ENERGY CONSERVATION IN COAL CONVERSION

Direct Coal Fired Steam Generation in Lieu of Low Btu Gas

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ABSTRACT

This report examines the feasibility of replacing the low Btu gas fired steam and power generating system in the Ralph M. Parsons Oil/Gas Complex with a direct coal fired steam and power generating system. The difference in capital cost between the coal fired alternate system and the fuel gas fired system is 36.4 million dollars. For a savings in coal of 586 TPD which is 1.6% of 36,000 TPD used by the Oil/Gas Complex or 6.1 million dollars annually, the rate of return on the additional capital investment is 8.21%.

ACKNOWLEDGEMENTS

I would like to thank Andrew Bela of the Ralph M. Parsons Company, T. S. Govindan of DuPont Co., George Gregorian of Westinghouse Company and George Keenan of Babcock and Wilcox for their valuable information and assistance in preparing this report.

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INTRODUCTION

This study examines using a direct coal fired steam and electric power generation system to replace the existing low Btu gas fired steam and power generation system in the Ralph M. Parsons Oil/Gas Complex. Elimination of the gasifier train which produces fuel gas for the utility boilers results in a 17% improvement in the overall thermal efficiency of the system shown in Figure 1.

The present system is described and an alternate coal fired system which meets plant requirements for electricity, steam and fuel gas is developed to replace the present system. An economic analysis shows that a rate of return of 8.21% can be realized on the additional capital investment of 36.4 million dollars.

PRESENT SYSTEM DESCRIPTION

The existing steam and power generating system in the Ralph M. Parsons Oil/Gas Complex is shown in Figure 1. The gasifier is an air-blown, two stage slagging type, and produces 33,030 MSCF/hr of 145 Btu/SCF gas from 472,510 lb/hr of coal, 746,600 lb/hr of char-filter cake mixture and 22,277 MSCF/hr air. 23,300 MSCF/hr of this gas is burned in four utility boilers producing a total of 2,871,070 lb/hr of 1215 psi, 950°F steam while 2596 MSCF/hr of the gas is used to superheat 785,555 lb/hr of steam generated in heat recovery boilers to 950°F. The balance of the fuel gas, 7134 MSCF/hr, is used in process superheaters, gas sweetening, and sulfur tail gas processing. Of the 3,656,625 lb/hr of 1215 psia, 950°F steam produced, 341,171 lb/hr is used for the 54,600 hp gasifier air compressor, and 1,905,700 lb/hr is used for electric power

