PART III

RELATED TOPICS IN COAL UTILIZATION

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A group of activities carried out by the project team cannot be characterized as coal utilization processes. These topics seemed to be of sufficient importance to be discussed separately in Part III as they relate to the general subject of coal use. The topics include combined cycle systems, retrofit capabilities, thermodynamics and coal slurry pipelines.

THE COMBINED CYCLE IN RELATION TO COAL AS A FUEL

by

John E. Powers
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In the burning of clean fossil fuels--natural gas, natural gas liquids, and liquids obtained from crude oil--to generate electric power, the advantages of the combined gas-steam turbine cycle have provided great incentive for its development. The net operating capability of combined cycle plants under construction or on order is 6047 MW according to the 54th Semi-Annual Electric Power Survey of the Edison Electric Institute. Over half this capacity is for Southern California Edison Company. As it appears that it may be necessary to replace oil and gas with coal not only in new plants but even by retrofitting old ones, it is essential to attempt to evaluate the effects that substitution of coal as fuel will have on the future development of the combined cycle.

WHAT AND WHY OF THE COMBINED CYCLE

As supercritical steam cycle generating units were installed and found to have problems with somewhat lower availability factors, it became evident that the energy efficiency of steam cycles had reached a plateau of about 36-38%. At the same time, modified aircraft gas turbines were being utilized for peak loads. Whereas the unit capital costs for gas turbines were low, the maintenance costs were high and fuel costs even higher because of the required use of premium fuels and the poor thermal efficiency, reflecting a large energy loss in the hot exhaust gases.

In an attempt to take advantage of the potential for the higher thermal efficiency resulting from the relatively high inlet temperatures to gas turbines and adapt them to intermediate and/or base load situations, the hot exhaust gases were utilized to generate steam in a more or less conventional steam cycle. This combination of a gas turbine and a steam cycle, tne "combined cycle" yielded higher thermal efficiencies with a reduction in capital cost per kilowatt of generating capacity.

RECENT DEVELOPMENTS

Such a development necessitated more than adaptation of existing aircraft engines because gas turbines for intermediate or base load use must meet basic requirements different from those in aircraft or for peak shaving applications. Whereas it is reasonable and perhaps economical to require complete inspections and overhaul of gas turbines used in commercial aircraft every 2000 hours or so, and current practice with stationary gas turbines used in electric power generation necessitates reblading after about 10,000 hours of operation, it is not uncommon for steam turbines to operate for 25,000-50,000 hours between major overhauls--which does not include reblading. Another difference is that weight is of little consequence in connection with power production. Perhaps the most important design difference is that gas turbines for electric utility power production are designed for use at one fixed set of conditions over relatively long periods of time at high efficiencies whereas aircraft engines, of necessity, must operate at reasonable efficiencies over extreme ranges of temperature and pressure at the inlet.

GAS TURBINES REQUIRE A "CLEAN" FUEL

Whether one is dealing with aircraft service or electrical power generation, gas turbines require a clean fuel. Principally, the amount and size of solid particles and liquid droplets which may enter the turbine are both extremely small--and no one knows just how low these must be. Secondly, many of the elements whose chemical compounds are harmful to turbine blades are present in coal. Attempts to burn pulverized coal directly in turbine combustors were unsuccessful. Further research in this direction should probably be directed toward pressurized, fluidized bed combustion. Ideally, if coal is to be used in connection with gas turbines in a combined cycle, the coal must first be converted to a clean gaseous or liquid fuel.

WHAT ALTERNATIVE METHODS WILL YIELD A CLEAN FUEL FROM COAL?

The major thrust of the report to EPRI, of which this manuscript is a part, is directed toward answering the above question. In brief, clean liquid fuel can be produced either by pyrolysis, solvent refining, or liquefaction (catalytic or noncatalytic). A variety of gasification schemes have been proposed. Each of these complete systems operates at a thermal efficiency of less than 100%--and very considerably less. Therefore, attention must be directed toward the thermal efficiency of the process required to obtain clean fuel from coal as well as the efficiency of the combined cycle in planning future developments.

WHAT ARE THE CURRENT AND PROJECTED THERMAL EFFICIENCIES OF COMBINED CYCLE PLANTS?

Hottel and Howard in New Energy Technology present a graph of Turbine Inlet Gas Temperature plotted against the Year. This graph is reproduced as Figure 1 with permission. Several additions have been made as explained below:

According to a reputable source (1), power generating plants in construction since 1971 and currently operating, have established gas inlet temperatures of 1850°F as indicated by a cross, "+". This appears right on the curve drawn in 1970 or 1971.

Present projections call for a combined cycle with a gas inlet temperature of 2050°F utilizing air cooled blades to be in operation in early 1975. This is shown as a circled cross on Figure 1. Future improvements in allowable operating temperatures involving gas cooled turbine blades are projected at the rate of 65°F per year as indicated by a dashed line. An increase in gas inlet temperature will certainly result in some increase in thermal efficiency. However, the picture is somewhat clouded by the inefficiencies associated with air cooling of the blades.

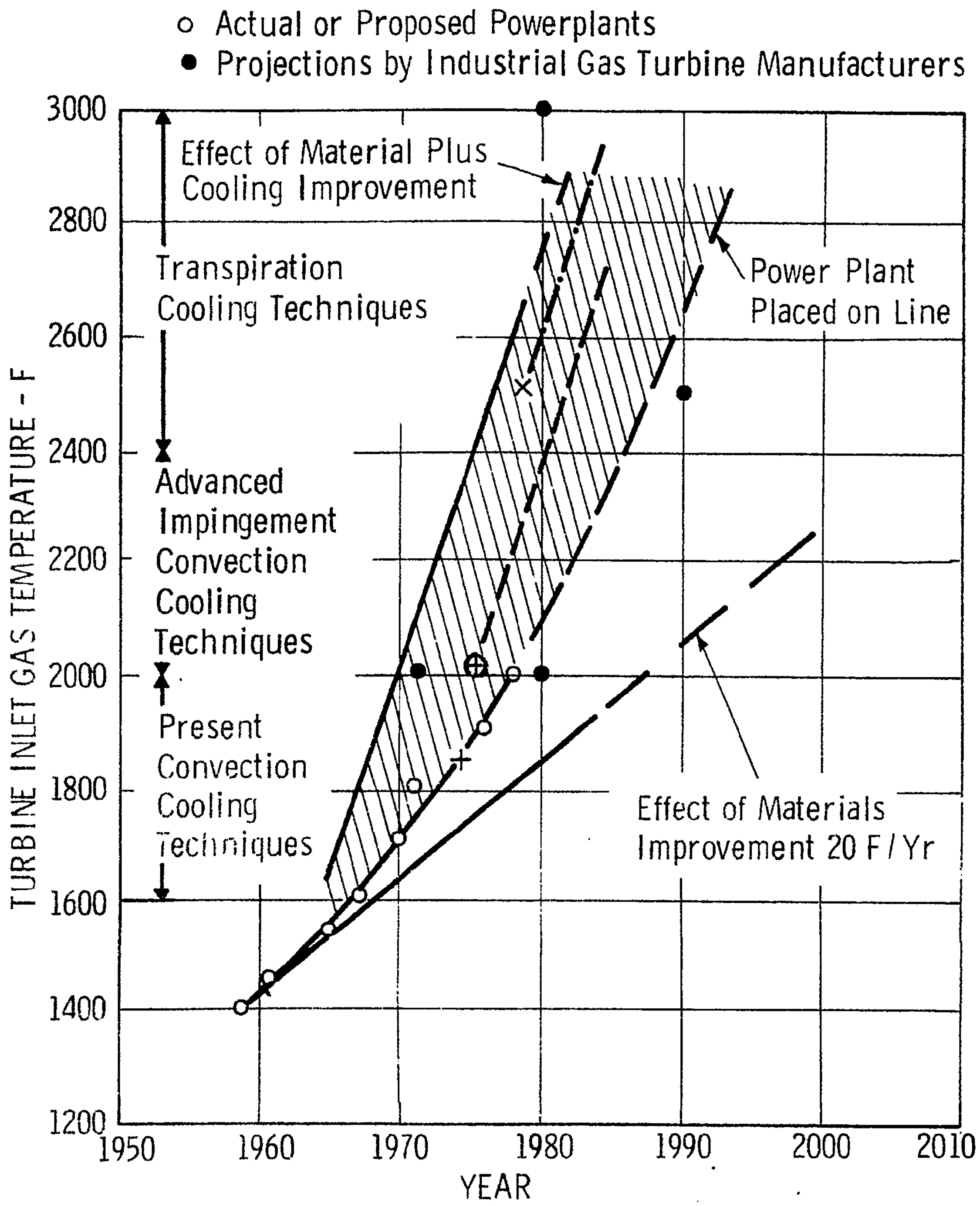

Figure 1. Progression of Gas Turbine and Compressor Technology (H. C. Hottel and J. B. Howard, New Energy Technology. Some Facts and Assessments. MIT Press, Cambridge, Mass. (1971)). See also Robson, F. L., Giramonti, A. J., Lewis, G. P., and Gruber, G., 1970. "Technological and Economic Feasibility of Advanced Power Cycles and Methods of Producing Nonpolluting Fuels for Utility Power Stations," Report prepared for National Air Pollution Control Administration, U.S. Department of Health, Education, and Welfare, December, 1970.

As with most problems associated with improvements suggested by thermodynamic considerations, the desirability of increasing the temperature of operations is hindered by the necessity of finding materials to withstand continued exposure to such conditions. There is some hope that silicon nitride turbine blades might soon prove practical and Westinghouse plans to have a large-scale gas turbine without cooling of the silicon nitride blades in operation by 1978. This point is plotted as an "X" on Figure 1. Future increases in operating temperatures are projected (rather arbitrarily) as a center line drawn with a slope of 65°F per year. General Electric has a similar development underway as reported in the business section of the New York Times recently.

From a practical point of view, gas inlet temperature is only important with respect to the thermal efficiency of the combined cycle. Several factors in addition to gas inlet temperatures serve to establish the thermal efficiency of the combined cycle so that it is difficult to establish thermal efficiencies of cycles involving gas turbines under development. However, Table I contains some values believed to be reasonable for simple combined cycles. The combined efficiency is a function of the steam conditions as well as the gas turbine inlet temperature. Brown Boveri is constructing a combined cycle, dual steam pressure plant at Geertruidenberg of PNEM for which the efficiency is projected to be 44%, with a turbine inlet of 1742°F (2). This is a somewhat complex cycle which includes much heat exchange surface.

TABLE I

		Thermal Efficiencies		
		Combined Cycle with Gas Turbine Blades		Required of Process to Provide Clean Fuel for Turbine from Coal,* %
Inlet Gas Temperature, °F	Year	Cooled with Air %	Uncooled Si-N, %	
1850	1973	41	--	90
2050	1975	43	--	86
2250	1978	45	--	82
2500	1978	--	49	75
2550	1981	47	--	78

*Based on an overall thermal efficiency of 37% for either a conventional steam cycle burning a clean coal or a steam cycle with fluidized bed combustion.

Table I gives the best estimates that could be made with the available data and time. It would certainly seem reasonable for EPRI to attempt to obtain better estimates although it should be recognized that it will be impossible to obtain exact numbers and, perhaps, difficult to obtain numbers that are significantly better than those presented above. To those who argue for even higher gas inlet temperatures based on data from military or commercial jet aircraft engines, we point out again that gas turbines for intermediate or base load use are really quite different from aircraft engines.

HOW DOES THE THERMAL EFFICIENCY OF PROCESSES TO PRODUCE CLEAN GASEOUS OR LIQUID FUELS FROM COAL TIE IN WITH THE COMBINED CYCLE?

The thermal efficiency of processes to produce clean gaseous and liquid fuels from coal have been estimated to be in the range from 50-80%. Firm figures based on actual continued plant operation are simply not available.* However, it is very simple to calculate the thermal efficiencies that would be required for such processes such that the overall efficiency when coupled with present and proposed combined cycles will at least equal that available from the standard steam cycle utilizing limestone in fluidized bed combustion for sulfur clean up. The thermal efficiency for the latter is taken to be 37%. Based on this figure, the required efficiency of processes to provide clean gaseous or liquid fuels can be easily calculated according to:

$$\text{Required Efficiency of Coal Conversion Process} = \frac{37\%}{\text{Thermal Efficiency of Combined Cycle}} \quad (1)$$

The values of required thermal efficiency of processes to provide clean fuels from coal calculated from Equation (1) are listed in the right-hand column of Table I.

Some tentative conclusions can be drawn based on the figures presented in Table I:

(1) The thermal efficiency of state-of-the-art gasifiers (Lurgi and Koppers-Totzek) is about 70%(3) when proper account is given to steam requirements for auxiliary processes, etc. Therefore, in accordance with Equation (1) and as summarized in Table I, unless gas turbine inlet temperatures approach 3000°F, current gasification technology in conjunction with the combined

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*There is good indication that operating gasifiers have thermal efficients with percentage efficiencies in the high 60's (3).

cycle is not competitive on the basis of thermal efficiency with fluidized bed combustion and a steam cycle.

