STEAM
ASH DISCHARGE
AIR OR OXYGEN

FIGURE 2

isothermal bed conditions which results in a lower residence time than a fixed-bed gasifier. This leads to a higher coal through-put per unit volume of reactor. Some of the disadvantages of the fluidized bed are that the coal must be crushed and sized, discarding particles smaller than 20 mesh, and the coal must have a low moisture content, requiring drying before gasifying.

Because there is no "Stirring and Chopping" mechanism within the reactor, caking coals require pretreatment. The high carbon loss with the ash increases the fuel cost of this system. Inasmuch as the gas velocity must be kept slightly above that to merely support the coal particles, the fluidization requirement is sensitive to fuel characteristics (density, particle size, etc.).

3.3 ENTRAINED BED GASIFIER

In the entrained bed gasifier, as shown in Fig. 3, finely pulverized coal is carried into the reaction chamber by a stream of steam and air (or oxygen). The coal, prior to injection, is pulverized to sizes approximately 70% smaller than 200 mesh, or 0.003 in. (0.075mm), providing for a high rate of reaction and ease of entrainment. In these systems the large surface area to mass ratio (because of the small particle size) of the coal and the increased retention times intensifies combustion within the bed. The temperature of the carrier air and the degree of dispersion of the fuel within the bed are also important. In present day practice of burning of pulverized fuel, the coal is introduced at high velocities, Hoffman(1978). These velocities may be greater than 100 ft/sec (30 m/s), and involve expansion from a jet into the combustion chamber.

The limiting factor for the conversion of coal into gas is the short residence time, a few seconds, which the coal is in the gasifier. To increase the extent of conversion in a single-stage gasifier, the gasifier is operated at a temperature of 3000F to 3500F (1920 to 2200K). The temperature of the gas leaving the gasifier is about 2700F (1755K), Stewart and Klett(1979).

An advantage of the entrained bed system is that it has the ability to handle all types of coal, including untreated highly caking coal. The small size of the coal which is

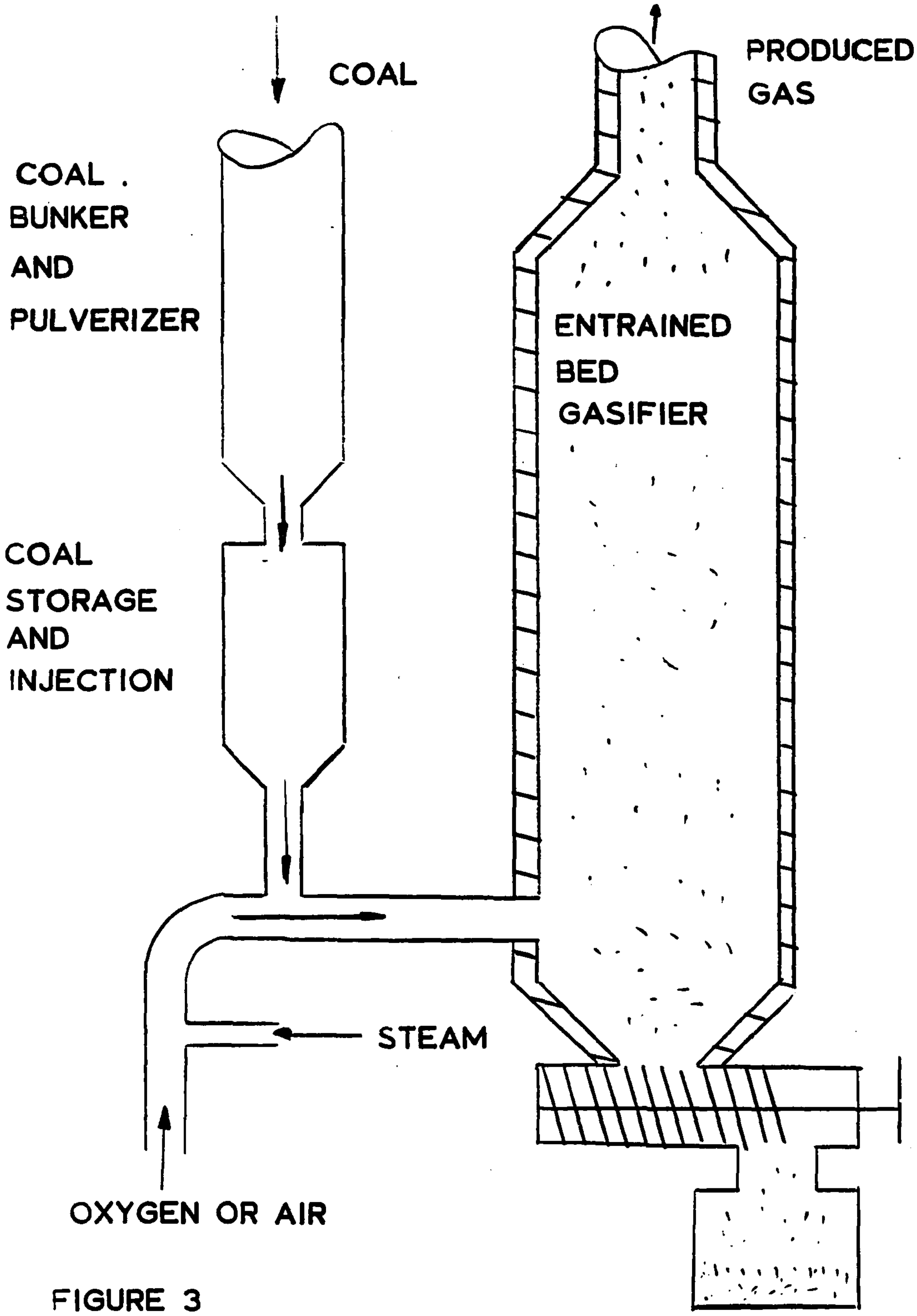

COAL
PRODUCED
GAS
COAL .
BUNKER
AND
PULVERIZER
ENTRAINED
BED
GASIFIER
COAL
STORAGE
AND
INJECTION
STEAM
OXYGEN OR AIR

FIGURE 3

used means that no briquetting (or wasting of fines) is needed as in the fixed bed. The entrained bed also has a low steam consumption and excellant solids/gas contact ratio. There are no tars or phenols formed to cause problems or to require extra equipment for scrubbing and the related expense. The gasifer has the ability to slag its ash, and the ash it produces is inert. The final advantage is its high capacity per unit volume of reactor.

The entrained bed also has several disadvantages. These include a small surging capacity and a requirement for finely crushed coal, which requires additional coal handing equipment.

4.1 STEAM GENERATING EQUIPMENT

The majority of the electrical power produced in the United States is generated by steam power plants using fossil fuels and high speed turbines. The larger of these plants (60-1300 Mw) require 8500-9500 Btu of fuel to generate a kilowatt-hour of electricity, Babcock & Wilcox(1975). These plants use steam driven turbine generators, supplied by boilers which produce from 0.5 to 10MMlb/hr of steam. For use in rural Alaska, two options for steam power plants exist. The first option is coal fired-boiler steam-engine-generator system, and the second is a coal fired-boiler steam-turbine-generator system. The primary components of the system is the steam boiler and the steam engine or steam turbine. The busbar cost of electricity from a power plant is controlled by three factors: (a) capital equipment cost, (b) fuel cost, and (c) operation and maintenance (O&M) cost.

A fuel resource evaluation is needed to determine if there is a sufficient quantity of fuel to last the life of the plant. Also, the quality is important because some equipment (stokers, for instance) is designed to operate only with certain types of coal. The cost of the fuel is important, not only because it directly affects the cost of electricity, but also because high fuel cost can justify expenditure to increase efficiency.

Prior to the selection process for a steam boiler, the steam requirements for the generator must be known. This includes steam flow rate and the pressure and temperature needed at the steam turbine or steam engine and the amount of allowable temperature and pressure variation. Also, the maximum continuous flow, the minimum continuous flow, and the rate of change in flow are important design parameters because the system must be able to handle extreme and varying loads. Other requirements such as feedwater heating must be determined, because these values put an additional load on the boiler or generator, reducing the net power output. Knowing the future requirements allows an economic evaluation to be performed on the selection and sizing of the boiler.

Information on the available raw water is important so that the types of water purification and conditioning equipment can be determined to meet boiler feedwater requirements. It is necessary to determine if any of this purification equipment will require steam from the boiler (or power from the generator), which would require a larger system. The source of the water is perhaps the most important, Matthews(1948). Even a steam power plant operating on a closed cycle requires a supply of makeup water (0.15 to 0.4 lb/hp-hr, Zarling(1982)). A utility system to provide water to the plant or a highly reliable method of water delivery to provide make-up water would be needed.

For use in rural Alaska the geographical considerations are of prime significance. Conventional considerations under this topic include elevation, seismic and wind loadings, geotechnical conditions, climate, and environmental requirements. There are additional parameters that must be addressed when designing for use in rural Alaska. The logistical inaccessibility for service and construction weigh heavily, because of the high cost of "rush" access for equipment. Part of the materials which would be needed for service and repair are likely to be unavailable in Alaska. This requires that they be shipped from the "lower 48" to Anchorage or Fairbanks and then shipped to the rural location, resulting in a time lag. For this reason, spare critical components must be stocked at the rural site.

The type and cost of energy that is needed to drive the auxiliaries such as auger feed motors and water purification equipment must also be included in the economic analysis. Because electrical power may be needed to bring the steam generator on-line, a diesel generator is also needed to bring the steam plant on-line via the "bootstrap" method. The diesels would also provide backup power for the village.

Additional considerations are the experience level of the workmen in operation and maintenance, and the cost of labor. In rural Alaska, the technical expertise of the local labor market is low. Thus, any system requiring a technically trained person requires that either: (a) a rural Alaskan be trained for the job, or (b) a technically trained person be brought into the village and supported there. Either way, this is very expensive and this cost must be included in the cost of the power plant. Guarantees are another consideration. Some companies do not recommend and will not guarantee their equipment for operation in Alaska. With the above information, it is possible to analyze the user's specific needs and coordinate the many components which make up the steam power plant into the most economical design.

4.2 STEAM ENGINE

A steam engine is defined as an engine that produces mechanical energy from heat, using steam as the working fluid. As it is used today, it is applied only to those steam engines of the reciprocating piston-cylinder nature, although technically steam turbines are also steam engines. For use in rural Alaska, the steam to power the steam engine would come from a coal-fired steam boiler, and the power generated by the steam engine would be used to turn an electric generator.

For a single-cylinder, single acting steam engine, steam under pressure begins entering the cylinder when the piston is just past the top dead center position (minimum volume in the cylinder) and pushes on the piston until it is about halfway to bottom dead center. At this time, the steam ceases to enter the cylinder and the steam expands to nearly exhaust pressure. Just before bottom-dead-center the exhaust valve opens, and the engine completes its revolution, expelling the wasted steam as it goes. Just before the piston reaches top dead center, the exhaust valve closes. Shortly thereafter the intake valve opens, allowing the steam to enter again. This cycle continues as long as the engine is operated. The energy which is required to expell the spent steam from the engine comes from a flywheel which receives energy from the cylinder on the down-stroke and releases energy on the up-stroke, expelling the steam.

In a double-acting steam engine, the power needed to expell the spent steam in one cylinder comes from the power stroke in the opposite cylinder. The difference between the energy needed to expell the energy and the energy released in the power stroke is the net energy produced by the steam engine.

Increased efficiencies and power outputs for steam engines are achieved by using them in multi-stage configurations (where the output of one steam engine feeds another) and multi-cylinder configurations.

At one time steam engines supplied most of the worlds power needs, but for the most part, they have been replaced by steam turbines in large applications and by electric motors or internal-combustion engines for small power requirements. In the smaller sizes, the steam engine is often more efficient than the steam turbine, and hence it may be advantageous for use in rural Alaska where relatively small engines are needed.

4.3 STEAM TURBINE

A steam turbine is defined as a machine which receives steam as its working fluid and converts this to rotary motion of a shaft. For use in rural Alaska, the steam would be supplied by a coal fired steam boiler, and the energy produced by the steam turbine would be used to turn an electric generator. Due to the high velocity of the steam in the turbine, the rotational speed of some of the smaller steam turbines exceeds 10,000 revolutions per minute, MacNaughton(1948). Because of their high operating speeds, it was the development of reliable and efficient speed-reduction gears which allowed the steam turbine to be used to drive equipment which requires high torque but operates at a low speed which greatly increased its applicability. The steam turbine has an advantage over the steam engine in that it produces a larger amount of power output for a specific size and weight of equipment. This increased specific power output and its availability in large power outputs make it advantageous, especially for large installations. There are steam turbine-generators in use which generate over 1,000 Megawatts of electricity.

There are two general classifications for turbines. A turbine which receives high pressure steam and discharges it at a pressure greater than atmospheric pressure is a non-condensing turbine. On the other hand, a turbine which expands steam to (at the exhaust flange of the turbine) a pressure less than atmospheric pressure is called a condensing turbine.

5.1 STIRLING ENGINE

The Stirling engine is an external-combustion engine that uses the closed regenerative thermodynamic cycle, with cyclic compression and expansion of the working fluid at different temperature levels, and where the flow is controlled by volume changes, so that there is a net conversion of heat to work or vice versa. The Stirling cycle is a highly-idealized thermodynamic cycle, comprised of four thermodynamic processes. These are (1) isothermal compression, (2) constant-volume regenerative heat transfer (to fluid from regenerator matrix), (3) isothermal expansion process, and (4) constant-volume regenerative heat transfer (from fluid to matrix).

The engine has pistons that move up and down in cylinders, using a fixed volume of a working fluid that continuously flows back and forth between a high-temperature upper cylinder and a low-temperature bottom cylinder. It relies on a continuous heat source to supply energy in the form of heat to the working fluid through the upper cylinder walls. This system has been proposed for use in rural Alaska using a coal fired combustor as the heat source and a fin-fan condenser to condense the gas.

Several engine configurations for accomplishing the Stirling process have been designed, but the most promising are the displacer system and the double-acting system.

