Economics of Four FGD Systems

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Prepared by
Stearns-Roger Engineering Corporation
Denver, Colorado

ELECTRIC POWER RESEARCH INSTITUTE

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ABSTRACT

The Electric Power Research Institute contracted with Stearns-Roger Engineering Corporation to prepare an assessment of the economics of four flue gas desulfurization (FGD) systems: a conventional limestone scrubber, a cocurrent limestone scrubber, a Chiyoda Thoroughbred 121 limestone scrubber, and a Wellman-Lord scrubber. This report presents and compares the economic evaluations of each of these systems.

Using the standardized evaluation premises, Stearns-Roger developed typical FGD systems for each of the four selected processes designed to meet the latest Federal New Source Performance Standards (NSPS) promulgated 6/11/79. EPRI's Economic Premises for Electric Power Generating Systems were used as the basis for the economic criteria. Technical and cost data were developed for the treatment of flue gases from large-scale utility boilers (500 MW) burning typical high sulfur coal (4%). These data were then evaluated to test cost sensitivities to changes in coal sulfur content and plant size.

EPRI PERSPECTIVE

PROJECT DESCRIPTION

This final report summarizes results of a study under RP1180-3 comparing the projected economics for flue gas desulfurization (FDG) processes. Three limestone throwaway systems and one SO_2 recovery system were chosen for evaluation:

- Conventional limestone with stabilized sludge by-product
- EPRI/Tennessee Valley Authority cocurrent limestone with stabilized sludge by-product
- Chiyoda Thoroughbred 121 limestone with gypsum by-product
- Wellman-Lord with acid by-product and with elemental sulfur by-product

The cocurrent and the Chiyoda scrubbing systems were selected for economic evaluation since these two systems were shown to be technically feasible under RP1033-1 and RP536-4, respectively. Specific innovations in the design of these two scrubbing systems indicate that the systems may be cheaper to build, operate, and maintain than a conventional limestone scrubbing process. We also evaluated a regenerable scrubbing system to determine how it would compare to the three limestone systems. The Wellman-Lord scrubbing system was selected since we regard this system as commercially available.

EPRI submitted report sections to the appropriate FGD suppliers. They were requested to provide their comments on the report. Vendor comments are incorporated as received.

Previous FGD evaluations are described in EPRI Final Reports FP-272, AF-342, CS-1428, and CS-1381. Each of the four processes evaluated in this report was described in one or more of the earlier reports. In addition, TVA has also evaluated many FGD processes for the U.S. Environmental Protection Agency.

PROJECT OBJECTIVE

The objective was to evaluate the economics of four FGD scrubbing systems (three limestone throwaway processes and one sulfur recovery process) using a uniform design approach and uniform economic criteria so that results can be compared on a common basis.

PROJECT RESULTS

As in other EPRI studies, limestone-based nonregenerable processes exhibited lower capital and levelized revenue requirements compared to the regenerable process. The busbar costs presented are broken out into three cost elements: variable operating costs, fixed operating costs, and total capital requirement. For each process these major elements are further broken down so that the reader can identify what minor cost elements contribute to the total cost. For instance, this report indicates that the reason the variable costs for the Chiyoda are so low is that the cost for "raw materials" is significantly lower than the other limestone scrubbing systems evaluated.

The total capital requirements calculated for these four scrubbing systems using common site criteria and economic premises are as follows:

Scrubbing System	Total Capital Requirement (per kW)	Levelized Busbar Cost (mills/kWh)	
		Without S Credit	With S Credit
Conventional limestone	$185	12.9	--
EPRI/TVA cocurrent	$190	13.3	--
Chiyoda Thoroughbred 121	$160	11.5	--
Wellman-Lord:			
(with acid plant)	$265	19.3	15.7
(with sulfur plant)	$245	20.3	19.0

These results should not be compared with other economic evaluations since these estimates are based on specific assumptions, site criteria, and economic premises. It is not appropriate to generalize these estimates or assume they represent manufacturer's current site-specific selling prices. The generalized cost estimates presented in this report are of value to utility personnel who require comparative estimates for research and development planning and/or FGD process screening. The report can also serve as a guide to utility engineers who want a format to follow when preparing economic evaluations of a number of FGD scrubbing systems for cross comparison.

EPRI intends to continually update and report FGD cost estimates on a regular basis as technologies and conditions change.

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1. SUMMARY

Capital and operating costs for four Flue Gas Desulfurization (FGD) processes have been estimated based on a consistent scope of supply and process design, and economic criteria. Although absolute values evolving from this estimate are specific to the selected criteria, the relative magnitude of each provides a more general view of the comparative costs for the four systems. A summary of the estimated levelized busbar cost for the four processes is presented in Figure 1-1. These levelized busbar costs represent the increase in cost of power production resulting from the inclusion of the FGD System in the power plant. For comparison, the 30-year levelized cost of power production without FGD is on the order of 55 mills/kWh, and the FGD systems studied raised this cost to 65-75 mills/kWh.

1.A. FGD SYSTEMS EVALUATED

Three limestone throwaway FGD systems and one SO_2 recovery FGD system were chosen for evaluation, including the following:

- Conventional Limestone
- EPRI/TVA Cocurrent
- Chiyoda Thoroughbred 121
- Wellman-Lord

The scope for all four systems included everything from the I.D. Fan discharge to the ultimate disposal area for the throwaway systems or byproduct storage for the recovery system. A pro rata share of peripheral items was also included; roads, office buildings, control rooms, shops, laboratories, etc. The FGD System cost reflects all components necessary to build a "grassroots" facility including earthwork, concrete, piping, equipment, buildings and structures, electrical, painting, instruments and controls, insulation, direct field labor, and all indirect field costs.

1.B. PROCESS DESIGN CRITERIA

The economic evaluation was based on a new 500 MW (net) pulverized coal-fired unit. The coal supply was assumed to be a 4 percent sulfur Illinois coal.

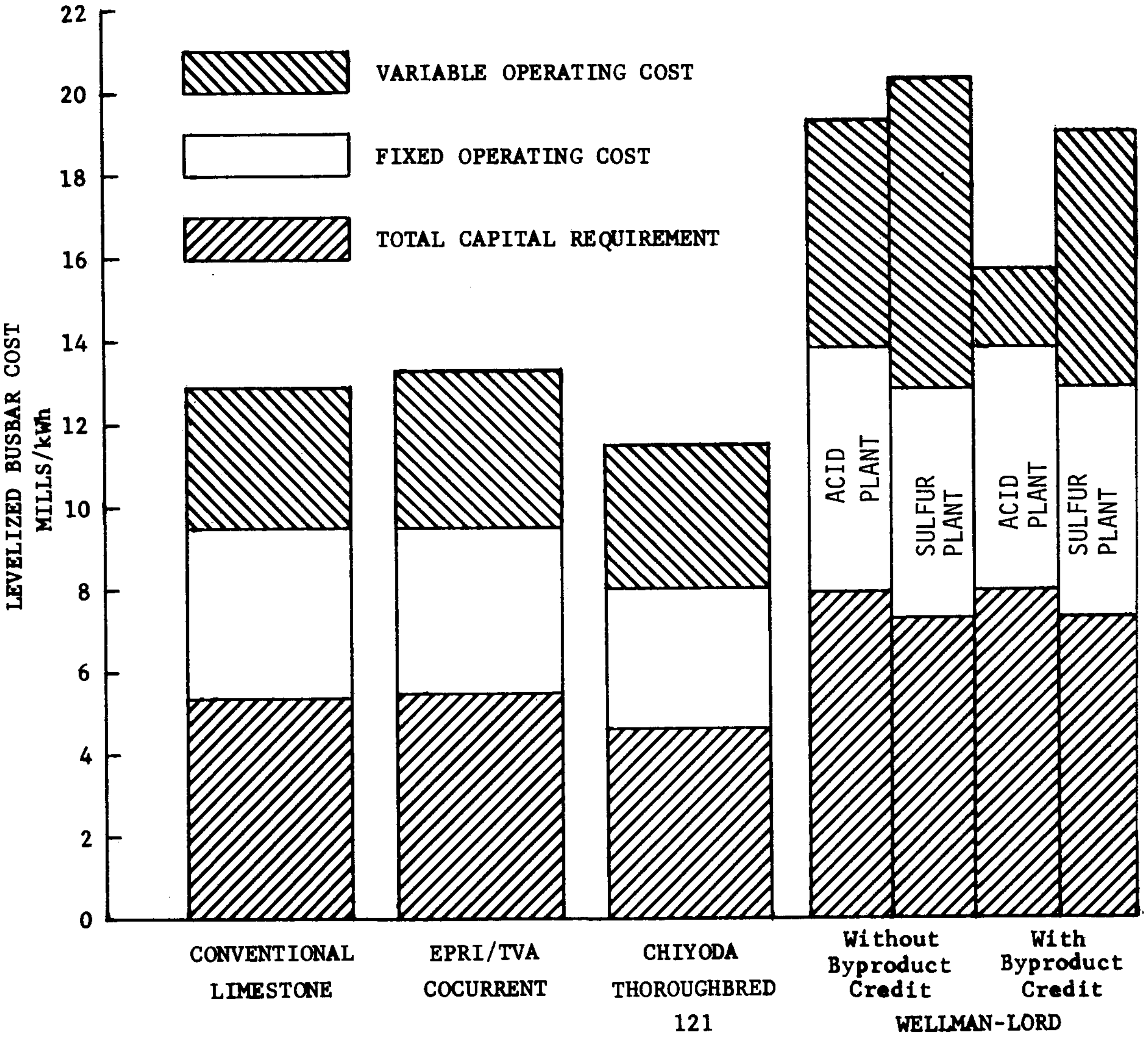


FIGURE 1-1

LEVELIZED BUSBAR COST BREAKDOWN

Boiler heat input at maximum continuous rating (MCR) was 4,862 x 10^6 Btu/hr based on a net plant heat rate of 9724 Btu/kWh (10,260 kJ/kWh). The unit gross output of about 540 MW assumes FGD steam consumption for 50^oF (125^oC) scrubbed gas reheat. The boiler heat input, and consequently the flue gas flow and sulfur dioxide production, was adjusted for FGD processes, requiring process steam in addition to reheat to maintain a net generator output of 500 MW. The adjustment for the Wellman-Lord process resulted in a boiler heat input about 5 percent higher than the limestone systems.

Sulfur dioxide removal requirement was based on the latest Federal New Source Performance Standards promulgated 6/11/79, which states that 90 percent removal is required for solid fuels that have an uncontrolled sulfur emission of greater than or equal to 0.6 lb SO_2 per million Btu input. The removal efficiency must be based on a 30-day rolling average. For this evaluation, it was assumed that all sulfur present in the coal is converted to sulfur oxides in the flue gas. (A conservative assumption, since about 5-10% of the S is captured in the fly ash and bottom ash).

The plant was assumed to be located near Kenosha, Wisconsin, at an elevation of 600 feet above mean sea level. Plant design life is 30 years with a capacity factor of 70 percent. Particulate removal was assumed to be achieved prior to the FGD System. Waste disposal of "throwaway" sludges was assumed to require landfill impoundment of dewatered, blended sludge.

1.C. ECONOMIC CRITERIA

The economic development was based on EPRI's Economic Premises for Electric Power Generating Systems dated July 1978 and amended June 1979 (see Appendix F). These premises provide guidelines for the capital investment basis, the operating cost basis, the cost of capital and the busbar power cost.

1.C.1. CAPITAL INVESTMENT BASIS

The capital investment consists of the following components:

Component	$/Kw
Process Capital	A
General Facilities	B
Engineering and Home Office Fees	C
Project Contingency	D

Component	$/Kw
Process Contingency	E
Sales Tax	F
Total Plant Investment	TPI=A+B+C+D+E+F

Component	$/Kw
Royalty Allowance	G
Preproduction Costs	H
Inventory Capital	I
Initial Catalyst and Chemicals	J
Allowance for Funds During Construction	K
Land	X
Total Capital Requirement	TCR=TPI+G+H+I+J+K+X

All capital costs were based on mid-1978 dollars and mid-1979 startup.

1.C.2 TOTAL CAPITAL REQUIREMENT

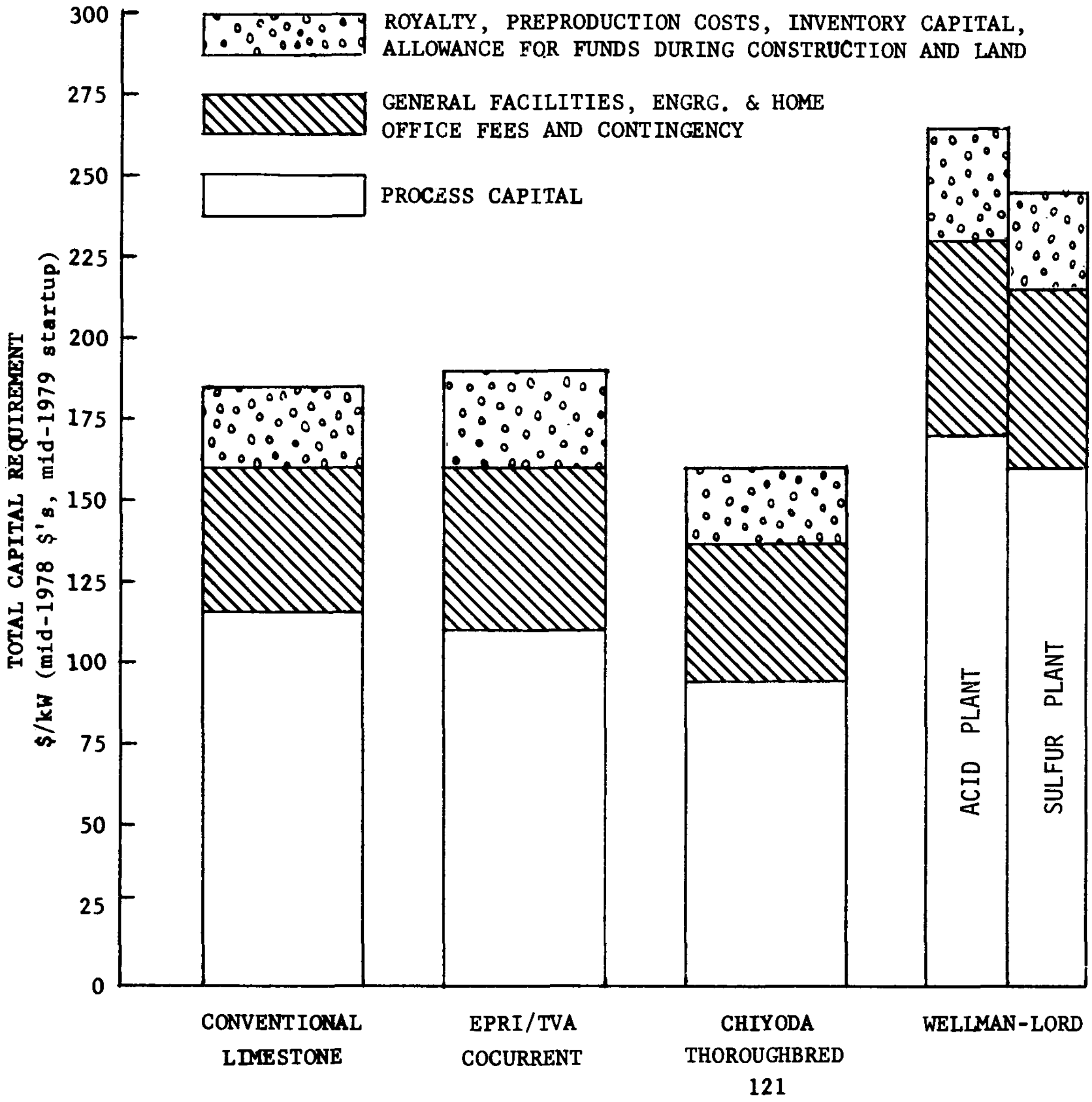
A summary of the Total Capital Requirement is presented in Figure 1-2. The cost components for the three limestone systems are approximately the same, however, greater contingencies were required for the EPRI/TVA Cocurrent System and the Chiyoda Thoroughbred 121 System due to their less advanced state of development compared to the Conventional Limestone System. The Wellman-Lord System costs are considerably greater as a result of the complexity of the SO_2 recovery process.

1.C.3. COST OF CAPITAL

The cost of capital was based on an assumed 6 percent/year inflation rate and certain economic assumptions listed in the General Criteria section. The 30-year levelized fixed charge rate (LFCR) calculated from those assumptions is 18 percent/year.

1.C.4. OPERATING COST BASIS

The operating costs were divided into fixed and variable costs. The fixed costs are essentially independent of capacity factor while the variable costs are directly proportional to the amount of power produced. The fixed operating costs include operating and maintenance labor, maintenance materials, and an overhead charge for administrative and support labor.



BASIS: NEW 500 MW COAL FIRED PLANT, MIDWEST LOCATION
30 YEAR PLANT LIFE; PRICING LEVEL MID-1978 FOR MID 1979 STARTUP
HIGH SULFUR COAL - 4.0% SULFUR (AVG)
CAPACITY FACTOR 70%, 6132 HRS/YR
SO_2 EMISSION PER PROMULGATED JUNE, 1979 NSPS

FIGURE 1-2

TOTAL CAPITAL REQUIREMENT BREAKDOWN

Variable operating costs include raw materials, power, steam, and items such as cooling water and methane, i.e. essentially all consumables.

1.C.5. FIXED OPERATING COST

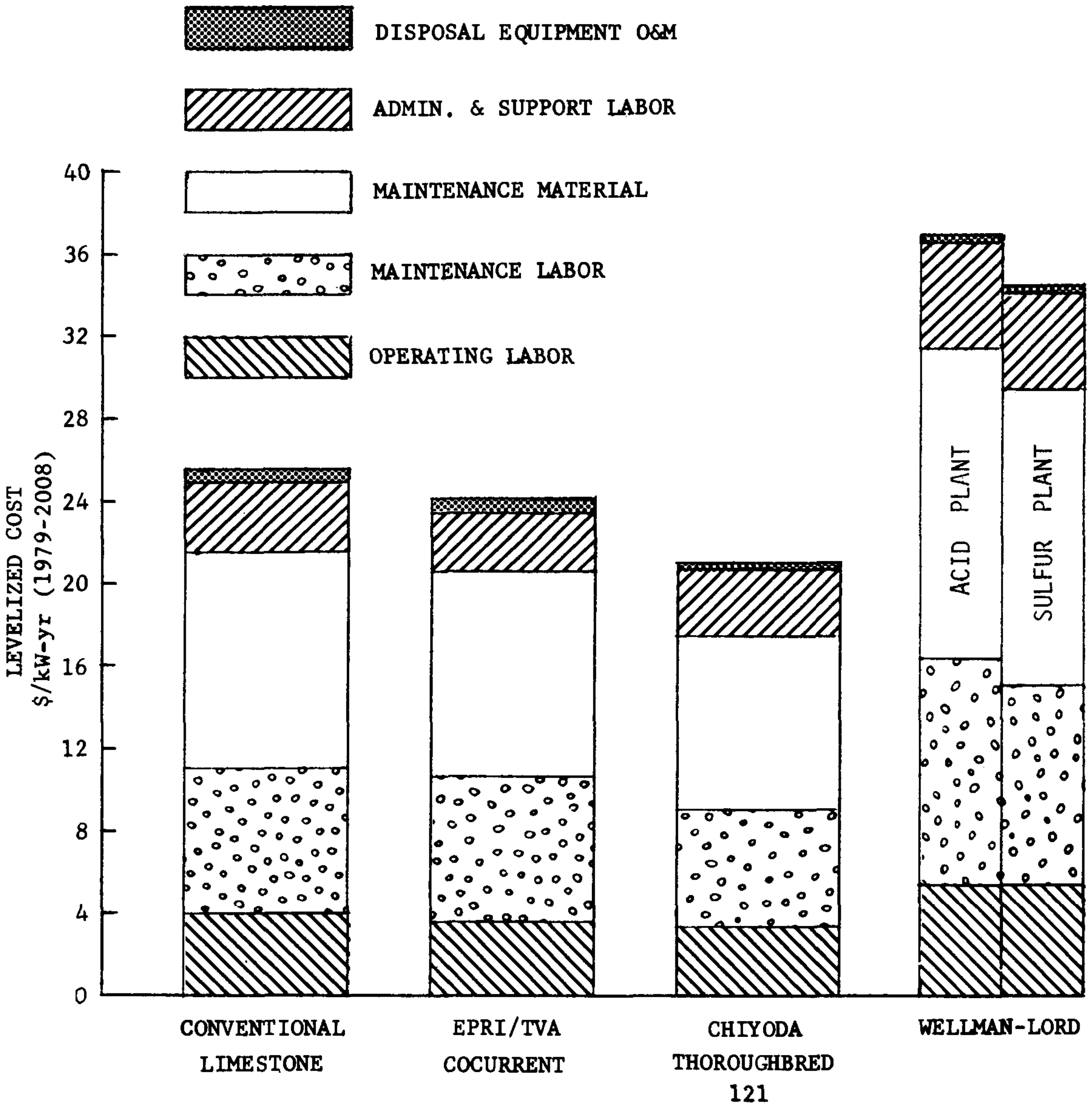
A summary of the Fixed Operating Costs is presented in Figure 1-3. Maintenance labor and material are the primary components of the fixed operating costs. These components are determined as a percentage of the Process Capital and therefore the fixed operating costs tend to reflect the relative magnitude of the Process Capital estimates. Operating labor is also a rather large component and reflects the higher complexity of the Wellman-Lord System requiring increased operating cost.

1.C.6. VARIABLE OPERATING COST

A summary of the Variable Operating Costs is presented in Figure 1-4. The limestone systems have equivalent steam costs but vary relative to power and raw materials. The raw material costs vary primarily the same as the differences in limestone stoichiometric ratios. The limestone system power costs reflect differences in the major contributors to power consumption, the gas-side pressure drop, and liquid-to-gas ratio. The Wellman-Lord System has a considerably higher variable operating cost than any of the limestone systems. Although raw material costs are less, steam and power are greater, and the Wellman-Lord System requires the additional component of cooling water for the SO_2 condensers and, for the sulfur plant, methane. The considerable increase in steam cost is a direct result of the substantial steam requirement for thermal decomposition to release the SO_2 from the scrubbing liquor. The power cost reflects increased complexity and a relatively high gas-side pressure drop. The cost of methane imposes a severe penalty to the Wellman-Lord system with sulfur plant alternate. The cost of methane was chosen as \$4.00 per mscf for this study, assuming unavailability of natural gas and reflecting the cost of gas derived synthetically from other feedstocks.

1.D. LEVELIZED BUSBAR POWER COST

The levelized busbar power costs for each system were determined from the estimated capital and operating costs. All costs were converted to a levelized cost in terms of mills/kWh. Appropriate levelization factors were applied to the operating costs and the fixed charge rate of 18 percent/yr was applied to the capital costs.



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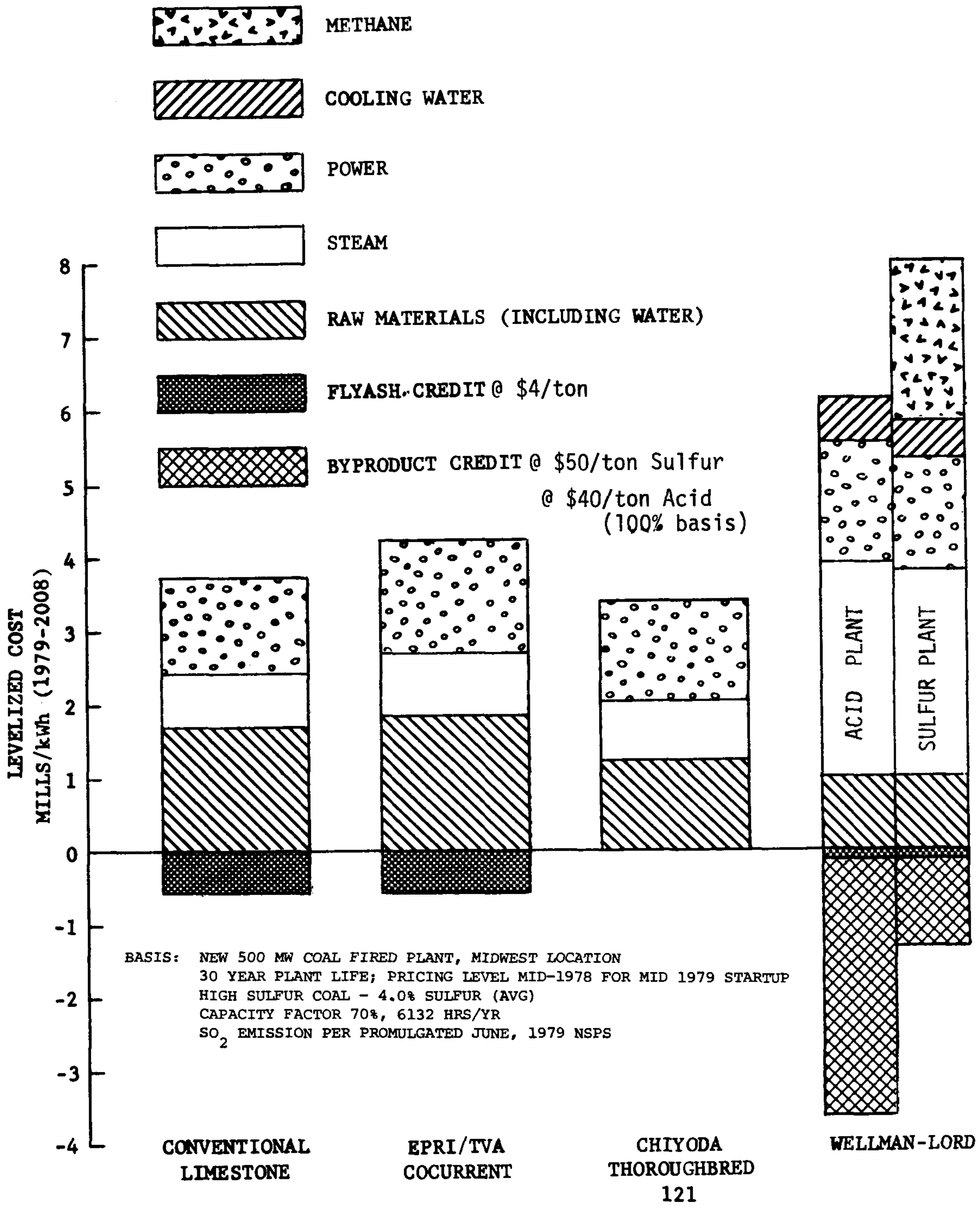
HIGH SULFUR COAL - 4.0% SULFUR (AVG)
CAPACITY FACTOR 70%, 6132 HRS/YR
SO_2 EMISSION PER PROMULGATED JUNE, 1979 NSPS

FIGURE 1-3

FIXED OPERATING COST BREAKDOWN



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CAPACITY FACTOR 70%, 6132 HRS/YR
SO_2 EMISSION PER PROMULGATED JUNE, 1979 NSPS

FIGURE 1-4

VARIABLE OPERATING COST BREAKDOWN

1.E. COST SENSITIVITY

Cost sensitivity to percent-sulfur and plant size are presented in Figures 1-5 and 1-6 for the four processes. The Wellman-Lord process cost sensitivity curves do not include a byproduct credit.

1.F. ESTIMATE ACCURACY

The accuracy of the estimates differ for absolute costs versus relative costs. It is felt that the cost estimating techniques is sufficient to produce estimates with an absolute accuracy of ±20 percent, however, the accuracy for relative comparison of the processes is thought to be more accurate, on the order of ±10 percent.

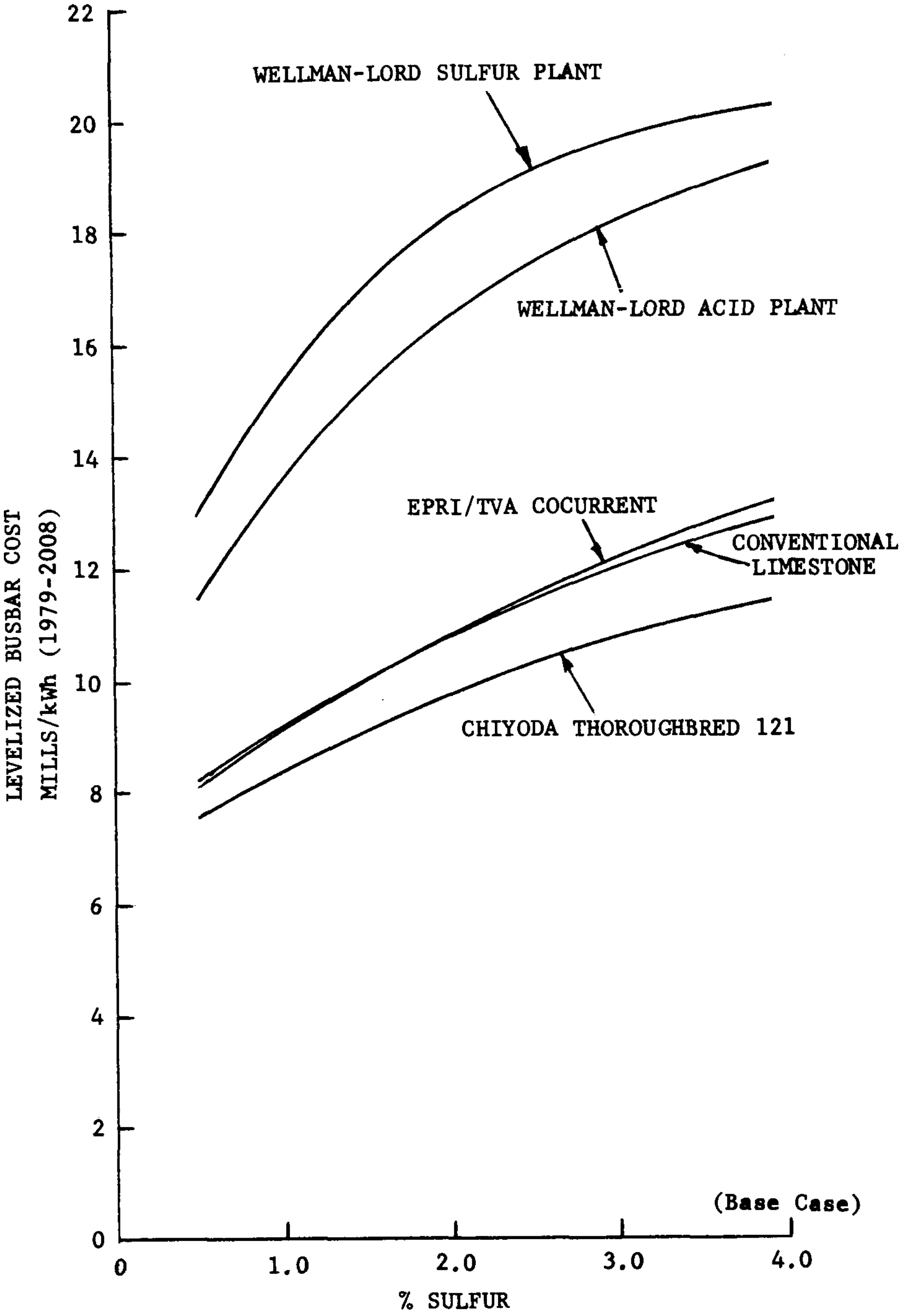


FIGURE 1-5

COST VERSUS SULFUR CONTENT OF COAL

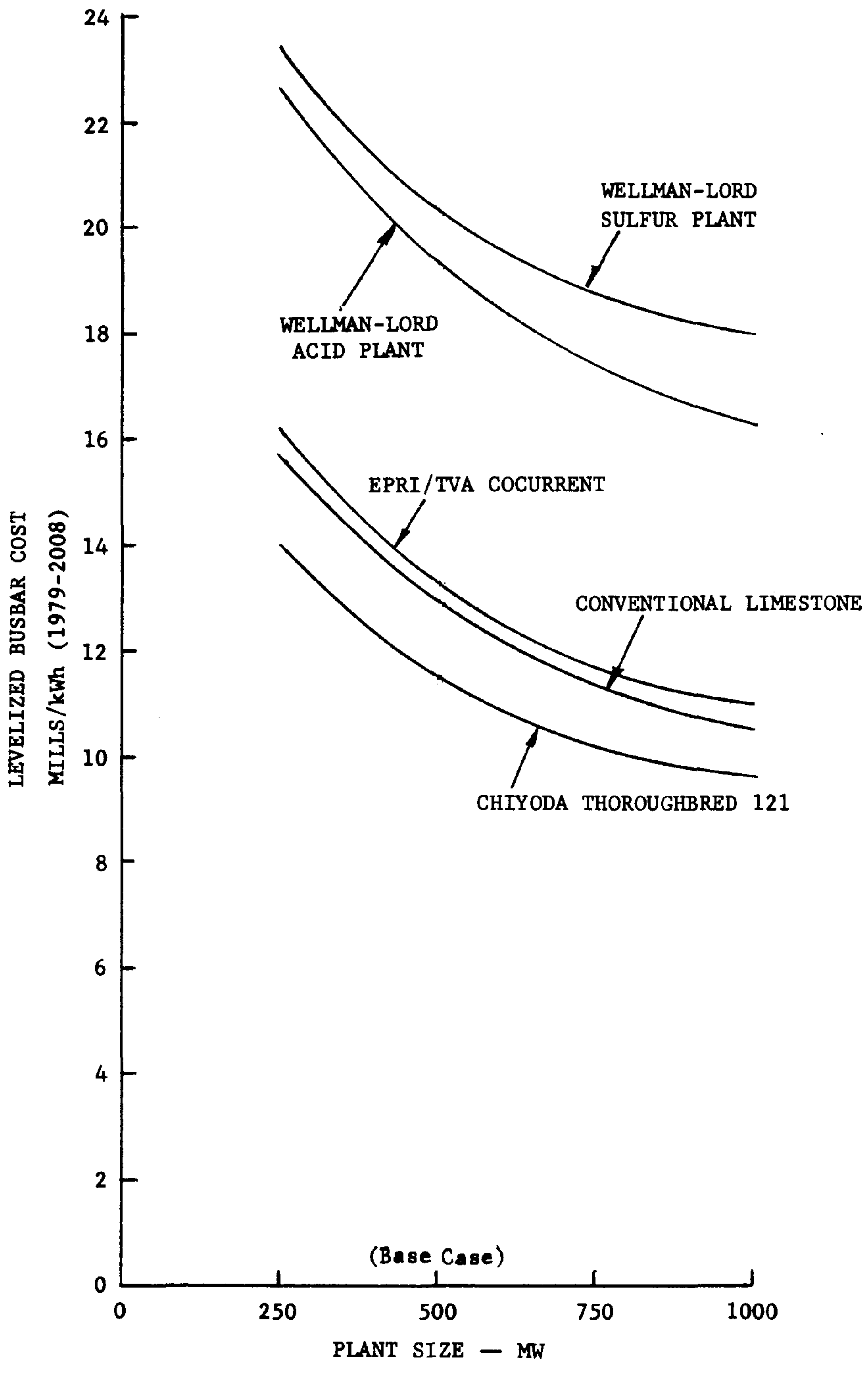


FIGURE 1-6

COST VERSUS PLANT SIZE

2. INTRODUCTION

Comparison of reported costs for FGD Systems is often difficult because of varying scope of supply, differences in process and/or economic criteria, and different estimate dates. To facilitate direct cost comparison of several FGD Systems, economic evaluations have been prepared for four processes using a common process approach and common economic criteria. Three limestone throwaway processes and one SO_2 recovery process were chosen. They are as follows:

- Conventional Limestone FGD System
- EPRI/TVA Cocurrent FGD System
- Chiyoda Thoroughbred 121 FGD System
- Wellman-Lord FGD System

Economic evaluations for each system were prepared for a new 500MW coal-fired power plant in the north central United States. The plant was assumed to fire an Illinois high sulfur coal and was required to meet the latest Federal New Source Performance Standards promulgated 6/11/79. EPRI's Economic Premises for Electric Power Generating Systems were used as the basis for the economic criteria.

3. GENERAL CRITERIA

This section documents the general criteria established to maintain consistency from case to case, and with other EPRI sponsored projects and criteria. General criteria, both process and economic, presented in this section are applicable to all processes evaluated. Criteria specific to each process are presented in the individual system sections. The items discussed in this section are as follows:

- Process Design Criteria
  - Generating Plant
  - Coal and Flue Gas
  - Sulfur Dioxide Removal Requirements
  - General Equipment
  - FGD System Battery Limits
  - Raw Materials
  - Waste Disposal
- Economic Design Criteria
  - Capital Estimate Summary
    - Total Plant Investment
    - Total Capital Requirement
  - Operating Cost Summary
    - Fixed Operating Costs
    - Variable Operating Costs
    - Levelized Busbar Cost

3.A. PROCESS DESIGN CRITERIA

3.A.1. GENERATING PLANT

The generating plant chosen for this study is a new 500 MW (net), 540 MW (gross) balanced draft, pulverized coal-fired, base loaded unit. Operating conditions for the boiler are assumed to be typical of modern units. Net plant heat rate was estimated to be 9724 Btu/kWh (10,260kJ/kWh). Boiler heat input at maximum load is 5105 x 10^6 Btu/hr (5386 GJ/h) (maximum load assumed to be 105 percent with turbine throttle Valves Wide Open - 105 percent, VWO) and 4862 X 10^6 Btu/hr (5130 GJ/h) at Maximum Continuous Rating (MCR). Plant capacity factor is 70 percent based on average plant operation 80 percent of the time at 87.5 percent load.

The plant is assumed to be located near Kenosha, Wisconsin, at an elevation of 600 feet (180m) above sea level. Atmospheric pressure used for flue gas composition and volume determination is 14.4 psia (99kPa). An ambient temperature range of -10 to 95^0F (250 to 380K) was assumed. Structural criteria were those for Seismic Zone 1 as defined by the Uniform Building Code. Plant design life was assumed to be 30 years.

The plant is equipped with a separate particulate removal device (electrostatic precipitator or fabric filter) prior to the FGD System. The particulate collection device is assumed to be designed to meet applicable Federal New Source Performance Standards of 0.03 lb/10^6 Btu (0.01kg/GJ). The cost of the particulate collection device is not included in the FGD System estimate.

3.A.2. COAL AND FLUE GAS

The coal used as a basis for the study is a deep-mined Illinois high sulfur bituminous coal. The analysis of this coal is presented in Table 3-1. The coal selected is consistent with one used in an earlier EPRI report, "Coal-Fired Power Plant Capital Cost Estimates", EPRI Report No. AF-342 (January 1977).

Boiler performance parameters used for the calculation of flue gas flow and composition are tabulated in Table 3-2.

Combustion calculations performed with the coal analyses from Table 3-1 and the combustion parameters from Table 3-2 resulted in the flue gas composition and flow rate in Table 3-3. The values in Table 3-3 represent plant operation at maximum load (105%, VWO). Some losses in boiler efficiency and variations to coal-firing rate and excess air occur at reduced load. The variations are small, however, and for use in this study, raw material and utility consumptions are based on full load flue gas conditions proportioned to 100 percent load. Annual totals are determined by applying the capacity factor (previously defined as 70 percent).

TABLE 3-1

COAL ANALYSES

Proximate Analysis, %	
Moisture	12.0
Ash	16.0
Fixed Carbon	39.0
Volatile Matter	33.0
Ultimate Analysis, %	
Moisture	12.0
Carbon	57.5
Hydrogen	3.7
Nitrogen	0.9
Chlorine	0.1
Sulfur	4.0
Ash	16.0
Oxygen	5.8
Btu/lb (KJ/kg)	10,100 (23,500)
Sulfur Content	3.96 lb S/10^6 Btu (1.70kg S/GJ)

TABLE 3-2

BOILER PERFORMANCE PARAMETERS

Excess Air	
Furnace Outlet	22%
Economizer Outlet	24%
Air Heater Outlet	39%
Particulate Removal Device Outlet	40%
FGD System Battery Limit	40%
Ambient Air Humidity	0.013 lb H_2O/lb Dry Air (0.013 kg H_2O/kg)
FGD System Inlet Flue Gas Temperature	283°F (413 K)
Total Coal Sulfur Converted to SO_2 & SO_3	100%
Total SO_3 as % of SO_2	1%
Total Coal Chlorine Converted to HCl	100%
Boiler Heat Input at Maximum Load	5105 x 10^6 Btu/hr (5386 GJ/h)
Boiler Efficiency	88%
Net Plant Heat Rate (with Conventional Limestone FGD System)	9724 Btu/kWh (2850 KJ/MJ)

TABLE 3-3

FLUE GAS CHARACTERISTICS

	%-Volume (Wet)	10^3 lb-mole/hr	10^3 lb/hr
O_2	5.6	11.4	365
CO_2	11.9	24.3	1068
SO_2	0.3	0.6	40
SO_3	0.003	0.006	0.51
HCl	0.007	0.014	0.52
H_2O	8.1	16.6	300
N_2	74.1	151.8	4251
TOTAL	100.0	204.8	6025
Molecular Weight		29.42	
Moisture Content lb/lb dry gas		0.052	
Flue Gas Flow Rate @ 283°F & 29.28 in. Hg (413 K & 99kPa)		1,300,000 scfm wet (610 m^3/s) 1,900,000 acfm (900 m^3/s)	
Fly ash (@.03 lb/10^6 Btu) (0.01 kg/GJ)		153 lb/hr (69.4 kg/h)	

3.A.3. SULFUR DIOXIDE REMOVAL REQUIREMENT

The latest Federal New Source Performance Standards require a 90 percent reduction in potential SO_2 emissions except when uncontrolled emissions to the atmosphere are less than 0.6 lb SO_2 per million Btu (0.3 kg SO_2/GJ) input. The 90 percent removal must be based on a 30-day rolling average. The coal analyses selected for the study requires that 90 percent removal be achieved. No credit has been given to sulfur removal in the ash. Table 3-4 illustrates sulfur dioxide production rates and removal requirements for the required 90 percent removal efficiency.