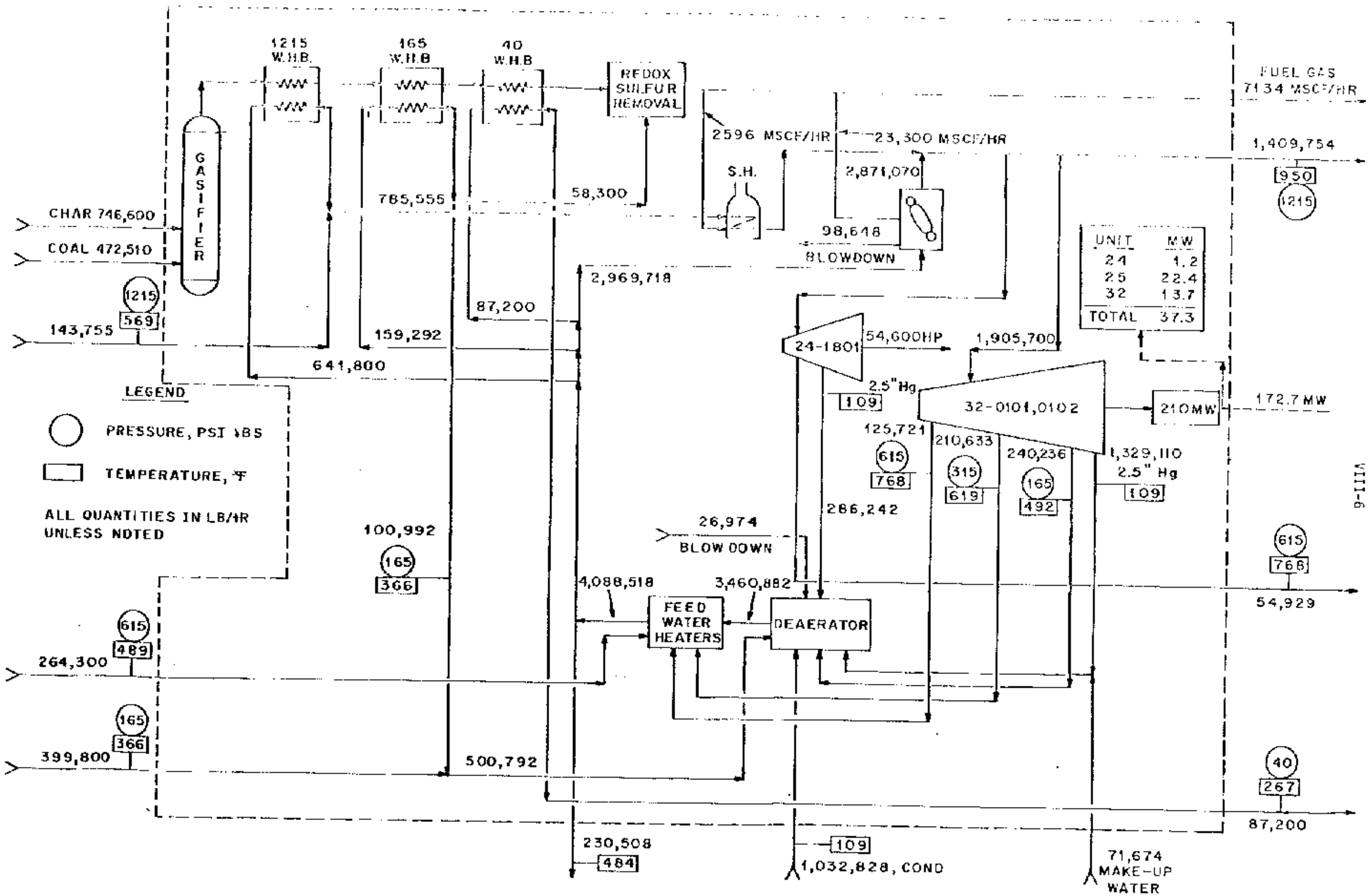

FIGURE 1 RALPH M. PARSONS OIL/GAS COMPLEX STEAM AND POWER GENERATION SYSTEM

generation in turbines 32-0101 and 32-0102 which produce a total of 210 MWE for in plant use. The remaining 1,409,754 lb/hr of 1215, 950°F steam is used for turbine process drivers throughout the plant. In addition to the 1215 psia, 950°F steam used in other areas of the plant, 54,929 lb/hr of 615 psia, 768°F steam and 87,200 lb/hr of 40 psia, 267°F steam are used in other areas of the plant.

DIRECT COAL FIRED ALTERNATE SYSTEM DESCRIPTION

The alternate direct coal fired steam and power generation system is shown in Figure 2. This system produces the same amount of steam and electric power, yet consumes 48,800 lb/yr or 586 short TPD less of coal and 325,196 lb/hr less of char-filter cake as a result of the elimination of the low Btu gasifier train and ancillary equipment. The overall thermal efficiency of the alternate steam and power generation system is 17% greater than the existing configuration (see Appendix A).

A low Btu gasifier and related equipment has been included in the alternate system to supply processes throughout the plant which require low Btu gas. This gasifier is similar to the existing gasifier except that it produces only 21.6% of the low Btu gas as the original, i.e., 7134 MSCF/hr. It has been assumed that the efficiency of the smaller gasifier is the same as the larger unit, i.e., 72.9%, where the efficiency is the Btu value of the products out divided by the total Btu value of the feed into the gasifier. Steam generation from waste heat boilers on the gasifier off-gas stream was reduced directly as the reduction in gas production, and the reduction in power required for the gasifier air compressor was direct also, resulting in a 11,794 hp turbine driver. Additional