In the displacer system, Fig. 4, the rapid heating and

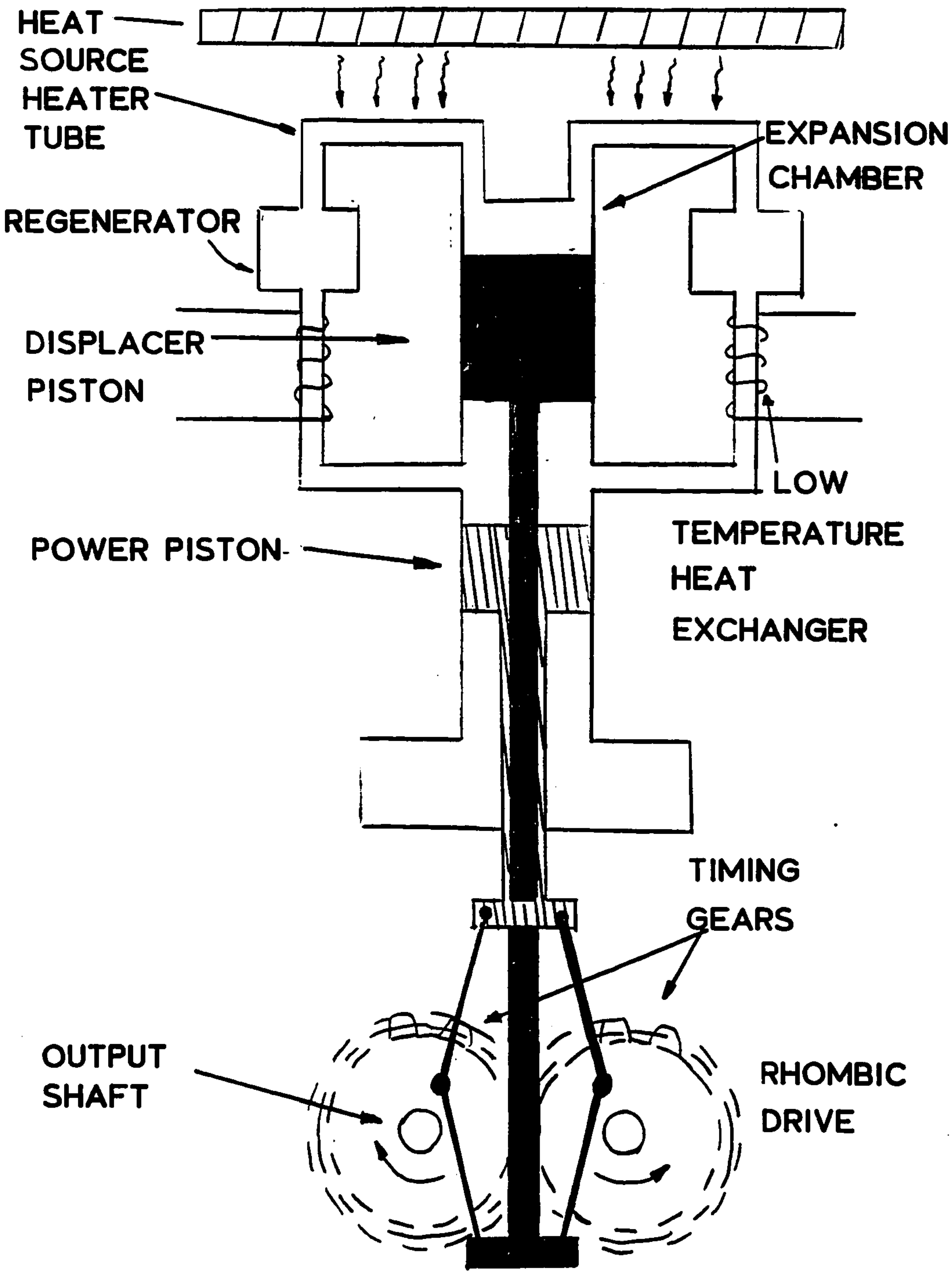

HEAT SOURCE
HEATER TUBE
REGENERATOR
DISPLACER PISTON
POWER PISTON
EXPANSION CHAMBER
LOW TEMPERATURE HEAT EXCHANGER
TIMING GEARS
OUTPUT SHAFT
RHOMBIC DRIVE

FIGURE 4

cooling of the working fluid takes place by means of a two-piston system (one displacer piston and one power piston) that makes the fluid flow back and forth through two heat exchangers, with one at a constant high temperature and the other at a constant low temperature. Between the heat exchangers there is a regenerator to prevent a wasteful loss of heat and increase the efficiency. The largest amount of progress has been made with a displacer system using a rhombic drive for two output shafts, one rotating clockwise and the other counterclockwise.

The double-acting system, Fig. 5, was invented by the N. V. Philips company in Eindhoven, Netherlands about 1942. In a double-acting engine, the top of each cylinder is at a high temperature and the bottom of each double-acting cylinder is at a low temperature. The high-temperature region of a cylinder is connected to the low-temperature region of an adjacent cylinder through a regenerator. The pistons in the cylinders move with a suitable phase-shift between them. For a four cylinder engine, the shift is 90 degrees.

An advantage in using Stirling engines in certain areas of rural Alaska exists because of the low ambient temperature. Because this engine operates on a temperature differential, the lower the temperature of the low-temperature heat exchanger the higher the efficiency. Assuming that a fin-fan cooler was used, the low ambient temperature in the

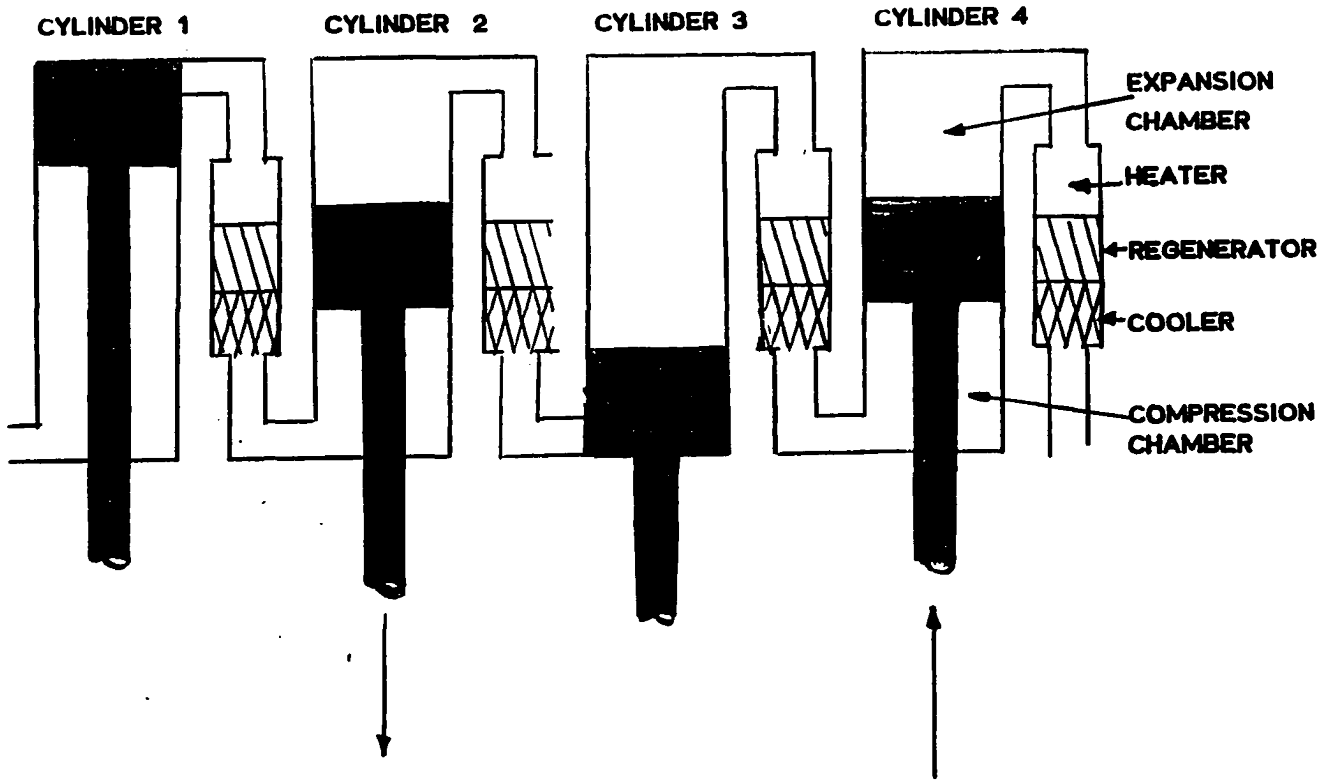


FIGURE 5 DOUBLE-ACTING STIRLING ENGINE

winter would aid in winter power production, when it is needed most. Also, the large amount of heat dissipated into the low-temperature heat exchanger may, if carefully designed, provide heat for heating purposes and possibly for pre-heating utility water prior to distribution to prevent freezing (in villages so equipped).

Unlike gasifiers (which inject steam into the combustion chamber) the amount of water vapor that is given off in the exhaust stream is relatively small. This is advantageous where the unit is to be operated in an area that is plagued with ice fog in the winter. By reducing the amount of water released into the air, there is less moisture available for fog formation. In fact, water is not needed at all, except possibly as a heat transfer fluid in the low temperature exchanger. This is advantageous because water is very expensive in rural villages where water aquisition is difficult.

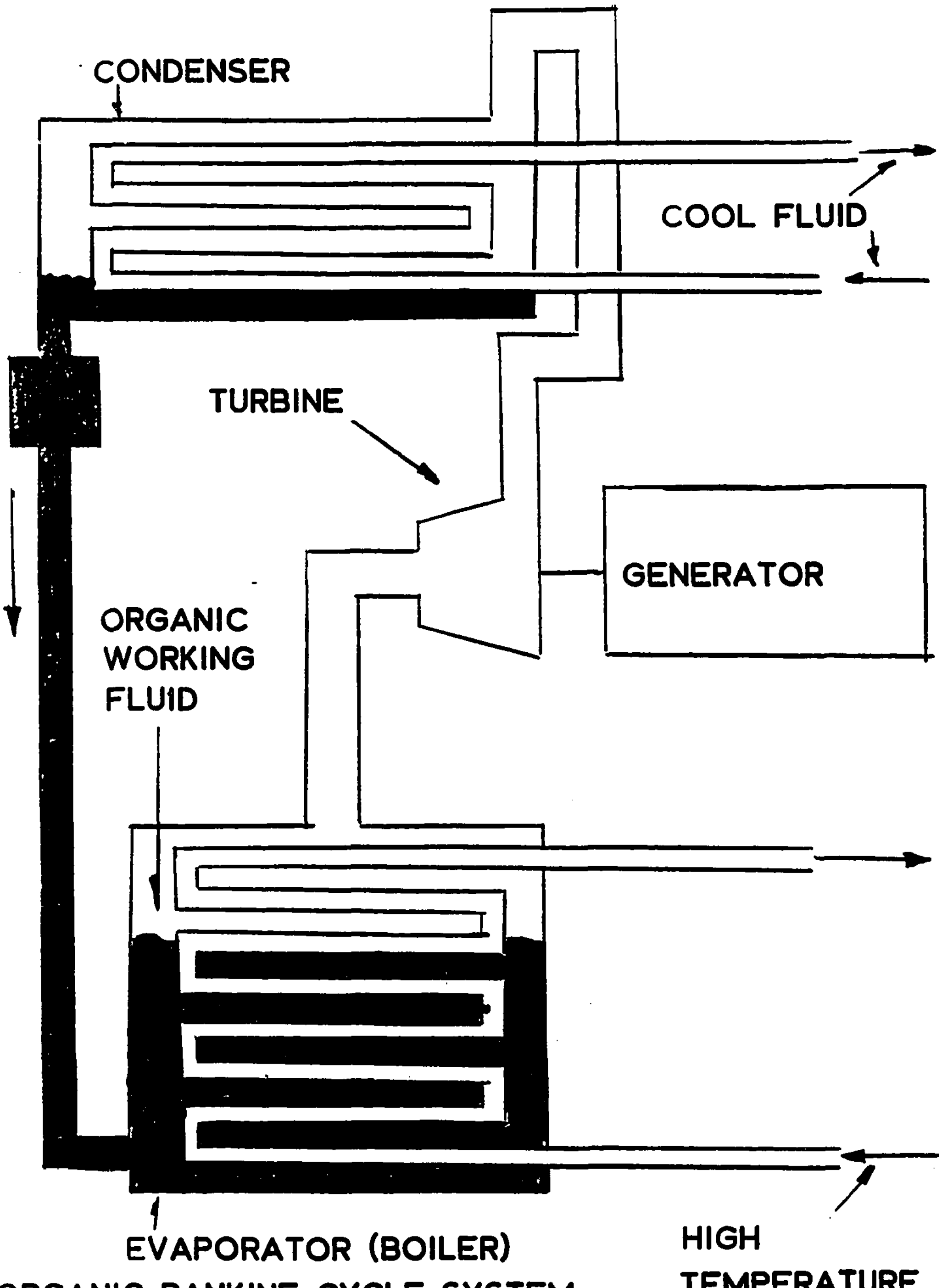
The Stirling engine also has good part-load economy and an excellant part-load torque characteristic which would be advantageous because the unit may not always be operated at full load. Unfortunately these engines are costly and complex. While cost and complexity are important, the latter is the one that causes the biggest problem for use in rural Alaska. Although cost is an important criteria, the most important aspect is for the unit to be highly reliable so the village has power. The more complex the system, the greater the skill level required for repair, which will not usually be available locally.

Although the Stirling engine operates on a closed cycle, a certain amount of leakage of the working fluid will occur around the seals. This will require injection of make-up working fluid. If the working fluid were helium or hydrogen, it would be expensive and possibly difficult to get in rural Alaska, but if the working fluid were air the working fluid would be free and plentiful. Because of the differences in the working properties of the gasses, the primary reason for the shifting of the working fluid from air to hydrogen or helium is to increase the specific power output, and because a high specific power output is not important for this use, the use of air as a working fluid would seem logical.

5.2 ORGANIC RANKINE CYCLE TURBINES

There are many industrial processes in which high quality heat energy is rejected into the environment. In certain cooling processes, such as those in petrochemical refineries, many millions of BTU's per hour are rejected to cool liquids or gasses. This energy has the potential of being tapped for the generation of electrical power at a zero fuel cost.

The Organic Rankine Cycle Turbine is being considered for use in rural Alaska for electric power generation. The turbine would be used to turn an electric generator. A company by the name of Ormat Turbines Ltd. was formed in 1965 for the development, manufacture and marketing of Rankine cycle, organic motive fluid-turbine driven systems to generate electrical power. The Organic Energy Converter (or O.E.C.) is comprised of a vapor generator, a turbine, a feed pump for circulation of the motive fluid, a condensor and the necesary instruments and controls, as shown in Fig. 6. The organic motive fluid (or working fluid) is heated in the vapor generator until it is vaporized. The vapor is expanded through a nozzle, causing the turbine wheel to rotate, turning the electrical generator. Having passed through the turbine, the vapor continues into the condenser where it is condensed. Assuming that a fin-fan cooler is used to condense the vapor, the relatively low ambient winter temperatures will aid in the dissipation of this



ORGANIC RANKINE CYCLE SYSTEM

FIGURE 6

heat. This will increase the capacity of the system when it is needed most. At this point it is pumped from the condenser to the vapor generator for re-vaporizing. This cycle continues indefinitely as long as the heat is supplied to the vapor generator and allowed to be rejected through the condenser. The system is sealed (closed) so none of the fluid is lost. The power output is controlled by regulating the quantity of heat applied to the vapor generator. In some of the systems, the heat source is waste heat, while in others it comes from combustion.

5.3 GAS TURBINES

An open cycle external combustion gas turbine is one option which is being considered as a prime mover for electrical power generation in rural Alaska. A gas turbine is generally operated as an internal combustion engine which generates power by compressing a gas (usually air), adding heat to the gas (usually by burning fuel), and expanding the gas, using rotating machinery which carries this process out on a continuous basis. This is in contrast to the gasoline and diesel internal combustion engines which operate on an cyclic (reciprocating) basis.

