# ENERGY CONSERVATION IN COAL CONVERSION

## Combined Cycle In-Plant Electrical Power Generation

## A Case Study

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## ABSTRACT

A combined cycle power generation scheme for the Ralph Parsons Oil/Gas plant was studied as an alternate to the steam turbine power generation system to see if energy can be saved in a cost effective way. Using the same amount of coal as the present system, generates an excess of 22.2 megawatts of electrical power or 10.6% of the 210 MW generated in the Oil/Gas Complex at a cost of $610/KW. If electricity is exported at $.025/KW-hr the annual gross revenues are 4.3 million dollars a year. This is a 19% return on investment, using a discounted cash flow analysis. From a life cycle cost stand point, this is a total revenue of 56.5 million dollars over the 20-year life of the plant.

The combined cycle alternate, which uses present state-of-the-art equipment is a cost effective way to better utilize energy.

## ACKNOWLEDGEMENTS

I would like to thank Andrew Bela of the Ralph M. Parsons Company for his valuable information and help in preparing this report.

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## INTRODUCTION

This report examines the present power generation scheme of the Ralph M. Parsons Oil/Gas Complex Conceptual Design to determine if the efficiency of the power generation system could be improved in a cost effective manner.

The alternative to the present system is a combined cycle utilizing low Btu fuel gas from the low Btu gasifier (unit 24) in a gas turbine, then using the hot exhaust gases in a heat recovery boiler to generate steam for process requirements and additional electric power generation.

The combined cycle was chosen as an alternative because (1) higher thermal efficiencies (35-45%) than straight rankine cycle efficiencies can be expected, and (2) current state-of-the-art gas turbines, heat recovery boilers and other equipment can achieve these higher efficiencies.

## DESCRIPTION OF PRESENT SYSTEM

The present power and steam generation system shown in Figure 1 burns low Btu fuel gas from a low Btu gasifier (unit 24) in boilers for 1200 psig steam generation. The steam generated in this boiler is then used in the process for process steam turbine drivers, and the steam turbine generators for 210 MW of electric power production. The power generation turbines each have three extraction points, at 600 psig, 300 psig and 150 psig, for use in feedwater heaters that service the large waste heat boiler.

## DESCRIPTION OF THE COMBINED CYCLE ALTERNATIVE

The combined cycle alternative must generate the same amount of steam for process use, steam turbine drivers in the process area and electric power requirements for in-plant use as the present system.

The combined cycle system shown in Figure 2 consists of a fuel gas preheater (Appendix A), two gas turbine-generators producing 112.7 megawatts each (Appendix C), one 1200 psig waste heat steam generator which uses the hot exhaust gases of the gas turbines to generate 1,508,000 lb/hr of steam (Appendix A), one each 150 and 25 psig waste heat steam generators utilizing the hot gas from the large waste heat boiler (Appendix A). The 1,508,000 lb/hr of 1200 psig steam generated in the large waste heat boiler is used for process with the balance of 131,500 lb/hr used in a steam turbine (Appendix D) for electric power generation. The turbine has one extraction point of 109,650 lb/hr of 300 psig, 619°F for feedwater heating. Because of the reduced amount of steam generated, the number of deaerators has been