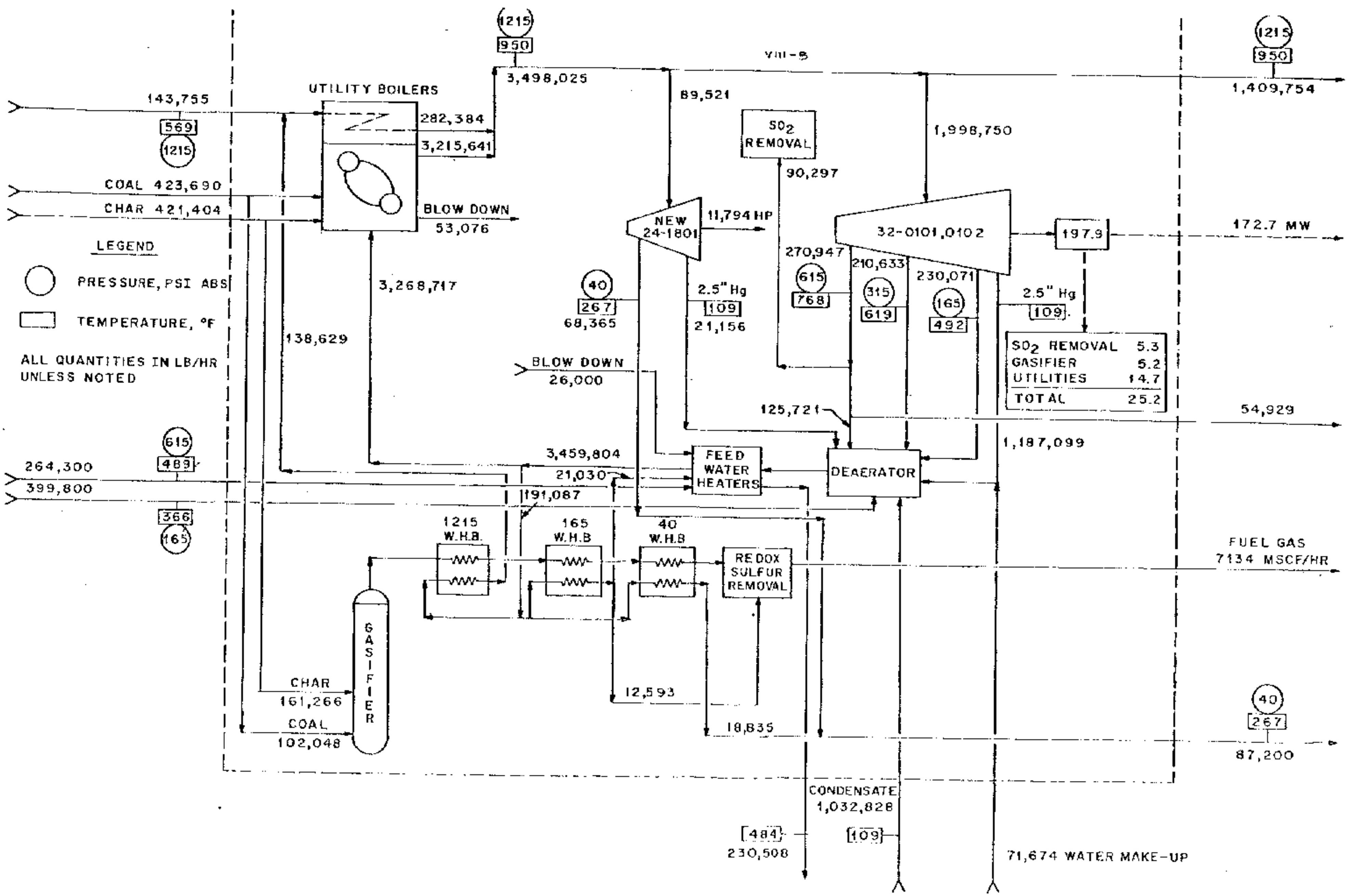

FIGURE 2 ALTERNATE DIRECT COAL FIRED STEAM AND POWER GENERATION SYSTEM

steam was required for the SO_2 scrubber system, and from Appendix B is calculated as 90,297 lb/hr at 615 psia, 768°F. The amount of 615 psia, 489°F steam required by the new redox sulfur removal system has been decreased proportionally to 12,543 lb/hr.