The simplest and most common of the cycles for the gas turbine is the open cycle. In this process, ambient air is drawn into the compressor, and compressed. This compressed air passes through a combustion chamber where fuel is mixed with the air and combustion takes place. (In contrast, in an external combustion gas turbine, the fuel is not mixed with the compressed air, but the air is indirectly heated using a heat exchanger and combustor.) The hot, compressed air leaves the combustion chamber and passes through a turbine, which extracts work from the gas. The turbine is able to extract more energy from the hot gas than went into compressing the cool air. The turbine supplies the work which is necessary to run the compressor and the energy which is left over is the net work output of the turbine. The pressure ratio of the compressor and the ratio of the turbine are essentially equal (the pressure drop through the combustor is negligible).

In the closed cycle gas turbine, there is a gas which is contained within the system at all times. This gas is compressed, heated in a heat exchanger using heat from a heat source, expanded in a turbine, and then heat is rejected from the discharge of the turbine (using another heat exchanger) prior to re-compressing. The working gas is chosen for its thermodynamic properties to deliver power.

Because the moving parts of a gas turbine rotate instead of reciprocate, the acceleration of its parts is negligible in comparison, and the machine can operate at much higher rotational speed than its reciprocating counterparts. For this reason, it has a much higher specific power output than other internal combustion engines.

The major disadvantage of the gas turbine is its low fuel efficiency. The blades of the expansion section are continuously exposed to the highest temperatures of the system, unlike the reciprocating ones which alternate between the high temperature state immediately after combustion and the low temperature state whenever the engine takes in another charge of air. As a result, the gas turbine cannot tolerate as high a temperature as the reciprocating engine. Therefore, the laws of thermodynamics show that the maximum theoretical efficiency of a gas turbine will be lower than that for a reciprocating engine. Also, the gas turbine is a poor part-load engine because its efficiency falls off very quickly when it is operated in a part-load condition, McAllister(1956). This is a result of the reduced pressure ratios and temperatures under part load.

5.4 DIESEL ENGINE

In construction, the diesel engine resembles the conventional gasoline engine. The diesel, however, is characterized by relatively heavy parts and slow operating speeds. This is the type of system used in rural Alaska today for the generation of electrical power. The diesel engine is used as a prime mover to turn an electric generator. It operates on a cycle consisting of compression of air in the cylinder, injection of fuel into the cylinder, combustion, expansion of the hot gases, and exhaust. The cycle then repeats itself, by drawing air into the cylinder for compression. The diesel engine, once running, requires no external source of ignition. When the air in the cylinder is compressed (to perhaps one-sixteenth of its original volume) the pressure rises (to perhaps 30 times its original value) and the temperature rises to a temperature in the order of 1000 F. Thus, when the fuel is injected into the chamber at a high pressure, it ignites spontaneously. Thus, there is no need for external ignition. It also has an advantage in that it can run without supervision, and with little maintenance. For these reasons it is being used for electrical power generation in rural Alaska.

6.0 ANTICIPATED PROBLEMS IN DESIGNING A COAL-FIRED SYSTEM

The first family of problems occurs because of the small scale, which frequently means increased operating expenses and decreased efficiencies. It is also expected that there will be a limited amount of appropriately small commercially available equipment.

The second family of problems deals with the locale for which the system is being designed. First, water in any form may be expensive to deal with in the arctic. Thus, any system which requires the use of water must account for this. Secondly, there is often a lack of technically trained people in the rural parts of Alaska, and unless the system is made to be of a very simple nature a trained person may have to be brought into the village and supported there, or locally hired people sent outside of the village for training.

The third family of problems which are to be expected develop from the need for reliability in the system. This is especially true when the option of gasifying the coal for combustion in the spark-ignited diesel engines is considered. Because any link in the system which breaks may take the rest of the system with it, and the addition of a gasifier to the system adds another potential problem, the gasifier must be highly dependable and reliable.

7.0 POTENTIAL SYSTEMS

There are seven systems which are being considered as options for generating electrical power in rural Alaska. These are: (1) a coal pyrolyzer system which could either be used as fuel for a diesel engine, O'Neill(1971) or as a gaseous fuel for a boiler, which would use either a steam engine or a steam turbine as a prime mover, (2) a coal gasification system, using the fuel gas as feed for a spark ignited engine, O'Neill(1971), (3) a conventional coal fired boiler plant using either a steam engine or a steam turbine as a prime mover, (4) a "package" system supplied by a single manufacturer containing a coal boiler with a steam engine and generator, (5) a fluidized bed combustor using air as the working fluid, and using an air turbogenerator to generate electricity, (6) a coal-fired indirectly heated gas turbine, and (7) a diesel-electric generator set. The diesel electric generator is the option presently being used in rural Alaska. Including it as an option allows a direct comparison between the coal-fired systems and the diesel-fired one.

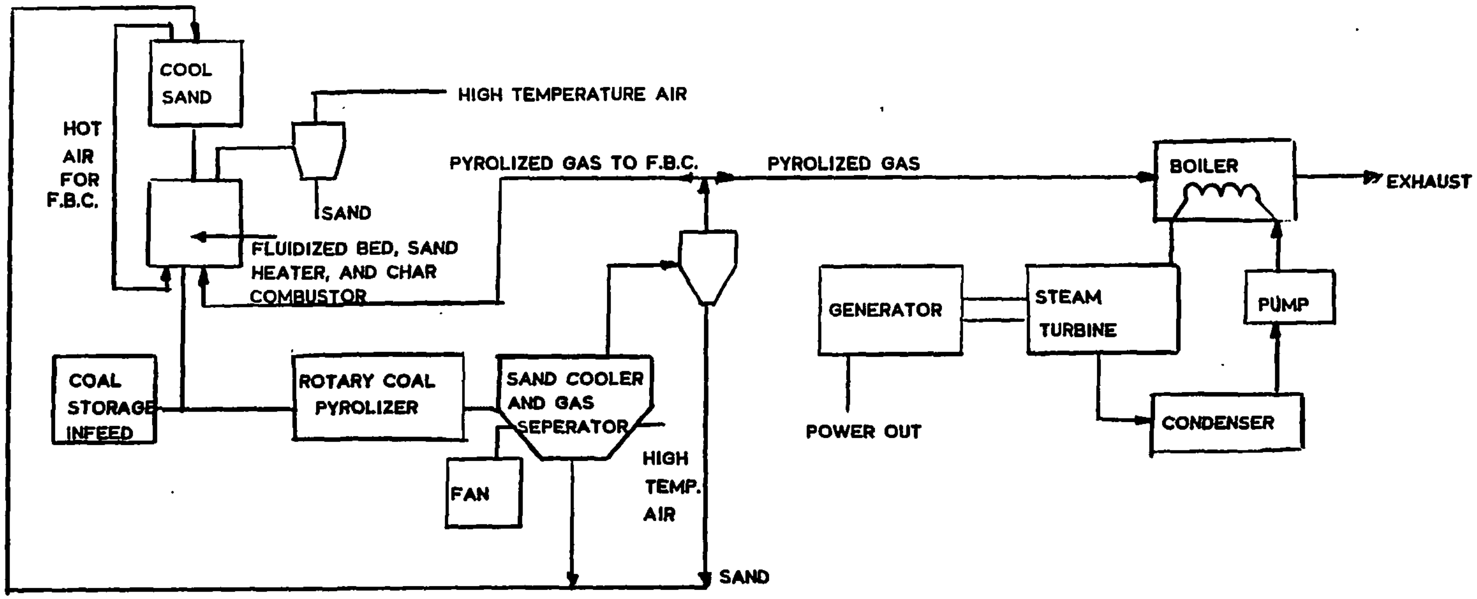
The organic rankine cycle turbine option is not being included in the list of options. This is because the manufacturer (ORMAT) did not send any engineering information on their equipment, but chose to send me a letter informing me that the equipment which they produce of this size in not of sufficient efficiency to be used for this purpose. The manufacturer states that for a system of this size to be economically feasible, the source of energy must be waste heat, and that having to pay for the heat makes the system uneconomical.

The Stirling Engine is also not being included in this listing. Despite the many companies which are doing research on these engines, most of the research is on units of a substantially smaller size. The companies which are doing research on units of this size stated that their units are still in the testing stage and are designed for use with liquid fuel. None of these companies have units near a commercial stage of development.

7.1 COAL-PYROLYZER SYSTEM

Voorheis Industries, Inc., Fairfield, New Jersey manufactures an indirect pyrolyzation system which they have designed to operate using peat as a fuel source, which they felt could be easily adapted to coal. The unit is essentially an indirectly heated coal gasification system, as shown in Fig. 7 and as such, the fuel-gas could be used as a feed for a spark-ignited engine, O'Neill(1971), or as fuel for a boiler. The system uses hot sand as a heat transfer medium for the gasification process. Thus, the gas is not diluted, as it would be if the pyrolization process were directly heated as it is in a conventional gasification system. This provides additional heat transfer when it is used as a boiler fuel gas, not only because of an increased heating value, but also because of an increase in the amount of heat transferred due to radiation.

There are three primary components of this system. The first of these is a fluidized bed sand heater and char combustor. The sand/char are the waste products from the pyrolyzer (which will be referred to below). The fluidized bed unit combusts the char and uses the heat from the char to reheat the sand to a temperature of 1600 F for the pyrolyzer, and the exhaust gas from the combustor (once passed through a cyclone) may be used as primary air if a boiler is used, or for heating or other purposes if a boiler is not used. The fluidized bed characteristics are taken



VOORHEIS GAS PYROLIZER SYSTEM

FIGURE 7

advantage of, using the velocity of the air in the fluidized bed unit to separate any fines from the reheated sand, and as a method for the removal of the char from the sand. The second of these is the pyrolyzer itself. The pyrolyzer is lined with refractory materials and it is rotated at approximately 2 R.P.M. (to allow for a complete mixing of the sand and coal). It receives a carefully controlled mixture of coal and hot sand at one end and outputs a continuous stream of hot fuel gas, sand, and char from the other. This gas is a combination of the volatile matter from the coal, as well as CO. The char formation is a result of the reducing atmosphere which is present within the gasifier. The third major component is a combination of a separator for separating the gas from the sand/char and a cooler for the sand/char mixture. The waste heat from the sand/char may either be used as secondary air for a boiler, or may be used as a heat source for heating or other applications.

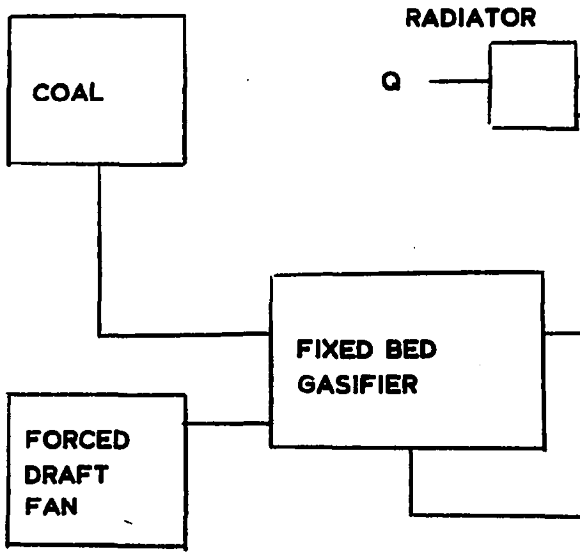
This system is designed to indirectly pyrolyze the coal, using high temperature sand as a heat transfer medium. The pyrolization is done at relatively high temperatures to prevent the tars and oils which are present in the coal from condensing. The hot air from this fluidized bed combustor is used as heated primary air, provided a boiler is used. Other equipment which is used in the system includes cyclones for separating solids from the gas streams, and makeup sand and coal silos, as well as fans, motors, and controls needed to make the system operate.

This concept is quite new, and the company has yet to receive its first contract, but they believe they will receive their first contract this year. They are presently using secrecy agreements with their prospects and declined a request for an approximate system cost but they provided drawings, brochures, and information on the system.

This system is not considered viable at this time, not because of its design, but because the company has yet to receive its first contract for operation.

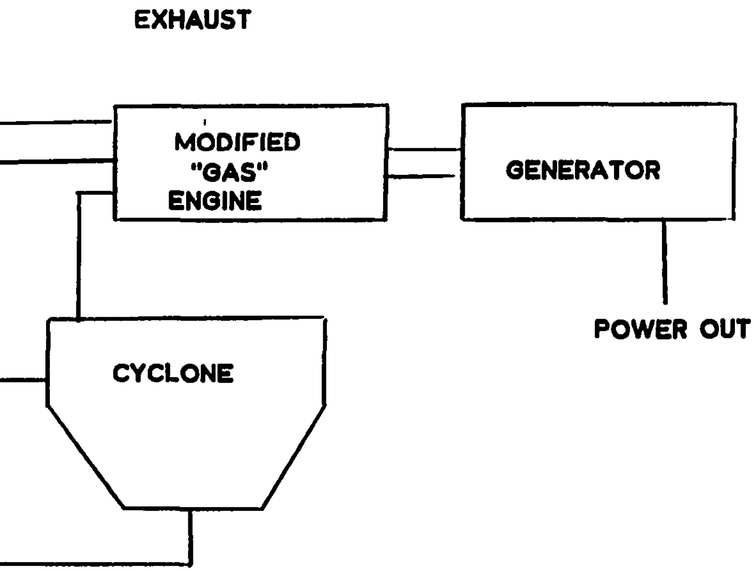
7.2 COAL GASIFICATION SYSTEM

Energy Products of Idaho, Coeur d'Alene, Idaho manufactures a fixed bed gasification system, which they have trademarked the Energas System. These gasifiers could be used to supply a fuel gas to either a spark ignited engine, as shown in Fig. 8, or as fuel to a boiler system. These units are designed to operate using wood as a fuel source, however, they have conducted several successful pilot and commercial tests using coal. The specifications for the gasifer are that it is available with outputs between 1MMBTU/HR and 150MMBTU/HR. The range of sizes for gasifiers of this output is between 2 and 22 feet in diameter. It is designed to use a fuel with a typical moisture content of less than 20% on a wet basis. A cost estimate and fuel comsumption information was promised by the company, but it was never received. For this reason, an economic evaluation on the system can not be run.



ENERGY PRODUCTS OF IDAHO

FIGURE 8



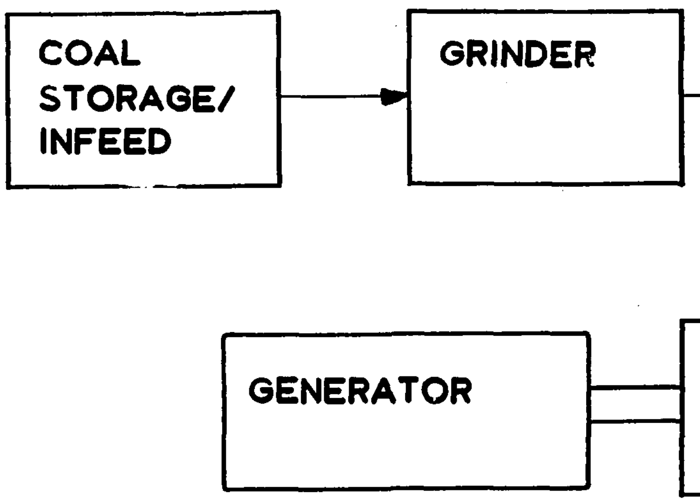
GASIFICATION SYSTEM

7.3 COAL FIRED BOILER PLANT

American Fyr-Feeder Engineers of Des Plaines, Illinois manufactures a Multi-burner Spreader Stoker with a horizontal return water tube (H.R.T.) boiler attached. These units are available for burning either wood or coal and are available in sizes ranging from 7.7 million to 26 million BTU/hr output. The smallest boiler has a furnace volume of 355 cubic feet, and weighs approximately 30 tons with boiler and firing equipment. Also available from Fyr-Feeder is a dumping grate for the system, including a grate-lock assembly, and power dumping of this grate. This would be advantageous in that it would facilitate setting-up the plant for fully automatic operation and reduce the labor requirements.