TABLE 3-4

SULFUR DIOXIDE DATA

Design Condition (105% load, VWO)	
SO_2 Production Rate	40,400 lb/hr (18,300 kg/h)
Required SO_2 Removal Rate	36,400 lb/hr (16,500 kg/h)
Total SO_2 Emission	0.79 lb $SO_2/10^6$ Btu (0.34 kg SO_2/GJ)
Maximum Continuous Rating (100% load)	
SO_2 Production Rate	38,500 lb/hr (17,500 kg/h)
Required SO_2 Removal Rate	34,600 lb/hr (15,700 kg/h)
Total SO_2 Emission	0.79 lb $SO_2/10^6$ Btu (0.34 kg SO_2/GJ)
Annual SO_2 Quantity (70% Capacity Factor)	
SO_2 Production	118,000 tpy (107,000 Mg/yr)
Required SO_2 Removal	106,000 tpy (96,200 Mg/yr)

The flue gas characteristics and sulfur dioxide data in the preceding tables apply to FGD Systems requiring steam only for flue gas reheat. For FGD Systems requiring significant quantities of steam in excess of that required for reheat, a larger boiler is required to maintain 500 MW (net) generating capacity. The larger boiler required for those processes with additional steam requirements results in greater flue gas flow, sulfur production, and sulfur removal requirement. The individual sections reiterate flue gas and sulfur data for each process and reflect increased FGD System sizing due to increased steam consumption and consequent increased boiler size.

3.A.4. GENERAL EQUIPMENT

Certain equipment requirements and criteria are common to all of the FGD processes. Scrubbed gas reheat of 50F^o (28K) over the saturated gas temperature has been included. Reheat is provided using steam-heated ambient air. Reheat steam coils utilize both latent heat and sensible heat by subcooling the condensate to 200^{o}F (370K) prior to return to the boiler feedwater cycle. Each system includes 100 percent flue gas bypass ductwork. Ducts are sized for 3600 fpm (18 m/s) gas velocity for normal operation and 4200 fpm (21 m/s) for reheat air ducts and flue gas bypass ducts.

Combined I.D./Booster Fans have been considered for all systems. The fans provide required induced draft pressure for the boiler and particulate removal device in addition to the FGD System pressure requirement. Fan inlet pressure is assumed to be - 15 inches water gauge (97.6kPa). The total flange-to-flange pressure drop of the FGD System combined with the 15-inch water gauge (3.7kPa) drop for the upstream pressure requirement determines total fan pressure requirement. Fan capital and operating costs are apportioned to the FGD System as the percentage of the total fan pressure attributable to the FGD System.

Equipment redundancy has been incorporated into all FGD Systems to increase reliability. Each FGD System includes a complete spare flue gas treatment module. Depending on sizing constraints, either four-33 percent modules or five-25 percent modules are used. Equipment in other areas is typically spared if its loss would require immediate shutdown of the system. Pumps are 100 percent spared where the loss of a single pump would require shutdown. No sparing is used where a bank of recycle pumps supply several spray levels in an absorber. Items such as tanks, bins, silos, agitators, and heat exchangers are not typically spared.

3.A.5. FGD SYSTEM BATTERY LIMITS

The FGD System battery limits are required to determine scope of necessary equipment and subsequent cost impact. For the purpose of this study, the following battery limits have been used:

a. Flue Gas - From the I.D. Fan discharge flange to the chimney flange. (I.D./Booster Fans costs are included as described previously.)
b. Fly Ash (if required) - Generating plant flyash silo bottom feeder.
c. Raw Water - Generating plant raw water system at the boundary of the FGD System and the generating plant. Supply conditions are 50 psig and 60°F (446kPa and 298K).
d. Steam - Process steam is available from the Generating Plant turbine cycle at Main Steam, Cold Reheat, and Crossover extraction points. (See Appendix E) Minimum available pressures at each extraction point are expected to exceed:

Main Steam	2400 psia (16,500kPa)
Cold Reheat	250 psia (1700kPa)
Crossover	70 psia (500kPa)

e. Electrical Power - Power supply to the FGD System is available from the Generating Plant transformer yard to the FGD Plant boundary as 34.5 KV feeders. All necessary electrical equipment for voltage reduction and distribution is included in the FGD System.

f. Emergency Power - Sufficient emergency power is available from the Generating Plant emergency power system. An emergency power bus at the Generating Plant emergency power grid is available for the FGD System. The FGD System includes switching and distribution for critical service items.

g. Instrument and Service Air - Instrument and Service Air requirements will be supplied within the FGD System.

h. Solid Waste Disposal - Disposal of solid waste includes transportation and ultimate placement and disposal in an environmentally acceptable manner.

3.A.6. RAW MATERIALS

Raw materials and assumed compositions for the FGD processes are listed in Table 3-5.

TABLE 3-5

RAW MATERIAL COMPOSITIONS

Limestone - $CaCO_3$ 92 wt.%
Inerts 8 wt.% or less
Particle Size 3/4 inch (0.19 m)

Fixative Lime - CaO 90 wt.%
Inerts 10 wt.% or less

Soda Ash - Na_2CO_3 99.5%

3.A.7. WASTE DISPOSAL

Waste disposal of "throwaway" limestone FGD sludges is assumed to be landfill impoundment of dewatered, blended filter cake. The Chiyoda Thoroughbred 121 effluent is dewatered using either mechanical dewatering or a "gypsum stack" approach. The dewatered cake is then transported to a landfill without additional blending. Those systems requiring a prescrubber to remove flyash, chlorides, and SO_3, and to presaturate the gas prior to the absorber will have an acidic purge stream which must be treated. For this study, it has been assumed that this smaller stream of prescrubber purge must be neutralized, thickened, dewatered, and blended prior to landfill disposal, similar to that for the "throwaway" sludges. Many factors affect sulfur dioxide removal efficiency in a prescrubber, including bleed rate, makeup water and fly ash metal ion content, flue gas oxygen content, prescrubber type, etc. For this study, a prescrubber SO_2 removal efficiency of 5 percent was assumed.

The following criteria are assumed for determining land requirements, equipment, and mode of operation required for disposal of "throwaway" sludges:

a. The waste is either fully-oxidized or stabilized and fixed with lime and flyash, and is sufficiently dewatered to allow landfill disposal.

b. The landfill disposal area is located 1 mile (1.6 km) from the FGD System.

c. The dry waste is transported to the disposal area in off-highway trucks.

d. The landfill disposal area average placement depth is 30 feet (9.1 m).

Additional criteria and guidance for waste disposal are available from the EPRI report, "FGD Sludge Disposal Manual," EPRI Report No. FP-977 (January 1979).

3.B. ECONOMIC DESIGN CRITERIA

The economic criteria for all evaluated FGD processes were standardized to provide consistent economic comparisons. The cost development and breakdown follow EPRI Economic Premises and are based on mid-1978 dollars with a mid-1979 plant start-up. Each of the processes was evaluated for a newly-constructed 500 MW net power plant located near Kenosha, Wisconsin. Table 3-6 lists the standard components of an EPRI estimate. A copy of the EPRI "Economic Premises for ELECTRIC POWER GENERATING SYSTEMS" is included in Appendix F.

3.B.1. CAPITAL ESTIMATE SUMMARY

The bases and items included for each component of the capital estimate are summarized below.

TABLE 3-6

FGD SYSTEM CAPITAL ESTIMATE COMPONENTS

Capital Investment (year $)	$/KW
Process Capital	A
General Facilities	B
Engineering and Home Office Fees	C
Project Contingency	D
Process Contingency	E
Sales Tax (Included in A)	F
Total Plant Investment	TPI=A+B+C+D+E+F
Royalty Allowance	G
Preproduction Costs	H
Inventory Capital	I
Initial Catalyst and Chemicals	J
AFDC (Allowance for Funds During Construction)	K
Land	X
Total Capital Requirement	TCR=TPI+G+H+I+J+K+X

3.B.1.a. Total Plant Investment (TPI)

A- PROCESS CAPITAL

Process Capital is the total constructed cost of on-site FGD and related facilities including direct and indirect construction costs. Table 3-7 is a listing of those items included in the estimate of process capital.

TABLE 3-7

ITEMS IN PROCESS CAPITAL ESTIMATE

Earthwork
Concrete
Buildings and Structures
Process Equipment
Piping
Electrical
Painting

Instruments and Controls
Insulation
Direct Field Labor
Indirect Field Costs
  Payroll Taxes
  Insurance, Bonds
  Construction Supplies
  Temporary Facilities
  Construction Equipment
  Vendor Fees

The estimate of process capital is based on process development to determine equipment sizing and costs. Remaining components of the process capital estimate are factored to the installed process equipment costs based on data for projects of similar size and scope. Although different process areas would have slightly different factors for items such as concrete, buildings and structures, piping, etc., the process capital costs for each area are based on a single factor value to adjust process equipment cost to total process capital. Direct field labor and indirect costs associated with field labor account for approximately one-third of the process capital estimate.

The process capital estimate is broken down on an area basis for each process. The processing areas chosen are not all applicable for each process, but some are common to all processes. The areas are listed in Table 3-8.

TABLE 3-8

COST AREAS FOR PROCESS CAPITAL BREAKDOWN

Area	Description
01	Raw Material Receiving and Storage
02	Feed Preparation and Storage
03	Flue Gas Scrubbing
04	Flue Gas Reheat
05	Purge Treatment
06	SO_2 Regeneration
07	SO_2 Processing
08	Waste Separation
09	Waste Disposal
10	Byproduct Storage
11	Flue Gas Handling
12	Waste Transfer and Placement

The equipment included in each cost area is based on the following guidelines. More detailed descriptions are included for each individual process:

- 01 Raw Material Receiving and Storage
  Includes equipment required for unloading, transfer to storage, long-term storage and transfer to storage facilities prior to process utilization. Typical interfaces would be rail car or truck hopper and a day bin.
- 02 Feed Preparation and Storage
  Includes day storage of raw material, feeders, preparation equipment and storage and transfer equipment for prepared raw material.
- 03 Flue Gas Scrubbing
  Includes scrubbers, absorbers and all tanks, pumps, agitators, and any other ancillary equipment associated with the scrubbers and/or absorbers.
- 04 Flue Gas Reheat
  Includes reheat fan, finned tube reheater coils, reheat ductwork, and reheat mix chamber.
- 05 Purge Treatment
  For processes requiring treatment of a specific purge stream and preparation of the purge for disposal, all equipment associated with handling and treatment of the purge is included.
- 06 SO_2 Regeneration
  Includes all equipment required to regenerate absorber blowdown for return to the absorbers and processing of SO_2 stream for interface with SO_2 Processing area. This area is applicable to regenerable processes which produce SO_2.
- 07 SO_2 Processing
  Includes all equipment required to produce ultimate sulfur byproduct utilizing SO_2 stream from SO_2 Regeneration area. This can include the production of sulfur dioxide, sulfuric acid, or elemental sulfur.
- 08 Waste Separation
  For throwaway processes, includes all equipment to thicken and dewater absorber blowdown stream. Also includes storage and return equipment for supernatant liquor but does not include equipment to further prepare the sludge for disposal.

- 09 Waste Disposal
  Includes equipment required for further treatment the of dewatered product from waste separation to make it suitable for disposal.
- 10 Byproduct Storage
  Includes equipment required for storage and delivery to transportation system of byproduct produced in SO_2 Processing area.
- 11 Flue Gas Handling
  Includes I.D./Booster Fan (prorated based on P scrubber system divided by P total fan) and all ductwork from the fan to the Flue Gas Treatment area and from the Flue Gas Treatment area to the chimney, excluding the reheat associated ductwork in the Flue Gas Reheat area.
- 12 Waste Transfer and Placement
  For processes with a "throwaway" solid waste, includes transportation to and final disposal of the waste product.

B- GENERAL FACILITIES OR OFF-SITE CAPITAL

The capital cost of the general facilities includes roads, office buildings, shops, laboratories, etc. EPRI guidelines for this cost item are 5 to 20 percent share of the Process Capital cost. A midpoint value of 12.5 percent of the Process Capital was chosen by Stearns-Roger for this study.

C- ENGINEERING AND HOME OFFICE FEES

An estimate of engineering and home office overhead and fees is included for costs representative of this type of plant. EPRI guidelines for this cost item are 10 to 15 percent of the Process Capital for this cost. A midpoint value of 12.5 percent was chosen by Stearns-Roger for this study. (Of this amount, approximately 10 percent is vendor engineering).

D- PROJECT CONTINGENCY

The project contingency is intended to cover additional equipment or other costs resulting from a more detailed design. The following project contingencies, as a percentage of the process capital, were chosen by Stearns-Roger for use in this study:

Conventional Limestone	5%
EPRI/TVA Cocurrent Limestone	10%
Chiyoda Thoroughbred 121 Limestone	10%
Wellman-Lord	5%

E- PROCESS CONTINGENCY

A process contingency is applied to new technology in an effort to quantify the uncertainty in the design and cost of the commercial-scale equipment. The contingency is related to the level of process development. EPRI has established guidelines which are presented in their economic premises. The process contingencies are expressed as percentages of the process capital and, based on EPRI guidelines, the following process contingencies were chosen by Stearns-Roger for use in this study:

Conventional Limestone	5%
EPRI/TVA Cocurrent Limestone	10%
Chiyoda Thoroughbred 121 Limestone	10%
Wellman-Lord	5%

F- SALES TAX

Sales Tax is included in the estimate for process capital.

3.B.1.b. Total Capital Requirement (TCR)

G- ROYALTY ALLOWANCE

The royalty allowance as established by EPRI is 0.5 percent of the process capital.

H- PREPRODUCTION COSTS

Preproduction Costs are intended to cover operator training, equipment checkout, major changes in plant equipment, extra maintenance, and inefficient use of materials during plant startup. Preproduction Costs are estimated as follows:

- One month fixed operating costs (fixed operating costs are operating and maintenance labor, administrative and support labor, and maintenance materials).
- One month of variable operating costs at full capacity (these variable operating costs include chemicals, water, and other consumables, and waste disposal charges). Full capacity estimates of the variable operating costs will assume operation at 87.5 percent load.
- 5 percent of the TPI (this charge covers expected changes and modifications to equipment required to bring the FGD System up to full capacity).

I- INVENTORY CAPITAL

The inventory capital includes the value of raw materials and other consumables on a capitalized basis. The inventory capital is estimated as follows:

One month supply of raw materials based on full capacity operation.

One month supply of other consumables (excluding water) based on full capacity operation.

Full capacity operation for inventory capital will be assumed as 100 percent load.

J- INITIAL CATALYST AND CHEMICALS

The initial cost of any catalyst or chemicals that are contained in the process equipment (other than that in storage, which is included in inventory capital) is included.

K- AFDC (ALLOWANCE FOR FUNDS DURING CONSTRUCTION)

The schedule duration for engineering, procurement, and construction of the FGD System is assumed to be 3 years.

A charge for AFDC is determined based on the time period from the center of gravity (cg) of expenditures until the plant is in commercial operation. For an interest rate of 8 percent per year, the AFDC is calculated from the TPI as follows:

$$\text{AFDC} = ((1.08)^{cg} - 1) \times (\text{TPI})$$

The center of gravity for FGD System expenditures is assumed to be 1 year. The calculation of AFDC for this study is:

$$\text{AFDC} = (0.08) \times (\text{TPI})$$

The AFDC charge is expressed in the same year dollars (mid-1978) as the total plant investment. Cost escalation is not involved.

X- LAND

Land Costs are based on a unit cost of $5000 per acre ($1.24/m^2). FGD System land requirements include the plant site area and disposal area.

3.B.2. OPERATING COST SUMMARY

Operating costs for the FGD Systems are separated into fixed and variable operating costs. Fixed operating costs include operating and maintenance labor, maintenance materials, and administrative and support labor. Factors for maintenance labor, maintenance material, and administrative and support labor costs are based on EPRI Economic Premises. Variable operating costs includes consumables such as fuel, water, chemicals, and waste disposal. Table 3-9 summarizes the criteria used for these operating costs.

3.B.3. LEVELIZED BUSBAR COST

The capital and operating costs determined for each FGD System are converted to a levelized cost using a fixed charge rate of 18 percent per year for capital costs and appropriate levelization factors (shown in Table 3-9) for operating costs. The total levelized cost of each FGD System is presented as mills per kWh. A further description of the levelization factor technique can be found in Appendix F.

TABLE 3-9

OPERATING COST CRITERIA

	Unit	Rate
Fixed Operating Costs		
Operating labor	Man-hours	$12.50 (mid-1978)
Maintenance Labor	$/yr	3.2% of Process Capital
Maintenance Material	$/yr	4.8% of Process Capital
Administrative & Support Labor	$/yr	30% of Operating and Maintenance Labor

	Unit	Mid-1978 Cost/Unit	Levelization Factor	30-Yr. Levelized Cost/Unit
Variable Operating Costs				
Raw Water	1000 gal.	$0.40	1.886	$0.75
Cooling Water	1000 gal.	$0.10	1.886	$0.19
Power	KwH	30 mills	1.909	57 mills
Limestone	ton	$10	1.886	$19
Lime	ton	$34	1.886	$64
Soda Ash	ton	$66	1.886	$125
Methane (Synthetic Natural Gas, Replacement Cost)	10^3 cf	$4	1.932	$7.70
Disposal Charges (or Credit)				
Dry Solids (Fly Ash)	ton	$4	1.886	$7.50
Condensate	1000 lb.	$0.45	1.886	$0.85
Steam, (minimum available pressures)				
70 psia	1000 lb.	---	---	$3.49
70 to 250 psia	1000 lb.	---	---	$4.41
Byproduct Credits				
Sulfur	Long ton	$50	1.886	$94
Sulfuric Acid (100%)	ton	$40	1.886	$75

Note: 1000 gal = 3.785 m^3, ton (short) = 0.9072 ton (SI),
1000ft^3 = 28.32 m^3, 1000 lb = 453.6 kg

4. CONVENTIONAL LIMESTONE FGD SYSTEM

4.A. SYSTEM DESCRIPTION

4.A.1. PROCESS DESCRIPTION

Conventional Limestone Flue Gas Desulfurization is the most prevalent sulfur dioxide (SO_2) removal process in use and on order today for full scale installations. Limestone ($CaCO_3$) is added as the absorbent, with SO_2 removal typically taking place in a spray tower or packed tower. The $CaCO_3$ and SO_2 combine to form calcium sulfite ($CaSO_3$). Some of the $CaSO_3$ is oxidized to calcium sulfate ($CaSO_4$). The simplified overall reaction of SO_2 and $CaCO_3$ can be stated as:

$$CaCO_3(s) + SO_2(g) + 1/2H_2O \longrightarrow CaSO_3\ 1/2H_2O(s) + CO_2(g)$$
$$CaCO_3(s) + SO_2(g) + 2H_2O + 1/2O_2 \longrightarrow CaSO_4\ 2H_2O(s) + CO_2(g)$$

In practice, anywhere from 20 to 80 percent of the SO_2 will form calcium sulfite ($CaSO_3$) rather than calcium sulfate ($CaSO_4$). Calcium sulfate or gypsum, as the dihydrate ($CaSO_4 \cdot 2H_2O$) is called, dewaters easier, yields a smaller volume of sludge for disposal, and properly controlled, has a lower scaling tendency than $CaSO_3$. Calcium sulfate formation (i.e. oxidation) increases with decreasing concentration of SO_2 in the flue gas. High sulfur coals (3 to 4 percent) typically yield a product of 80 to 85 percent sulfite.

An integral component of the absorption process is a reaction tank with adequate residence time for limestone dissolution and sulfite and sulfate crystal formation. A bleed stream from the reaction tanks is taken to thickening and dewatering steps to reduce the volume of sludge for disposal. Sulfites settle more slowly and less densely than sulfates. A system high in sulfites will require a larger thickener and filtration system to handle the greater volume of sludge.

The final waste solid must be disposed of in an environmentally acceptable manner. Several sludge disposal alternatives are available including ponding or landfill impoundment with or without fixation. Currently, there is a moderate trend toward dry landfill disposal as opposed to ponding. This study assumes landfill impoundment of a fixed sludge.

This study has assumed a conventional limestone system stoichiometry of 1.15. Although experience indicates removal efficiency greater than 90 percent is achievable with this stoichiometric ratio, a process contingency amounting to 5 percent has been included to account for the rigors of the 30-day rolling average and for the use of an open, spray tower for SO_2 scrubbing. Specific design criteria for the Conventional Limestone System are presented in Table 4-1. A process flow diagram and major stream material balance are presented in Figures 4-1 and 4-2.

TABLE 4-1

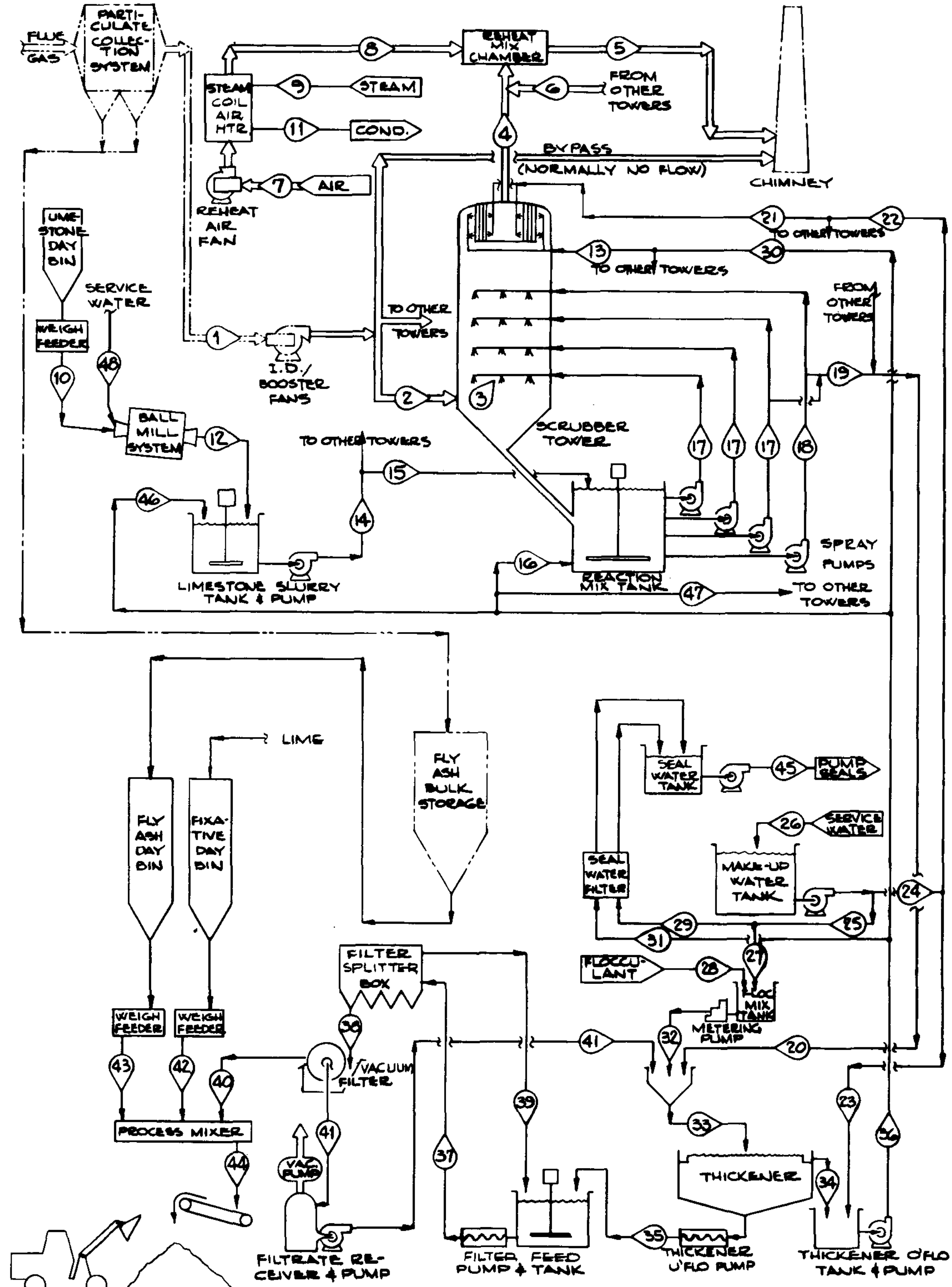
CONVENTIONAL LIMESTONE SYSTEM
PROCESS DESIGN CRITERIA

Flue Gas Flow (Max. Load)	1,900,000 acfm (900 m^3/s)
Sulfur Dioxide Removal	90% (based on a 30-day rolling average)
Scrubber Modules	4 @ 33-1/3% capacity each (3 operating, 1 spare)
Scrubber Type	Spray Tower
Liquid-to-Gas Ratio (L/G)	80 gpm/1000 acfm (10.7 l/m^3)
Absorber Superficial Velocity	10 f/s (3m/s)
Scrubber Slurry Solids Concentration	10%
Total System Pressure Drop (Flange-to-flange)	10 in. H_2O (2.5kPa)
$CaCO_3$ Stoichiometric Ratio	1.15 lb-mole $CaCO_3$/lb-mole SO_2
Thickener Underflow Solids Concentration	25 wt. %
Dewatered Sludge Solids Concentration	45 wt. %

4.A.2. EQUIPMENT DESCRIPTION

Equipment required for the Conventional Limestone System is divided into several major cost and process areas as follows:

Area 01 - Raw Material Receiving and Storage
Area 02 - Feed Preparation and Storage
Area 03 - Flue Gas Scrubbing
Area 04 - Flue Gas Reheat



NOTE: PHANTOMED EQUIPMENT NOT WITHIN BATTERY LIMITS OF FGD SYSTEM.

FIGURE 4-1

CONVENTIONAL LIMESTONE FGD SYSTEM PROCESS FLOW DIAGRAM

STREAM NO.	1	2	3	4	5	6	7	8
TEMP. ^{o}F.	283	283	127	127	177	127	60	382
PRESS. IN. H_2O	-15	+10	+9	+4	+1	+4	0	+10
10^3 ACFM	1,974	611	518	524	2,153	1,049	343	529
CO_2 (10^3 #/HR)	1,068	356	356	364	1,093	729	-	-
H_2O "	300	100	179	179	537	358	-	-
N_2 "	4,251	1,417	1,417	1,417	5,469	2,834	1,218	1,218
SO_2 "	40	13	13	1.3	4	2.7	-	-
O_2 "	365	122	122	122	690	244	324	324
TOTAL "	6,024	2,008	2,087	2,083	7,793	4,168	1,542	1,542

* intermittent

STREAM NO.	9	10	11	12	13*	14	15	16	17	18
TEMP. ^{o}F.	432	60	200	90	70	90	90	70	126	126
GPM			240	150	90	630	210	470	10,490	11,060
SLUDGE 10^3 #/HR	-	-	-	-	-	-	-	-	-	-
$CaCO_3$ "	-	65	-	65	-	65	22	-	-	-
INERTS "	-	7	-	7	-	7	2	-	-	-
H_2O (STEAM) "	(121)	-	121	48	44	288	96	234	-	-
TOTAL "	121	72	121	120	44	360	120	234	5,563	5,865
% SOLIDS	-	100	0	60	0	20	20	0	10	10

STREAM NO.	19	20	21*	22	23	24	25	26	27	28
TEMP. ^{o}F.	126	125	60	60	60	60	60	60	60	60
GPM	570	1,710	90	15	490	505	95	600	10	-
SLUDGE 10^3 #/HR	30	91	-	-	-	-	-	-	-	-
$CaCO_3$ "	-	-	-	-	-	-	-	-	-	-
INERTS "	-	-	-	-	-	-	-	-	-	.0214
H_2O "	272	816	44	7	246	253	47	300	4	-
TOTAL "	302	907	44	7	246	253	47	300	4	.0214
% SOLIDS	10	10	0	0	0	0	0	0	0	100

STREAM NO.	29	30	31	32	33	34	35	36	37	38
TEMP. ^{o}F.	60	70	70	70	110	70	70	70	70	70
GPM	85	15	30	10	2,145	1,420	600	1,910	900	600
SLUDGE 10^3 #/HR	-	-	-	-	91	-	91	-	136	91
REAGENT "	-	-	-	-	-	-	-	-	-	-
INERTS "	-	-	-	.021	-	-	-	-	-	-
H_2O "	43	7	14	4	982	710	272	956	408	272
TOTAL "	43	7	14	4	1,073	710	363	956	544	363
% SOLIDS	0	0	0	0	9	0	25	0	25	25

STREAM NO.	39	40	41	42	43	44	45	46	47	48
TEMP. ^{o}F.	70	70	60	60	80	80	60	70	70	60
GPM	300	-	325	-	-	-	115	480	935	95
SLUDGE 10^3 #/HR	45	91	-	-	-	91	-	-	-	-
REAGENT "	-	-	-	5	-	5	-	-	-	-
INERTS "	-	-	-	-	73	73	-	-	-	-
H_2O "	136	111	161	-	-	111	58	240	467	48
TOTAL "	181	202	161	5	73	280	58	240	467	48
% SOLIDS	25	45	0	100	100	60	0	0	0	0

(To convert from ^{o}F to K, multiply by 5/9 and add 255.37; to convert from IN. H_2O to kPa, multiply by .2488 and add 101.325; to convert 10^3 ACFM to m^3/s, multiply by .4720; to convert 10^3 #/HR to kg/s, multiply by .1260; to convert GPM to m^3/S, multiply by 6.31×10^{-5})

FIGURE 4-2

CONVENTIONAL LIMESTONE SYSTEM PROCESS FLOW BALANCE

Area 08 - Waste Separation
Area 09 - Waste Disposal
Area 11 - Flue Gas Handling
Area 12 - Waste Transfer and Placement

An equipment list including descriptive information and cost data is presented in Appendix A.

4.A.2.a. Area 01 - Raw Material Receiving and Storage

Limestone is received in bottom dump railcars. A railcar unloading facility is provided with the capacity to unload two railcars simultaneously. A belt conveyor system and stacker transfers the limestone to a 45-day bulk storage pile. The reclaim system includes a front-end loader, with a load hopper and conveyor system to transfer limestone to the process. Fixative lime is received in pneumatic railcar or truck and is stored in a silo prior to pneumatic transfer to the process.

4.A.2.b. Area 02 - Feed Preparation and Storage

A limestone day bin and feeders supply limestone to one of two-100 percent capacity ball mills. The ball mills grind the limestone to 90 percent less than 200 mesh (74 um) and utilize a wet recycle classification loop to ensure proper size distribution to the process. The 60 percent solids slurry from the ball mills is diluted to 20 percent and stored in limestone slurry tanks prior to transfer to the absorbers.

4.A.2.c. Area 03 - Flue Gas Scrubbing

The absorber towers (three operating and one spare) are vertical spray towers with counter current contact of flue gas and calcium carbonate/scrubber slurry. Four levels of sprays are utilized. Scrubbed flue gas passes through vertical chevron mist eliminators prior to leaving the absorbers. Scrubber slurry from each absorber drains to individual agitated reaction tanks which provide adequate retention time for reaction completion and crystal growth. Makeup calcium carbonate slurry is added to the reaction tanks.

Rubber-lined slurry pumps circulate scrubber slurry to abrasion resistant spray nozzles at each spray level. Each spray level has its own recirculation pump, but the pumps are not spared. Bleed from the absorber is pumped from the reaction tanks to the Waste Separation area.

Necessary ancillary equipment items included in this area are the makeup water tank and pumps, seal water tank, filter, and pumps, and the instrument and service air compressor system.

4.A.2.d. Area 04 - Flue Gas Reheat

The scrubbed gas from the absorbers is reheated $50F^{o}$ (28K) in a reheat mix chamber. Ambient air is drawn via a reheat fan and is heated by finned tube steam coils which utilize both condensation and subcooling sections. The heated air is blown into the reheat mix chamber where it mixes with the scrubbed gas.

4.A.2.e. Area 08 - Waste Separation

The bleed from the scrubbers is pumped to a thickener. Flocculant is added to the thickener feed to aid settling of the scrubber slurry. The supernatant is returned to the scrubbing system via an overflow tank and pumps. The thickener underflow is pumped to a filter feed tank prior to mechanical dewatering by rotary drum vacuum filters. The filtrate is pumped back to the system while the filter cake is conveyed to the Waste Disposal area for further preparation prior to disposal. Area sumps, agitators, and pumps are also included in this area.

4.A.2.f. Area 09 - Waste Disposal

The filter cake from the vacuum filters is blended with lime and fly ash in a process mixer to form a solid waste. Fly ash is pneumatically conveyed from the plant fly ash silos to a day bin near the process mixer. The fixative reagent (lime) is pneumatically conveyed from its storage silo to day bins near the process mixer. The lime, fly ash, and scrubber waste are blended in the process mixer and conveyed by belt conveyor to a truck loading spot. A stacker is provided to pile solid waste, to allow surge capacity for periods when trucks are not operating.

4.A.2.g. Area 11 - Flue Gas Handling

Flue gas from the generating plant particulate removal system passes through one of two combined I.D./Booster Fans. The fans provide sufficient pressure for both the furnace draft and particulate removal system, as well as the flow resistance of the absorber towers and duct system to the chimney. The ductwork includes common inlet and outlet manifolds and total FGD system bypass if required. Dampers are provided for isolation of individual absorbers for maintenance or inspection.

4.A.2.h. Area 12 - Waste Transfer and Placement

The waste solids from the process mixer are loaded onto off-highway trucks by either a shuttle loader (belt conveyor) or a front-end loader. The trucks transport the waste solids to a landfill disposal area assumed to be 1 mile (1.6km) from the plant site. A bulldozer at the disposal area spreads and compacts the waste to an average depth of 30 feet (9.1 m). The loading, transfer, and landfill area equipment operates one shift only, 5 days per week.

4.A.3. GENERAL ARRANGEMENT

Figure 4-3 shows a basic view of the general arrangement of the Conventional Limestone System. The arrangement allows for the intire FGD System to be bypassed if required, while minimizing bypass ductwork. The ductwork also allows for turning vanes at each absorber inlet to minimize flue gas maldistribution. The arrangement is not necessarily optimized but the concept is consistent with the other processes evaluated.

4.A.4. RAW MATERIAL AND UTILITY CONSUMPTION

Table 4-2 lists raw material and utility consumptions by the Conventional Limestone System at maximum load.

4.A.5. WASTE DISPOSAL

The waste sludge from the vacuum filters requires further stabilization prior to ultimate disposal. Fixative lime and flyash from the particulate collection device are blended with the sludge in a pug mill-type process mixer. The fixed sludge is more stable than the untreated sludge and is adequate for landfill impoundment. The components and maximum load quantity of blended sludge for disposal are as follows:

Component	tph	wt. %
Lime	2.5	2
Flyash	36.5	26
Waste Sludge	45.5	32
Water	55.5	40
Total Waste to Disposal	140	100

Note: tph (English) = .9072 t/h (SI)

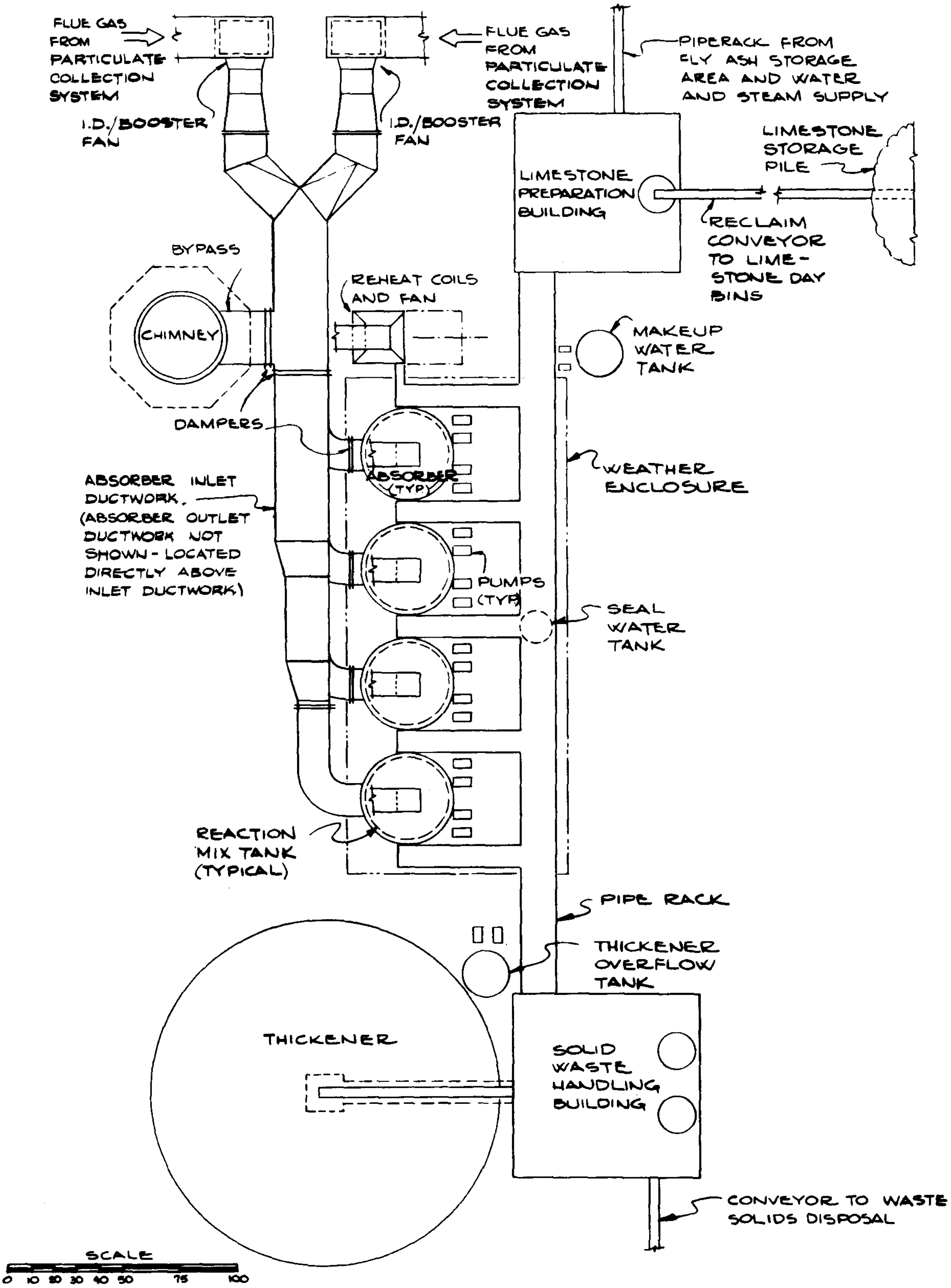


FIGURE 4-3

PLOT PLAN OF CONVENTIONAL LIMESTONE FGD SYSTEM

Based on a density of 95 lb/ft^3 (1500 kg/m^3), the following volumes are estimated for daily, yearly and plant life sludge production:

Daily Maximum - 2630 yd^3 (2010 m^3)
Annual - 395 acre-ft (487,000 m^3)
Plant Life (30-yr.) - 11,850 acre-ft (14,620,000 m^3)

TABLE 4-2

CONVENTIONAL LIMESTONE SYSTEM
RAW MATERIAL AND UTILITY CONSUMPTION
(MAXIMUM LOAD - 105%)

Item	Quantity
Limestone @ 1.15 Stoichiometric Ratio	36 t/h (9.07 kg/s)
Fixative Lime @ 3% of Dry Sludge and Fly Ash	2.5 tph (0.64 kg/s)
Raw Water	700 gpm (0.04 m^3/s)
Steam	121,000 lb/hr(15.25 kg/s)
Power (Operating Horsepower)*	
Area 01 - Raw Material Receiving and Storage	180 hp (130 kW)
Area 02 - Feed Preparation and Storage	1150 hp (860 kW)
Area 03 - Flue Gas Scrubbing	5680 hp (4240 kW)
Area 04 - Flue Gas Reheat	800 hp (600 kW)
Area 08 - Waste Separation	700 hp (520 kW)
Area 09 - Waste Disposal	330 hp (250 kW)
Area 11 - Flue Gas Handling	4000 hp (3000 kW)
Fly Ash (Entire quantity available from plant)	36.5 tph (9.20 kg/s)

*Total power consumption equal to approximately 1.9 percent of net generating capacity.