The electric power requirements for the alternate power generation system are:

	172.7 MW	Process
	5.2 MW	New gasifier and redox sulfur removal system
	5.3 MW	SO_2 scrubber system
	14.7 MW	Utilities, including coal fired boilers, coal and ash handling systems, electrostatic precipitators
TOTAL	197.9 MW	

It was assumed that the coal fired boilers consumed 1 MW more than equivalent gas fired boilers of the same size. The power requirements for the SO_2 scrubber system are calculated in Appendix B.

The amount of steam and electrical power required external to the two power generation systems is equal.

The amount of steam and electric power used within the alternate system is different, therefore, the steam extracted at various pressures from the large turbines 32-0101, 32-0102 and also the new gasifier air compressor turbine was adjusted to maintain the same output of steam and power from the alternate power generation system "control volume". The new coal fired boilers were sized to supply the required amount of 1215, 950°F steam, or 3,498,025 lb/hr. Turbine steam requirements and boiler calculations are given in Appendix C.

ECONOMIC ANALYSIS

The difference in the installed costs for the two power generation systems shown in Figures 1 and 2 is the installed cost of equipment added to the present system in the Oil/Gas Complex, minus the installed cost of equipment deleted, to arrive at the alternate system shown in Figure 2.

Installed costs of $25/lb-steam for coal fired boilers and $10/lb-steam for gas fired boilers were given by Babcock and Wilcox[1]. The costs include feeders, conveyors, preheaters, blowers, burners, piping, precipitators and controls. Ash removal equipment is not included in the $25/lb-steam cost and has been calculated at $1,430,000 in Appendix B. The installed cost and operating cost of the SO_2 scrubber were also calculated in Appendix B and are $36,970,000 and $2,332,600 respectively. It was assumed that the operating and maintenance costs for the original power generation system and the alternate would be equal except for the SO_2 scrubber operating and maintenance cost, above. The installed costs for the gasifier system, (unit 24), redox sulfur removal system, (unit 25), and the process steam superheaters are from reference 14, and the new gasifier system and redox system are calculated from these costs in Appendix D. Table 1 lists the equipment added or deleted, and the associated costs.

DISCOUNTED CASH FLOW ANALYSIS

The coal savings for the alternate steam and power generation system is 48,800 lb/hr. At the 1978 price of $31.53 per ton[5], the yearly gross savings for a 330 day year[14] is $6,095,600. The net yearly savings is $6,095,600 - 2,332,600 or $3,763,000. For the additional capital investment of $36,384,000, a 20 year project life, 100 per cent equity, the rate of return using a discounted cash flow analysis is 8.21%. The yearly cash flows are presented in Table 2.

LIFE CYCLE COST OF ALTERNATE SYSTEM

If the additional capital investment of $36,384,000 is borrowed at 9% interest for a period of 20 years, the life cycle cost is given by:

$$LCC = 20 \quad (R - C_{OM} - CRF \times \Delta C)$$

where

R = the annual savings in coal costs

C_{OM} = the annual operating and maintenance cost

CRF = the uniform capital recovery factor, for 20 years at 9% interest

ΔC = the additional capital investment required for the alternate system.

Therefore:

$$LCC = 20 \quad (6{,}095{,}600 - 2{,}332{,}600 - .1095 \times 36{,}384{,}000) = - \$4{,}421{,}000$$

TABLE 1

Equipment Descriptions and 1978 Installed Costs

Equipment No. and Description	Equipment Quantity Oil/Gas / Alternate	Total Installed Cost Oil/Gas / Alternate
32-1601,02,03,04 fuel gas fired boilers, 719 MMBtu/hr	4/-	28,710,000/-
Coal fired boilers*, 1048 MMBtu/hr	-/4	-/87,451,000
Ash Handling Equipment	-/1	-/ 1,430,000
Fuel gas gasifier, process unit 24**	1/-	78,071,000/-
Fuel gas gasifier, alternate system**	-/1	-/31,128,000
Redox sulfur removal, process unit 25	1/-	19,658,000/-
Redox sulfur removal, alternate system	-/1	-/ 7,838,000
32-1309,1310 process steam superheaters 112.9 MMBtu/hr	2/-	1,994,000/-
SO_2 scrubber system	-/1	-/36,970,000
		TOTAL 128,433,000/164,817,000
		ACOST = 36,384,000

* The coal fired boilers include conveyors, feeders, blowers, all piping, preheaters, burners, controls and electrostatic precipitators.

