A THERMODYNAMIC-ECONOMIC ANALYSIS
OF THE SYNTHANE PROCESS

Final Report

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cannot be created or destroyed; whatever energy is supplied must either be delivered in the products or lost in wastes. Consequently, the apparent inefficiencies are all in the effluent wastes. Because it cannot be created or consumed, there is no way that energy can be used to measure the amount of resources consumed by a process in order to accomplish the process. Energy analyses inevitably overestimate the importance of effluent wastes, and fail even to recognize--let alone evaluate--the consumptions, which generally are much larger than the real losses (if not the apparent, energy losses).

Because available energy is the commodity of value, it provides the key to the cost accounting of "power" in various forms. Costing with energy is impossible with many systems, leads to erroneous results with most, and works only when it can be manipulated so that it is tantamount to available energy costing.

Availability accounting is useful for several purposes. If a utility system and/or chemical process delivers several products, then the proper apportionment of "energy" costs to the various products requires use of available energy. This apportionment is critical, of course, inasmuch as (1) the "energy" costs are usually major ones, and (2) the costs are needed in order to establish prices and/or evaluate profits of each product. Or, if the utilities are used in-plant, the apportionment is needed to establish costs to be charged to the different manufactured goods, which consume the utilities in various proportions.

Another purpose for which availability accounting is important is for the determination of the cost of the "power" streams which fuel the various unit operations and components of complex processes and systems. For existing processes, knowledge of these costs allows economic analyses to be made of the tradeoffs between power costs and other operating/capital expenses. Thereby, operating decisions can be made rationally--regarding maintenance, replacement, revision, and operation.

With the same type of economic analysis, for processes which are being designed the various components and units can be designed and/or selected optimally. Also, the effect of various variations--in parameters, in alternative technologies, . . .--upon the unit cost of the process

products can be estimated accurately without complete system re-designs.

Results

Figure 1 shows the flows of available energy between the major groups of equipment in the SYNTHANE process. Also shown is the consumption in each group, and its efficiency.

It is evident from Figure 1 that the largest inefficiencies in the process are associated with (i) the production of "utilities"--steam, power, and oxygen--and (ii) the gasification process.

The inefficiency in the production of utilities is, at this time, more important than that in the gasifier. The reason is not simply because the consumption is greater or that the per cent efficiency is lower. Rather, it is because the efficiency with which each utility is produced is substantially lower than the state-of-the-art efficiency with which the utility can now be produced economically. The 26% overall efficiency should be compared with an expected efficiency of at least 35% and up to 40%.

The large consumption of available energy in the gasifier, on the other hand, is indicative of the current state-of-the-art. However, it would be very worthwhile to calculate the efficiency of other gasifiers for the sake of comparison. The large consumption does indicate the desirability R&D on gasifiers and auxiliaries (e.g., concentration cells).

Further details regarding the consumptions and losses are depicted by Figure 5-2; they are discussed in the report, along with possible means of improvement.

Figure 2 presents the unit costs of the available energy flows between major component groups. (See Figure 6-4 for more details.) Notice the inordinately high unit costs of steam, shaft power, electricity and oxygen--especially considering the inexpensive cost of fuel to the group, $0.35¢/\text{kwhr} = \$1.03/10^6 \text{ Btu}$. These high unit costs clearly point out that the design of the utility plant is far from optimal. It can be surmised that the low-efficiency utility production is a critical factor leading to the high unit cost of product gas; this conclusion is correct, as will be shown shortly.

Figure E-1

Available Energy Flow Diagram

SYNTHANE PROCESS CONCEPTUAL DESIGN

Figure E-2

Unit Costs of Available Energy Flows (¢/kwhr)

Available Energy Flow Diagram

SYNTHANE PROCESS CONCEPTUAL DESIGN

- * $c_{\text{steam}} = 3.08\text{¢/kwhr}$
- * $c_{\text{shaft}} = 5.22\text{¢/kwhr}$
- * $c_{\text{electricity}} = 8.50\text{¢/kwhr}$
- * $c_{\text{oxygen}} = 43.5\text{¢/kwhr}$

(It should be recognized that the \$6.10 per million Btu of product gas available energy [which is $\$5.73/10^6$ Btu of energy] assumes that the excess electricity could be sold at the cost of producing it, 8.5¢/kwhr. Obviously, it could not. If the sales price were stipulated to be 0.45¢/kwhr, and the product gas were required to carry the burden of the loss associated with electricity sale, then the "cost" of the product gas would be $\$7.20/10^6$ Btu of available energy = $\$6.75/10^6$ Btu of energy--which is the same figure obtained by C. F. Braun and Co. [Ref. 28].)

Figure 3 illustrates the unit costs of a modified SYNTHANE process, with a more efficient utility system. In order to appraise the importance of the power plant inefficiency, assume that steam and electric power could be produced at any reasonable costs. The figure is for steam at $\$6.30/10^6$ Btu of available energy and electricity at 2.35¢/kwhr; these costs are conservatively high--attainable even with fuel costs of $\$1.60/10^6$ Btu. Other conservative factors of Figure 3 are: (i) the same oxygen plant efficiency was employed as in the original design; (ii) direct-drive shaft power, produced from steam turbines in the original design, was generated even more inefficiently. (Shaft power was produced by electric motors in Fig. 3, compounding turbine and motor inefficiencies.) Even with these conservative estimates, the unit cost of product gas is reduced from $\$6.10/10^6$ Btu of available energy to $\$4.97/10^6$ Btu. (Or from $\$5.72/10^6$ Btu of energy to $\$4.66/10^6$ Btu.)

Conclusions

These results prove quantitatively that the inefficiency of the power plant and consequent cost of steam and power (which are much too expensive with the C. F. Braun Conceptual Design) is a critical factor, with important impact on product gas cost.

- If excess electricity could be sold at the cost of 2.35¢/kwhr, then $\$4.97/10^6$ Btu of available energy ($\$4.66/10^6$ Btu of energy) would be the net cost of the product gas.
- If excess electricity had to be sold at a lower price, then the product gas would need to bear the loss, and its net cost would be higher. For example, if excess electricity had to be sold at 0.45¢/kwhr,

Figure E-3

Available Energy Flows and Unit Costs (¢/kwhr)

MODIFIED SYNTHANE PROCESS

then the net unit cost of product gas would be approximately $\$5.2/10^6$ Btu of available energy ($\$4.87/10^6$ Btu of energy), still much lower than the C. F. Braun results of $\$7.2/10^6$ Btu of available energy ($\$6.75/10^6$ Btu of energy).

- It is reasonable to assume that the steam and power could actually be produced at even lower costs than the $\$4.97/10^6$ Btu and 2.35¢/kwhr, so that
 - the cost of producing gas would be significantly less than $\$4.97/10^6$ Btu--and that it would be sold for significantly less than $\$5.2/10^6$ Btu even if the excess electricity had to be sold at 0.45¢/kwhr. (Furthermore, a stipulated price of 0.45¢/kwhr on excess electricity is an unrealistic constraint, which is prejudicial against the SYNTHANE process.)
 - The foregoing results give a quantitative indication that the unit cost of SYNTHANE product gas can be reduced substantially by plant re-design.
- There is a significant potential for improvement of the SYNTHANE process

Evidently, the design philosophy that was adopted for the conceptual design of the SYNTHANE process was this: Inasmuch as "unlimited" amounts of char are available--as an inherent by-product of the SYNTHANE gasifier and therefore at "no cost"--the efficiency of utility production is important--especially since any excess electricity can supposedly be sold only at 0.45¢/kwhr. Therefore capital expenditure for utility systems can and should be kept to a minimum, in order to minimize the cost of the product gas. The Second-Law costing analysis, however, shows that it is crucial to the viability of the SYNTHANE process to build a better utility system, and that a reasonable price be acquired for electricity.

It should be noted that, with available-energy accounting, effect of prospective design changes upon product cost can be estimated accurately, without a complete system re-design and re-costing.

Recommendations

I. Process Modifications

- A. Above all, the utility subsystems--Units 30, 31, and 32--should be redesigned, and capital costs need to be determined carefully. It can be expected that the unit cost of producing gas will be reduced by a large amount.
 - Also, the plant should be viewed as a cogeneration facility, and the principal products should be costed at the expense of producing them.
- B. A program should be encouraged for research and development on cells (and other conceivable methods) for reducing the available energy consumption due to combustion in the gasifier. (Such technology would be of great value in all systems where combustion is an important operation.)
- C. Other Process Modifications
 1. The purported technology (and/or flow stream conditions and power) for Unit 18, Acid Gas Removal, should be checked carefully. Also, means for utilizing the available energy of vented CO_2 might be worth pursuing.
 2. Ways of eliminating (or reducing) available energy consumption associated with the mixing of by-pass and shifted gas in Unit 17 might well be studied.

II. Further Analyses

- A. The costing made in this report should be repeated, with the corrected flow rate of available energy-- $800(10^6)$ kcal/hr rather than $686(10^6)$ kcal/hr--of steam to power production.
- B. The study made in this report might well be repeated using other values for various parameters such as (1) Second-law efficiency of various units, and (2) Assumed costs for utilities (fuel costs, etc.).
- C. Sequel studies on other processes besides SYNTHANE and later designs of SYNTHANE.

Other recommendations are presented in Chapter 7.

Chapter 1

INTRODUCTION

This report describes the results of an exhaustive Second-Law Analysis of the SYNTHANE Coal Gasification Process. The first part of the study was devoted to the quantification of the various consumptions of useful energy and the effluent losses thereof, for each of the main unit operations--thereby pinpointing the true inefficiencies.

The subject of the second part was the costing of the useful energy streams flowing between unit operations. Then, each unit operation--which takes useful energy ("fuel") supplied in one or more forms and modifies it or transforms it to another form--can be analyzed economically as a distinct entity, separate from the other units of the overall process. Crucial to such economic analysis is knowledge of the cost of "fuel"--the cost of the useful energy which drives the transformations undergone in the unit. Generally, this cost is known only for the raw fuel coming into the plant, from its price. To obtain the cost of "fuel" at intermediate junctures within a plant, the key is to recognize that the common commodity of value, delivered from one unit operation to another, is the Second Law concept called available energy (exergy).

It is available energy, not the First Law energy, which is the commodity of value. (Indeed what the layman calls energy, and is willing to pay for, is the available energy.) As is commonly known, different forms of energy (chemical, electrical, thermal, hydraulic, . . .) are not equivalent, inasmuch as they have different degrees of usefulness. And, more exactly, the extent of usefulness of a particular form also varies, depending upon the degree of intensity (chemical potential, electrical potential, temperature, pressure, . . .)

The Second Law concept, available-energy (exergy) provides the common basis which measures the usefulness of any form of energy at any intensity. Thus, in general one unit of thermal energy is not equivalent to one unit of electrical energy, nor is one unit of thermal energy at 1000°K

equivalent to one unit at 500°K . However, one unit of thermal available energy at 100°K is equivalent to one at 500°K ; both are equivalent to one unit of electrical available energy, and to one unit of chemical available energy

Each of these different units of available energy is equivalent inasmuch as a task (change, transformation) that could be accomplished by any one could be accomplished by any other. Indeed, any one unit, for example a unit of thermal available energy at 500°K , could be converted to any other unit, such as one at 1000°K . So, then, a unit at 500°K could certainly accomplish whatever could be done with a unit at 1000°K .

It is the available-energy content of a substance, not its energy content, which truly represents the potential of the substance to cause change. Available-energy is the only rational basis for evaluating (1) fuels and resources, (2) process, device, and system efficiencies, (3) dissipations and their costs, (4) the value and cost of system outputs.

Available-energy is based on the Second Law, and goes back to Maxwell (1) and Gibbs (2). Unfortunately, it has not yet caught on in engineering practice, or in managerial decision-making, at least in the United States.

The Subject Analyzed, and the Resources Employed

The present study was made on the PERC Synthane Process, Dry Feed, Export Power. In particular, the system analyzed is the conceptual design by C. F. Braun and Company, described in their "Interim Report" (to U.S.A.E.R.D.A. and A.G.A., numbered FE-2240-5) entitled Factored Estimates for Western Commercial Coal Concepts, and in ancillary reports. A block flow diagram, taken from the Braun report, is shown as Figure 1.

All flow sheets and related information (such as flow rates, compositions, temperatures, pressures, powers, etc.) were obtained from these reports; in particular from Table I-E, Drawings 4568-204-100-XD-1 through -131-XD-1. Also, there was some minor but important augmentation by Mr. Robert A. Johnson of C. F. Braun and Company.

PRELIMINARY
THIS DRAWING IS FOR ESTIMATING
PURPOSES ONLY AND IS NOT TO BE
USED FOR DESIGN OR CONSTRUCTION

FIGURE 1-1

COMMERCIAL CONCEPT DESIGN-WESTERN COAL
PERC SYNTHANE PROCESS
BLOCK FLOW DIAGRAM

ALHAMBRA	C F BRAUN & CO	CALIFORNIA
SCALE NONE	DRAWING NUMBER 4568-204-100-XD-1	REVISION 0

In addition, all capital costs for the various unit operations (and some sub-units) were obtained from the Braun interim report. Tables III-A through III-O and Table VIII-C were used directly for each unit; for sub-units some of the costs were directly available in these tables while others needed to be apportioned on a pro-rate basis. Certain capital requirements for a unit had to be estimated from the overall plant capital requirements in Table III-A on a pro-rata basis: initial charge of catalysts and chemicals, royalties, start-up costs, working capital.

Except for "Raw Materials," by far the largest operating cost, the other annual operating costs were calculated for each unit following the same procedures shown in Table VIII-B for the whole plant. The cost of "Process Operating Labor" was assigned to units on a pro-rata basis, in proportion to unit capital costs. Operating costs for "Catalysts and Chemicals" and for "Purchased Water" were also assigned to units on a pro-rata basis, weighted by expected utilization of these commodities. "By-product Credits" were, of course, given only to units which produced by-products. In the case of "Surplus Electrical Power," no by-product credit was given; instead, the cost of producing this power was calculated (with available energy accounting).

If the cost of "Raw Materials" to a unit were known, then the above-mentioned cost-accounting procedures would allow the cost of delivering the unit's product to be determined. If there is more than one product, a means is necessary for apportioning the total costs among the products. Available energy accounting provides the means for determining the unit cost of "raw materials" at junctures within the plant, and the means for apportioning costs among multiple products.

Chapter 2

SECOND LAW ANALYSIS

Thermodynamics--Its Basic Implications

The basic concepts of Thermodynamics are two commodities called Energy and Available-Energy.^{*} The basic principles are the First Law, dealing with energy, and the Second Law, dealing with available-energy.

Some commodities, like charge, that cannot be produced or consumed, are said to be conserved. The essence of the First Law is that energy is conserved; there is another aspect: the transport of any commodity has an associated energy transport.