(2) If a gasification process with a thermal efficiency of 82% can be developed by 1978 at which time a gas turbine with cooled blades might be available for operation with a gas inlet temperature of 2250°F, the thermal efficiency of the coupled gasification process and combined cycle will just equal the thermal efficiency of atmospheric pressure, fluidized-bed boiler, steam cycle generating plants presently planned or under construction, i.e., 37%.

(3) If uncooled silicon nitride gas turbines can be made operational by 1978 with an inlet temperature of 2500°F, the thermal efficiency required of any gasification process to be used to provide clean fuel for a combined cycle must exceed 75% to be competitive based on thermal efficiency alone.

(4) The cost of coal processing plants are such that there is little doubt that the capital cost of such plants coupled with a combined cycle will be in excess of that of a steam cycle incorporating either a conventional boiler burning clean coal or a fluidized bed combustor. Therefore, it seems obvious that the anticipated thermal efficiency of coal processing plants must exceed 75% to justify extensive expenditures in development of coal processing plants on the part of the utility industry.

WHAT RESEARCH SHOULD BE DONE?

Interpretation of Table I together with a knowledge and/or understanding of some of the limitations of coal gasification and/or liquefaction processes seems to give strong indication that combined cycle operation based on the indirect use of coal as a fuel will require significant technological developments. The present severe limitation that the bed temperature in atmospheric fluidized bed boilers should not exceed 1600°F if sulfur is to be removed in the bed, dictates that the thermal efficiency of an atmospheric fluidized bed coupled with a combined cycle will probably not be increased above 40%. An increase from 37% to 40% hardly justifies substantial expenditures for research and development. On the other hand, removal of sulfur in pressurized fluidized bed boilers is apparently effective at temperatures up to 1750°F as established experimentally by Hoy in England. Operation at such elevated temperatures produces other problems. Some money should be spent on attempts to gain additional knowledge relative to the temperature limitations and to increase the temperature of operation of fluidized beds of limestone especially in connection with operation at pressure.

If gasification processes to produce a clean, low Btu gaseous fuel are to be developed, the problem of particulate and H_2S removal at high temperature must be studied. If the hot gas from the gasifier is usable in a gas turbine without quenching, substantial thermal economy can be achieved, thereby partially off-setting the energy losses in the gasifier. At present there seems to be no practical way to utilize the hot gasifier product gas and therefore this would appear to be a fruitful area for research--if coal gasification proves to be of interest to the utility industry.

Bibliography

1. Jack Farrow, Westinghouse Electric Co., Personal Communication, Jan. 23, 1974.
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ECONOMIC EVALUATION

by

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ECONOMIC EVALUATIONS OF COAL CONVERSION PROCESSES TO PROVIDE CLEAN FUELS FROM COAL

In evaluating the several routes and processes leading from coal to clean fuels for electric power generation it becomes essential that a common basis be used in order to make relevant, fair and valid comparisons. The bases used during this project have resulted from modifications, wherever warranted, of the basis adopted in the supply - Technical Advisory Task Force - Synthetic Gas-Coal Report of Federal Power Commission.

Investments required for all of the processes must be based on a common point in time (mid 1973) then escalated through the years 1975, 1980, 1985, 1990. It is reasonable to assume excalation costs of 4% per year for 1973-75, 3.5% per year for 1975-80 and 3% per year thereafter.

Plant Capacities

The plant capacities used as basis during this study are those with heating value of product equivalent to the output of standardized 250 MMCF/D SNG plants with heat output of 2.5 X 10" Btu/day.

Coal Costs

The basis used for coal costs were 30¢/MMBtu for the bituminous coal and 15¢/MMBtu for the subbituminous coal.

By-product Credits

Reasonable by-product credits must be allowed for sulfur ammonia, oil and char.

OVERALL ECONOMIC COMPARISONS BETWEEN SOLID LIQUID AND GASEOUS FUELS FROM COAL

The Table I gives an overview of the major processes for which economic analyses were made during this study and some figures obtained from the literature. The two major quantities listed for solid liquid and gaseous fuels from coal are total capital required in MM$ or $/BID, and the average selling price of fuel between now and 1990 as computed by AGA-FPC recommended accounting techniques. For the purposes of EPRI these two overall economic criteria may readily be translated in terms of $/KW-H and cents/KW by making the necessary efficiency assumption to translate the Btu permitted by the fuel to KW generated at the power plant.

The following section is a tabular presentation of the items involved in determination of total plant investment required, of annual operating cost, and finally the selling price of the fuel by AGA-FPC Public Utility and discounted cash flow accounting procedure.

Quick estimating methods and bases for auxilliary onsite investments required such as oxygen plant, Claus sulfur recovery, particulate recovery, etc. have been also included at the end. These materials have been taken from the Final Report of Supply Technical Advisory Task Force - Synthetic Gas - Coal, Federal Power Commission. A detailed example of complete economic analysis is given at the end.

FUEL COST EQUATION DCF METHOD

On the basis of 25 year project life, 16 years "sum-of-the years" digits depreciation, 100% equity capital, 12% DCF return rate and 48% Federal Income Tax rate, the following equation has been developed for the cost of the fuel:

$$\text{Fuel Cost @ 12\% D.C.F. return} = \frac{aN + 0.2353I \text{ X } 0.1275S + 0.2308W}{G}$$

a is a dimensionless parameter describing escalation of operating cost during the project life.

If there is no escalation from start-up through project completion date a = 1.0. If escalation is to be considered on the operating costs during the project life it is recommended (1) that a = 1.2651 for 1975 and a = 1.2422 for 1980 and beyond.

N = Total Net Operating Cost in First Year, MM$/year

I = Total Plant Investment, MM$

S = Start-up Costs, MM$

W = Working Capital, MM$

G = Annual Fuel Production, MMMM Btus/year, Trillion Btus/year

The values of I.S.W and N above must be adjusted to reflect the actual costs for the start-up completion date. The synthetic gas coal task force[1] has recommended to calculate the total plant investment, start-up costs, working capital and total net operating cost for a base year (say 1973) then escalate them to the cases of interest. Total plant investment to be escalated to 2 years prior to start-up completion; Start-up costs, working capital and total net operating costs to start-up completion. The rates of escalation selected were 4% during 1971-1975, 3.5% during 1976-1980, and 3% after 1980.

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1. Supply Technical Advisory Task Force - Synthetic Gas - Coal REport of Federal Power Commission.

COST ESTIMATING AUXILIARY ONSITE INVESTMENTS

a. Oxygen Manufacture

On site oxygen plant investment may be calculated from the following data (1)

1. Maximum capacity per train: 2000 ST/SD (Short Tons/Stream Day)
2. Discharge pressure 0.5 to 5.0 psig
3. Product oxygen compression to be estimated separately

$$\text{Oxygen Plant Investment MM\$ (Mid 1971)} = \frac{\text{Capacity, ST/SD}^{a}}{1500} \times 7.4 \qquad (1)$$

In Eq (1) a is investment capacity slope.

if capacuty <1500 ST/SD a = 0.55

if 1500 ST/SD $\le$ capacity < 2000 ST/SD a = 0.80

b. Claus Sulfur Recovery

The Claus sulfur recovery plant to handle SH_2 and OO_2 streams from gas fortification and SO_2 produced in Wellman-Lord scrubbing step can be quick estimated from Table 1 below.

Table I Investment for Sulfur Recovery

Base Capacity 100 LT/SD of Product Sulfur

Mole % SH_2+SO_2 in feed gas	Investment MM$, Mid 1971	Investment Capacity Slope		Maxproduct S° per train ST/SD	% Sulfur Recovery
		<100T/D	>100T/D		
5	1.45	0.6	0.8	100	84
10	1.20			200	89
20	.95			350	91
50	.75			700	93
100	.65			>1000	95

c. Estimating Investment Costs for Wellman-Lord SO_2 Recovery

In order to meet the atmospheric pollution regulations

CALCULATION OF TOTAL CAPITAL REQUIREMENT PROCESS

1. All onsite plant sections

    Coal Storage

    Coal Preparation

    Coal Gasification

    Waste Heat Recovery

    Gas Purification (particulate removal scrubbing)

    Fresh Water Treatins

    Compression Facilities

    Cooling Towers

    Power Generation and Distribution

    Steam Generation

    Waste Disposal Facilities

    Office

    Shop

    Control System

    Oxygen Plant

    Hydrogen Plant

    Other on site plant sections

SUBTOTAL ____________________

2. Contractors overhead and profit

    Engineering and Design costs

PLANT INVESTMENT SUBTOTAL ____________________

TABLE I

OVERALL ECONOMIC COMPARISONS BETWEEN SOLID LIQUID AND GASEOUS FUEL FROM COAL

		SOLIDS		LIQUIDS	GASES				
						Low Btu		High Btu	SNG
		TRW	Liquefaction	Liquefaction	Overall	Mollen Salt	HYGAS	LURGI	Other
Plant Investment MM $ ** $/Bld (*** 30,000 B/SD Basis)	Bituminous Coal	146 (M.R. Tek) 108 (Dow Chemical)				232.1	181.1	270	230
	Western Coal			225*** (325 at 1980)*** 7500** 11000**				250	210 (200 @ 1990)
Gas Costs ¢/MM Btu	Bituminous Coal	70-90			(1) 75-11,5	1101	97-116	145	125 (115 @ 1990)
	Western Coal			1.15 ≅ 7 $/Bdl (1.60 at 1980 ≅ 10 $/B)	60-80			110	90 (80 @ 1990)

Basis Coal Costs 30¢/MM Btu bituminous coals
15¢/MM Btu Sulbituminous Western Coals

(1) As projected by Esso Paper, "Technology and Cost of Coal Gasification: The Cost and Commercialization of Gas and Liquid from Coal," Howard M. Siegel, Esso Research and Engineering Company, IGT Symposium on "Clean Fuels from Coal" September 10-14, 1973

3. Project Contingency

(In the absence of detail below use 15% of subtotal plant Investment)

Allowances for Results of a Detailed Design

a. New railroad spur to plant site

b. New roadways to plant site

c. New power transmission to plant site

d. New pipeline for water to plant site

e. New slurry pipeline if applicable

f. New unitrain if applicable

g. Contingency site problems:

    Prilling

    Grading

h. Additional clean up facilities foe efficient water gas etc.

i. Additional equipment for start up shut down stand by facilities

j. Additional safety equipment

k. Additional equipment for process or mechanical emergencies

l. Standby equipment for reliability

m. Additional spare equipment

n. Contingency for missed cost estimates

o. Premium labor for construction

p. Contingency for low labor productivity and strikes

TOTAL PROJECT CONTINGENCY ______________

4. Process Development Contingency

(In the absence of detail below use 7% of Plant Investment Subtotal)

<u>Detailed Allowances for Process Development Contingency</u>

a. Lower gasification rates

b. Lower product yields from reactors

c. Lower thermal efficiency

d. Lower distillation contacting performance

e. Need for more sophisticated reactor, gasifier intervals (plates, grids, distributions, downcomers, cyclones, nozzles, turbulence promoters, etc...)

f. Cost escalation in feed or ash removal systems

g. Need for additional coal treatment

h. Unexpected fine removal problems

i. Unexpectedly high sulfur

j. Unexpected heat transfer, drying problems

TOTAL PROCESS DEV. CONTINGENCY

Sum of the items 1 through 4 above gives

5. Total Plant Investment

6. Interest during construction [Interest Rate X Total Plant Investment X 1.875 construction period]

7. Start-up costs [20% of total gross operating cost]

8. Working Capital

a. Coal Inventory (for 60 days at designate)

b. Materials and supplies 019% of Total Plant Investment

c. Net receivables @ 1/24 of annual gas revenue @ $1,00/MM Btu

BASIS FOR CALCULATING GROSS AND NET OPERATING COST

Base Load Plants @ 90% Load Factor

1. Coal (30¢/MM Btu high heating value, deep mined Bituminous coals and 15¢/MM Btu surface mined subbituminous coals)
2. Other Raw Materials
3. Catalysts and Chemicals
4. Purchased Utilities
    a. Electric Power @ 0.9¢/KWH
    b. Raw Water @ 30¢/M Gal (delivered)
    c. Cooling Water
5. Labor
    a. Process Labor [(Men/s hift) X 8304 Man-hours/year X 5.20 $/Man hour] (1)
    b. Maintenance Labor (1.5%/year of total Plant Investment)
    c. Supervision (15% of operating and maintenance labor)
    d. Admisistration & General Overhead 60% of total items a,b,c, above.
6. Supplies
    Operating Supplies (30% of process operating labor)
    Maintenance Supplies (1.5%/year of Total Plant Investment)
7. Local Taxes and Insurance (2.7%/year of Total Plant Investment)

TOTAL GROSS OPERATING COST/YEAR

8. By Product Credits

    Sulfur (10.00 $/LT)

    Ammonia (25.0 $/ST)

    Light Oil (where applicable) @ 15¢/gas

    Heavy Oil (Tars 30¢/MM Btu)

    Char (90% of Coal Cost)

(1) Based on 1973 figures

TOTAL COSTS

TOTAL NET OPERATING COST / YEAR

PROCEDURE FOR CALCULATING THE COST OF FUEL - UTILITIES FINANCING METHOD

BASIS

1. 20 year project life
2. Depreciation 20 year straight line, 5%/year

ESSENTIAL INPUT PARAMETERS

3. Debt/Equity Ration for the mix of total Capital Requirement
4. Percent Interest on debt
5. Percent Return on Equity
6. Federal Income Tax Rate

DERIVED PARAMETERS

7. Rate Base = Total Capital Required - less accrued depreciation including 1/2 depreciation for current year
8. Percent Return on Rate Base = Fraction Debt X Percent Interest + Fraction Equity X Percent Return on Equity

CASH FLOW CALCULATION

9. Return on Rate Base X Fraction Return on Rate Base
10. Return on Equity - Fraction Equity X Rate Base X Fraction Return on Equity
11. Federal Income Tax = Return on Equity X Fraction Tax Rate/ (1-fv. tax rate)
12. Depreciation = 0.05 X (Total Capital Requirement - Working Capital
13. Total Cash flow revenue required = Iten 9 + Item 11 + Item 12 + Total Net Operating Cost

14. In given year = Total Cash Revenue required (project life)/
20 X Annual Production

Average Fuel Cost Equation (UTILITY FINANCING METHOD)

By Utility Financing Method

Basis 20 year project life

5%/year straight line depreciation on (Total Capital Required less working capital)

Average Cost of Fuel

$$\$/\text{MM Btu} = \frac{aN + 0.05(C-W) + 0.005\left[p + \frac{48}{52}(1-d)r\right]C + W}{G}$$

where $p = (d)i + (1-d)r$

a = a dimensionless parameter describing escalation of operating cost during the project life. If from plant start up through project completion date there is no escalation use a = 1.0. If escalation is to be considered on the operating costs during the project life it is recommended to use a = 1.3726 for 1975 and, a = 1.3435 for 1980 and beyond.