** The gasifier system includes feeders, char cyclones, heat exchangers, waste heat boilers, slag and dust removal equipment, precipitators, compressors, pumps and sour water removal equipment.

TABLE 2

Discounted Cash Flow for Coal Cost of $1.30/MMBtu

****

100 PERCENT EQUITY
9 PERCENT INTEREST

0 PERCENT TAX CREDIT ON
0 PERCENT OF INVESTMENT

THE CALCULATED RATE OF RETURN IS 0.21 PERCENT

YEAR	GROSS CASH FLOW	ANNUAL DEPREC	ANNUAL TAX	NET CASH FLOW	DISCNTD CASH FLOW
1	3763	4280.471	0	3763	3420.909
2	3763	4012.941	0	3763	3109.917
3	3763	3745.412	0	3763	2827.198
4	3763	3477.882	0	3763	2570.18
5	3763	3210.353	0	3763	2336.527
6	3763	2942.824	0	3763	2124.116
7	3763	2675.294	0	3763	1931.014
8	3763	2407.765	0	3763	1755.467
9	3763	2140.235	0	3763	1595.879
10	3763	1872.706	0	3763	1450.8
11	3763	1605.176	0	3763	1318.909
12	3763	1337.647	0	3763	1199.008
13	3763	1070.118	0	3763	1090.007
14	3763	802.5882	0	3763	990.9157
15	3763	535.0588	0	3763	900.8324
16	3763	267.5294	0	3763	818.9386
17	3763	0	0	3763	744.4896
18	3763	0	0	3763	676.8088
19	3763	0	0	3763	615.2807
20	3763	0	0	3763	559.3461
TOTAL	71497	32103.53	0	71497	32036.54

NET PRESENT VALUE AT A DISCOUNT RATE OF 10 PERCENT-4347.457

Note: Figures are in thousands of dollars.

CONCLUSIONS

The alternate coal fired power generation system saves 48,800 lb/hr of coal or $6,095,600 annually, at an increase in capital cost of 36.4 million dollars. This yields a rate of return of 8.21% on the capital investment.

The cost of the gasifier and redox sulfur removal system in the alternate design to supply low Btu gas for process use throughout the plant is 39 million dollars. For processes which would not require low Btu gas, the economics of the coal fired alternate would be much more attractive.

The removal of SO_2 from boiler stack gases is another major consideration in the implementation of the alternate power generation system. State-of-the-art technology in SO_2 removal from stack gases has encountered problems in meeting required emmission standards, because of equipment reliability(6). However, given the estimated lead time of six years for construction of the Oil/Gas facility, there is a strong possibility that problems associated with SO_2 removal will have been solved, prior to start-up of the proposed plant.

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APPENDIX A

Comparison of Overall Thermal Efficiencies Fuel Gas Steam and Power Generation System and the Direct Coal Fired Alternate System

Cycle efficiency, η is defined as:

$$\eta = \frac{w_{net}}{q_{in}}$$

where,

w_{net} = the net work out of the system

q_{in} = the net heat input to the system.

From Figures 1 and 2, it can be seen that

$$w_{net\ 1} = w_{net\ 2}$$

Therefore,

$$\frac{\eta_1}{\eta_2} = \frac{q_{in\ 2}}{q_{in\ 1}}$$

For the values of 1130.5 Btu/lb for char-filter cake[14] and 12,125 Btu/lb for the coal used[14], the heat inputs for the two systems are:

$$q_{in\ 1} = 472{,}510 \text{ lb/hr} \times 12{,}125 \text{ Btu/lb} + 746{,}600 \text{ lb/hr} \times 1130.5$$
$$= 6.57 \times 10^9 \text{ Btu/hr}$$