4.B. TECHNICAL EVALUATION

Conventional limestone processes are the most common FGD systems currently in operation and under construction. Several different vendors offer limestone systems. The process can be applied to high or low sulfur coal applications. A major advantage for limestone scrubbing is the use of an abundant raw material as the absorbent. Limestone scrubbing (and lime scrubbing, which is very similar) is considered a throwaway process. Future requirements concerning the disposal of the waste sludge from limestone scrubbing may adversely affect its economic advantage relative to recovery systems.

Limestone systems are not without their problems. Scaling and plugging have occurred in nearly every limestone system to date. Better understanding of the mechanisms of scale formation has led to design and operating improvements resulting in systems of acceptable reliability. Stoichiometric ratio's have historically been quite high, resulting in considerable absorbent being thrown away with the waste sludge. The stoichiometric ratio is the ratio of moles of $CaCO_3$ required to remove 1 mole of SO_2. Ideally, the stoichiometric ratio should be 1.0. The higher the stoichiometric ratio, the higher the operating cost, because more usable limestone is lost. Additionally, the nature of the waste sludge from the process requires that additives be blended to increase its stability. The result is an even greater land requirement for the disposal area. Limestone systems typically have a high energy demand caused by the large liquid-to-gas ratios necessary to achieve the required SO_2 removal efficiencies. Continued process and equipment developments attempt to improve SO_2 removal and stoichiometric ratio, decrease scaling and plugging problems, improve disposal properties of the waste sludge, and decrease energy requirements.

Several promising approaches to improved limestone system performance and/or decreased costs include:

4.B.1. The addition of soluble additives to the slurry to increase limestone reactivity, utilization and SO_2 removal efficiency.

4.B.2. Forced oxidation of the slurry to improve waste sludge disposal characteristics.

4.B.3. Improved absorber design to provide better gas-liquid contact, lower pressure drop, decreased scaling tendency, and lower material cost.

4.B.4. Improved stoichiometry through separation processes designed to recover unused limestone prior to disposal.

Development efforts in the limestone scrubbing area point toward a continued major role in future power plant FGD use.

4.C. ECONOMIC EVALUATION

The economic evaluation of the Conventional Limestone System is presented in the following tables:

Table 4-3 Total Capital Requirement
Table 4-4 Operating Costs
Table 4-5 Levelized Busbar Cost

Cost sensitivity to coal percent-sulfur and plant size was determined by adjusting capital and operating costs and reevaluating the levelized busbar cost. Cost sensitivity to coal percent-sulfur is illustrated in Figure 4-4, and to plant size in Figure 4-5. These curves are based on two additional estimates for the system for each parameter. Costs were adjusted to values for 0.5 percent and 2.0 percent sulfur coal, and for 250MW and 1000MW plant sizes. These values, combined with the base case value, were used to plot the cost sensitivity curves.

TABLE 4-3

CONVENTIONAL LIMESTONE SYSTEM
TOTAL CAPITAL REQUIREMENT
500 MW NEW PLANT
MID-1978 COSTS, MID-1979 START-UP
ILLINOIS COAL - 4% SULFUR

Process Capital

Area	Description	$/kW
01	Raw Material Receiving and Storage	7.4
02	Feed Preparation and Storage	10.9
03	Flue Gas Scrubbing	42.0
04	Flue Gas Reheat	7.3
08	Waste Separation	6.8
09	Waste Disposal	3.9
11	Flue Gas Handling	32.1
12	Waste Transfer and Placement	6.3
	Total Process Capital	116.7
General Facilities		14.6
Engineering and Home Office Fees		14.6
Project Contingency		5.8
Process Contingency		5.8
Sales Tax (Included in Process Capital)		---
	Total Plant Investment (TPI)	157.6
Royalty Allowance		0.6
Preproduction Costs		10.0
Inventory Capital		0.6
Initial Catalyst and Chemicals		0
Allowance for Funds During Construction (AFDC)		12.6
Land		4.6
	Total Capital Requirement (TCR)	186.0

TABLE 4-4

CONVENTIONAL LIMESTONE SYSTEM
OPERATING COSTS
500 MW NEW PLANT
MID-1978 COSTS, MID-1979 START-UP
ILLINOIS COAL - 4% SULFUR

Fixed Operating Costs	1st Year ($/yr)	1st Year $/kw-Yr	Levelized $/kw-Yr
Operating Labor			
FGD System	$ 896,000	1.79	3.38
Sludge Disposal	$ 156,000	0.31	0.58
Maintenance Labor	$1,870,000	3.74	7.05
Maintenance Material	$2,800,000	5.60	10.56
Admin. & Support Labor	$ 884,000	1.77	3.34
Disposal Equipment	$ 140,000	0.28	0.53
Total Fixed Operating Cost	$6,750,000	13.49	25.44

Variable Operating Costs	1st Year ($/yr)	1st Year Mills/kWh	Levelized Mills/kWh
Limestone, 210,000 t/y @ $10/ton	$2,100,000	0.69	1.30
Fixative Lime, 14,600 t/y @ $34/ton	$ 496,000	0.16	0.30
Raw Water, 245,000 X 10^3 gal/yr @ $\$0.40/10^3$ gal	$ 98,000	0.03	0.06
Steam, 700,000 x 10^3 lb/yr (levelized cost) @ $\$3.49/10^3$ lb	----	----	0.80
Power, 68 x 10^6 kWh/yr @ 30 mills/kWh	$2,010,000	0.66	1.26
Fly Ash (credit) 213,000 t/y @ $4/ton	$ (853,000)	(0.28)	(0.53)
Total Variable Operating Cost			3.19

Note: 1.0 t/y = 9.071 X 10^2 kg/y
1.0 gal = 3.785 X 10^{-3} m^3

TABLE 4-5

CONVENTIONAL LIMESTONE SYSTEM
LEVELIZED BUSBAR COST
500 MW NEW PLANT
MID-1978 COSTS, MID-1979 START-UP
ILLINOIS COAL - 4% SULFUR

	Levelized Mills/kWh
Process Capital	3.56
General Facilities	0.43
Engineering and Home Office Fees	0.43
Project Contingency	0.17
Process Contingency	0.17
Total Plant Investment	4.76
Royalty Allowance	0.02
Preproduction Costs	0.29
Inventory Capital	0.02
Allowance for Funds During Construction (AFDC)	0.37
Land	0.04
Total Capital Requirement	5.60
Fixed Operating Cost	4.15
Variable Operating Cost	3.19
Total Levelized Busbar Cost	12.94

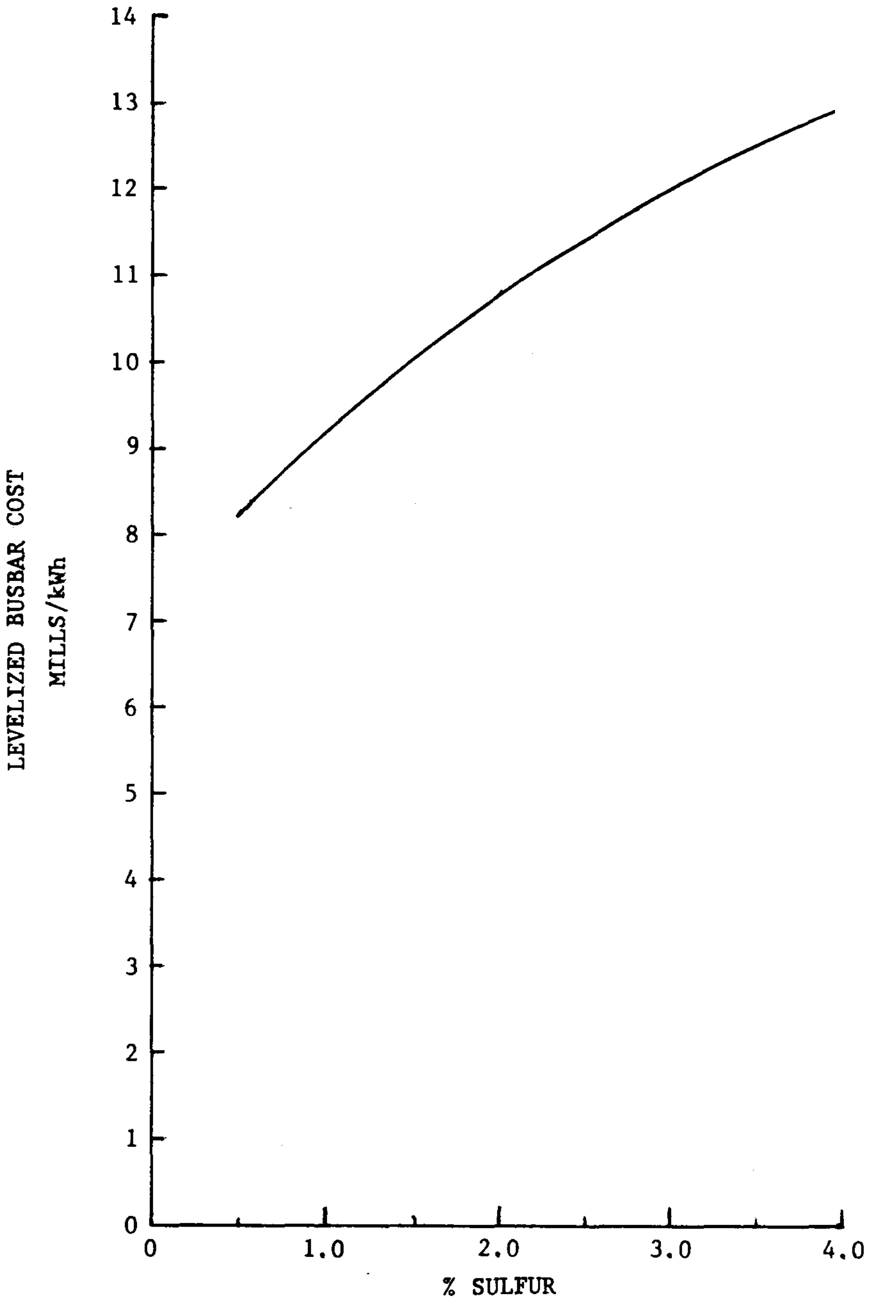


FIGURE 4-4

CONVENTIONAL LIMESTONE SYSTEM
COST VERSUS SULFUR CONTENT OF COAL

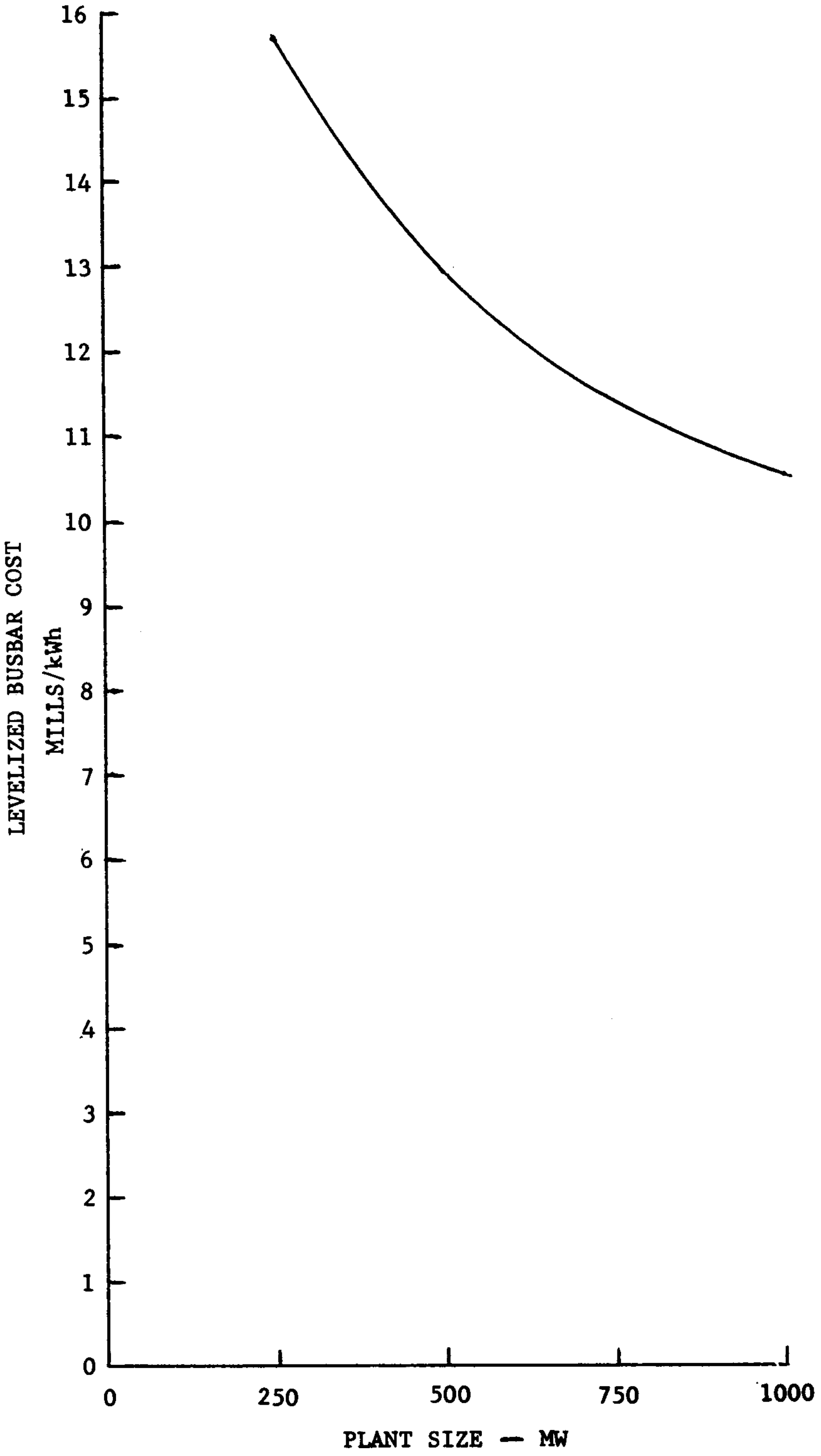


FIGURE 4-5

CONVENTIONAL LIMESTONE SYSTEM
COST VERSUS PLANT SIZE

5. EPRI/TVA COCURRENT FGD SYSTEM

5.A. SYSTEM DESCRIPTION

5.A.1. PROCESS DESCRIPTION

The Electric Power Research Institute/Tennessee Valley Authority (EPRI/TVA) Cocurrent FGD System is a limestone system utilizing a cocurrent rather than a countercurrent absorber. Gas flow is downward rather than upward as in a conventional countercurrent spray tower. Limestone ($CaCO_3$) is added as the absorbent, with SO_2 removal taking place in the cocurrent absorber. The $CaCO_3$ and SO_2 combine to form calcium sulfite ($CaSO_3$). Some of the $CaSO_3$ is oxidized to calcium sulfate ($CaSO_4$). The simplified overall reactions of SO_2 and $CaCO_3$ can be stated as:

$$CaCO_{3(s)} + SO_{2(g)} + H_2O \longrightarrow CaSO_3 \cdot H_2O(s) + CO_{2(g)}$$

$$CaCO_{3(s)} + SO_{2(g)} + 2H_2O_{(l)} + O_{2(g)} \longrightarrow CaSO_4 \cdot 2H_2O_{(s)} + CO_{2(g)}$$

An integral component of the absorption process is a reaction tank with adequate residence time for limestone dissolution and sulfite and sulfate crystal formation. A bleed stream from the reaction tanks is taken to thickening and dewatering steps to reduce the volume of sludge for disposal.

The final waste solid must be disposed of in an environmentally acceptable manner. Several sludge disposal alternatives are available including ponding or landfill impoundment with or without fixation. Currently, there is a moderate trend toward an increase in dry landfill disposal rather than ponding. This study assumes landfill impoundment of a fixed sludge. Lime and fly ash are mixed with the dewatered solids prior to trucking to a landfill.

The EPRI/TVA Cocurrent FGD System is basically a modification of a conventional limestone system. The modification involves the type of contactor used to absorb the sulfur dioxide. Most conventional limestone systems utilize a countercurrent spray or packed tower as the SO_2 contactor. This type of contactor has the flue gas entering the bottom of the tower and flowing upward, contacting the scrubbing liquid traveling downward. Superficial gas velocities are typically limited to a maximum of about 10 fps (3 m/s) to minimize scrubbing liquid carryover and gas-side pressure drop. Liquid-to-gas ratios of 60 to 100 gal/1000 ft^3 (8 to 13 l/m^3) of saturated flue gas are required, and spray nozzles or tower internals are often required to improve mass transfer and absorption efficiency. The cocurrent scrubber concept (flue gas and scrubbing liquid enter the scrubber at the top and flow downward through the absorber) is designed to provide required SO_2 removal at higher gas velocities and equivalent pressure drops compared to a countercurrent tower. The higher gas velocities in a cocurrent scrubber allow for a smaller, and consequently less expensive, absorber vessel.

Specific design criteria for the EPRI/TVA Cocurrent System are presented in Table 5-1. A process flow diagram and major stream material balance are presented in Figures 5-1 and 5-2.

TABLE 5-1

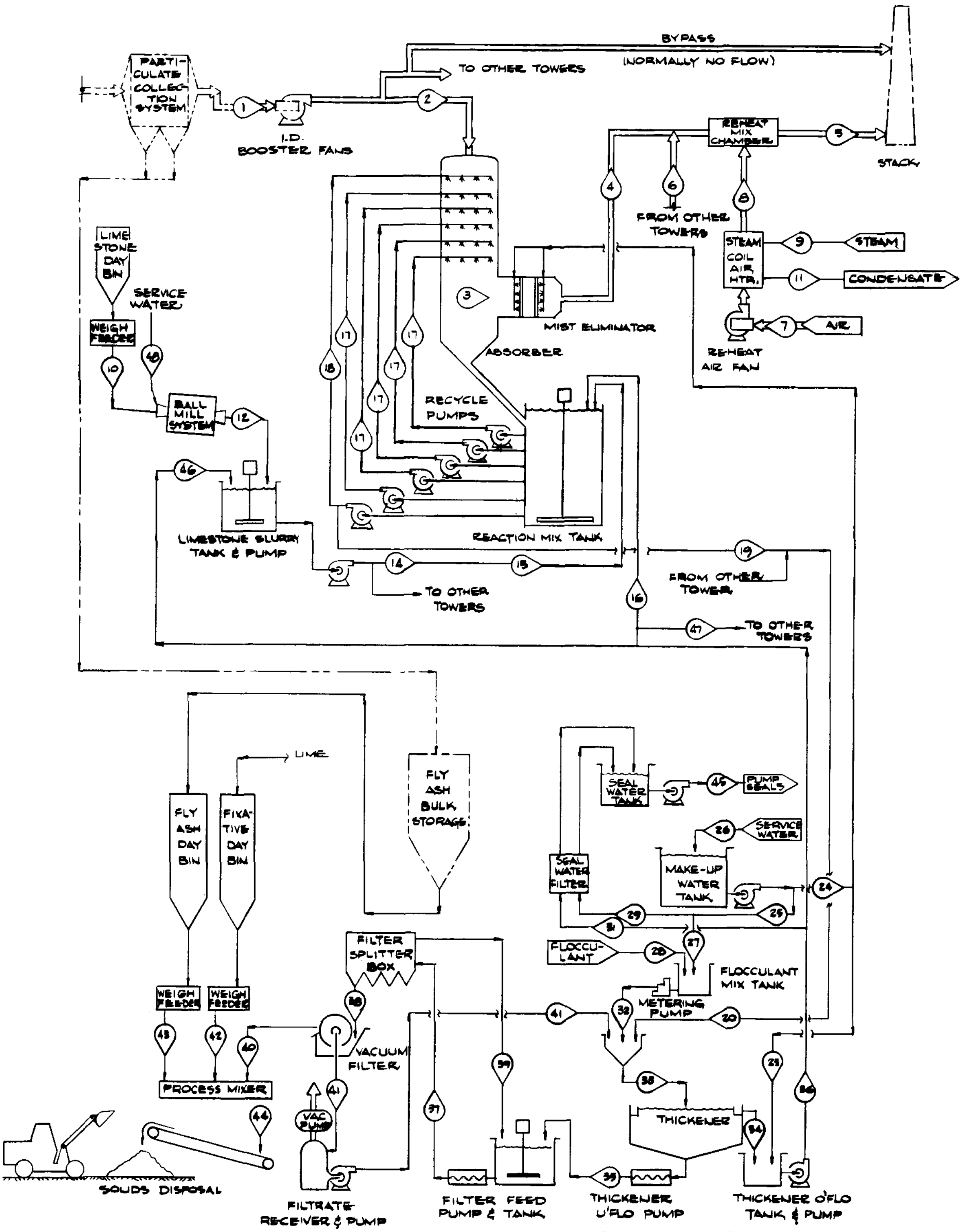
EPRI/TVA COCURRENT SYSTEM
PROCESS DESIGN CRITERIA

Flue Gas Flow (Max. Load)	1,900,000 acfm (900 m^3/s)
Sulfur Dioxide Removal	90% (based on a 30-day rolling average)
Scrubber Modules	Four @ 33-1/3% capacity each (3 operating, 1 spare)
Scrubber Type	Cocurrent Spray Tower
Stages of Grid Packing	Six - 3-3/4" height/stage (9.52 cm)
Liquid-to-Gas Ratio (L/G)	100 gpm/1000 acfm (13 l/m^3)
Absorber Superficial Velocity	27 fps (8.2 m/s)
Scrubber Slurry Solids Concentration	10%
Total System Pressure Drop	15 in. H_2O (3.7 kPa)
$CaCO_3$ Stoichiometric Ratio	1.3 lb-mole $CaCO_3$/lb-mole SO_2 removed
Thickener Underflow Solids Concentration	25 wt. %
Dewatered Sludge Solids Concentration	45 wt. %

5.A.2. EQUIPMENT DESCRIPTION

Equipment required for the EPRI/TVA Cocurrent System is divided into several major process cost and areas as follows:

• Area 01	Raw Material Receiving and Storage
• Area 02	Feed Preparation and Storage



NOTE: PHANTOMED EQUIPMENT NOT WITHIN BATTERY LIMITS OF FGD SYSTEM.

FIGURE 5-1

EPRI/TVA COCURRENT FGD SYSTEM PROCESS FLOW DIAGRAM

STREAM NO.	1	2	3	4	5	6	7	8
TEMP. °F.	283	283	127	127	177	127	60	382
PRESS. IN. H_2O	-15	+15	+13.5	+3.5	+1	+3.5	0	+10
10^3 ACFM	1,974	567	478	490	1,959	1,046	320	506
CO_2 10^3 #/HR.	1,068	356	356	364	1,093	729	-	-
H_2O "	300	100	174	174	530	348	-	-
N2 "	4,251	1,417	1,417	1,417	5,386	2,834	1,136	1,136
SO_2 "	40	13	13	1.3	4	2.7	-	-
O_2 "	365	122	122	122	668	244	302	302
TOTAL "	6,024	2,008	2,087	2,083	7,681	4,157	1,438	1,438

*intermittent

STREAM NO.	9	10	11	12	13*	14	15	16	17	18
TEMP. °F.	432	60	200	90	70	90	90	70	126	126
GPM	-	-	226	169	48	710	237	494	9,800	10430
SLUDGE 10^3#/HR	-	-	-	-	-	-	-	-	-	-
$CaCO_3$ "	-	73	-	73	-	73	24	-	-	-
INERTS "	-	8	-	8	-	8	3	-	-	-
H_2O(STEAM)"	(121)	-	121	54	24	325	108	247	5,194	5,528
TOTAL "	121	81	121	135	24	407	136	247	5,194	5,528
% SOLIDS	0	100	0	60	0	20	20	0	10	10

STREAM NO.	19	20	21*	22	23	24	25	26	27	28
TEMP. °F.	126	125	60	60	60	60	60	60	60	60
GPM	630	1,890	48	7	598	606	96	708	10	-
SLUDGE 10^3#/HR	33	100	-	-	-	-	-	-	-	-
$CaCO_3$ "	-	-	-	-	-	-	-	-	-	-
INERTS "	-	-	-	-	-	-	-	-	-	.0245
H_2O "	300	901	24	4	299	303	48	354	5	-
TOTAL "	333	1,001	24	4	299	303	48	354	5	.0245
% SOLIDS	10	10	0	0	0	0	0	0	0	100

STREAM NO.	29	30	31	32	33	34	35	36	37	38
TEMP. °F.	60	70	70	70	110	70	70	70	70	70
GPM	86	7	29	10	2,260	1,456	662	2,054	993	662
SLUDGE 10^3#/HR	-	-	-	-	100	-	100	-	150	100
REAGENT "	-	-	-	-	-	-	-	-	-	-
INERTS "	-	-	-	.025	-	-	-	-	-	-
H_2O "	43	4	14	5	1,028	728	300	1,027	451	300
TOTAL "	43	4	14	5	1,128	728	400	1,027	601	400
% SOLIDS	0	0	0	0	9	0	25	0	25	25

STREAM NO.	39	40	41	42	43	44	45	46	47	48
TEMP. °F.	70	70	60	60	80	80	60	70	70	60
GPM	331	-	356	-	-	-	115	542	988	108
SLUDGE 10^3#/hr	50	100	-	-	-	100	-	-	-	-
REAGENT "	-	-	-	5	-	5	-	-	-	-
INERTS "	-	-	-	-	73	73	-	-	-	-
H_2O "	150	122	178	-	-	122	58	271	494	54
TOTAL "	200	222	178	5	73	300	58	271	494	54
% SOLIDS	25	45	0	100	100	60	0	0	0	0

(To convert from °F to K, multiply by 5/9 and add 255.37; to convert from IN. H_2O to kPa, multiply by .2488 and add 101.325; to convert from 10^3 ACFM to m^3/s, multiply by .4720; to convert from 10^3 #/HR to kg/s, multiply by .1260; to convert from GPM to m^3/S, multiply by 6.31×10^{-5})

FIGURE 5-2

EPRI/TVA COCURRENT SYSTEM PROCESS FLOW BALANCE

Area 03	Flue Gas Scrubbing
Area 04	Flue Gas Reheat
Area 08	Waste Separation
Area 09	Waste Disposal
Area 11	Flue Gas Handling
Area 12	Waste Transfer and Placement

An equipment list including descriptive information and cost data is presented in Appendix B.

5.A.2.a. Area 01 - Raw Material Receiving and Storage

Limestone is received in bottom dump railcars. A railcar unloading facility is provided with the capacity to unload two railcars simultaneously. A belt conveyor system and stacker transfer the limestone to a 45-day bulk storage pile. The reclaim system includes a front-end loader with a load hopper and conveyor system to transfer limestone to the process. Fixative lime is received in pneumatic railcar or truck and is stored in a silo prior to pneumatic transfer to the process.

5.A.2.b. Area 02 - Feed Preparation and Storage

A limestone day bin and feeders supply limestone to one of two-100 percent capacity wet ball mills. The ball mills grind the limestone to 90 percent less than 200 mesh (74 um) and utilize a wet recycle loop to ensure proper size distribution to the process. The 60 percent solids slurry from the ball mills is diluted to 20 percent and stored in limestone slurry tanks prior to transfer to the absorbers.

5.A.2.c. Area 03 - Flue Gas Scrubbing

The absorber towers (three operating and one spare) are cocurrent towers with six levels of poly-grid packing to achieve the required 90 percent SO_2 removal. Scrubbed flue gas passes through vertical chevron mist eliminators prior to leaving the absorbers. Scrubber slurry from each absorber drains to individual agitated reaction tanks which provide adequate retention time for reaction completion and crystal growth. Makeup calcium carbonate slurry is added to the reaction tanks.

Rubber-lined slurry pumps recycle scrubber slurry to liquid distributors at each grid packing level. Each packing level has its own recycle pump but the pumps are not spared. Bleed from the absorber is pumped from the reaction mix tanks to the Waste Separation area.

Necessary ancillary equipment items included in this area are the makeup water tank and pumps, seal water tanks, filter, and pumps, and the instrument and service air compressor system.

5.A.2.d. Area 04 - Flue Gas Reheat

The scrubbed gas from the absorbers is reheated 50F^{o} (28K) in a reheat mix chamber. Ambient air is drawn via a reheat fan and is heated by finned tube steam coils which utilize both condensation and subcooling sections. The heated air is blown into the reheat mix chamber where it mixes with the scrubbed gas.

5.A.2.e. Area 08 - Waste Separation

The bleed from the scrubbers is pumped to a thickener. Flocculant is added to the thickener feed to aid settling of the scrubber slurry. The supernatant is returned to the scrubbing system via an overflow tank and pumps. The thickener underflow is pumped to a filter feed tank prior to mechanical dewatering by rotary drum vacuum filters. The filtrate is pumped back to the system while the filter cake is transferred to the Waste Disposal area for further preparation prior to disposal. Area sumps, agitators, and pumps are also included in this area.

5.A.2.f. Area 09 - Waste Disposal

The filter cake from the vacuum filters is blended with lime and fly ash in a pug mill type process mixer to form a solid waste material. Fly ash is pneumatically conveyed from the plant fly ash silos to a day bin near the process mixer. The fixative reagent (lime) is pneumatically conveyed from its storage silo to a day bin near the process mixer. The lime, fly ash, and scrubber waste are blended in the process mixer and conveyed by belt conveyor to a truck loading spot. A stacker is provided to pile solid waste to allow surge capacity when the trucks are not operating.

5.A.2.g. Area 11 - Flue Gas Handling

Flue gas from the generating plant particulate removal system passes through one of two combined I.D./Booster Fans. The fans provide sufficient pressure for both the furnace draft and particulate removal system, as well as the flow resistance of the absorber towers and duct system to the chimney. The ductwork includes common inlet and outlet manifolds and total FGD system bypass if required. Dampers are provided for isolation of individual absorbers for maintenance or inspection.

5.A.2.h. Area 12 - Waste Transfer and Placement

The waste solids from the process mixer are loaded onto off-highway trucks by either a shuttle loader (belt conveyor) or a front-end loader. The trucks transport the waste solids to a landfill disposal area assumed to be 1 mile (1.6km) from the plant site. A bulldozer at the disposal area spreads and compacts the waste to an average depth of 30 feet (9.1 m). The loading, transfer, and landfill area equipment operates one shift only, 5 days per week.

5.A.3. GENERAL ARRANGEMENT

Figure 5-3 shows a basic view of the plant site area general arrangement of the EPRI/TVA Cocurrent System. The arrangment allows for the entire FGD System to be bypassed if required, while minimizing bypass ductwork. The ductwork manifolding allows for turning vanes at each absorber inlet to minimize flue gas maldistribution. The arrangement is not necessarily optimized but the concept is consistent with the other processes evaluated.

5.A.4. RAW MATERIAL AND UTILITY CONSUMPTION

Table 5-2 lists raw material and utility consumptions by the EPRI/TVA Cocurrent FGD System at maximum load.

5.A.5. WASTE DISPOSAL

The waste sludge from the vacuum filters requires further stabilization prior to ultimate disposal. Fixative lime and fly ash from the particulate collection device are blended with the sludge in a pug mill-type process mixer. The fixed sludge is more stable than the untreated waste and is adequate for landfill impoundment. The components and maximum load quantity of blended sludge for disposal are as follows:

Component	t/h*	wt %
Lime	2.5	2
Fly ash	36.5	24
Waste Sludge	50.0	33
Water	61.0	41
Total Waste to Disposal	150.0	100

*t/h = 907.2 kg/h

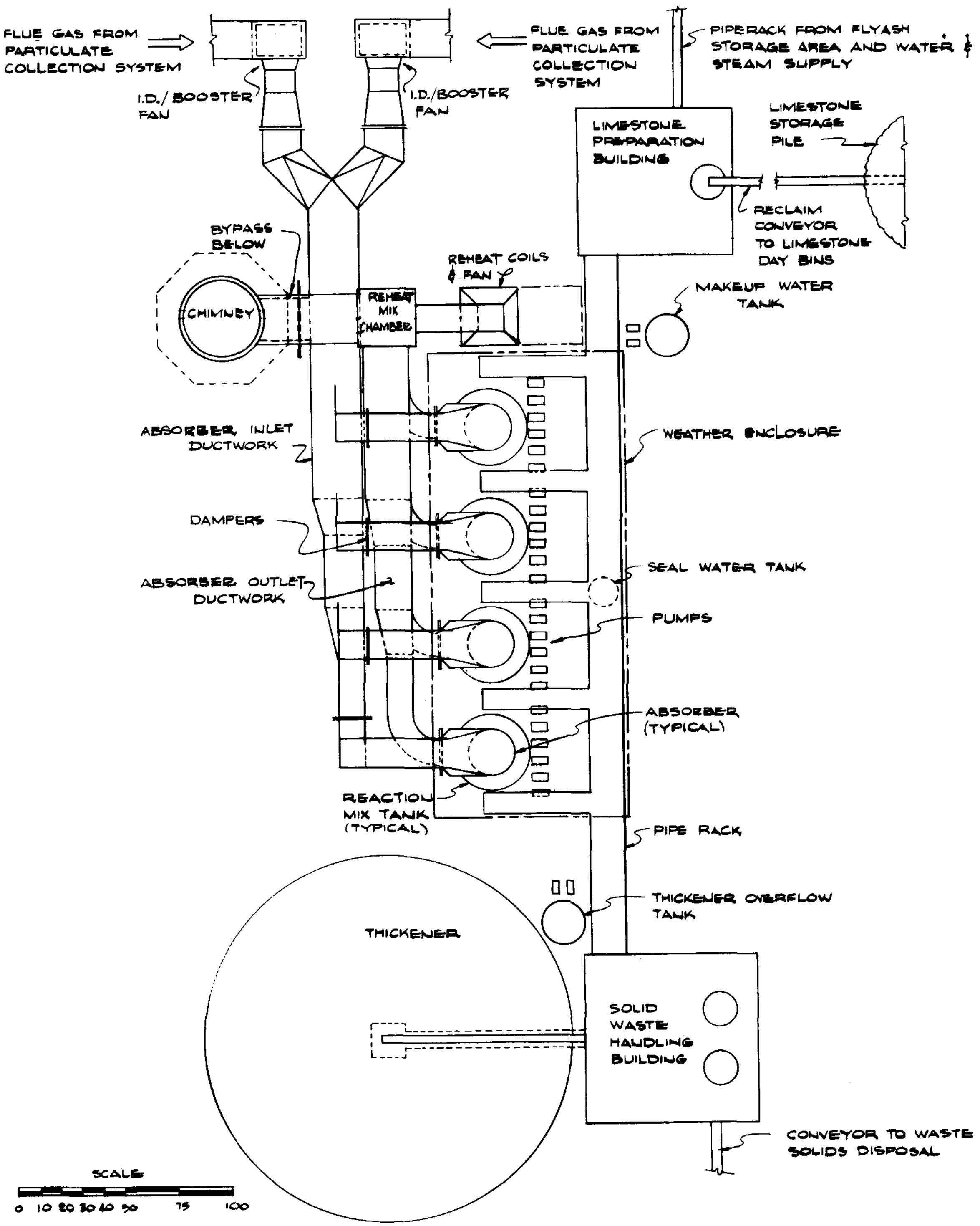


FIGURE 5-3

PLOT PLAN OF EPRI/TVA COCURRENT FGD SYSTEM

TABLE 5-2

EPRI/TVA COCURRENT FGD SYSTEM RAW MATERIAL AND UTILITY CONSUMPTION (MAXIMUM LOAD - 105%)

Item	Quantity
Limestone @ 1.30 Stoichiometric Ratio	40.5 t/h (10.2 kg/s)
Fixative Lime @ 3% of Dry Sludge and Fly Ash	2.5 t/h (0.6 kg/s)
Raw Water	800 gpm (0.05 m^3/s)
Steam	121,000 lb/hr (15.25 kg/s)
Power (Operating Horsepower)*	
Area 01 - Raw Material Receiving and Storage	180 hp (130 kW)
Area 02 - Feed Preparation and Storage	1345 hp (1002 kW)
Area 03 - Flue Gas Scrubbing	7665 hp (5716 kW)
Area 04 - Flue Gas Reheat	800 hp (600 kW)
Area 08 - Waste Separation	670 hp (500 kW)
Area 09 - Waste Disposal	330 hp (250 kw)
Area 11 - Flue Gas Handling	6000 hp (4500 kW)
Fly Ash (Entire quantity available from plant)	36.5 tph (9.2 kg/s)

*Total power consumption equal to approximately 2.5 percent of net generating capacity.

Based on a density of 95 lb/ft^3 (1500 kg/m^3), the following volumes are estimated for daily, yearly, and plant life sludge production:

Daily Maximum	2,800 yd^3 (2100 m^3)
Annual	420 acre-ft (518,000 m^3)
Plant Life	12,800 acre-ft (15,800,000 m^3)

5.B. TECHNICAL EVALUATION

The EPRI/TVA Cocurrent FGD System primarily involves an attempt to develop a more efficient and more economical absorber vessel than existing countercurrent systems. It represents a program to develop a scrubber which can provide required SO_2 removal efficiencies while operating at high superficial gas velocities and low pressure drops. This combination is attractive since it would result in a decrease in both initial capital investment and operating costs.

The cocurrent scrubber concept is presently undergoing pilot scale testwork to establish design parameters and optimize operation. Areas of design and operation being evaluated include:

- Different combinations of gas velocity, liquid-to-gas ratio, and scrubber internals, and their effect on SO_2 removal efficiency.
- Wet-elbow design required to minimize slurry carryover into the mist eliminator and reheater.
- Scrubber height required for lime and limestone dissolution.
- Plugging and scaling tendencies of the cocurrent scrubber, if any, and means to eliminate them.

The Tennessee Valley Authority, with funding from EPRI, is conducting evaluations of the cocurrent scrubber concept at the Colbert 1-MW pilot plant facility and the Shawnee Scrubber Test Facility as a 10-MW prototype. Testing at the 1-MW Colbert pilot plant was conducted to provide design data for construction of a 10-MW prototype to be operated at the Shawnee Scrubber Test Facility. The emphasis was to study gas-liquid distribution, SO_2, and particulate removal efficiencies as a function of gas velocity and liquid rates, and the effect of spray nozzle type and location and scrubber internals on SO_2 removal. Information concerning 1-MW Colbert pilot plant testing can be found in the EPRI report, "Cocurrent Scrubber Evaluation TVA's Colbert Lime-Limestone Wet-Scrubbing Pilot Plant," EPRI Report No. FP-941 (January 1979).

Testing continues of the 10-MW prototype at the Shawnee Scrubber Test Facility, and reports concerning the progress and results of the 10-MW cocurrent test program can be requested from EPRI.

5.C. ECONOMIC EVALUATION

The economic evaluation of the EPRI/TVA Cocurrent System is presented in the following tables:

Table 5-3	Total Capital Requirement
Table 5-4	Operating Costs
Table 5-5	Levelized Busbar Cost

Cost sensitivity to coal percent-sulfur and plant size was determined by adjusting capital and operating costs and reevaluating the levelized busbar cost. Cost sensitivity to coal percent-sulfur is illustrated in Figure 5-4, and to plant size in Figure 5-5. These curves are based on two additional estimates for the system for each parameter. Costs were adjusted to values for 0.5 percent and 2.0 percent sulfur coal, and for 250MW and 1000MW plant sizes. These values, combined with the base case values, were used to plot the cost sensitivity curves.