C = Total Capital Required, MM$

W = Working Capital, MM$

p = Return on rate base %/year

a = Fraction debt

r = Return on Equity %/year

G = Annual production, MMMM Btu/year, Trillion Btu/year

i = interest on debt %/year

PROCEDURE FOR CALCULATING COST OF FUEL

DISCOUNTED CASH FLOW METHOD (PRIVATE INVESTOR FINANCING)

BASIS

1. 25 year project life

2. 16 year sum of the uear's digits depreciation on total investment

3. 100% equity capital

ESSENTIAL INPUT PARAMETERS

4. Discounted cash flow return rate

5. Federal Income Tax rate

PRINCIPAL COST ITEMS

6. Total Plant Investment and Working Capital are treated as capital costs at the completion of start up.

7. Return on Investment during construction (TPI X DCF rate X 1.875 years) is treated as capital cost at the completion of start up.

FUEL COST

8. In D.C.F. method a single value for fuel cost is calculated for the desired DCF return over the life of the project.

DISCOUNTED CASH FLOW

To determine the discounted cash flow a table is prepared where the gas revenue, start-up and operating costs, depreciation, taxable income, net income and investment costs are listed for each year of the project. A discount factor is calculated for every year. Depreciation plus net income after F.I.T. investment for each particular year is multiplied by the discoune factor for that year to compute the necessary discounted cash flow.

as of 1971 SO_2 recovery is required on the following streams:

1. Claus Tail Gases after incineration
2. CO_2/SH_2 streams from second stage of 2-stage scrubbing systems if SO_2 level after incineration is larger 150 vppm
3. Combustion flue gases where SO_2 level is 7500 vppm (corresponding to 0.7% by wt. sulfur in fuel)

If, for the above streams Wellman-Lord process is used for SO_2 scrubbing then the required investment for Wellman-Lord Process units can be quick estimated from Table II below.

Table II Investment Required for Wellmans Lord SO_2 Scrubbing
Base Capacity 120,000 SCFM Feed Gas
2,700 lbs/hr Feed SO_2

	Investment MM$ Mid 1971	Investment-Capacity Slope
Gas Rate Related	0.85	0.60
Sulfur Rate Related	1.95	0.60
TOTAL	2.80	

d. Investment Costs for Process Water Treatment

Contaminants in process waters such as dissolved phenols, ammonia, hydrogen cyanide, hydrocarbons, etc. must be to particular process, estimated in quantity so that precise calculations may be made for the cost of their removal. The various processes available for the removal of these contaminants cannot be generalized at this point.

A rough guideline for investment required for treatment of process and other mescellaneous water streams was given in the "Final Report of the Supply Technical Advisory Task Force Synthetic Gas-Coal" as follws.

	Investment MM$ Mid 1971
Process Water	8
Miscellaneous Water streams	2
TOTAL	10

e. Investment Costs for Particulate Removal

For typical coal gasification processes the investment required for removal of particulates resulting from coal handling, crushing, conveying etc. was estimated in the F.P.C. report above for typical 250 MMCF/D plant to be 2 MM$. This investment figure however is to reduce the particulate emissions to environmentally acceptable levels via, cyclones, scrubbers, draft fans etc....

It does not represent investment for more sophisticated levels of particulate removal as dictated by erosion, corrosion, other problems, the low Btu gases would encounter in combined power generation.

Example

Economic Analysis TRW Chemical Beneficiation of Coal Meyers Process

Basis

10,000 Tons/Day

$10^4 \times 2 \times 10^3 = 2 \times 10^7 lb_m$ of coal per day

15 X 2000 lbs $\quad$ 390×10^6 Btus

$$Btus/lb_{coal} = \frac{3.9 \times 10^8}{15 \times 2000} = 13000 \text{ Btu/lb.}$$

Btu's/day $\quad 13000 \times 2 \times 10^7 = 2.6 \times 10^{11}$

Which compares with a 250 MMCF/Day

or $2.5 \times 10^8 \times 10^3 = 2.5 \times 10^{11}$ Btu/Day gasification flame.

Costs analysis for coal preparation and chemical desulfurizatio n

Basis for Design

10,000 T/D of product coal

including inert components and 5% moisture and fuel coal

operation 24 hrs/day

330 production days/year

10 days product inventory

3 days raw coal inventory

Calculation of Total Capital Requirement Process .....

1. All on site plant sections

Coal Storage	MM$	
Coal Preparation S- product drying compacting shipping		16
Coal Processing Equipment		38
Waste Heat Recovery		
Gas Purification (particulate removal scrubbing)		
Site Development and Land Costs		4
Fresh Water Treating		
Compression Facilities		
Cooling Towers		
Power Generation and Distribution		
Steam Generation		
Waste Disposal Facilities		
Utilities, Buildings		22
Office		
Shop		
Control System		

Oxygen Plant	
Hydrogen Plant	
Other on site plant sections	
Special lining, tankage	10
SUBTOTAL	90

2. Contractors Overhead and Profit (included in the above)

   Engineering and Design costs (included in the above)

Plant Investment Subtotal 90

3. Project Contingency

   (In the absence of detail below use 15% of subtotal plant investment)

   Allowances for results of a Detailed Design

   a. New railroad spur to plant site
   b. New roadways to plant site
   c. New power transmission to plant site
   d. New pipeline for water to plant site
   e. New slurry pipeline if applicable
   f. New unitrain if applicable
   g. Contingency site problems:

      Piling

      Grading
   h. Additional clean up facilities for effluent water gas etc.
   i. Additional equipment for start up shut down stand by facilities

j. Additional safety equipment

k. Additional equipment for process on mechanical emergencies

l. Standby equipment for reliability

m. Additional space equipment

n. Contingency for missed costs estimates

o. Premium labor for construction

p. Contingency for low lavor productory and strikes

Total Project Contingency 13.5

4. Process Development Contingency

(In the absence of detail below use 7% of plant investment subtotal) 6.3

Detailed Allowances for Process Development Contingency

a. Lower gasification rates

b. Lower product yields from reactors

c. Lower thermal efficiency

d. Lower distillation contacting performance

e. Need for more sophisticated reactor-gasifier internals (plates, grids, distributors, downcomers, cyclones nozzles, turbulence fromolers, etc...)

f. Costs escalation in feed or ash removal systems

g. Need for additional coal healment

h. Unexpected fine removal problems

i. Unexpectedly high sulfur

j. Unexpected heat transfer, drying problems

Total Process Dev. Contingency 6.3

Sum of the items 1 through 4 above gives

5.	Total Plant Investments	109.8
6.	Interest during construction [= Interest Rate X Total Plant Investment X 1.875 construction Period]	
	I. Rate 9.5%	19.56
7.	Start-up costs [20% of total gross operating costs]	
8.	Working capital	
	a. Coal inventory (for 60 days at design rate)	4.680
	b. Materials and supplies 0.9% of Total plant investment	.988
	c. Net receivables @ 1/24 of annual gas reserve @ $1.00/MMBtu	1.0
	Total W.C.	6.67

Details

8a. Btus equivalent of coal per day 2.6×10^{11} using 30¢ per MM Btu Bituminous Eastern Coal

$$\text{Detail cost of Coal } \frac{.30 \times 2.6 \times 10^{11}}{10^{6}} = .78 \times 10^{5} \text{ S}$$

60 day inventory $60 \times 0.78 \times 10^{5} = 4.68$ MM$

8c. Estimated at 28¢/10^6 Btu

$$1/24 \quad \frac{.28 \times 2.6 \times 10^{11} \times 330.0}{10^{6}} = 10^{6}\$ = 1 \text{ MM\$}$$

Basis for calculating gross and net operating cost

Base load plants @ 90% load factor

1.	Coal (30¢/MM Btu high heating value, deep mined bituminous coals and 15¢/MM Btu surface mined subbituminous coals	25.74

2. Other Raw Materials detailed list Page T6	17.00
3. Catalysts and Chemicals	
4. Purchased Utilities	
a. Electrical Power @ 0.9¢/KWH	0.297
b. Raw water @ 30¢/MGal (delivered)	
c. Cooling Water 20° temperature rise	0.119
d. Sewerage @ 0.001 $/MGal	0.003
e. Refuse disposal @ $0.50/ton	0.167
5. Labor	
a. Process labor [(Men/shifts) X 8304 Man-hours/year X 5.20 $/Man hour] (1)	.593
b. Maintenance Labor (1.5%/year of total plant investment)	1.650
c. Supervision (15% of operating and maintenance labor)	.338
d. Administration and General Overhead 60% of total items a,b,c, above	1.550

Raw Materials

Oxygen 99.5% pure @ $17/ton

Animal Coal $\frac{3.0400}{10^6} \times \frac{17}{10} \times \frac{10000}{2,400}$

Oxygen $\frac{3.04}{102.4} \times 17$ MM$ 2.153

Solvent Naptha

@ 200 lb/hr X $\frac{10}{2.4}$ X 24 = 20000 lbs/Day

cost @ $45/ST $\frac{4500}{2000}$ = 2.25¢ lb.

Annual cost of solvent

20,000 X 330 X $2.25/10^6$ = 14.85 $MM 14.850

(1) Based on 1973 Figures.

Total Raw Materials MM$/year 17.003

Utilities

Electric Power $1000 \frac{10}{2.4} = 4166.7$ KW.

Annual cost @ $0.012/KWH.

$$\frac{4166.7 \times 0.012 \times 24 \times 330}{1 \times 10^6} = 0.396 \text{ MM\$/year}$$

@ 0.9 0.009 0.297 MM$/year

Cooling water $2000 \text{ GPM} \times \frac{10}{2.4} = 8333.3$ gpm

Annual cost delivered @ flat @ 30¢/MGal/

$$\frac{8333.3 \times 1440 \times 330 \times 0.30}{1000 \times 1 \times 10^6} = 1.188$$

1.188 X 0.001

.30

= .003.96

Annual Labor Cost 3.3 operating positions $\times \frac{10}{2.4}$

13.75 positions operating

Process Labor $13.75 \times 8304 \times \frac{5.20}{10^6} = .593$ MM$

Operating and maintenance labor

1.650 + .593 = 2.243

Supervision 15% X 2.243 = .338

Operating and maintenance and supervision 2.581

Administration and general overhead 60% X 2.581 = 1.550 MM$

Credits

Total coal handled per year

$.8 \frac{10}{2.4} = 3.33$ MMT/year

Refuse generated $3.33 \times 0.067 = 0.223$ MMTons of ash &

$3.33 \times 0.036 \times .92 = 0.110$ MMTons of Sulfur

.333 MMTons/refuse

Refuse disposal cost @ $0.50/Ton

$.333 \times 10^6 \times 0.5 = 0.1665$ MM$

6. Supplies

Operating supplies (30% of process operating labor) .178

Maintenance supplies (1.5%/year of total plant investment) 1.650

7. Local Taxes and Insurance (2.7%/year of total plant investment) 2.960

Total Gross Operating Cost/year $MM 52.245

8. By products Credits

Sulfur (10.00 $/LT) 1.0

Ammonia (25.0 $/ST)

Light Oil (Where applicable) @ 15¢/Gal

Heavy Oil (Tars 30¢/MM Btu)

Char (90% of coal cost)