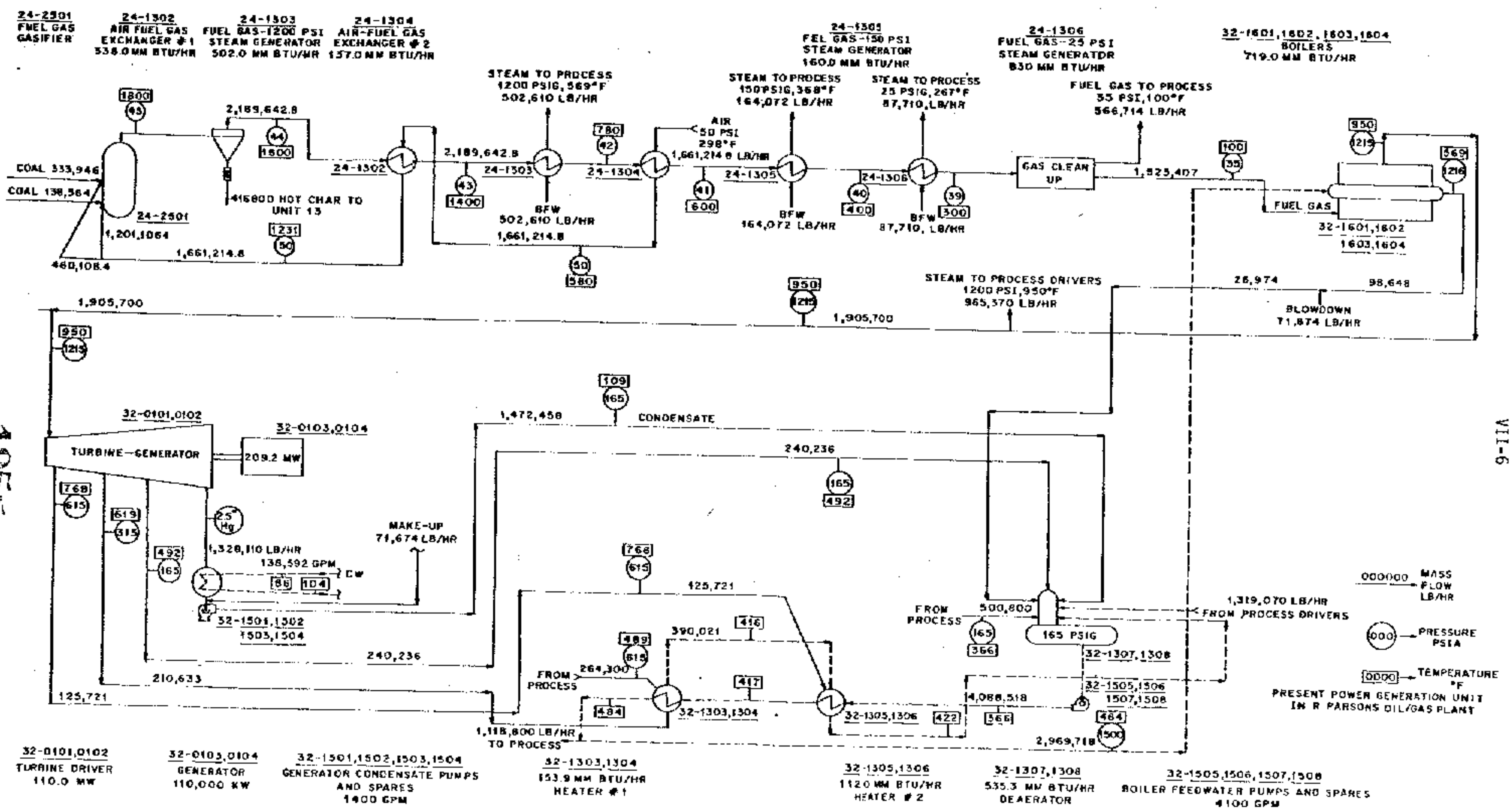


FIGURE 1 PRESENT POWER GENERATION UNIT IN R. PARSONS OIL/GAS PLANT

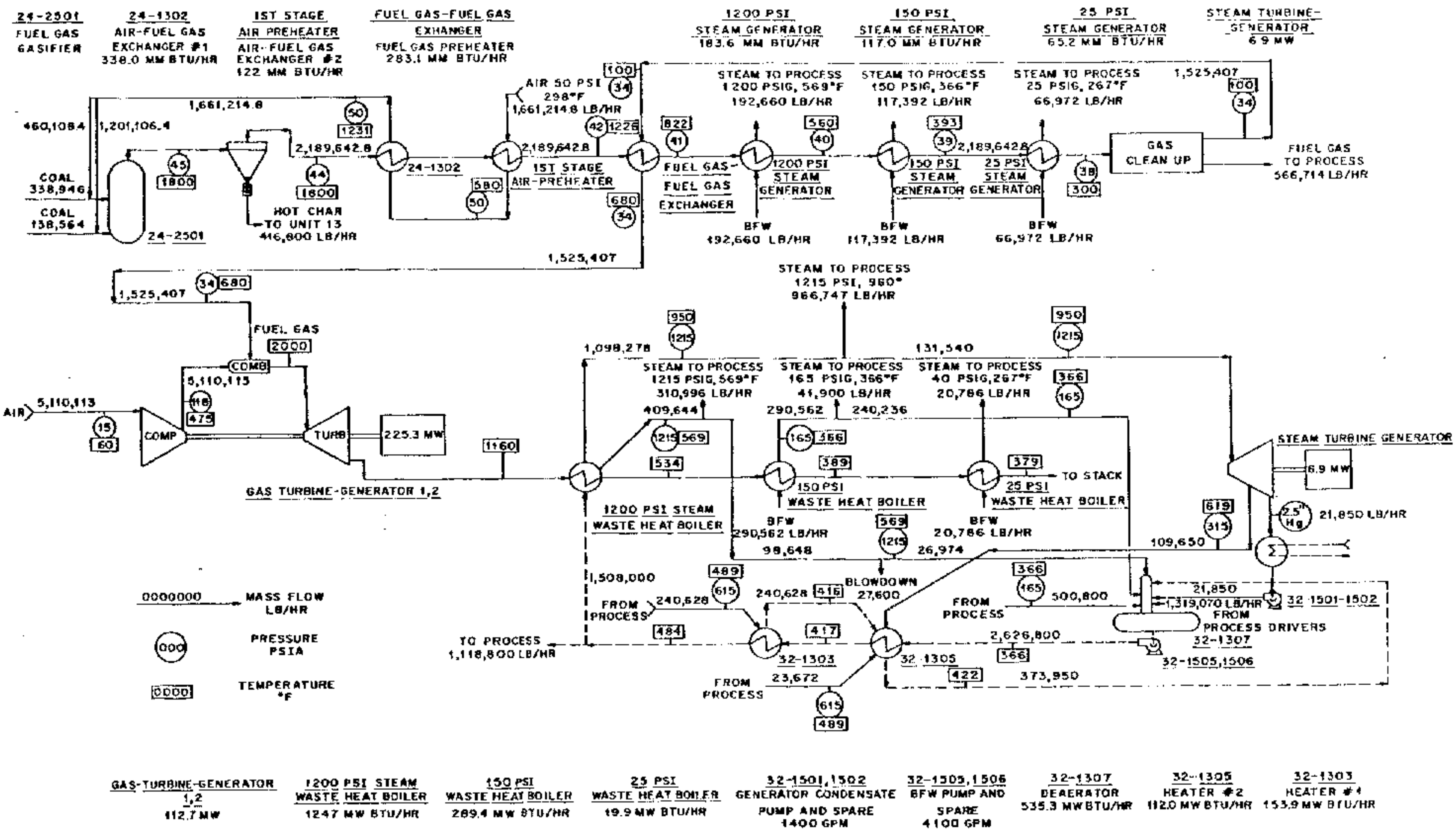


FIGURE 2 COMBINED CYCLE ALTERNATE ELECTRIC POWER AND STEAM GENERATION SCHEME FOR THE R. PARSONS OIL/GAS COMPLEX

decreased from 2 (32-1307,08) to one (32-1307), the number of condensate pumps has been reduced from 4 (32-1501,02,03,04) to two (32-1501,02), the number of feedwater heaters has been reduced from 4 (32-1303,04,05,06) to two (32-1303,04), and the number of feedwater pumps has been decreased from 4 (32-1505,06,07,08) to 2 (32-1505,06).

## ECONOMIC ANALYSIS

Installed costs shown in Table 1 for the combined cycle equipment and for the equipment in the present design are from references 1, 2,5,7,8 and calculations in the appendices. From Table 1, the installed cost of the combined cycle alternative is 99.1 million dollars while the installed cost of the present power generation unit is 85.6 million dollars, the increase in cost for the combined cycle alternative is 13.5 million dollars.

The combined cycle generates a surplus of 22.2 megawatts of electricity over and above the requirements of the plant. This is an installed cost of $610/KW. For this analysis, the electric power would be exported for revenue at a price of $ .025/KW-hr base cost and $.033/KW-hr optimistic price. These prices are given in Section XII, basis for fuel and utility costs. At $ .025/KW-hr, the gross revenue is 4.3 million dollars per year and at $.033/KW-hr the annual gross revenue is 5.7 million dollars. This assumes a 330 day operating year as specified in the Oil/Gas Conceptual Design. In addition the operating and maintenance costs for the present system and the combined cycle alternate are equal.