The Potential to Cause Change: a Commodity. When does something have the potential to cause change? The answer is: whenever it is not in complete, stable equilibrium with the environment.

In contrast with energy and charge, available-energy is not a conserved commodity. Available-energy is called "energy" in lay terminology, and is the true measure of the potential of a substance to cause change. Consider any "energy" conversion system, such as a power plant (Figure 2-2a) which takes in coal and produces electric power. The rate at which available-energy is delivered (i.e., the power output) is much less than the supply rate of available-energy with coal (i.e., the chemical power input). Most of the difference is consumed--irreversibly destroyed--driving the various processes (such as combustion, heat transfer, fluid flow) going on in the power plant, and a portion is effluent losses (stack gas, cooling water). The effluent losses are generally small compared to the consumptions, contrary to misconceptions which prevail as a result of first law analyses.

The Second Law. In summary, then, whenever something is not in complete equilibrium with the environment it has available-energy. It is available-energy, and not energy, which represents the "capacity to cause change." To accomplish change, available-energy is invariably consumed (irreversibly destroyed).

^{*} Different authors have presented the concept, available energy, with a variety of names (available-work, energie-utilisable, exergy, essergy, potential energy, availability, . . .).

Second Law Efficiency. The general notion of the efficiency of an energy-conversion process, device, or system involves the comparison of the power output divided by the fuel or power input, $\eta = P_{\text{product}}/P_{\text{fuel}}$. However, the crucial aspect in determining the efficiency is the selection of the proper commodity of value.

The conventional first law efficiency is given in terms of energy flows as

$$\eta_I = \frac{P_{E,\text{product}}}{P_{E,\text{fuel}}}$$

where $P_{E,\text{product}}$ is the energy flow rate out, with the product, and $P_{E,\text{fuel}}$ is the rate of energy input with fuel.

Energy is conserved; hence, the denominator of η_I exceeds the numerator by the amount of effluent losses. (The usefulness of the first law efficiency is proportional to the degree to which it approximates the second law efficiency.)

In the theoretical limit, available-energy supplies with any commodity can be completely transferred to any other commodity. In the case of real transformations, the degree to which this perfection is approached is measured by the so-called second law efficiency (also known as the effectiveness^{*}).

$$\eta_{II} = \frac{P_{A,\text{product}}}{P_{A,\text{fuel}}}$$

Here, $P_{A,\text{product}}$ is the power output--available energy of the product--and $P_{A,\text{fuel}}$ is the fuel input rate. The denominator of η_{II} exceeds the numerator by the amount of available-energy consumed plus the amount lost in effluents.

$$\eta_{II} = \frac{P_{A,\text{product}}}{P_{A,\text{product}} + P_{A,\text{consumed}} + P_{A,\text{lost}}}$$

For any conversion process, the theoretical upper limit of η_{II} is 100 percent, which corresponds to the ideal case with no dissipations or losses.

^{*} The concept of effectiveness in this context should not be confused with the more publicized "heat-exchanger effectiveness"; hence, in this report the term "second law efficiency" or "true efficiency" will be used.

To approach that limit, in practice, requires greater and greater capital investment of money and/or time. The tradeoff, then, is the classical one: operating costs (for fuel) versus capital (for equipment and time). An important point here is that optimization of this tradeoff can be greatly facilitated by the application of second law analyses, applying available energy analyses to processes, devices and systems (3-11).

Reference (12) presents relationships for practical evaluation of these energy and available-energy flows for several important special cases. Chapter 4 of this report illustrates the means employed for calculating P_A for the various streams of the SYNTHANE flow diagram.

The Methodology of Available-Energy Analysis

To date, practically all investigations that are made with the intention of locating and evaluating inefficiencies in energy-conversion systems are energy analyses. Energy analyses do not account for the consumptions that serve to drive the different processes and devices. The energy that does not leave in the product must go out with the effluents. As a consequence, the importance of losses associated with effluents is generally over-estimated. The upshot of all this is that energy analyses not only misconstrue the importance of effluents, but also greatly miscalculate the comparative efficiencies of different processes and energy systems (12-14).

Analyses made with available-energy do properly account for both the consumptions that drive the various processes and devices and the effluent losses. In nearly all systems, the consumptions of available-energy are much larger than the effluent losses. In fact, the available-energy content of effluents is usually much less than the associated energy content. Thus available-energy analyses are needed to evaluate "energy" systems.

To improve the operating "fuel" economy of an "energy" system means to lessen the available-energy consumed within the system and lost in effluent streams, so that, for a specified amount of product, the amount of available-energy--"fuel"--that needs to be supplied is thereby reduced.

The second law efficiency of the system is just such a measure of

"fuel" economy. To ascertain this efficiency requires the evaluation of the rate at which available-energy leaves and the rate at which it is supplied. These calculations involve exactly the same type of procedures as the evaluation of energy flows--using (1) balances for each independent commodity which is transported into or out of the system, (2) transport relations between different commodities (such as $P_A = [\phi - \phi_0]I_q$ or $P_E = pI_v$), (3) sometimes kinetic relations (like $Q = -kA[dT/dL]$ or $Q = UA[\Delta T]_m$), which relate transports or reaction rates to driving forces, and (4) invariably, property relations of materials (such as those of H_2O embodied in the steam tables, or $pV = RT$ for perfect gases).

Not only is an overall analysis of an "energy" system valuable, but so is a detailed analysis which pinpoints the location and magnitude of the available-energy consumptions within the system. The procedures for making a more detailed analysis are identical to those for the overall analysis. It is simply a matter of applying balances to subsystems of the overall system. Thus, as is done in this report, a chemical process can be broken down into its unit operations, and each can be analyzed for its own efficiency and for the amount of available-energy it consumes, say as a fraction of the total used by the overall process. Furthermore, units can be analyzed component by component.

Some Results from the Literature

Reistad has estimated the efficiency of available energy utilization in various economic sectors and industrial sectors (13). Figure 2-1 shows his results, in comparison with the mistaken impressions one gets when energy is taken as the commodity of value. Note that from an energy viewpoint, the Utility Sector appears to be quite inefficient, whereas in actuality it is the most efficient. Energy analysis makes the Residential and Commercial sector, and the Industrial Sector, to appear very efficient. Really they are very inefficient, particularly the Household and Commercial. (The efficiency of the Industrial Sector, as calculated by Reistad, is conservatively high--assuming that the temperature at which heat is needed in this sector is the same as the temperature at which it is delivered to processes. More recent analyses (15) would reduce the end-use

Flow of energy in the U. S. [Cook]. All values reported are 10^{15} Btu [$1.055(10^{12})$ J]. $a/$ = The energy value for hydropower is reported in the usual manner of coal equivalent.

Flow of available energy in the U. S. All values reported are 10^{15} Btu [$1.055(10^{12})$ J]. (a) = All values in () are energy, other values reported are available energy. (b) = The energy value for hydropower is reported in the usual manner of coal equivalent: actual energy is 1.12×10^{15} Btu.

(a) Fossil-fueled Steam Power Plant

(b) Total Energy

HEATING

Furnace: $\epsilon - 10\%$

Heat Pump: $\epsilon - 10\%$

REFRIGERATION: $\epsilon - 40\%$

AIR-CONDITIONING SYSTEMS

At design conditions: $\epsilon - 5\%$

Annual average: $\epsilon - 2\%$

(c) Heating and Air-conditioning - 20% of U.S. Fuel Consumption

ENGINES

Compression-ignition (1000 hp)

Full-load: $\epsilon - 48\%$ (34% mechanical, 14% thermal @ 250°F)

Half-load: $\epsilon - 44\%$ (31%, 13%)

Spark-ignition (700 hp)

Full-load: $\epsilon - 45\%$ (33%, 12%)

Half-load: $\epsilon - 43\%$ (29%, 14%)

(Thermal outputs, when 250° steam is generated with exhaust gases and in cooling jacket)

VEHICLE PROPULSION (Typical automobile)

30 mph: 8 hp @ drive wheels, 15 hp throttling loss, 40 hp other losses

80 mph: 65 hp @ drive wheels, 40 hp throttling loss

(d) Large Engines and Vehicle Propulsion

—Availability (and energy) flow diagrams for some typical conversion systems. (a) Steam power plant, (b) All-electric and all-fossil total energy systems, (c) Heating and air-conditioning systems, (d) Large engines (500-1000 hp) and vehicle propulsion.

Figure 2-2

Figure 2-1

available energy in the industrial sector by more than one-half.) The 10 to 15 per cent effectiveness with which available energy is used in this country, though greatly improved over the 2 or so per cent of a century ago, is very low; basically this is encouraging inasmuch as it shows that there is great opportunity for improvement remaining. Conservation, in conversion not in end use, does offer a realistic means for improving the energy situation--especially over the short term, with today's technology--provided capital is brought to bear.

References (16) and (17) analyze the Industrial Sector in more detail. The most efficient industry is Iron and Steel, which utilizes available energy at an efficiency of over 20%; it is the largest consumer, using 15%. As shown by the 30% efficiency of the Japanese Iron and Steel Industry, there is significant room for improvement; however, there is a great amount of capital sunk into existing low-efficiency U.S. heavy equipment and installations. Nevertheless, there are ways for improving the iron and steel fabrication and treatment industry substantially. There are numerous opportunities in other industries also (18).

Figure 2-2, from Reference (19), illustrates the available energy utilization by several common energy-conversion systems and devices. Consider the typical fossil-fired electric power plant in Figure 2-2a. Most notable is that 50% of the potential energy (the available energy) of the incoming fuel is lost immediately, by the boiler: (1) 30% is used up in combustion, an uncontrolled, highly dissipative process; (2) 15% is consumed in the heat transfer from high-temperature combustion products to the steam (and preheated air); and (3) 5%--1% "thermal" and 4% "chemical"--is lost in the stack gases.

An energy analysis implies that the boiler is very efficient, losing only 8% of the input energy--and virtually all associated with stack gas "thermal" losses.

"Energy losses" associated with the condenser, carried into the environment by the cooling water, are great. We hear much about the need to utilize that energy. Actually, virtually none (< 2%) of the resources which went into the power plant is lost in that water. The real loss was (primarily) back in the boiler where "heat" (entropy) was produced.

Once produced, to get its potential energy we must ultimately transmit it to "ground"--to the environment. It carried much energy with it to the environment, but essentially no potential energy. Hence, it has practically no value, and can't be sold. Attempts to take advantage of "all that energy" and thereby improve the utilization of the fuel used by the plant are futile.

(That is not to say that it is never wise to increase turbine back-pressure (or to bleed off steam), in order to get potential energy in thermal form. The point is that there is no gain in effectiveness of plant fuel utilization; the increased potential energy of the cooling water (or the potential energy taken with bleed steam) is at the expense of potential energy of electricity. Nevertheless, from the standpoint of overall fuel utilization, dual-purpose power plants can be wise; there is no gain from plant fuel, but there is hardly any loss. Whereas, to provide the thermal potential energy independently, large losses would be incurred. For example, furnaces and "boilers" used for comfort heating have an abominable effectiveness of about 10%, compared with 50% for the power boiler, due to much larger losses associated with heat transfer--because the heated commodity is at such a low temperature.)

Another important point is that the production of electricity is one of our most efficient energy conversions. The great losses commonly ascribed to the stack gases and cooling water are not losses at all; the actual losses are elsewhere in the plant, and as a fraction of input are small compared with most conversion systems. Furnaces and all-fossil total energy systems, considered to be very efficient, are very inefficient or fairly inefficient, respectively; the total energy systems are certainly no better than all-electric systems. (If they were as much better as is often touted, they would remain competitive even while their fuel is considerably more expensive.) For example, these comments have considerable negative impact on the desirability of high-Btu coal gasification and of "Hydrogen Economy," for the purposes of distributing these synthetic fuels about for combustion in furnaces and boilers.

The foregoing methods for analyzing "energy" systems are aimed at pinpointing the losses and measuring their magnitudes and resultant percent

inefficiencies, in order to determine where opportunities for improvement and conservation lie, for the purposes of decision-making for allocation of resources--capital, R&D effort, and so on. The methods, which involve exactly the same kinds of calculations as energy analyses, also enhance the germination of prospective ideas and the quick evaluation thereof.

Availability analyses are valuable not only for pinpointing losses but also for direct application to the design of energy systems and for other engineering projects (system modifications, maintenance, etc.), as well as for cost allocation. The key to these applications, in their infancy, (3-11) is that monetary value can be assigned to the availability at the different junctures between components of a system, where availability flows into a component as "fuel." Because it is availability, not energy, which "fuels" each device in a system, the only rational way of assigning monetary value (cost) to the "fuel" for each device or process is to assign the value to availability. Then rational comparisons of fuel costs with other operating and capital costs can be made for economic optimization.

Chapter 3

AVAILABLE ENERGY ACCOUNTING

In a variety of circumstances it is desired to cost different forms of "power" delivered by an energy-conversion system, or by sub-systems of a complex system. Once again, the Second-Law concept, available energy, is the commodity of value and, hence, the appropriate commodity to be costed. (See References 3-11, 14)

Costing Energy Flow Streams

Suppose that an industrial concern is engaged in the manufacture of products, some of which are steam-intensive while others are electricity-intensive, while co-generating its own steam and electric power. It is then vitally important for management to debit each product properly for the cost of the electricity and steam used in its manufacture.

A company which co-generates may wish to sell excess steam or electricity to an outside concern; it needs to know the correct costs of these commodities. Or an electric utility may also be distributing and selling steam or hot water.

The goal of the following discussion is to show that "energy" flows (power flows) should be costed on the basis of available-energy content and not energy content. Several rational schemes, each based on the concept of available-energy, are presented along with results of such costing analysis for the co-generating power plants described previously.

Money Balances. The first step in costing "energy" flow streams is the application of money balances to the system of interest. The cost of the product of an energy-converter equals the total expenditure made to obtain it--the fuel expense, plus the capital and other expenses:

$$\$_{\text{product cost}} = \$_{\text{expended}} = \$_{\text{fuel}} + \$_{\text{capital, etc.}}$$

The average unit cost, c_p , of the product is the total cost divided by the output power: $c_p = \$_{\text{prod}} / P_{\text{prod}}$. Similarly, the fuel cost can be expressed as $\$_{\text{fuel}} = c_f P_{\text{fuel}}$ where c_f is the unit cost of fuel and P_{fuel}

is the power input to the converter. One may then write

$$c_p = \frac{c_f P_{\text{fuel}}}{P_{\text{prod}}} + \frac{\$_{\text{capital}}}{P_{\text{prod}}}$$

Recall that the efficiency is simply $P_{\text{prod}}/P_{\text{fuel}}$ so that

$$c_p = \frac{c_f}{\eta} + \frac{\$_{\text{capital}}}{P_{\text{prod}}}$$

The first term on the right reflects fuel costs, and the second, the capital (and other) costs. Normally, to decrease the first requires an increase in the second; and, of course, the aim is to make the investment that minimizes the total. Equations like the latter can be developed to determine the unit cost of the power flows at various junctures of an energy system, including the costs of the products of a multi-purpose system. Such costing is invaluable for the design and operation of energy systems, for technology assessment, and for decision-making.