$$q_{in\ 2} = 423{,}690 \times 12{,}125 + 421{,}404 \times 1130.5$$
$$= 5.614 \times 10^9 \text{ Btu/hr}$$

$$\frac{\eta_1}{\eta_2} = \frac{5.614 \times 10^9}{6.57 \times 10^9}$$

$$= .854 \quad \text{or} \quad \eta_2 = 1.17\ \eta_1$$

APPENDIX B

SO_2 Scrubber Utility Requirements, Installed, and Operating Costs

An SO_2 scrubber system for a 500 MW power plant consumes 129,440 lb/hr of 615 psia steam and 7.6 Mw of electricity[3]. To obtain an equivalent power generation output for the alternate system shown in Figure 2, it is assumed that the net heat out of the control volume is utilized in a Rankine Cycle with a cycle efficiency of 35%. Assuming isentropic expansion of steam through ideal turbines to a pressure of 2.5" Hg, the net total change in the enthalpy of the streams into and out of the control volume is:

$$\Delta h_{NET} = \sum \Delta h_{OUT} - \sum \Delta h_{IN}$$

where Δh is the isentropic change in enthalpy from the initial stream temperature and pressure to 2.5" Hg.

From Figure 2:

Δh_1 = -264,300 lb/hr (1203.2 - 820) Btu/hr

Δh_2 = -399,800 (1195.6 - 880)

Δh_3 = 1,409,754 (1470 - 920)

Δh_4 = 54,929 (1391 - 920)

Δh_5 = 87,200 (1169 - 950)

Δh_{NET} = 592.88 MMBtu/hr

$$w = \frac{\eta \times \Delta h_{NET}}{3413 \text{ Btu/hr-kw}}$$

$$= \frac{.35 \times 592.88 \times 10^6}{3413}$$

$$= 60.8 \text{ MW}$$

Assuming the fuel gas is burned in a boiler with an 85% efficiency, the work available from the fuel gas is:

$$w = \frac{7134 \times 10^3 \text{ SCF/hr} \times 145 \text{ Btu/SCF} \times .85 \times .35}{3413 \text{ Btu/hr-kw}}$$

$$= 90.2 \text{ MW}$$

The total equivalent MW output for the alternate system is:

$$w_{TOTAL} = 197.9 + 60.8 + 90.2$$

$$= 348.8 \text{ MW}$$

The 615 psia steam requirements for the SO_2 scrubber are:

$$\dot{m}_s = \left(\frac{348.8}{500}\right) \quad 129{,}440$$

$$= 90{,}297 \text{ lb/hr}$$

and the electical requirements are:

$$\left(\frac{348.8}{500}\right) \quad 7.6 = 5.3 \text{ MW}$$

SO_2 Scrubber Installed Cost and Operating Cost

Reference 3 gives the 1978 total installed cost of a 500 MW SO_2 scrubber as:

$45,885,000

Using a .6 power law[13] the cost for a 348.8 MW scrubber is:

$$C = \$45,885,000 \left(\frac{348.8}{500}\right)^{.6}$$

$$= \$36,970,000$$

For comparison, an approximate installed SO_2 scrubber cost of $10/lb-steam was obtained from Babcock and Wilcox[1], which is $34,980,000 for the alternate power generation system. The two cost are within 6% of each other.

From reference 3, the 1978 annual operating costs for a 500 MW scrubber system are:

$ 1,114,000	Limestone
2,229,700	Operating manpower and maintenance cost
$ 3,343,700	Total annual operating and maintenance cost

Assuming a direct ratio between operating and maintenance cost and scrubber size, the cost for the alternate power system scrubber is:

$$\left(\frac{348.8}{500}\right) \quad 3,343,700 = \$2,332,600/yr$$

Ash Removal Equipment

From reference 4, a 1975 cost of \$10.73/kw is given for coal and ash handling equipment for coal fired boilers. It is assumed that 1/3 of this cost is for ash handling equipment which is not included in the installed cost of \$25/lb-steam for coal fired boilers. Using the Marshall and Stevens Electrical Power Industries Cost Index[9,12], the 1978 installed cost for the ash handling equipment is:

$$\left(\frac{510}{445.1}\right) \quad \$10.73 \times \frac{1}{3} = \$4.10/\text{kw}$$