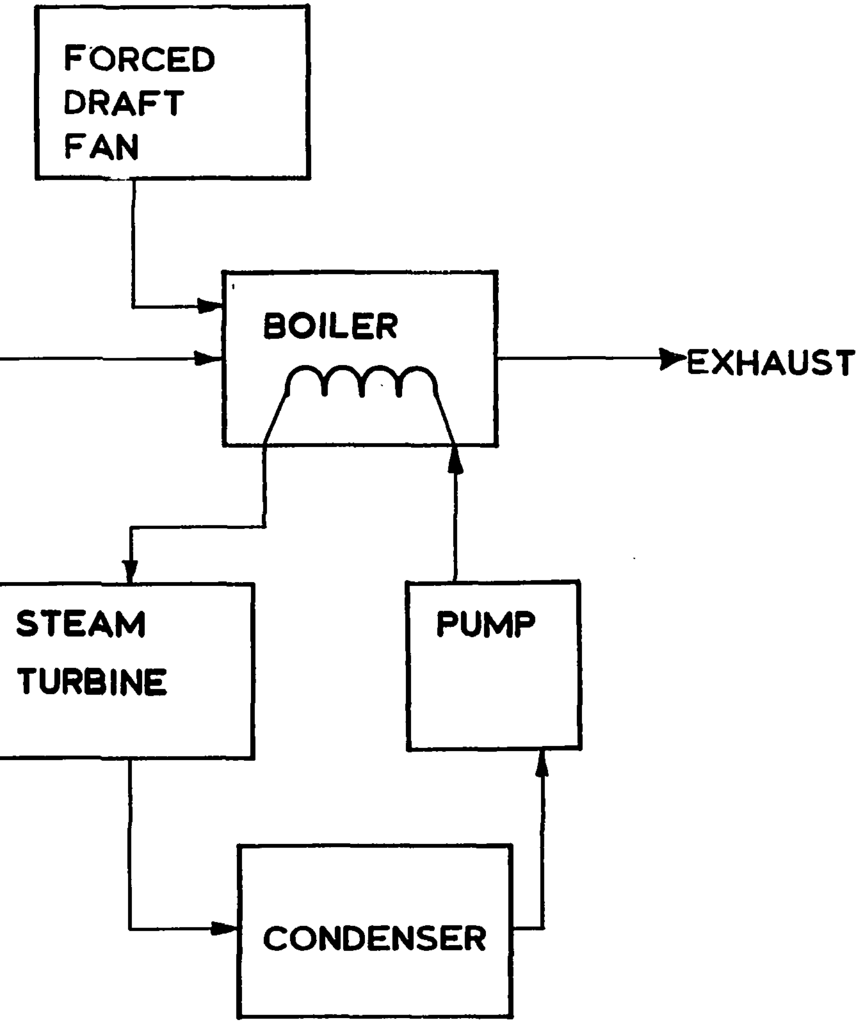
System cost information for this system, although promised, has not been received so it was impossible to do a complete economic evaluation. However, the vendor informed me that the cost of a coal system exceeds the cost of a diesel system by more than a factor of two, so unless the fuel cost for these systems is less than for the diesel, there is no need for further economic consideration of the system.

Calculations will be done for a Fyr-Feeder boiler with a Skinner Steam engine and condenser, as shown in Fig. 9, and for a Fyr-Feeder boiler with a Trane Turbomizer Turbogenerator and condenser, with both operating at 2 psia.



AMERICAN FYR-FEEDER ENGINEERS

FIGURE 9


FORCED
DRAFT
FAN
BOILER
EXHAUST
STEAM
TURBINE
PUMP
CONDENSER

7.4 COAL FIRED BOILER-STEAM ENGINE PACKAGE SYSTEM

Sandley Light Railway Equipment Works of Wisconsin Dells, Wisconsin offers for sale a system which actually contains three systems in one. The system includes three 100kw compound steam engines with generators, and three Johnston coal fired boilers. Included in this system are all of the necessary controls for fully automatic operation, except for coal being delivered to the infeed bin and the ash being removed (whether by a conveyor or by hand) from the ash pit, as shown in Fig. 10. Also included in this system is all of the electronics necessary to intertie the units such that any one, two, or all three of the units may be used simultaneously to generate power. The economic evaluation will include the use of a condenser which is operating at 2 p.s.i.a. to decrease the fuel consumption of the system. The fuel consumption rate for the system is 9,900,000 BTU/hr. Using 8000 BTU/lb coal, this corresponds to 1237.5 lb/hr or 14.85 Tons/day.

System cost information was not received, hence insufficient data was available to run a complete economic evaluation. However, fuel efficiency information is available, so a fuel cost evaluation was performed.

SANDLEY LIGHT RAILWAY EQUIPMENT SYSTEM

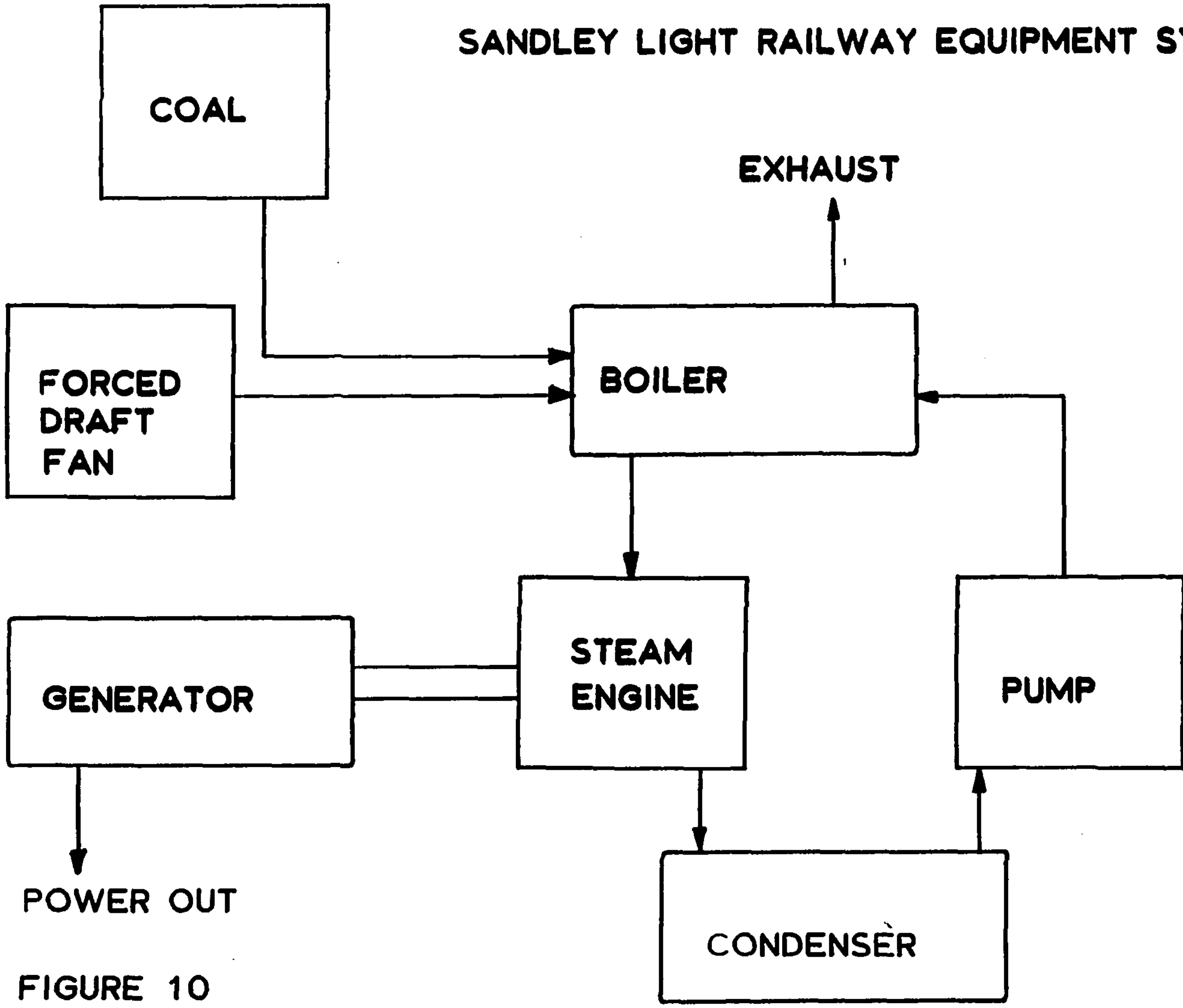


FIGURE 10

7.5 FLUIDIZED BED AIR TURBOGENERATOR SYSTEM

FluiDyne Engineering Corporation of Minneapolis, Minnesota manufactures a fluidized bed combustor which they recommend as part of an external combustion gas turbine system, as shown in Fig. 11. It would be much simpler than a steam system because it would not require a phase change of the working fluid, and once the working fluid (air) had been run through the turbine, it could simply be passed into the atmosphere or, even better yet, be used for heating applications. Their claim is that the hardware is already in existence, is of older design than the steam turbine or steam engine technology, and claim that its maintenance problems should be fewer and simpler.

A cost estimate and fuel consumption information was promised by the company, but it was never received. For this reason, an economic evaluation of this system could not be performed.

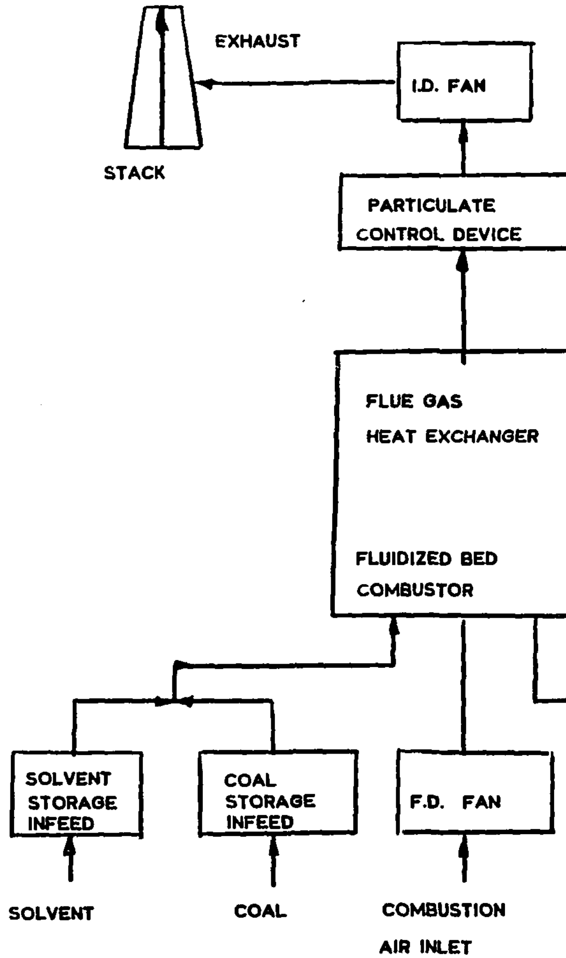
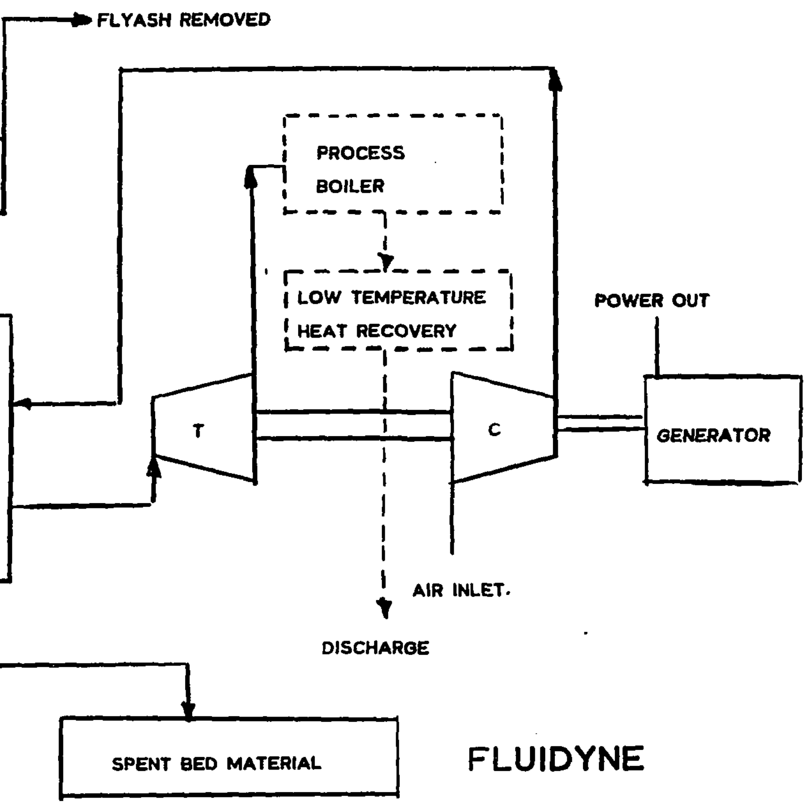

EXHAUST
I.D. FAN
STACK
PARTICULATE
CONTROL DEVICE
FLUE GAS
HEAT EXCHANGER
FLUIDIZED BED
COMBUSTOR
SOLVENT
STORAGE
INFEED
COAL
STORAGE
INFEED
F.D. FAN
SOLVENT
COAL
COMBUSTION
AIR INLET