## TABLE 1

### Equipment Description and Installed Costs for the Ralph M. Parsons Design and Combined Cycle Alternate

| Equipment No. | and Description | Unit Capacity | Number Req'd Parsons/Comb. Cycle | Total Installed Costs Parsons/Comb. Cycle |
|---|---|---|---|---|
| 24-1303* | 1200 psi waste heat steam generator | 502 MM Btu/hr 55000 sq.ft. | 1/- | $ 31,411,782 |
| 24-1304 | air-fuel gas exchanger #2 | 137 MM Btu/hr 75440 sq.ft. | 1/- | $ 3,437,323 |
| 24-1305 | fuel gas 150 psi steam generator | 160 MM Btu/hr 88500 sq.ft. | 1/- | $ 405,817 |
| 24-1306 | fuel gas 25 psi steam generator | 83 MM Btu/hr 61360 sq.ft. | | $ 656,989 |
| 32-1601,02,03,04 | boiler | 853.4 MM Btu/hr | 4/- | $ 28,710,700 |
| 32-0101,02 | steam turbine-generator | 110.0 MW | 2/- | $ 17,827,909 |
| 32-1307,08 | deaerator | 535.3 MM Btu/hr | 2/1 | $ 273,398/136,600 |
| 32-1501,02,03,04 | condensate pumps and spares | 1400 gpm | 4/- | $ 42,472 |
| 32-1505,06,07,08 | feedwater pumps and spares | 4100 gpm | 4/2 | $ 1,389,954/69497 |
| 32-1303,04 | feedwater heaters | 112 MM Btu/hr | 2/1 | $ 694,978/347,489 |
| 32-1303,04 | feedwater heaters | 153.9 MM Btu/hr | 2/1 | $ 694,978/347,489 |
| --- | air-fuel gas exchanger | 122 MM Btu/hr 15683 sq.ft. | -/1 | $ 870,086 |
| --- | fuel gas-fuel gas heat exchanger | 283.1 MM Btu/hr 66,222 sq.ft. | -/1 | $ 3,632,278 |
| --- | 1200 psi waste heat steam generator | 183.6 MM Btu/hr 54384 sq.ft. | -/1 | $ 29,612,088 |
| --- | 150 psi waste heat steam generator | 117 MM Btu/hr 82748 sq.ft. | -/1 | $ 386,433 |
| --- | 25 psi waste heat steam generator | 65.2 MM Btu/hr 58719 sq.ft. | -/1 | $ 688,744 |
| --- | gas turbine-generators | 112.7 MW | -/2 | $ 38,994,200 |
| --- | steam turbine-generator | 6.6 MW | -/1 | $ 956,440 |
| --- | 1200 psi waste heat steam generator | 124.7 MM Btu/hr 1,205,473 sq.ft. | -/1 | $ 19,227,294 |
| --- | condensate pump and spare | 45 gpm | -/2 | $ 4,720 |
| --- | 150 psi waste heat steam generator | 289.4 MM Btu/hr 223371 sq.ft. | -/1 | $ 3,562,770 |
| --- | 25 psi waste heat steam generator | 20 MM Btu/hr 12619 sq.ft. | -/1 | $ 201,273 |
| | | | TOTALS: | $ 85,546,300/ 99,037,361 |
| | | | | ΔCOST = 13,491,061 |

* Equipment number given in Reference 9.
Installed costs are from Refs. 1,2,5,7,8 and calculations in Appendices A,B,C and D.

## Discounted Cash Flow Analysis

A discounted cash flow analysis was performed using the two selling prices of electricity to obtain a rate of return on the additional capital investment for the combined cycle alternate. The following bases were used:

1) 20 year project life
2) 16 year SYD depreciation
3) 52% combined state and federal income tax
4) No investment tax credit
5) 100% equity

The rate of return using $ .025/KW-hr for the price of electricity is 19% and the rate of return using $.033/KW-hr is 24.8%, each one being above the rate of return of 12% specifed by Ralph Parson's as the minimum desired rate of return on the Oil/Gas Complex(9). The yearly tabulation of the discounted cash flow analysis is shown in Tables 2 and 3.

## LIFE CYCLE COST ANALYSIS

The life cycle cost analysis assumes that 100% of the additional capital cost for the change in power generation schemes must be borrowed at 9% interest for the 20-year project life. This results in uniform annual payments of $1.48 million dollars on the loan. This cost is subtracted from the annual revenue of 4.3 million dollars to obtain a net yearly revenue of 2.82 million dollars per year, or 56.6 million dollars over the life of the plant. Using $.033/KW-hr, the net annual revenue is 4.27 million dollars per year, or 85.3 million dollars over the life of the plant.

## CONCLUSION

At a cost of $610/KW, the combined cycle power generation scheme provides a minimum gross revenue of 4.3 million dollars, with a rate of return of 19% on the additional capital investment. The combined cycle alternate steam and power generation scheme is a cost effective way to generate steam and electric power in the Oil/Gas Complex using present state-of-the-art equipment.