TABLE 5-3

EPRI/TVA COCURRENT SYSTEM
TOTAL CAPITAL REQUIREMENT
500 MW NEW PLANT
MID-1978 COSTS, MID-1979 START-UP
ILLINOIS COAL - 4% SULFUR

Process Capital

Area	Description	$/kW
01	Raw Material Receiving and Storage	7.4
02	Feed Preparation and Storage	12.2
03	Flue Gas Scrubbing	37.9
04	Flue Gas Reheat	6.5
08	Waste Separation	7.1
09	Waste Disposal	3.8
11	Flue Gas Handling	30.2
12	Waste Transfer and Placement	6.3
	Total Process Capital	111.4
General Facilities		13.8
Engineering and Home Office Fees		13.8
Project Contingency		11.1
Process Contingency		11.1
Sales Tax (Included in Process Capital)		0.0
	Total Plant Investment (TPI)	161.2
Royalty Allowance		0.6
Preproduction Costs		10.4
Inventory Capital		0.7
Initial Catalyst and Chemicals		0.0
Allowance for Funds During Construction (AFDC)		12.8
Land		4.8
	Total Capital Requirement (TCR)	190.4

TABLE 5-4

EPRI/TVA COCURRENT SYSTEM
OPERATING COSTS
500 MW NEW PLANT
MID-1978 COSTS, MID-1979 START-UP
ILLINOIS COAL - 4% SULFUR

Fixed Operating Costs	1st Year ($/Yr)	1st Year $/kW-Yr	Levelized $/kW-Yr
Operating Labor			
FGD System	$ 896,000	1.79	3.38
Sludge Disposal	156,000	0.31	0.58
Maintenance Labor	1,770,000	3.54	6.68
Maintenance Material	2,660,000	5.31	10.01
Admin. & Support Labor	840,000	1.68	3.17
Disposal Equipment	110,000	0.22	0.41
	$6,400,000	12.80	24.23

Variable Operating Costs	1st Year ($/yr)	1st Year (Mills/kWh)	Levelized (Mills/kWh)
Limestone, 237,000 t/y @ $10/ton	$2,370,000	0.77	1.45
Fixative Lime, 14,600 t/y @ $34/ton	496,000	0.16	0.30
Raw Water, 280,000 x 10^3gal/yr @ $0.40/$10^3$ gal	110,000	0.03	0.06
Steam, 700,000 x 10^3 lb/yr @ $3.49/$10^3$ lb (levelized cost)	--	--	0.80
Power, 83.9 x 10^6 kWh/yr @ 30 mills/kWh	2,660,000	0.87	1.66
Fly Ash (credit), 213,000 tpy @ $4/ton	(853,000)	(0.28)	(0.53)
Total Variable Operating Cost			3.74

Note: 1.0 t/y = 9.071 x 10^2 kg/y
1.0 gal = 3.785 x 10^{-3} m^3

TABLE 5-5

EPRI/TVA COCURRENT SYSTEM
LEVELIZED BUSBAR COST
500 MW NEW PLANT
MID-1978 COSTS, MID-1979 START-UP
ILLINOIS COAL - 4% SULFUR

	Levelized Mills/kWh
Process Capital	3.27
General Facilities	0.41
Engineering and Home Office Fees	0.41
Project Contingency	0.32
Process Contingency	0.32
Total Plant Investment	4.73
Royalty Allowance	0.02
Preproduction Costs	0.30
Inventory Capital	0.02
Allowance for Funds During Construction (AFDC)	0.38
Land	0.14
Total Capital Requirement	5.59
Fixed Operating Cost	3.95
Variable Operating Cost	3.74
Total Levelized Busbar Cost	13.28

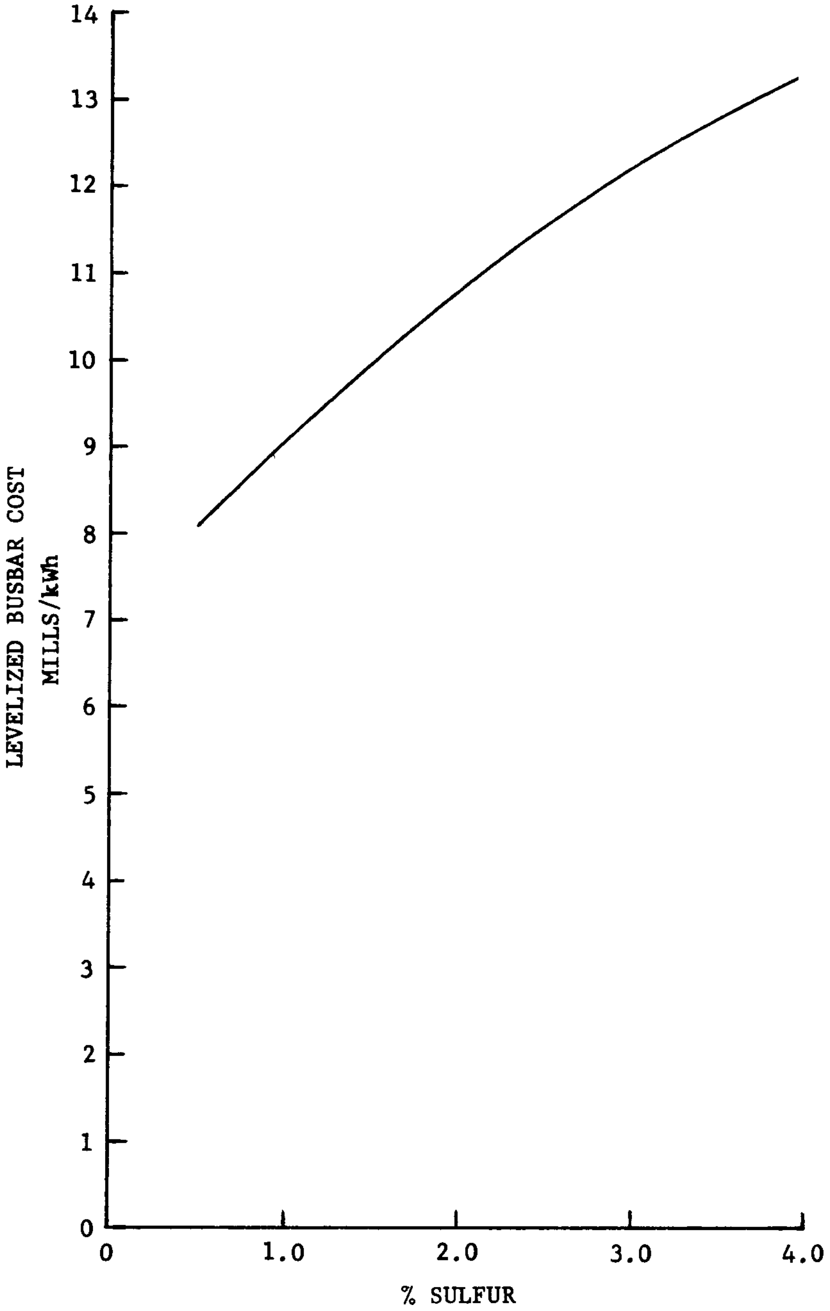


FIGURE 5-4

EPRI/TVA COCURRENT SYSTEM
COST VERSUS SULFUR CONTENT OF COAL

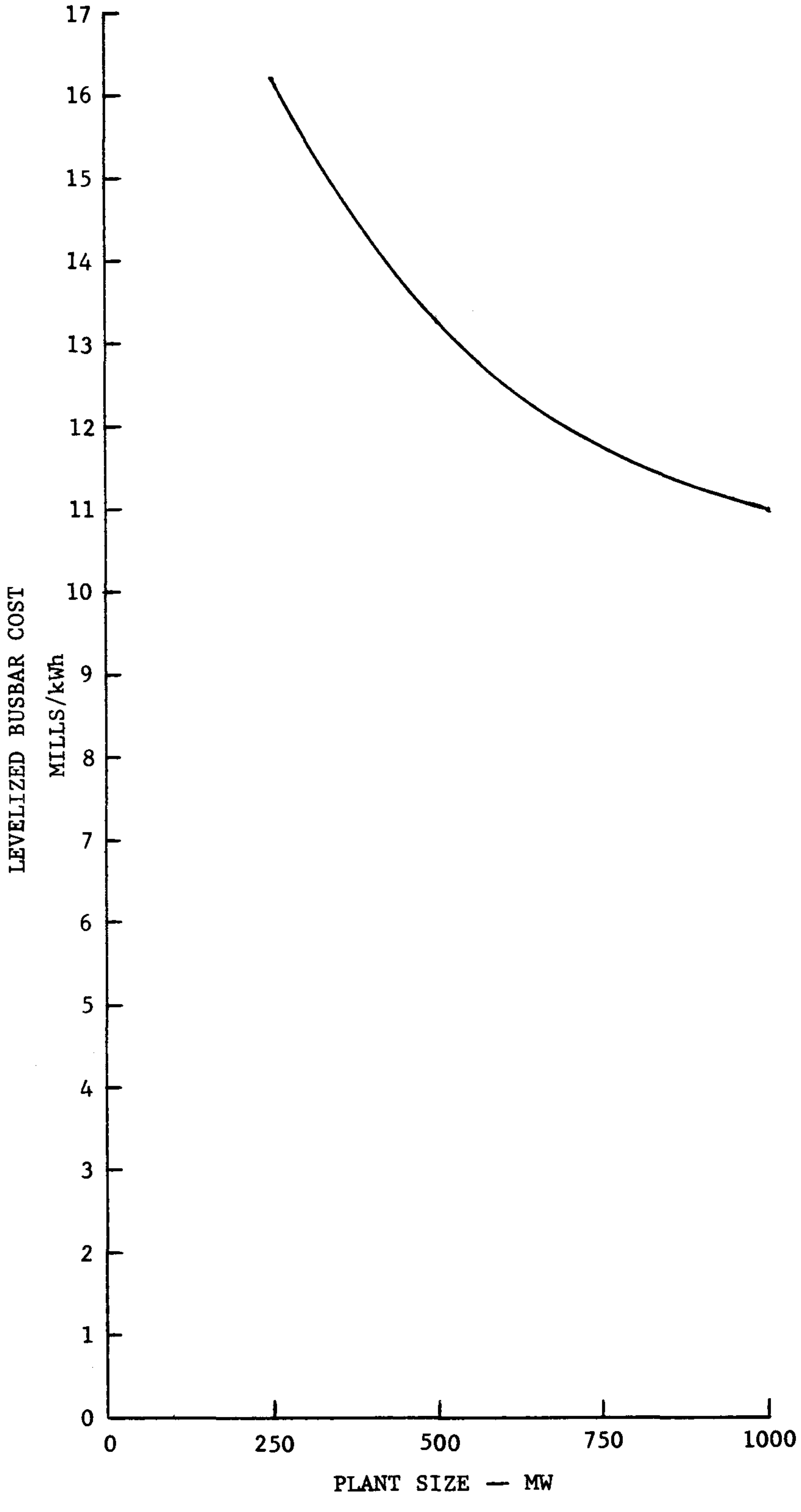


FIGURE 5-5

EPRI/TVA COCURRENT SYSTEM
COST VERSUS PLANT SIZE

6. CHIYODA THOROUGHBRED 121 FGD SYSTEM

6.A. SYSTEM DESCRIPTION

6.A.1. PROCESS DESCRIPTION

The Chiyoda THOROUGHBRED 121 (CT-121) FGD Process is a limestone process designed to produce gypsum, i.e. a fully oxidized sludge. Gypsum is physically more stable than conventional limestone sludges and is easier to process and dispose. In contrast to a conventional limestone sludge, fully oxidized gypsum need not be mixed with lime and fly ash to "fix" it.

The process utilizes forced oxidation and absorption in a single absorber vessel called a Jet Bubbling Reactor (JBR). The JBR is designed to achieve required sulfur dioxide removal efficiencies at pH values (3-5 pH units) lower than in conventional wet limestone scrubbing processes. Oxidation air is injected into the JBR to promote formation of gypsum ($CaSO_4 \cdot 2H_2O$). The JBR approach combines the absorption, oxidation, neutralization, and crystallization processes into a single vessel. The simplified overall reaction in the system is:

$$CaCO_{3(s)} + SO_{2(g)} + 2H_2O + 1/2\ O_2 \longrightarrow CaSO_4\ X\ 2H_2O + CO_{2(g)}$$

The chemistry is basically the same as a conventional limestone system. The design intends, however, to attain both complete oxidation of sulfite and limestone utilization approaching 100 percent.

The flue gas is cooled in the Precooler prior to introduction into the Jet Bubbling Reactor (JBR). The JBR functions as a flue gas scrubber, an oxidizer for sulfites, and a reaction crystallizer for gypsum. The flue gas is injected into the absorbent slurry through many gas spargers placed 4 to 16 inches (.10-.41 m) below the surface of the slurry. The flue gas is dispersed and forms a "jet bubbling zone" where SO_2 absorption occurs. The main body of liquid in the JBR is called a "reaction zone." The entire vessel contents are agitated mechanically and injected into the bottom of the vessel with oxidation air. The reaction zone provides for both the oxidation of sulfites and crystallization of gypsum.

The gypsum slurry bleed stream from the JBR's is transferred to a gypsum slurry tank. From this point, the gypsum slurry can either be mechanically dewatered or gravity dewatered with a gypsum stack. The gypsum stack approach is common practice in the phosphoric acid industry and requires less land area than ponding. The dewatered gypsum must be disposed of in an environmentally-acceptable manner. The dewatered gypsum from the CT-121 process is stable enough to be placed in a landfill disposal area without further blending or treatment.

If the potential of selling gypsum for wallboard manufacture exists, efforts must be made to maintain its purity. Any residual fly ash from the particulate collection device and chloride in the flue gas (as HCl) which is removed in the Precooler would have to be separately neutralized, dewatered, and disposed. The sale of gypsum for wallboard construction is site specific and normally not feasible.

Specific design criteria for the CT-121 System are presented in Table 6-1. A process flow diagram and major stream material balance are presented in Figures 6-1 and 6-2.

TABLE 6-1

CHIYODA THOROUGHBRED 121 SYSTEM
PROCESS DESIGN CRITERIA

Flue Gas Flow (Max. Load)	1,900,000 acfm (900 m^3/s)
Sulfur Dioxide Removal	90% (based on a 30-day rolling average)
Scrubber Modules	4 @ 33-1/3% capacity each (3 operating, 1 spare)
Scrubber Type	Jet Bubbling Reactor
Scrubber Slurry Solids Concentration	10% - 30%
Total System Pressure Drop	(15% used for material balance)
(Flange-to-flange)	21 in. H_2O (5.2 kPa)
$CaCO_3$ Stoichiometric Ratio	1.01 lb-mole $CaCO_3$/lb-mole SO_2 removed
Oxidation Air Stoichiometric Ratio	4
Dewatered Sludge Solids Concentration	
- Mechanically Dewatered	85%
- Gypsum Stack Dewatered	80%

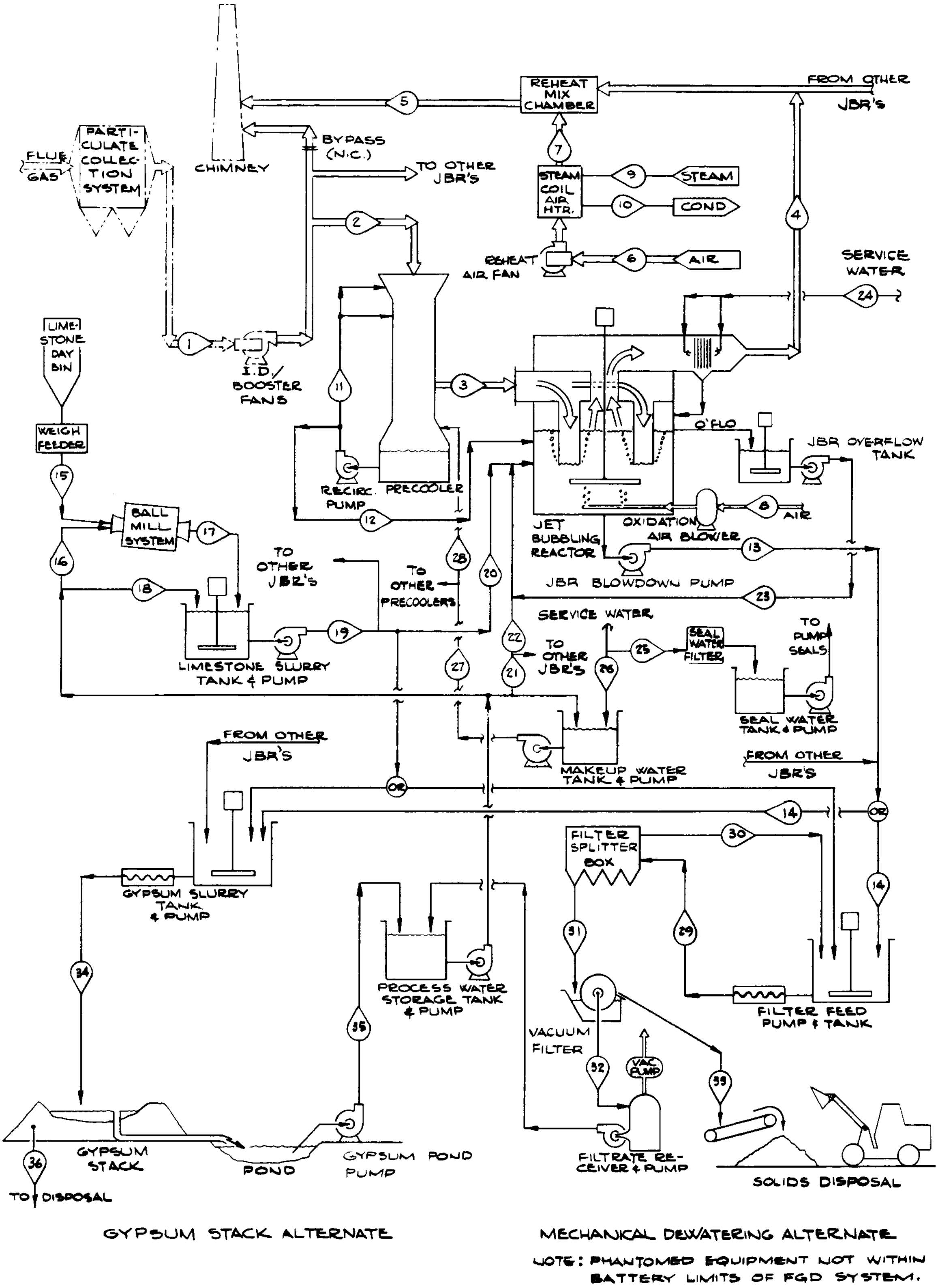


FIGURE 6-1
CHIYODA THOROUGHBRED 121 FGD SYSTEM PROCESS FLOW DIAGRAM

STREAM NO.	1	2	3	4	5	6	7	8
TEMP. °F.	283	283	127	127	177	60	382	60
PRESS. IN. H_2O	-15	+21	+19	+4	+1	0	+10	0
10^3 ACFM	1,974	601	506	524	2,144	345	545	35
CO_2 (10^3 #/HR)	1,068	356	356	365	1,095	-	-	-
H_2O "	300	100	179	174	537	-	-	-
N_2 "	4,251	1,417	1,417	1,417	5,434	1,183	1,183	120
SO_2 "	40	13	12	1.3	4	-	-	-
O_2 "	365	122	122	122	724	359	359	36
TOTAL "	6,025	2,008	2,086	2,084	7,794	1,542	1,542	156

STREAM NO.	9	10	11	12	13	14	15	16	17	18
TEMP. °F.	432	200	127	127	127	127	60	120	120	120
GPM	-	250	10,600	90	406	1,220	-	85	130	427
SLUDGE(10^3#/HR)	-	-	-	-	33	98	-	-	-	-
$CaCO_3$ "	-	-	-	-	0.2	0.6	59	-	59	-
INERTS "	-	-	5	trace	2.2	6.7	5	-	5	-
H_2O(STEAM)"	(121)	121	5,298	44	199	596	-	43	43	213
TOTAL "	121	121	5,303	44	234	701	64	43	107	213
% SOLIDS	-	-	0.1	0.1	15	15	100	-	60	-

STREAM NO.	19	20	21	22	23	24*	25**	26	27	28
TEMP. °F.	120	120	120	120	127	60	60	60	100	100
GPM	533	178	415	138	360	55	120	391	738	246
SLUDGE(10^3#/HR)	-	-	-	-	29	-	-	-	-	-
$CaCO_3$ "	59	20	-	-	0.2	-	-	-	-	-
INERTS "	5	2	-	-	2	-	-	-	-	-
H_2O "	256	85	208	69	176	27	60	196	369	123
TOTAL "	320	107	208	69	207	27	60	196	369	123
% SOLIDS	20	20	-	-	15	-	-	-	-	-

STREAM NO.	29	30	31	32	33	34	35	36
TEMP. °F.	127	127	127	120	100	127	120	100
GPM	1,828	609	1,220	1,154	-	1,220	1,139	-
SLUDGE(10^3#/HR)	147	49	98	-	98	98	-	98
$CaCO_3$ "	0.9	0.3	0.6	-	0.6	0.6	-	0.6
INERTS "	10	3.4	6.7	-	6.7	6.7	-	6.7
H_2O "	893	298	596	577	19	596	569	26
TOTAL "	1,051	350	701	577	124	701	569	131
% SOLIDS	15	15	15	-	85	15	-	80

(To convert from °F to K, multiply by 5/9 and add 255.37; to convert from IN. H_2O to kPa, multiply by .2488 and add 101.325; to convert from 10^3 ACFM to m^3/s, multiply by .4720; to convert from 10^3 #/HR to kg/s, multiply by .1260; to convert from GPM to m^3/s, multiply by 6.31×10^{-5})

*Intermittent flow; not included in overall water balance.

**For water balance consideration seal water was allocated to makeup water tank.

FIGURE 6-2

CHIYODA THOROUGHBRED 121 PROCESS FLOW BALANCE

6.A.2. EQUIPMENT DESCRIPTION

Equipment required for the Chiyoda THOROUGHBRED 121 System is divided into several major cost and process areas as follows:

- Area 01 - Raw Material Receiving and Storage
- Area 02 - Feed Preparation and Storage
- Area 03 - Flue Gas Scrubbing
- Area 04 - Flue Gas Reheat

  Area 08 - Waste Separation
    1) Mechanical Dewatering Alternate
    2) Gypsum Stack Dewatering Alternate
- Area 11 - Flue Gas Handling
- Area 12 - Waste Transfer and Placement

An equipment list including descriptive information and cost data is presented in Appendix C.

- Area 01 - Raw Material Receiving and Storage

  Limestone is received in bottom dump railcars. A railcar unloading facility is provided with the capacity to unload two railcars simultaneously. A belt conveyor system and stacker transfers the limestone to a 45-day bulk storage pile. The reclaim system includes a front-end loader with a load hopper and a conveyor system to transfer limestone to the process.

- Area 02 - Feed Preparation and Storage

  A limestone day bin and feeders supply limestone to one of two 100 percent capacity ball mills. The ball mills grind the limestone to 90 percent less than 200 mesh (74 um) and utilizes a wet recycle classification loop to ensure proper size distribution to the process. The 60 percent solids slurry from the ball mills is diluted to 20 percent and stored in limestone slurry tanks prior to transfer to the absorbers.

- Area 03 - Flue Gas Scrubbing

  The flue gas treatment area includes a precooler for saturating the flue gas and the Jet Bubbling Reactors (JBR) for sulfur dioxide absorption. The Precoolers are open spray chambers which saturate the gas before it enters the JBR. Rubber-lined pumps circulate liquor in the Precooler and purge some of the recirculating liquor to the JBR for neutralization. If the system were designed to produce a marketable gypsum product, the precooler purge stream would have to be separately neutralized, dewatered, and disposed to minimize fly ash and chloride content in the gypsum.

Saturated flue gas enters the JBR's where it passes through gas spargers into the scrubbing liquid, up through the vessel, and through vertical chevron mist eliminators. Level control in the JBR's is maintained by overflow to an Overflow Receiving Tank. Makeup calcium carbonate slurry is added to the JBR. An oxidation air blower injects air into the bottom of each JBR to promote oxidation. A gypsum slurry bleed is continuously pumped to the Waste Separation area.

Necessary ancillary equipment items included in this area are the makeup water tank and pumps, seal water tank, filter, and pumps, and the instrument and service air compressor system.

Area 04 - Flue Gas Reheat

The scrubbed gas from the absorbers is reheated $50F^o$ (28 K) in a reheat mix chamber. Ambient air is drawn via a reheat fan and is heated by finned tube steam coils which utilize both condensation and subcooling sections. The heated air is blown into the reheat mix chamber where it mixes with the scrubbed gas.

Area 08 - Waste Separation

The gypsum slurry bleed stream is pumped to a slurry storage tank prior to dewatering. The following two alternate dewatering approaches have been selected:

1) Mechanical Dewatering
2) Gypsum Stack Dewatering

The mechanical dewatering alternate utilizes rotary drum vacuum filters. A thickener is not required because the gypsum slurry dewaters easier than conventional limestone sludge. The filtrate is pumped to a process water storage tank for return to the scrubbing system. The filter cake is conveyed to a storage pile from which it is trucked to disposal.

The gypsum stack dewatering alternate utilizes gravity sedimentation to dewater the gypsum. Gypsum stacking is a common practice in the phosphoric acid industry. The gypsum slurry is pumped from the storage tank to a sedimentation pond on top of the gypsum stack. Gypsum settles on the stack while the clarified liquor overflows to a surge pond and is then pumped to the process water storage tank. The supernatant is then returned to the system. Dewatered gypsum is excavated and trucked to disposal.

Area sumps, agitators, and pumps are also included in this area for either alternative.

- Area 09 - Waste Disposal

  The dewatered gypsum from the vacuum filters is conveyed by belt conveyor to a truck loading spot. A stacker is provided to pile solid waste to provide surge capacity for periods when trucks are not operating.

- Area 11 - Flue Gas Handling

  Flue gas from the generating plant particulate removal system passes through one of two combined I.D./Booster Fans. The fans provide sufficient pressure for both the furnace draft and particulate removal system, as well as the flow resistance of the precoolers, JBR's, and duct system to the chimney. The ductwork includes common inlet and outlet manifolds and total FGD system bypass if required. Dampers are provided for isolation of individual scrubbing trains for maintenance or inspection.

- Area 12 - Waste Transfer and Placement

  The dewatered gypsum from either the vacuum filters or the gypsum stack is loaded on to off-highway trucks by a front-end loader. The disposal scheme assumes truck transport of the gypsum solids to a landfill disposal area assumed to be one mile (1.6 km) from the plant site. A bulldozer at the disposal area spreads and compacts the waste to an average depth of 30 feet (9.1 m). The loading, transfer and landfill area equipment operates one shift only, five days per week. (Note: Depending on site conditions, the gypsum stack could be the landfill, thereby eliminating this area.)

6.A.3. GENERAL ARRANGEMENT

Figure 6-3 shows a basic view of the general arrangement of the CT-121 System. The arrangement allows for the entire FGD System to be bypassed, if required while minimizing bypass duct length. The ductwork manifolding also allows for turning vanes at each absorber inlet to minimize flue gas maldistribution. The arrangement is not necessarily optimized but the concept is consistent with the other processes evaluated.

6.A.4. RAW MATERIAL AND UTILITY CONSUMPTION

Table 6-2 lists raw material and utility consumptions by the CT-121 System at maximum load.

TABLE 6-2

CHIYODA THOROUGHBRED 121 SYSTEM
RAW MATERIAL AND UTILITY CONSUMPTION
(Maximum Load - 105%)

Item	Quantity
Limestone @ 1.01 Stoichiometric Ratio	32 t/h (8.1 kg/s)
Raw Water	570 gpm (0.04 m^3/s)
Steam	121,000 lb/hr (15.25 kg/s)
Power (Operating Horsepower)*	
Area 01 - Raw Material Receiving and Storage	180 hp (130 kW)
Area 02 - Feed Preparation and Storage	915 hp (682 kW)
Area 03 - Flue Gas Scrubbing	4,065 hp (3031 kW)
Area 04 - Flue Gas Reheat	800 hp (600 kW)
Area 08 - Waste Separation	400 hp (300 kW)
Area 09 - Waste Disposal	25 hp (29 kW)
Area 11 - Flue Gas Handling	8,160 hp (6080 kW)

*Total power consumption equal to approximately 2.2% of net generating capacity

6.A.5. WASTE DISPOSAL

The gypsum sludge from the vacuum filters is stable enough to be disposed and adequate for landfill impoundment. The solids content of the sludge varies slightly depending on the dewatering alternate. Percent solids concentration in the dewatered sludge is assumed to be 85 percent for mechanical dewatering and 80 percent for gypsum stack dewatering. Estimated sludge quantities at maximum load are 62 tph after mechanical dewatering and 66 tph after gypsum stack dewatering.

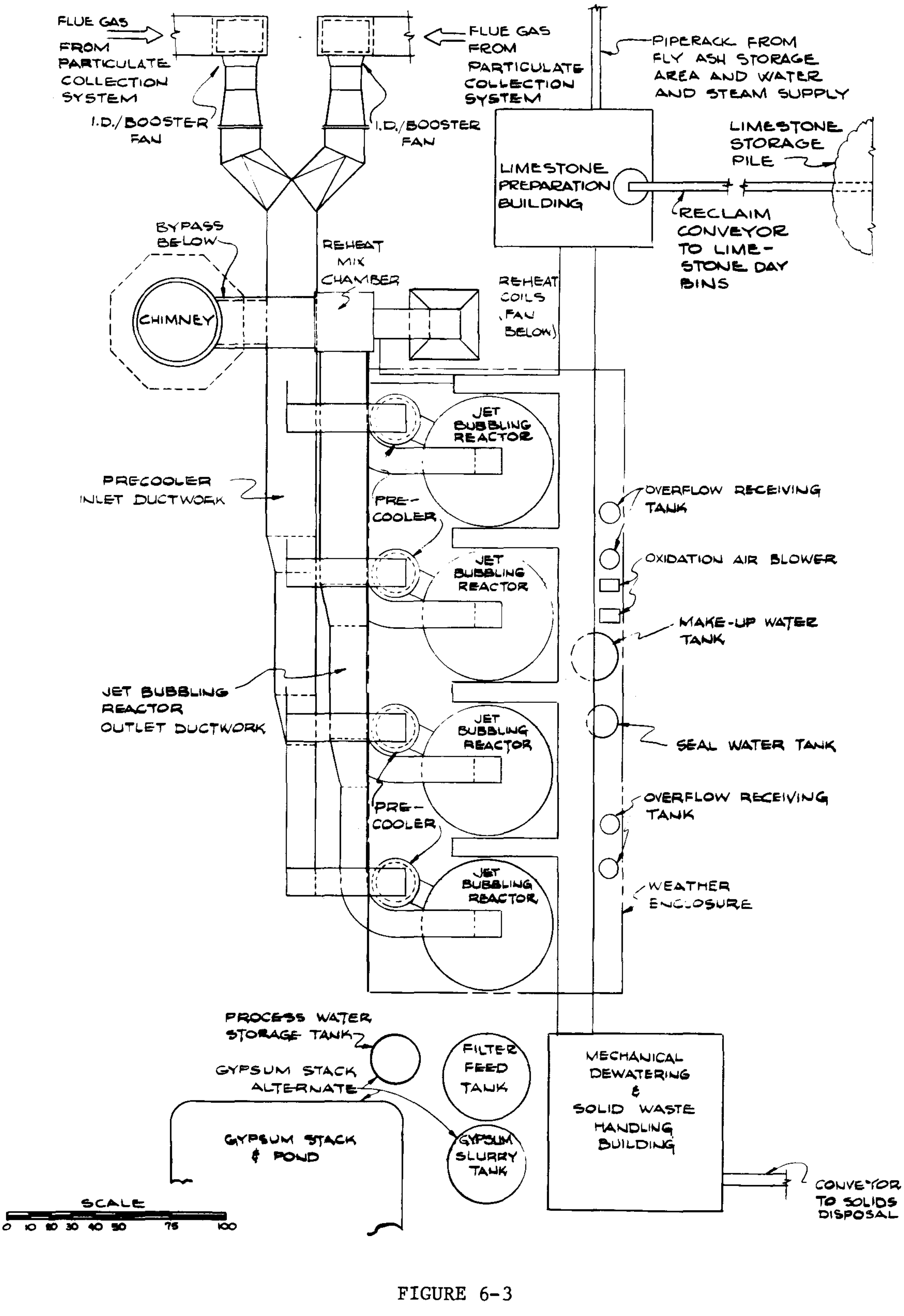


FIGURE 6-3

PLOT PLAN OF CHIYODA THOROUGHBRED 121 FGD SYSTEM

Based on a density of 95 lb/ft^3 (1500 Kg/m^3), the following volumes are estimated for daily, yearly, and plant life sludge production:

Daily Maximum - 1170 yd^3 (895 m^3)
Annual - 176 acre-ft (217,000 m^3)
Plant Life - 5280 acre-ft (6,510,000 m^3)

6.B. TECHNICAL EVALUATION

The Chiyoda THOROUGHBRED 121 Process represents an approach to improving the conventional limestone scrubbing process by redesign of the scrubbing vessel. The change provides for a single vessel which combines the absorption, oxidation, neutralization, and crystallization processes into one vessel, the JBR.

The JBR represents a different approach to gas-liquid contacting for SO_2 removal. The contact is achieved by injecting the flue gas through gas sparger tubes which are immersed 4-16 inches (.10-.41 m) below the liquid surface of the scrubbing slurry. A "jet bubbling layer" is formed where the gas dispersion results in efficient gas-liquid contact promoting SO_2 absorption. The total gas pressure drop is the sum of the sparger liquid immersion depth plus the gas pressure drop through openings at the bottom of the spargers provided to disperse the gas bubbles. The total system pressure drop is slightly greater than most conventional limestone processes. Significant energy savings are realized, however, due to the elimination of large slurry recycle pumps which are required for conventional limestone processes' liquid-to-gas ratio requirements of 60 to 100 gallons per 1000 ACFM of gas (64-107 l/m^3).

The main body of liquid in the JBR is called a "reaction zone." The reaction zone is where the oxidation of sulfites and formation of gypsum crystals occurs. Both mechanical agitation and air injection combine to continually circulate the JBR contents and promote oxidation. The liquid pH level is maintained in the range of 3 to 5 where both the oxidation reaction and neutralization reaction rates are increased. The slurry concentration is maintained between 10 and 30 wt % to provide crystal surface area for gypsum crystal growth and thereby prevent sulfate scaling. (A slurry concentration of 15 wt % was chosen for this study.) The resultant slurry has been virtually 100 percent oxidized so all calcium-sulfur salts exist as sulfate rather than sulfite. This allows the slurry to be dewatered to 80-85 wt % solids.

The CT-121 process has been tested as a 23-MW pilot unit at the Scholz Station of Gulf Power. The testwork began in mid-1978 as a modification of the CT-101 pilot plant unit at Scholz. Preliminary test results have been encouraging, and formal test results will soon be published. Although preliminary results from this facility indicate improved process economics, the results were not available for inclusion in this study. The basis for this study does not utilize any data from the test work. Chiyoda feels confident that the process is ready for full-scale application.

The CT-121 process offers several encouraging approaches to the improvement of limestone system performance. It combines the goals of increased limestone utilization and waste sludge oxidation in a single, improved absorber design. Further testing, design and operation of a prototype or full-scale installation will be necessary to prove the CT-121 system's applicability to the nation's utility industry, but initial information indicates that it represents a promising improvement to the conventional limestone approach.

6.C. ECONOMIC EVALUATION

The economic evaluation of the Chiyoda THOROUGHBRED 121 System is presented in the following tables:

Table 6-3	Total Capital Requirement
Table 6-4	Operating Costs
Table 6-5	Levelized Busbar Cost

Cost sensitivity to coal %-sulfur and plant size was determined by adjusting capital and operating costs and reevaluating the levelized busbar cost. Cost sensitivity to coal %-sulfur is illustrated in Figure 6-4 and to plant size in Figure 6-5.

The potential exists with the CT-121 System that wallboard-grade gypsum could be produced and sold rather than disposed. This approach would require additional equipment to treat the purge stream from the precoolers to avoid contamination of the gypsum by chlorides and possibly fly ash. The sludge produced from the neutralization of the purge stream would require thickening, dewatering, and blending prior to landfill disposal, although its volume would be less than for the total gypsum produced in the base case. A detailed analysis of the process and economic implications of the marketable gypsum approach was not performed. A rough analysis of the option indicates an increased levelized busbar cost of about 0.8 mills/kWh to modify the CT-121 System to produce a marketable gypsum product.

TABLE 6-3

CHIYODA THOROUGHBRED 121 SYSTEM
TOTAL CAPITAL REQUIREMENT
500 MW NEW PLANT
MID-1978 COSTS, MID-1979 STARTUP
ILLINOIS COAL - 4% SULFUR

Process Capital

Area	Description	Mechanical Dewatering $/kW	Gypsum Stacking $/kW
01	Raw Material Receiving and Storage	5.5	5.5
02	Feed Preparation and Storage	9.6	9.6
03	Flue Gas Scrubbing	26.7	26.7
04	Flue Gas Reheat	7.3	7.3
08	Waste Separation	5.1	3.1
09	Waste Disposal	1.1	1.1
11	Flue Gas Handling	35.3	35.3
12	Waste Transfer and Placement	3.7	3.7
	Total Process Capital	94.3	92.3
General Facilities		11.8	11.5
Engineering and Home Office Fees		11.8	11.5
Project Contingency		9.4	9.2
Process Contingency		9.4	9.2
Sales Tax (Included in Process Capital)		0	0
	Total Plant Investment (TPI)	136.7	133.8
Royalty Allowance		0.5	0.5
Preproduction Costs		8.9	8.7
Inventory Capital		0.4	0.4
Initial Catalyst and Chemicals		0.0	0.0
Allowance for Funds During Construction (AFDC)		10.9	10.7
Land		2.1	2.3
	Total Capital Requirement (TCR)	159.6	156.5

TABLE 6-4

CHIYODA THOROUGHBRED 121 SYSTEM
OPERATING COSTS
500 MW NEW PLANT
MID-1978 COSTS
ILLINOIS COAL - 4% SULFUR

	Mechanical Dewatering Alternate			Gypsum Stack Alternate		
Fixed Operating Costs	1st Yr ($/yr)	1st Yr $/kW-Yr	Levelized $/kW-Yr	1st Yr ($/Yr)	1st Yr $/kW-Yr	Levelized $/kW-Yr
Operating Labor						
FGD System	$ 807,000	1.61	3.04	$ 807,000	1.61	3.04
Sludge Disposal	104,000	0.21	0.40	130,000	0.26	0.49
Maintenance Labor	1,510,000	3.02	5.70	1,480,000	2.95	5.56
Maintenance Material	2,260,000	4.53	8.54	2,215,000	4.43	8.35
Admin. & Support Labor	734,000	1.47	2.77	716,000	1.43	2.70
Disposal Equipment	72,000	0.14	0.26	88,000	0.18	0.34
	$5,490,000	10.98	20.71	$5,430,000	10.87	20.50

Variable Operating Costs	1st Yr ($/yr)	1st Yr (Mills/kWh)	Levelized (Mills/kWh)
Limestone 187,000 t/y @ $10/ton	$1,870,000	0.61	1.15
Raw Water 200,000 x 10^3gal/yr @ $0.40/$10^3$gal	80,000	0.03	0.06
Steam 700,000 x 10^3lb/yr @ $3.49/$10^3$lb (Levelized Cost)	---	--	0.80
Power 76 x 10^6 kWh/yr @ 30 mills/kWh	2,280,000	0.74	1.41
Total Variable Operating Cost			3.42

Note: 1.0 t/y = 9.071 x 10^2 kg/y
1.0 gal = 3.785 x 10^{-3} m^3

TABLE 6-5

CHIYODA THOROUGHBRED 121 SYSTEM
LEVELIZED BUSBAR COST
500 MW NEW PLANT
MID-1978 COSTS, MID-1979 STARTUP
ILLINOIS COAL - 4% SULFUR

	Levelized Mills/kWh	
	Mechanical Dewatering Alternate	Gypsum Stack Alternate
Process Capital	2.77	2.71
General Facilities	0.35	0.34
Engineering and Home Office Fees	0.35	0.34
Project Contingency	0.28	0.27
Process Contingency	0.28	0.27
Total Plant Investment	4.03	3.93
Royalty Allowance	0.01	0.01
Preproduction Costs	0.26	0.26
Inventory Capital	0.01	0.01
Allowance for Funds During Construction (AFDC)	0.32	0.31
Land	0.06	0.07
Total Capital Requirement	4.69	4.59
Fixed Operating Cost	3.38	3.34
Variable Operating Cost	3.42	3.42
Total Levelized Busbar Cost	11.49	11.35

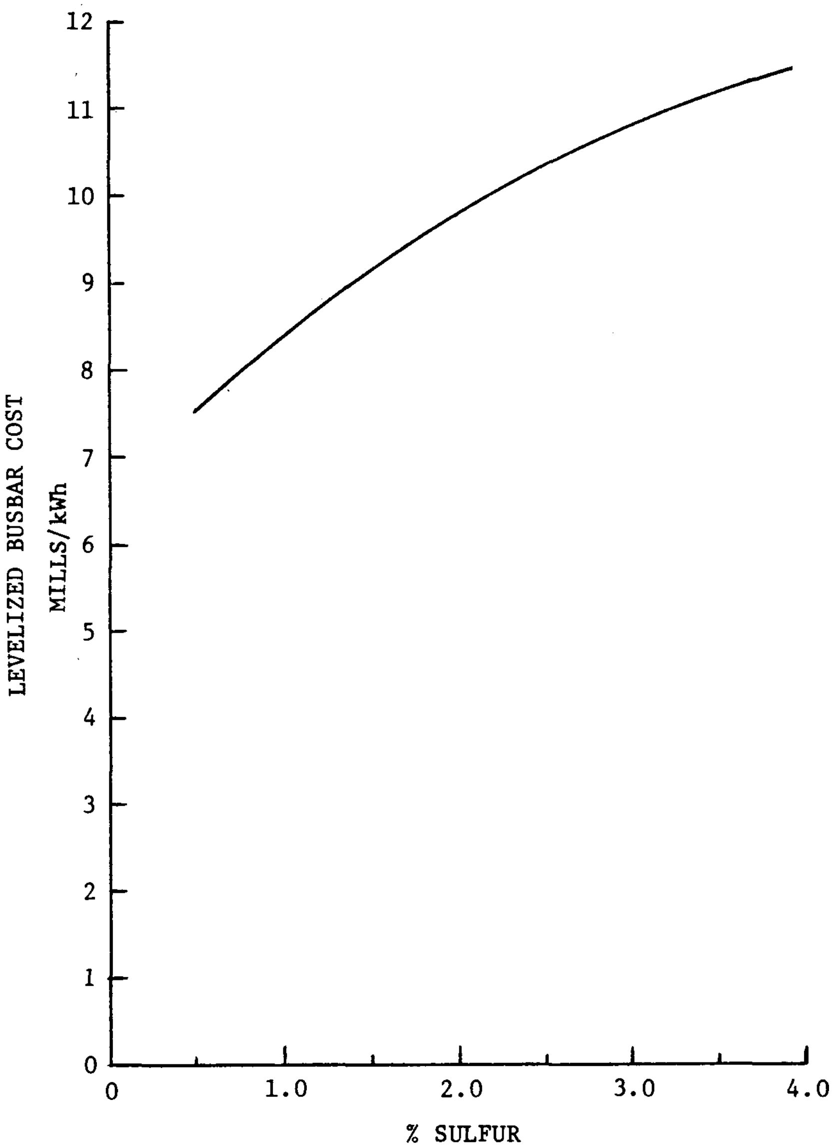


FIGURE 6-4

CHIYODA THOROUGHBRED 121 SYSTEM
COST VERSUS COAL SULFUR CONTENT

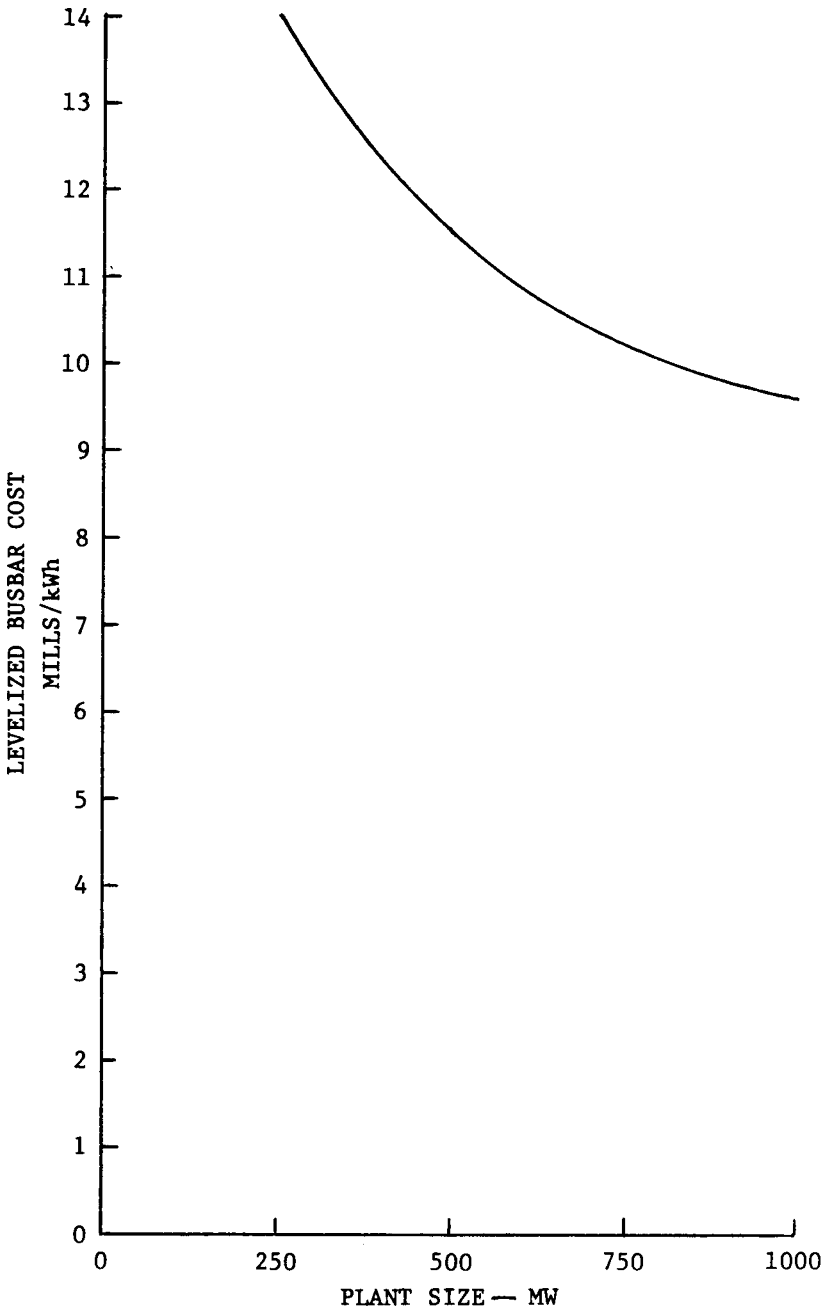


FIGURE 6-5

CHIYODA THOROUGHBRED 121 SYSTEM
COST VERSUS PLANT SIZE

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7. WELLMAN-LORD FGD SYSTEM

7.A. SYSTEM DESCRIPTION

7.A.1. PROCESS DESCRIPTION

The Wellman-Lord FGD Process, marketed by Davy-McKee Corp., of Lakeland, Florida, is a recovery process producing a concentrated SO_2-rich off-gas which can be sold as liquid SO_2 or converted to high purity sulfuric acid or elemental sulfur. The Wellman-Lord process absorbs SO_2 by contacting the flue gas with an aqueous sodium sulfite solution. The reaction forms soluble sodium bisulfite which is regenerated to sodium sulfite, with the liberation of gaseous SO_2, in an evaporator. The regenerated sodium sulfite is returned to the absorber circuit for reuse while the SO_2 is either liquefied, converted to sulfuric acid, or converted to elemental sulfur.