Costing Methods. Consider an energy-converter, for example a boiler, that takes in fuel and produces a single output such as steam. A money balance on the boiler gives

$$\$_{HP \text{ steam}} = c_{HP} P_{HP} = \$_{\text{fuel}} + \$_{\text{boiler}}$$

Once the fuel cost and boiler costs are known, all that remains is to choose a measure of the product and solve for the unit cost of product. For single-output devices it makes no difference which measure of product output is chosen; it could be mass, energy, available-energy and so on.

In some situations energy-converters yield multiple outputs, as in the case of the turbine in a co-generating power plant, which delivers shaft power and low-pressure (LP) steam. A money balance on the turbine results in the expression

$$c_{LP} P_{LP} + c_{\text{shaft}} P_{\text{shaft}} = c_{HP} P_{HP} + \$_{\text{turbine}}$$

Generally the right-hand side and the power flows, P_{LP} and P_{shaft} , are known. This results in one equation with two unknowns; the unit costs c_{LP} and c_{shaft} . Another equation is needed. There are various methods

for obtaining a second equation, depending on economic considerations.

The presentation which follows, for co-generation systems that have only two outputs (say steam and shaft power from a turbine), discusses the economic considerations underlying various methods for obtaining additional cost equations.

The extraction method charges the shaft work for the capital cost of the turbine and for the available-energy extracted from the steam to produce the work. With this rationale, the additional equation is obtained by equating the unit costs of high- and low-pressure steam available-energy, $c_{LP} = c_{HP}$. The result is that the shaft work bears the entire burden of the costs associated with the turbine process and capital expense.

On the other hand, the equality method charges the shaft work available-energy and the low-pressure steam available-energy equally for the cost of high pressure steam and turbine capital: $c_{LP} = c_{shaft}$. Then, the money balance on the turbine gives

$$c_{shaft} = (c_{HP} P_{HP} + \$_{turbine}) / (P_{LP} + P_{shaft})$$

Insofar as the purpose of a turbine is to produce shaft work, the extraction method is appropriate since it charges the work for the turbine capital and inefficiency. However, if there were no turbine, the efficiency of producing any required low-pressure steam would be lower and, hence, its unit cost higher. So, it is not inappropriate to charge this steam proportionately for the costs attributable to the turbine--to charge the back-pressure steam power and shaft-work power equally.

Sometimes an industrial concern may view the shaft-work as a by-product. The by-product work method assumes that the steam delivered by the turbine would have to be produced anyhow (say to meet process requirements), even if no power were produced. The available-energy in steam is therefore costed as if it alone were produced--in a hypothetical low-pressure boiler which would deliver steam at the pressure and temperature at which it is needed:

$$c_{LP} = \frac{c_{fuel} P_{fuel}}{P_{LP}} + \frac{\$_{LP \text{ boiler}}}{P_{LP}} = \frac{c_{fuel}}{\eta_{II, LP \text{ boiler}}} + \frac{\$_{LP \text{ boiler}}}{P_{LP}}$$

The low-pressure boiler has a lower efficiency, η_{11} , than does a high-pressure boiler and, as a result, the cost c_{LP} will be greater than for high-pressure steam. Once this c_{LP} is known, the money balance on the turbine can be solved for c_{shaft} . This method results in unit cost values for the low-pressure steam that are substantially higher than the equality or extraction methods. Conversely, the cost of shaft work will be lower.

Similarly there are instances in which the steam should be considered as a by-product. The by-product steam method charges the shaft work on the basis of the cost to produce shaft work from a condensing turbine or on the cost of purchased shaft work (really electricity plus the cost of a motor), whichever is cheaper:

$$c_{shaft} = c_{shaft, condensing} \text{ or } c_{shaft} = c_{shaft, purchased}$$

The cost of low-pressure c_{LP} can then be obtained from the turbine money balance.

The choice of a costing method depends upon the object of economic study and/or upon the circumstances under which it is being made

Up to this point the methods discussed involve only average unit costs of flow streams. A different problem is one in which an economic study needs to be made to ascertain the desirability of increasing (or decreasing) the manufacture of some product, which results in additional power requirements. The incremental method--which charges the additional units of power required for the cost of producing them--is then appropriate. The use of the average cost to produce all of the units would be inappropriate. Incremental costing also should be employed when the costs at junctures within a system are needed for purposes of selecting system components in a way which gives an optimal system design. (See (8) for examples of incremental costing.) Many times the incremental costs are well approximated by the average costs--especially for devices in which the Second-Law efficiency is relatively constant.

Improvised Energy Methods. Having realized the inadequacy of energy methods, some have improvised methods for adapting them. Even though they are awkward, these schemes sometimes give good results inasmuch as they approximate available-energy techniques. For cogeneration systems delivering

two products, and where one of the two can clearly be called the principal product, costing can be done without recourse to available energy--for the same reason that the output of a single-product system can be costed using any measure of the output. For example, if back-pressure steam is produced by an electric power plant, costs would be apportioned to steam and electricity by determining the "electricity equivalent" of the steam--i.e., the amount of electricity that could have been produced had the steam not been bled off. This calculation can be made with an energy analysis alone. But it is a calculation of the available energy of the steam!

When there are several products co-generated (e.g., electricity, compressed air, steam at several pressures, refrigeration at $T < T_0$!, . . .) such equivalence schemes become virtually impossible to contend with. In any case, they are only roundabout ways of getting to the fundamental results that could have been reached much more directly. Therefore, it is important that the fundamental validity of available-energy techniques, and the straightforward methodology for applying them become well known.

Chapter 4

CALCULATION OF AVAILABLE-ENERGY QUANTITIES

Introduction

The specific purpose of this chapter has to do with the mechanics of translating the availability concepts and equations explained in preceding chapters into concrete numerical values for particular instances. Some of the expressions to be introduced are formulae yielding the value of the availability itself; others serve to obtain values of properties which are required in the evaluation of the availability formulae. Several concrete applications will be discussed by way of illustrations. The procedures employed were generally equivalent to those presented in Reference 20, augmented as described in the following sections.

Not only were available energy quantities evaluated relative to the dead state--the stable species as they exist in the reference environment (20)--but so were the energies. Indeed, if values of availability are established with reference to stable species as they exist in the reference atmosphere, it is only logical to use the same criterion for the enthalpy values of the various substances. Thus, if a given component exists as a stable species in the reference atmosphere, its base enthalpy will be zero by definition. If it does not, then $h_j(T_0)$ represents the energy exchange that would be involved in bringing that constituent to equilibrium by allowing it to react with stable species of the reference atmosphere. Thus, for example, the value of $h_j(T_0)$ for the stable species O_2 or CO_2 is zero, whereas that of CO is determined from the reaction

$$h_{CO}(T_0, P_0) = h_{f_{CO}}(T_0, P_0) + 1/2 h_{f_{O_2}}(T_0, P_0)$$

$$- h_{f_{CO_2}}(T_0, P_0) = 282.964 \text{ kJ/mol}$$

Base enthalpy values for several substances are given in table 4-1, along with the chemical available energies. Numerical values for all enthalpies of formation have been taken from Reference 21 for use in the

Table 4-1

Base Enthalpies and Chemical Availabilities of
Some Components

<u>COMPONENT</u>	<u>BASE ENTHALPY (kJ/mol)</u>	<u>CHEMICAL AVAILABILITY (kJ/mol)</u>
Ammonia	382.585	$2.478907 \ln x_{\text{NH}_3}^* + 402.541$
Benzene	3,301.511	$2.478907 \ln x_{\text{C}_6\text{H}_6} + 3,353.305$
Carbon (graphite)	393.505	365.140
Carbon Dioxide	0.0	$2.478907 \ln x_{\text{CO}_2} + 20.108$
Carbon Monoxide	282.964	$2.478907 \ln x_{\text{CO}} + 275.346$
Carbon Oxsulfide	888.012	$2.478907 \ln x_{\text{COS}} + 756.892$
Ethane	1,559.896	$2.478907 \ln x_{\text{C}_2\text{H}_6} + 1,632.082$
Hydrogen	285.851	$2.478907 \ln x_{\text{H}_2} + 290.757$
Hydrogen Sulfide	901.757	$2.478907 \ln x_{\text{H}_2\text{S}} + 759.380$
Methane	890.359	$2.478907 \ln x_{\text{CH}_4} + 918.248$
Nitrogen	0.0	$2.478907 \ln x_{\text{N}_2} + 0.693$
Oxygen	0.0	$2.478907 \ln x_{\text{O}_2} + 3.948$
Phenol	3,127.749	$2.478907 \ln x_{\text{C}_6\text{H}_5\text{OH}} + 3,275.605$
Sulfur (rhombic)	636.052	513.159
Sulfur Dioxide	339.155	$2.478907 \ln x_{\text{SO}_2} + 216.748$
Water	0.0	$2.478907 \ln x_{\text{H}_2\text{O}} + 8.595$

* x represents the component's molal fraction; for pure substances, of course, $\ln x = 0$.

pertinent calculations; the same source yielded the values of absolute entropy needed for the calculation of chemical availabilities at (T_0, p_0) .

Correction for Real-Gas Mixtures

The formulas for evaluating available energy in Reference 20 are for ideal gas mixtures. For real gases, two corrections are needed; the enthalpy and entropy of the mixture itself, rather than those of each constituent, can be corrected by means of generalized deviation charts or equations. In order to make their use possible, a mixture rule to obtain pseudo critical temperature and pressure is needed; because it offers the greatest simplicity, Kay's rule has been employed.

Although in principle it is possible to program the corrections using generalized virial equations of state with T_r and p_r as variables, the direct use of charts for correcting the ideal values obtained from programmed calculations has been used here.

Some Special Gas Mixtures

Not infrequently, the thermodynamic state of a mixture is such that the coexistence of liquid and vapor phases is suspected. In this situation it is important to determine the molal composition of the vapor phase in order to apply to it the formulae just discussed, treating the liquid phase or phases separately. As an engineering approximation, the following procedure has been used to determine which components could possibly be in two phases and in what respective amounts.

A first step rules out a two-phase existence for all those components whose critical temperatures are lower than that of the mixture. When the latter is lower, the component could conceivably exist in two phases. In the cases encountered in this study, the number of potential two-phase components was normally one or two and exceptionally as high as four. These cases were analyzed as follows.

First, the individual saturation pressures at the mixture's temperature were obtained. If $p_{\text{sat}_i} > p_{\text{mix}}$, it follows that the partial pressure p_i is smaller than the corresponding saturation pressure and that,

therefore, that component is entirely vapor. If $p_{\text{sat}_i} < p_{\text{mix}}$, the reasoning must be carried on further. Since the saturation pressures encountered were considerably smaller than the respective critical pressures, the vapor phase was assumed to behave ideally and, hence,

$$x_{\text{sat}_i} = p_{\text{sat}_i} / p$$

It is known that the total molal mass of the gas mixture at saturation can be expressed as

$$N = N_v + \sum x_{\text{sat}_i} N$$

where N_v represents the combined molal mass of all components known to be in the vapor phase only and the subscript i refers to any component potentially present in two phases. To simplify the illustration, it will be assumed that only two components ($i = 1, 2$) can exist in two phases. Then,

$$N - N_v = x_{\text{sat}_1} N + x_{\text{sat}_2} N$$

$$N = \frac{N_v}{1 - (x_{\text{sat}_1} + x_{\text{sat}_2})}$$

Thus, it follows that the values $N_{\text{sat}_1} = x_{\text{sat}_1} N$

and

$$N_{\text{sat}_2} = x_{\text{sat}_2} N$$

can be estimated.

If N_{sat_i} exceeds the actual molal mass of component i , that component exists in the vapor phase only. Indeed, since $x_i N = N_i < x_{\text{sat}_i} N$, the smaller molal fraction $x_i < x_{\text{sat}_i}$ reflects a partial pressure $p_i = x_i p$ smaller than the corresponding saturation pressure $x_{\text{sat}_i} p$. If, on

the other hand, $N_{\text{sat}_i} < N_i$, then N_{sat_i} represents the molal amount of vapor phase of that component. The balance, $N_i - N_{\text{sat}_i}$, exists in the liquid phase. If more than one component exists in the liquid phase, the resulting liquid mixture is then treated as an ideal solution.

Availability of Incompressible Fluids

For a pure substance, the availability transfer associated with a flowing fluid is

$$a = h - T_0 s - \mu_0$$

It is readily shown that, to the extent that a liquid is incompressible, its availability can be expressed as

$$a_{\text{liq}} = a_t + v[p - p_0] + a_c$$

where a_t and a_c are the usual thermal and chemical availabilities.

Chemical Availability of Hydrocarbon Fuels

Many of the fuels ordinarily encountered in industrial applications are not pure substances but a mixture of an often large number of components. Szargut and Styrylska (22) obtained in 1964 a series of equations applicable to hydrocarbon fuels. The chemical availability of many fuels with known values of LHV and s_0 was computed by Szargut and Styrylska and a correlation established for a_c/LHV in terms of their atomic ratios or corresponding mass ratios. Three categories of fuels were studied, namely, solid fuels containing no sulfur, sulfur-bearing solid fuels, and fluid fuels. Their equations were employed in the present study, using LHV values from (21) and (23).

In the study of fluid fuels by Szargut and Styrylska, availability losses associated with mixing were ignored since they are insignificant compared with the chemical availability of a fluid mixture. Thus, for instance, in the case of a gas mixture of ten components in equal proportions, the decrease in availability due to mixing was calculated to be

5,700 kJ/kmol, while its chemical availability had a value of at least 800,000 kJ/kmol; in this illustration, then, the availability lost in the mixing process amounted to no more than 0.71% of the chemical availability.

All the correlation formulas were obtained from fuels for which both the lower heating value and the absolute entropy at (T_0, p_0) are known. Because the latter is not known for the generally used solid and fluid fuels such as bituminous coal, lignite, cokes, oil, tar, and so on, the equations are offered as plausible approximations for these based on analogy of behavior. An important observation should be made in this respect.

The model used in these equations presupposes that the effect of intermolecular and intramolecular interactions upon the ratio a_c/LHV depends only on the atomic ratios. This is clearly an assumption, and the good correlations obtained by Szargut and Styrylska show that the assumption is good at least for the fuels they considered--all of these pure substances. There is no apparent reason to suspect that the correlation would not hold acceptably well for mixtures such as coal, petroleum, and so forth.

Availability of Coals, Chars and Ashes

Of the three contributions to availability (chemical, thermal, pressure) only the thermal and chemical availability are of any significance when dealing with solids, since their thermodynamic behavior is independent of pressure in the pressure ranges ordinarily encountered.