## TABLE 2

## Discounted Cash Flow for

## Electricity Selling Price of $ .025/KW-hr

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100 PERCENT EQUITY
9 PERCENT INTEREST

0 PERCENT TAX CREDIT ON
0 PERCENT OF INVESTMENT

THE CALCULATED RATE OF RETURN IS 19.04 PERCENT

| YEAR | GROSS CASH FLOW | ANNUAL DEPREC | ANNUAL TAX | NET CASH FLOW | DISCNTD CASH FLOW |
|---|---|---|---|---|---|
| 1 | 4305 | 1592 | 1410.76 | 2894.24 | 2516.73 |
| 2 | 4305 | 1492.5 | 1462.5 | 2842.5 | 2149.338 |
| 3 | 4305 | 1393 | 1514.24 | 2790.76 | 1834.97 |
| 4 | 4305 | 1293.5 | 1565.98 | 2739.02 | 1566.044 |
| 5 | 4305 | 1194 | 1617.72 | 2687.28 | 1336.053 |
| 6 | 4305 | 1094.5 | 1669.46 | 2635.54 | 1139.417 |
| 7 | 4305 | 995 | 1721.2 | 2583.8 | 971.3461 |
| 8 | 4305 | 895.5 | 1772.94 | 2532.06 | 827.7349 |
| 9 | 4305 | 796 | 1824.68 | 2480.32 | 705.0617 |
| 10 | 4305 | 696.5 | 1876.42 | 2428.58 | 600.3078 |
| 11 | 4305 | 597 | 1928.16 | 2376.84 | 510.8856 |
| 12 | 4305 | 497.5 | 1979.9 | 2325.1 | 434.5778 |
| 13 | 4305 | 398 | 2031.64 | 2273.36 | 369.4846 |
| 14 | 4305 | 298.5 | 2083.38 | 2221.62 | 313.9786 |
| 15 | 4305 | 199 | 2135.12 | 2169.88 | 266.6663 |
| 16 | 4305 | 99.5 | 2186.86 | 2118.14 | 226.3545 |
| 17 | 4305 | 0 | 2238.6 | 2066.4 | 192.0221 |
| 18 | 4305 | 0 | 2238.6 | 2066.4 | 166.9757 |
| 19 | 4305 | 0 | 2238.6 | 2066.4 | 145.1963 |
| 20 | 4305 | 0 | 2238.6 | 2066.4 | 126.2576 |
| TOTAL | 86100 | 13532 | 37735.36 | 48364.64 | 16399.4 |

Note: Figures are in thousands of dollars.

## TABLE 3

### Discounted Cash Flow for Electricity

### Selling Price of $.033/KW-hr

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100 PERCENT EQUITY
9 PERCENT INTEREST

0 PERCENT TAX CREDIT ON
0 PERCENT OF INVESTMENT

THE CALCULATED RATE OF RETURN IS 24.76 PERCENT

| YEAR | GROSS CASH FLOW | ANNUAL DEPREC | ANNUAL TAX | NET CASH FLOW | DISCNTD CASH FLOW |
|---|---|---|---|---|---|
| 1 | 5746 | 1592 | 2160.08 | 3585.92 | 3118.191 |
| 2 | 5746 | 1492.5 | 2211.82 | 3534.18 | 2672.348 |
| 3 | 5746 | 1393 | 2263.56 | 3482.44 | 2289.761 |
| 4 | 5746 | 1293.5 | 2315.3 | 3430.7 | 1961.514 |
| 5 | 5746 | 1194 | 2367.04 | 3378.96 | 1679.94 |
| 6 | 5746 | 1094.5 | 2418.78 | 3327.22 | 1438.449 |
| 7 | 5746 | 995 | 2470.52 | 3275.48 | 1231.374 |
| 8 | 5746 | 895.5 | 2522.26 | 3223.74 | 1053.846 |
| 9 | 5746 | 796 | 2574 | 3172 | 901.6804 |
| 10 | 5746 | 696.5 | 2625.74 | 3120.26 | 771.2805 |
| 11 | 5746 | 597 | 2677.48 | 3068.52 | 659.5576 |
| 12 | 5746 | 497.5 | 2729.22 | 3016.78 | 563.8577 |
| 13 | 5746 | 398 | 2780.96 | 2965.04 | 481.9019 |
| 14 | 5746 | 298.5 | 2832.7 | 2913.3 | 411.7328 |
| 15 | 5746 | 199 | 2884.44 | 2861.56 | 351.6699 |
| 16 | 5746 | 99.5 | 2936.18 | 2809.82 | 300.2708 |
| 17 | 5746 | 0 | 2987.92 | 2758.08 | 256.297 |
| 18 | 5746 | 0 | 2987.92 | 2758.08 | 222.867 |
| 19 | 5746 | 0 | 2987.92 | 2758.08 | 193.7974 |
| 20 | 5746 | 0 | 2987.92 | 2758.08 | 168.5195 |
| TOTAL | 114920 | 13532 | 52721.76 | 62198.24 | 20728.86 |