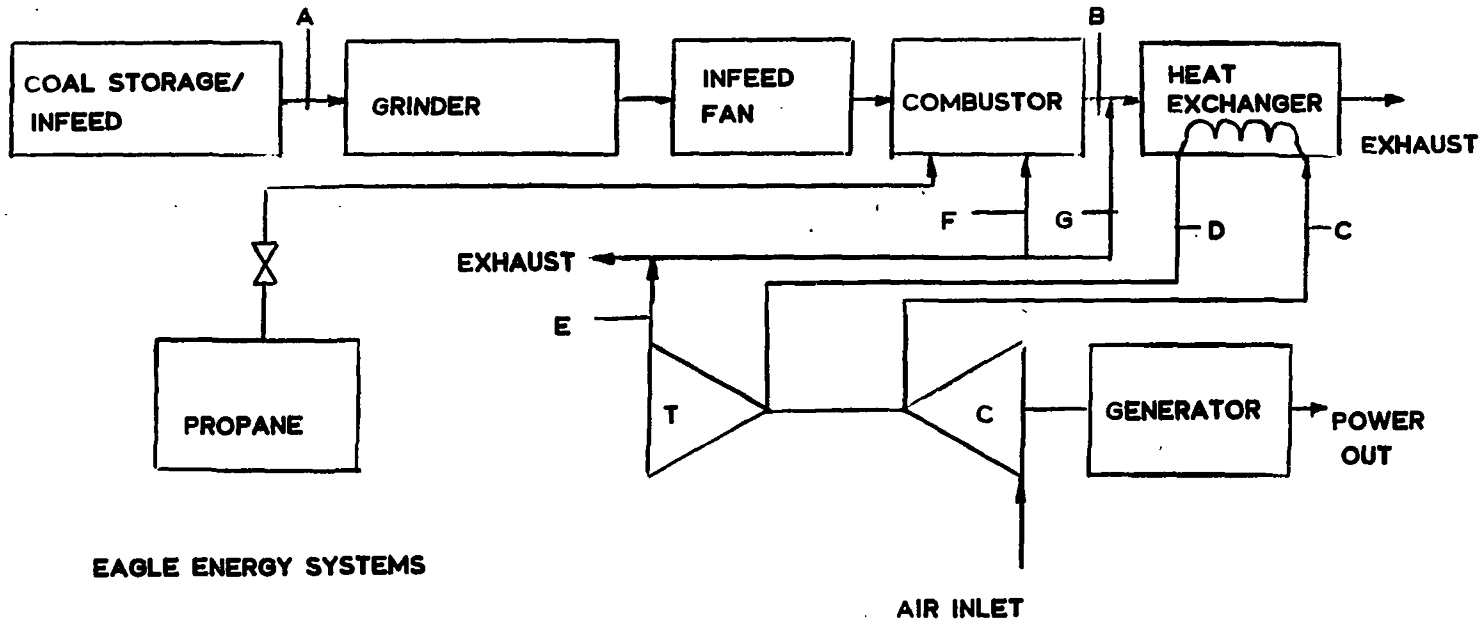
FIGURE 11


FLYASH REMOVED
PROCESS
BOILER
LOW TEMPERATURE
HEAT RECOVERY
POWER OUT
T
C
GENERATOR
AIR INLET.
DISCHARGE
SPENT BED MATERIAL
FLUIDYNE

7.6 COAL BURNING GAS TURBINE SYSTEM

Eagle Energy Systems of Spokane, Washington manufactures a 225kw (200 kw continuous) mobile turbine-generator system which is designed to be mounted on a trailer for portability. A schematic diagram of this system is shown in Fig. 12. They have a prototype of the system under construction at this time, however the system is designed to operate using biomass (wood) as a fuel source. The system has been designed so that changing from biomass to coal feed will require an altering of flow rates so that a smaller fuel (0.10 lb/sec of coal) and air flow would be used. The air exiting the turbine would be approximately 1000 F and a heat recovery system could be installed to remove almost half of the otherwise wasted heat, releasing it to the atmosphere at a temperature of approximately 350 F. Considering that the mass flow rate of the air is about 6 lb/sec, the heat which would be recovered in the heat recovery system would be between 3.4 and 6 MMBtu/hr (depending upon the amount of moisture in the air). Because the cost of the fuel has been included in the economic analysis of the power plant assuming no heat recovery, the incremental cost of heat recovery would involve only the cost of additional equipment and the operation of that equipment.

The output of the generator is 480 volt, 3 phase, 60 cycle A.C. power. The unit is set up with a bin on the



EAGLE ENERGY SYSTEMS

FIGURE 12

front for fuel storage with a capacity of six hours of fuel. For use in rural Alaska, the small bin would be replaced by a large bin having a capacity of at least a weeks supply of coal.

Because the prototype for the biomass system is presently under construction, and as such the only available price is the price for the prototype unit, it is difficult to make an accurate price assumption. However, Gene Johnson, a systems engineer for Eagle Energy Systems informed me that the price for the prototype biomass system was $600,000 and that for a coal operated system, using later models; the cost would be approximately $1,200 per KW (installed) which comes to a total of $270,000 for the system. There is, however, a parasitic 60 hp load for the grinder, auger, and induced draft fan which would have to be deducted from the power output in the economic analysis. The system life should be 10 years, except for the heat exchanger which would require replacing after 5 years.

Complete information on this system was received and an economic evaluation was performed based upon the purchase of two units, one unit to be operated and the other on standby.

7.7 DIESEL ENGINE GENERATOR SYSTEMS

Caterpillar Tractor Company of Peoria, Illinois manufactures the diesel engine generator system, as shown in Fig. 13. The unit is a model 3304T, rated at 100KW, with a purchase cost of $25,000, F.O.B. Fairbanks. A system consisting of four engines (two operating and two on standby) would require purchasing the necessary switchgear for intertieing the units costing approximately $24,000. Thus, the total system cost would be about $124,000. An estimated fuel consumption rate is .1 gallon/hr per KW, down to 20 KW.

Complete information on this sytem has been received and a complete economic evaluation has been performed. This system was evaluated first, to ease economic comparison with the other systems.

CATERPILLAR DIESEL SYSTEM

CATERPILLAR DIESEL SYSTEM

CATERPILLAR DIESEL SYSTEM

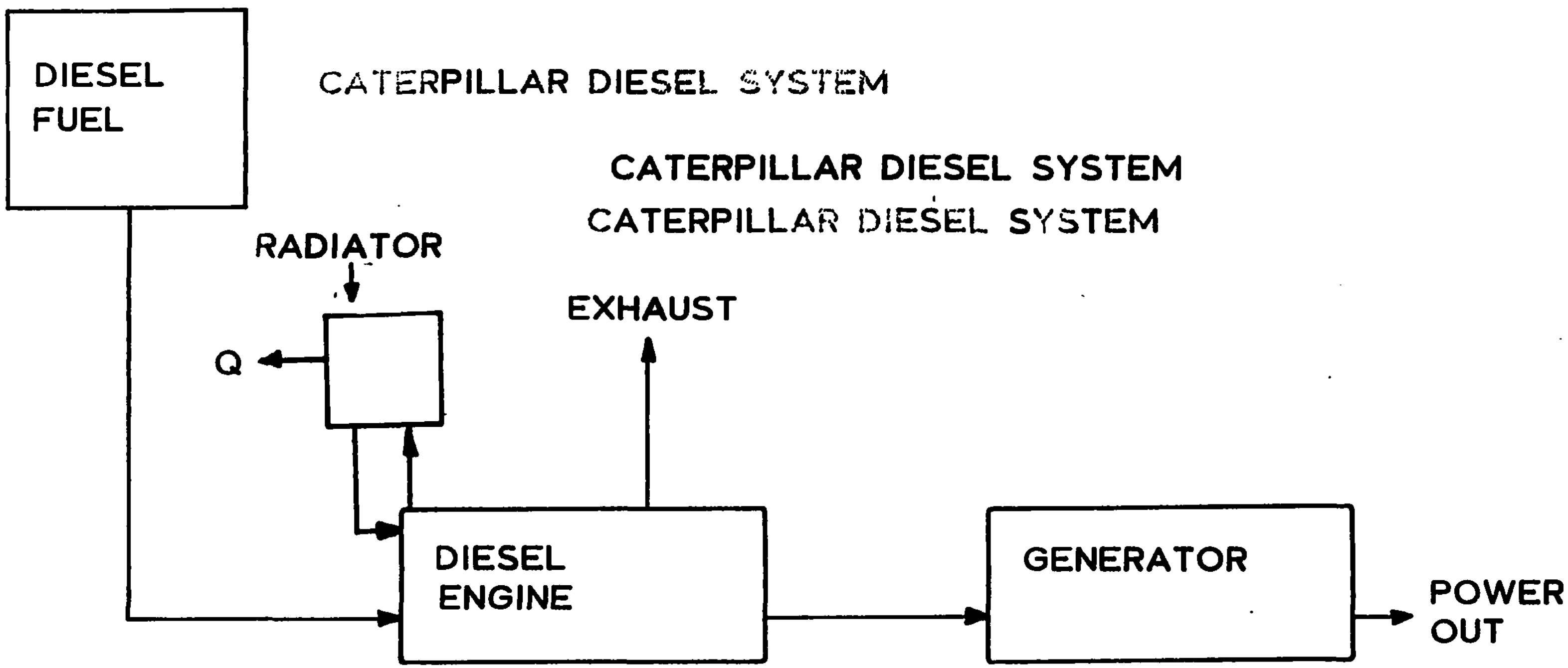


FIGURE 13

8.0 CONCLUSIONS

Due to the lack of availability of equipment and the hesitancy of some manufacturers to provide estimates of system costs, there were only 4 systems (in addition to the diesel system) for which it was possible to do fuel consumption and cost evaluations. Of these, there was only one system where sufficient information was available to do an overall economic analysis.

For three of the systems, although the equipment cost was not available, the vendor stated that the capital cost of a coal system is more than twice the cost of a diesel system. Thus, unless the fuel cost of these systems is less than the fuel cost of the diesel system, the system is not economically feasible. All three of the steam systems had a fuel cost which was greater than the cost for the diesel system, as shown in the following charts, hence they are not economically feasible.

The fourth system, which is an external combustion gas turbine power plant manufactured by Eagle Energy Systems, is economically feasible, as shown in the following charts. There is no provision for labor in the economic analysis. The manufacturer states that although there must be an operator on-duty at all times when the plant is running, this is simply for safety's sake, as the plant is automated. He also states that the system will require less maintenance than the present diesel power plants, hence the system would not require additional labor. The calculation has been performed with the assumption that an operator would be on-duty 24 hours per day for operation and maintenance of either system, so there would be no additional cost. Nome Utilities presently employs two operators and two maintenance men during the day, and operators on-duty all night for their diesel system, so this assumption is not without basis.

Although the cost of diesel fuel in Nome is lower than in most rural areas of Alaska, the Eagle Energy System's coal fired external combustion gas turbine appears advantageous compared with the diesel power plants which are presently being used in Nome for electrical power generation.

At 10.5% Interest

	EQUIPMENT COST	FUEL/DAY	ANNUAL COST/KW
DIESEL	$124,000	$616.80	$ 1,305.06
EAGLE ENERGY SYSTEM	$996,000	$259.20	$ 1,181.86
FYR-FEEDER W/SKINNER STEAM ENGINE	*	$806.40	**
FYR-FEEDER W/TRANE STEAM TURBINE	*	$846.45	**
SANDLEY LT. RAILWAY "PACKAGE" BOILER STEAM ENGINE	*	$891.00	**

Based upon April, 1982 costs for Nome, Alaska.

Diesel Fuel (#1 Heating Oil) at $1.24/gallon.

$60/ton for 8000 Btu/lb coal.

Life Expectancy: Diesel System - 5 years

Coal System - 10 years

*Equipment costs greater than $250,000

At 14.0% Interest

	EQUIPMENT COST	FUEL/DAY	ANNUAL COST/KW
DIESEL	$124,000	$616.80	$ 1,325.96
EAGLE ENERGY SYSTEM	$996,000	$259.20	$ 1,205.51
FYR-FEEDER W/SKINNER STEAM ENGINE	*	$806.40	**
FYR-FEEDER W/TRANE STEAM TURBINE	*	$846.45	**
SANDLEY LT. RAILWAY "PACKAGE" BOILER STEAM ENGINE	*	$891.00	**

Based upon April, 1982 costs for Nome, Alaska.

Diesel Fuel (#1 Heating Oil) at $1.24/gallon.

$60/ton for 8000 Btu/lb coal.

Life Expectancy: Diesel Plant - 5 years
Coal Plant - 10 years

*Equipment cost greater than $250,000

At 17.5% Interest

	EQUIPMENT COST	FUEL/DAY	ANNUAL COST/KW
DIESEL	$124,000	$616.80	$ 1,347.35
EAGLE ENERGY SYSTEM	$996,000	$259.20	$ 1,229.16
FYR-FEEDER W/SKINNER STEAM ENGINE	*	$806.40	**
FYR-FEEDER W/TRANE STEAM TURBINE	*	$846.45	**
SANDLEY LT. RAILWAY "PACKAGE" BOILER STEAM ENGINE	*	$891.00	**

Based upon April, 1982 costs for Nome, Alaska.

Diesel Fuel (#1 Heating Oil) at $1.24/gallon.

$60/ton for 8000 Btu/lb coal.