The thermal availability can easily be obtained from the expression

$$a_t = \int_{T_0}^T c_p \left(1 - \frac{T_0}{T}\right) dT$$

if the function $c_p(T)$ is known. This information, however, is not always available for every variety of coal or char, but approximate formulas have been offered in the pertinent literature.

A. Lee (24) has developed a formula that correlates the mean specific heat of coal between 70 F and T in terms of its volatile matter content.

An alternative to the analytical approach offered by Lee is found in

the tabulated values of mean specific heat between 0 and T degrees C, at different values of volatile matter content, published by the Institute of Gas Technology (25). In contrast to Lee's formula, the volatile matter content is here expressed as a mass fraction of the dry, ash-free (not just dry) coal at 0 C. In the present work nearly equal results were obtained using both approaches, but the use of tables is more straightforward.

The above formula holds also for ash, but its mean specific heat between 0 and T degrees C is given by a different expression found also in the Institute of Gas Technology report referred to earlier. The formula

$$\bar{c}_{\text{ash}} = 0.18 + 7 \times 10^{-5} T \text{ (C)} \frac{\text{cal}}{\text{g K}}$$

holds in the temperature 0 - 1,100 C. The chemical availability of ash is assigned a value of zero at the temperature and pressure of the reference environment.

Availability of Tars

If the chemical composition of the tar is known, the procedure to compute its chemical availability is entirely parallel to that used for coals and chars. After estimating the tar's lower heating value and determining its atomic ratios, the corresponding formula of Szargut and Styrylska is applied.

The pressure availability can be obtained by using the formula developed earlier in this paper for the incompressible fluid model, namely,

$$a_p = v (p - p_0)$$

The value of v is easy to compute if the specific gravity of the tar at hand is known. Because frequently this is not the case, an average of representative specific gravity values for tars can be used as an alternative since the contribution from either the pressure availability, a_p , or the thermal availability, a_t , is usually much smaller than the chemical availability, a_c .

The last remark serves also to obviate the difficulty of lack of

specific heat data for individual tars that prevents the exact evaluation of the thermal availability. A graphical procedure was used here (as an approximation in cases where no information was available on the specific heat of a tar present at some stages of the coal gasification process) based on specific heat data at seven temperatures for two different tar samples as reported by Hyman and Kay (27).

Chapter 5

Results of Efficiency Analysis

Every unit operation of the SYNTHANE process, shown on Figure 1-1, has been analyzed in detail. All available energy flows to and from a unit were evaluated, in order to determine the amount of available energy consumed by the unit and to evaluate the efficiency of the unit. Furthermore, for the more important units--those with the largest consumptions--the principal sub-units were also analyzed, in order to ascertain what were the causes of large consumptions. (In some instances, though, internal details for a unit were unavailable, so that sub-units could not be studied: Unit 32, Oxygen Production; and Unit 18, Acid Gas Removal.)

In this chapter, the results will be presented in several stages. Each stage will show more and more details.

An Overview

The first stage is presented by a single figure, Figure 5-1. Therein, many of the units have been lumped together into groups:

- Coal Preparation Group
 - Unit 11, Coal Storage and Reclaiming
 - Unit 12, Coal Preparation
 - Unit 14, Coal Feeding
- Gasifier
 - Unit 15, Gasification and Char Cooling
- Steam, Power and Oxygen Group. This group consists of those auxiliary units which provide "utilities" to the chemical processing
 - Unit 30, Steam, Shaft Power and Electric Power Production
 - Unit 31, Water Treatment
 - Unit 32, Oxygen Production

In actuality, shaft power for chemical unit operations is not produced in Unit 30; rather, Unit 30 delivers steam to turbines at

Figure 5-1

Available Energy Flow Diagram
 SYNTHANE PROCESS CONCEPTUAL DESIGN

AVAILABILITY FLOWS

10020 PLANT 28
ALL UNITS: MILLION KCAL/HR

PRELIMINARY
THIS DRAWING IS FOR ESTIMATING
PURPOSES ONLY AND IS NOT TO BE
USED FOR DESIGN OR CONSTRUCTION

FIGURE 5-2

COMMERCIAL CONCEPT DESIGN-WESTERN COAL PERC SYNTHANE PROCESS BLOCK FLOW DIAGRAM			
ALHAMBRA C F BRAUN & CO CALIFORNIA			
DESIGN NO.	5-1	PROJECT NO.	4568-204-100-XD-1
DATE	5-1-1978	REVISION	0

the unit. However, for the purposes of the efficiency analysis, the inefficiencies associated with production of shaft power were allocated to Unit 30.

- Conversion, Methanation, Treatment Group. This "remainder group" consists of two categories:
 - Gas Processing Units, which process the gas from the Gasifier into acceptable Product Gas
 - Unit 16, Raw Gas Quench
 - Unit 17, Shift Conversion
 - Unit 18, Acid Gas Removal
 - Unit 19, Methanation
 - Unit 23, Product Gas Drying
 - The second category includes the auxiliary units which are devoted to Waste Treatment and Recovery.
 - Unit 20A, Sour Water Stripping
 - Unit 20B, Ammonia Recovery
 - Unit 20C, Biological Oxidation
 - Unit 21, Sulfur Recovery
 - Unit 22, Solids Disposal

The overall Second-Law efficiency of the process could be defined as the total available energy of product gas, export electricity and by-products, all divided by the available energy in the coal supplied:

$$\eta_{II} = \frac{2863 + 128 + 335}{7195} = 46\%$$

This can be compared with the First-Law "Plant Thermal Efficiency"

$$\eta_I = \frac{3048 + 128 + 323}{6367} = 55\%$$

and with the "Cold Gas Efficiency"

$$\eta_{CG} = \frac{3048}{6367} = 48\%$$

There does not appear to be substantial differences in these First and Second

UNIT 11

COAL STORAGE AND RECLAIMING AVAILABILITY FLOWS,
(10^6) kcal/hr

IN		OUT	
1. Coal from Loading System:	6,183	2. Coal to Unit 12:	6,183
2. Electricity:	1.4		

Second-Law Efficiency = 99.98%

Availability Consumption = 1.2

Figure 5-3

UNIT 12
COAL PREPARATION AVAILABILITY FLOWS,
(million kcal/hr)

IN		OUT	
1. Coal from Unit 11:	6,183.44	4. Coal to Unit 14:	5,967.10
2. Water from Unit 22:	1.90	5. Slurry to Unit 22:	2.10
3. Air (95°F; 13 psia; W = 0.0112):	≈0.00	6. Flue gas to Unit 21:	9.70
7. Electricity	12.1		

Second Law Efficiency: 96.5%

Availability Consumption: 218

Figure 5-4

UNIT 14
COAL FEEDING AVAILABILITY FLOWS
(million kcal/hr)

IN		OUT	
1. Coal from Unit 13:	5,966.21	3. Coal to Unit 15:	5,968.17
7. CO ₂ from Unit 18:	111.68	5. Vent Gas:	24.11
8. Electricity:	2.60	6. Gas with Coal:	53.05
9. Shaft power:	44.00		

Second Law Efficiency: 98.71%

Availability Consumption: 79.1

Figure 5-5

UNIT 15
GASIFICATION AVAILABILITY FLOWS,
(million kcal/hr)

IN			OUT		
1.	Coal from Unit 14:	5,966.56	9.	Gas to Unit 16:	3,661.17
2.	CO ₂ with Coal	53.18	10.	Steam and Char to	
3.	Oxygen from Unit 32	30.00		Unit 30:	1,599.53
4.	1450 psig Steam to Gasifier	142.0	11.	Hopper Vent Gas:	1.00
5.	Purge Gas from Unit 23:	2.68			
6.	1450 psig Steam to Educator	14.4			
7.	1450 psig Atomizing Steam:	4.87			
12 & 13.	Process water from Unit 17:	24.23			
14.	150 psig Steam to Char Lock				
	Hoppers:	1.67			
15.	Electricity	1.0			

Second Law Efficiency: 84.33%
Availability Consumption: 978.8

Figure S-6

Figure 5-7a

$$\text{Net Steam Availability Output} = 1030 - 23 - 6.5 = 1000$$

$$\text{Availability Consumption} = 1392$$

UNIT 16

RAW GAS QUENCHING AVAILABILITY FLOWS,
(million kcal/hr)

IN		OUT	
1. Gas from Unit 15:	3,661.74	4. Gas to Unit 17:	3,191.01
5. Water from Unit 17:	16.77	7. Tar:	152.64
29. Electricity:	1.3	8. Flash Gas:	0.27
		26. Quench slurry to Unit 22:	2.02
		27. Waste heat to steam system:	225
		28. Waste heat to cooling water:	0.08
Second Law Efficiency: 97.1%			
Availability Consumption: 108			

Figure 5-8

UNIT 17
SHIFT CONVERSION AVAILABILITY FLOWS,
(million kcal/hr)

IN		OUT	
1. Gas from Unit 16:	3,191.01	9. Gas to Unit 18:	2,885.98
27. Electricity:	0.9	10. Sour Water:	41.65
		11. Water to Unit 16:	16.70
		13. Water to Unit 15:	24.56
		26. Waste heat to water system:	123.91

Second Law Efficiency: 96.91%

Availability Consumption: 99.2

Figure 5-9

UNIT 18

ACID GAS REMOVAL AVAILABILITY FLOWS,
(million kcal/hr)

IN		OUT	
1. Product gas from Unit 17:	2,885.98	4. Product gas to Unit 19:	2,642.05
2. Steam from Unit 30:	13.50	5. Acid gases to Unit 21:	38.82
3. Heat exchange from Unit 19:	28.69	6. CO ₂ to vent and to Unit 14:	217.30
7. Shaft power:	56.00	8. Electricity (net):	1.5
		9. Light Oil:	98.3

Second Law Efficiency: 100.46%*

*Second-law efficiency greater than 100% is impossible. Unit 18 is proprietary, and not described in adequate detail in Technical Appendix I (C.F. Braun Interim Report). Although additional information was obtained from C.F. Braun, it was not possible to conduct a sufficiently detailed analysis to determine the source of this impossible 100.55% efficiency. Conceivable sources are (1) additional availability inputs, (2) erroneous data, (3) impossibility of the proprietary unit to perform as claimed, etc.

Figure S-10

UNIT 19
METHANATION AVAILABILITY FLOWS,
(million kcal/hr)

IN		OUT	
1. Gas from Unit 18:	2,642.05	17. Gas to Unit 23:	2,463.03
39. Electricity:	2.06	33. Condensate to water system:	0.63
40. Shaft power:	6.00	36. Waste heat to Unit 30:	109.41
		37. Waste heat to water system:	6.98
		38. Waste heat to feed gas loop from Unit 18:	28.69

Second Law Efficiency: 98.44%

Availability Consumption: 41.4

Figure 5-11

UNIT 23

PRODUCT GAS DRYING AVAILABILITY FLOWS
(million kcal/hr)

IN		OUT	
1.	Gas from Unit 19: 2,462.28	2.	Gas to pipeline: 2,461.47
16.	Heat exchange from Unit 30: 0.59	3.	Flash gas: 0.59
17.	Electricity: 0.5	4.	Vent gas: 0.20
18.	Shaft power: 1.6	5.	Purge gas to Unit 15: 2.80

Second Law Efficiency: 99.95%

Availability Consumption: 1.22

Figure 5-12

IN		OUT	
1. Shift Condensate:	40.96	9. NH_3 Recovery Feed:	19.16
2. Quench Condensate:	0.27	13. Water to Unit 20C:	22.40
3. Sour Water from Unit 18:	0.001	22. Waste heat to Unit 30:	3.21
21. Heat exchange from Unit 30:	7.10		

Second Law Efficiency: 92.36%

Availability Consumption: 3.7

*Throttle or turbine (pressure reduced from 933 to 73 psia). Stream 117 is sour water as it leaves Unit 17 ($A_{117} = 41.65$ million kcal/hr).

Figure 5-13

UNIT 20B

AMMONIA RECOVERY AVAILABILITY FLOWS

(million kcal/hr)

IN		OUT		
9.	NH ₃ recovery feed:	19.16	10. NH ₃ to storage:	14.40
15.	Boiler feed water:	0.05	11. Waste gas to Unit 21:	3.73
16.	Steam from Unit 30:	6.74	12. Water for cooling tower makeup:	0.35
17.	Cooling water in:	0.09	14. Condensate to water system:	0.12
19.	Electricity:	0.1	18. Cooling water out:	1.25

Second Law Efficiency: 75.59%

Availability Consumption: 6.4

Figure 5-14

UNIT 20C

BIOLOGICAL OXIDATION AVAILABILITY FLOWS,
(million kcal/hr)

Second Law Efficiency: 73%*

Availability Consumption: 6.5

Figure 5-15

*Available Energy Inputs with Sodium Hydroxide and Phosphoric Acid are 0.011 and 0.007 10^6 kcal/hr, respectively.

UNIT 21

SULFUR RECOVERY AVAILABILITY FLOWS

42

(million kcal/hr)

IN

OUT

1. Acid gases from Unit 18:	38.82	6. Steam to Unit 30:	0.50
2. Ammonia acid gas from Unit 20B:	3.73	7. Clean flue gas to stack:	76.92
3. Water from Unit 22:	0.02	8. Sulfur to storage:	23.10
4. Steam from Unit 30:	0.30	9. Waste heat to Unit 30:	2.00
5. Raw flue gas from Units 12 and 30:	80.00		
10. Shaft power:	1.50		
11. Electricity	5.8		

Second Law Efficiency: 78.8%

Availability Consumption: 27.6

Figure S-16

UNIT 22

SOLIDS DISPOSAL AVAILABILITY FLOWS,
(million kcal/hr)

IN		OUT	
1. Slurry from Unit 12:	0.113	7 & 16. Water to Units 12 and 21:	0.045
2. Solids from Quench:	0.003	11. Solids to off plot:	0.185
3. Solids from S recovery:	0.002	19. Ash from superheaters:	0.377
4. Solids from evaporator:	0.004	20. Ash from boilers:	2.138
17. Compressed air:	0.020	21. Electricity:	0.438
18. Water from water system:	0.008		

Figure 5-17

Law efficiencies. (This is a consequence of the "quirk" that the energy and available energy of each product, and of the coal supplies, happen to be close in value.) But where, within the plant are the inefficiencies?

Figure 5-1 shows that the largest consumptions of available energy are associated with the production of utilities and with gasification.

With regard to the generation of utilities, large consumptions of available energy are to be expected, with today's technology. However, the 26% efficiency with which they are produced in the SYNTHANE process conceptual design is extremely low. An overall efficiency approaching 35% should be achievable, 30% easily. As will be shown later, such an improvement would result in a surprisingly large reduction of the cost of product gas. There is a substantial amount of consumption in the Gas and Waste Treatment group; but, as will be seen, this is the sum of several small consumptions from each of several units. On the other hand, the consumption in Unit 15 is virtually all associated with the chemical kinetics of the gasification, which could perhaps--could very likely--be reduced significantly.