The Wellman-Lord process consists of three basic steps:

- Sulfur dioxide absorption
- Absorbent regeneration and SO_2 production
- Sulfur dioxide conversion to elemental sulfur or sulfuric acid

The SO_2 is absorbed in a sodium sulfite scrubbing solution by the following simplified reaction:

$$Na_2SO_3 + H_2O + SO_2 \longrightarrow 2NaHSO_3$$

Two additional reactions occur between the sodium sulfite and SO_3 or oxygen in the flue gas to form sodium sulfate:

$$Na_2SO_3 + 1/2\ O_2 \longrightarrow Na_2SO_4$$
$$2Na_2SO_3 + SO_3 + H_2O \longrightarrow Na_2SO_4 + 2NaHSO_3$$

The sodium sulfate formed must be purged from the recycle stream since it cannot be thermally decomposed in the process. A portion of the sodium bisulfite-rich absorber product solution is purged to an evaporator-crystallizer where the unwanted sulfate crystallizes at a greater rate than the useful sodium compounds. The sodium sulfate crystallized from the purge stream is dried and stored prior to sale or disposal. The sodium associated with the purge stream must be replaced with a caustic soda or soda ash feed.

A prescrubber is required to cool and presaturate the flue gas and ensure that a minimal quantity of particulates and chlorides enter the absorption recycle stream. The prescrubber also removes some SO_3 and chlorides as well as a portion of the entering SO_2. Chloride removal is particularly important when firing high-chloride coals to prevent the buildup of sodium chloride in the absorption-regeneration loop. The purge stream from the prescrubbers is neutralized, thickened, dewatered, and blended with fly ash and a fixative reagent. The solid waste is then disposed using the same means as lime or limestone throwaway systems, but much less volume is involved.

The sodium bisulfite-rich absorber product solution is pumped through fly ash filters to remove any remaining particulates (the filter sluice goes to the prescrubber purge neutralization system) and then proceeds to the thermal regeneration loop, except for a small portion which is purged to remove sulfates. The absorber product solution is passed through two stages of forced circulation evaporators where the sodium bisulfite is converted to sodium sulfite crystals and gaseous SO_2. The sodium sulfite crystals are redissolved and returned to the absorbers for reuse in scrubbing. The gaseous SO_2 is concentrated in two stages of water cooled condensers.
The SO_2-rich gases leaving the secondary condenser are compressed before entering the recovery area where SO_2 is liquified or, as for this study, converted to either elemental sulfur or sulfuric acid.

The SO_2 exiting the regeneration loop can be converted to elemental sulfur via a sulfur reduction process or to sulfuric acid by a conventional contact acid process. A sulfur reduction process which has been used in this study is the Allied Chemical reduction process which includes a Claus reactor. The first stage reduces the SO_2 using natural gas to produce sulfur and hydrogen sulfide (H_2S):

$$2SO_2 + CH_4 \longrightarrow CO_2 + 2H_2O + 2S$$
$$3SO_2 + 2CH_4 \longrightarrow 2CO_2 + 2H_2O + 2H_2S + S$$

The second stage involves a Claus reaction to convert the H_2S to elemental sulfur:

$$2H_2S + SO_2 \longrightarrow 2H_2O + 3S$$

The sulfur produced is condensed and stored for shipment or disposal. The tail gas from the Claus reaction is incinerated and returned to the flue gas stream ahead of the absorber towers.

Sulfuric acid production can be achieved by a contact acid plant. The SO_2 gas stream is first passed through a drying tower. The high purity SO_2 gas is then oxidized to convert it to SO_3. The SO_3 is passed through an absorbing tower where the SO_3 reacts with water to form sulfuric acid (H_2SO_4) of up to 98 percent concentration. Several heat exchangers form a part of the system for temperature optimization and heat recovery.

Specific design criteria for the Wellman-Lord System are presented in Table 7-1. A process flow diagram and major stream material balance are presented in Figures 7-1A, B and Figures 7-2A, B. Simplified flow diagrams of a sulfur and a sulfuric acid plant are shown in Figure 7-3.

TABLE 7-1

WELLMAN-LORD SYSTEM
PROCESS DESIGN CRITERIA

Flue Gas Flow (Max. Load)	1,990,000 acfm (940 m^3/s)
Sulfur Dioxide Removal	90% (based on a 30-day rolling average)
Absorber Modules	4 @ 33-1/3% capacity each (3 operating, 1 spare)
Absorber Type	Valve Tray Tower (3 trays)
Tray Recirculation Rate	3 gpm per tray/1000 acfm (0.4 l/m^3)
Absorber Superficial Velocity	10 f/s (3 m/s)
Total System Pressure Drop (Flange to flange)	24 in. H_2O (6.0 kPa) (Including 3 in. H_2O (0.7 kPa) for reheat mixing)

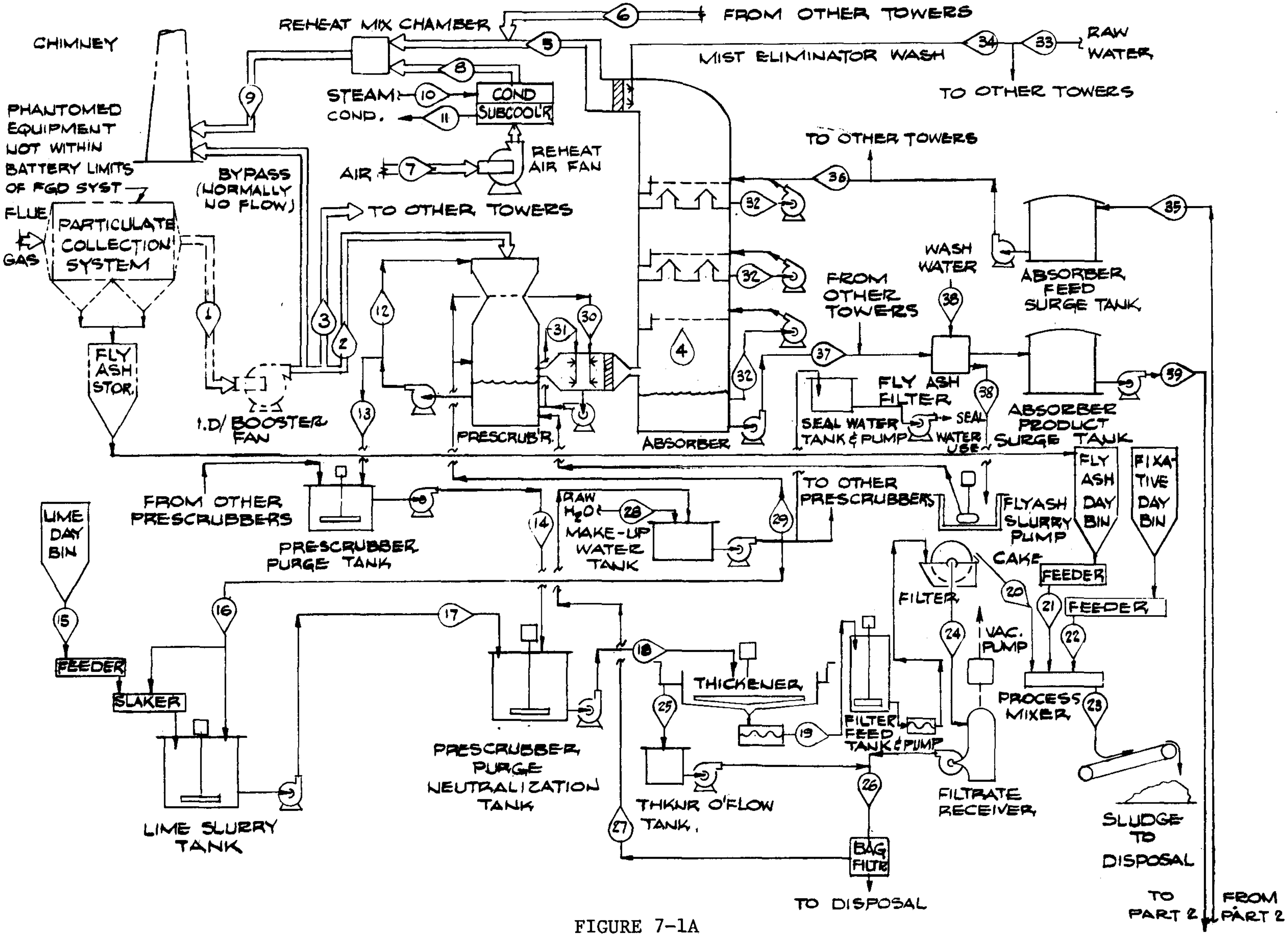


FIGURE 7-1A

WELLMAN-LORD FGD SYSTEM PROCESS FLOW DIAGRAM, PART 1

STREAM NO.	1	2	3	4	5	6	7	8	9
TEMP. °F.	277	283	283	127	127	127	60	382	177
PRESS. IN. H_2O	-15	+24	+24	+14	+4	+4	0	+10	+1
10^3 ACFM	2053	626	1253	540	551	1103	399	630	2296
CO_2, 10^3#/HR.	1125	375	750	375	375	750	-	-	1125
H_2O "	316	105	211	189	189	378	-	-	567
N_2 "	4478	1493	2985	1493	1493	2985	1412	1412	5890
SO_2 "	42	14	28	13	1	3	-	-	4
O_2 "	385	128	257	128	128	257	375	375	760
TOTAL "	6347	2116	4231	2198	2186	4373	1788	1788	8347

STREAM NO.	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TEMP. °F.	432	200	127	127	126	60	60	90	115	75	60	80	60	75	60
GPM (PSIG)	(350)	267	5400	45	135	-	30	35	185	45	-	-	-	-	28
Na_2SO_3, 10^3#/HR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
$NaHSO_3$ "	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Na_2SO_4 "	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REAGENT "	-	-	-	-	-	2.7	-	2.7	-	-	-	-	0.7	0.7	-
SO_2 "	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SLUDGE "	-	-	-	-	-	-	-	-	8	8	8	-	-	8	-
INERTS "	-	-	-	-	-	0.3	-	0.3	-	-	-	14	-	14	-
H_2O "	136	136	-	23	-	-	15	15	92	20	6	-	-	6	14
TOTAL "	136	136	2780	23	68	3	15	18	100	28	14	14	0.7	29	14
% SOLIDS	0	0	< 3	< 3	< 3	100	0	20	9	30	60	100	100	80	0

STREAM NO.	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39
TEMP. °F.	75	70	60	60	60	60	127	127	60	60	150	125	127	60	127
GPM (PSIG)	145	173	173	516	164	3	12520	1654	17	5	960	320	334	5	1000
Na_2SO_3, 10^3#/HR	-	-	-	-	-	-	-	-	-	-	119	40	15	-	45
$NaHSO_3$ "	-	-	-	-	-	-	-	-	-	-	18	6	45	-	135
Na_2SO_4 "	-	-	-	-	-	-	-	-	-	-	30	10	12	-	36
REAGENT "	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SO_2 "	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SLUDGE "	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
INERTS "	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H_2O "	72	86	86	258	82	1	-	-	9	3	428	143	142	2	426
TOTAL "	72	86	86	258	82	1	6258	1042	9	3	595	199	214	2	642
% SOLIDS	0	0	0	0	0	0	< 3	~30	0	0	28	28	33	0	33

(To convert from °F to K, multiply by 5/9 and add 255.37; to convert from IN. H_2O to kPa, multiply by .2488 and add 101.325; to convert from 10^3 ACFM to m^3/s, multiply by .4720; to convert from 10^3 #/HR to kg/s, multiply by .1260; to convert from GPM to m^3/s, multiply by 6.31×10^{-5})

FIGURE 7-2A

WELLMAN-LORD SYSTEM PROCESS FLOW BALANCE, PART 1

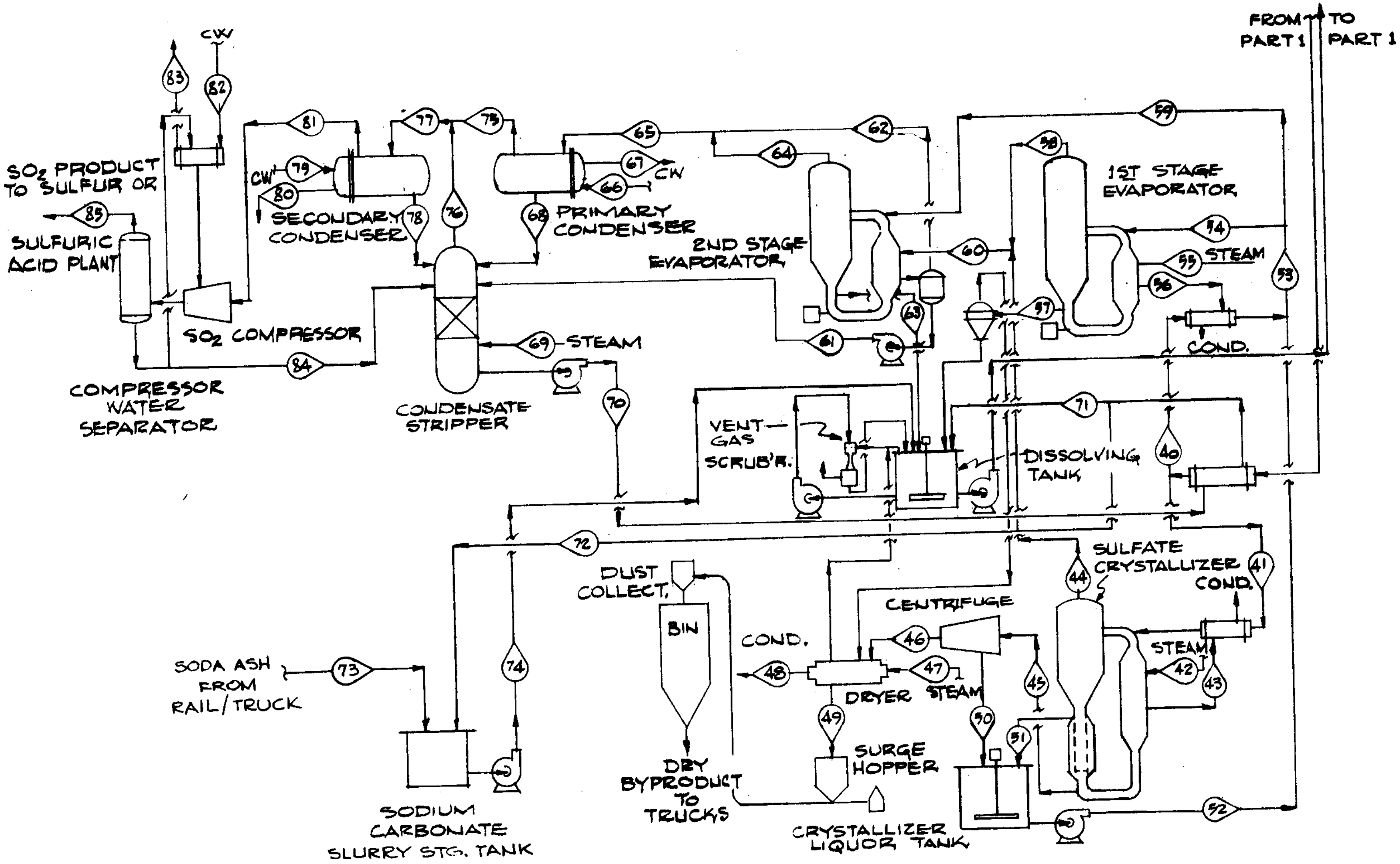


FIGURE 7-1B

WELLMAN-LORD FGD SYSTEM PROCESS FLOW DIAGRAM, PART 2

STREAM NO.	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
TEMP. °F.	-	-	250	200	200	200	-	388	-	-	-	200	-	-	-
GPM (PSIG)	647	355	(15)	78	-	22	-	(200)	7	-	10	281	291	938	563
Na_2SO_3 10^3#/HR	29	16	-	-	-	2	2	-	-	2	-	16	16	45	27
$NaHSO_3$ "	87	48	-	-	-	2	-	-	-	-	2	41	43	130	78
Na_2SO_4 "	22	12	-	-	-	4	4	-	-	4	-	9	9	31	19
REAGENT "	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SO_2 "	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-
SLUDGE "	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
INERTS "	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H_2O "	276	152	39	39	31	6	2	3	3	-	4	115	119	395	237
TOTAL "	414	227	39	39	32	14	8	3	3	6	6	181	187	601	361
% SOLIDS	33	33	0	0	0	40	70	0	0	100	38	36	36	34	34

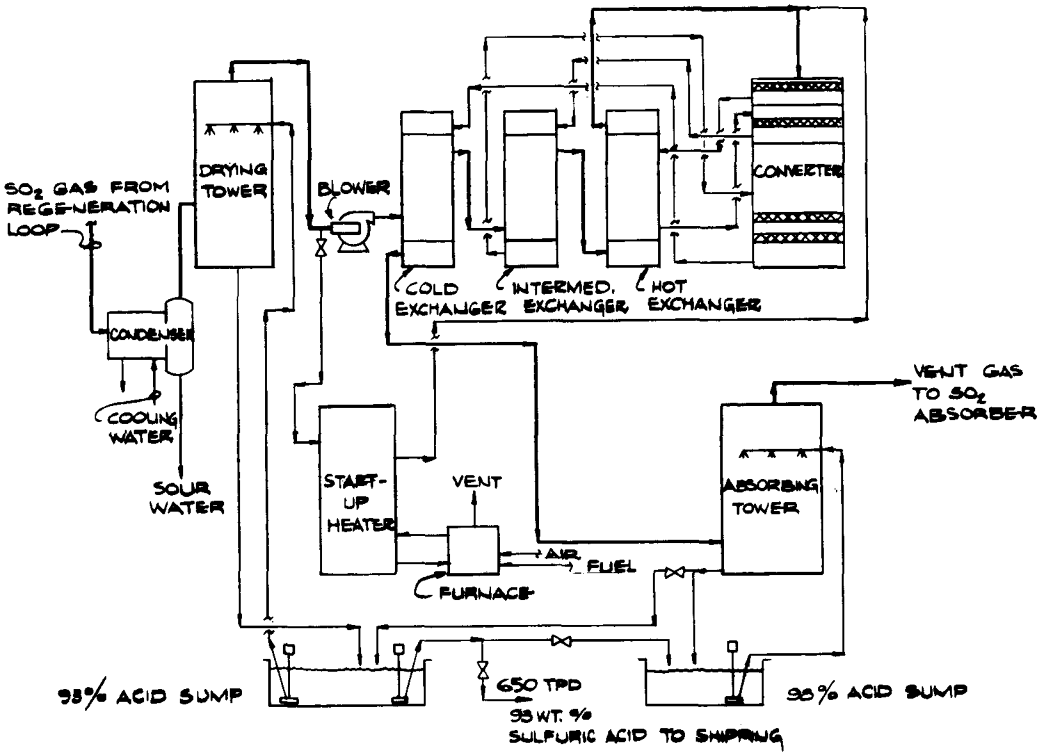
STREAM NO.	55	56	57	58	59	60	61	62	63	64	65	66	67	68	69
TEMP. °F.	250	200	200	200	-	200	170	170	170	170	170	85	105	-	250
GPM (PSIG)	(15)	515	-	-	375	-	-	-	-	-	-	20900	20900	310	(15)
Na_2SO_3 10^3#/HR	-	-	65	-	18	-	-	-	42	-	-	-	-	-	-
$NaHSO_3$ "		-	17	-	52	-	-	-	12	-	-	-	-	-	-
Na_2SO_4 "	-	-	18	-	12	-	-	-	12	-	-	-	-	-	-
REAGENT "	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SO_2 "	-	-	-	19	-	20	<1	20	-	13	33	-	-	<1	-
SLUDGE "	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
INERTS "	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H_2O "	257	257	42	200	158	231	172	57	29	133	190	10450	10450	155	4
TOTAL "	257	257	142	219	240	251	173	77	95	146	223	10450	10450	155	4
% SOLIDS	0	0	70	0	34	0	0	0	70	0	0	0	0		0

STREAM NO.	70	71	72	73	74	75	76	77	78	79	80	81	82	83	84	85
TEMP. °F.	-	-	-	60	-	-	-	-	-	85	105	-	85	105	-	-
GPM	733	697	36	-	38	-	-	-	-	4575	4575	-	924	924	-	-
Na_2SO_3 10^3#/HR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
$NaHSO_3$ "	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Na_2SO_4 "	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REAGENT "	-	-	-	5	5	-	-	-	-	-	-	-	-	-	-	-
SO_2 "	-	-	-	-	-	33	<1	33	<<1	-	-	33	-	-	<<1	33
SLUDGE "	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
INERTS "	-	-	-	<1	<1	-	-	-	-	-	-	-	-	-	-	-
H_2O "	366	348	18	-	18	35	5	40	32	2286	2286	8	462	462	6	2
TOTAL "	366	348	18	5	23	68	5	73	32	2286	2286	41	462	462	6	35
% SOLIDS	0	0	0	100	20	0	0	0	0	0	0	0	0	0	0	0

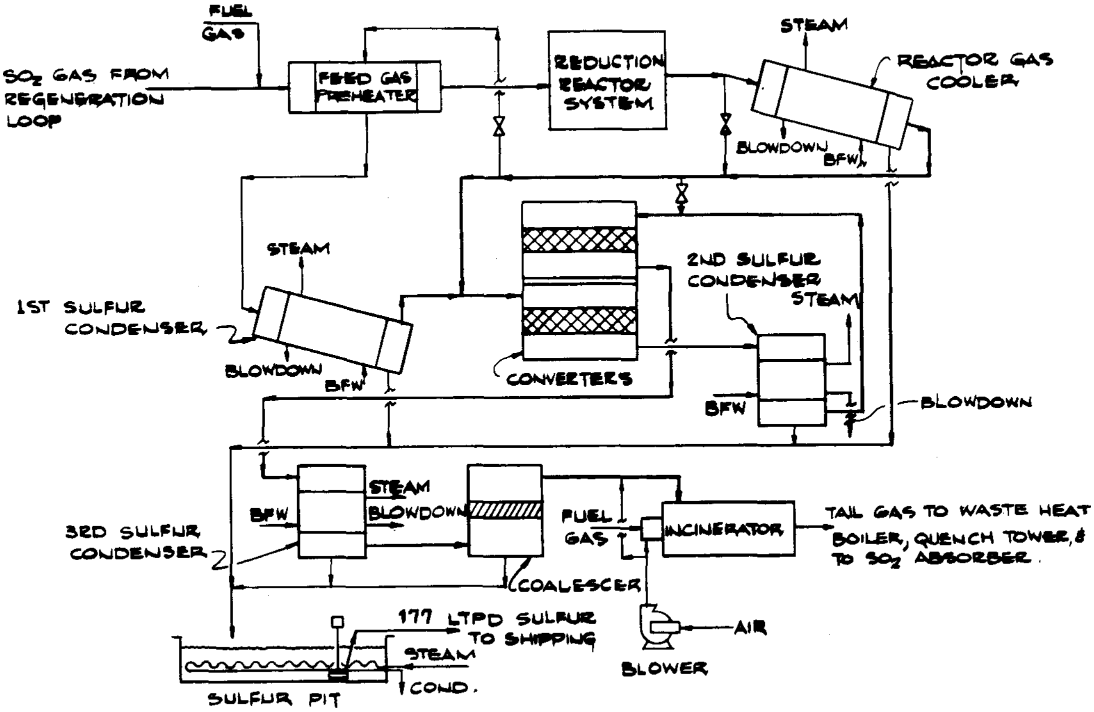
(To convert from °F to K, multiply by 5/9 and add 255.37; to convert from IN. H_2O to kPa, multiply by .2488 and add 101.325; to convert from 10^3 ACFM to m^3/s, multiply by .4720; to convert from 10^3 #/HR to kg/s, multiply by .1260; to convert from GPM to m^3/s, multiply by 6.31×10^{-5})

FIGURE 7-2B

WELLMAN-LORD SYSTEM PROCESS FLOW BALANCE, PART 2



SULFURIC ACID PLANT



SULFUR PLANT

FIGURE 7-3

WELLMAN-LORD SYSTEM SULFUR & SULFURIC ACID PLANTS

PROCESS FLOW DIAGRAM

7.A.2. EQUIPMENT DESCRIPTION

Equipment required for the Wellman-Lord System is divided into several major cost and process areas as follows:

Area 01 - Raw Material Receiving and Storage
Area 02 - Feed Preparation and Storage
Area 03 - Flue Gas Scrubbing
Area 04 - Flue Gas Reheat
Area 05 - Purge Treatment
Area 06 - SO_2 Regeneration
Area 07 - SO_2 Processing
Area 10 - Byproduct Storage
Area 11 - Flue Gas Handling
Area 12 - Waste Transfer and Placement

An equipment list including descriptive information and cost data is presented as Appendix D.

7.A.2.a. Area 01 - Raw Material Receiving and Storage

Soda ash is received in pneumatic railcar or truck and is stored as a slurry in the slurry storage tank prior to transfer to the process. Lime for prescrubber purge neutralization and fixative is also received in pneumatic railcar or truck and stored in a silo prior to pneumatic transfer to the process.

7.A.2.b. Area 02 - Feed Preparation and Storage

Sodium carbonate solution is pumped from the slurry storage tank to the process as required. A lime day bin and feeders supply lime to one of two 100 percent capacity lime slakers. The lime slurry is stored in a tank prior to pumping to the prescrubber purge neutralization tank as required.

7.A.2.c Area 03 - Flue Gas Scrubbing

The prescrubbers (3 operating and 1 spare) are low pressure drop venturi's with rubber-lined recirculation pumps. A chloride removal section with recirculation pumps is located between the prescrubbers and absorbers. The prescrubbed flue gas passes through vertical chevron mist eliminators before entering the absorbers.

The absorbers (3 operating and 1 spare) are vertical valve tray towers with three levels of trays. Each tray has its own recirculation pump. The scrubbed flue gas passes through vertical chevron mist eliminators prior to leaving the absorbers.

The spent absorber product liquor is pumped from the base of the absorbers to a common absorber product surge tank. The spent absorbent passes through a fly ash filter before entering the product surge tank. The absorber product is pumped from the surge tank to the regeneration area. An absorber feed surge tank and pumps are provided to receive regenerated absorber solution from the regeneration area prior to transfer to the absorbers.

The solution level in the absorber feed tank is maintained as high as practical, and the level in the absorber product tank is maintained as low as practical in normal operation. This mode of operation isolates the regeneration section from the effects of load swings in the generating plant, and permits routine maintenance of downstream areas to be performed without interrupting the SO_2 removal function of the absorber section.

Necessary ancillary equipment items included in this area are the makeup water tank and pumps, seal water tank, filter, and pumps, and the instrument and service air compressor system.

7.A.2.d. Area 04 - Flue Gas Reheat

The scrubbed gas from the absorbers is reheated $50F^{o}$ (28 K) in a reheat mix chamber. Ambient air is drawn via a reheat fan and is heated by finned tube steam coils which utilize both condensing and subcooling sections. The heated air is blown into the reheat mix chamber where it mixes with the scrubbed gas.

7.A.2.e. Area 05 - Purge Treatment

The Purge Treatment area involves the handling of two distinct purge streams. A purge stream from the prescrubber is neutralized and disposed and a purge stream from the absorber loop must be treated to remove sulfates.

The prescrubber purge streams from each prescrubber are pumped to a common purge tank. The combined purge streams are pumped to a neutralization tank where the purge is neutralized with lime. The neutralized purge stream is pumped to a thickener. The thickener overflow is returned to the system via an overflow tank and pumps. The thickener underflow is pumped to a filter feed tank prior to mechanical dewatering by rotary drum vacuum filters. The filtrate is returned to the process. The filter cake is blended with lime and fly ash in a process mixer to form a solid waste. Fly ash is pneumatically conveyed from the plant fly ash silos to a day bin near the process. The fixative reagent (lime) is pneumatically conveyed from its storage silo to a day bin near the process mixer. The lime, fly ash, and filter cake are blended in a process mixer and conveyed to a truck loading spot. A stacker is provided to pile solid waste to provide surge capacity for periods when trucks are not operating.

The absorber sulfate purge stream is taken as a slipstream from the absorber product solution pumped to the regeneration area. The sulfate purge stream is pumped to a sulfate crystallizer which is a specially designed single-stage evaporator system. The crystallized sulfate stream is centrifuged to break up the crystals and remove trapped solution. The dewatered solids are passed through a dryer and stored in a sulfate product bin prior to removal by truck.

Area sumps, agitators, and pumps are also included in this area.

7.A.2.f. Area 06 - SO_2 Regeneration

The majority of the absorber product stream is routed to a double effect evaporator system where the sodium bisulfite ($NaHSO_3$) is thermally decomposed to sodium sulfite (Na_2SO_3) and sulfur dioxide (SO_2) gas. The Na_2SO_3 is sent to a dissolving tank where stripped condensate and makeup sodium carbonate (Na_2CO_3) are added. The regenerated solution is pumped back to the absorber feed surge tank in the flue gas treatment area. The SO_2-water vapor stream from the evaporators is condensed in two stages of condensers. The condensate is stripped and returned to the system in the dissolving tank. The concentrated SO_2 gas stream is compressed and delivered to the SO_2 Processing area.

7.A.2.g. Area 07 - SO_2 Processing

The concentrated SO_2 stream is processed to either sulfuric acid in a contact sulfuric acid plant or elemental sulfur in an Allied/Claus sulfur reduction plant. These plants were considered as complete units designed and supplied by a single source.

7.A.2.h. Area 10 - Byproduct Storage

Storage facilities are provided for 5-day storage of either sulfuric acid or molten sulfur depending on the SO_2 processing concept used.

7.A.2.i. Area 11 - Flue Gas Handling

Flue gas from the generating plant particulate removal system passes through one of two combined I.D./Booster Fans. The fans provide sufficient pressure for both the furnace draft and particulate removal system as well as the flow resistance of the prescrubbers, absorbers, and associated duct system to the chimney. The ductwork includes common inlet and outlet manifolds and total FGD system bypass if required. Dampers are provided for isolation of individual absorbers for maintenance or inspection.

7.A.2.j. Area 12 - Waste Transfer and Placement

The neutralized prescrubber purge stream waste solids from the process mixer are loaded on to off-highway trucks by either a shuttle loader (belt conveyor) or a front-end loader. The trucks transport the waste solids to a landfill disposal area approximately 1 mile (1.6 km) from the plant site. A bulldozer at the disposal area spreads and compacts the waste to an average depth of 30 feet (9.1 m). The loading, transfer, and landfill area equipment operates one shift only, 5 days per week.

7.A.3. GENERAL ARRANGEMENT

Figure 7-4 provides a basic view of the general arrangement of the Wellman-Lord System. The arrangement allows for the entire FGD System to be bypassed if required. The ductwork allows for turning vanes at each absorber inlet to minimize flue gas maldistribution. The arrangement is not necessarily optimized but the concept is consistent with the other processes evaluated.

7.A.4. RAW MATERIAL AND UTILITY CONSUMPTION

Table 7-2 lists raw material and utility consumptions by the Wellman-Lord System at maximum load.

7.A.5. WASTE DISPOSAL

The dewatered waste sludge from the neutralized prescrubber purge stream requires further stabilization prior to ultimate disposal. Fixative lime and fly ash from the particulate collection device are blended with the sludge in

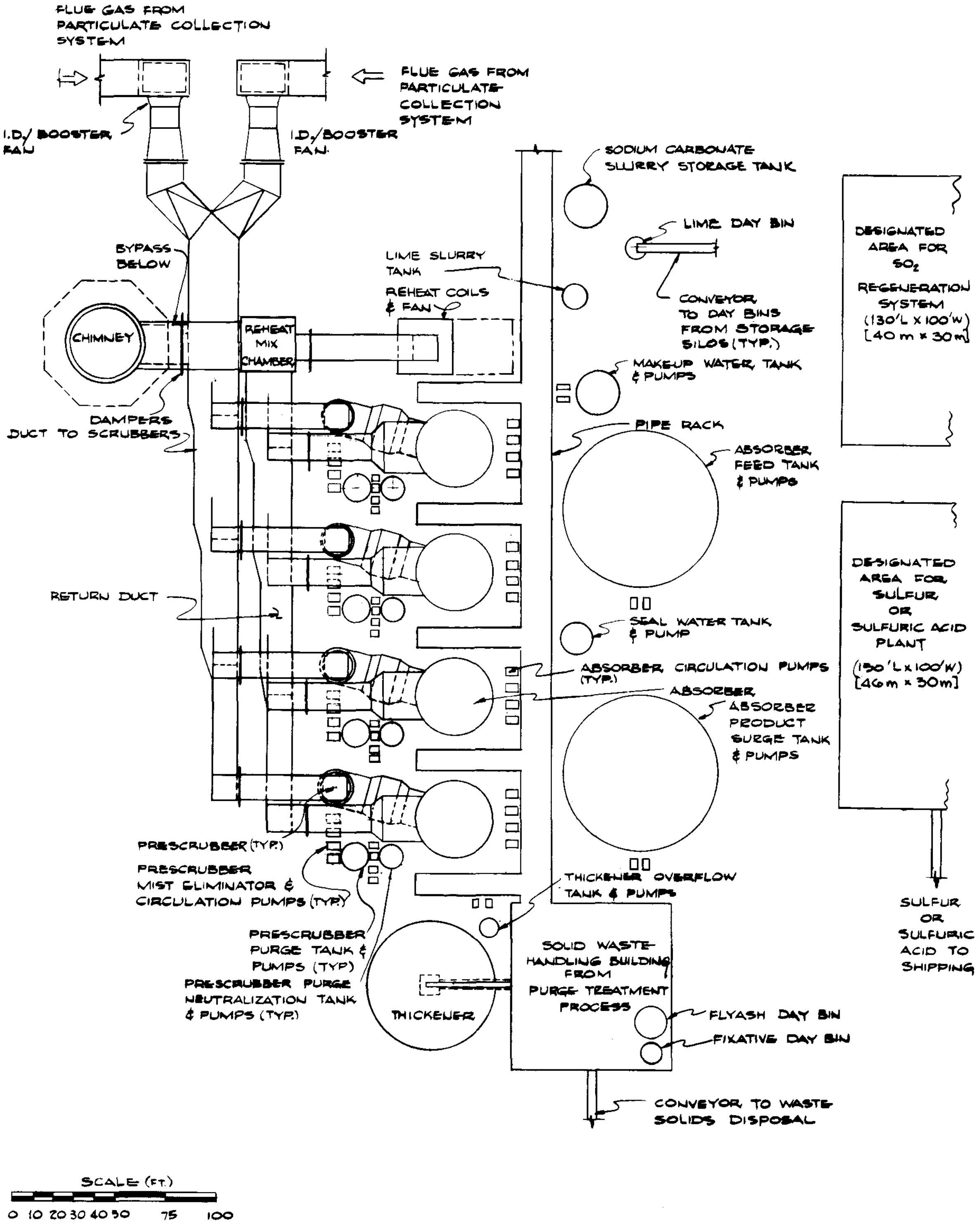


FIGURE 7-4

PLOT PLAN OF WELLMAN-LORD FGD SYSTEM

TABLE 7-2

WELLMAN-LORD SYSTEM
RAW MATERIAL AND UTILITY CONSUMPTION
(MAXIMUM LOAD - 105%)

Item	Quantity
Soda Ash	2.5 t/h (0.63 kg/s)
Lime (Fixative and Neutralization)	1.8 t/h (0.45 kg/s)
Raw Water	525 gpm (0.03 m^3/s)
Cooling Water	
FGD System	26,400 gpm (1.67 m^3/s)
Sulfuric Acid Plant	4,500 gpm (0.28 m^3/s)
Steam	439,000 lb/hr (55.3 kg/s)
Power (Operating Horsepower)*	
Area 01 - Raw Material Receiving and Storage	165 hp (123 kW)
Area 02 - Feed Preparation and Storage	50 hp (40 kW)
Area 03 - Flue Gas Scrubbing	3,700 hp (2800 kW)
Area 04 - Flue Gas Reheat	800 hp (600 kW)
Area 05 -Purge Treatment	530 hp (400 kW)
Area 06 - SO_2 Regeneration	520 hp (390 kW)
Area 07 - SO_2 Processing	
Sulfur Plant	.01 kWh/lb S (0.02 kWh/kg S)
Sulfuric Acid Plant	.023 kWh/lb acid (0.051 kWh/kg acid)
Area 10 - Byproduct Storage	50 hp (40 kW)
Area 11 - Flue Gas Handling	8,500 hp (6300 kW)
Steam Credit	
Sulfur Plant	20,300 lb/hr (2.56 kg/s)
Sulfuric Acid Plant	11,900 lb/hr (1.48 kg/s)
Methane (Sulfur Reduction Plant)	146 10^3 ft^3/hr (1.15 m^3/s)

*Total FGD system power consumption equal to approximately 2.1 percent of net generating capacity.

a pug mill-type process mixer. The fixed sludge is more stable than the untreated sludge and is suitable for landfill impoundment. The components and maximum load quantity of blended sludge for disposal are as follows:

Components	t/h	Wt %
Lime	0.35	2
Fly Ash	7	49
Waste Sludge	4	28
Water	3	21
Total Waste to Disposal	14.35	100

t/h = 907.2 kg/h

Based on a density of 95 lb/ft^3 (1500 kg/m^3), the following volumes are estimated for daily, yearly and plant life sludge production:

Daily Maximum - 270 yd^3 (210 m^3)
Annual - 41 acre-ft (51,000 m^3)
Plant Life - 1250 acre-ft (1,540,000 m^3)

7.B. TECHNICAL EVALUATION

The Wellman-Lord process is considered a wet recovery process producing a concentrated SO_2-rich off-gas which can be further processed to a saleable product. It is a fairly complex and sophisticated process, using a soluble sodium alkali to remove the SO_2 and thermal decomposition to recover an SO_2-rich off-gas. Sulfur is considered to be the most versatile end product from a storage and potential marketing viewpoint, but this option may be dependent on the availability of natural gas supplies. Processes using other reductants for the production of sulfur are in development, but are not considered commercial at this time.