Life Expectancy: Diesel System - 5 years

Coal System - 10 years

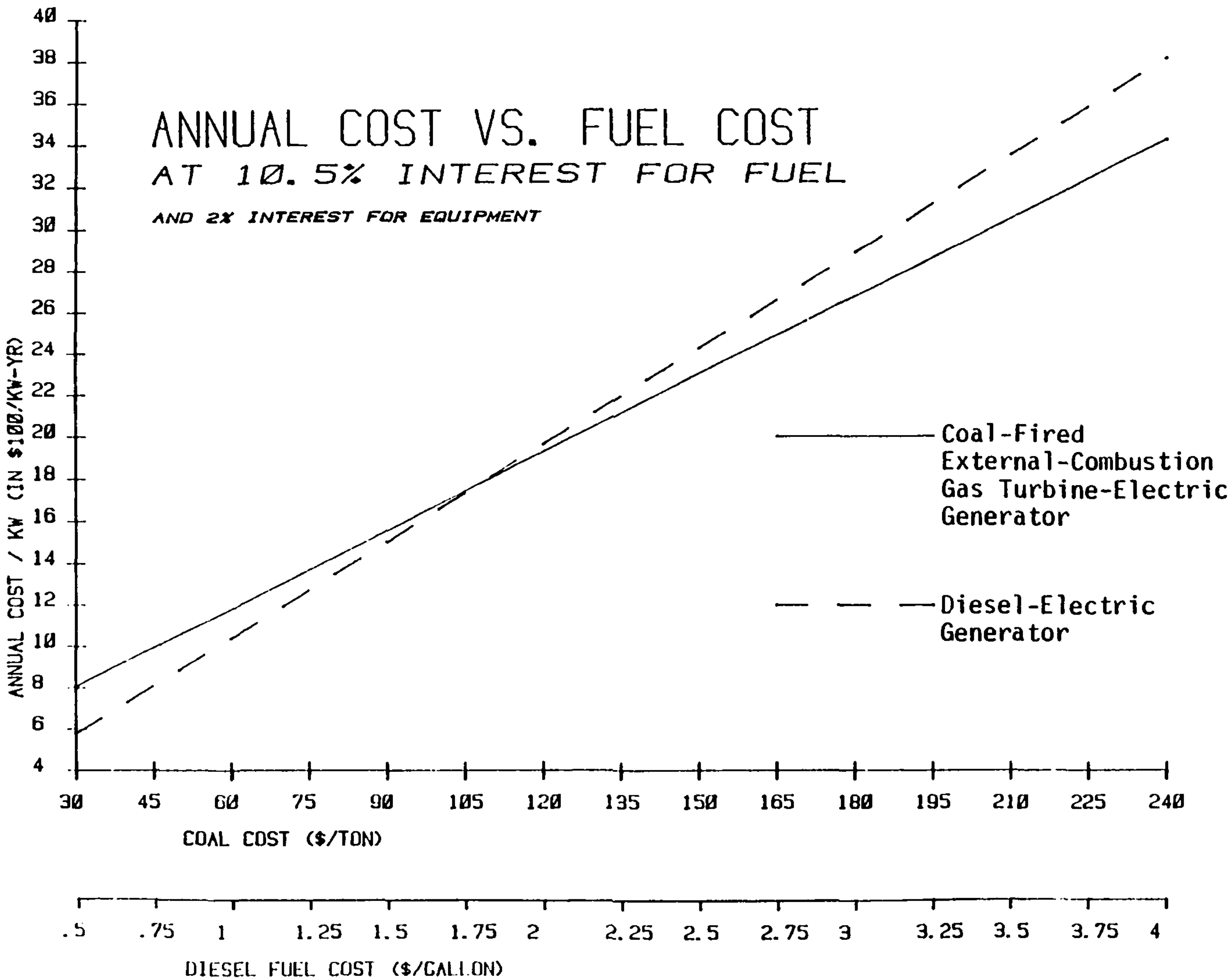
*Equipment cost greater than $250,000

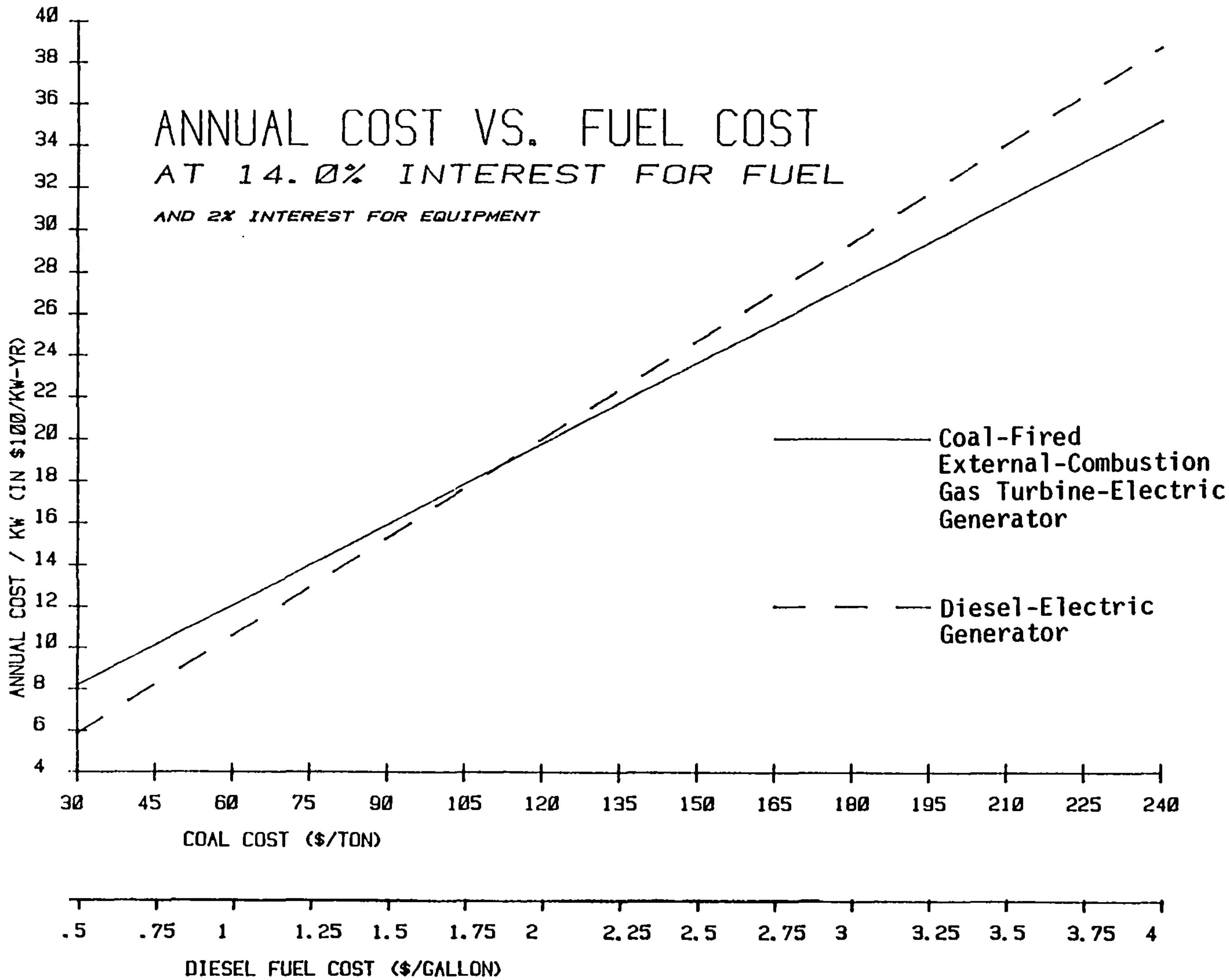
Many of the calculations for economic evaluation of this system for use in Nome may be applicable for other areas as well.

Figures 14, 15, and 16 contain graphs for Annual Cost versus Fuel Cost for the three assumed interest rates for fuel (10.5%, 14%, and 17.5%). These charts include the annual cost for purchasing the equipment at 2% interest (R.E.A.). These charts may be used two different ways: (1) to determine the equivalent cost of fuel oil that is equal to a known cost for coal, or (2) to determine the maximum acceptable coal cost based upon the diesel fuel cost at that location. When the annual cost/kw for the coal system is lower than the equivalent cost for the diesel system, the system is economically advantageous over the diesel system.

There are three things which are required to make this system financially competitive in any location. These are: (a) the coal must be available at an economic price (based upon figures 14, 15, and 16); (b) the system should be used to base load a system which has a continuous demand in excess of 140Kw (as fuel efficiency drops off very quickly for gas turbines under part-load conditions); and (c) the location must have an operator which is on-duty 24 hours per day using their present system, such that no additional labor would be needed. Given time, the system may reach a level of sophistication where it can operate with only being attended for perhaps 8 hours per day, but this is not at all certain at this time.

FIGURE 14


ANNUAL COST VS. FUEL COST
AT 10.5% INTEREST FOR FUEL
AND 2% INTEREST FOR EQUIPMENT
ANNUAL COST / KW (IN $100/KW-YR)
40
38
36
34
32
30
28
26
24
22
20
18
16
14
12
10
8
6
4
30
45
60
75
90
105
120
135
150
165
180
195
210
225
240
COAL COST ($/TON)
.5
.75
1
1.25
1.5
1.75
2
2.25
2.5
2.75
3
3.25
3.5
3.75
4
DIESEL FUEL COST ($/GALLON)
Coal-Fired External-Combustion Gas Turbine-Electric Generator
Diesel-Electric Generator



ANNUAL COST VS. FUEL COST
AT 14.0% INTEREST FOR FUEL
AND 2% INTEREST FOR EQUIPMENT
ANNUAL COST / KW (IN $100/KW-YR)
40
38
36
34
32
30
28
26
24
22
20
18
16
14
12
10
8
6
4
30 45 60 75 90 105 120 135 150 165 180 195 210 225 240
COAL COST ($/TON)
.5 .75 1 1.25 1.5 1.75 2 2.25 2.5 2.75 3 3.25 3.5 3.75 4
DIESEL FUEL COST ($/GALLON)
Coal-Fired External-Combustion Gas Turbine-Electric Generator
Diesel-Electric Generator

FIGURE 15

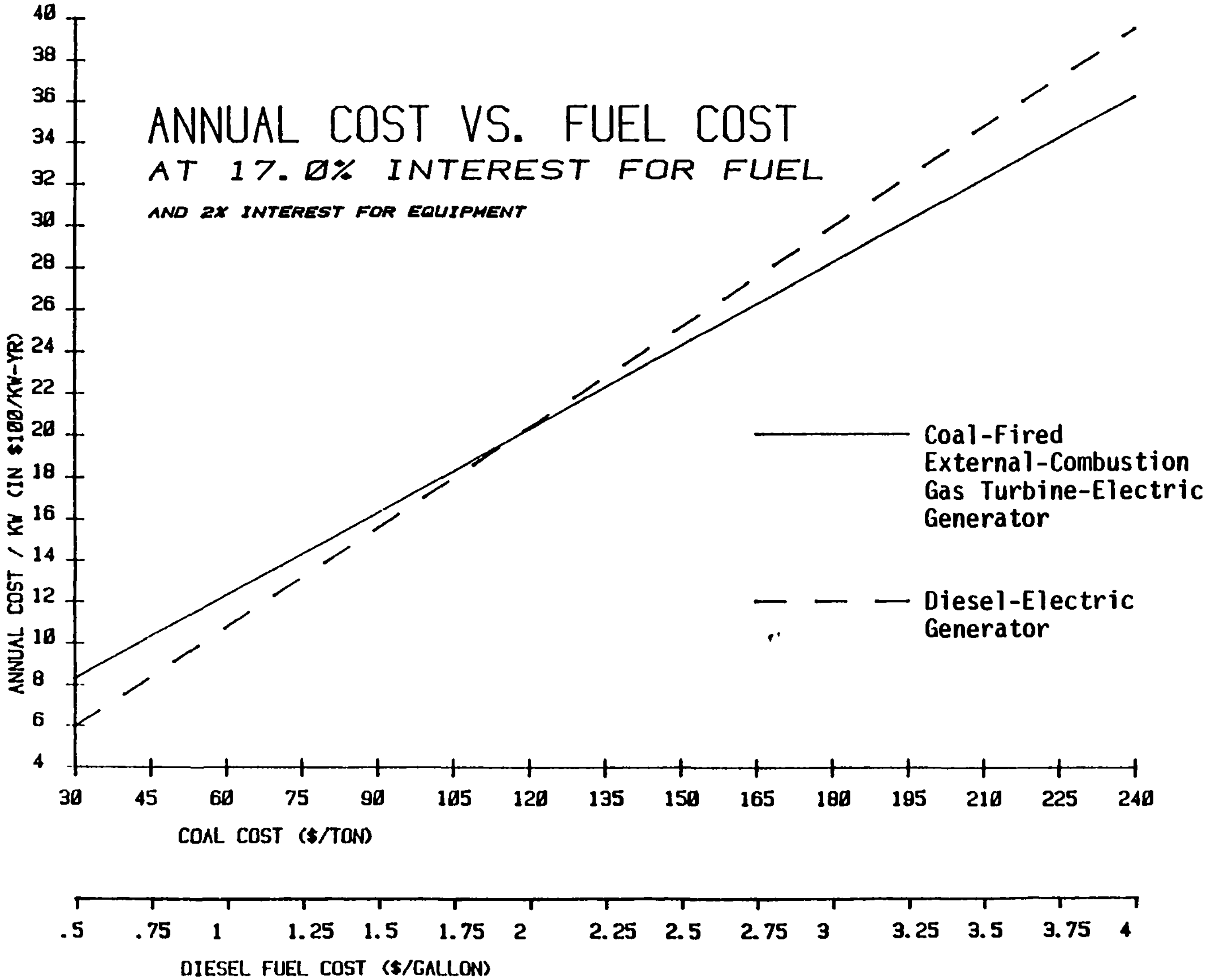

ANNUAL COST VS. FUEL COST
AT 17.0% INTEREST FOR FUEL
AND 2X INTEREST FOR EQUIPMENT
ANNUAL COST / KW (IN $100/KW-YR)
40
38
36
34
32
30
28
26
24
22
20
18
16
14
12
10
8
6
4
30 45 60 75 90 105 120 135 150 165 180 195 210 225 240
COAL COST ($/TON)
.5 .75 1 1.25 1.5 1.75 2 2.25 2.5 2.75 3 3.25 3.5 3.75 4
DIESEL FUEL COST ($/GALLON)
Coal-Fired External-Combustion Gas Turbine-Electric Generator
Diesel-Electric Generator

FIGURE 16

9.0 RECOMMENDATIONS FOR FUTURE WORK

Recommendations for future work relating to this project include a site-specific feasibility study. Included would be a detailed economic analysis of the present cost for generating power at the location, and a more accurate evaluation of the maximum expected fuel cost. A social acceptance study should also be done to ascertain the social acceptance of the system. A study to increase the accuracy of the costs for local coal mining is needed, as annual costs are highly dependent upon the fuel cost. A non-remote operational test on the system would be needed to aid in the confirmation of the systems performance as determined by the manufacturers, and to determine the reliability of the system. Depending upon the results of the above work, and after a local coal mining operation has been established, the next step will then be to install several units in a remote location which presently has a sustained power requirement in excess of the 140KW net power output, and where there are personnel already employed 24 hours per day.

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ASSUMPTIONS

1. All costs are calculated on an annual life-cycle basis.

2. Money for capital investments is available at 2% interest from R.E.A.

3. Money for fuel and other O & M costs are to be financed commercially. There are three different interest rates which might be chosen depending upon the source of the funds.

A. The minimum attractive rate of return used by the State of Alaska is 10.5%.

B. Assuming funds are available within the corporation, they would be available at an interest rate which is greater than or equal to the next best investment. This would have to be greater than the interest on money market certificates. Thus, the interest rate would have to be equal to or greater than 14%, Hawk(1982).

C. Assuming the funds come from a commercial lending institution, the interest rate for "best" customers is 17.5%, Hawk(1982).

The annual cost based upon each of these interest rates have been performed.

DIESEL

Expected Engine Life = 20,000 hrs.

(With good maintenance)

Expected Switchgear Life = 10 yrs.

Fuel Consumption: .1 gal/hr. per kw

Engine Cost (100 kw units): $25,000 each, Schmidt(1982)

Switchgear Cost: $6,000 per engine, Schmidt(1982)

20,000hrs. = 2.283yrs.

Assuming a 2.5 year life for the engines

(2.5yrs = 21,900hrs.)

With a 50% duty cycle for the engines, (2 units running at a time) the four 100 Kw units have a 5 year life.

Thus, four additional engines must be purchased after 5 years.

With the two generators operating at rated output the system is consuming 20 gal/hr or 480 gal/day.

At $1.285/gallon for fuel, Wolf(1982), the daily fuel cost is $616.80/day.

ANNUAL COST

ENGINES - First Set $i=2\%$

$PV_{E1} = 4 * \$25,000 = \$100,000$

$A_{E1} = \$11,132.65$

ENGINES - Second Set $i=2\%$

$FV_{E2} = 4 * \$25,000 = \$100,000$

$PV_{E2} = \$90,573.08$

$A_{E2} = \$10,083.19$

SWITCHGEAR $i=2\%$

$PV_S = \$24,000$

$A_S = \$2,671.84$

FUEL

Because fuel is delivered weekly, the average weekly

fuel cost is $616.80 * 365 / 52 = $4329.46

At 10.5% interest

Weekly interest = 10.5% / 52 = 0.201923%

$A_F = \$237,124.00$

$A_T = A_{E1} + A_{E2} + A_S + A_F$

$A_T = \$11,132.65 + \$10,083.19 + \$2,671.84 + \$237,124.00$

$A_T = \$261,011.68$

At 14% interest,

Weekly interest = 14% / 52 = 0.262307%

$A_F = \$241,305.11$

$A_T = A_{E1} + A_{E2} + A_S + A_F$

$A_T = \$11,132.65 + \$10.083.19 + \$2,671.84 + \$241,305.11$

$A_T = \$265,192.79$

At 17.5% interest

Weekly interest = 17.5% / 52 = 0.336538

$A_F = \$245,581.95$

$A_T = A_{E1} + A_{E2} + A_S + A_F$

$A_T = \$11,132.65 + \$10,083.19 + \$2671.84 + \$245,581.95$

$A_T = \$269,469.63$

Dividing the annual cost by continuous power output

to put it in an Annual cost/Kw (at half of maximum output).