Note: Figures are in thousands of dollars.

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# APPENDIX A

## Heat Exchanger Area and Cost Calculations

The method for calculating heat exchanger heat transfer areas, and installed costs with examples is given below.

The heat transfer in a heat exchanger is:

$$q = \dot{m}_{fg} \times C_p \times \Delta T_{fg}$$

where:

$\dot{m}_{fg}$ = mass flow of fluid, lb/hr

$C_p$ = constant pressure specific heat of fluid, Btu/lb-°F

$\Delta T_{fg}$ = change in temperature of the fluid, °F

The heat transferred is also:

$$q = U \times A \times \Delta T_m$$

where:

U = overall heat transfer coefficient, Btu/hr-ft$^2$-°F

A = area of exchanger, ft$^2$

$\Delta T_m$ = log mean temperature difference of the exchanger, °F

$$\Delta T_m = \frac{(GTD - LTD)}{\ln(GTD/LTD)}$$

where:

GTD = the greatest temperature difference of the fluids

LTD = the least temperature difference of the fluids.

EXAMPLE:

Calculation of Required Area for the Fuel Gas Preheater (Figure 2)

From Figure 2:

$$\dot{m}_{fg} = 2{,}189{,}643 \text{ lbm/hr}$$

$$\Delta T_{fg} = 1226°F - 822°F$$

and from reference 3,

$$C_p = .32 \text{ Btu/lb-°F.}$$

Therefore,

$$q = 2{,}189{,}643 \times .32 \text{ Btu/lb-°F} \times (1226°F - 822°F)$$

$$= 283.1 \text{ MM Btu/hr.}$$

The log-mean temperature difference is:

$$\Delta T_m = \frac{1126°F - 142°F}{\ln(1126°F/142°F)}$$

$$= 475°F$$

Using a value of 9 from reference 6 for the over-all heat transfer coefficient U we have:

$$283.1 = UA\Delta T_m$$

$$A = \frac{283.1 \times 10^6}{9 \times 475}$$

$$= 66{,}222 \text{ ft}^2$$

From reference 1, the 4th quarter, 1976 installed cost per foot for this type of exchanger is \$47.54. Assuming 10% inflation, the 1978 price is:

$$\$47.54 \times (1.1)^{1.5} = \$54.85$$

Therefore, the total installed cost is:

$$C = A \times \$54.85$$
$$= 66{,}222 \text{ ft}^2 \times \$54.85/\text{ft}^2$$
$$= \$\ 3{,}632{,}278$$

The method used for calculating the required surface areas and installed costs of steam generators is similar to the heat exchanger calculations.

1200 psi Heat Recovery Boiler Calculations

From Figure 2:

$$\dot{m}_s = 1{,}098{,}278 \text{ lb/hr}$$
$$\Delta T = 950°F - 569°F$$
$$\Delta h_{SH} = 187 \text{ Btu/lb}$$

Therefore, the heat transferred in the superheater is:

$$q_{SH} = 1{,}098{,}278 \text{ lb/hr} \times 187 \text{ Btu/lb}$$
$$q_{SH} = 205 \text{ MM Btu/hr}$$

The log mean temperature difference between the two streams is:

$$\Delta T_m = 330°F.$$

From reference 2, $U = 6$ Btu/hr-°F-ft$^2$.

The superheater area is:

$$A_{SH} = \frac{205 \text{ MM Btu/hr}}{6 \text{ Btu/hr-°F-ft}^2 \times 330\text{°F}}$$

$$A_{SH} = 103{,}535 \text{ ft}^2$$

The heat transfer in the boiler is:

$$q_B = \dot{m}\, h_{fg}$$

where:

$q_B$ = heat transfer in the boiler

$\dot{m}$ = mass flow of steam in boiler.