Relative to limestone "throwaway processes" the Wellman-Lord process has several distinct advantages and disadvantages.

Advantages -

- The use of a soluble sodium alkali absorbent minimizes the potential for scaling and plugging in the absorber.
- A useful byproduct is recovered, minimizing disposal problems.

Disadvantages -

- It is a more complex system than the limestone systems and requires more skillful operators.
- A dry sodium sulfate/sodium sulfite purge stream is produced.
- It requires large quantities of steam either from the steam generator or an auxiliary boiler.

The Wellman-Lord process has been used successfully in several chemical process plants and oil-fired boilers. Coal-fired boiler application of the process include a 115 MW unit at Northern Indiana Public Service Company's D. H. Mitchell Station and Public Service Company of New Mexico's San Juan Station, where two 350 MW units have been completed and two 560 MW units are under construction.

7.C. ECONOMIC EVALUATION

The economic evaluation of the Wellman-Lord System is presented in the following tables:

Table 7-3	- Total Capital Requirement
Table 7-4A,B	- Operating Costs
Table 7-5	- Levelized Busbar Cost

Cost sensitivity to coal %-sulfur and plant size was determined by adjusting capital and operating costs and reevaluating levelized busbar cost. Cost sensitivity to coal %-sulfur is illustrated in Figure 7-5 and to plant size in Figure 7-6.

A byproduct credit has been considered for the sale of either sulfur or sulfuric acid in the economic analysis as shown in Tables 7-4 and 7-5. The cost sensitivity curves, however, are based on no byproduct credit.

These curves are based on two additional estimates for the system for each parameter. Costs were adjusted to values for 0.5 percent and 2.0 percent sulfur coal and for 250 MW and 1000 MW plant sizes. These values, combined with the base case value, were used to plot the cost sensitivity curves.

TABLE 7-3

WELLMAN-LORD SYSTEM
TOTAL CAPITAL REQUIREMENT
500 MW NEW PLANT
MID-1978 COSTS, MID-1979 STARTUP
ILLINOIS COAL - 4% SULFUR

Process Capital

Area	Description	Byproduct Options Sulfuric Acid $/Kw	 Sulfur $/Kw
01	Raw Material Receiving and Storage	3.5	3.5
02	Feed Preparation and Storage	0.6	0.6
03	Flue Gas Scrubbing	50.1	50.1
04	Flue Gas Reheat	7.3	7.3
05	Purge Treatment	16.1	16.1
06	SO_2 Regeneration	33.4	33.4
07	SO_2 Processing	25.1	16.9
10	Byproduct Storage	8.0	3.1
11	Flue Gas Handling	25.4	25.4
12	Waste Transfer and Placement	1.4	1.4
	Total Process Capital	170.9	157.7
General Facilities		21.4	19.7
Engineering and Home Office Fees		21.4	19.7
Project Contingency		8.5	7.9
Process Contingency		8.5	7.9
Sales Tax (Included in Process Capital)		--	--
	Total Plant Investment (TPI)	230.7	212.9
Royalty Allowance		0.9	0.8
Preproduction Costs		15.9	15.4
Inventory Capital		0.4	0.4
Initial Catalyst and Chemicals		--	--
Allowance for Funds During Construction (AFDC)		18.5	17.0
Land		1.0	1.0
	Total Capital Requirement (TCR)	267.4	247.5

TABLE 7-4A

WELLMAN-LORD SYSTEM
FIXED OPERATING COSTS
500 MW NEW PLANT
MID-1978 COSTS, MID-1979 STARTUP
ILLINOIS COAL - 4% SULFUR

	Sulfuric Acid Plant			Sulfur Plant		
Fixed Operating Costs	1st Year $/Yr	1st Year $/kW Yr	Levelized $/kW-Yr	1st year $/Yr	1st year $/kW-Yr	Levelized $/kW-Yr
Operating Labor						
FGD System	$1,410,000	2.83	5.34	$1,410,000	2.83	5.34
Sludge Disposal	78,000	0.16	0.30	78,000	0.16	0.30
Maintenance Labor	2,730,000	5.47	10.31	2,520,000	5.04	9.51
Maintenance Material	4,090,000	8.18	15.43	3,780,000	7.56	14.26
Admin. & Support Labor	1,260,000	2.52	4.75	1,200,000	2.40	4.53
Disposal Equipment	38,000	0.08	0.15	38,000	0.08	0.15
	$9,600,000	19.24	36.28	$9,026,000	18.05	34.04

TABLE 7-4B

WELLMAN-LORD SYSTEM
VARIABLE OPERATING COSTS
500 MW NEW PLANT
MID-1978 COSTS, MID-1979 STARTUP
ILLINOIS COAL - 4% SULFUR

		Sulfuric Acid Plant			Sulfur Plant		
Variable Operating Costs		1st Year $/Yr	1st Year Mills/kWh	Levelized Mills/kWh	1st year $/Yr	1st year Mills/kWh	Levelized Mills/kWh
Soda Ash -	14,100 t/y @ $66/ton	$ 930,000	0.30	0.57	$ 930,000	0.30	0.57
Lime -	8800 t/y @ $34/ton	300,000	0.10	0.19	300,000	0.10	0.19
Raw Water -	184,000 x 10^3/gal/yr @ $0.40/$10^3$ gal	74,000	0.02	0.05	74,000	0.02	0.05
Methane -	853,000 MCF/yr @ $4/MCF	-	-	-	3,410,000	1.11	2.14
Cooling Water							
FGD System	9,250,000 x 10^3 gal/yr @ $0.10/$10^3$ gal	925,000	0.30	0.57	925,000	0.30	0.57
Acid Plant	1,600,000 x 10^3 gal/yr @ $0.10/$10^3$ gal	160,000	0.05	0.10	-	-	-

Note: 1.0 t/y = 9.071×10^2 kg/y
1.0 gal = 3.785×10^{-3} m^3

TABLE 7-4B (Continued)

WELLMAN-LORD SYSTEM
VARIABLE OPERATING COSTS
500 MW NEW PLANT
MID-1978 COSTS, MID-1979 STARTUP
ILLINOIS COAL - 4% SULFUR

Variable Operating Costs (Continued)		Sulfuric Acid Plant 1st Year \$/Yr	Sulfuric Acid Plant 1st Year Mills/kWh	Sulfuric Acid Plant Levelized Mills/kWh	Sulfur Plant 1st year \$/Yr	Sulfur Plant 1st year Mills/kWh	Sulfur Plant Levelized Mills/kWh
Steam (Levelized Cost)							
FGD System	2,560,000 x 10^3 lb./yr @ \$3.49/10^3lb	-	-	2.91	-	-	2.91
Acid Plant	120,000 x 10^3 lb./hr @ \$3.49/10^3lb (credit)	-	-	(0.14)	-	-	-
Sulfur Plant	70,000 x 10^3lb/yr @ \$3.49/10^3lb (Credit)	-	-	-	-	-	(0.08)
Power							
FGD System	65 x 10^6 kWh/yr @ 30 mills/kWh	1,960,000	0.64	1.22	1,960,000	0.64	1.22
Acid Plant	7.6 x 10^6 kWh/yr @ 30 mills/kWh	230,000	0.07	0.14	-	-	-
Sulfur Plant	1.0 x 10^6 kWh/yr @ 30 mills/kWh	-	-	-	30,000	0.01	0.02

Note: 1.0 t/y = 9.071 X 10^2 kg/y

TABLE 7-4B (Continued)

WELLMAN-LORD SYSTEM
VARIABLE OPERATING COSTS
500 MW NEW PLANT
MID-1978 COSTS, MID-1979 STARTUP
ILLINOIS COAL - 4% SULFUR

Variable Operating Costs (Continued)		Sulfuric Acid Plant			Sulfur Plant		
		1st Year $/Yr	1st Year Mills/kWh	Levelized Mills/kWh	1st year $/Yr	1st year Mills/kWh	Levelized Mills/kWh
Power (Continued)							
Fly Ash	43,000 t/y @ $4.00/ton (credit)	(172,000)	(0.06)	(0.11)	(172,000)	(0.06)	(0.11)
Total Variable Operating Cost				5.5			7.48

Byproduct Credit		1st Year $/Yr	1st Year Mills/kWh	Levelized Mills/kWh
Sulfuric Acid (100% basis)	147,000 t/y @ $40/ton	($5,880,000)	(1.92)	(3.62)
Sulfur	43,000 t/y @ $50/long ton	($2,150,000)	(0.70)	(1.32)

Note: 1.0 t/y = 9.071 X 10^2 kg/y

TABLE 7-5

WELLMAN-LORD SYSTEM
LEVELIZED BUSBAR COST
500 MW NEW PLANT
MID-1978 COSTS, MID-1979 STARTUP
ILLINOIS COAL - 4% SULFUR

	Levelized Mills/kWh	
	Byproduct Option	
	Sulfuric Acid	Sulfur
Process Capital	5.02	4.63
General Facilities	0.63	0.58
Engineering and Home Office Fees	0.63	0.58
Project Contingency	0.25	0.22
Process Contingency	0.25	0.22
Total Plant Investment	6.78	6.23
Royalty Allowance	0.03	0.02
Preproduction Costs	0.47	0.45
Inventory Capital	0.01	0.01
Allowance For Funds During Contruction (AFDC)	0.54	0.50
Land	0.03	0.03
Total Capital Requirement	7.86	7.24
Fixed Operating Cost	5.92	5.55
Variable Operating Cost	5.5	7.48
Total Levelized Busbar Cost	19.3	20.3
Byproduct Credit	(3.62)	(1.32)
Total Levelized Busbar Cost Adjusted for Byproduct Credit	15.7	19.0

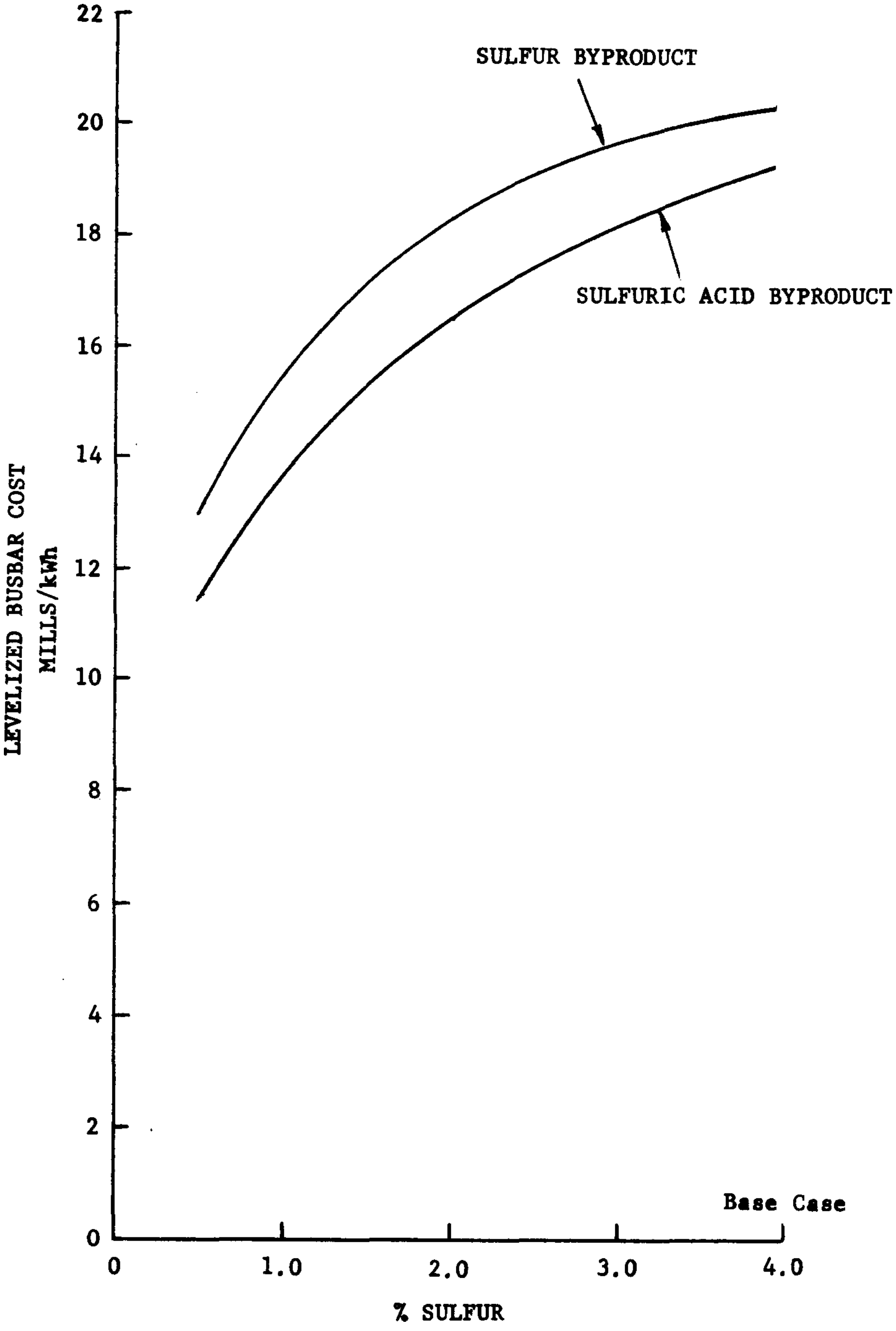


FIGURE 7-5

WELLMAN-LORD SYSTEM
COST VERSUS SULFUR CONTENT OF COAL
(No Byproduct Credit)

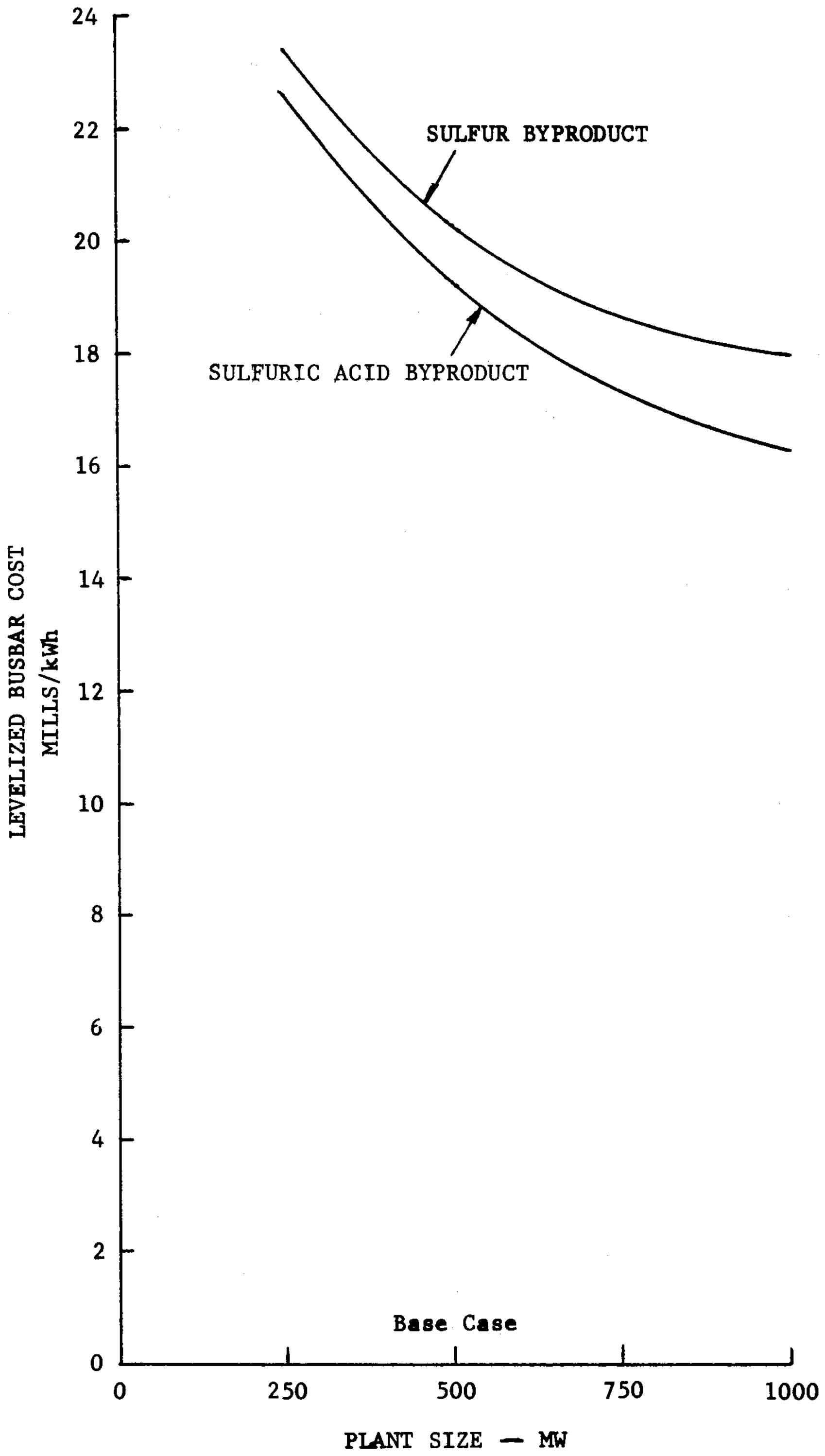


FIGURE 7-6

WELLMAN-LORD SYSTEM
COST VERSUS PLANT SIZE
(No Byproduct Credit)

Appendix A

CONVENTIONAL LIMESTONE SYSTEM EQUIPMENT LIST

AREA 01 - RAW MATERIAL RECEIVING AND STORAGE

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Limestone Receiving System	1 Lot	$362,000	$362,000
Service: Limestone receiving area, - 3/4" limestone			
Includes: 1-two railcar covered spot 4-50-ton, below-rail hoppers 4-vibratory feeders, 10 HP 2-24" x 75' feed belts, 10 HP 1-24" x 200', 10% inclined belt, 10 HP 1-4000 ACFM baghouse, 10 HP			
Limestone Bulk Storage Transfer System	1 Lot	$147,000	$147,000
Service: Transfer of limestone from unloading area to bulk storage pile			
Includes: 1-24" x 100', 10% inclined belt, 10 HP 1-24" x 200' horizontal belt, 10 HP 1-24" x 150' mobile stacker, 20 HP 1-10,000 ACFM baghouse, 20 HP			
Live Storage Load Hopper	2	$ 32,000	$ 64,000
Size: 25' x 25' x 20' straight side with sloped bottom Service: -3/4" limestone Capacity: 200 tons Material: Carbon steel			
Limestone Live Storage Transfer System	1 Lot	$114,000	$114,000
Service: Transfer of limestone from bulk storage to top of limestone day bin			
Includes: 1-24" x 300', 15% inclined belt, 10 HP motor			

AREA 01 RAW MATERIAL RECEIVING AND STORAGE (Continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
2-24" x 100', feed conveyor belts, 10 HP motor 1-4000 ACFM baghouse, 10 HP motor			
Fixative Reagent Storage Silo	1	$149,000	$149,000
Dimensions: 30' dia. x 75' straight side with conical bottom			
Fixative Reagent Storage Silo	1	$149,000	$149,000
Dimensions: 30' dia. x 75' straight side with conical bottom Retention: 30 days Material of Construction: Steel-reinforced concrete Accessories: Combination rail and truck receiving spot for pneumatic unloading			
Fixative Storage Silo Baghouse	1	$ 47,000	$ 47,000
Type: Pulse-jet Air Flow: 10,000 ACFM Material: Carbon steel Blower Motor: 20 HP Accessories: Compressor and blowers			
Fixative Pneumatic Conveyor System	2	$ 16,700	$ 33,400
Type: Pneumatic Service: Granular quicklime Solids Rate: 30 TPH Air Rate: 3000 ACFM Transfer Lines: 6", 300' long Blower Motor: 50 HP			

Area 01 Total Equipment Cost = $916,000

AREA 02 - FEED PREPARATION AND STORAGE

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Limestone Day Bin	4	$ 42,000	$168,000
Size: 16' dia. x 40' straight side, 70° cone bottom Service: -3/4" limestone Sizing Criteria: Total storage equal to 30-hr. surge at maximum continuous consumption Material: Carbon steel Accessories: Displacement filter, bin discharger			

AREA 02 FEED PREPARATION AND STORAGE (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Limestone Vibratory Feeder Type: Vibratory Service: -3/4" limestone Motor: 20 HP	4	$ 6,000	$ 24,000
Limestone Feeder Type: Weigh belt gravimetric feeder Service: -3/4" limestone Motor: 3 HP	2	$ 10,000	$ 20,000
Ball Mill & Classifier System Service: -3/4" limestone Grind: 90 wt % - 200 mesh Feed Rate: 36 TPH limestone Construction: Carbon steel with Chrome-molybdenum liner Motor: 1000 HP	2	$400,000	$800,000
Limestone Grind Tank Size: 16' dia. x 20' straight side Service: 60 wt % solids limestone slurry Material: Rubber-lined carbon steel Normal Level: 12' Accessories: Agitator bridge	2	$ 32,500	$ 65,000
Limestone Grind Tank Agitator Tank Size: 16' dia. x 20' straight side Service: 60 wt % limestone slurry Normal Level: 12' Motor: 15 HP	2	$ 5,500	$ 11,000
Limestone Grind Tank Slurry Pump Type: Horizontal centrifugal Material: Rubber-lined cast iron Flow: 150 GPM Head: 50' TDH Motor: 7.5 HP	2	$ 2,000	$ 4,000
Limestone Slurry Tank Size: 25' dia. x 25' straight side Service: 20 wt % limestone slurry Sizing Criteria: Total capacity to equal 8-hr. surge at maximum continuous consumption	3	$ 80,000	$240,000

AREA 02 - FEED PREPARATION AND STORAGE (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Material: Carbon steel Normal Level: 20' Accessory: Agitator bridge, 50% height wear-ring			
Limestone Slurry Tank Agitator Tank Size: 25' dia. x 25' straight side Service: 20 wt % limestone slurry Normal Level: 20' Motor: 15 HP	3	$ 6,000	$ 18,000
Limestone Slurry Pump Type: Horizontal centrifugal Material: Rubber-lined cast iron Flow: 630 GPM Head: 100' TDH Motor: 40 HP	2	$ 3,000	$ 6,000

Area 02 Total Equipment Cost = $1,360,000

AREA 03 - FLUE GAS SCRUBBING

Absorber Tower Type: Vertical countercurrent spray tower Dimensions: 38' I.D. x 110' straight side with 16' diameter outlet cap Material of Construction: 317L stainless steel Internal Superficial Gas Velocity: 10 fps Mist Eliminator: Vertical chevron, 20 fps maximum design velocity	4	$970,00	$3,880,000
Spray Pump Type: Horizontal centrifugal Material: Rubber-lined carbon steel Flow: 11,000 GPM Head: 100' TDH Motor: 400 HP	16	$25,000	$400,000
Reaction Mix Tank Size: 35' dia. x 36' straight side Service: 10 wt % scrubber slurry Sizing Criteria: 6 minute retention of recirculaterd flow rate Material: Rubber-lined carbon steel Normal Level: 30' Accessories: Agitator bridge	4	$160,000	$640,000

AREA 03- FLUE GAS SCRUBBING (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Reaction Mix Tank Agitator Tank Size: 36' dia. x 36' straight side Service: 10 wt % scrubber slurry Normal Level: 30' Motor: 20 HP	4	$ 16,000	$ 64,000
Makeup Water Tank Size: 25' dia. x 25' straight side Service: Water Sizing Criteria: 2-hr. surge capacity at estimated maximum consumption Material: Carbon steel Normal Level: 20'	1	$ 50,000	$ 50,000
Makeup Water Pump Type: Horizontal centrifugal Material: Cast steel Flow: 700 GPM Pressure: 125 psi Motor: 85 HP	2	$ 8,500	$ 17,000
Seal Water Tank Size: 15' dia. x 15' straight side Service: Water Sizing Criteria: 2-hr. surge capacity Material: Carbon steel Normal Level: 10'	1	$ 22,500	$ 22,500
Seal Water Filter Unit Type: Cartridge (fiber) filter Service: Makeup water Capacity: 175 GPM Power Required: 10 HP	1	$ 6,000	$ 6,000
Seal Water Pump Type: Horizontal centrifugal Material: Cast steel Flow: 160 GPM Pressure: 125 psi Motor: 40 HP	2	$ 1,800	$ 3,600
Instrument/Plant Air Compressor System Type: Multi-stage, centrifugal air compressor unit complete with control unit, motor driver, and	2	$ 90,000	$180,000

AREA 03 -FLUE GAS SCRUBBING (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
instrument air-dryer, pre-filter, after-filter, after-cooler, and air receivers Service: Air Air-Dryer Power Consumption: 9.9 kW Motor: 700 HP			

Area 03 Total Equipment Cost = $5,260,000

AREA 04 - FLUE GAS REHEAT

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Reheat Air Fan	1	$125,000	$125,000
Conditions: 343,300 ACFM @ 10" WC 60°F air Type: Air-foil centrifugal fan with variable inlet vanes for flow control Motor: 800 HP			
Reheat Steam Coil Air Heater	1	$150,000	$150,000
Type: Finned Tube Steam Coil - includes condensing and subcooling sections Service: Air heater Duty: 125 x 10^6 Btu/HR			
Reheat Mix Chamber	1	$310,000	$310,000
Service: Flue gas Material: 316L stainless steel Size: 27' x 27' x 27' total length			
Reheat Duct	1 Lot		$244,000
Service: Flue gas Type: Rectangular with external stiffeners Material: Carbon steel Size: 11'-3" x 11'-3" x 25' total length			
Reheat Isolation Damper	1	$ 80,000	$ 80,000
Type: Double-louver system, opposed-blade for control/parallel blade for tight shutoff with purge air blower Service: Air and flue gas (382°F maximum temperature) Materials: Stainless steel Duct Size: 11'3" x 11'3"			

Area 04 Total Equipment Cost = $909,000

AREA 08 - WASTE SEPARATION

Equipment Item and Desctiption	Qty.	Unit Cost	Total Cost
Thickener System	1	$150,000	$150,000
Size: 150' dia. Service: Scrubber sludge Sizing Criteria: 18 ft^2/TPD dry solids Materials: Epoxy coated carbon steel rake/bridge, carbon steel shell, concrete bottom Motor: 25 HP Accessories: Tunnel, feed launder, personnel bridge			
Flocculant System	1	$ 10,000	$ 10,000
Includes mixing tank, multiple metering pumps, agitator, water booster pumps, and local controls Power Required: 10 HP			
Thickener Overflow Tank	1	$ 33,000	$ 33,000
Size: 25' dia. x 12' straight side Service: Water Sizing Criteria: 30 min. surge capacity Material: Carbon steel Normal Level: 8'			
Thickener Overflow Pump	2	$ 11,000	$ 22,000
Type: Horizontal centrifugal Material: Cast steel Flow: 1900 GPM Pressure: 100 psi Motor: 200 HP			
Thickener Underflow Pump	2	$ 11,000	$ 22,000
Type: Progressive cavity, positive displacement Material: Cast iron housing; hardened stainless steel rotor; rubber stator Flow: 600 GPM Head: 50' TDH Motor: 15 HP			
Filter Feed Tank	2	$ 90,000	$180,000
Size: 25' dia. x 30' straight side Service: 25 wt % scrubber slurry Sizing Criteria: 4-hr. surge capacity Material: Carbon steel with reinforced			

AREA 08 WASTE SEPARATION (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
polyester lining Normal Level: 15' Accessories: Agitator bridge			
Filter Feed Tank Agitator Tank Size: 25' dia. x 30' straight side Service: 25 wt % scrubber slurry Normal Level: 20' Motor: 20 HP	2	$ 16,500	$ 33,000
Filter Feed Pump Type: Progressive cavity Material: Cast iron housing; hardened stainless steel rotor; rubber stator Flow: 900 GPM Pressure: 50 psi Motor: 50 HP	2	$ 22,000	$ 44,000
Vacuum Filter System Type: Face scraper rotary drum vacuum filter Size: 12' dia. x 12' wide cloth Sizing Criteria: 100 lb/hr/ft^2 - dry solids basis Service: Scrubber sludge Accessories: Receiver, pumps, blower, and control panel Power Required: 130 HP	3	$105,000	$315,000
Filtrate Receiver Pump Type: Horizontal centrifugal Material: Cast steel Flow: 325 GPM Pressure: 100' TDH Motor: 15 HP	3	Price included in vacuum filter system	
Area Sump Pump Type: Vertical centrifugal Material: Rubber-lined carbon steel Flow: 100 GPM Head: 40'-60' TDH Motor: 7.5 HP	16	$ 2,700	$ 43,200
Area Sump Agitator For assorted area sumps of varied size and service	8	$ 1,300	$ 10,400

AREA 08 WASTE SEPARATION (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Power Required: 1 HP ea.			
Area 08 Total Equipment Cost = $863,000			
AREA 09 - WASTE DISPOSAL			
Fixative Day Bin Size: 16' dia. x 18' straight side, 70° cone bottom Service: Granular quicklime Sizing Criteria: 36-hr. storage capacity Material: Carbon steel Acessories: Baghouse & airlock	1	$ 21,000	$ 21,000
Fixative Weigh Feeder Type: Weigh belt gravimetric feeder Service: Granular quicklime Motor: 3 HP	1	$ 5,500	$ 5,500
Fly Ash Pneumatic Conveyor System Type: Pneumatic Service: Fly ash Solids Rate: 150 TPH Air Rate: 10,000 CFM Transfer Lines: 10", 700' long, abrasion resistant Blower Motor: 150 HP	2	$ 89,000	$178,000
Fly Ash Day Bin Size: 15' dia. x 45' straight side, 70° cone Service: Fly ash Sizing Criteria: 8-hr. storage capacity @ maximum load Material: Carbon steel Accessories: Baghouse & airlock	1	$ 44,000	$ 44,000
Fly Ash Weigh Feeder Type: Weigh belt gravimetric feeder Service: Fly ash Motor: 3 HP	1	$ 8,500	$ 8,500
Process Mixer System Type: Pug mill Service: Ash, sludge, sludge water, fixative lime	2	$ 43,500	$ 87,000

AREA 09 - WASTE DISPOSAL (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Capacity: 300 Mlb/hr Motor: 150 HP			
Waste Solids Conveyor	2	$13,000	$ 26,000
Type: Belt Service: Waste solids Lenght: 40' Width: 24" Motor: 5 HP			
Waste Solids Stacker	1	$ 59,000	$ 59,000
Type: Inclined belt conveyor for stacking waste solids when hauling equipment not operating Service: Waste solids Length: 100' Width: 24" Motor: 10 HP			
Waste Solids Shuttle Loader	1	$ 45,500	$ 45,500
Type: Belt conveyor for direct loading of waste solids to trucks Service: Waste solids Length: 50' Width: 24" Motor: 10 HP			
Waste Solids Conveyor Dust Collector	2	$ 5,000	$ 10,000
Type: Pulse-jet fabric filter Air Flow: 1000 ACFM Material: Carbon steel Blower Motor: 3 HP			

Area 09 Total Equipment Cost = $485,000

AREA 11 - FLUE GAS HANDLING

Equipment Item and Description	Qty.	Unit Cost	Total Cost
I.D./Booster Fan	2	$415,000	$830,000
Conditions: 950,000 ACFM @ 25" WC and 283°F Type: Armored radial tip, centrifugal fan with variable inlet vanes for flow control Motor: 5000 HP			
Apportioned to FGD System: 10" of 25" WC (10/25 = 0.4)		$166,000	$332,000

AREA 11 - FLUE GAS HANDLING (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Inlet Ducting from I.D. Fan to Manifold Service: Flue gas Type: Circular to Rectangular Transition Materials: Carbon steel Size: 18' dia. x 75' total length	2	$113,000	$226,000
Inlet Ducting Manifold Service: Flue gas Type: Rectangular with external stiffeners Material: Carbon steel Size: Section 1 - 23' x 23' x 150' total length Section 2 - 19' x 19' x 50' total length Section 3 - 13' x 14' x 50' total length	1 Lot		$740,000
Inlet Ducting to Scrubber Tower Service: Flue gas Type: Rectangular with external stiffeners Material: Carbon steel Size: 14' x 14' x 80' total length	4	$30,000	$120,000
Outlet Ducting Manifold Service: Scrubbed gas Type: Rectangular with external stiffeners Material: Carbon steel, reinforced polyester lined Size: Section 1 - 21' x 21' x 100' total length Section 2 - 17' x 17' x 50' total length Section 3 - 12' x 12' x 50' total length	1 Lot		$920,000
Outlet Ducting from Scrubber Tower Service: Scrubbed gas Type: Rectangular with external stiffeners Material: Carbon steel, reinforced polyester lined Size: 12' x 12' x 120' total length	4	$142,000	$568,000
Bypass Service: Flue gas Type: Rectangular with external stiffeners	1	$75,000	$75,000

AREA 11 - FLUE GAS HANDLING (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Material: Carbon steel, acid resistant gunnite-lined Size: 22' x 22' x 25' total length			
Chimney Transition Service: Reheated scrubbed gas Type: Rectangular with external stiffeners Material: Carbon steel, reinforced polyester lined Size: 22' x 22' x 50' total length	1	$150,000	$150,000
I.D./Booster Fan Inlet Isolation Damper Type: Spade guillotine w/purge air Service: Flue gas (283°F) Materials: Carbon steel with stainless steel trim Duct Size: 18' diameter	2	$105,000	$210,000
Scrubber Inlet Isolation Damper Type: Duplex guillotine with purge air Service: Flue gas Materials: Carbon steel with stainless steel trim Duct Size: 14' x 14'	4	$ 61,000	$244,000
Scrubber Outlet Isolation Damper Type: Duplex guillotine with purge air Service: Scrubbed gas Materials: Carbon steel and nickel basemetal for wetted parts Duct Size: 12' x 12'	4	$ 78,000	$312,000
FGD System Bypass Damper Type: Double-louver, opposed blade & parallel blade w/purge air Service: Flue gas Materials: Carbon steel with stainless steel trim Duct Size: 21'3" x 21'3"	1	$ 90,000	$ 90,000

Area 11 Total Equipment Cost = $3,990,000

AREA 12 - WASTE TRANSFER AND PLACEMENT

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Waste Solids Loader Type: Wheel loader	1	$165,000	$165,000

AREA 12 - WASTE TRANSFER AND PLACEMENT (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Bucket Capacity: 5 yd^3			
Estimated Service Life: 10,000 hr			
Interim Replacement Book Life: 6 yrs			
Equivalent Capital Cost		$425,000	$425,000
Waste Solids Transfer Truck	4	$220,000	$880,000
Type: Off-highway truck			
Capacity: 22 yd^3			
Estimated Service Life: 15,000 hr			
Interim Replacement Book Life: 7.5 yr			
Equivalent Capital Cost		$485,000	$1,940,000
Waste Solids Landfill Bulldozer	1	$137,000	$ 137,000
Type: Tracked bulldozer			
Estimated Service Life: 10,000 hr			
Interim Replacement Book Life: 6 yr			
Equivalent Capital Cost		$353,000	$ 353,000

Area 12 Total Equivalent Equipment Cost = $2,720,000

Blank

Appendix B

EPRI/TVA COCURRENT SYSTEM EQUIPMENT LIST

AREA 01 - RAW MATERIAL RECEIVING AND STORAGE

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Limestone Receiving System	1 Lot	$362,000	$362,000
Service: Limestone receiving area, - 3/4" limestone Includes: 1-two railcar covered spot 4-50-ton, below-rail hoppers 4-vibratory feeders, 10 HP 2-24" x 75' feed belts, 10 HP 1-24" x 200', 10% inclined belt, 10 HP 1-4000 ACFM baghouse, 10 HP			
Limestone Bulk Storage Transfer System	1 Lot	$147,000	$147,000
Service: Transfer of limestone from unloading area to bulk storage pile Includes: 1-24" x 100', 10% inclined belt, 10 HP 1-24" x 200' horizontal belt, 10 HP 1-24" x 150' mobile stacker, 20 HP 1-10,000 ACFM baghouse, 20 HP			
Live Storage Load Hopper	2	$ 32,000	$ 64,000
Size: 25' x 25' x 20' straight side with sloped bottom Service: -3/4" limestone Capacity: 200 tons Material: Carbon steel			
Limestone Live Storage Transfer System	1 Lot	$114,000	$114,000
Service: Transfer of limestone from bulk storage to top of limestone day bin Includes: 1-24" x 300', 15% inclined belt, 10 HP motor 2-24" x 100', feed conveyor belts, 10 HP motor 1-4000 ACFM baghouse, 10 HP motor			

AREA 01 - RAW MATERIAL RECEIVING AND STORAGE (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Fixative Reagent Storage Silo Dimensions: 30' dia. x 75' straight side with conical bottom Retention: 30 days Material of Construction: Steel-reinforced concrete Accessories: Combination rail and truck receiving spot for pneumatic unloading	1	$149,000	$149,000
Fixative Storage Silo Baghouse Type: Pulse-jet Air Flow: 3000 ACFM Material: Carbon steel Blower Motor: 20 HP Accessories: Compressor and blowers	1	$ 47,000	$ 47,000
Fixative Pneumatic Conveyor System Type: Pneumatic Service: Granular quicklime Solids Rate: 30 TPH Air Rate: 3000 ACFM Transfer Lines: 6", 300' long Blower Motor: 50 HP	2	$ 16,700	$ 33,400

Area 01 Total Equipment Cost = $916,000

AREA 02 - FEED PREPARATION AND STORAGE

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Limestone Day Bin Size: 18' dia. x 36' straight side, 70° cone bottom Service: -3/4" limestone Sizing Criteria: Total storage equal to 30-hr. surge at maximum continuous consumption Material: Carbon steel Accessories: Displacement filter, bin discharger	4	$ 48,000	$192,000
Limestone Vibratory Feeder Type: Vibratory Service: -3/4" limestone Motor: 20 HP	4	$ 6,000	$ 24,000

AREA 02 - FEED PREPARATION AND STORAGE (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Limestone Feeder Type: Weigh belt gravimetric feeder Service: -3/4" limestone Motor: 3 HP	2	$ 10,000	$ 20,000
Ball Mill & Classifier System Service: -3/4" limestone Grind: 90 wt %, -200 mesh Feed Rate: 42 TPH limestone Construction: Carbon steel with Chrome-molybdenum liner Motor: 1200 HP	2	$440,000	$880,000
Limestone Grind Tank Size: 22' dia. x 24' straight side Service: 60 wt % solids limestone slurry Material: Rubber-lined carbon steel Normal Level: 16' Accessories: Agitator bridge	2	$ 50,000	$100,000
Limestone Grind Tank Agitator Tank Size: 22' dia. x 24' straight side Service: 60 wt % limestone slurry Normal Level: 16' Motor: 15 HP	2	$ 5,500	$ 11,000
Limestone Grind Tank Slurry Pump Type: Horizontal centrifugal Material: Rubber-lined cast iron Flow: 170 GPM Head: 50' TDH Motor: 7.5 HP	2	$ 2,000	$ 4,000
Limestone Slurry Tank Size: 26' dia. x 26' straight side Service: 20 wt % limestone slurry Sizing Criteria: Total capacity to equal 8-hr. surge at maximum continuous consumption Material: Carbon steel Normal Level: 21' Accessory: Agitator bridge, 50% height wear-ring	3	$ 87,000	$261,000