The Second Law efficiency of the Gasification Unit is

$$\eta_{II} = \frac{4261}{7005 - 1862 + 228} = 79\%$$

Compare this with the First-Law efficiency

$$\eta_I = \frac{4896}{6200 - 1776 + 451} = 100\%$$

Naturally this First-Law efficiency is 100%; energy is conserved, and there are practically no energy losses from the Gasifier Unit (at least according to the C. F. Braun flow sheet data)! Looking at this unit operation from the First-Law standpoint, with energy viewed as the commodity of value, the Gasifier appears to be a highly efficient converter. The wise technologist (scientist, engineer) realizes that there are some irreversible dissipations in the gasification. But how can it be quantified, using energy? With cold gas efficiency? η_{CG} is a reasonable attempt--underneath it all, an attempt to find an "energy" substitute for available energy. However,

the cold gas efficiency of the gasifier fails to give any credit to the gas for its "heat," which certainly has some value. If it is argued that one should look at the combination of Gasification Unit and Raw Gas Quench Unit, for which cold gas efficiency would then be meaningful, then the question is returned, "Where, in the combination, are the inefficiencies and what are their relative magnitudes?" The only resolution is to face the fact that available energy is the true commodity of value and, in turn, that Second-Law efficiency is the appropriate measure."

A Detailed View

Figure 5-2 is another available energy flow diagram; in this instance each unit is shown separately. However, not all flows between units are shown; in some cases "minor" flows have been combined, or even neglected if very small. Figures 5-3 through 5-17 show each of the units alone, Units 30 and 31 (Steam Production and Plant Water System) have been combined; and, as will be explained, no separate figure is presented for Unit 32 (Oxygen Plant).

The source of information for the thermodynamic state and composition of the flow streams is the aforementioned report of C. F. Braun and Company, Reference 28. This report also provided the needed information to evaluate most of the other available energy flows, such as process and steam for turbine shaft power. The report was augmented by information from Mr. R. A. Johnson of C. F. Braun and Company, who verbally provided (1) the composition and temperatures of flue gases, (2) the flow rates and compositions of the streams to and from Units 18 and 21, in particular the acid-gas stream between them, and (3) the distribution of electric power consumptions throughout the plant.

As already mentioned, Figures 5-3 through 5-17 include more details than Figure 5-2, inasmuch as all available energy flows to or from a unit are shown. However, no additional details regarding the breakdown of the available energy consumption among sub-units is shown (except for Units 30 and 31). It should be mentioned, though, that, for the principal processing units, a more detailed analysis was made, yielding the breakdown of consumptions; when relevant, these details will be presented in the discussion which follows.

* Figure A-1, Appendix, shows both available energy and energy flows.

In contrast to Figure 5-1, whereupon the units for available energy and energy are megawatts (Mw), on Figures 5-2 through 5-17 the units are million kilocalories per hour (10^6 kcal/hr).

Also, in Figure 5-2 through Figure 5-17, the Second-Law efficiency of every unit is defined in the same way:

$$\eta_{II} = \frac{E(\text{all available energy outputs})}{E(\text{all available energy inputs})}$$

Unit 15, for example, has a higher efficiency when evaluated in this manner than in the manner associated with Figure 5-1--namely available energy output in the principal product, divided by the net input. Regardless of how the efficiency is calculated, the fundamental quantities of interest--the available energy consumptions in a unit, and the effluent losses therefrom--remain the same.

Coal Preparation. The quantities shown on Figure 5-2 amplify on those in Figure 5-1. It can be seen that, of the 392 Mw = 337 (10^6) kcal/hr of available energy consumed in Units 11, 12 and 14, a majority of 217 (10^6) kcal/hr is used up in Unit 12, primarily for drying the coal. Unit 14, which pressurizes the coal for feeding into the gasifier, uses up about half as much, with 79 (10^6) kcal/hr consumed within the unit and 24 (10^6) kcal/hr wasted in vented CO_2 .

Before proceeding to discuss the steam generation unit, the following explanation should be presented: A fraction of the steam is generated in waste-heat boilers in various other units (such as Units 16 and 19); also there is a fair amount of feedwater heating in different units (e.g., 16, 17, 19, 20, 21, 31). The available energy which is consumed in waste-heat boilers and feedwater heaters have been attributed to Steam Generation, Unit 30. In other words, the unit which supplies heat to a feedwater heater (or waste-heat boiler) is credited with all of the available energy given up by the flow stream. Part of the available energy which is given up reaches the steam, while part is consumed in accomplishing the transfer to the steam. Unit 30 is charged (debited) for both the available energy added to the steam and that consumed to accomplish the addition. Thus, for example, Unit 19 (Fig. 5-11) is credited for 109 million kcal/hr of

available energy delivered to the waste-heat boiler. Unit 30 (Fig. 5-7) is debited for this amount; 31 = 62 - 31 units end up in the steam, while 78 = 109 - 31 units are consumed by the waste-heat boiler--taken to be a part of Unit 30.

The generation of steam consumes $1152(10^6)$ kcal/hr; the efficiency of steam generation is

$$\eta_{II} = \frac{800}{800 + 1152} = 41\%$$

compared to an expectable (see Ref. 19) Second-Law efficiency of 50% for the production of steam at such high pressures. It is clear, then, that the process could be improved greatly by generating steam more efficiently. For example, if steam generation were at $\eta_{II} = 50\%$, and the additional available energy in the steam were used to produce electricity at an expectable $\eta_{II} = 75\%$, then the electricity output could be increased by $130(10^6)$ kcal/hr = 150 Mw.

From Figure 5-2 the Second-Law efficiency of the Oxygen Plant is seen to be approximately 20%, compared to an expectable (29) value of about 45%. Thus, to produce the $30(10^6)$ kcal/hr of oxygen, a shaft power input of $30/0.45 = 67(10^6)$ kcal/hr should suffice, leaving another $142 + 8 - 67 = 83(10^6)$ kcal/hr = 97 Mw of shaft power for, say, the production of an additional 90 Mw or more of electricity. (A separate diagram is not presented for Unit 32, inasmuch as no more detail could be shown than on Fig. 5-2; also, the Braun report gives no details regarding the oxygen production unit, so that a breakdown of the inefficiencies could not be made.)

The efficiency with which shaft power is produced from steam available energy is very low:

$$\eta_{II} = \frac{470}{800} = 59\%$$

compare this to an expectable 85%, which would yield an output of 680 million kcal/hr instead of the 470. The additional 210 would yield close to $200(10^6)$ kcal/hr = 230 Mw of additional electric power.

These three improvements alone--in steam generation, oxygen production;

and shaft power generation--could increase the export power from 128 Mw to over 600 Mw. As will be elaborated upon later, if the export power were sold at merely the cost of producing it (but higher than the paltry 4.5 mill/kwhr credit allowed by ERDA in the Braun study), then the consequent decrease in cost of product gas is very large.

Gasification Unit. The available energy consumed in this unit is by far the largest among the "processing" units. Detailed analysis of the unit shows that virtually all of the 977.8 million kcal/hr used up by the unit is consumed by the highly dissipative kinetics of the gasification process; 6.2 units are consumed in the Char Cooler, 19.4 units in the mixing of oxygen and steam, and 952.2 in the Gasifier.

Follow-up studies such as these would be worthwhile: (1) Establish the sensitivity of the consumption to changes in the operating parameters, such as pressure; (2) Compare the consumption in the SYNTHANE gasifier to the consumption in other gasifiers, to determine whether the estimates of operating conditions for the different gasifiers are prejudicial.

Also, the large consumption in the gasifier raises the question, "What basic modifications could be made in order to reduce the inefficiency?" In turn, "What specifically is the cause of the dissipation?" The cause is the large chemical affinity of the reactions occurring in the gasifier; i.e., the large imbalance of the (weighted) chemical potentials of the reactants over those of the products. For example, suppose that the chemical reactions were represented, crudely, by

Then, the rate of available energy consumption is given by

$$\begin{aligned} \dot{A}_c = &[\mu_{C_{33}H_{42}O_{14}} + 10 \mu_{O_2} + 8 \mu_{H_2O} \\ &- 12 \mu_{H_2} - 8.5 \mu_{CH_4} - 7 \mu_{CO} - 17.5 \mu_{CO_2}] \dot{N}_{H_2} / 12 \end{aligned}$$

where the μ 's are the chemical potentials and $\dot{N}_{H_2}$ is the rate of production of H_2 by the reaction. Thus, the rate of available energy consumption can

be reduced by raising the chemical potential of the products (e.g., by raising the pressure) or by reducing the chemical potential of the reactants. Are there any modifications which could accomplish the latter? Conceivably the O_2 and/or H_2O could be fed to the reaction zone through concentration cells (in common use for monitoring combustion gas composition), which would drop the chemical potential of these reactants as they were drawn through the cells by the burning process.* Upon dropping the chemical potential, an electric power output would be obtained.

To elaborate further, during combustion each reactant gas diffuses through the other gases to the flame as a consequence of the gradient in the chemical potential of the reactant--which, roughly, is proportional to the gradient in the partial pressure. A very low partial pressure of reactants is maintained in the flame by the combustion process, with its affinity for reactants. The greater the difference in the partial pressure between the source of the reactant and the flame, the more rapid the diffusion--or, the more compact will the diffusion region be. The larger the gradient in partial pressure the larger the consumption of available energy in the diffusion process--in driving the reactant through the other gases to the flame (just as larger gradients in electric potential cause larger dissipations in the diffusion of electrons--in driving electrons through a wire). By allowing a gaseous reactant to be drawn into the reactor through a concentration cell, which would yield an electric output while dropping its partial pressure (and chemical potential), a significant portion of the available energy (which is usually consumed by diffusion) would be obtained electrically. The partial pressure of the reactant in the reactor will now be lower, and the diffusion to the flame will be slower. Consequently, the reaction will not be as fast; to get the same rate of output, the reactor will need to be larger.

The foregoing conceivable scheme for improving the gasifier process--or any combustion process--deserves further investigation. Even if only a small fraction of the available energy consumption associated with combustion were saved, the dividends would be great. If only 15% of the consumption were saved (~ 140 million kcal/hr), the electric power output would be raised by another 160 Mw, over and above the aforementioned 600 Mw. (Also,

* The cells could also be used to separate O_2 from air; recall the low η_{II} of O_2 production.

consider the substantial improvement in overall performance of a typical fossil-fired electric power plant that would be accomplished by a 15% improvement of combustion. Recall from Figure 2-2 that 30% of the fuel available energy is consumed in the boiler by combustion; thus, for every 100 units of fuel available energy, 4.5 units could be saved with a 15% improvement in combustion. If these 4.5 units are converted to electric power (delivered to the consumer) at an efficiency of 33/50--see Fig. 2-2a--then the overall efficiency would be raised by 3%; e.g., from 33% to 36.7% for delivered electric power.)

These discussions of gasifier (and boiler) improvement illustrate the utility of Second Law analysis for (1) pinpointing inefficiencies, (2) germinating ideas for conceivable means of improvement, and (3) deducing quantitative estimates of the consequences of prospective improvement without making a complete technical feasibility study--without making a design--of the whole plant.

Gas Treatment. The Raw Gas Quench, Unit 16, and Shift Conversion, Unit 17, are relatively efficient units. The largest consumption in Unit 16 is in the Venturi, which consumes over 83 (10^6) kcal/hr, primarily as a consequence of the thermal mixing of the hot 1690°F raw gas from the gasifier with 450°F water. (Of course there is no loss of energy in the Venturi, and hence a First-Law viewpoint fails to recognize this important consumption, let alone evaluate it.) Possible means of saving this large consumption should certainly be investigated, making use of the thermal available energy of the raw gas, while cooling it down before mixing.

The total available energy consumption in Unit 17, Shift Conversion, is nearly 100 (10^6) kcal/hr. Detailed analyses of the mixing of shifted gas with by-pass gas indicates a fairly large consumption there: ~ 60 (10^6) kcal/hr. (However, an energy balance is not well satisfied at this mixing. From the flow stream data given by Braun, the leaving energy is 98.35% of the two supply streams--while the leaving available energy is 98.19%. The leaving stream condition should be re-calculated, invoking an energy balance. Then the available energy consumption should be re-evaluated.)

Unit 18, Acid Gas Removal, is a proprietary unit. Therefore, only

a minimum of flow stream data were available in the Braun report--namely data for flow streams from or to other non-proprietary units. However, because one leaving flow stream from Unit 18 is to vent, and because another is to another proprietary unit (Unit 21, Sulfur Recovery) additional details were needed. They were kindly provided by R. A. Johnson of C. F. Braun and Company. With the information that was made available, an overall Second-Law analysis of the unit could be made; analysis of components of the unit could not be done. The overall analysis showed zero available energy consumption which, of course, is impossible. Table III-G of the Braun Report shows that Unit 18 has large capital investments in Columns, Compressors and Blowers and Refrigeration Equipment, for examples. The processes that occur in such equipment consume sizeable amounts of available energy. Therefore, there is an inconsistency. Perhaps the information provided by Mr. Johnson was incomplete; for example, there may be other available energy inputs besides those shown on Figure 5-10. Or else one or more of the inputs is greater than the (calculated) value shown, or outputs are less. It is also conceivable that the unit cannot perform according to the claims of the proprietor.* It is highly recommended that exact input and output data be obtained from C. F. Braun and Company, and/or the proprietor, so that the Second-Law analysis can be repeated.† If the efficiency again turns out to be near 100%, then the unit will not function. By the way, note the large effluent loss of available energy from Unit 18, in the vented CO_2 , amounting to $105 (10^6)$ kcal/hr. Totaled with the vented CO_2 from Unit 14, the loss is $130 (10^6)$ kcal/hr.

Unit 19, Methanation, is quite efficient, with a consumption of only $41 (10^6)$ kcal/hr of available energy. The consumption is more or less evenly distributed among the different sub-units. The methanators (like the shift converters in Unit 17) have a seemingly very low consumption--presumably because the catalyzed reactions follow a near equilibrium path. However, whether such high Second-Law efficiencies ($> 99.8\%$) would actually

* The explanation may be that the unit exists only as a pencil-and-paper preliminary design, with a design made with the assumption of reversible processes.

† These results would be important to all the processes in the Braun report, not just SYNTHANE.

be obtained in practice might be questioned. Similarly for the absorber and regenerator in Unit 23, Product Gas Drying.

In any case, though, it is evident that preoccupation with Units 19 and 23, and for that matter Units 16 and 17, would not be worthwhile. Similarly for Units 20 through 22. The big inefficiencies offering significant prospects for improving the SYNTHANE process are:

- (i) Generation of steam, shaft power and oxygen, which could be improved greatly with state-of-the-art technology.
- (ii) Gasification, which conceivably could be accomplished with much less consumption with new technology. Even a small improvement would be important.