Total Credits 1.0 1.000

Total Net Operating Cost/Year 51.245

Fuel Cost Calculation By Year (in M$) Utilities Financing

End of Year	(1) Rate Base TCR-Accrued Depr. @ Mid-Year	(2) Return on Rate Base 10.86% of (1)	(3) Return on Equity 15% of .25 of RB	(4) Fed. Inc. Tax $\frac{48}{52}$ X 3	(5) Deprec. 0.05 (TCR-Work Cap)	(6) Total Net Op. Cost	(7) Total Fuel Rev. Reg. (2)+(4)+(5)+(6)	(8) Fuel Cost (7)/annual Feed ¢/MMBtu
1	142,980	15,500	5350	4950	7000	51,245	78,695	91.7
2	135,980	14,767	5099	4707	7000	51,245	77,719	90.6
3	128,980	14,007	4836	4464	7000	51,245	76,716	89.4
4	121,880	13,247	4742	4222	7000	51,245	75,714	88.2
5	114,980	12,487	4311	3980	7000	51,245	74,712	87.1
6	107,980	11,727	4049	3738	7000	51,245	73,710	85.9
7	100,980	10,966	3787	3495	7000	51,245	72,706	84.7
8	93,980	10,206	3524	3253	7000	51,245	71,704	83.6
9	86,980	9,446	3263	3011	7000	51,245	70,702	82.4
10	79,980	8,686	2999	2769	7000	51,245	69,100	81.2
11	72,980	7,926	2736	2525	7000	51,245	68,696	80.1
12	65,980	7,165	2474	2284	7000	51,245	67,694	78.9
13	58,980	6,405	2212	2042	7000	51,245	66,692	77.7
14	51,980	5,645	1949	1799	7000	51,245	65,689	76.6
15	44,980	4,885	1686	1556	7000	51,245	64,686	75.4
16	37,980	4,125	1424	1315	7000	51,245	63,685	74.2
17	30,980	3,364	1162	1072	7000	51,245	62,681	73.1
18	23.980	2,604	899	830	7000	51,245	61,679	71.9

SUMMARY ECONOMIC EVALUATION OF MEYERS (TRW) PROCESS

COAL FEED

LOWER KITTANING COAL 14 MESH TOPSIZE

Chemical Analysis % Dry Basis

Component	
Ash	20.7
Pyritic Sulfur	3.6
Organic Sulfur	0.6
Sulfate Sulfur	Nil

Heating Value 12,300 Btu/lb

RATE 10,000 Tons/Day

∿ 260 Billion Btu/day

COAL PRODUCT

Chemical Analysis % Dry Basis

Ash	14
Pyritic Sulfur	0.3
Organic Sulfur	0.6
Sulfate Sulfur	Nil

Heating Value 12,900 Btu/lb

COST OF FUEL BY UTILITIES FINANCING METHOD

Input Parameters

Debt/Equity Ratio 75%/25%

Per cent Interest on Debt = 9.5%

Per cent Return on Equity = 15%

Federal Income Tax Rate = 48%

Total Capital Requirement	MM$
Total Plant Investment	109.80
Interest During Construction	19.56
Start-up Costs (20% of Gross Operating Cost)	10.45
Working Capital	6.67
TOTAL CAPITAL REQUIRED (T.C.R.) =	146.48 MM$
Initial Debt 75% of TCR	110.00
Initial Equity 25% of TCR	36.48

Annual Fuel Production Rate

Plant Capacity 10,000 T/SD

Annual Fuel Production $\cong 2.6 \times 10'' \times 3.3 \times 10^{2}$ (1)

$= 8.58 \times 10^{13}$ Btus/year

= 85,800 Billion Btu/year

Per cent return on Rate Base: 0.75 X 9.5% + 0.25 X 15% = 10.86%

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(1) 330 Stream Days per year

CAPABILITY OF EXISTING ELECTRIC GENERATING UNITS TO USE CLEAN FUELS DERIVED FROM COAL

by

Edward R. Lady

The processing of coal into a clean, low-sulfur fuel yields a combustible product that is delivered as a solid, liquid, or gas. Although specific combustion tests must be carried out, there is little doubt that such fuels can be utilized in steam generating equipment or combustion powered prime movers that are designed to handle the particular fuels to be used. With these fuels new plants will be able to meet the air quality standards required by statute.

The existing coal fired electric generating units ultimately will have to reduce their sulfur dioxide and particulate emissions according to present law. The average sulfur content of the coal burned by the utilities in 1970 was 2.58 percent by weight (1), a content considerably in excess of the approximately 0.6 percent sulfur coal needed to reduce sulfur dioxide emissions to the required level. Some boilers are being modified to burn low-sulfur, high ash western coal to meet pollution standards. The majority of existing coal fired plants will have to utilize eastern, high sulfur coal or shut down for the lack of fuel. This section of the report considers some of the problems and potentialities of utilizing clean, coal-derived fuels in power plants currently in operation.

EXISTING FOSSIL FUELED GENERATION CAPACITY

The projected growth of the installed generating capacity of the United States is shown in Table I. Although the projected share of the fossil-fueled steam generation capacity decreases from 77 percent in 1970 to 44 percent in 1990, the Federal Power Commission projections (2) indicate that 382,000 MW of new fossil fuel plants will be added during these two decades, while only 85,000 MW of old plant capacity will be retired. Thus, of the 259,000 MW fossil capacity units operating in 1970, 174,000 MW will see service throughout the period 1970-1990 and must be considered as candidate units for retrofitting to utilize clean fuel or install stack gas scrubbing. The units scheduled to be retired during this twenty year time period (1970-1990) do not have sufficient useful life to justify large capital investments required by the various clean fuel processes. A few of these latter units have been selected to be used as the fuel consuming section of clean-fuel demonstration plants. Such demonstration plants, to be placed into service in the 1975-1985 period, cannot be operated economically due to their small (50-100 MW) size and will be retired from service within five to ten years, thus matching the remaining life of the older steam plants connected to them. Let us examine the 174,000 MW of relatively new fossil steam plants and determine the portion which burns high sulfur coal.

TABLE I

Installed and Projected Electrical
Generation Capacity of United States,
in 1000 MW

	1970	1990
Fossil - Fueled Steam	259	577
Hydro and Nuclear	81	683
Total	340	1260

The 1970 fossil fuel breakdown by type of fuel was 55.6 percent coal, 15.3 percent oil and 29.1 percent gas (2). Assuming that generating units fueled by coal, oil or gas had about the same capacity factor, this indicates that plants representing some 97,000 MW burned coal. In addition, during the period 1965-1970 there were 226 boilers, supplying 16,250 MW of generation capacity, that had been converted from coal to oil firing (3). Seventy-seven percent (12,500 MW) of these converted boiler are re-convertible to coal.

The coal-fired generating plants in the Mountain Region, Figure 1, use coal averaging 0.65 percent sulfur and therefore need not be included in plants which may require low sulur fuel unless local regulations specify less than 1.2 pounds sulfur dioxide per million Btu. However, this region represents only 8000 MW of capacity and may be off-set against possible reconversions of East Coast plants from oil to coal. Therefore, the potential of the market for

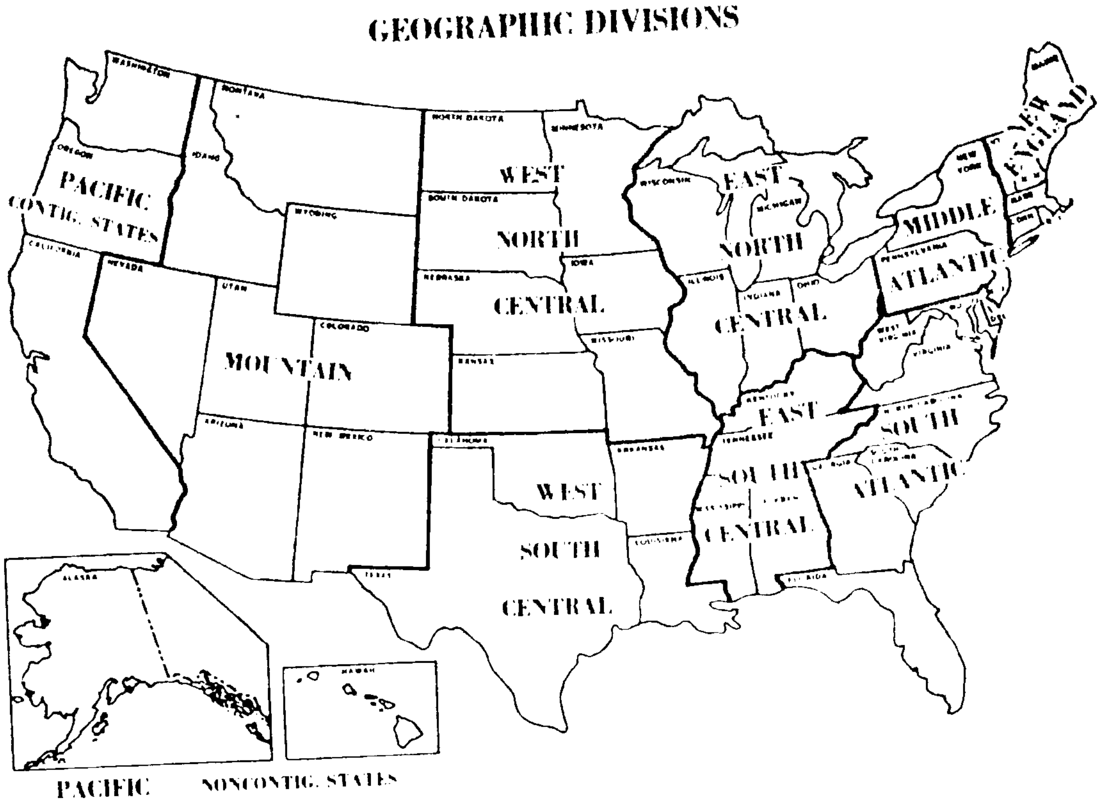

Figure 1. Major Geographic Divisions of the United States

retrofit of existing plants burning high sulfur coal to a clean fuel is 90,000 - 100,000 MW of generation capacity.

FUEL CONVERSION CONSIDERATIONS

Boilers may be designed to burn coal, oil or gas, either singly or in various combinations. A boiler designed for a given fuel can be converted to use a different fuel through burner replacement, adjustment in the heat transfer surface and possible changes in the forced draft, induced draft, and recirculation fan speeds. Each boiler must be examined on a case by case basis by the original manufacturer, a process that requires several weeks of engineering per boiler. It is agreed, however, that such conversions are possible and in the eight year period, 1965-1972, 398 boilers were converted from coal to oil. Table II shows the annual rate these boilers were converted. It is estimated that another 40 boilers were converted from coal to gas during this period.

The combustion of oil or natural gas results in a higher heat release rate per unit volume than the combustion of pulverized coal. Because of this, boilers designed for oil or gas are smaller in volume and conversion to coal firing would be impractical. As discussed above the reverse conversion is feasible and has been accomplished many times. The general considerations in converting coal fired boilers to the various clean fuels derived from coal are tabulated in Table III.

TABLE II Electric Utility Boiler Conversion from Coal To Oil 1/ 1965 - 1972

Year	Number of Boilers Converted from Coal to Oil	Total Nameplate Capacity of Generators Associated with Boilers Converted from Coal to Oil, Megawatts	Associated Generator Nameplate Capacity of Boilers Re-Convertible to Coal, Megawatts 2/	Associated Generator Nameplate Capacity of Boilers Not Re-Convertible to Coal, Megawatts
1965	9	651.9	35.5	616.4
1966	16	1,411.0	375.0	1,036.0
1967	36	1,703.9	1,267.7	436.2
1968	51	2,295.3	1,427.4	867.9
1969	51	5,589.4	5,048.6	540.8
1970	63	4,602.5	4,430.0	172.5
1971	87	7,512.6	6,608.4	904.2
1972	85	5,018.5	3,511.3	1,507.2
TOTAL	398	28,785.1	22,703.9	6,081.2
Percent of Total		100.0	78.9	21.1

1/ Table taken from Reference (3).

2/ The electric utilities estimated the total cost of re-conversion at $106.5 million

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TABLE III

Fuel Conversion Considerations

Present Fuel	Replacement Fuel	Considerations Involved
Coal	Solvent Refined Coal	a. Pulverizers may be too hot and cause SRC to become sticky b. Negligible ash problem c. Additional combustion tests required to determine flame characteristics d. Long term storage characteristic unknown
Coal	Liquefied Coal	a. Eliminates solid coal handling b. New burners and atomizers required c. Special heating of fuel may be required d. Storage tanks required e. Similar to coal-oil conversions
Coal	High Btu Gas	a. New burners, gas piping b. Precipitators not required c. Superheater and reheater banks may have to be modified d. Eliminates coal and ash handling e. Similar to coal-natural gas conversions
Coal	Low Btu Gas	a. Ductwork and burners must be added b. Induced draft fan changes c. Superheater and reheater banks may need adjustment d. Furnace volume probably sufficient e. No ash, particulate problem

Such fuel conversions as listed in Table III require varying lengths of time to complete but it is extremely unlikely that the replacement fuel could be supplied more quickly than the time to complete the boiler conversion. The boiler conversion costs vary with the installation but will probably average more than the $4.67 per KW cost reported (3) to reconvert oil-fired boilers back to the original coal firing.

CONVERSION CASE STUDY

A study (4) has been made by a major boiler manufacturer to determine the modifications necessary to a modern 500 MW coal-fired boiler so that low Btu gas can be burned. The boiler was placed into operation in 1969 and operated some thirty months. It was then converted to No. 6 oil firing by adding steam atomized oil guns, gas recirculation through the hopper bottom and removing superheater surface. The coal to oil conversion cost was $16.60/KW, not including charges for loss of capacity during conversion.