AREA 02 FEED PREPARATION AND STORAGE (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Limestone Slurry Tank Agitator Tank Size: 26' dia. x 26' straight side Service: 20 wt % limestone slurry Normal Level: 21' Motor: 15 HP	3	$ 6,000	$ 18,000
Limestone Slurry Pump Type: Horizontal centrifugal Material: Rubber-lined cast iron Flow: 710 GPM Head: 100' TDH Motor: 40 HP	2	$ 3,000	$ 6,000

Area 02 Total Equipment Cost = $1,520,000

AREA 03 - FLUE GAS SCRUBBING

Absorber Tower Type: Vertical cocurrent spray tower with grid packing Dimensions: 22' I.D. x 120' straight side Material of Construction: 317L stainless steel Internal Gas Velocity: 27 fps Mist Eliminator: Vertical chevron, 20 fps maximum design velocity	4	$800,000	$3,200,000
Spray Pump Type: Horizontal centrifugal Material: Rubber-lined carbon steel Flow: 10,000 GPM Head: 100' TDH Motor: 400 HP	24	$ 24,000	$ 576,000
Reaction Mix Tank Size: 36' dia. x 36' straight side Service: 10 wt % scrubber slurry Sizing Criteria: 6 minute retention of recirculated flow rate Material: Rubber-lined carbon steel Normal Level: 30' Accessories: Agitator bridge	4	$165,000	$ 660,000
Reaction Mix Tank Agitator Tank Size: 36' dia. x 36' straight side Service: 10 wt % scrubber slurry	4	$ 16,000	$ 64,000

AREA 03- FLUE GAS SCRUBBING (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Normal Level: 30' Motor: 20 HP			
Makeup Water Tank	1	$ 50,000	$ 50,000
Size: 25' dia. x 25' straight side Service: Water Sizing Criteria: 2-hr. surge capacity at estimated maximum consumption Material: Carbon steel Normal Level: 20'			
Makeup Water Pump	2	$ 8,500	$ 17,000
Type: Horizontal centrifugal Material: Cast steel Flow: 700 GPM Pressure: 125 psi Motor: 85 HP			
Seal Water Tank	1	$ 22,500	$ 22,500
Size: 15' dia. x 15' straight side Service: Water Sizing Criteria: 2-hr. surge capacity Material: Carbon steel Normal Level: 10'			
Seal Water Filter Unit	1	$ 6,000	$ 6,000
Type: Cartridge (fiber) filter Service: Makeup water Capacity: 175 GPM Power Required: 10 HP			
Seal Water Pump	2	$ 1,800	$ 3,600
Type: Horizontal centrifugal Material: Cast steel Flow: 160 GPM Pressure: 125 psi Motor: 40 HP			
Instrument/Plant Air Compressor System	2	$ 90,000	$180,000
Type: Multi-stage, centrifugal air compressor unit complete with control unit, motor driver, and instrument air-dryer, pre-filter, after-filter, after-cooler and air receivers Service: Air			

AREA 03- FLUE GAS SCRUBBING (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Air-Dryer Power Consumption: 9.9 kW Motor: 700 HP			

Area 03 Total Equipment Cost = $4,780,000

AREA 04 - FLUE GAS REHEAT

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Reheat Air Fan	1	$125,000	$125,000
Conditions: 343,300 ACFM @ 10" WC 60°F air Type: Air-foil centrifugal fan with variable inlet vanes for flow control Motor: 800 HP			
Reheat Steam Coil Air Heater	1	$150,000	$150,000
Type: Finned Tube Steam Coil - includes condensing and subcooling sections Service: Air heater Duty: 125 x 10^6 Btu/HR			
Reheat Mix Chamber	1	$310,000	$310,000
Service: Flue gas Material: 316L stainless steel Size: 27' x 27' x 27' total length			
Reheat Duct	1 Lot		$150,000
Service: Flue gas Type: Rectangular with external stiffeners Material: Carbon steel Size: 11'-3" x 11'-3" x 15' total length			
Reheat Isolation Damper	1	$ 80,000	$ 80,000
Type: Double-louver system, opposed-blade for control/parallel blade for tight shutoff with purge air blower Service: Air and flue gas (382°F maximum temperature) Materials: Stainless steel Duct Size: 11'3" x 11'3"			

Area 04 Total Equipment Cost = $815,000

AREA 08 - WASTE SEPARATION

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Thickener System Size: 170' dia. Service: Scrubber sludge Sizing Criteria: 18 ft^2/TPD dry solids Materials: Epoxy coated carbon steel rake/bridge, carbon steel shell, concrete bottom Motor: 25 HP Accessories: Tunnel, feed launder, personnel bridge	1	$180,000	$180,000
Flocculant System Includes mixing tank, multiple metering pumps, agitator, water booster pumps, and local controls Power Required: 10 HP	1	$ 10,000	$ 10,000
Thickener Overflow Tank Size: 28' dia. x 12' straight side Service: Water Sizing Criteria: 30 min. surge capacity Material: Carbon steel Normal Level: 8'	1	$ 38,000	$ 38,000
Thickener Overflow Pump Type: Horizontal centrifugal Material: Cast steel Flow: 2055 GPM Pressure: 100 psi Motor: 200 HP	2	$ 11,500	$ 23,000
Thickener Underflow Pump Type: Progressive cavity, positive displacement Material: Cast iron housing; hardened stainless steel rotor; rubber stator Flow: 670 GPM Head: 50' TDH Motor: 15 HP	2	$ 12,000	$ 24,000
Filter Feed Tank Size: 36' dia. x 36' straight side Service: 25 wt % scrubber slurry Sizing Criteria: 4-hr. surge capacity Material: Carbon steel with reinforced	1	$137,000	$137,000

AREA 08 WASTE SEPARATION (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
polyester lining Normal Level: 20' Accessories: Agitator bridge			
Filter Feed Tank Agitator Tank Size: 36' dia. x 36' straight side Service: 25 wt % scrubber slurry Normal Level: 20' Motor: 20 HP	1	$ 20,000	$ 20,000
Filter Feed Pump Type: Progressive cavity Material: Cast iron housing; hardened stainless steel rotor; rubber stator Flow: 995 GPM Pressure: 50 psi Motor: 50 HP	2	$ 23,000	$ 46,000
Vacuum Filter System Type: Face scraper rotary drum vacuum filter Size: 12' dia. x 14' wide cloth Sizing Criteria: 100 lb/hr/ft^2 - dry solids basis Service: Scrubber sludge Accessories: Receiver, pumps, blower, and control panel Power Required: 125 HP	3	$120,000	$360,000
Filtrate Receiver Pump Type: Horizontal centrifugal Material: Cast steel Flow: 360 GPM Pressure: 100' TDH Motor: 15 HP	3	Price included in vacuum filter system	
Area Sump Pump Type: Horizontal centrifugal Material: Rubber-lined carbon steel Flow: 100 GPM Head: 40'-60' TDH Motor: 7.5 HP	16	$ 2,700	$ 43,200
Area Sump Agitator For assorted area sumps of varied size and services Power Required: 1 HP ea.	8	$ 1,300	$ 10,400

Area 08 Total Equipment Cost = $892,000

AREA 09 - WASTE DISPOSAL

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Fixative Day Bin Size: 16' dia. x 18' straight side, 70° cone bottom Service: Granular quicklime Sizing Criteria: 36-hr. storage capacity Material: Carbon steel Acessories: Baghouse & airlock	1	$ 21,000	$ 21,000
Fixative Weigh Feeder Type: Weigh belt gravimetric feeder Service: Granular quicklime Motor: 3 HP	1	$ 5,500	$ 5,500
Fly Ash Pneumatic Conveyor System Type: Pneumatic Service: Fly ash Solids Rate: 150 TPH Air Rate: 10,000 CFM Transfer Lines: 10", 700' long, abrasion resistant Blower Motor: 150 HP	2	$ 89,000	$178,000
Fly Ash Day Bin Size: 15' dia. x 45' straight side, 70° cone Service: Fly ash Sizing Criteria: 8-hr. storage capacity @ maximum load Material: Carbon steel Accessories: Baghouse & airlock	1	$ 44,000	$ 44,000
Fly Ash Weigh Feeder Type: Weigh belt gravimetric feeder Service: Fly ash Motor: 3 HP	1	$ 8,500	$ 8,500
Process Mixer System Service: Ash, sludge, sludge water, fixative lime Capacity: 300 Mlb/hr Motor: 150 HP	2	$ 43,500	$ 87,000
Waste Solids Conveyor Type: Belt Service: Waste solids	2	$13,000	$ 26,000

AREA 09 - WASTE DISPOSAL (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Length: 40' Width: 24" Motor: 5 HP			
Waste Solids Stacker	1	$ 59,000	$ 59,000
Type: Inclined belt conveyor for stacking waste solids when hauling equipment not operating Service: Waste solids Length: 100' Width: 24" Motor: 10 HP			
Waste Solids Shuttle Loader	1	$ 45,500	$ 45,500
Type: Belt conveyor for direct loading of waste solids to trucks Service: Waste solids Length: 50' Width: 24" Motor: 10 HP			
Waste Solids Conveyor Dust Collector	2	$ 5,000	$ 10,000
Type: Pulse-jet Air Flow: 1000 ACFM Material: Carbon steel Blower Motor: 3 HP			

Area 09 Total Equipment Cost = $485,000

AREA 11 - FLUE GAS HANDLING

Equipment Item and Description	Qty.	Unit Cost	Total Cost
I.D./Booster Fan	2	$460,000	$920,000
Conditions: 950,000 ACFM @ 30" WC and 283°F Type: Armored radial tip, centrifugal fan with variable inlet vanes for flow control Motor: 6000 HP			
Apportioned to FGD System: 15" of 30" WC (15/30 = 0.5)		$230,000	$460,000
Inlet Ducting from I.D. Fan to Manifold	2	$113,000	$226,000
Service: Flue gas Type: Circular to Rectangular Transition Materials: Carbon steel Size: 18' dia. x 75' total length			

AREA 11 - FLUE GAS HANDLING (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Inlet Ducting Manifold Service: Flue gas Type: Rectangular with external stiffeners Material: Carbon steel Size: Section 1 - 23' x 23' x 150' total length Section 2 - 19' x 19' x 50' total length Section 3 - 13' x 14' x 50' total length	1 Lot		$550,000
Inlet Ducting to Cocurrent Scrubber Service: Flue gas Type: Rectangular Material: Carbon steel Size: 14' x 14' x 125' total length	4	$200,000	$800,000
Outlet Ducting Manifold Service: Scrubbed gas Type: Rectangular with external stiffeners Material: Carbon steel, reinforced polyester lined Size: Section 1 - 21' x 21' x 85' total length Section 2 - 17' x 17' x 50' total length Section 3 - 12' x 12' x 50' total length	1 Lot		$560,000
Outlet Ducting from Cocurrent Scrubber Service: Scrubbed gas Type: Rectangular with external stiffeners Material: Carbon steel, reinforced polyester lined Size: 12' x 12' x 60' total length	4	$30,000	$120,000
Bypass Service: Flue gas Type: Rectangular with external stiffeners Material: Carbon steel, acid resistant gunnite-lined Size: 22' x 22' x 25' total length	1	$75,000	$75,000

AREA 11 - FLUE GAS HANDLING (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Chimney Transition Service: Reheated scrubbed gas Type: Rectangular with external stiffeners Material: Carbon steel, reinforced polyester lined Size: 22' x 22' x 50' total length	1	$150,000	$150,000
I.D./Booster Fan Inlet Isolation Damper Type: Spade guillotine w/purge air Service: Flue gas (283°F) Materials: Carbon steel with stainless steel trim Duct Size: 18' diameter	2	$105,000	$210,000
Scrubber Inlet Isolation Damper Type: Duplex guillotine with purge air Service: Flue gas (283°F) Materials: Carbon steel with stainless steel trim Duct Size: 14' x 14'	4	$ 61,000	$244,000
Scrubber Outlet Isolation Damper Type: Duplex guillotine with purge air Service: Scrubbed gas Materials: Carbon steel and nickel basemetal for wetted parts Duct Size: 12' x 12'	4	$ 78,000	$312,000
FGD System Bypass Damper Type: Double-louver, opposed blade & parallel blade w/purge air Service: Flue gas Materials: Carbon steel with stainless steel trim Duct Size: 21'3" x 21'3"	1	$ 90,000	$ 90,000

Area 11 Total Equipment Cost = $3,800,000

AREA 12 - WASTE TRANSFER AND PLACEMENT

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Waste Solids Loader Type: Wheel loader Bucket Capacity: 5 yd^3 Estimated Service Life: 10,000 hr	1	$165,000	$165,000

AREA 12 - WASTE TRANSFER AND PLACEMENT

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Interim Replacement Book Life: 6 yrs			
Equivalent Capital Cost		$425,000	$ 425,000
Waste Solids Transfer Truck	4	$220,000	$ 880,000
Type: Off-highway truck			
Capacity: 22 yd^3			
Estimated Service Life: 15,000 hr			
Interim Replacement Book Life: 7.5 yr			
Equivalent Capital Cost		$485,000	$1,940,000
Waste Solids Landfill Bulldozer	1	$137,000	$ 137,000
Type: Tracked bulldozer			
Estimated Service Life: 10,000 hr			
Interim Replacement Book Life: 6 yr			
Equivalent Capital Cost		$353,000	$ 353,000

Area 12 Total Equivalent Equipment Cost = $2,720,000

Blank

Appendix C

CHIYODA THOROUGHBRED 121 SYSTEM EQUIPMENT LIST

AREA 01 - RAW MATERIAL RECEIVING AND STORAGE

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Limestone Receiving System Service: Limestone receiving area, - 3/4" limestone Includes: 1-two railcar covered spot 4-50-ton, below-rail hoppers 4-vibratory feeders, 10 HP 2-24" x 75' feed belts, 10 HP 1-24" x 200', 10% inclined belt, 10 HP 1-4000 ACFM baghouse, 10 HP	1 Lot	$362,000	$362,000
Limestone Bulk Storage Transfer System Service: Transfer of limestone from unloading area to bulk storage pile Includes: 1-24" x 100', 10% inclined belt, 10 HP 1-24" x 200' horizontal belt, 10 HP 1-24" x 150' mobile stacker, 20 HP 1-10,000 ACFM baghouse, 20 HP	1 Lot	$147,000	$147,000
Live Storage Load Hopper Size: 25' x 25' x 20' tall with sloped bottom Service: -3/4" limestone Capacity: 200 tons Material: Carbon steel	2	$ 32,000	$ 64,000
Limestone Live Storage Transfer System Service: Transfer of limestone from bulk storage area to top of limestone day bin Includes: 1-24" x 300', 15% inclined belt, 10 HP motor 2-24" x 100', feed conveyor belts, 10 HP motor 1-4000 ACFM baghouse, 10 HP motor	1 Lot	$114,000	$114,000

Area 01 Total Equipment Cost = $687,000

AREA 02 - FEED PREPARATION AND STORAGE

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Limestone Day Bin Size: 18' dia. x 42' straight side, 70° cone bottom Service: -3/4" limestone Sizing Criteria: Total storage equal to 30-hr. surge at maximum consumption Material: Carbon steel Accessories: Displacement filter, bin discharger	2	$ 65,000	$130,000
Limestone Vibratory Feeder Type: Vibratory Service: -3/4" limestone Motor: 20 HP	2	$ 6,000	$ 12,000
Limestone Feeder Type: Weigh belt gravimetric feeder Service: -3/4" limestone Motor: 3 HP	2	$ 10,000	$ 20,000
Ball Mill & Classifier System Service: -3/4" limestone Grind: 90 wt % -200 mesh Feed Rate: 32 TPH limestone Construction: Carbon steel with Chrome-molybdenum liner Motor: 800 HP	2	$373,000	$746,000
Limestone Grind Tank Size: 18' dia. x 20' straight side Service: 60 wt % solids limestone slurry Material: Rubber-lined carbon steel Normal Level: 12' Accessories: Agitator bridge	1	$ 37,000	$ 37,000
Limestone Grind Tank Agitator Tank Size: 18' dia. x 20' straight side Service: 60 wt % limestone slurry Normal Level: 12' Motor: 15 HP	1	$ 5,500	$ 5,500

AREA 02 - FEED PREPARATION AND STORAGE

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Limestone Grind Tank Slurry Pump Type: Horizontal centrifugal Material: Rubber-lined cast iron Flow: 130 GPM Head: 50' TDH Motor: 7.5 HP	2	$ 2,000	$ 4,000
Limestone Slurry Tank Size: 30' dia. x 28' straight side Service: 20 wt % limestone slurry Sizing Criteria: Total capacity to equal 8-hr. surge at maximum continuous consumption Material: Carbon steel Normal Level: 25' Accessory: Agitator bridge, 50% height wear-ring	2	$110,000	$220,000
Limestone Slurry Tank Agitator Tank Size: 30' dia. x 28' straight side Service: 20 wt % limestone slurry Normal Level: 25' Motor: 20 HP	2	$ 8,000	$ 16,000
Limestone Slurry Pump Type: Horizontal centrifugal Material: Rubber-lined cast iron Flow: 535 GPM Head: 100' TDH Motor: 30 HP	2	$ 2,700	$ 5,400

Area 02 Total Equipment Cost = $1,200,000

AREA 03 - FLUE GAS SCRUBBING

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Precooler Type: Vertical spray tower with wetted inlet Size: 18' I.D. x 45' tall with 22' dia. sump section Material of Construction: Carbon steel with chlorobutyl rubber lining Internal Gas Velocity: 33 fps	4	$115,000	$460,000

AREA 03 - FLUE GAS SCRUBBING (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Jet Bubbling Reactor Type: Chiyoda design-vertical cylindrical tower Size: 58' I.D. x 33' straight side Material: Carbon steel with reinforced polyester lining Accessories: Agitator supporting bridge, gas distribution plates and gas spargers Mist Eliminator: Vertical chevron, 20 fps maximum design velocity	4	$460,000	$1,840,000
Precooler Recirculation Pump Type: Horizontal centrifugal Material: Rubber-lined carbon steel Flow: 10,700 GPM Head: 100' TDH Motor: 400 HP	8	$ 25,000	$ 200,000
Jet Bubbling Reactor Agitator Tank Size: 58' dia. x 33' straight side Service: 15 wt % scrubber slurry Type: Pitched blade turbine Material: Rubber-lined carbon steel Motor: 15 HP	16	$ 7,500	$ 120,000
Jet Bubbling Reactor Overflow Receiving Tank Size: 9' dia. x 12' straight side Service: 15 wt % scrubber slurry Material: Carbon steel with reinforced polyester lining Normal Level: 8' Accessories: Agitator bridge	4	$ 13,000	$ 52,000
JBR Overflow Receiving Tank Agitator Tank Size: 9' dia. x 12' straight side Service: 15 wt. % scrubber slurry Type: Pitched blade turbine Material: Rubber-lined carbon steel Normal Level: 8' Motor: 5 HP	4	$ 5,000	$ 20,000

AREA 03 - FLUE GAS SCRUBBING (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
JBR Overflow Receiving Tank Pump Type: Horizontal centrifugal Material: Rubber-lined carbon steel Flow: 360 gpm Head: 50' TDH Motor: 10 HP	8	$ 2,500	$ 20,000
Oxidation Air Blower Type: Centrifugal Capacity: 34,900 ACFM @ 60°F & 29.28" Hg Pressure: 10 psig Motor: 1700 HP	2	$180,000	$360,000
JBR Gypsum Blowdown Pump Type: Horizontal centrifugal Material: Rubber-lined carbon steel Flow: 410 gpm Head: 75' TDH Motor: 15 HP	8	$ 2,700	$ 21,600
Makeup Water Tank Size: 21' dia. x 27' straight side Service: Water Sizing Criteria: 2-hr. surge capacity at estimated maximum consumption Material: Carbon steel Normal Level: 20'	1	$ 45,000	$ 45,000
Makeup Water Pump Type: Horizontal centrifugal Material: Cast steel Flow: 740 GPM Pressure: 125 psi Motor: 75 HP	2	$ 6,500	$ 13,000
Seal Water Tank Size: 15' dia. x 15' straight side Service: Water Sizing Criteria: 2-hr. surge capacity Material: Carbon steel Normal Level: 10'	1	$ 22,500	$ 22,500
Seal Water Filter Unit Type: Cartridge (fiber) filter Service: Makeup water	1	$ 5,000	$ 5,000

AREA 03 - FLUE GAS SCRUBBING (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Capacity: 150 GPM Power Required: 10 HP equiv.			
Seal Water Pump Type: Horizontal centrifugal Material: Cast steel Flow: 120 GPM Pressure: 100 psi Motor: 20 HP	2	$ 1,700	$ 3,400
Instrument/Plant Air Compressor System Type: Multi-stage, centrifugal air compressor unit complete with control unit, motor driver, instrument air-dryer, pre-filter, after-filter, after-cooler and air receivers Service: Air Air-Dryer Power Consumption: 9.9 kW Motor: 700 HP	2	$ 90,000	$180,000

Area 03 Total Equipment Cost = $3,360,000

AREA 04 - FLUE GAS REHEAT

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Reheat Air Fan Conditions: 343,000 ACFM @ 10" WC Type: Air-foil centrifugal fan with variable inlet vanes for flow control Motor: 800 HP	1	$125,000	$125,000
Reheat Steam Coil Air Heater Type: Finned Tube Steam Coil - includes condensing and subcooling sections Service: Air heater Duty: 125×10^6 Btu/HR Material: Carbon steel	1	$150,000	$150,000
Reheat Mix Chamber Service: Flue gas Material: 316L stainless steel Size: 27' x 27' x 27' total length	1	$310,000	$310,000
Reheat Duct Service: Flue gas Type: Rectangular with external stiffeners	1 Lot		$244,000

AREA 04 - FLUE GAS REHEAT (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Material: Carbon steel Size: 11'-3" x 11'-3" x 25' total length			
Reheat Isolation Damper	1	$ 80,000	$ 80,000
Type: Double-louver, opposed-blade for control/parallel blade for tight shutoff with purge air blower Service: Air and flue gas (382°F maximum temperature) Materials: Stainless Steel Duct Size: 11'3" x 11'3"			

Area 04 Total Equipment Cost = $909,000

AREA 08 - WASTE SEPARATION

Mechanical Dewatering Alternate

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Filter Feed Tank	1	$260,000	$260,000
Size: 40' dia. x 50' straight side Service: 15 wt % scrubber slurry Sizing Criteria: 4-hr. surge capacity @ maximum sludge production Material: Carbon steel with reinforced polyester lining Normal Level: 25' Accessories: Agitator bridge			
Filter Feed Tank Agitator	1	$ 16,000	$ 16,000
Tank Size: 40' dia. x 50' straight side Service: 15 wt % scrubber slurry Normal Level: 20' Motor: 25 HP			
Filter Feed Pump	2	$ 34,000	$ 68,000
Type: Progressive cavity Material: Cast iron housing; hardened stainless steel rotor; rubber stator Flow: 1800 GPM Pressure: 50 psi Motor: 125 HP			

AREA 08 - WASTE SEPARATION (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Vacuum Filter System Type: Face scraper rotary drum vacuum filter Size: 12' dia. x 14' wide cloth Sizing Criteria: 200 lb/hr/ft^2 - dry solids basis Service: Gypsum slurry Accessories: Receiver, pumps, blower, and control panel Power Required: 150 HP	2	$120,000	$240,000
Filtrate Receiver Pump Type: Horizontal centrifugal Material: Cast steel Flow: 1150 GPM Pressure: 100' TDH Motor: 50 HP	2	Included in vacuum filter system cost	
Gypsum Slurry Tank Size: 35' dia. x 50' straight side Service: 15 wt. % scrubber slurry Sizing Criteria: 4-hr. surge capacity @ maximum sludge production Material: Carbon steel with reinforced polyester lining Normal Level: 25' Accessories: Agitator bridge	1	$210,000	$210,000
Gypsum Slurry Tank Agitator Tank Size: 35' dia. x 50' straight side Service: 15 wt. % scrubber slurry Normal Level: 25' Motor: 25 HP	1	$ 16,000	$ 16,000
Gypsum Slurry Pump Type: Progressive cavity Material: Cast iron housing; hardened stainless steel rotor; rubber stator Flow: 1200 gpm Pressure: 75 psi Motor: 100 HP	2	$ 26,500	$ 53,000
Gypsum Pond Pump Type: Horizontal centrifugal Material: Rubber-lined carbon steel	2	$ 6,500	$ 13,000

AREA 08 - WASTE SEPARATION (continued)

Equipment Item and Description	Qty.	Unit Total Cost	Cost
Flow: 1140 gpm Pressure: 100' TDH Motor: 50 HP			
Process Water Storage Tank	1	$ 47,000	$ 47,000
Size: 22' dia. x 27' straight side Service: Water Sizing Criteria: 1 hr. retention @ maximum flow Material: Carbon steel Normal Level: 15'			
Process Water Pump	2	$ 4,000	$ 8,000
Type: Horizontal centrifugal Material: Carbon steel Flow: 1140 gpm Pressure: 75' TDH Motor: 35 HP			
Mechanical Dewatering and Gypsum Stack Alternates			
Area Sump Pump	16	$ 2,700	$ 43,200
Type: Horizontal centrifugal Material: Rubber-lined carbon steel Flow: 100 GPM Head: 40'-60' TDH Motor: 7.5 HP			
Area Sump Agitator	8	$ 1,300	$ 10,400
For assorted area sumps of varied size and services Power Required: 1 HP ea.			

Area 08 Total Equipment Cost = $638,000 (Mechanical Dewatering Alternate)

= $400,000 (Gypsum Stack Alternate)

AREA 09 - WASTE DISPOSAL

Equipment Item and Description	Qty.	Unit Total Cost	Cost
Gypsum Conveyor	2	$ 13,000	$ 26,000
Type: Belt Service: Gypsum @ 85 wt. % solids Length: 40' Width: 24" Motor: 5 HP			

AREA 09 - WASTE DISPOSAL (continued)

Mechanical Dewatering Alternate

Gypsum Stacker	1	$ 59,000	$ 59,000
Type: Inclined belt conveyor for stacking waste solids when hauling equipment not operating Service: Gypsum @ 85 wt. % solids Length: 100' Width: 24" Motor: 10 HP			
Gypsum Shuttle Loader	1	$ 45,500	$ 45,500
Type: Belt conveyor for direct loading of gypsum to trucks Service: Gypsum @ 85 wt. % solids Length: 50' Width: 24" Motor: 10 HP			

Area 09 Total Equipment Cost = $130,000

AREA 11 - FLUE GAS HANDLING

I.D./Booster Fan	2	$580,000	$1,160,000
Conditions: 1,021,500 ACFM @ 39" WC and 283°F Type: Armored radial tip, centrifugal fan with variable inlet vanes for flow control Motor: 8,000 HP Apportioned to FGD System: 24" of 39" WC (24/39 = .62)		$360,000	$ 720,000
Inlet Ducting from I.D. Fan to Manifold	2	$113,000	$ 226,000
Service: Flue gas Type: Circular to Rectangular Transition Materials: Carbon steel Size: 18' dia. x 75' total length			
Inlet Ducting Manifold	1 Lot		$ 810,000
Service: Flue gas Type: Rectangular with external stiffeners Material: Carbon steel Size: Section 1 - 24' x 24' x 160' total length Section 2 - 20' x 20' x 50' total length Section 3 - 14' x 14' x 50' total length			

AREA 11 - FLUE GAS HANDLING

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Inlet Ducting to Precooler Service: Flue gas Type: Rectangular with external stiffeners Material: Carbon steel Size: 22' x 22' x 25' total length	1	$ 75,000	$ 75,000
Outlet Ducting Manifold Service: Scrubbed gas Type: Rectangular with external stiffeners Material: Carbon steel, reinforced polyester lined Size: Section 1 - 21' x 21' x 140' total length Section 2 - 17' x 17' x 70' total length Section 3 - 12' x 12' x 70' total length	1 Lot		$800,000
Outlet Ducting from Jet Bubbling Reactor Service: Scrubbed gas Type: Rectangular with external stiffeners Material: Carbon steel, reinforced polyester lined Size: 12' x 12' x 100' total length	4	$110,000	$440,000
Bypass Service: Flue gas Type: Rectangular with external stiffeners Material: Carbon steel, acid resistant gunnite-lined Size: 22' x 22' x 20' total length	1	$ 60,000	$ 60,000
Chimney Transition Service: Reheated scrubbed gas Type: Rectangular with external stiffeners Material: Carbon steel, reinforced polyester lined Size: 22' x 22' x 50' total length	1	$150,000	$150,000
I.D./Booster Fan Inlet Isolation Damper Type: Spade guillotine Service: Flue gas (283°F) Materials: Carbon steel with stainless steel trim Duct Size: 18' diameter	2	$105,000	$210,000

AREA 11 - FLUE GAS HANDLING (continued)

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Precooler Inlet Isolation Damper	4	$ 61,000	$244,000
Type: Duplex guillotine with purge air Service: Flue gas Materials: Carbon steel with stainless steel trim Duct Size: 14' x 14'			
JBR Outlet Isolation Damper	4	$ 78,000	$312,000
Type: Duplex guillotine with purge air Service: Scrubbed gas Materials: Carbon steel and nickel basemetal for wetted parts Duct Size: 12' x 12'			
FGD System Bypass Damper	1	$ 90,000	$ 90,000
Type: Double-louver, opposed blade & parallel blade with purge air Service: Flue gas Materials: Carbon steel with stainless steel trim Duct Size: 21'3" x 21'3"			

Area 11 Total Equipment Cost = $4,140,000

AREA 12 - WASTE TRANSFER AND PLACEMENT

Equipment Item and Description	Qty.	Unit Cost	Total Cost
Waste Solids Loader	1	$ 87,000	$ 87,000
Type: Wheel loader Bucket Capacity: 3.5 yd^3 Estimated Service Life: 10,000 hr Interim Replacement Book Life: 6 yrs			
Equivalent Capital Cost		$223,000	$223,000
Waste Solids Transfer Truck	2	$220,000	$440,000
Type: Off-highway truck Capacity: 22 yd^3 Estimated Service Life: 15,000 hr Interim Replacement Book Life: 7.5 yr			
Equivalent Capital Cost		$485,000	$970,000
Waste Solids Bulldozer	2	$ 77,000	$154,000
Type: Tracked bulldozer Estimated Service Life: 10,000 hr Interim Replacement Book Life: 6 yr			
Equivalent Capital Cost		$200,000	$400,000

Area 12 Total Equivalent Equipment Cost = $1,590,000

Appendix D

WELLMAN-LORD SYSTEM EQUIPMENT LIST

AREA 01 - RAW MATERIAL RECEIVING AND STORAGE

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Soda Ash Slurry Storage System Size: 40' diameter x 35' straight side Retention: 30 days Design: Arm, covered, insulated Material: Carbon steel Accessories: 9 ft^2 heater	1	$ 125,000	$ 125,000
Lime Storage Silo Dimensions: 25' diameter x 67' straight side, 70° cone bottom Retention: 30 days Material of Construction: Steel Reinforced Concrete Accessories: Unloading blower, pneumatic conveyor piping	1	$ 112,000	$ 112,000
Lime Storage Silo Baghouse Type: Pulse-jet Air Flow: 7,500 ACFM Material: Carbon steel Blower Motor: 15 HP Accessories: Compressor and blower	1	$ 36,000	$ 36,000
Lime Silo Screw Conveyor Type: Screw Feed Rate: 1.5 TPH Service: Lime Length: 30' Motor: 10 HP	1	$ 5,000	$ 5,000
Lime Pneumatic Conveyor Type: Pneumatic Service: Lime	1	$ 16,700	$ 16,700

AREA 01 - RAW MATERIAL RECEIVING AND STORAGE (continued)

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Solids Rate: 20 TPH Air Rate: 3,100 ACFM Transfer Lines: 4", 300' Length Blower Motor: 50 HP			
Fixative Storage Silo	1	$ 110,000	$ 110,000
Dimensions: 25' diameter x 65' straight side, with conical bottom Retention: 30 days Material of Construction: Steel Reinforced Concrete Accessories: Unloading blower, pneumatic conveyor piping			
Fixative Silo Baghouse	1	$ 36,000	$ 36,000
Type: Pulse-jet Air Flow: 7,500 ACFM Material: Carbon steel Blower Motor: 15 HP Accessories: Compressor and blower			
Fixative Silo Screw Conveyor	1	$ 6,500	$ 6,500
Type: Screw Feed Rate: 0.5 TPH Service: Pebble Lime Length: 40' Motor: 15 HP			
Fly Ash Pneumatic Conveyor	1	$ 16,700	$ 16,700
Type: Pneumatic Service: Pebble - Granular Lime Solids Rate: 30 TPH Air Rate: 5,000 ACFM Transfer Lines: 4", 100' length Blower Motor: 50 HP			

Area 01 Total Equipment Cost = $464,000

AREA 02 - FEED PREPARATION AND STORAGE

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Sodium Carbonate Feed Pump	2	$ 3,000	$ 6,000
Type: Horizontal centrifugal Material: Cast steel Flow: 50 GPM Head: 100' TDH Motor: 10 HP			

AREA 02 - FEED PREPARATION AND STORAGE

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Lime Day Bin Size: 16' diameter x 18' straight side 70° cone bottom Service: Lime Material: Carbon steel Accessories: Baghouse and airlock	1	$21,000	$ 21,000
Lime Feeder Type: Weigh belt, gravimetric feeder Service: Lime Motor: 3 HP	1	$ 8,000	$ 8,000
Lime Slakers Service: Lime Feed Rate: 1.5 TPH Motor: 10 HP	2	$10,000	$ 20,000
Lime Slurry Tank Size: 12' diameter x 14' straight side Service: 20 wt % lime slurry Material: Carbon steel Normal Level: 10' Accessories: Agitator bridge, wear ring	1	$20,000	$ 20,000
Lime Slurry Tank Agitator Tank Size: 12' diameter x 14' straight side Service: 20 wt % lime slurry Normal Level: 10' Motor: 10 HP	1	$ 4,000	$ 4,000
Lime Slurry Pumps Type: Horizontal centrifugal Material: Rubber lined cast steel Flow: 50 GPM Head: 100' TDH Motor: 15 HP	2	$ 1,500	$ 3,000

Area 02 Total Equipment Cost = $82,000

AREA 03 - FLUE GAS SCRUBBING

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Prescrubber Towers (System) Type: Venturi Dimensions: 16' diameter x 20' straight side Material: Carbon steel shell, chlorobutyl rubber lining Gas Velocity: 60 fps inlet/outlet	4	$385,000	$1,540,000
Prescrubber Circulation Pumps Type: Horizontal centrifugal Material: Rubber-lined cast steel Flow: 5,500 GPM Head: 250' TDH Motor: 250 HP	8	$ 15,000	$ 120,000
Prescrubber Chloride Removal Circulation Pumps Type: Horizontal centrifugal Material: Rubber lined cast steel Flow: 12,500 GPM Head: 100' TDH Motor: 425 HP	8	$ 19,000	$ 152,000
Absorber Tower Type: Vertical tray tower Dimensions: 33' diameter x 60' overall height Material: Carbon steel, rubber lined Alloy trays Internal Gas Velocity: 10 fps	4	$975,000	$3,900,000
Absorber Circulation Pump Type: Horizontal centrifugal Material: Rubber-lined cast steel Flow: 1,700 GPM Head: 100' TDH Motor: 75 HP	12	$ 9,000	$ 144,000
Absorber Feed Pumps Type: Horizontal centrifugal Material: Rubber-lined cast steel Flow: 950 GPM Head: 100'TDH Motor: 40 HP	2	$ 5,500	$ 11,000

AREA 03 - FLUE GAS SCRUBBING (continued)

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Absorber Feed Surge Tank Size: 75' diameter x 40' straight side Service: Regenerated sodium scrubbing solution Material: Carbon steel with reinforced polyester lining Normal Level: 20'	1	$310,000	$ 310,000
Absorber Product Pumps Type: Horizontal centrifugal Material: Rubber-lined cast steel Flow: 1000 GPM Head: 100' TDH Motor: 40 HP	2	$ 5,500	$ 11,000
Absorber Product Surge Tank Size: 75' diameter x 40' straight side Service: Spent sodium scrubbing solution Material: Carbon steel Normal Level: 20'	1	$310,000	$ 310,000
Precoat Tank Size: 6' diameter x 6' straight side Service: Precoat media slurry Material: Carbon steel Normal Level: 4' Accessories: Agitator mounting	1	$ 1,300	$ 1,300
Precoat Tank Agitator Tank size: 6' diameter x 6' straight side Service: Precoat media slurry Normal Level: 4' Motor: 3 HP	1	$ 2,000	$ 2,000
Precoat Pump Type: Horizontal centrifugal Material: Cast steel Flow: 100 GPM Head: 50 psi Motor: 7.5 HP	2	$ 1,000	$ 2,000

AREA 03 - FLUE GAS SCRUBBING (continued)

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Fly Ash Filters Type: Cartridge Service: 3 wt % fly ash solution from prescrubbers Capacity: 1,000 gpm	2	$ 10,000	$ 20,000
Fly Ash Slurry Sump Pump Type: Vertical turbine Material: Rubber Lined Cast steel Flow: 5 GPM Motor: 1 HP	2	$ 2,800	$ 5,600
Fly Ash Slurry Sump Agitator Sump Size: 5' wide x 5' depth Service: Water Normal Level: 4' Motor: 1 HP	1	$ 1,300	$ 1,300
Makeup Water Tank Size: 25' diameter x 25' straight side Service: Water Sizing Criteria: 2-hr surge capacity at estimated maximum consumption Material: Carbon steel Normal Level: 15'	1	$52,000	$ 52,000
Makeup Water Pumps Type: Horizontal centrifugal Material: Cast steel Flow: 550 GPM Pressure: 125 psi Motor: 50 HP	2	$ 7,000	$ 14,000
Seal Water Filter Unit Type: Cartridge (fiber) filter Service: Makeup water Capacity: 180 GPM	1	$ 6,000	$ 6,000
Seal Water Tank Size: 15' diameter x 15' straight side Service: Water Material: Carbon steel Normal Level: 10'	1	$22,500	$ 22,500

AREA 03 - FLUE GAS SCRUBBING (continued).