At 10.5%

A_T = \$1305.06/Kw

At 14%

A_T = \$1325.96/Kw

At 17.5%

A_T = \$1347.35/Kw

COAL BURNING GAS TURBINE

This system is to be supplied by Eagle Energy Systems. The life of the system (with the exception of the heat exchanger) is 10 years of continuous service. The life of the heat exchanger is 5 years of continuous service. Purchasing two units and at a 50% duty cycle, the system life is 20 years and a second pair of heat exchangers must be purchased after 10 years.

Fuel Consumption = 0.1 lbm/sec = 4.32 Tons/day (with 1 unit running and a gross output of 200 Kw).

At $60/Ton for the coal in Nome, Conwell and Triplehorn(1980)

Daily Fuel Cost = 4.32 * $60 = $259.20

Yearly Fuel Cost = 365 * $259.20 = 94,608.00

Unit Cost = 2 * $270,000 = $540,000

Exchanger Replacement after 10 years = 2 * $150,000 = $300,000

Providing a years storage for coal at 4.32 TPD for coal at a density of 50 lbm/ft3, the volume = 63,072 ft3.

Letting the Volume = 90,000 ft3,

At an installed cost of $1/ft3 including the feed augers (this is 1.5 times E. E. S. 's "conservative" estimate), the Storage Bin Cost = $90,000

Baghouse Cost = $60,000

Ash Handling Equipment Cost = $60,000

(Both values at 1.5X the E.E.S. estimate)

ANNUAL COST

TOTAL EQUIPMENT INVESTMENT i=2% n=20yrs.

PV_E = (2 * \$270,000) + \$90,000 + \$60,000 + \$60,000

PV_E = 750,000

A_E = \$45,867.54

REPLACEMENT HEAT EXCHANGERS i=2%

FV_X = \$300,000

PV_X = \$246,104.49

A_X = \$15,050.94

FUEL COST

Assuming a years supply of fuel must be purchased at one time.

At 10.5% interest

PV_F = \$94,608.00

A_F = \$104,541.84

$A_T = A_E + A_X + A_F$

A_T = \$45,867.54 + \$15,050.94 + \$104,541.84

A_T = \$165,460.32

At 14% interest

PV_F = \$94,608.00

A_F = \$107,853.12

$A_T = A_E + A_X + A_F$

A_T = \$45,867.54 + \$15,050.94 + \$107,853.12

A_T = \$168,771.60

At 17.5% interest

PV_F = \$94,608.00

A_F = \$111,164.40

$A_T = A_E + A_X + A_F$

A_T = \$45,867.54 + \$15,050.94 + \$111,164.40

A_T = \$172,082.88

This system produces a gross electrical power output of 200 Kw, however there are two parasitic loads. These are a 50 hp load for the grinder and auger, and a 10hp load for the induced draft fan. Using 75% efficient motors, this will put a 60 Kw load on the generator, leaving 140 Kw net power output (per unit).

Dividing the annual cost by 140 Kw to put it on an Annual Cost/Kw basis (with 1 unit operating), such that it may be easily compared with the diesel system.

At 10.5% interest,

A_T = \$1,181.86/Kw

At 14% interest,

A_T = \$1,205.51/Kw

At 17.5% interest,

A_T = \$1,229.16/Kw

FYR-FEEDER BOILER W/SKINNER STEAM ENGINE & CONDENSER

<u>Steam Engine Inlet - 1</u>

125 p.s.i.g. Saturated Steam (139.7 p.s.i.a.)

h_1 = 1192 BTU/lb

<u>Condenser Outlet - 3</u>

Absolute Pressure = 4"Hg = 1.9 p.s.i.a. (Liquid)

h_3 = 94 BTU/lb

<u>Across the pump 3 - 4</u>

$W = \dot{m} * \rho * \Delta P = \dot{m} * (h_4 - h_3)$

$(h_4 - h_3) = \rho * \Delta P = (139.7 - 1.9)* 144 / 62.4$

= 318 ft*lbf/lbm = 0.4 BTU/lbm

$h_4 = h_3 + (h_4 - h_3)$ = 94.4 BTU/lbm

Q_O = 200Kw = 682,428 BTU/hr

$Q_I = \dot{m} * (h_1 - h_4)$

Q_I = 22.1 lbm/Kw-hr * 200 Kw * (1192 - 94.4 BTU/lbm)

Q_I = 4,851,392 BTU/hr

The thermal efficiency of the steam engine and condenser system (excluding pumping costs) is equal to Q_O / Q_I , both in BTU/hr.

e = 682,428 / 4,851,392 = 0.1407 = 14.07%

The thermal efficiency of the boiler at rated output is equal to Q_O / Q_I, both in BTU/hr.

Q_O = 7,690,000 BTU/hr

Q_I = 1,100 lbm/hr * 10,000 BTU/lbm = 11,000,000 BTU/hr.

e = 7,690,000 / 11,000,000 = 0.699 = 69.9%

The steam engine / condenser system, at rated output, consumes 4,851,393 BTU/hr while the boiler is rated at 7,690,000 BTU/hr.

Thus, the boiler would never exceed 63% of its rated output. The efficiency of a boiler drops off at a reduced load. An approximation for fuel consumption at partial load is to take the average of the fuel consumption at rated power output and the fuel consumption calculated using linear extrapolation from full load Sandley(1982).

At full load, the heat rate is 11,000,000 BTU/hr, while at 63% of rated output, the heat rate is calculated using linear extrapolation is 63% of 11,000,000 BTU/hr or 6,390,000, BTU/hr.

The average off these two values is 8,960,000 BTU/hr.

Using 8,000 BTU/lb coal, this is 1,120 lb/hr or 13.44 Tons/day. At $60/ton, this is $806.40/day. This is higher than the fuel cost for the diesel power plant.

FYR-FEEDER BOILER W/TRANE TURBOGENERATOR & CONDENSER

Steam Turbine Inlet - 1

Using 165 p.s.i.a., 366 F Steam

h_1 = 1208 BTU/lb

Condenser Outlet - 3

2 p.s.i.a. liquid

h_3 = 94 BTU/lb

Pump Outlet - 4

Across the pump, h = 0.4 BTU/lbm

h_4 = 94.4 BTU/lbm

The theoretical steam rate (TSR) is 8.8 lb/hp-hr

At 300 hp, using Trane's chart, the efficiency (e) is 0.54

The Actual Steam Rate (ASR) = TSR / e

= 8.8 lbm/hp-hr / .54 = 16.3 lbm/hp-hr

Using 300 hp to generate 200 Kw of electricity,

m = 16.3 * 300 = 4890 lbm/hr

Q_o = 200Kw = 682,428 BTU/hr

$Q_I = \dot{m} * (h_1 - h_4) = 4890 * (1208 - 94.4)$

Q_I = 5,445,504 BTU/hr

The efficiency of the steam turbine / condenser system (excluding pumping costs) is Q_o / Q_I , both in BTU/hr.

e = 682,428 / 5,445,504 = 0.125 = 12.5%

The thermal efficiency of the boiler at rated output (from the previous section) is 0.699 = 69.9%.

The steam turbine / condenser system at rated output consumes 5,445,504 BTU/hr while the boiler is rated at 7,690,000 BTU/hr. Thus, the boiler would never exceed 71% of rated output. The efficiency of a boiler drops off at reduced load. An approximation for the fuel consumption is to take an average of the fuel consumption at rated output and the fuel consumption calculated using linear extrapolation from full load Sandley(1982).

At full load, the heat rate is 11,000,000 BTU/hr.

At 71%, heat rate is .71 * 11,000,000 or

7,810,000 BTU/hr. The average is 9,405,000 BTU/hr.

Using 8000 BTU/lb coal, this is 1175 lb/hr or 14.1 tons per day. At $60/Ton. this is $846.45/day.

This is a higher fuel cost than the fuel cost for a diesel powerplant.

SANDLEY LIGHT RAILWAY BOILER AND STEAM ENGINE/CONDENSER SYSTEM

Q_o = 200KW

Fuel Consumption = 1237.5 lbm/hr = 14.85 Tons/day.

At $60/ton, this is $891.00/day.

This is higher than the fuel cost for the diesel power plant.

Gasification Thermodynamics

Oxygen Blown

Temperature of Reaction: 1200 - 1400^{o}F up to 2200^{o}F or more

ΔT = 1500^{o}F (Enthalpy values used for 200^{o}F and 1700^{o}F)

Chemical Equation:

$$6\ C + 9\ H_2O_{(g)} + 1\ O_2 \rightarrow 2\ CO + 4\ H_2 + CH_4 + 3\ CO_2 + 3\ H_2O_{(g)}$$

$$\Sigma n_p \Delta h_p = \frac{2\ lb_{mo}CO}{} \ \frac{451.3 - 44.8\ BTU}{lb_m} \ \frac{28.0\ lb_m CO}{lb_{mo}CO}$$

$$+ \frac{4\ lb_{mo}H_2}{} \ \frac{5918.9 - 619.2\ BTU}{lb_m} \ \frac{2.016\ lb_m H_2}{lb_{mo}H_2}$$

$$+ \frac{1\ lb_{mo}CH_4}{} \ \frac{1470.8 - 98.1\ BTU}{lb_m} \ \frac{16.04\ lb_m CH_4}{lb_{mo}CH_4}$$

$$+ \frac{3\ lb_{mo}CO_2}{} \ \frac{448.7 - 37.4\ BTU}{lb_m} \ \frac{44.011\ lb_m CO_2}{lb_{mo}CO_2}$$

$$+ \frac{3\ lb_{mo}H_2O}{} \ \frac{847.4 - 80.1\ BTU}{lb_m} \ \frac{18.016\ lb_m H_2O}{lb_{mo}H_2O}$$

= 22,760.6 + 42,737.1 + 22,017.8 + 41,473.2

= 183,280 BTU

Total Heating Value of Products:

$$21/2\ O_2 + 2\ CO + 4\ H_2 + CH_4 + 3\ CO_2 + 3\ H_2O_{(g)} \rightarrow 6\ CO_2 + 9\ H_2O_{(g)}$$

$$\Delta H^o_{rxn} = [\ 6\ \Delta H^o_f\ (\ CO_2\ ) + 9\ \Delta H^o_f\ (\ H_2O\ )\ ]$$

$$-\ [\ 21/2\ \Delta H^o_f\ (\ CO_2\ ) + 2\ \Delta H^o_f\ (\ CO\ ) + 4\ \Delta H^o_f\ (\ H_2\ )$$

$$+\ \Delta H^o_f\ (\ CH_4\ ) + 3\ \Delta H^o_f\ (\ CO_2) + 3\ \Delta H^o_f\ (\ H_2O\ )\ ]$$

$$\Delta H^o_{rxn} = \frac{6\ lb_{mo}CO_2}{} \frac{-169{,}336\ BTU}{lb_{mo}CO_2} + \frac{9\ lb_{mo}H_2O}{} \frac{-104{,}054\ BTU}{lb_{mo}H_2O}$$

$$- \frac{21/2\ lb_{mo}O_2}{} \frac{0\ \ BTU}{lb_{mo}O_2} + \frac{2\ lb_{mo}CO}{} \frac{-47{,}552\ BTU}{lb_{mo}}$$

$$+ \frac{4\ lb_{mo}H_2}{} \frac{0\ \ BTU}{lb_{mo}H_2} + \frac{1\ lb_{mo}CH_4}{} \frac{-32{,}210\ BTU}{lb_{mo}CH_4}$$

$$+ \frac{3\ lb_{mo}CO_2}{} \frac{-188{,}475\ BTU}{lb_{mo}CO_2} + \frac{3\ lb_{mo}H_2O}{} \frac{-104{,}054\ BTU}{lb_{mo}H_2O}$$

$$\Delta H^o_{rxn} = [\ -1{,}016{,}013 - 936{,}488\ BTU\ ] - [\ 0 - 95{,}103 - 0 - 32{,}210$$

$$-\ 508{,}006 - 312{,}163\ BTU\ ] = 1{,}005{,}019\ BTU\ (net)$$

Volume of Products:

$$V = \frac{n\,R\,T\,(\,M.\,W.\,)}{P}$$

$$V_{CO} = \frac{\dfrac{2\ lb_{mo}CO}{} \quad \dfrac{55.16\ ft\text{-}lb_f}{lb_m\text{-}R^o} \quad \dfrac{537\ ^oR}{} \quad \dfrac{28.01\ lb_mCO}{lb_{mo}CO}}{\dfrac{14.7\ lb_f}{in^2} \quad \dfrac{144\ in^2}{ft^2}} = 783.9\ ft^3$$

$$V_{H_2} = \frac{\dfrac{4\ lb_{mo}H_2}{} \quad \dfrac{766.4\ ft\text{-}lb_f}{lb_m\text{-}R^o} \quad \dfrac{537\ ^oR}{} \quad \dfrac{2.016\ lb_mH_2}{lb_{mo}H_2}}{\dfrac{14.7\ lb_f}{in^2} \quad \dfrac{144\ in^2}{ft^2}} = 1567.8\ ft^3$$

$$V_{CH_4} = \frac{\dfrac{1\ lb_{mo}CH_4}{} \quad \dfrac{96.4\ ft\text{-}lb_f}{lb_m\text{-}R^o} \quad \dfrac{537\ ^oR}{} \quad \dfrac{16.04\ lb_mCH_4}{lb_{mo}CH_4}}{\dfrac{14.7\ lb_f}{in^2} \quad \dfrac{144\ in^2}{ft^2}} = 392.1\ ft^3$$

$$V_{CO_2} = \frac{\dfrac{3\ lb_{mo}CO_2}{} \quad \dfrac{35.1\ ft\text{-}lb_f}{lb_m\text{-}R^o} \quad \dfrac{537\ ^oR}{} \quad \dfrac{44.01\ lb_mCO_2}{lb_{mo}CO_2}}{\dfrac{14.7\ lb_f}{in^2} \quad \dfrac{144\ in^2}{ft^2}} = 1175.6\ ft^3$$

Total Volume $= 3919.4\ ft^3$

To get the gross heating value of the gas, we must calculate the energy released during the condensation of the water vapor from the combustion process and add this to the term accounting for sensible heat. The value used for this calculation is based upon the condensation of the difference between the number of moles of water after combustion and the number of moles of water before combustion. This is based upon the assumption that the gas is dried prior to combustion. With this system being used in rural Alaska, the gas must be dried because a reserve supply of this gas would have to be kept and the moisture would condense within the storage tank if it were not first dried. This energy is:

$$L = \frac{9 - 3\ lb_{mo} H_2O}{} \quad \frac{18\ lb_m H_2O}{lb_{mo} H_2O} \quad \frac{970.1\ BTU}{lb_m H_2O}$$

$$L = 104{,}803\ BTU$$

The gross heating value is the sum of the net value and the latent value. This is: 1,005,019 BTU + 104,803 BTU = 1,109,822 BTU.