Although the boiler is now oil fired, it may be considered a representative of a coal fired boiler since coal was the design fuel. The references study is based upon changing from oil to gas of 127 Btu/scf higher heating value. The changes necessary to burn this gas consist of:

a. New windbox internals

b. New gas ducts

c. New induced draft fans and drives

d. Gas recirculation not required

The oil-to-gas conversion cost estimate is $5.60/KW. Boiler outage time for conversion is 6 to 8 weeks.

It is seen that the conversion from coal to oil to gas or coal to gas can be done quickly and at relatively low cost. This conversion does not include the time and expense of the coal gasifier. This was estimated to cost $138.60/KW based on an atomospheric pressure gasifier design of the boiler manufacturer. This large capital cost of the gasifier increases the energy cost from this 500 MW unit by 5.9 mills/KWHR, based on a 51.5% capacity factor and 20% fixed charge rate.

CONCLUSIONS

In the United States there are several hundred relatively new boilers designed for and firing high sulfur Eastern coal. These could be modified to burn any of the clean fuels from coal that are likely to be developed. However, in addition to this 100,000 MW of convertible capacity, there will be added during the 1970-1990 period some 382,000 MW of new fossil-fuel steam plants. It is believed that half of the new fossil steam plants must rely on coal as the fuel source, or some 190,000 MW of new capacity will need clean fuel from coal or stack gas scrubbing.

Many factors lead to the belief that it will be new plants, rather than existing plants, that will utilize clean fuels derived from coal. Among these are:

a. There will be twice as much new plant capacity

b. Integration of coal processing and fuel consumption must be carried out for maximum economy

c. Coal processing should be continuous, 24 hours per day, to reduce capital charges. New generation plants are more suitable for continuous base-load operation.

d. Coal processing should be on a large scale, equivalent to 1000 MW generation capacity. Most older plants are smaller.

e. Existing plants have many site limitations which would prevent on-site coal processing

f. New plants designed to handle the clean fuel will avoid the cost and capacity loss of retrofitting existing plants.

In summary it is recommended that a few existing steam generation units be used as demonstration plants for the new generation of clean fuels but that full scale use of these fuels be directed toward the new plants as they are designed and constructed.

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THERMODYNAMIC ANALYSES

by

John E. Powers
Andre W. Furtado

The projected needs of the utility industry are such that coal--low-grade sulfurous coal--must be reconsidered to be the primary source of energy for power generation not only at present but especially in the immediate future. Most of the coal burning plants presently in operation will have to be modified in some way so that degradation of the environment is not worsened. Many power generating stations now fueled with natural gas and petroleum fluids will have to be converted--or reconverted--to coal. New plants abuilding, in design or planned, will have to burn coal.

Many alternative solutions have been proposed to permit the utility industry to utilize the existing coal reserves in environmentally acceptable ways. It seems likely that no one solution will solve all of the problems of the utility industry. However, since the magnitude of the problem is so huge and the time scale which reflects needs is continually shrinking, it is essential that as many factors as possible be taken into account when considering alternative paths and processes. One factor that will be of ever increasing importance is the overall efficiency of generating electrical power from coal. In the utility industry this is succinctly expressed in terms of the Heat Rate, i.e., the Btu of heating value of the fuel per KW hr of net electrical power generation. The value for modern power plants is about 8500-9000 Btu/KW hr.

This method of expressing the Heat Rate has a parallel formulation in terms of the first and second laws of thermodynamics (as will be developed later) for power plants as currently operated. However as changes in methods of utility plant operation are brought about--as they most certainly will be--it is essential that the basis for thermodynamic analyses be understood so that this powerful analytical tool can be applied more generally.

Therefore the purposes of this section are to:

(1) Set forth a model that should be generally applicable to all processes whereby coal is used as the fuel in the generation of electric power.

(2) Illustrate the application of both the first and second laws of thermodynamics to both conventional boiler plants and to more complicated plants involving extensive processing of the coal and/or effluents.

(3) Describe some calculations that have been carried out to illustrate the required thermodynamic calculations.

A GENERAL MODEL FOR THE UTILITY INDUSTRY

No model will be realistic in its applications without recognition of the magnitude of the tasks facing the utility industry as outlined in the introduction to this section. Therefore the following restrictions are incorporated in the model:

(1) Coal is the fuel to be used. In addition, the coal is taken to be as provided by mother nature--i.e., "in place." That's the only kind that is available for purchase now and in the forseeable future.

(2) Nothing can be purchased for use by the utility on a continuing basis that is not in abundant supply in nature. The only raw materials permitted for large scale purchase and use are:

(a) Limestone

(b) Air

(c) Water

All other materials used in the process must either have long life (boilers, turbines, condensers, etc.) or be capable of being almost completely regenerated (diethanol amime, methanol, etc.) so that relatively small amounts are actually consummed.

(3) All effluents from the plant must be disposed of in an environmentally acceptable manner.

The system selected for thermodynamic analyses is represented in Figure 1:

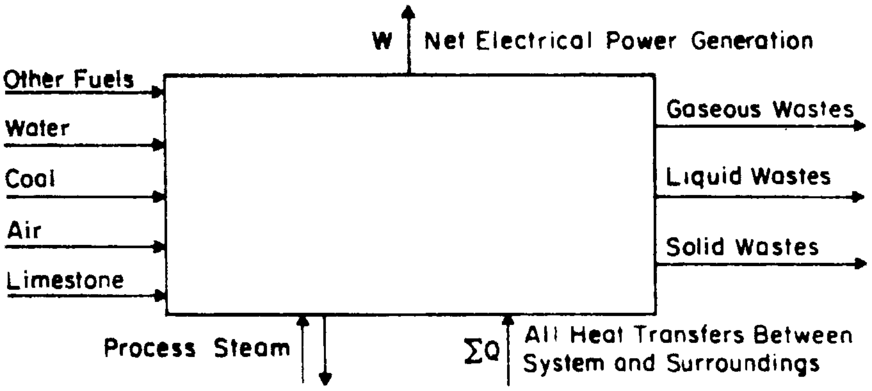

Figure 1. Generalized Power Generating Station

Whereas it is relatively simple to draw a box and designate the box as the system, it is essential that each point at which material or energy crosses the boundary be carefully identified. Consider first the inlet streams. It has already been decided that the system boundaries include the coal in the ground. This choice has several consequences:

(1) The coal (and associated ash material as mined) is at ambient temperature.

(2) The energy requirements necessary to mine, clean, and otherwise prepare the coal (crushing, grinding, screening, briqueting, etc.) must be taken into account in determining the net electrical power generation of the entire complex.

(3) Transporation of the coal must be taken into consideration. If fuels other than coal are required for transportation they must be factored in. If other fuels are required for light-off or to sustain combustion these must also be accounted for.

Unless there is evidence to the contrary it will be assumed that all other raw materials (water, air, and limestone) are also available to the plant as found in nature. Therefore energy requirements associated with winning these materials from nature and transporting them to the site will have to be taken into account. Unless otherwise justified it will be assumed that these raw materials are available at ambient temperature. Exceptions might include geothermal or other such natural sources of hot water. Of course pumping and/or required treatment of such waters would be charged against the process.

Consider now the various wastes emanating from the plant. It is self evident that every attempt should be made to produce such "wastes" in forms usable to society. Alas, the amounts are of such magnitudes that it is difficult for society to make use of them. However this should be the goal not only for the direct benefit of society but also for the economic benefit of the utility. More on this aspect later.

The symbol W is used to represent the net electrical power generation of the station. (There may be very exceptional cases where mechanical energy is transferred out of the system and this would be included as W.) ΣQ represents all transfer of heat energy between system and surroundings, and here is where a liberal and very useful view of the "surroundings" is taken in establishing the boundaries of the system. Consider, for example, the combustion products which issue from practically all such plants. In general they are at temperatures in excess of 300°F. However as they mix with the air the temperature is reduced by mixing or heat transfer or what have you. The important thing is that there is no practical way of gaining useful work by reducing the temperature much below 300°F--unless the SO_2 is removed. Therefore the system boundaries are taken such that the combustion products have attained ambient temperature.

If similar considerations are applied to other gaseous wastes and to the liquid and solid wastes, it will be seen that it is logical and consistent to consider that sufficient heat is transferred to cool all of these products to ambient temperature and that effectively, all of this heat is transferred at ambient temperature, i.e., a system is selected that is large enough to justify these assumptions. The same reasoning applies to heat losses from the boiler and turbine; the system is chosen to include the air surrounding these devices so that heat is transferred at ambient temperature. Exceptions will be made if the proponents of a process can establish that the temperature in excess of ambient is important to some other process. This will be very unusual.

Of course most of the heat transferred in any power generating station is transferred to water in condensers. If this is done without effective utilization of the heat for any useful purpose, it can be considered that the heat is effectively transferred at ambient temperature.

Two streams labeled "Process Steam" are placed alongside ΣQ in Figure 1. In some large industries (refineries generally) plus large universities, power plants serve the primary function of providing steam to heat buildings and find it economically attractive to first generate electrical power for their own use or for sale. It would seem apparent that such use of "waste heat" provides great potential on a national basis for conservation of fuel for home heating. This subject will also be addressed in some detail later.

In summary, the model is formulated so that in most cases all materials and energy (other than electrical energy and process steam) are accepted from nature and returned to nature at ambient temperature. The net electric power is the major objective and further consideration must be given as to how the process steam is taken into account.

APPLICATION OF THE MATERIAL BALANCE CONSTRAINTS AND THE FIRST LAW OF THERMODYNAMICS

Application of a steady-state model to the utility industry is certainly of questionable validity in view of the very significant changes in load that are indeed experienced over relatively short periods of time. However, in order to obtain some reasonable answers in a short period of time, it is almost mandatory to accept a period of observation (accounting period) long enough so that unsteady state effects are assumed to be negligible. For example if an intermediate load plant is to operate for 8 hours per day it seems reasonable to work with the total power generated during that period, the total coal used, etc. Under these conditions the energy required to heat up the boilers, etc., is taken into account even though these factors are indeed insignificant. Such an assumption may not be valid for peak-load plants but these are not of principal concern at this time.

In addition to assuming that pseudo-steady-state conditions prevail, it is also reasonable to assume that potential and kinetic energy effects will be negligible for the model proposed. Therefore the material balance and first law of thermodynamics for the model can be written as follows:

$$\Sigma M_{RM} + M_{PSi} = \Sigma M_{W} + M_{PSo} \qquad (1)$$

where M_{RM} refers to raw materials entering the system,

M_W refers to waste streams leaving the system, and

M_{PSi} and M_{PSo} refer to the process steam entering and leaving the system, respectively.

Similarly, the first law of thermodynamics can be written (1) as:

$$\Sigma H_{W} - \Sigma H_{RM} + [H_{PSo} - H_{PSi}] = \Sigma Q - W \qquad (2)$$

where the symbol H is used to represent the enthalpy of a total stream and the subscripts are those identified in connection with Equation (1). ΣQ and W were identified in the previous section.

Under the conditions set forth in the model it is a relatively simple procedure to determine the specific enthalpies of each stream. For example, given the pressure, temperature and/or quality of the process steam the specific enthalpy, $\underline{H}$, can be obtained from steam tables. Thus Equation (2) can be rewritten as:

$$\Sigma M_{W}\underline{H}_{W} - \Sigma M_{RM}\underline{H}_{RM} + [M_{PSo}\underline{H}_{PSo} - M_{PSi}\underline{H}_{PSi}] = \Sigma Q - W \qquad (3)$$

In making calculations of this type it is found to be convenient to take the enthalpy of any compound in a stream to be equal to its heat of formation at that temperature and pressure relative to the elements at some base conditions. In most cases the enthalpy of the total stream can then be found by assuming ideal mixing of the component. Only in extreme cases (such as large amounts of liquid wastes) will it be necessary to take into account the non-ideality of mixtures.

So how are these equations to be applied?

(1) Unless a complete material balance as represented by Equation (1) is provided, one can't tell whether even the most basic and fundamental factors have been taken into account. Indeed, it is essential to extend the simple balance to individual molecular and atomic species to insure that stoichiometric constraints are met, i.e., that the law of conservation of mass is not violated.

(2) Once the amount, composition, temperature, and pressure of each stream is identified, it is a challenging but nevertheless fairly straightforward matter to determine a value for the specific enthalpy of that stream. The net amount of electrical energy must be either measured (as in the case of analysis of an operating plant) or estimated by some valid procedure (i.e., the proposed procedures for obtaining electrical energy cannot be in violation of the second law of thermodynamics).

> Under these conditions one can calculate ΣQ using Equations (2) or (3). Of course one would expect the number obtained to be approximately equal to the amount of heat transferred in the condenser when the temperature of the exiting flue gas and "heat losses" are properly identified.

The question of how this relates directly to the current and proposed methods of analysis of power plants is delayed until after discussion of the second law in the next section.