From Figure 2:

$$\dot{m} = 1{,}507{,}922 \text{ lb/hr}$$

This mass flow differs from the superheater mass flow, since some saturated steam is extracted from the boiler for process use and does not pass through the superheater.

From reference 4:

$$h_{fg} = 606 \text{ Btu/lb}$$

$$q_B = 1{,}507{,}922 \text{ lb/hr} \times 606 \text{ Btu/lb}$$

$$q_B = 913.8 \text{ MM Btu/hr}$$

From reference 2:

$$U = 6 \text{ Btu/hr-ft}^2\text{-°F}$$

and from Figure 2:

$$\Delta T_m = 163°F$$

$$A_B = 913.8 \text{ MM Btu/hr} \Big/ 6 \text{ Btu/hr-°F-ft}^2 \times 163°F$$

$$A_B = 934{,}355 \text{ ft}^2$$

where: $A_B$ = surface area of boiler heat transfer.

The heat transfer in the economizer is:

$$q_E = \dot{m} C_p \Delta T$$

From Figure 2:

$$\dot{m} = 1{,}507{,}922 \text{ lb/hr}$$

$$\Delta T = 569°F - 484°F$$

$$q_E = 1{,}507{,}922 \text{ lb/hr} \times 1 \text{ Btu/lb-°F} \times (569°F - 484°F)$$

$$q_E = 128.2 \text{ MM Btu/hr}$$

From Figure 2:

$$\Delta T_m = 85°F$$

and from reference 2:

$$U = 9 \text{ Btu/hr-ft}^2\text{-°F}$$

$$A_E = \frac{128.2 \text{ MM Btu/hr}}{9 \text{ Btu/hr-ft}^2\text{-°F} \times 85°F}$$

$$A_E = 167{,}582 \text{ ft}^2$$

where: $A_E$ = surface area of economizer heat transfer.

The TOTAL AREA is:

$$A_T = A_E + A_B + A_{SH}$$

$$A_T = 103{,}535\ ft^2 + 934{,}355\ ft^2 + 167{,}582\ ft^2$$

$$A_T = 1{,}205{,}473\ ft^2$$

Installed cost per square foot was determined from Reference 2, therefore, the cost for the boiler is:

$$C = 1{,}205{,}473\ ft^2 \times \$15.95/ft^2 = \$19{,}227{,}294$$

## APPENDIX B

### Electrical Power for Export

The additional electric power generated by the combined cycle alternative was claculated by subtracting the electric power requirements of the Oil/Gas plant from the total power produced by the combined cycle:

$$P_{net} = P_{cc} - P_{o/g}$$

where:

$P_{net}$ = excess electric power

$P_{cc}$ = electric power produced by the combined cycle

$P_{o/g}$ = electric power required by the Oil/Gas complex

Therefore:

$$P_{net} = 232.18 \text{ MW} - 210.0 \text{ MW}$$

$$P_{net} = 22.2 \text{ MW}$$

## APPENDIX C

### Gas Turbine-Generator Work and Cost Calculations

For a turbine inlet temperature of 2000°F, the air to fuel ratio calculated from the adiabatic flame temperature is 3.35. Therefore, the mass flow of air into the compressor is:

$$\dot{m}_a = a/f \times \dot{m}_f.$$

From Figure 2, $\dot{m}_f$ = 1,525,407 lb/hr

$$\dot{m}_a = 3.35 \times 1,525,407 \text{ lb/hr}$$

$$\dot{m}_a = 5,110,113 \text{ lb/hr} - 1419 \text{ lb/s}$$

This mass flow dictates two gas turbines, since present designs are limited to mass flows of air in the 750 lb/s range[2]. So for each turbine $\dot{m}_a$ = 2,555,057 lb/hr.