Nevertheless, the following smaller inefficiencies are worthy of attention:

- (iii) Unit 16 (Raw Gas Quench): thermal mixing in the Venturi;
- (iv) Unit 17: mixing of shifted and by-pass gas;
- (v) Units 18 and 14: CO_2 vent;
- (vi) Unit 12: coal drying.

Chapter 6

Costing Analysis and Results

The costing study was carried out following the principles outlined in Chapter 3. It will be more convenient if the results are presented first, and then the procedures used to get those results.

Results

Analogously to Chapter 5, the results will be presented in stages. Figure 6-1 is a counterpart to Figure 5-1; it includes not only the available energy flow rates shown on Figure 5-1 but also the money flow rates associated with each stream--shown in parentheses. Thus, when the 7195 Mw of input coal is multiplied by the 0.13¢/kwhr "raw material" cost of coal (which corresponds to the \$7.50/ton specified in the C. F. Braun report) the rate of money expenditure for raw coal is $9.32 (10^3)$ dollars/hour.

The total expenditure for "prepared coal," ready for the gasifier, is shown on Figure 6-1 to be $24.6 (10^3)$ \$/hr. This expenditure consists of (a) the 9.32 for coal delivered to the Coal Preparation Group (Units 11, 12, 14), plus (b) 4.45 for 72 Mw of other "fuels" (steam, shaft power, electric power) supplied to these units, plus a total of 10.83 for (c) other operating costs such as Labor, Supplies, Taxes and Insurance, and General Overhead associated with the operation of Units 11, 12 and 14, and (d) amortization of the capital expenditure for the equipments in the group and other related costs such as Start-up and Working Capital. The unit cost for available energy in "prepared coal" going to the gasifier is then equal to the expenditure divided by available energy:

$$\frac{24.6 (10^3) \text{ $/hr}}{7005 (10^3) \text{ kw}} = 0.00352 \frac{\text{\$}}{\text{kwhr}} = 0.352 \frac{\text{¢}}{\text{kwhr}}$$

Unit costs are shown in parentheses on Figure 6-2.

The methods used to determine (a) through (d) above will be discussed later.

As shown on Figure 6-1, the expenditure for raw gas leaving the Gasifier Unit is $42.58 (10^3)$ \$/hr, which is the sum of (a) primary "raw materials" expense, namely $24.6 (10^3)$ \$/hr, (b) secondary fuels (steam and

† Byproducts costed at
C. F. Braun credit.

Figure 6-2

Unit Costs of Available Energy Flows (¢/kwhr)

Available Energy Flow Diagram

SYNTHANE PROCESS CONCEPTUAL DESIGN

* $c_{\text{steam}} = 3.08\text{¢/kwhr}$

$c_{\text{shaft}} = 5.22\text{¢/kwhr}$

$c_{\text{electricity}} = 8.50\text{¢/kwhr}$

$c_{\text{oxygen}} = 43.5\text{¢/kwhr}$

power) expenses of \$21.11 (10^3) \$/hr, plus a total of 3.41 (10^3) \$/hr for (c) operating expenses and (d) capital amortization, minus (e) a by-product available-energy credit of 6.54 (10^3) \$/hr for char which is supplied to the Steam Plant. The credit was determined by taking the unit cost of available energy in the by-product char to be the same as that in the "unprocessed char"--the prepared coal delivered to the Gasifier. Thus, the credit is

$$0.00352 \frac{\$}{\text{kwhr}} \cdot 1862 (10^3) \text{ kw} = 6.54 (10^3) \$/\text{hr}$$

The other hourly expenditures of money shown on Figure 6-1 and unit costs on Figure 6-2 are calculated in the same manner as the above. It should be mentioned that Tar, Oil, Ammonia and Sulfur were credited as by-products at the unit price stipulated by ERDA and reported in the C. F. Braun interim report, Table VIII-B. On the other hand, electric power was costed on the basis of the expenditure for producing it--which turns out to be much greater than the 0.45¢/kwhr credit stipulated by ERDA.

In actuality, Figures 6-1 and 6-2 were not constructed by applying the principles of Chapter 4 to each group of units. Figures 6-1 and 6-2 were really derived from Figures 6-3 and 6-4, which show the hourly dollar expenditures and the unit costs in much more detail--showing each Unit, and showing many separate flow streams which had been grouped in Figures 6-1 and 6-2.

The results shown on Figures 6-3 and 6-4 were determined from the principles of Chapter 4, applying them to one unit at a time.

Procedures

The detailed procedures employed will be explained by considering a typical unit, Unit 11, in detail.

Operating Costs. Coal reaches the site at a cost of \$7.50/ton or, equivalently, \$1.50 per 10^6 kcal of availability. The rate of coal consumption is 6,183 (10^6) kcal/hr, so the rate of expenditure is 1.5 (6183) = 9.27 thousand dollars per hour. The annual rate of expenditure is obtained by employing the 90% plant capacity factor stipulated in the Braun report:

$$9.27 (10^3) \frac{\$}{\text{hr}} \times 8760 \frac{\text{hr}}{\text{yr}} \times 0.90 = 73.1 (10^6) \frac{\$}{\text{yr}}$$

100% PLANT 57
UNITS: MILLION KCAL/HR
[1,000\$/HR]

AVAILABILITY FLOWS [DOLLAR FLOWS]

PRELIMINARY
THIS DRAWING IS FOR ESTIMATING
PURPOSES ONLY AND IS NOT TO BE
USED FOR DESIGN OR CONSTRUCTION

FIGURE 6-3

DATE	REVISION	BY	CHECKED	APPROVED
NOTES FOR CONSTRUCTION				
DATE	BY	DATE	BY	DATE
DESIGNED	SAJ	DRAWN	VLM	CHECKED
FOR COAL CONVERSION AND UTILIZATION AMERICAN GAS ASSOCIATION WASHINGTON, DC				
COMMERCIAL CONCEPT DESIGN-WESTERN COAL PERC SYNTHANE PROCESS BLOCK FLOW DIAGRAM				
ALHAMBRA C F BRAUN & CO CALIFORNIA				
SCALE	NONE	OTHER SHEETS	4568-204-100-XD-1	0
SHEET	57

PRELIMINARY
THIS DRAWING IS FOR ESTIMATING PURPOSES ONLY AND IS NOT TO BE USED FOR DESIGN OR CONSTRUCTION

FIGURE 6-4

* $C_{steam} = \$40.36/10^6 \text{ kcal} = \$13.17/10^6 \text{ Btu} = 3.47 \text{¢/kWh}$
 $C_{raw} = \$30.91/10^6 \text{ kcal} = \$10.0/10^6 \text{ Btu} = 3.06 \text{¢/kWh}$
 $C_{electric} = \$96.73/10^6 \text{ kcal} = \$31.9/10^6 \text{ Btu} = 8.32 \text{¢/kWh}$

† 10 Btu of product gas energy corresponds to 0.9375 Btu of availability (The 6 - 5 L.C. value is 1.0 = 57.51 Btu of energy)
 = The availability value is shown to correct credit

NO.	DESCRIPTION	BY	CHECKED	DATE	REVISION
1	NOTES				
2	DESIGNED FOR CONSTRUCTION				
3	DESIGNED FOR CONSTRUCTION				
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Table 6-1
Annual Operating Costs
PERC SYNTHANE PROCESS
Unit 11

CATALYSTS AND CHEMICALS	\$ 0.00 (10^6)
PURCHASED WATER	0.03
LABOR	
Process Operating	0.03
Maintenance (60% of Total Maintenance)	0.66
Supervision (20% of Direct Labor)	0.14
ADMINISTRATION AND GENERAL OVERHEAD (60% of Labor)	0.50
SUPPLIES	
Operating (30% of Process Operating Labor)	0.01
Maintenance (40% of Total Maintenance)	0.44
LOCAL TAXES AND INSURANCE (2.7% of Total Plant Investment)	0.48
BY-PRODUCT CREDITS	
Sulfur (@ \$25/long ton)	(0.00)
Ammonia (@ \$0.07/lb)	(0.00)
Light Oil (@ \$0.38/gal)	(0.00)
Tar (@ \$0.15/gal)	<u>(0.00)</u>
SUB-TOTAL (N_0)	\$ 2.30 (10^6)
FUELS AND EXPENSES	
Coal (48.75×10^{12} kcal/yr @ \$1.50/ 10^6 kcal)	73.12
Electricity (11.83×10^9 kcal/yr @ \$96.73/ 10^6 kcal)	1.15
FUEL CREDITS	<u>(0.00)</u>
TOTAL (N)	\$ 76.62 (10^6)

The hourly and annual costs for electric power to Unit 11 are determined in the same manner.

The other operating costs, besides those for available energy inputs, are determined as illustrated by Table 6-1, which is patterned after Table VIII-B of the Braun report. (Table VIII-B lists the operating costs for the whole plant, not for just one unit.)

The entries in Table 6-1 were determined as follows:

CATALYSTS AND CHEMICALS. The total annual cost of these items for the whole plant is $\$3.30 (10^6)$. This total was apportioned between Units 17, 18, 19, 20, 21, 22, 31. The total capital cost for these units is $\$435.4 (10^6)$. The capital cost of Unit 17, for example, is $\$66.55 (10^6)$. The catalysts and chemicals to Unit 17 were costed at $(66.55/435.4) (\$3.30 (10^5)/\text{yr}) = \$0.504 (10^6)/\text{yr}$. Similarly for the other units listed. For Units 11, 12, 14, 15, 16, 23 and 30 it was assumed that any costs for catalysts and chemicals were negligible.

PURCHASED WATER. The total annual cost of purchased water is given as $\$0.47 (10^6)$ in Table VIII-B. According to Table VIII-C the capital cost for Unit 11 is $\$17.92 (10^6)$ compared to a total plant capital cost of $\$10,50 (10^6)$. It was assumed that the cost of purchased water attributable to any unit was in proportion to its capital cost. Thus, for Unit 11, purchased water was costed at the rate of $(17.92/1500) (\$0.47 (10^6)/\text{yr}) = \$0.006 (10^6)/\text{yr}$, which was rounded off to $\$0.01 (10^6)/\text{yr}$ in Table 6-1.

LABOR.

Process Operating Labor: The total process operating labor listed in Table VIII-B is $\$2.78 (10^6)/\text{yr}$. This, too, is apportioned among the units in proportion to their capital cost. Thus, for Unit 11, the cost is $(17.92/1500) (\$2.78 (10^6)/\text{yr}) = \$0.03 (10^6)/\text{yr}$.

Maintenance Labor: According to Table VIII-C, the total annual maintenance cost of Unit 11 is $\$1.08 (10^6)$; Table VIII-B assigns 60% of this to Labor and 40% to Supplies. Thus, for Unit 11 maintenance labor, $(0.6) (\$1.08 (10^6)) = \$0.66 (10^6)/\text{yr}$.

Supervision: Table VIII-B estimates this to be 20% of the sum of Process Operating Labor and Maintenance Labor. For Unit 11, $(0.2) (0.03 + 0.66) (10^6) = \$0.14 (10^6)/\text{yr}$.

ADMINISTRATION AND GENERAL OVERHEAD. Table VIII-B assumes that this cost is 60% of the total labor costs. Hence, $(0.6)(0.03 + 0.66 + 0.04)(10^6) = \$0.50(10^6)/\text{yr}$ is the amount for Unit 11.

SUPPLIES.

Operating: Table VIII-B assumes these costs to be 30% of Process Operating Labor. For Unit 11, $(0.3)(\$0.03(10^6)/\text{yr}) = \$0.01(10^6)/\text{yr}$.

Maintenance: The aforementioned 40% of total maintenance yields, for Unit 11, $(0.4)(1.08(10^6)) = \$0.44(10^6)/\text{yr}$.

LOCAL TAXES AND INSURANCE. Table VIII-B assigns this cost at the rate of 2.7% of the plant capital investment. As mentioned above, for Unit 11 this capital cost is $\$17.92(10^6)$, so that the local taxes and insurance is costed at $(0.027)(17.92)(10^6) = \$0.48(10^6)$.

BY-PRODUCT CREDITS. Some units deliver one or more of the commodities listed in Table 6-1 as by-products. When this is the case, the by-products are credited at the rates shown, in accord with Table VIII-B. Electric power outputs, however, are not credited at the rate indicated in Table VIII-B; rather, they are costed and credited in proportion to the expenditure for producing them.

SUB-TOTAL (N_0). This is simply the sum of all the foregoing operating costs minus the by-product credits.

FUEL EXPENSES. The only other expenses associated with the operation of a unit, besides those sub-totaled above, are the expenses incurred for available energy (fuel) supplies. Thus, Unit 11 receives available energy in coal, and in electricity. The annual cost for coal is evaluated as shown earlier. That for electricity is

$$1.5(10^6) \frac{\text{kcal}}{\text{hr}} \times 8760 \frac{\text{hr}}{\text{yr}} \times 0.9 \times \frac{\$96.73}{10^6 \text{ kcal}} = \frac{\$1.15}{\text{yr}}$$

where 0.9 is the plant capacity factor, and $\$96.73/10^6 \text{ kcal}$ is the calculated cost for electricity.

FUEL CREDITS. Some units deliver available energy as a by-product in one or more forms.

TOTAL (N). The total operating costs N are equal to (i) N_0 , the above SUB-TOTAL, plus (ii) N_F , FUEL EXPENSE minus FUEL CREDIT.

The costs associated with (a) primary fuels and (b) secondary fuels are covered by FUEL EXPENSES; those with (c) other operating expenses by the SUB-TOTAL; the evaluation of those for (d) capital amortization will be explained in the following paragraphs; and credits for (e) by-product available energy outputs are covered above by FUEL CREDITS.

Capital Costs. There are three capital expenses associated with each unit. By far the largest is the so-called INVESTMENT in the unit, denoted by I. There are three categories in I, shown in Table VIII-A: Total Investment, Initial Charge of Catalysts and Chemicals, Paid-up Royalties. As shown by Table VIII-A or Table III of the Braun report, the Total Investment consists of the following components: (1) Installed Cost; (2) Contractor's Home Office Costs and Fee, 11.1% of Installed Cost; (3) Project Contingency, 15% of the first two components. In turn, the Installed Cost consists of (i) Total Engineered Equipment cost, plus (ii) cost of installation. For each unit, the major pieces of equipment, their costs, and the total installed cost are listed in a table of the Braun report: Unit 11 on Table III-A, Unit 12 on Table III-B, and so on. For Unit 11, the value of the Total Investment (or Unit Cost) listed in Table VIII-C is $\$17.92 (10^6)$, compared to a total of $\$1,500 (10^6)$ for the whole plant. The value of I, including royalties and initial charge of chemicals is $\$19.93 (10^6)$ --where the latter have been apportioned according to Total Investment.