APPLICATION OF THE SECOND LAW OF THERMODYNAMICS

Ask five mechanical engineers, five chemical engineers, five chemists, and five physicists to write down the most general statement of the second law of thermodynamics that they can think of and you can rest assured that you will get at least 4 very different statements and more probably closer to 20 than 4. Therefore we will accept the general statement contained in a recent undergraduate text(1). In slightly abbreviated form it is presented in terms of a balance made on entropy analagous to those made on mass [Equation (1)] and on energy [Equations (2) and (3)] i.e., under steady-state conditions

$$\Sigma M_W \underline{S}_W - \Sigma M_{RM} \underline{S}_{RM} + [M_{PSo} \underline{S}_{PSo} - M_{PSi} \underline{S}_{PSi}] = \Sigma \frac{Q}{T_b} + S_p \qquad (4)$$

where $\underline{S}$ refers to specific entropy

T_b is the temperature at which heat energy crosses the boundaries of the system, and

S_p is the entropy production.

In this context a very complete and general statement of the second law is:

(1) For any actual process the value of S_p is always greater than zero, i.e.,

$$S_p > 0 \text{ [All actual processes]} \tag{5}$$

(2) Only in the case of <u>conceptual</u> perfection does S_p approach zero, i.e., a thermodynamically ideal process, i.e., a reversible process, is defined by

$$S_p = 0 \text{ [Definition of a reversible process]} \tag{6}$$

So how can this be applied to aid in evaluating processes which produce electrical power?

If one can evaluate the specific entropy, $\underline{S}$, for each component of a stream and further estimate the resulting entropy of the entire stream taking into account the effects of either ideal or non-ideal mixing, numerical values can be assigned to most of the terms in Equation (4). Without going into detail (2), it is noted that the third law of thermodynamics provides a convenient basis for such calculations in permitting one to assign values of absolute entropies to compounds at any temperature and pressure. This is similar in many respects to identifying the enthalpy of compounds in terms of heats of formation in application of the first law [Equation (3)].

With this knowledge based on the most fundamental of thermodynamic data, most of the terms in Equation (4) can be assigned numerical values. Further, if, as has been specified in the general model, all heat transfer occurs at ambient (dump) temperatures, T_D such that

$$\Sigma\frac{Q}{T_b} = \frac{\Sigma Q}{T_D} \qquad (7)$$

then the entropy produced by any actual or proposed process can be calculated. In comparing actual processes, it can be assumed that the one with the lowest rate of entropy production (on comparable bases) has advantages over the one with the higher rate of entropy production. This point will be clarified in a later section.

Again we return to the question "How does this relate to the thermal efficiency of power generating stations as currently calculated?" An attempt will be made to explain this in the next section.

ENERGY EFFICIENCY OF CONVENTIONAL POWER PLANTS USING COAL

Most power plants do not produce significant amounts of process steam and therefore Equations (1), (3), and (4) reduce to

$$\Sigma M_W - \Sigma M_{RM} = 0 \tag{8}$$

$$M_W\underline{H}_W - M_{RM}\underline{H}_{RM} = \Sigma Q - W \tag{9}$$

$$M_W\underline{S}_W - M_{RM}\underline{S}_{RM} = \frac{\Sigma Q}{T_D} + S_p \tag{10}$$

In conventional power plants limestone would not be used nor would it appear as a solid waste.

As pointed out previously, Equation (8) (and similar expressions as applied to individual atomic species) can be used to insure that matter is conserved, Equation (9) can be applied to calculate the net amount of heat transferred (wasted) and Equation (10) can be used to calculate S_p, the entropy production, i.e., a direct measure of the degradation of energy. However, entropy production is sort of a foreign concept and we might attempt to make it more understandable. To do this it has been found convenient to compare the actual (or proposed actual) process with a completely idealized, conceptual process . Consider two alternative processes as illustrated in Figure 2.

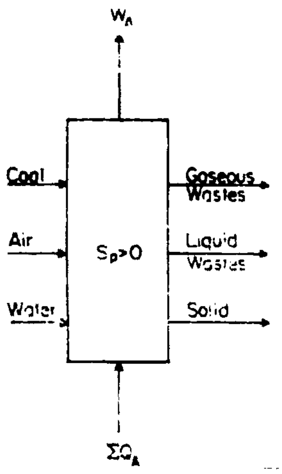

Figure 2a. Actual Process to Generate Electrical Power.

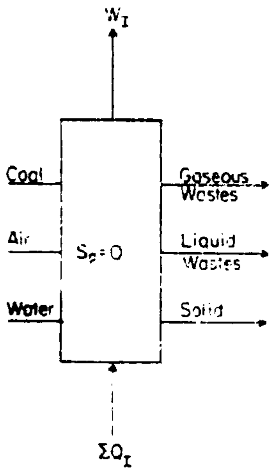

Figure 2b. Idealized, Process to Generate Electrical Power

Note that in the actual process, $S_p > 0$, as required by the second law of thermodynamics [Equation (5)] while in the idealized conceptual process (Figure 2b) $S_p = 0$ as permitted by Equation (6). Note also that the subscript A is used to identify amounts of heat and work transfer in the <u>A</u>ctual process and I serves a similar purpose for the <u>I</u>dealized process.

Now there are an infinite number of idealized processes that could serve to convert coal, air, and water to electrical energy with concurrent production of wastes and thermal pollution, ΣQ. For purposes of direct comparison it seems reasonable to stipulate that the ideal process uses amounts of raw materials identical to the actual process, produces amounts of wastes identical to those of the actual process, and that the raw materials and wastes for both processes have identical compositions, temperatures, and pressures. As a direct result, the left-hand side of Equations (9) and (10) have identical numerical values for both the actual and the idealized processes; only those terms on the right are different. Thus it follows that

$$\Sigma Q_A - W_A = \Sigma Q_I - W_I \tag{11}$$

and

$$\frac{\Sigma Q_A}{T_D} + S_p = \frac{\Sigma Q_I}{T_D} \tag{12}$$

Naturally $S_p = 0$ for the idealized process as stated previously.

In order to emphasize the difference between the actual and idealized process it is convenient to define differences in heat transfer, ΔQ, and differences in work generation, ΔW as follows:

$$\Delta Q \equiv \Sigma Q_I - \Sigma Q_A \tag{13}$$

$$\Delta W \equiv W_I - W_A \tag{14}$$

Combination of Equations (11), (13), and (14) with cancellation of terms yields

$$\Delta W = \Delta Q \tag{15}$$

Similarly combination of Equations (12) and (13) yields:

$$S_p = \frac{\Delta Q}{T_D} \tag{16}$$

so that

$$\Delta W \equiv W_I - W_A \tag{17}$$

$$\Delta W = \Delta Q = T_D\ S_P \tag{18}$$

ΔW is the difference between the amount of work (electrical energy) that might conceivably have been obtained from the fuel,

W_I, and the amount that was actually obtained, W_A and is therefore sometimes referred to as the lost work, lw. Thus, from Equation (18) we see that the entropy production can be converted to the amount of lost work by multiplying by the ambient (dump) temperature, T_D.

One might reasonably be interested in the ratio of the actual work, W_A, to that which might have been obtained from the same fuel, W_I. Equations (9), (10), and (17) can be combined to yield an expression in terms of "availability" of energy .

$$\Sigma M_w(\underline{H}_w - T_D\underline{S}_w) - \Sigma M_{RM})\underline{H}_{RM} - T_D S_{RM}) = - W_I \qquad (19)$$

where the combination of thermodynamics properties and dump temperature, T_D, $\underline{H} - T_D\underline{S}$, is commonly referred to as availability.

Therefore the ratio , W_A/W_I, is given by

$$\frac{W_A}{W_I} = \frac{W_A}{\Sigma M_W(\underline{H} - T_D S_W) - \Sigma M_{RM}(\underline{H}_{RM} - T_D S_{RM})} \qquad (20)$$

How does this compare to the more commonly utilized thermal efficiency? This expression is defined by

$$\text{Thermal efficiency} = \frac{W_A}{\text{Heating value of fuels.}} \qquad (21)$$

If the heating value if taken as the <u>net</u> heating value, i.e., corresponding to water vapor rather than liquid water as product, at 25°C (77°F) it can be shown that this is equivalent to

$$\text{Thermal efficiency} = \frac{W_A}{\Sigma M_W \underline{H}_W - \Sigma M_{RM} \underline{H}_{RM}} \qquad (22)$$

where the enthalpies are identified in terms of heats of formation.

When comparing Equation (22) with Equation (20), it will be seen that the thermal efficiencies is sort of related to the thermodynamic efficiency, W_A/W_I, but only sort of.

WHAT ABOUT COMPARISON AND/OR CHARACTERIZATION OF MORE COMPLICATED PROCESSES?

In the preceding section, only the most simplified case in power generation was considered and only a *similarity* was found between thermal efficiency and thermodynamic efficiency. What happens if process steam is generated in the process? How should that be taken into account? What if limestone is fed to the plant and large amounts of ash containing gypsum and lime are carted away for disposal? The complete answers to these problems are much more complicated on a practical basis than on a thermodynamic one as will be considered in some detail in a later section. No attempt will be made to answer the question with regard to calculation of thermal efficiency because this would probably require development of an entirely new expertise. There are no problems associated with the calculation of thermodynamic efficiency. Carrying through similar manipulations but retaining the terms associated with process steam yields

$$W \equiv lw = T_D S_P \tag{17}$$

$$= T_D \{\Sigma M_W \underline{S}_W - \Sigma M_{RM} \underline{S}_{RM} + [M_{PSo} \underline{S}_{PSo} - M_{PSi} \underline{S}_{PSi}] - \Sigma Q_A\} \tag{23}$$

and

$$\frac{W_A}{W_I} = \Sigma M_W (\underline{H}_W - T_D \underline{S}_W) - \Sigma M_{RM} (\underline{H}_{RM} - T_D \underline{S}_{RM}) + [M_{PSo} (\underline{H}_{PSo} - T_D \underline{S}_{PSo})$$

$$- M_{PSi} (\underline{H}_{PSi} - T_D \underline{S}_{PSi})] \tag{24}$$

These equations can be applied to calculate the lost work and/or the thermodynamic efficiency of any process in which electrical power is generated.

SHOULD A FOURTH LAW BE FORMULATED?

Consider two alternatives procedures by which electrical power is generated and homes and/or office buildings in the surrounding area are heated. If the utility alone is considered as the system it can be shown that application of the first and second laws of thermodynamics will yield no significant distinction as to whether the heat transferred so as to condense the steam from the turbine is rejected as thermal pollution or used to heat the homes and/or office buildings in the surrounding area. It seems obvious that much fuel would be saved and thermal pollution would be reduced if the condensing steam were used for some heating. This will definitely show up in the thermodynamic analysis if the homes and/or office building are included in the system of analysis and the existing method of analysis should be modified to include such a possibility. If the utilities were forced to provide such heating on a basis that is more wide spread than currently practiced, the savings in the nations prime energy, natural gas and fuel oil, would be very significant and the utility industry would double their income--at least in the winter--with very little capital expenditure.

SAMPLE CALCULATION FOR FLUIDIZED BED COMBUSTION PROCESS

Figure 3 illustrates a scaled-down version of a power plant employing a fluidized bed combustion chamber and using $CaCO_3$ to remove the majority (90%) of the sulfur in the solid waste. The original design specifications were provided by the Foster Wheeler Corporation (3). The proximate, ultimate, and ash analyses for the coal used in the design are indicated below:

a) Proximate Analysis (wt%)

Moisture	3.3
Volatile Matter	39.5
Fixed Carbon	48.7
Ash	8.5

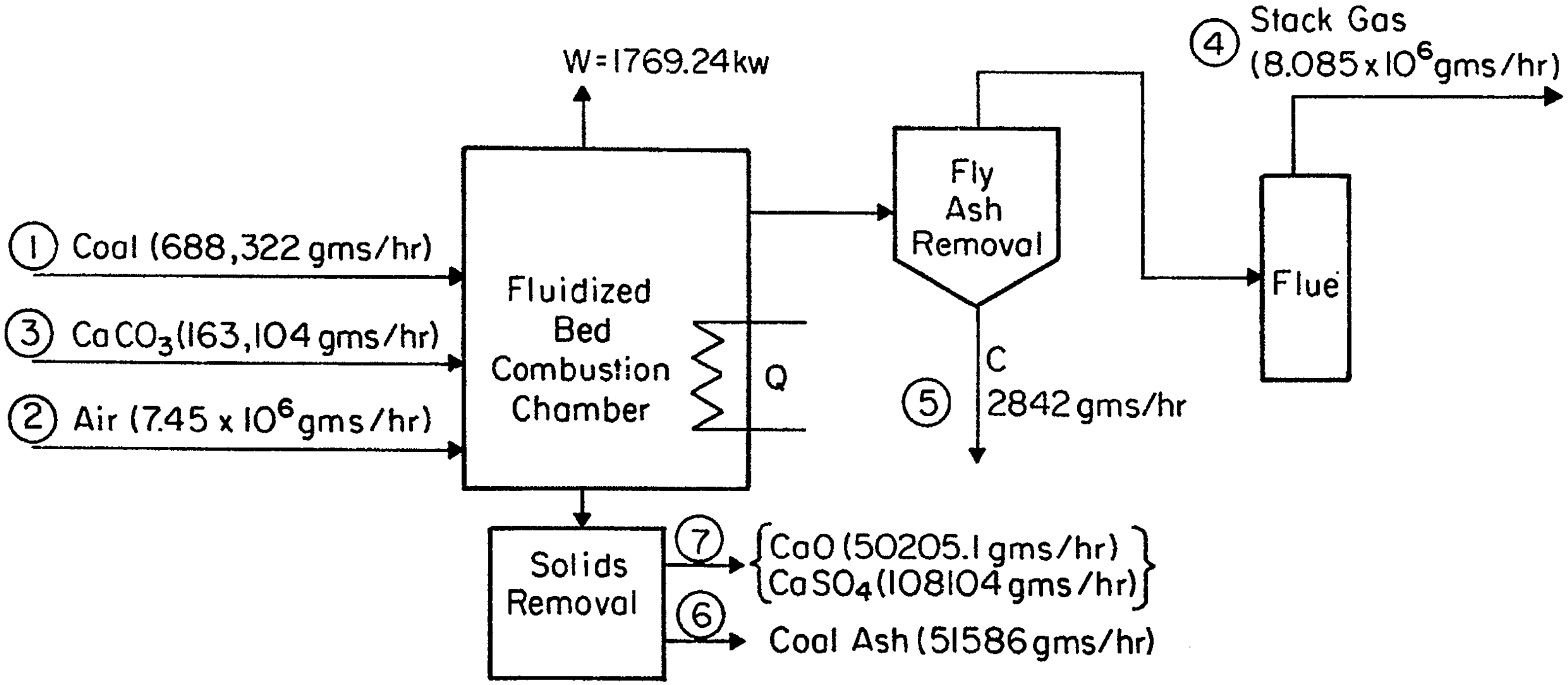

Figure 3. Schematic of Process Used to Illustrate the Calculation of the Thermodynamic Efficiency

b) Ultimate Analysis (wt%)