Heating Value of Gas:

$$\frac{1{,}109{,}822\ BTU}{3{,}919.4\ SCF} = 283.2\ BTU/SCF \quad \text{(gross)}$$

$$\frac{1{,}005{,}019\ BTU}{3{,}919.4\ SCF} = 256.4\ BTU/SCF \quad \text{(net)}$$

Air Blown

The chemical reaction and reaction conditions are assumed to be the same as for oxygen blown gasification. The air introduces four moles of nitrogen for every mole of oxygen which does not affect the heat of reaction, but it does change the sensible heat summation.

$$\Sigma n_p \Delta h_p = 183{,}280 + \frac{4\ lb_{mo}\ N_2}{} \ \frac{444.2 - 44.6\ BTU}{lb_m H_2} \ \frac{28\ lb_m N_2}{lb_{mo} N_2}$$

$$= 183{,}280 + 44{,}755 = 228{,}035\ BTU$$

$$V_{N_2} = \frac{\dfrac{4\ lb_{mo} N_2}{} \ \dfrac{55.16\ ft\text{-}lb_f}{lb_m\text{-}R^o} \ \dfrac{537\ ^oR}{} \ \dfrac{28\ lb_m N_2}{lb_{mo} N_2}}{\dfrac{14.7\ lb_f}{in^2} \ \dfrac{144\ in^2}{ft^2}} = 1{,}567.8\ ft^3$$

Total Volume = 3,919.4 + 1,567.8 = 5,487.2 ft^3

Heating Value of Gas:

$$\frac{1{,}109{,}822\ BTU}{5{,}487.2\ SCF} = 202.6\ \ BTU/SCF \quad (gross)$$

$$\frac{1{,}005{,}019\ BTU}{5{,}487.2\ SCF} = 183.2\ \ BTU/SCF \quad (net)$$

Gasification Thermodynamics

External Combustion (Oxygen)

Temperature of Reaction: 1800 - 2000 ^{o}F

$\Delta T = 1700^{o}F$ (Enthalpy Values used for $200^{o}F$ and $1900^{o}F$)

Chemical Equation

$$13\ C + 19\ H_2O_{(g)} + 3\ O_2 \rightarrow 7\ CO + 13\ H_2 + 6\ H_2O_{(g)} + 6\ CO_2$$

$$\Sigma n_p \Delta h_p = \frac{7\ lb_{mo}CO}{} \quad \frac{504 - 44.8\ BTU}{lb_m CO} \quad \frac{28.0\ lb_m CO}{lb_{mo} CO}$$

$$+ \frac{13\ lb_{mo}H_2}{} \quad \frac{4790.8 - 619.2\ BTU}{lb_m H_2} \quad \frac{2.016\ lb_m H_2}{lb_{mo} H_2}$$

$$+ \frac{6\ lb_{mo}H_2O}{} \quad \frac{952.7 - 80.1\ BTU}{lb_m H_2O} \quad \frac{18.016\ lb_m H_2O}{lb_{mo} H_2O}$$

$$+ \frac{6\ lb_{mo}CO_2}{} \quad \frac{504.4 - 37.4\ BTU}{lb_m CO_2} \quad \frac{44.011\ lb_m CO_2}{lb_{mo} CO_2}$$

$$= 90{,}034.6 + 156{,}241.6 + 94{,}328.8 + 123{,}297.7$$

$$= 463{,}902.8\ BTU$$

Total Heating Value of Products:

$$10\ O_2 + 7\ CO + 13\ H_2 + 6\ H_2O_{(g)} + 6\ CO_2 \rightarrow 13\ CO_2 + 19\ H_2O$$

$$\Delta H^o_{rxn} = [\ 13\ \Delta H^o_f\ (\ CO_2\ ) + 19\ \Delta H^o_f\ (\ H_2O\ )\ ]$$

$$-\ [\ 10\ \Delta H^o_f\ (\ O_2\ ) + 7\ \Delta H^o_f\ (\ CO\ ) + 13\ \Delta H^o_f\ (\ H_2\ )$$

$$+\ 6\ \Delta H^o_f\ (\ H_2O\ ) + 6\ \Delta H^o_f\ (\ CO_2)\ ]$$

$$\Delta H^o_{rxn} = \frac{13\ lb_{mo}CO_2}{} \ \frac{-169{,}336\ BTU}{lb_{mo}CO_2} + \frac{19\ lb_{mo}H_2O}{} \ \frac{-104{,}054\ BTU}{lb_{mo}H_2O}$$

$$-\ \frac{10\ lb_{mo}O_2}{} \ \frac{0\ \ BTU}{lb_{mo}O_2} + \frac{7\ lb_{mo}CO}{} \ \frac{-47{,}552\ BTU}{lb_{mo}CO}$$

$$+\ \frac{13\ lb_{mo}H_2}{} \ \frac{0\ \ BTU}{lb_{mo}H_2} + \frac{6\ lb_{mo}H_2O}{} \ \frac{-104{,}054\ BTU}{lb_{mo}H_2O}$$

$$+\ \frac{6\ lb_{mo}CO_2}{} \ \frac{-188{,}475\ BTU}{lb_{mo}CO_2}$$

$$= [\ -2{,}201{,}362\ -1{,}977{,}030\ ] - [\ 0 - 332{,}862 + 0$$

$$-\ 624{,}862 - 1{,}016{,}013\ BTU\ ] = 2{,}205{,}192\ BTU\ (net)$$

Volume of Products (Moisture Free)

$$V = \frac{n \; R \; T \; (\text{M. W.})}{P}$$

$$V_{CO} = \frac{\dfrac{7\ lb_{mo}CO}{} \; \dfrac{55.16\ ft\text{-}lb_f}{lb_m\text{-}R^o} \; \dfrac{537\ ^oR}{} \; \dfrac{28.01\ lb_m CO}{lb_{mo}CO}}{\dfrac{14.7\ lb_f}{in^2} \; \dfrac{144\ in^2}{ft^2}} = 2{,}743.7\ ft^3$$

$$V_{H_2} = \frac{\dfrac{13\ lb_{mo}H_2}{} \; \dfrac{766.4\ ft\text{-}lb_f}{lb_m\text{-}R^o} \; \dfrac{537\ ^oR}{} \; \dfrac{2.016\ lb_m H_2}{lb_{mo}H_2}}{\dfrac{14.7\ lb_f}{in^2} \; \dfrac{144\ in^2}{ft^2}} = 5{,}095.0\ ft^3$$

$$V_{CO_2} = \frac{\dfrac{6\ lb_{mo}CO_2}{} \; \dfrac{35.1\ ft\text{-}lb_f}{lb_m\text{-}R^o} \; \dfrac{537\ ^oR}{} \; \dfrac{44.01\ lb_m CO_2}{lb_{mo}CO_2}}{\dfrac{14.7\ lb_f}{in^2} \; \dfrac{144\ in^2}{ft^2}} = 2{,}351\ ft^3$$

Total Volume = $10{,}189.7\ ft^3$

To get the gross heating value of the gas, we must calculate the energy released during the condensation of the water vapor from the combustion process and add this to the term accounting for sensible heat. The value used for this calculation is based upon the condensation of the difference between the number of moles of water after combustion and the number of moles of water before combustion. This is based upon the assumption that the gas is dried prior to combustion. With this system being used in rural Alaska, the gas must be dried because a reserve supply of the fuel gas would have to be kept and the moisture would condense within the storage tank if the fuel was not first dried. This energy is:

$$L = \frac{19 - 6\ lb_{mo}H_2O}{} \quad \frac{18\ lb_m H_2O}{lb_{mo}H_2O} \quad \frac{970.1\ BTU}{lb_m H_2O}$$

$$L = 227{,}003\ BTU$$

The gross heating value is the sum of the net value and the latent value. This is: 2,205,192 BTU + 227,003 BTU = 2,432,195 BTU

Heating Value of Gas:

$$\frac{2{,}432{,}195\ BTU}{10{,}189.7\ SCF} = 238.7\ BTU/SCF \qquad \text{(gross)}$$

$$\frac{2{,}205{,}192\ BTU}{10{,}189.7\ SCF} = 216.4\ BTU/SCF \qquad \text{(net)}$$

Gasification Thermodynamics

Entrained Gasification (Oxygen)

Temperature of Reaction: 1800 - 2000°F

ΔT = 1700°F (Enthalpy Values used for 200°F and 1900°F)

Chemical Equation:

$$16\ C + 6\ H_2O_{(g)} + 7\ O_2 \rightarrow 12\ CO + 6\ H_2 + 4\ CO_2$$

Hoffman(1978)

$$\Sigma n_p \Delta h_p = \frac{12\ lb_{mo}CO}{} \quad \frac{504 - 44.8\ BTU}{lb_m CO} \quad \frac{28.0\ lb_m CO}{lb_{mo} CO}$$

$$+ \frac{6\ lb_{mo}H_2}{} \quad \frac{6580.0 - 619.2\ BTU}{lb_m H_2} \quad \frac{2.016\ lb_m H_2}{lb_{mo} H_2}$$

$$+ \frac{4\ lb_{mo}CO_2}{} \quad \frac{504.4 - 37.4\ BTU}{lb_m CO_2} \quad \frac{44.01\ lb_m CO_2}{lb_{mo} CO_2}$$

$$\Sigma n_p \Delta h_p = 154{,}339.6 + 72{,}111.5 + 82{,}198.5 = 308{,}649.6\ BTU$$

Total Heating Value of Products:

$$9\ O_2 + 12\ CO + 6\ H_2 + 4\ CO_2 \rightarrow 6\ H_2O_{(g)} + 16\ CO_2$$

$$\Delta H^o_{rxn} = [\ 6\ \Delta H^o_f\ (\ H_2O\ ) + 16\ \Delta H^o_f\ (\ CO_2\ )\ ]$$

$$-\ [\ 9\ \Delta H^o_f\ (\ O_2\ ) + 12\ \Delta H^o_f\ (\ CO\ ) + 6\ \Delta H^o_f\ (\ H_2)$$

$$+\ 4\ \Delta H^o_f\ (\ CO_2\ )\ ]$$

$$\Delta H^o_{rxn} = \frac{6\ lb_{mo}H_2O}{} \ \frac{-104{,}054\ BTU}{lb_{mo}H_2O} + \frac{16\ lb_{mo}CO_2}{} \ \frac{-169{,}336\ BTU}{lb_{mo}CO_2}$$

$$-\ \frac{9\ lb_{mo}O_2}{} \ \frac{0\ \ BTU}{lb_{mo}O_2} + \frac{12\ lb_{mo}CO}{} \ \frac{-47{,}552\ BTU}{lb_{mo}CO}$$

$$+\ \frac{6\ lb_{mo}H_2}{} \ \frac{0\ \ BTU}{lb_{mo}H_2} + \frac{4\ lb_{mo}CO_2}{} \ \frac{-188{,}475\ BTU}{lb_{mo}CO_2}$$

$$\Delta H^o_{rxn} = [\ -624{,}325 - 2{,}709{,}369\ ] - [\ -570{,}620 - 677{,}342\ ]$$

$$= \ 2{,}085{,}732 \qquad \text{(net)}$$

Volume of Products: (Moisture Free)

$$V = \frac{n\ R\ T\ (M.W.)}{P}$$

$$V_{CO} = \frac{\dfrac{12\ lb_{mo}CO}{} \ \dfrac{55.16\ ft\text{-}lb_f}{lb_m\text{-}R^o} \ \dfrac{537\ ^oR}{} \ \dfrac{28.01\ lb_m CO}{lb_{mo}CO}}{\dfrac{14.7\ lb_f}{in^2} \ \dfrac{144\ in^2}{ft^2}} = 4{,}703.4\ ft^3$$

$$V_{H_2} = \frac{\dfrac{6\ lb_{mo}H_2}{} \ \dfrac{766.4\ ft\text{-}lb_f}{lb_m\text{-}R^o} \ \dfrac{537\ ^oR}{} \ \dfrac{2.016\ lb_m H_2}{lb_{mo}H_2}}{\dfrac{14.7\ lb_f}{in^2} \ \dfrac{144\ in^2}{ft^2}} = 2{,}351.7\ ft^3$$

$$V_{CO_2} = \frac{\dfrac{4\ lb_{mo}CO_2}{} \ \dfrac{35.1\ ft\text{-}lb_f}{lb_m\text{-}R^o} \ \dfrac{537\ ^oR}{} \ \dfrac{44.01\ lb_m CO_2}{lb_{mo}CO_2}}{\dfrac{14.7\ lb_f}{in^2} \ \dfrac{144\ in^2}{ft^2}} = 1{,}567.5\ ft^3$$

Total Volume $= 8{,}622.6\ ft^3$

To get the gross heating value of the gas, we must calculate the energy released during the codensation of the water vapor from the combustion process and add this to the term accounting for sensible heat. The value used for this calculation is based upon the condensation of the difference between the number of moles of water after combustion and the number of moles of water before combustion. This is based upon the assumption that the gas is dried prior to combustion. With this system being used in rural Alaska, the gas must be dried because a reserve supply of the fuel gas would have to be kept and the moisture would condense within the fuel tank if the fuel was not first dried. This energy is:

$$L = \frac{6\ lb_{mo}H_2O}{} \quad \frac{18\ lb_mH_2O}{lb_{mo}H_2O} \quad \frac{970.1\ BTU}{lb_mH_2O}$$

$$L = 104{,}760\ BTU$$

The gross heating value is the sum of the net value and the latent value. This is: 2,205,192 BTU + 104,760 BTU = 2,309,952 BTU

Heating Value of Gas:

$$\frac{2{,}309{,}952\ BTU}{8{,}622.6\ SCF} = 267.9\ \ BTU/SCF \qquad \text{(gross)}$$

$$\frac{2{,}205{,}192\ BTU}{8{,}622.6\ SCF} = 255.8\ \ BTU/SCF \qquad \text{(net)}$$

Entrained Gasification (Air)

The chemical reaction and reaction conditions are assumed to be the same as for oxygen fed gasification. The air introduces four moles of nitrogen for every mole of oxygen which does not affect the heat of reaction, but it does change the sensible heat summation.

$$\Sigma n_p \Delta h_p = 308{,}650 + \frac{28\ \mathrm{lb_{mo}N_2}}{} \ \frac{496.6 - 44.6\ \mathrm{BTU}}{\mathrm{lb_m N_2}} \ \frac{28\ \mathrm{lb_m N_2}}{\mathrm{lb_{mo} N_2}}$$

$$= 308{,}650 + 354{,}352 = 663{,}002\ \mathrm{BTU}$$

$$V_{N_2} = \frac{\dfrac{28\ \mathrm{lb_{mo}N_2}}{} \ \dfrac{55.16\ \mathrm{ft\text{-}lb_f}}{\mathrm{lb_m\text{-}R^o}} \ \dfrac{537\ {}^oR}{} \ \dfrac{28\ \mathrm{lb_m N_2}}{\mathrm{lb_{mo}N_2}}}{\dfrac{14.7\ \mathrm{lb_f}}{\mathrm{in^2}} \ \dfrac{144\ \mathrm{in^2}}{\mathrm{ft^2}}} = 10{,}972.64\ \mathrm{ft^3}$$

Total Volume = 8,622.6 + 10,972.6 = 19,595.2 ft^3

Heating Value of Gas:

$$\frac{2{,}309{,}952\ \mathrm{BTU}}{19{,}595.2\ \mathrm{SCF}} = 117.9\ \mathrm{BTU/SCF} \qquad \text{(gross)}$$

$$\frac{2{,}205{,}192\ \mathrm{BTU}}{19{,}595.2\ \mathrm{SCF}} = 112.5\ \mathrm{BTU/SCF} \qquad \text{(net)}$$