Another capital expense to be amortized is the START-UP COSTS, S. The total for the whole plant is given as $\$37.89 (10^6)$ in Table VIII-A. Here, these total costs were also apportioned in accord with the Total Investment costs. Thus, for Unit 11 the start-up costs were taken to be $(17.92/1500)(37.8 (10^6)) = \$0.45 (10^6)$. The third capital expense, for WORKING CAPITAL, W, is apportioned in the same way. With the total plant W of $\$40.54 (10^6)$ listed in Table VIII-A, the portion assigned to Unit 11 was $(17.92/1500)(\$40.54 (10^6)) = \$0.48 (10^6)$.

Unit Costs

The cost per unit of available energy output from Unit 11, the coal delivered to Unit 12, is evaluated with the following formula

$$c = [N + 0.247I + 0.1337S + 0.2305W]/G$$

The coefficients on I, S and W are amortization factors for annualizing these costs. This unit cost equation is equivalent to that used in the Braun report (see Table 4 of Appendix A) to get the cost of product gas assuming private financing. The following assumptions are inherent to the coefficients: 12% discounted cash flow rate of return, 20-year project life, 16-year sum-of-the-year-digits depreciation, 48% Federal income tax rate, 100% equity capital.

In the present work this equation is used not only for the product gas but also for every flow stream between unit operations. This is possible by recognizing that the value of all the "fuel" inputs and "power" outputs can be measured by a common commodity--the available energy content. Thus, the equation is applied to each unit of the SYNTHANE process to obtain the costs of each relevant internal flow stream and to obtain the true cost of operation of each unit.

For Unit 11, with the values for I, S, W and N listed above, and an output $G = (6,183 (10^6) \text{ kcal/hr})(8760 \text{ hrs/yr})(0.9) = 48.75 (10^9) \text{ kcal/yr}$

$$\begin{aligned} c &= [76.62 + 0.247(19.92) + 0.1337(0.50) + 0.2305(0.44)]/48,750 \\ &= \$1.67/(10^6) \text{ kcal} \end{aligned}$$

as shown on Figure 6-4.

The same procedures were employed for each of the other units. Table 6-2 lists the values of I, S, W, N_0 and N_f for each unit. Some additional comments are in order regarding the determination of these values for certain units.

Table 6-2
Costs for Each Unit Operation

Unit	Description	I Investment (10 ⁶ \$)	S, Start- Up Costs (10 ⁶ \$)	W, Working Capital (10 ⁶ \$)	N _O , Base Operating Cost (10 ⁶ \$/yr)	N _F , Fuel Operating Cost (10 ⁶ \$/yr)
11	Coal Storage and Reclaiming	19.93	0.50	0.44	2.33	74.09
12	Coal Preparation	89.67	2.26	2.01	10.47	94.28
14	Coal Feeding	115.29	2.91	2.58	12.47	151.88
15	Gasification	68.32	1.72	1.53	7.94	314.24
16	Raw Gas Quench	25.33	0.64	0.57	3.00	323.62
17	Shift Conversion	43.21	0.70	0.62	2.80	348.07
18	Acid-Gas Recovery	184.4	4.56	4.04	14.86	397.10
19	Methanation	35.55	0.84	0.82	3.10	458.01
20A	Sour Water Stripping	18.61	0.48	0.43	1.48	15.37
20B	Ammonia Recovery	10.16	0.26	0.23	0.81	-0.4
20C	Bio-oxidation	29.42	0.73	0.65	2.34	0.39
21	Sulfur Recovery	111.85	2.77	2.46	9.51	5.07
22	Solids Disposal	13.36	0.46	0.29	1.01	0.46
23	Product Gas Drying	1.13	0.03	0.02	0.07	470.91
30,31	Steam Raising and Water System	497.54	12.54	11.12	24.25	130.55
30	Power Generation	123.89	3.13	2.78	5.78	84.58
32	Oxygen Plant	138.1	3.49	3.09	10.00	72.13
TOTAL		1,525.76	38.02	33.68	112.22	2,940.35

Before the unit cost of product coal leaving Unit 12 can be evaluated, the costs of the flue gases and solids waste leaving Unit 12 must be determined. These unit costs will be negative (penalty costs) inasmuch as these effluent streams must be chemically treated before release to the environment. Hence, it is only fair that Unit 12 bear its proportionate burden of these costs. The unit costs of flue gas and solids waste are determined by viewing these streams as the "products" of Units 21 (Sulfur Recovery) and 22 (Solids Disposal). Unit 21 is charged for electricity and shaft power. The steam entering Unit 21 from Unit 22 was not costed due to its extremely small available energy content. Unit 21 is, however, credited for small exports of steam and waste heat and for sulfur, which is sent to storage. The unit cost of waste heat was taken to be equal to the unit cost of char entering Unit 15 divided by 0.65 to account for the fact that this waste heat represents thermal available energy that does not need to be supplied by the char (i.e., chemical available energy). The factor 0.65 accounts approximately for (i) the destruction of available energy in going from chemical form to thermal form, (ii) boiler capital, and (iii) stack losses. The sulfur was credited at the unit price specified in the Braun Report (\$25/long ton which is equal to $\$5.36/10^6$ kcal-available energy). Given these costs a value for N is computed which then allows the unit cost of flue gas entering Unit 21 to be determined. Note that here the value for G in the costing equation is negative corresponding to the fact that the "product" flue gases are an input to Unit 21; this forces the unit cost to be negative. (Note that the unit cost assigned to the flue gas coming from Unit 12 and Unit 30 differs slightly from the unit cost assigned to flue gas going to Unit 21. The reason for this is that, as the flue gas streams coming from Unit 12 and Unit 30 merge to enter Unit 21, there is a consumption of $13.2 (10^6)$ kcal/hr of available energy. Thus the unit cost of flue gas leaving Unit 12 and Unit 30 is assigned a value equal to the ratio of flue gas available energy entering Unit 21 and that leaving Unit 12 and Unit 30 multiplied by the unit cost of flue gas entering Unit 21.)

Unit 22 is handled in much the same way as Unit 21 except that the solid wastes were divided into types: ash (from the boilers) and other

solids (from Unit 12 and Unit 16). Here the capital cost, I, was broken down by attributing the pug mill and vacuum filter capital costs to the ash from the boilers and allocating the remainder to the solids from Unit 12 and Unit 16. The other costs, S, W, and N were allocated to ash or solids in the same ratio as the capital cost. In calculating N, the process water going to Unit 12 was credited at the cost of coal entering Unit 12. The solids to mine were not assigned a credit inasmuch as the solids are thrown away. Values for the flows (G) of ash and solids were obtained from the engineering specifications provided in the Braun Report.

Once the unit costs for solids and flue gas are at hand, the coal leaving Unit 12 (Coal Preparation) can be costed in the same way as Unit 11.

When costing the coal leaving Unit 14 no charge is made for the net CO_2 supplied to the unit inasmuch as the CO_2 from Unit 18 would have been vented to the environment along with the majority of CO_2 from that unit.

At this juncture Unit 30 was analyzed to obtain unit costs for process steam, shaft power, and electricity. The analysis here combines the Plant Water System (Unit 31) with that part of Unit 30 which raises steam. The major fuel input for steam production is the char coming from Unit 15. This char was assigned the same unit cost as the coal entering Unit 15. That is, Unit 15 was charged for the net available energy extracted from the coal coming from Unit 14. The process waste heat entering the steam-raising system is charged at the unit cost of char divided by the factor 0.65 for reasons discussed earlier. All other fuel charges and credits on this unit have already been discussed in connection with upstream units. The product steam is essentially costed on an extraction basis--the unit cost of steam per unit of available energy is the same irrespective of the steam temperature and pressure. Thus, if high pressure steam is used to drive a turbine, the shaft power produced is charged for the available energy extracted from the steam, which means that the unit cost of low-pressure steam is assigned the same value as high-pressure steam.

The shaft power was costed by simply dividing the unit cost of steam by the second-law efficiency of the turbines. Capital and other costs (I, S, W) were neglected inasmuch as these costs are included in the I,

S and W of the various units which use steam for producing power. So, what is called "shaft power" is really "shaft power to be." Thus, the "shaft power to be" is charged for the turbine inefficiencies, and the other costs (I, S, W) are charged as the "shaft power to be" is consumed unit-by-unit, to produce shaft power. (This was done as a matter of expediency inasmuch as the cost breakdowns of equipment, in Tables III-A through III-O were not detailed enough for determining what the values of I, S and W would be for the components involved in power production--while it was deemed informative to cost process steam and "shaft power to be" steam separately.)

Electricity production was charged for both fuel (shaft power) and capital and other costs. The capital and other costs were obtained from the breakdown in Table III-M, of generating equipment contained in Unit 30.

With unit costs for shaft power and electricity at hand, the unit cost of oxygen from Unit 32 (Oxygen Plant) is calculated, which in turn enables Unit 15 (Gasification) to be costed. The water inputs to Unit 15 from Unit 17 and Unit 23 are both charged at the unit cost of char divided by 0.65.

When costing Unit 16 (Raw Gas Quench) the tar is credited at the cost prescribed in the Braun Report (which when converted to an available energy unit cost is equal to $\$4.92/10^6$ kcal).

Before costing Unit 17 (Shift Conversion) it was determined that the leaving water would be treated as follows: 42 (10^6) kcal/hr of the 66 (10^6) kcal/hr which go to Unit 20A would be assigned a negative cost obtained from an analysis on Unit 20A while the remaining 24 (10^6) kcal/hr would be costed at the "waste heat" cost--the cost of char divided by 0.65--inasmuch as this water is a "heat" supply to Unit 15.

However, to ascertain the negative unit cost of water going to Unit 20A, Units 20C and 20B must first be considered. Unit 20C (Biological Oxidation) is handled by costing the process water to Units 30 and 31 at the cost of char divided by 0.65, while the stripped water is considered as the "output"--that is the stripped water is assigned a negative cost. Given the stripped water cost and the ammonia credit (obtained from the Braun Report) the negative cost of sour gas entering Unit 20B (Ammonia Recovery) is obtained. In turn, the negative cost of sour water entering

Unit 20A (Sour Water Stripping) is computed. Given this sour water cost the costing of Unit 17 can be completed.

The remaining Units--18 (Acid-Gas Removal), 19 (Methanation), 23 (Product Gas Drying) are costed in the usual manner with the light oil from Unit 18 being credited at the price listed in the Braun Report.

As indicated earlier, the results of the costing analysis are shown in detail on Figure 6-4, while in Figure 6-2 many of the streams have been combined.* What conclusions can be drawn from these results?

Explanation of Results; and Conclusions

Before proceeding with the explanation of the results and the deduction of conclusions, the reader should be reminded that this costing study has assumed private financing. The costs would be reduced significantly--by approximately 25%--with utility financing [28].

Table 6-3

Changes in Cost of Mainstream Available Energy

Unit Number	11	12	14	15	16	17	18	19	23	Overall
Unit Cost of Feed (\$/10 ⁶ kcal)	1.50	1.67	2.73	4.08	11.76	13.31	15.90	22.28	24.21	24.29
Incremental Increase (\$/10 ⁶ kcal)	0.17	1.06	1.35	7.68	1.55	2.59	6.38	1.93	0.08	22.79
Per Cent Increase (%)	11	63	49	188	13	19	40	9	0.3	1500

* It should be noted that the available energy flow to power turbines is shown as 800 (10⁶) kcal/hr on Figure 5-2, but only as 686 (10⁶) kcal/hr on Figure 6-4. The former is the right value, corrected after an error on C. F. Braun's Drawing No. 4568-204-116-XD-1 was discovered--at the end of the project, after the costing had been completed. There was no time or money available to re-do the costing; but the effects of this correction would not affect the principal conclusions. A few commodities were re-costed; following are the corrected values in \$/10⁶ kcal: Steam, 35.76; Shaft Power, 60.76; Electricity, 98.83; Oxygen, 505.83; Product Gas, 24.20.

Table 6-3 shows the increase in unit costs, across each of the "mainstream" units of the SYNTHANE process. Each increase is presented in two ways: (i) the absolute increase, in $\$/10^6$ kcal, and (ii) the relative increase, as per cent of the unit cost of the mainstream available energy fed to the unit. It is clear that the largest increases are across the Gasification unit, number 15, and across the Acid Gas Removal unit, number 18. Units 12 and 14 also have relatively large per cent increases.

The breakdown of the incremental costs will now be described unit by unit.

The increase in unit cost across Unit 12 is, in part, a result of the expense of treating the gases and solid wastes leaving the unit.

The cost of treating flue gas in Unit 21 is about 35% from operating costs and 65% capital, while the costs of treating solids and ash in Unit 22 are over 75% capital. (It should be mentioned that the purpose of these units, especially Unit 21, is to remove undesirable available energy from effluent streams--available energy (the cause of changes) which is undesirable because it would cause unwanted effects in the environment. Thus, Unit 21 takes 80 units of available energy in raw flue gases plus 38.82 units in acid gases from Unit 18, and reduces the total to 76.92--which is vented to the atmosphere and, therefore, has no value; i.e., a unit price of zero. Even with the credit given for by-product sulfur, the capital and fuel costs for operating Unit 21 consequently lead to a negative unit cost for the available energy in the raw flue gases and the acid gases--the cost of reducing the undesirable available energy which otherwise would have been vented at zero unit price.)

Unit 12 raises the unit cost of the available energy in the main process stream by over \$1 per million kilocalories. Nearly half of this is due to capital, and half as a result of operating costs. The breakdown for operating costs is: Over 50% for electric (available) energy consumption, nearly 20% for available energy consumed by drying, and about 25% for treatment of effluent flue gases and solids.

The $\$1.35/10^6$ kcal rise in unit cost across Unit 14 is 46% from capital and 50% from available energy consumption (especially that supplied with shaft power), and about 4% for other operating expenses.

Inasmuch as a substantial portion of the expenses of Unit 15 are associated with steam, electric power and oxygen, the cost of producing these utilities will be described first.

The cost of steam production is split almost exactly between capital and operating expenses, which in turn are about 85% "fuel" expenses. The cost of producing electric power from steam is 43% capital expenses; steam accounts for 45% of the cost. The $\$40.36/10^6 \text{ kcal} = \$9.01/10^6 \text{ Btu}$ of available energy = 3.09¢/kwhr for steam is a very high cost, as is 8.5¢/kwhr for electricity. Compare these costs to figures such as 2 to 2.5¢/kwhr with which co-generated steam and electricity are readily produced, even with more expensive fuels than the $\$1.03/10^6 \text{ Btu}$ char.

The oxygen production cost is nearly 55% for "fuel" available energy, 10% for other operating expenses, and 35% for capital. The very high cost for O_2 (2.5¢/lbm = 43.5¢/kwhr) is not surprising in light of the highly inefficient O_2 plant, as shown in Chapter 5.

These high costs for "utilities"--steam, power, oxygen--take their toll in the cost of product gas, as will be seen clearly.