Compressor power, assumine an efficiency of 87.5% is:

$$W_C = (\dot{m}_a \, C_{p_a} \, \Delta T_a)/.875$$

where:

$W_C$ = compressor power, Btu/hr

$\dot{m}_a$ = mass flow of air = 2,555,057 lb/hr

$C_{p_a}$ = constant pressure specific heat of air[3] = .28 Btu/lb-°F

$\Delta T_a$ = change in temperature of air through the compressor = (775°F - 60°F) (from Figure 2)

Therefore:

$$W_C = (2,555,057 \text{ lb/hr} \times .28 \text{ Btu/lb°F} \times 415\text{°F})/.875$$

$W_C$ = 339.3 MM Btu/hr

The heat transferred in the combustor, assuming an efficiency of 98% is then:

$$Q_{in} = ((\dot{m}_A C_{p_a} \Delta T_a) + (\dot{m}_f C_{p_f} \Delta T_f)) / .98$$

where:

$Q_{in}$ = heat transferred in combustion, Btu/hr

$\Delta T_a$ = change in temperature of the air = 2000°F - 475°F (from Figure 2)

$\dot{m}_f$ = mass flow of fuel gas - 762,704 lb/hr (from Figure 2)

$C_{p_f}$ = constant pressure specific heat of fuel gas - .32 Btu/lb-°F[3]

$\Delta T_f$ = change in temperature of fuel gas = 2000°F - 680°F (from Figure 2)

$$Q_{in} = (2{,}555{,}000 \times .28 \times 1525°F) + (762{,}704 \times .32 \times 1320°F)/.98$$

$$Q_{in} = 1442 \text{ MM Btu/hr}$$

The power out of the turbine, assuming an efficiency of 87.5%[8] is:

$$W_t = (\dot{m}_p C_{p_p} \Delta T_p).875$$

where:

$W_t$ = turbine power, Btu/hr

$\dot{m}_p$ = mass flow of products of combustion - 3,317,761 lb/hr (from Figure 2)

$C_{p_p}$ = constant pressure specific heat of products = .30 Btu/lb-°F[3]

$\Delta T_p$ = change in temperature of products through the turbine, 2000°F - 1160°F (from Figure 2)

$$W_t = 3,317,761 \text{ lb/hr} \times .30 \text{ Btu/lb-°F} \times 840°\text{F} \times .875$$

$$W_t = 731.6 \text{ MM Btu/hr}$$

The net power out is then:

$$W_{net} = W_T - W_C$$

$$W_{net} = 731.6 \text{ MM Btu/hr} - 339.3 \text{ MM Btu/hr}$$

$$W_{net} = 392.3 \text{ MM Btu/hr}$$

The electrical power out of the generator, assuming a 98% efficiency, is:

$$P_g = .98\ (W_{net})$$

$$P_g = .98(.29307 \text{ W/Btu/hr})(392.3 \text{ MM Btu/hr})$$

$$= 112.7 \text{ MW}$$

The installed cost for the gas turbine-generator set is \$173/KW from Reference 7. Therefore, the total cost for two gas turbine generator sets is:

$$C_{GT} = \$173/\text{KW} \times 2 \times 112,700 \text{ KW}$$

$$= \$38,994,200$$

## APPENDIX D

### Calculation of Steam Turbine Work and Cost

From Figure 2, the total mass flow of steam into the turbine is 131,500 lb/hr with 109,650 lb/hr extracted at 300 psig, 619°F for the feedwater heaters. The power out of the steam turbine-generator is:

$$P_{ST} = (\dot{m}_{SE} \times \Delta h_{SE}) + (\dot{m}_{SC} \times \Delta h_{SC})$$

where:

$P_{ST}$ = power out of steam turbine.

$\dot{m}_{SE}$ = mass flow of steam extracted at 315 psi, 619°F - 109,650lb/hr (from Figure 2)

$\Delta h_{SE}$ = enthalpy change of steam extracted = 139 Btu/lb

$\dot{m}_{SC}$ = mass flow of steam condensed = 21,850 lb/hr (from Figure 2)

$\Delta h_{SC}$ = enthalpy change of condensed steam = 357 Btu/lb

$$P_{ST} = (109{,}650 \text{ lb/hr} \times 139 \text{ Btu/lb}) + (21850 \text{ lb/hr} \times 357 \text{ Btu/lb})$$

$$P_{ST} = 23.0 \text{ MM Btu/hr}$$

The generator power, assuming an efficiency of 98% is:

$$P_G = .98\ (P_{ST})$$

$$P_G = .98\ (.29307 \text{ W/Btu/hr})(23.0 \text{ MM Btu/hr})$$

$$P_G = 6.6 \text{ MW}$$

An installed cost of $118.4/KW for the steam turbine-generator set is from Reference 7, and an estimate of $175,000 additional for each extraction point was supplied by Westinghouse Co.

The total installed cost is then:

$$C_{ST} = 6{,}600 \text{ KW} \times \$118.4/\text{KW} + \$175{,}000$$

$$= \$956{,}440$$