The total cost for the equipment is:

$$\$4.10/\text{kw} \times 348.8 \times 10^3 \text{kw} = \$1,430,000$$

APPENDIX C

Steam Turbine and Boiler Calculations

Mass flow rates of steam from the extraction points of the new turbine are adjusted to maintain the original net steam output and power output from the power generation "control volume" shown in Figure 2. Since the original turbine and the alternate operate at nearly the same conditions it is assumed that the turbine efficiencies are equal. It is first necessary to determine the efficiency of the power generating turbine in the original system. First the Rankine Cycle steam rate, described by:

$$\text{RCSR}\ \frac{\text{Lb}_m}{\text{Hp-hr}} = \frac{2545\ \text{Btu/hp-hr}}{(h_1 - h_{2s})\ \text{Btu/lbm}}$$

is found by using a weighted average of the available energy described by the isentropic enthalpy drop across each extraction point. For turbines 32-0101,0102 shown in Figure 1, the Rankine Cycle steam rate can be written:

$$\text{RCSR} = \frac{2545\ \text{Btu/hp-hr}}{(1470-1375).066 + (1470-1300).111 + (1470-1242).126 + (1470-900).697}$$

$$= 5.64\ \text{lbm/hp-hr}$$

The actual steam rate, ASR is:

$$\text{ASR} = \frac{1{,}905{,}700\ \text{lbm/hr}}{210{,}000\ \text{kw} \times 1.340\ \text{hp/kw}}$$

$$= 6.77\ \text{lbm/hp-hr}$$

Therefore, the turbine efficiency is:

$$\eta_{TURB} = \frac{RCSR}{ASR} \times 100\%$$

$$= \frac{5.64}{6.77} \times 100\%$$

$$= 83.3\%$$

The new turbines have the same efficiency. From Figure 2, the output must be 197.9 MW or 265,280 hp. In addition, the required mass flows from each extraction point which yield the same steam output from the system are:

270,947 lbm/hr @ 615 psia, 768°F

210,633 lbm/hr @ 315 psia, 619°F

330,071 lbm/hr @ 165 psia, 492°F

It remains to solve for $\dot{m}$, the amount of steam condensed at 2.5" Hg. We can write:

$$RCSR = \frac{2545 \text{ Btu/hp-hr}}{95\left(\frac{270{,}947}{811{,}615+\dot{m}}\right) + 170\left(\frac{210{,}633}{811{,}615+\dot{m}}\right) + 228\left(\frac{330{,}071}{811{,}615+\dot{m}}\right) + 570\left(\frac{\dot{m}}{811{,}615+\dot{m}}\right)}$$

The ASR is:

$$ASR = \frac{811{,}615 + \dot{m}}{265{,}280}$$

Dividing the RCSR by ASR we have:

$$.833 = \frac{2545}{517.7 + .00215\ \dot{m}}$$

or

$$\dot{m} = 1,187,094$$

Therefore, the total steam required for the new turbines is:

$$\dot{m}_s = 1,187,094 + 811,651$$
$$= 1,998,750 \text{ lbm/hr}$$

A similar calculation was performed on the original 54,600 hp gasifier air compressor turbine driver, yielding a steam flow of 89,521 lb/hr for the new, 11,794 hp gasifier air compressor turbine driver.

Boiler Calculations

The amount of heat input to the boilers is:

$$q_{in} = \frac{1}{\eta_B} [\dot{m}_{SH}(h_2-h_1) + \dot{m}_{STm}(h_2-h_f)]$$

where:

η_B = boiler efficiency, assumed to be .8[1]

$\dot{m}_{SH}$ = amount of steam entering the boiler at 1215 psia, 569°F to be superheated to 950°F

h_2 = 1470 Btu/lbm, (1215 psia @ 950°F)

h_1 = 1183.2 Btu/lb (1215 psia @ 569°F)

h_f = 468 Btu/lb (1215 psia @ 484°F)

From Figure 2, $\dot{m}_{SH}$ = 143, 755 lbm/hr, and $\dot{m}_{STm}$ = 3,268,717 lbm/hr

Therefore:

$$q_{in} = 4.194 \times 10^9 \text{ Btu/hr}$$

In the original system, 746,600 lb/hr of a char-filter cake mixture was fed to the gasifier along with coal in a ratio of .633 coal to char-filter cake. The char-filter cake mixture consists of 329,800 lb/hr of filter-cake from the coal liquifaction process in unit 13 of the Oil/Gas Complex, and 416,800 lb/hr of char which is recovered from the gasifier off-gas and mixed with the filter-cake to aid in drying the mixture.