Across the Gasification unit (Unit 15), the $\$7.68/10^6 \text{ kcal}$ rise in unit cost is due almost completely to consumption of "fuels." Only $\$0.95/10^6 \text{ kcal}$ are associated with capital and other operating expenses. The fuel breakdown is approximately 60% for oxygen, 25% for steam and 15% for available energy consumed from the coal. It will be seen that the rise in unit cost across Unit 15 can readily be reduced by 30%, with steam and oxygen produced at reasonable costs. (And, conceivably, the expense could be reduced even further with the development of concentration cells which would reduce the available energy consumption of the gasifier, while yielding electric power.)

Across Unit 16, Raw Gas Quench, the cost of raw gas rises 13%, by $\$1.55/10^6 \text{ kcal}$. Approximately 25% is for amortization of capital. Of the ~\$1.15 for operating costs, \$1 is for available energy, consisting of only \$0.05 for consumption, but \$0.95 because the value of by-products (tar, waste heat) is substantially less than the cost ($\$11.66/10^6 \text{ kcal}$) of the available energy from which it was derived.

The cost of treating stripped water ($\$58.01/10^6$ kcal) in Unit 20C, Biological Oxidation, is almost 75% capital expense; little (15%) of the operating expense is from "fuel" consumption. For Unit 20B, Ammonia Recovery, over 85% of the net cost of treating sour gas ($\$19.87/10^6$ kcal) is for capital. The 15% net operating cost ($\sim \$3.00$) consists of a net fuel credit of about $\$3.00$ and other operating costs of about $\$6.00$. The fuel credit is a consequence of the value of the by-product ammonia, which exceeds the costs for steam and for acid gas treatment.

The cost of treating sour water is $\$65.25/10^6$ kcal; $\$25$ of this cost is from Unit 20A, Sour Water Stripping, while the other $\$40$ is the net costs from Units 20B and 20C. Of the $\$25$, 60% is for capital; the other 40% is primarily for the steam.

The cost of gas increases by $\$2.59/10^6$ kcal as a result of the Shift Conversion, Unit 17. Only 20% is attributable to capital expenditure. Of the operating expenses, nearly half is associated with treatment of sour water effluent from Unit 17, almost 30% is from available energy consumption; the remainder--nearly 25%--is because by-product waste heat and sour water available energy has less value than the cost ($\$13.31/10^6$ kcal) of the available energy from its source.

The unit cost of gas available energy leaving Unit 18, Acid Gas Removal, is $\$6.38/10^6$ kcal more than that entering. Thirty-five percent (35%) is from capital and 65% from operating expenses. One-sixth of the operating expenses (N) are associated with the subtotal, N_0 ; about 30% is for shaft power; approximately 15% is associated with the expense of treating acid gas effluent, 5% is for steam and 5% because by-product oil is priced below the cost ($\$15.90/10^6$ kcal) of the input available energy. The remaining 30% is the cost of the input available energy ultimately wasted in the effluent CO_2 . Recall the erroneous results of the available energy analysis on Unit 18 (attributed to mistaken or incomplete data) which imply that there is no net consumption. Consequently, in the costing of gas leaving Unit 18, it appears that there is no expenditure associated with the consumption of available energy in the unit. Of course, there must be; and, hence, the rise in cost across Unit 18 would be even more than indicated.

The gas output from Methanation, Unit 19, costs $\$1.93/10^6$ kcal more than the input. One-fourth is for capital; 8% is for other operating expenses (N_0) besides those associated with available energy (power). Over 15% is for consumed gas available energy; nearly 40% is because the waste heat credited to the unit is worth less than the cost of the available energy from which it was derived. The remaining few percent is for shaft power and electricity.

The final rise in cost of product gas, for drying in Unit 23, is a mere $9¢/10^6$ kcal, which is negligible in comparison with other units.

Conclusions. By far the largest rise in the unit cost of the main-stream "energy" is associated with the Gasification unit. The costing analysis of that unit makes it clear that the principal cause is the high cost of utilities--steam and oxygen. In turn, the analysis of Units 30 and 32 shows that the unit cost of the output steam, shaft power and electric power is extremely high, in spite of the low cost of the fuel (char) supply to the units. These high utility costs must be a consequence of (i) unit designs which are far from the optimal of standard design practice, and/or, more importantly, (ii) from apparently high (Braun) estimates of capital expense for the utility units.

Perhaps this is a good juncture to explain the differences in the cost of product gas, leaving Unit 23, obtained in the foregoing study ($\$2.09¢/\text{kwhr} = \$6.12/10^6 \text{ Btu} = \$24.29/10^6 \text{ kcal}$) and that obtained by C. F. Braun ($\$6.75/10^6 \text{ Btu}$). One cause of the differences is that the unit costs presented here are per unit of available energy, whereas the Braun costs are per unit of energy; for the product gas, $\$6.75/10^6 \text{ Btu}$ of energy equals $\$7.20/10^6 \text{ Btu}$ of available energy. The cause of the difference--the $\$7.20/10^6 \text{ Btu}$ Braun cost versus the $\$6.12/10^6 \text{ Btu}$ calculated here--was mentioned earlier: The present study derived the unit costs of electricity and product gas by evaluating separately the expenses incurred to produce each. (Inasmuch as the product gas is the principal product, the fuel expenses attributable to the electricity were determined on the extraction basis; cf. Chapter 3. Had the two products been considered to be on a par, the equality basis would have been used--which would have made steam, power and electricity even more costly and gas

less.) Thus, the present procedure determines the cost of producing each product. In contrast, the Braun study takes the viewpoint that, no matter what it actually costs to produce the electricity, the price of the electricity will be 0.45¢/kwhr; any additional expenses for producing electricity must be borne by the product gas. As it turns out, for each kwhr of electricity exported, the loss would be $8.34¢ - 0.45¢ = 7.87¢/\text{kwhr}$. If this loss were to be made up by increasing the price of product gas, it would be necessary to raise the price by $\$7.20 - \$6.12 = \$1.08$ per 10^6 Btu.

There are two important points, related to the difference between the Braun costs and those calculated here which deserve further elaboration:

1. One reason the Braun study begins by assuming a stipulated price for the electricity--whatever that price might be--is because, without the available energy concept, it would be powerless in any attempt to determine the proportions of fuel costs which are incurred to produce electricity and product gas respectively. Without making that separation of expenses incurred to produce the two commodities, it is impossible to determine the distinct costs of the two. So, "for convenience" the price of one is assumed, which reduces the system to one which has only one product to be costed. As explained in Chapter 3, if there is only one product to be costed, the available energy concept is not needed--any measure may be used for the single-product commodity. But, if the price of other commodities were assumed in order to reduce the system to one with supposedly a single product, then the calculated unit cost of the product does not reflect fairly the expenses for producing it. As a result of mixing costing and pricing, misconceptions ensue.

2. The second, related point is this: The aim of the economic analysis made here is to determine the unit cost of producing the gas and of producing the electricity, but certainly not the price--which will depend not only on the cost of production but also on the market. Clearly, the electricity could not be sold at the cost of 8.32¢/kwhr, any more than the gas could be sold at \$6.75 (or \$3.91) per 10^6 Btu of energy. What then is utility of having calculated the 8.34¢/kwhr cost for producing electricity?

Since large amounts of electricity and of the other expensive utilities are used within the process, the 8.34¢/kwhr points out clearly what is the principal cause which makes the SYNTHANE process relatively uneconomical--or more precisely, which makes the C. F. Braun conceptual design of the SYNTHANE process relatively uneconomical--in comparison to the other processes designed? The results presented in Chapter 5 for the utility subsystem make it clear that significant improvements in efficiency can be achieved with state-of-the-art technology. And it is clear that, in turn, the unit costs for producing the utilities can be reduced greatly, since the calculated costs (such as 8.34¢/kwhr for electricity) far exceed the known costs with which utilities can be produced today--even with more expensive fuels.

As a consequence of these conclusions, an additional costing study has been made, using reasonable (yet conservatively high) costs for utilities. The results of that study will be presented after further discussion of the foregoing results.

Unit 18, Acid Gas Removal, also raises the unit cost of gas by a large amount. A large portion of the increase is due to shaft power expense, so reduced utility costs will improve this unit too. Utilization of CO₂ available energy at some reasonable efficiency would also help significantly. It is estimated that the \$6.38/10⁶ kcal increase in unit cost could be reduced to \$5.00 with reasonable steam costs and with CO₂ available energy utilization. Also, it may be possible to reduce the costs associated with effluents. The accuracy of capital cost estimates for all waste treatment facilities should be scrutinized, inasmuch as treatment costs are large components of the expenses for many "mainstream" units.

On the other hand, it is likely that costs associated with Unit 18 and auxiliaries would increase even more when available energy consumptions are properly accounted for. The technology for the proposed Unit 18 should be analyzed carefully (and, of course, alternative technologies should be further studied and/or developed).

Unit 17 raises the cost of gas by a fairly large amount. A reasonable savings could be attained if the available energy consumption--largely from mixing shifted and by-pass gas (cf. Chapter 5)--were reduced. Effluent treatment expenses are the largest costs for this unit.

Results and Conclusions of Costing a Modified SYNTHANE Process

The most important conclusion drawn above is that the high expenditure for utilities is the main cause of the high cost of product gas. Therefore, the costing analysis has been repeated, employing reduced prices for steam, shaft power, electricity and oxygen. The price of steam was assumed to be 2.15¢ per kwhr of available energy and 2.35¢/kwhr for marketable electricity. These prices are conservatively high; they can be achieved readily, even with fuels which are significantly more expensive than the char (\$1.03/10⁶ Btu) which fires the steam plant. The costs of shaft power and oxygen are derived from these steam costs, as before, employing the same efficiencies and capital costs for the O₂ plant and the power equipment--another conservative effect. Electricity produced at 2.35¢/kwhr is in general marketable, depending, of course, on the plant locale.

The results of the re-costing are shown on Figure 6-5 and, with more detail, on Figure 6-6. As the figures show, the unit cost of product gas was readily reduced by 20%, from 2.1¢/kwhr to 1.7¢/kwhr of available energy--or from \$5.72 to \$4.66 per 10⁶ Btu of energy.

It can be expected that the unit cost of gas could be reduced even further because there is no reason that the electricity produced as a part of SYNTHANE could not be produced as inexpensively as in modern coal-fired power plants--the technological requirements are the same--for significantly less than 2.35¢/kwhr. Indeed, the electricity could even be a profitable product; the overall economy of SYNTHANE would thereby be improved further--especially considering the increased export power (600 Mw, as described in Chapter 5) that would be achieved by improvement of the utility subsystems.* Too, the cost of shaft power and oxygen could be lowered even more with more efficient oxygen plant and power equipment. In any case, the cost of the product gas could be reduced further, below the 1.7¢/kwhr of available energy or \$4.66/10⁶ Btu of energy. The inefficient utility

* The electric output of the process could be increased even further with the development of concentration cells for reducing available energy consumption in the gasifier. But, since that technology is not in existence, its economy is a question.

Figure 6-5
Available Energy Flows and Unit Costs (¢/kwhr)
MODIFIED SYNTHANE PROCESS

AVAILABILITY FLOWS (UNIT COSTS)

100% PLANT 76
ALL UNITS: MILLION KCAL/HR
(\$/10⁶ KCAL)

PRELIMINARY
THIS DRAWING IS FOR ESTIMATING
PURPOSES ONLY AND IS NOT TO BE
USED FOR DESIGN OR CONSTRUCTION

* $C_{\text{steam}} = \$25/10^6 \text{ kcal} = 2.15 \$/\text{kwh}$
 $C_{\text{shaft}} = \$31.4/10^6 \text{ kcal} = 2.7 \$/\text{kwh}$
 $C_{\text{elec}} = \$27.3/10^6 \text{ kcal} = 2.35 \$/\text{kwh}$

† 10 Btu of energy corresponds to 0.9375 Btu of available
energy; 4.97 \$/10⁶ Btu of availability = 4.64 \$/10⁶ Btu of energy.

FIGURE 6-6

COMMERCIAL CONCEPT DESIGN-WESTERN COAL PERC SYNTHANE PROCESS BLOCK FLOW DIAGRAM			
ALHAMBRA C F BRAUN & CO CALIFORNIA			
SCALE	DATE	DESIGNED BY	APPROVED
1" = 10'	5/75	4568-204-100-XD-1	0

subsystem makes the C. F. Braun conceptual design prejudicial against SYNTHANE, especially when coupled with the exceedingly low stipulated price of 0.45¢/kwhr for excess electricity. A re-design of the utility subsystems is called for, with careful estimates of capital costs.

Chapter 7

Summary of Principal Recommendations

Category I. Process Modifications

1. Above all, the utility subsystems--Units 30, 31 and 32--should be redesigned, and capital costs need to be determined carefully. It can be expected that the unit cost of producing gas will be reduced by a large amount.
 - Also, the plant should be viewed as a cogeneration facility, and the principal products should be costed at the expense of producing them.
2. A program should be encouraged for research and development on cells (and other conceivable methods) for reducing the available energy consumption due to combustion in the gasifier. (Such technology would be of great value in all systems where combustion is an important operation.)

Less importantly,

3. The purported technology (and/or flow stream conditions and power) for Unit 18, Acid Gas Removal, should be checked carefully. Also, means for utilizing the available energy of vented CO_2 might be worth pursuing.
4. Ways of eliminating (or reducing) available energy consumption associated with the mixing of by-pass and shifted gas in Unit 17 might well be studied.

Category II. Further Analyses

1. The costing made in this report should be repeated, with the corrected flow rate of available energy-- $800(10^6)$ kcal/hr rather than $686(10^6)$ kcal/hr--of steam to power production.
2. The study made in this report might well be repeated using other values for various parameters such as
 - (a) Second-law efficiency of various units, especially for the production of shaft power and for the oxygen plant;
 - (b) Assumed costs for electricity and steam, and for shaft power and oxygen as well, in the modified costing.
 - (c) coal costs.

3. A sequel study to the one in this report should be made on any later designs than that for SYNTHANE presented by C. F. Braun and Company in Reference 28. Also, the case with export char could be studied.
4. A study like the one in this report should be made on other gasification processes reported upon in Reference 28, for the sake of (i) ascertaining means for improving them, and (ii) to discover any inequities (unintended) which may favor some processes and/or disfavor others, as a result of "arbitrary" design decisions.
5. The costing study could be repeated with the corrected available energy, $800 (10^6)$ kcal/hr, in place of the $686 (10^6)$ kcal/hr, for steam delivered to shaft and electric power production.
6. The figure in Appendix A shows an available energy flow diagram similar to Figure 5-1, with energy flows superimposed. A more detailed diagram, like Fig. 5-2, might well be constructed with energy flows.

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APPENDIX A

Figure A-1
(Energy) and
Available Energy Flow Diagram, 10⁶ kcal/hr
SYNTHANE PROCESS CONCEPTUAL DESIGN