(Moisture and Ash Free)

C	75.91
H	6.28
O	11.72
N	1.495
S	4.58

c) Ash Analysis (wt%)

SiO_2	45.3
Al_2O_3	26.7
Fe_2O_3	28.0

Note: Although the ash actually contained ten oxides, the above three oxides constituted over 94% of the ash. As a first approximation, the ash analysis was normalized and expressed in terms of the three oxides above.

d) Heating value of coal = 13,000 Btu/lb.

The flue gas analysis is as follows:

CO_2	.1462 (mole %)
H_2O	.07419
SO_2	.00032
N_2	.75138
O_2	.02784

STOICHIOMETRIC DEFINITION OF THE ORGANIC MATERIAL IN COAL

The chemical composition of coal is complex and undefinable and therefore deserves special attention. In particular, the ultimate analysis (moisture and ash free basis) is assumed to define a hypothetical pure component for the carbonaceous material in coal, and together with the proximate analysis and ash analysis permits the mole fraction of all components to be specified as required.

The basis chosen for the stochiometric definition of the organic material in coal is 1 gm atom of C.

Gm Atoms of C per 100 gms of coal analyzed = 75.91/12.01 = 6.32.

Gm Atoms of H per 100 gms of coal analyzed = 6.28/1.00 = 6.28. Therefore, Gm Atoms of H/Gm Atom of C = 6.28/6.32 = 0.986.

By performing similar calculations given the O, N, and S content in the ultimate analysis we obtain the stoichiometric constitution of the organic combustible material in coal as

$$C_1H_{0.986}O_{0.116}N_{0.017}S_{0.023}$$

The molecular wt. of this compound is calculated as 15.82.

DEFINITION OF THE COMPOSITION AND RELEVANT THERMODYNAMIC PROPERTIES OF COAL

i) Calculation of the composition of the coal

The coal is now assumed to contain H_2O, $C_1H_{0.986}O_{0.116}N_{0.017}S_{0.02}$, SiO_2, Al_2O_3, and Fe_2O_3. Given the ultimate and the ash analysis and the molecular weights of all constituent components, the coal composition is calculated as:

H_2O	0.0313 (mole fraction)
$C_1H_{.986}O_{.116}N_{.017}S_{.023}$	0.9519
SiO_2	0.0109
Al_2O_3	0.0038
Fe_2O_3	0.0021

ii) Calculation of the Heating Value of the Coal

If the heating value of the coal is not supplied in the data, then it is calculated using Dulong's Law

$$\text{Heating Value} = [6.543\ H + 424.62]\ [\frac{C}{3} + \frac{H}{2} - \frac{O}{8} - \frac{S}{8}]$$

where the symbols stand for the wt. fraction of the appropriate element on a dry ash free basis.

$$= [6.543\ \frac{(6.28)}{(1-0.118)} + 424.62]\ [\frac{75.91}{3} + \frac{6.28}{2} - \frac{11.72}{8} - \frac{4.58}{8}]$$

$$[\frac{1}{1-0.118}]$$

where 0.118 is the combined weight fraction of water and ash as determined from the ultimate analysis

$= 14088$ Btu/lb

In this particular case we note that the calculated heating value overestimates the measured value of 13000 Btu/lb by 8.3 percent.

iii) Calculation of the Heat of Formation of Coal

The energy balance requires us to specify the enthalpy of each stream indicated in Figure 3. In this example the enthalpies are specified from heat of formation data for each component in its natural state at 77°F. Such direct information is unavailable for coal, but the heat of formation of the organic material in coal can be indirectly calculated from the heating value using the formula (4)

$$-\Delta H_f = -\Delta H_c - N_C(\Delta H_{f_{CO_2}}) - N_H(\Delta H_{f_{H_2O}})/2 - N_S(\Delta H_{f_{SO_2}})$$

where N_C, N_H, and N_S represent the number of C, H, and S atoms in the formula for the hypothetical pure carbonaceous compound that has been selected to represent the coal. In essence the separate heats of combustion of the elements constituting the organic compounds minus the heat of combustion of the organic compound is used to calculate its heat of formation.

$$\text{Ht. value} = \frac{13000\ \cancel{\text{Btu}}}{\cancel{\text{lb}}}\ \frac{\cancel{\text{lb}}}{454\ \cancel{\text{gms}}}\ \frac{0.252\text{Kcal}}{\cancel{\text{Btu}}}\ \frac{15.82\ \cancel{\text{gms}}}{\text{gm mole}}$$

$$= 109.87\ \frac{\text{Kcal}}{\text{gm mole}}$$

Therefore,

$$(-\Delta H_f)_{C_1H_wO_xN_yS_z} = -109.87-(1)(-94.05)-\frac{(0.986)}{2}(-68.3)-(.023)(-71.00)$$

$$= 19.45\ \text{Kcal/gm mole}$$

The heats of formation of CO_2, H_2O, and SO_2 at 298°K used in the calculation are summarized in Table I which includes values for the other species involved in the analysis.

TABLE 1

Summary of Heats of Formation, Absolute Entropies at 298°K, and Molecular Weights for All Species in Sample Problem (5,6)

Species		(ΔH_f) 298°K (Kcal/gm mole)	$S_{298°K}$ (cal/gm mole/°K)	M.W.
N_2	(g)	0.	46.76	28.02
CO_2	(g)	-94.05	51.07	44.01
O_2	(g)	0.	69.00	32.00
H_2O	(g)	-68.3	45.11	18.02
SO_2	(g)	-59.34	75.43	64.06
C	(s)	0.00	1.37	12.01
$CaCO_3$	(s)	-288.40	21.20	100.09
$CaSO_4$	(s)	-342.4	25.5	136.14
CaO	(s)	-151.8	9.5	56.08
SiO_2	(s)	-217.6	9.9	60.09
Al_2O_3	(s)	-399.6	12.2	101.96
Fe_2O_3	(s)	-196.5	21.5	196.2

iv) Calculation of the Absolute Entropy of the Organic Material in Coal at 298°K

The specification of the entropy of coal is a problem. The examination of the literature (7) indicates that for pure branched chain polycyclic compounds the entropy per C atom varies from 3.8 to 2.6 cal/mole°K/C atom as the number of C atoms varies from 11 to 25. As the carbonaceous material in coal is assumed to consist of a high mol. wt. compound of similar nature, an assumed value of 100 for the number of C atoms produced an $S_{298°K}$ value of 1.37 cal/mole/°K/C atom on extrapolation.

Therefore $(S_{298°K})_{C_1H_wO_xN_yS_z}$ = 1.37 cal/gm mole/°K

v) Calculation of the Properties of the Coal Stream

Having calculated the coal composition in mole fractions in Part (i), the average molecular wt. of the coal is calculated as $MW = (.0313)(18.02)+(0.9519)(15.82)+(0.0109)(60.09)$

$$+(0.0038)\ (101.96)+(0.0021)(196.2) = 17.08$$

The heat of formation of the mixture of water, organic compound and ash is calculated assuming ideal mixing

$$-(\Delta H)_{f_{298°K}} = (.0313)(-68.3)+(0.9519)(-19.46)+(0.0109)(-217.6)+$$
$$(0.0038)(-399.6)+(0.0021)(-196.5) = 24.97 \text{ Kcal/gm mole}$$

The absolute entropy at 298°K is also calculated using ideal mixing

$$S_{298°K} = (.0313)(45.11)+(0.9519)(1.37)+(0.0109)(9.9)+(0.0038)$$
$$(12.2)+(0.0021)(21.5) = 2.91 \text{ cal/gm mole/°K}$$

The stream properties as calculated by the computer program are summarized in Table II.

MATERIAL BALANCE CHECKS

i) Check on Overall Material Balance (1 hour basis)

Material in = $(\dot{F}_1)\ (MW)_1 + (\dot{F}_2)\ (MW)_2 + (\dot{F}_3)\ (MW)_3$

where $\dot{F}$ stands for the flowrate in gm moles/hr and the subscript stands for the stream identification number. From the results of Table III we obtain:

Material in = $(0.4031\text{x}10^5)(17.08)+(0.2582\text{x}10^6)(28.85)$ $+ (0.1629\text{x}10^4)(100.09) = 0.8301\text{x}10^7$ gms/hr

Material out = $(\dot{F}_4)\ (MW)_4 + (\dot{F}_5)(MW)_5 + (\dot{F}_6)(MW)_6)_6+(\dot{F}_7)(MW)_7$ $= (0.2719\text{x}10^6)(29.73)+(0.2366\text{x}10^3)(1201)+(.5976\text{x}10^3)$ $(86.32)+(0.1704\text{x}10^4)(92.91) = 0.8298\text{x}10^7$ gms/hr.

% Error in overall material balance = $\dfrac{(0.8298-0.8301)}{\dfrac{(0.8298+0.8301)}{2}} \text{ x } 100 = .036\%$

ii) Stoichiometric Balance Check (1 hour basis)

For the case of a C balance we obtain

Gm atoms of C in = $(\dot{F}_c)_1 + (\dot{F}_c)_3$

where $(\dot{F}_c)_i = (\dot{F})_i \sum_{j=1} x_j (n_c)_j$

x_j is the mole fraction of substance j in stream i

$(n_c)_j$ is the number of atoms of C per mole of substance j

Gm atoms of C in = $(.4031\text{x}10^5)(0.952)(1.0)+(0.1629\text{x}10^4)$ $(1.0)(1.0) = 0.400\text{x}10^5$ gm atoms/hr

Gm atoms of C out = $(\dot{F}_c)_4 + (\dot{F}_c)_5$

$= (0.2719\text{x}10^6)(0.1462)(1.0)+(0.2366\text{x}10^3)(1.0)(1.0)$

$= 0.400\text{x}10^5$ gm atoms/hr

Similar stoichiometric balance checks were made for H, O, N, S, and Ca. The results are summarized in Table II below.