The gasifier in the alternate system produces .216 the amount of product gas as the original, therefore, the amount of char recovered from the product gas is:

$$416{,}800 \times .216 = 90{,}028 \text{ lb/hr}$$

The amount of char-filter cake mixture available for the alternate system is:

$$329{,}800 + 90{,}028 = 419{,}828 \text{ lb/hr.}$$

The ratio of coal to char-filter cake, .633, is maintained for the new gasifier, therefore, the amount of coal and char-filter cake required is:

$$\dot{m}_{COAL} = .216 \times 472{,}510 \text{ lbm/hr}$$

$$= 102{,}062 \text{ lbm/hr}$$

$$\dot{m}_{CHAR} = \frac{102{,}062}{.633}$$

$$= 161{,}235 \text{ lbm/hr}$$

This leaves:

$$419{,}828 - 161{,}235 = 258{,}593 \text{ lb/hr}$$

of char-filter cake for the boiler. For the char-filter cake heating value of 1130.5 Btu/lb, the amount of coal required by the boiler can be calculated.

$$q_{CHAR} = 258{,}593 \text{ lb/hr} \times 1130.5 \text{ Btu/lb}$$
$$= 2.92 \times 10^{8} \text{ Btu/hr}$$

$$q_{COAL} = 4.194 \times 10^{9} \text{ Btu/hr} - 2.92 \times 10^{8} \text{ Btu/hr}$$
$$= 3.9 \times 10^{9} \text{ Btu/hr.}$$

Therefore,

$$\dot{m}_{COAL} = \frac{3.9 \times 10^{9} \text{ Btu/hr}}{12{,}125 \text{ Bru/hr}}$$
$$= 321{,}649 \text{ lb/hr.}$$

The total amount of coal required for the gasifier and the boiler is:

$$321{,}649 + 102{,}062 = 423{,}711 \text{ lb/hr}$$

The savings in coal is:

$$472{,}510 \text{ lb/hr} - 423{,}711 \text{ lb/hr} = 48{,}799 \text{ lb/hr}$$

or 586 short TPD

APPENDIX D

Gasifier and Sulfur Removal System Costs

From reference 14, the 1975 installed cost for the gasifier and associated equipment is \$66,563,000. Using the Marshall and Stevens Chemical Process Industries Equipment Index[9,12], the 1978 installed cost is:

$$\frac{530.5}{452.3} \times \$66,563,000 = \$78,071,000$$

Using the same index, the 1978 installed cost for the redox sulfur removal system is:

$$\frac{530.5}{452.3} \times 16,760,000 = 19,658,000$$

Similarly, the 1978 cost for the superheaters in the original steam and power generation system is:

$$\frac{530.5}{452.3} \times 1,700,000 = \$1,994,000$$

The cost of the gasifier system for the alternate power generation system shown in Figure 2 is calculated by the .6 power law[13], which is:

$$\left(\frac{\text{Capacity A}}{\text{Capacity B}}\right)^{.6} = \frac{\text{Cost A}}{\text{Cost B}}$$

For the gasifier:

$$CG_{ALT} = 78{,}071{,}000 \left(\frac{7134\ \text{MSCF/hr}}{33{,}030\ \text{MSCF/hr}}\right)^{.6}$$

$$= \$31{,}128{,}000$$

Similarly, for the redox sulfur removal process:

$$CSR_{ALT} = \$19{,}658{,}000 \left(\frac{7134\ \text{MSCF/hr}}{33{,}030\ \text{MSCF/hr}}\right)^{.6}$$

$$= \$7{,}838{,}000$$