TABLE II

Material Balance Summary

Elements	Gm Atoms/Hr In	Gm Atoms/Hr Out
C	400,000	400,000
H	403,600	403,500
O	1,206,000	1,205,000
N	4,086,000	4.086,000
S	868.1	870.8
Ca	1629	1704

ENERGY BALANCE - CALCULATION OF Q

The application of the energy balance to the model of Figure 3 yields the heat released -Q in Kcal/hr as

$$-Q = (\underline{H}_1\dot{F}_1 + \underline{H}_2\dot{F}_2 + \underline{H}_3\dot{F}_3) - (\underline{H}_4\dot{F}_4 + \underline{H}_5\dot{F}_5 + \underline{H}_6\dot{F}_6) - W$$

where $\underline{H}_i$ is the specific enthalpy of stream i in Kcal/gm mole and W is the work done in Kcal/hr. Using values from Table II we obtain

$$\begin{aligned} -Q = {} & [(-24.97)(0.4031\text{x}10^5) + (0.00)(0.2582\text{x}10^6) + \\ & (-288.4)(0.1629\text{x}10^4)] - [(-18.06)(0.2719\text{x}10^6) + \\ & (0.00)(.2366\text{x}10^3) + (0256.1)(.5976\text{x}10^3)] \\ & - \ 1769.24 \text{ k. watts } \left(\frac{1.}{1.1626\text{x}10^3} \ \frac{\text{Kcal/hrs}}{\text{Kwatts}}\right) \\ = {} & + .24742\text{x}10^7 \text{ Kcal/hr} \end{aligned}$$

ENTROPY BALANCE

The application of the entropy balance to the model of Figure 3 yields the entropy production $\dot{S}p$ in cal/gm mole/°K/hr. as

$$-\dot{S}p = (\underline{S}_1\dot{F}_1 + \underline{S}_2\dot{F}_2 + \underline{S}_3\dot{F}_3) - (\underline{S}_4\dot{F}_4 + \underline{S}_5\dot{F}_5 + \underline{S}_6\dot{F}_6) - Q/T_D$$

where $\underline{S}_i$ is the absolute specific entropy of stream i in cal/gm mole/°K and T_D is the dump temperature assumed to be 298°K in this particular case.

$$= [(2.91)(0.4031\text{x}10^5)+(46.44)(0.2582\text{x}10^6)+(21.20)(0.1629\text{x}10^4)]$$

$$- [(46.58)(0.2719\text{x}10^6)+(1.37)(0.2366\text{x}10^3)+(11.85)(0.5976\text{x}10^3)$$

$$+ (16.68)(0.1704\text{x}10^4)] + 0.24742\text{x}10^7/298.15$$

$$= 0.8854\text{x}10^4 \text{ Kcal/hr/°K}$$

$$\text{Lost work} = lw = T_D\ \dot{S}p = W_I - W_A$$

$$= (298.15)(0.8854\text{x}10^4)$$

$$= 0.2640\text{x}10^7 \text{ Kcal/hr}$$

CALCULATION OF EFFICIENCIES

$$\text{Thermodynamic Efficiency} = \frac{W_A}{(W_A + lw)} = \frac{0.1521\text{x}10^7\text{Kcal/hr}}{(0.1521\text{x}10^7 + 0.2640\text{x}10^7)}$$

$$= 0.3655$$

$$\text{Thermal Efficiency} = \frac{W_A}{(\text{Heating Value})(\text{Coal Flowrate})}$$

$$= \frac{0.1521\text{x}10^7 \text{ Kcal/hr}}{(109.97\ \frac{\text{Kcal}}{\text{gm mole}})(0.4031\text{x}10^5\ \frac{\text{gm moles}}{\text{hr}})}$$

$$= 0.3436$$

The thermodynamic efficiency is seen to have a slightly higher value that that of the more commonly used thermal efficiency for the combustion reaction considered. This situation occurs because the entropy change ΔS for the combustion reaction is negative and proper credit is given in the calculation of the thermodynamic efficiency in contrast to the thermal efficiency which is restricted to the examination of the heat effects involved in the reaction.

TABLE III

SUMMARY OF STREAM PROPERTIES

Stream* No.	No. Comp.	Mol. Wt.	T_K	P ATM	Flow Moles/Hr	Enthalpy Kcal/Mol	Entropy Cal/K/ Mole	Phase	Comp ID	Symbol	Mole Fraction
1	5	17.08	298.15	1.0	40312	-24.97	2.91	Solid			
									29	H_2O	0.0313
									38	Coal	0.9519
									48	SiO_2	0.0109
									49	Al_2O_3	0.0038
									50	Fe_2O_3	0.0021
2	2	28.85	298.15	1.0	258200	0.00	46.66	Gas			
									6	N_2	0.7900
									8	O_2	
3	1	100.09	298.15	1.0	1629	-288.40	21.20	Solid			
									41	$CaCO_3$	1.0000
4	5	29.73	298.15	1.0	271910	-18.06	46.58	Gas			
									7	CO_2	0.1462
									29	H_2O	0.0742
									34	SO_2	0.0003
									6	N_2	0.7514
									8	O_2	0.0278
5	1	12.01	298.15	1.0	236.6	0.00	1.37	Solid			
									43	C	1.0000
6	3	86.32	298.15	1.0	597.6	-256.14	11.85	Solid			
									48	SiO_2	0.6508
									49	Al_2O_3	0.2261
									50	Fe_2O_3	0.1232
7	2	92.91	298.15	1.0	1704	-239.48	16.86	Solid			
									42	$CaSO_4$	0.4600
									47	CaO	0.5400

*See Figure 3 for identification

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BLACK MESA COAL SLURRY PIPELINES

by

Brymer Williams

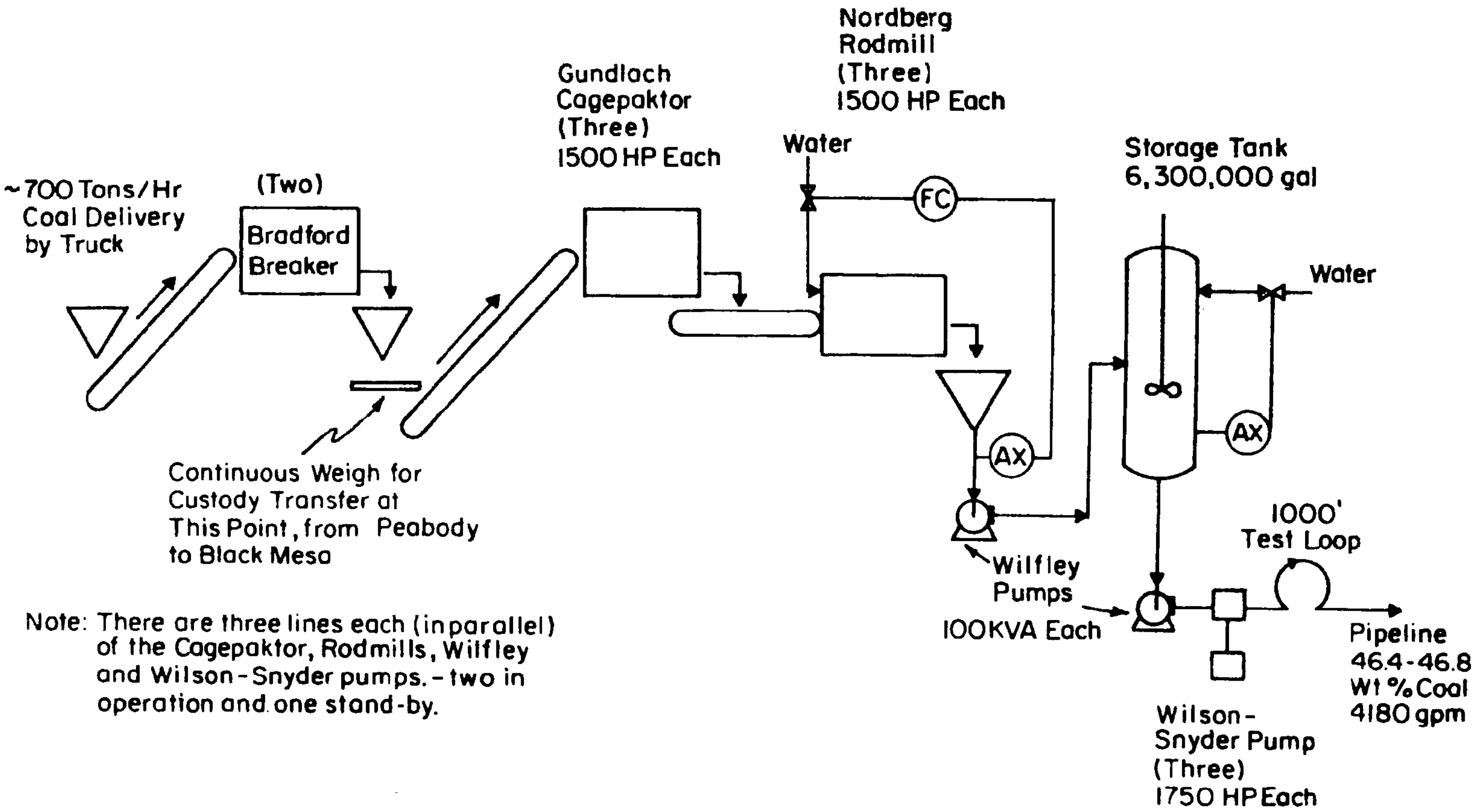
Donald L. Katz

The Black Mesa coal slurry pipeline is mentioned because of the experience with continuous pumping of coal slurries. It extends 273 miles from near Kayenta, Arizona in the Navaho reservation to the Mohave Power Plant on the Colorado River just below Davis Dam. The plant is on the Arizona side of the river and is owned primarily by the Southern California Edison of Los Angeles but has three other partners in the operation of the two 790 megawatt thermal generating units. Coal, strip-mined by Peabody Coal Company is delivered by truck to the Black Mesa coal preparation plant. There it is crushed and slurried for entrance to the pipeline. There are three pumping stations along the 273 mile route across Arizona in addition to the entrance station. Pressures as high as one thousand pounds per square inch are used and the pipe is graded according to the pressure level which varies with the terrain. The entire system was built for about $35 million. It was engineered and built by Bechtel Inc. using data obtained from Consolidation Coal Co. plus information from additional tests with the Consolidation pipeline in Northeastern Ohio. There have been no serious interruptions with operation of the line. Twice the line stopped and it was necessary to locate the ensuing short plug and remove it, but this was done within 48 hours in each instance.

Approximately 660 tons per hour of coal are transported through an 18 inch diameter pipeline as an aqueous slurry of 46.4 weight per cent solids. Figure 1 shows the coal grinding and slurry preparation circuit. A three step crushing and grinding process prepares the coal to pass a 14 mesh screen, with a considerable fraction of -320 mesh. The design and operation know-how are proprietary, but the following items are noted as being of importance or of interest:

1. The slurry concentration is set within narrow limits, to retain flow characteristics while minimizing water to be handled at the power plant end. Limits are 44-48 weight percent solids, but are actually held at 46.5+0.1%
2. The size range of -14-+325 mesh is a compromize between pipeline and power plant requirements.
3. Slurry pumping is by Wilfley centrifugal pumps for low heads (up to 100 psi) and Wilson-Snyder positive displacement pumps for pipeline injection, up to 1500 psi. There are two parallel pumps in service at any one time, each pumping 2100 gallons of slurry per minute.

   The service record of the pumps is reportedly excellent, but with a schedule of replacement parts. To ensure 100 percent on-stream time a third, standby, pump is installed for each service.



Note: There are three lines each (in parallel) of the Cagepaktor, Rodmills, Wilfley and Wilson-Snyder pumps. - two in operation and one stand-by.

Figure 1. Schematic Flow Sheet for Coal Preparation Plant of Black Mesa Pipeline Company

4. The operators have developed effective techniques for restarting the pipeline after unavoidable shutdowns caused by such problems as power failures.
5. As an extra precaution, the slurry circles the plant in a 1000 foot loop where its behavior is monitored before leaving the plant limits.

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AUGUST 24, 1973

THE UNIVERSITY OF MICHIGAN NEWS RELEASE

CONTACT: JIM ALLYN

ANN ARBOR---A team of University of Michigan engineers has undertaken an intensive, seven-month study to determine which of the existing methods for converting coal to clean fuels are the most likely to prove commercially feasible in the near future.

"The Board of Directors of the Electric Power Research Institute (EPRI) has approved a budget of $150,000 and contract negotiations are in progress," said project coordinator Donald L. Katz, the Alfred Holmes White University Professor of Chemical Engineering at U-M.

"Our goal is to recommend to EPRI those processes whose development warrants acceleration through the Institute's support," Prof. Katz said. EPRI is a national effort by the electric power industry, both public and private, to sponsor energy research of common interest and importance.

Joining Katz in the project are Dale E. Briggs, John E. Powers and M. Rasin Tek, professors of chemical engineering; Brymer Williams, professor of chemical and metallurgical engineering; Edward R. Lady, professor of mechanical engineering, all at U-M. Walter E. Lobo, independent consulting engineer, will be project consultant.

"Over the next few decades, clean fuels derived from coal will play a key role in helping electric utility companies handle the ever increasing demand for energy," Katz explained, adding that "clean" coal is that which has had most of the sulfur, a serious pollutant, removed.

"However, coal can be converted to clean fuels by either gasification, liquefication, or solvent extraction," he continued, "and there are currently ten major coal gasification processes and several for liquefication and solvent extraction."

(more)

In view of the steadily mounting energy crisis, the U-M chemical engineer pointed out, EPRI cannot afford either the time or the money required to see that every coal conversion process be fully explored.

"By analyzing and comparing the different processes, we hope to assist EPRI in focusing and intensifying its research so that the best processes can be realized in time to help alleviate the energy dilemma," Katz emphasized.

He said that all conversion processes which satisfy the environmental standards established by the Environmental Protection Agency will be considered. He said a comprehensive method for evaluating the different processes will be developed by the U-M team.

"We will be interested in such things as the percentage of energy remaining after cleaning, the difficulty in the physical handling of the fuel, the simplicity of the equipment required, the type of waste left after cleaning and problems associated with its disposal, the overall economics, and other factors," he observed.

Initially, the group will examine reports describing the processes and review papers on the subject prepared by the EPRI Task Force of Utilization of Coal. But it also plans to conduct extensive interviews with engineers and those managing the organizations sponsoring or offering coal conversion processes to the industry.

"The engineers on the project have considerable experience in industry," Katz noted, "and when it comes to handling thermodynamics, rate processes, or other technical aspects of these various processes, they will be fully capable of putting the information gathered into proper perspective." The final report prepared by the group for EPRI will be presented in January 1974.

Commenting on the project, David V. Ragone, dean of the U-M College of Engineering, said, "Nuclear power is not yet ready to assume the major portion of power production. And shortages of natural gas and limited domestic crude oil supply have put a new emphasis on coal. Therefore, I am highly pleased that our engineers are participating in a project that ultimately could help our country meet its energy needs through the environmentally sound consumption of coal."

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