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Seal Water Pumps Type: Horizontal centrifugal Material: Cast steel Flow: 160 GPM Pressure: 125 psi Motor: 20 HP	2	$ 1,800	$ 3,600
Instrument/Plant Air Compressor Systems Type: Multi-stage, centrifugal air compressor unit, complete with control unit, motor driver, instrument air-dryer, pre-filter, after-filter, after-cooler, and air receivers. Service: Air Air Dryer Power Consumption: 9.9 kW Motor: 700 HP	2	$100,000	$ 200,000

Area 03 Total Equipment Cost = $6,800,000

AREA 04 - FLUE GAS REHEAT

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Reheat Air Fan Conditions: 343,000 ACFM @ 10" W.C. 60°F air Type: Air-foil centrifugal fan with variable inlet vanes for flow control Motor: 800 HP	1	$125,000	$ 125,000
Reheat Steam Coil Air Heater Type: Finned Tube Steam coil - includes condensing and subcooling sections Service: Air heater Duty: 125 x 10^6 Btu/hr	1	$150,000	$ 150,000
Reheat Mix Chamber Service: Flue gas Material: 316L stainless steel Size: 27' x 27' x 27' total length	1	$310,000	$ 310,000

AREA 03 - FLUE GAS SCRUBBING (continued)

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Reheat Duct Service: Flue gas Type: Rectangular with external stiffeners Material: Carbon steel Size: 11'3" x 11'3" x 25' total length	1 lot		$ 244,000
Reheat Isolation Damper Type: Double-louver system, opposed-blade for control/parallel blade for tight shutoff with purge air blower Service: Air and flue gas (382°F maximum temperature) Materials: Stainless steel Duct size: 11'3" x 11'3"	1	$80,000	$ 80,000

Area 04 Total Equipment Cost = $909,000

AREA 05 - PURGE TREATMENT

Prescrubber Purge Stream

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Prescrubber Purge Tank Size: 12' diameter x 14' straight side Service: 3 wt % solids prescrubber slurry Material: Carbon steel with chlorobutyl rubber lining Normal Level: 10' Accessories: Agitator bridge	1	$20,000	$ 20,000
Prescrubber Purge Tank Pump Type: Horizontal centrifugal Material: Rubber-lined carbon steel Flow: 150 GPM Head: 100' TDH Motor: 10 HP	2	$ 2,500	$ 5,000
Prescrubber Purge Tank Agitator Tank Size: 12' diameter x 14' straight side Service: 3 wt % prescrubber slurry Normal Level: 10' Motor: 5 HP	1	$ 3,500	$ 3,500

AREA 05 - PURGE TREATMENT

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Prescrubber Purge Neutralization Tank Size: 12' diameter x 12' straight side Service: 9 wt % neutralized prescrubber slurry Material: Carbon steel with chlorobutyl rubber lining Normal Level: 8' Accessories: Agitator bridge	1	$ 16,000	$ 16,000
Prescrubber Purge Neutralization Tank Pumps Type: Horizontal centrifugal Material: Rubber-lined carbon steel Flow: 200 GPM Head: 100' TDH Motor: 10 HP	2	$ 3,000	$ 6,000
Prescrubber Purge Neutralization Tank Agitator Tank Size: 12' diameter x 12' straight side Service: Neutralized prescrubber slurry Normal Level: 8' Motor: 3 HP	1	$ 3,500	$ 3,500
Purge Treatment Thickener Size: 50' diameter Service: Prescrubber sludge Materials: Epoxy coated carbon steel rake/bridge, carbon steel shell, concrete bottom Motor: 15 HP Accessories: Tunnel, feed trough, personnel bridge	1	$ 50,000	$ 50,000
Flocculant System Includes mixing tank, multiple metering pumps, agitator, water booster pumps, and local controls Power Required: 5 HP	1	$ 6,000	$ 6,000
Thickener Overflow Tank Size: 10' diameter x 10' straight side Service: Water Sizing Criteria: 30 min. surge capacity Material: Carbon steel Normal Level: 6'	1	$ 9,000	$ 9,000

AREA 05 - PURGE TREATMENT (continued)

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Thickener Overflow Pump Type: Horizontal centrifugal Material: Water Flow: 150 GPM Pressure: 125 psi Motor: 20 HP	2	$ 2,000	$ 4,000
Thickener Underflow Pumps Type: Progressive cavity Material: Cast iron housing, hardened stainless steel rotor, rubber stator Flow: 50 GPM Head: 50'TDH Motor: 10 HP	2	$ 4,000	$ 8,000
Filter Feed Tank Size: 10' diameter x 10' straight side Service: 25 wt % neutralized prescrubber slurry Material: Rubber lined carbon steel Normal Level: 6' Accessories: Agitator bridge	1	$ 7,000	$ 7,000
Filter Feed Tank Agitator Tank Size: 10' diameter x 10' straight side Service: 25 wt % neutralized prescrubber slurry Normal Level: 6' Motor: 5 HP	1	$ 3,500	$ 3,500
Filter Feed Pump Type: Progressive Cavity Material: Cast iron housing, hardened stainless steel rotor, rubber stator Flow: 75 GPM Pressure: 50 psi Motor: 7.5 HP	2	$ 9,000	$ 18,000
Vacuum Filter System Type: Face scraper drum vacuum filter Size: 3' diameter x 4' wide cloth Service: Prescrubber sludge Accessories: Receiver, pumps, blower, control panel	2	$ 45,000	$ 90,000

AREA 05 PURGE TREATMENT (continued)

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Motor: 15 HP Sizing Criteria: 100 $lb/hr/ft^2$ - dry solids basis			
Fixative Pneumatic Conveyor System	1	$ 8,000	$ 8,000
Type: Pneumatic Service: Granular quicklime Solids Rate: 1 TPH Air Rate: 1,000 ACFM Transfer Lines: 4" diameter x 50' length Blower Motor: 5 HP			
Fixative Day Bin	1	$ 8,000	$ 8,000
Size: 9' diameter x 12' straight side 70° Cone bottom Service: Lime Sizing Criteria: 36-hr storage capacity Material: Carbon steel Accessories: Baghouse and airlock			
Fixative Weigh Feeder	1	$ 5,000	$ 5,000
Type: Weigh belt, gravimetric feeder Service: Granular quicklime Motor: 1] HP			
Fly Ash Pneumatic Conveyor System	1	$ 30,000	$ 30,000
Type: Pneumatic Service: Fly Ash Solids Rate: 10 TPH Air Rate: 5,000 ACFM Transfer Lines: 6" 50' length, abrasion resistant Blower Motor: 40 HP			
Fly Ash Day Bin	1	$ 40,000	$ 40,000
Size: 12' diameter x 45' straight side 70° cone bottom Service: Fly ash Material: Carbon steel Accessories: Baghouse and air lock			
Fly Ash Weigh Feeder	1	$ 6,000	$ 6,000
Service: Fly Ash Motor: 1] HP Type: Weigh belt, gravimetric feeder			

AREA 05 PURGE TREATMENT (continued)

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Process Mixer System Type: Pug mill Service: Ash, sludge, sludge water, fixative lime Capacity: 40 Mlb/hr Motor: 40 HP	2	$ 22,500	$ 45,000
Waste Solids Conveyor Type: Belt Service: Waste solids Length: 40' Motor: 5 HP	2	$ 13,000	$ 26,000
Waste Solids Stacker Type: Inclined belt conveyor for stacking waste solids when hauling equipment not operating Service: Waste solids Length: 100' Motor: 10 HP	1	$ 59,000	$ 59,000
Waste Solids Shuttle Loader Type: Belt conveyor for direct loading of waste solids to trucks Service: Waste Solids Length: 50' Motor: 10 HP	1	$ 45,500	$ 45,500
Waste Solids Conveyor Dust Collector Type: Pulse-jet fabric filter Air Flow: 1,000 ACFM Material: Carbon steel Blower Motor: 3 HP	2	$ 5,000	$ 10,000
Sulfate Purge Stream Crystallizer Condensate Receiver Size: 6' diameter x 9' length Service: Condensate Material: Carbon steel Type: Pressure vessel Pressure: 15 psig	1	$ 5,500	$ 5,500
Crystallizer Liquor Tank Size: 10' diameter x 15' straight side Service: Sodium sulfite/sulfate solution	1	$ 11,700	$ 11,700

AREA 05 PURGE TREATMENT (continued)

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Material: Carbon steel Normal Level: 13' Accessories: Agitator bridge			
Crystallizer Liquor Tank Agitator	1	$ 5,300	$ 5,300
Tank Size: 10' diameter x 15' straight side Service: Sodium sulfite/sulfate solution Normal Level: 13' Motor: 7.5 HP			
Crystallizer Condensate Pump	1	$ 6,000	$ 6,000
Type: Horizontal centrifugal Material: Carbon steel Flow: 690 GPM Pressure: 50 psi Motor: 30 HP			
Crystallizer Circulating Pump	1	$ 4,300	$ 4,300
Type: Horizontal centrifugal Material: Carbon steel Flow: 275 GPM Pressure: 50 psi Motor: 15 HP			
Crystallizer Liquor Pump	1	$ 4,300	$ 4,300
Type: Horizontal centrifugal Material: Carbon steel Flow: 265 GPM Pressure: 50 psi Motor: 15 HP			
Sulfate Crystallizer System	1	$980,000	$ 980,000
Size: 16'6" diameter x 17' straight side Type: Forced circulation evaporator/crystallizer Accessories: Heating element, circulation pump and piping			
Sulfate Centrifuge	1	$ 50,000	$ 50,000
Type: Solid bowl Material: 316 Stainless steel internals Size: 5'H x 12'L x 12'W with motor Motor: 75 HP			

AREA 05 PURGE TREATMENT (continued)

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Sulfate Centrifuge Feed Pump Type: Horizontal centrifugal Material: Cast steel Flow: 265 GPM Pressure: 50 psi Motor: 15 HP	1	$ 4,300	$ 4,300
Sulfate Surge Hopper Size: 10' dia x 10' straight side with 70° cone bottom Service: Sulfate crystals Retention: Four hours	1	$ 8,000	$ 8,000
Sulfate Dust Collector Type: Pulse-jet fabric filter Air Flow: 1000 ACFM Material: Sulfate crystals Blower Motor: 3 HP	1	$ 4,300	$ 4,300
Sulfate Outlet Hopper Feeder Type: Weigh belt, gravimetric feeder Service: Sulfate crystals Motor: 3 HP	1	$ 8,500	$ 8,500
Sulfate Product Bins Size: 25' diameter x 45' straight side 70° cone bottom Material: Carbon steel Service: Sulfate crystals Retention: 30 days Accessories: Bin activators and slide gates	3	$ 69,000	$ 207,000
Sulfate Dryer Size: 4'W x 5' H x 16' L Type: Horizontal, cylindrical shell Material: 316 Stainless steel Outlet Moisture: 0.2% Motor: 25 HP	1	$ 235,000	$ 235,000
Area Sump Pump Type: Vertical centrifugal Material: Rubber-lined carbon steel Flow: 100 GPM Head: 40'-60' TDH Motor: 7.5 HP	24	$ 2,700	$ 64,800

AREA 05 PURGE TREATMENT (continued)

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Area Sump Agitator	12	$ 1,300	$ 15,600
For assorted area sumps of varied size and service Power Required: 1 HP ea.			

Area 05 Total Equipment Cost = $2,150,000

AREA 06 - SO_2 REGENERATION

Multi-Stage Evaporator System	2	$1,670,000	$3,340,000
Size: 16'6" diameter x 17' straight side Type: Forced circulation evaporator Accessories: Includes all associated vacuum equipment, condensers, heaters, preheaters, circulation piping and pumps			
Condensate Stripper	1	$ 35,000	$ 35,000
Type: Vertical Column, steam stripper Material: Alloy 20 Service: SO_2 removal Duty: 175,000 lb/hr Pressure: 15 psig			
Condensate Stripper Pumps	2	$ 7,000	$ 14,000
Type: Horizontal centrifugal Material: Alloy 20 Flow: 750 GPM Head: 200' TDH Motor: 50 HP			
Stripped Condensate Cooler	1	$ 11,000	$ 11,000
Type: Heat exchanger Material: Carbon steel Service: Condensate Flow: 750 GPM			
Dissolving Tank	1	$ 45,000	$ 45,000
Size: 20' diameter x 20' straight side Service: Sodium Sulfite/Bisulfite/Sulfate Solution Material: Carbon steel with reinforced polyester lining Normal Level: 15' Accessories: Agitator bridge			

AREA 06 - SO_2 REGENERATION

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Dissolving Tank Agitator Tank Size: 20' diameter x 20' straight side Service: Sodium Sulfite/Bisulfite/Sulfate Solution Normal Level: 15' Motor: 10 HP	1	\$ 8,000	\$ 8,000
Dissolving Tank Pump Type: Horizontal centrifugal Material: Rubber-lined carbon steel Flow: 1000 GPM Head: 100' TDH Motor: 40 HP	2	\$ 6,000	\$ 12,000
SO_2 Product Compressor Type: Centrifugal Service: Sulfur Dioxide and Water Vapor Flow: 41,000 lb/hr Material: Cast steel Motor: 400 HP	2	\$ 400,000	\$ 800,000
Compressor Seal Water Cooler Type: Heat exchanger Material: Carbon steel Service: Water Flow: 925 GPM	2	\$ 30,000	\$ 60,000
Compressor Seal Water Pumps Type: Horizontal centrifugal Material: Cast steel Flow: 925 GPM Head: 50' TDH Motor: 20 HP	4	\$ 3,000	\$ 12,000
Compressor Water Separator Type: Pressure tank, ASME code Size: 12' diameter x 15' straight side Material: Carbon steel Service: SO_2/Water Freeboard: 3'	2	\$ 15,000	\$ 30,000

AREA 06 - SO_2 REGENERATION (continued)

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Compressor Seal Water Filter Type: Cartridge (fiber) filter Service: Water Capacity: 1000 GPM	2	\$ 15,000	\$ 30,000
Clean Condensate Receiver Size: 20' diameter x 35' straight side Material: Carbon steel Service: Water Normal Level: 30'	1	\$ 12,000	\$ 12,000
Sour Condensate Receiver Size: 16' diameter x 20' straight side Material: Carbon steel Service: SO_2-laden water Normal Level: 15'	1	\$ 7,000	\$ 7,000
Vent Gas Scrubber Type: Vertical spray tower Size: 3' diameter x 15' straight side Service: SO_2 fuel gas Flow: 15,000 ACFM Material: 316L stainless steel	1	\$ 10,000	\$ 10,000
Vent Gas Scrubber Circulation Pump Type: Horizontal centrifugal Material: Cast steel rubber lined Service: Lime slurry Flow: 70 GPM Motor: 3 HP	1	\$ 3,500	\$ 3,500

Area 06 Total Equipment Cost = \$4,430,000

AREA 07 - SO_2 PROCESSING

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Sulfuric Acid Plant Includes equipment as shown on sulfuric acid plant process flow diagram and all appurtenances necessary for complete sulfuric acid (93 wt %) production of 614 TPD (66° Be). Feed stream of 15.5 TPH of SO_2 gas supplied by regeneration loop. (Area 06)	1		\$9,000,000

AREA 07 - SO_2 PROCESSING (continued)

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Sulfur Plant	1		$6,000,000
Includes complete equipment package as shown on sulfur plant process flow diagram for production of 169 LTPD sulfur. Feed supplied by SO_2 regeneration loop (Area 06) at 16.5 TPH SO_2 gas.			
AREA 10 - BYPRODUCT STORAGE			
Sulfuric Acid Storage Facility	1	$ 400,000	$ 400,000
Size: 50' diameter x 40' straight side Service: 93 wt % H_2SO_4 (66° Be) Material: Carbon steel Retention: 5 day storage at maximum production Accessories: Includes all piping and miscellaneous appurtenances for complete tank storage and transfer facility.			
AREA 10 - BYPRODUCT STORAGE			
Sulfur Storage Facility	1	$ 410,000	$ 410,000
Earth pit storage of molten sulfur. Transfer from sulfur production unit to pit via one quarter mile 6" line steam jacketed with 8" surrounding line. Three slip tube loading arms (two truck and one rail loader on swivel joint).			
AREA 11 - FLUE GAS HANDLING			
I.D./Booster Fan	2	$515,000	$1,030,000
Conditions: 950,000 ACFM @ 36" WC and 283°F Type: Armored radial tip, centrifugal fan with variable inlet vanes for flow control Motor: 7,000 HP			
Apportioned to FGD System: 21" of 36" WC (21/36 = .583)		$300,000	$600,000

AREA 11 - FLUE GAS HANDLING (continued)

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Inlet Ducting from I.D. Fan to Manifold	2	$113,000	$226,000
Service: Flue gas Type: Circular to rectangular transition Materials: Carbon steel Size: 18' dia. x 75' total length			
Inlet Ducting Manifold	1 Lot		$870,000
Service: Flue gas Type: Rectangular with external stiffeners Material: Carbon steel Size: Section 1-23'x 23'x 160' total length Section 2-19'x 19'x 75' total length Section 3-13'x 14'x 75' total length			
Bypass	1	$100,000	$400,000
Service: Flue gas Type: Rectangular with external stiffeners Material: Carbon steel, acid resistant gunnite-lined Size: 14'x 14'x 160' total length			
Chimney Transition	1	$150,000	$150,000
Service: Reheated, scrubbed gas Type: Rectangular with external stiffeners Material: Carbon steel, reinforced polyester lined Size: 23' x 23' x 50' total length			
Inlet Ducting to Prescrubber	4	$ 30,000	$120,000
Service: Flue gas Type: Rectangular with external stiffeners Materials: Carbon steel Size: 14' x 14' x 80' total length			
Outlet Ducting Manifold	1 lot		$ 900,000
Service: Scrubbed gas Type: Rectangular with external stiffeners Materials: Carbon steel reinforced polyester lined Duct Size: Section 1-22'x 22'x 150' total length Section 2-19'x 19'x 60' total length Section 3-14'x 14'x 60' total length			

AREA 11 - FLUE GAS HANDLING (continued)

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Outlet Ducting from Absorber	4	$ 34,000	$136,000
Service: Scrubbed gas Type: Rectangular with external stiffeners Materials: Carbon steel, reinforced polyester lined Duct Size: 13' x 13' x 50' total length			
I.D. Booster Fan Inlet Isolation Damper	2	$105,000	$210,000
Type: Spade guillotine Service: Inlet flue gas (283°F) Materials: Carbon steel with stainless steel trim Duct Size: 18' diameter			
Prescrubber Inlet Isolation Damper	4	$ 65,000	$260,000
Type: Duplex guillotine with purge air Service: Flue gas (283°F) Materials: Carbon steel with stainless steel trim Duct Size: 14' x 14'			
Absorber Outlet Isolation Damper	4	$ 82,000	$328,000
Type: Duplex guillotine Service: Scrubbed gas (127°F) Materials: Carbon steel and nickel base metal for wetted parts Duct Size: 13' x 13'			
FGD System Bypass Damper	1	$90,000	$ 90,000
Type: Double louver - opposed blade Service: Flue gas (283°F) Materials: Carbon steel with stainless steel trim Duct Size: 21'6" x 21'6"			

Area 11 Total Equipment Cost = $4,300,000

AREA 12 - WASTE TRANSFER AND PLACEMENT

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Waste Solids Loader	1	$ 55,000	$ 55,000
Type: Wheel loader Bucket capacity: 1-3/4 yd^3 Estimated Service Life: 10,000 hr. Interim Replacement Book Life: 6 yrs			
Equivalent Capital Cost		$142,000	$ 142,000

AREA 12 - WASTE TRANSFER AND PLACEMENT (continued)

Equipment Item and Description	Quantity	Unit Cost	Total Cost
Waste Solids Transfer Truck	1	$220,000	$ 220,000
Type: Off-highway truck Capacity: 22 yd^3 Estimated Service Life: 15,000 hr Interim Replacement Book Life: 7.5 yr			
Equivalent Capital Cost		$485,000	$ 485,000
Waste Solids Landfill Bulldozer	1	$ 36,600	$ 36,600
Type: Tracked bulldozer Estimated Service Life: 10,000 hr. Interim Replacement Book Life: 6 yr			
Equivalent Capital Cost		$ 94,000	$ 94,000

Area 12 Total Equivalent Equipment Cost = $720,000

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Appendix E

ECONOMICS OF AUXILIARY STEAM FROM COAL-FIRED POWER PLANTS

1. INTRODUCTION AND SUMMARY

1.A. INTRODUCTION

Within any coal-fired power plant numerous demands exist for process steam. The plants may carry a combination of loads including flue gas reheat, flue gas desulfurization, steam coil air heaters, soot blowing, and space heating. Therefore, determination of the least costly source of this steam becomes a major concern. The ultimate use of the steam, however, has no bearing on its cost. The operating characteristics of a typical 540 MW gross power plant cycle were used to assess the relative merits of various sources of this process steam. Such an assessment implies the enumeration, evaluation, and quantification of all relevant costs.

1.A.1 OBJECTIVES

This study was conducted to analyze, from an economic basis, various methods of obtaining process steam from a coal-fired power plant. Primary objectives were to:

1. determine sensitivity of steam cost to steam source, i.e. pressure,
2. determine sensitivity of steam cost to steam flow rate,
3. determine sensitivity of steam cost to condensate return point, and
4. establish unit cost factors for steam.

1.A.2. SCOPE

The following criteria were established to define the limits of this study:

1. A typical 540 MW gross/500 MW net, 2400 psig/1000°F RH, power plant cycle was used.
2. The consumption of the process steam was limited to an amount equivalent to 15 percent of the boiler duty. Requirements for more than this amount would probably be in the realm of cogeneration power plant applications.
3. The plant will be located near Kenosha, Wisconsin, and will utilize pulverized Illinois bituminous coal.

4. Further plant description can be obtained from the EPRI report, AF-342, "Coal Fired Power Plant Capital Cost Estimates," prepared by Bechtel Power Corporation, January 1977.
5. Three different quantities of process steam were studied equivalent to 5, 10, and 15 percent of turbine cycle heat input (boiler duty). A process condensate return temperature of 200°F was assumed.
6. Three options were studied for obtaining steam:
   - Main steam from the boiler, 250 to 2415 psia
   - Extraction steam from the cold reheat line, 70 to 250 psia
   - Extraction steam from the crossover line, less than 70 psia
7. Three options were studied for process condensate disposal:
   - Return to the deaerator
   - Return to the condenser
   - No return (Discard)

The steam sources and disposal points described above were those which are usually found in current power plant cycles. This study did not consider higher, more complex levels of integration such as steam extraction within the high, intermediate, or low pressure turbines.

1.B. SUMMARY

Based on economic analyses performed for each alternative, the following conclusions were reached:

1. The cost of steam is directly related to the pressure at the extraction point. The extraction point for process steam should always be the one with the lowest pressure which fulfills process requirements. Table E-1 and E-2 illustrate this point.
2. The cost of process steam is relatively insensitive to variations in the amount of flow extracted. Figures E-1, E-2, and E-3 illustrate the insensitivity of steam cost to flow quantity. Figure E-1 also illustrates the proportions of the steam cost applicable to capital, fuel, and operation and maintenance (O&M).
3. For condensate returned at 200°F, the most economical point of return is the deaerator. If the condensate return temperature varies significantly from 200°F, additional studies should be performed to determine the most economical return point.

4. The results indicate that the cost of process steam decreases as the extraction point approaches the end of the turbine cycle, i.e. low pressure turbine exhaust. Process steam uses which do not require a specific pressure could benefit from lower pressure extraction steam.

   Extraction of low pressure steam was not considered in this study since it would involve special design turbines. Additionally, as pressure at a proposed extraction point decreases, the volume for a specific quantity of steam increases. The cost of piping the low pressure steam to the process use location would become significant.

TABLE E-1

AVERAGE PRESENT WORTH OF STEAM

	$/1000#/hr			$/10^6/Btu/hr*		
Source \ Return Point	No Return	Condenser	Deaerator	No Return	Condenser	Deaerator
Main Steam 250 to 2415 psia	439,800	396,700	391,500	340,400	307,000	303,000
Cold Reheat 70 to 250 psia	304,800	261,700	254,800	271,500	233,000	277,000
Crossover Less than 70 psia	249,700	209,100	201,500	209,100	175,100	168,700

*Btu/hr based on utilization of process steam enthalpy from extraction point value to 200°F condensate.

TABLE E-2

30-YR LEVELIZED STEAM COST
(7/1/79→7/1/09)

Extraction Point	Point of Return	30-Yr Levelized Steam Cost $/1000 lb
Main Steam	Not Returned	7.61
Main Steam	Condenser	6.86
Main Steam	Deaerator	6.77
Cold Reheat	Not Returned	5.27
Cold Reheat	Condenser	4.53
Cold Reheat	Deaerator	4.41
Crossover	Not Returned	4.32
Crossover	Condenser	3.62
Crossover	Deaerator	3.49

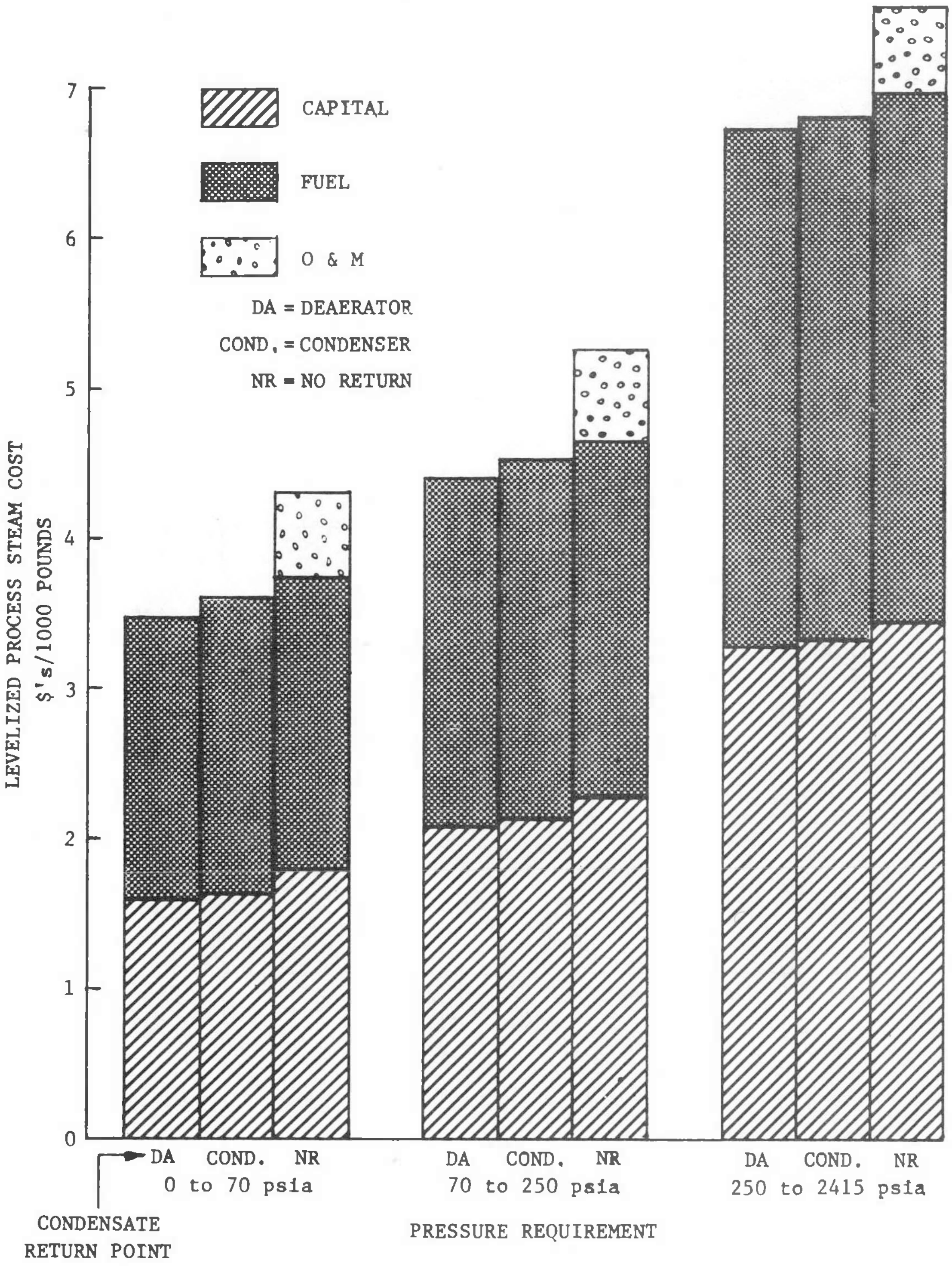


FIGURE E-1

COST BREAKDOWN
30 YEAR LEVELIZED STEAM COSTS

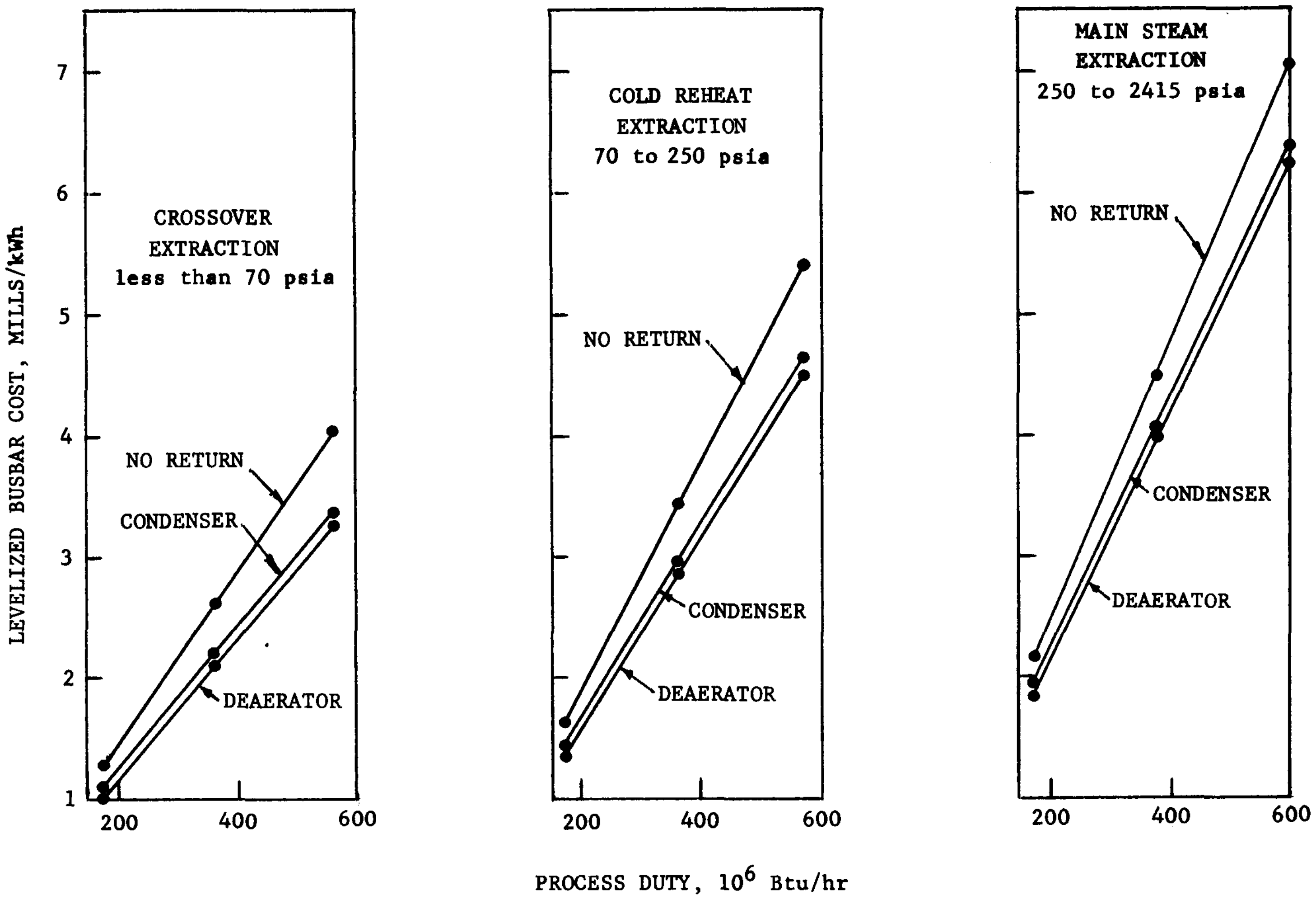


FIGURE E-2

LEVELIZED BUSBAR COST VS. PROCESS DUTY

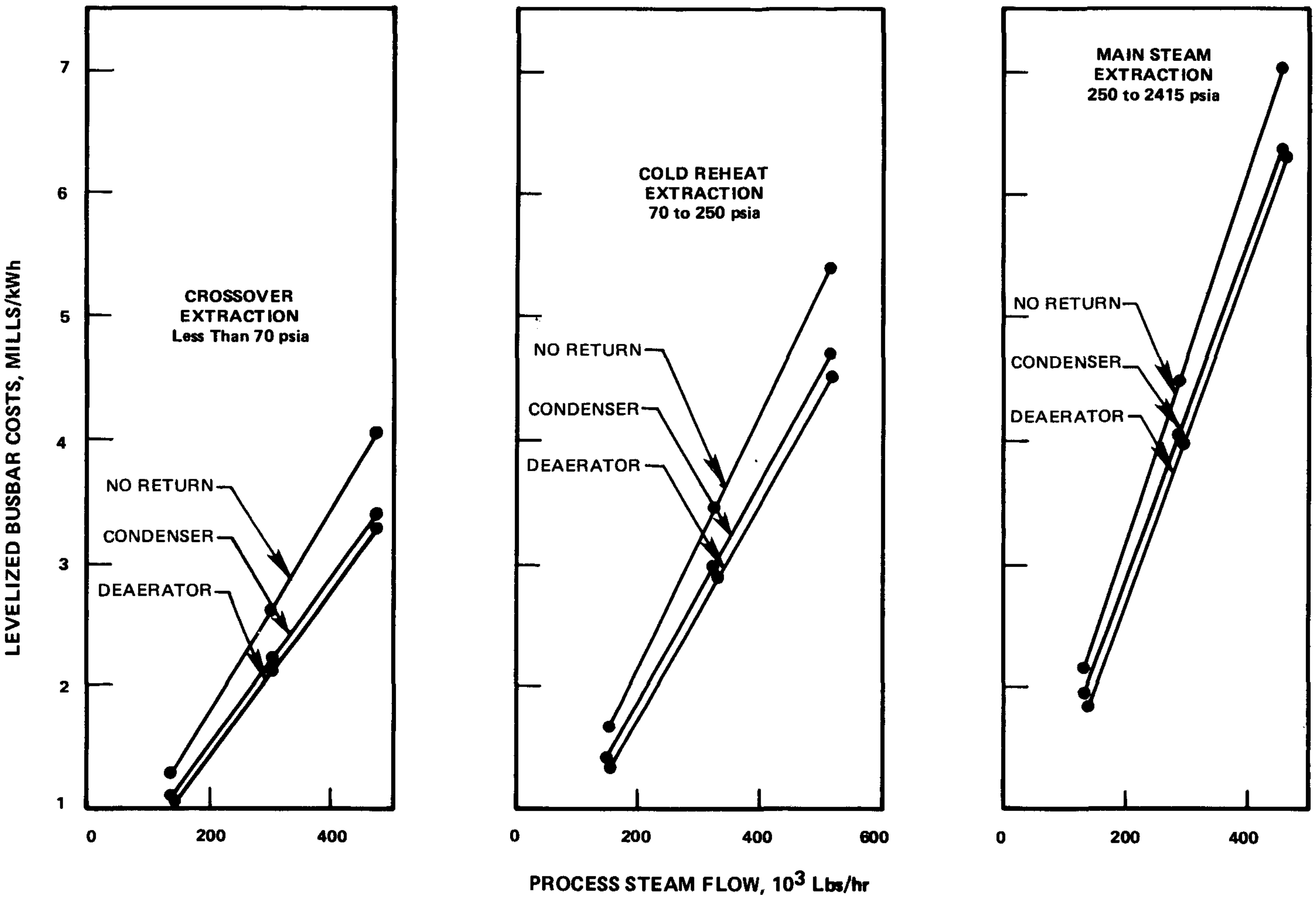


FIGURE E-3

LEVELIZED BUSBAR COST VS. PROCESS STEAM FLOW

2. ANALYSIS PROCEDURE

2.A. IDENTIFICATION OF ALTERNATES

There are three areas in the extraction and return of process steam which offer distinct alternatives, including quantity, point of extraction, and point of condensate return.

2.A.1. QUANTITY OF STEAM EXTRACTED

The quantities of steam selected for study were 5, 10, and 15 percent of boiler duty based on the boiler duty determination at 80 percent load.

2.A.2. POINT OF EXTRACTION

The three extraction points considered were main steam (250 to 2415 psia), cold reheat (70 to 250 psia), and crossover (less than 70 psia) steam lines.

2.A.3. CONDENSATE RETURN POINT

The three options for return of condensate are to return it to the condenser, return it to the deaerator, and to discard it.

The 3 x 3 x 3 matrix which follows illustrates the possible combinations.

Steam Quantity As Percent of Boiler Duty	Extraction Point	Condensate Return Point
5%	Main Steam (250 to 2415 psia)	No Return
10%	Cold Reheat (70 to 250 psia)	Condenser
15%	Crossover (less than 70 psia)	Deaerator

The same power plant configuration without extraction of process steam was evaluated as a base case. Added to the 27 possible combinations described above, this produced the 28 alternatives considered. This base case provided a reference point, and any increase in cost relative to this base can be attributed to generation of the auxiliary steam. Thus, throughout the report, the figure "Δ" indicates increase over the base case.

2.B. GENERAL CRITERIA

In addition to the scope guidelines stated, detailed assumptions were made concerning construction and operation of the model plant. These assumptions served as analysis guidelines.

1. The model plant operated at a 70 percent load factor (derived as the product of 80 percent annual operation and 87.5 percent load for the entire 30 year life of the facility).
2. The costs associated with reducing the extraction steam pressure to any specific process demand pressure were considered negligible.
3. The cost of coal for this plant was assumed to be $\$1/10^6$ Btu on July 1, 1978, per EPRI premises.

2.C. GENERAL DESCRIPTION OF METHODOLOGY

A present worth cost for each option was determined through the following steps:

1. The turbine cycle was computer simulated and a boiler duty determined at 80 percent load for each of the 28 options.
2. From the boiler duty calculated in Step 1, an annual cost of fuel was calculated.
3. The final annual cost was determined by adding other items such as labor, maintenance, and overhead to Step 2.
4. The size of the plant, excluding the turbine, had to be increased to maintain the net steam flow to the turbine. The capital cost of the enlarged plant was determined as an exponential ratio to the base case plant cost. The factor used was the ratio of the boiler steam flows raised to the 0.8 power.
5. The final capital cost of the plant was determined by adding any component costs which, for a particular scheme, might not scale up accurately. An example was the additional water treatment costs required for any scheme which did not return the condensate from the process to the cycle.
6. The final PW cost for each alternative was derived using present worth calculation methods defined in this section.
7. The results were then presented graphically to show the costs of specific options versus the base case with respect to process steam and heat consumption.

2.D. TURBINE CYCLE DEVELOPMENT

The steam cycle investigated was assumed to be a typical 540 MW (gross) coal-fired power plant. The specific cycle chosen was a General Electric 7 heater cycle with 2400 psig/1000^{o}F throttle conditions, 1000^{o}F reheat temperature, tandem compound, four flow, 30-inch last stage bucket (TC4F-30LSB) turbine. This turbine was assumed to have a 2-inch Hg Abs back pressure at normal operating conditions. The General Electric turbine was chosen to be representative and the turbine cycle would be applicable to other turbine vendors. The final results of the study are not vendor-specific.

For the purposes of this study, the cycle performance parameters for all cases were determined at the 80 percent load condition. Load changes from about 70 to 100 percent have little impact on boiler and turbine efficiency.

When determining the cycle heat rates, "Condensate Return to Condenser" and "No Condensate Return" are equivalent. The differences between these two modes of operation are accounted for in condenser-cooling tower duty and make-up water treatment.

The turbine cycle calculations were performed using the Stearns-Roger heat balance program D135. This program has previously been verified in comparisons with the manufacturer's heat balances submitted on actual designs. The program was verified for this study by comparison of heat rates given in General Electric's manual "Heat Rates for Fossil Reheat Cycles Using General Electric Steam Turbine-Generators, 150,000 KW and Larger" (GET-2050C, February 1974).

The generator load was held constant at 80 percent load (432,000 KW), while the process steam extraction locations, condensate return points, and flow rates were varied. The effects on turbine cycle heat rate were determined for each case. Turbine cycle heat rate was utilized as the overall cycle performance indicator. However, since generator output was held constant throughout this study, a study of boiler duty would have yielded the same results. Typical turbine cycle heat balances are illustrated as Figures E-4 through E-8.

Heat rate can be defined as follows:

$HR_{TC} = BD/kW_g$; Turbine Cycle Heat Rate

HR_{NP} = (BD/NB) x (1/kW_n); Net Plant Heat Rate
HR_{GP} = (BD/NB) x (1/kW_g); Gross Plant Rate

Also:
N_{TC} = 3412.14/HR_{TC}; Turbine Cycle Efficiency
N_{NP} = 3412.14/HR_{NP}; Net Plant Efficiency
N_{GP} = 3412.14/HR_{GP}; Gross Plant Efficiency

where
HR = Heat Rate in Btu/kW-hr
BD = Total Boiler Duty (heat to the cycle), Btu/hr
kW_g = Generator gross terminal output, kW
kW_n = Generator net terminal output, kW, i.e., gross output less plant auxiliary power
NB = Boiler Efficiency, decimal

The boiler duty calculations for this study were performed as follows:

$$BD = W_{TH}\ (H_{TH} - H_{FFW}) + W_{RH}\ (H_{HRH} - H_{CRH}) + W_{aux}\ (H_{aux} - H_{FFW})$$

where
W_{TH} = Throttle steam flow, lbs/hr
H_{TH} = Throttle enthalpy, Btu/lb
H_{FFW} = Final Feedwater enthalpy, Btu/lb
W_{RH} = Reheater steam flow, lbs/hr
H_{HRH} = Hot reheat enthalpy, Btu/lb
H_{CRH} = Cold reheat enthalpy, Btu/lb
W_{aux} = Respective flows for auxiliary steam - Flow to the steam jet air ejector or flow to the process (if applicable), lbs/hr
H_{aux} = Respective enthalpy for the auxiliary flow above, Btu/lb

The heat and mass flow for the 28 alternatives are tabulated in Table A-1.

2.E. OPERATING COST DETERMINATION

The operating cost for each alternative studied was developed from the cycle performance parameters discussed previously. Calculation of the steam cycle yielded a boiler duty at 80 percent load which served as the basis for fuel cost determination. The following equation was used to calculate the annual cost of fuel:

$FC_a = (BD \div NB) \times T \times FC$

where

FC_a = Annual cost of fuel, \$/yr

NB = Boiler efficiency, decimal. The efficiency was taken at 80 percent load and was assumed to be a constant value of 88 percent.

T = Hours per year of plant operation. The hours per year were based on an 87.5 percent availability; therefore, the value .875 x 8760 hrs/yr = 7665 hrs/yr was used.

FC = Fuel costs, \$/Btu. As specified in "Economic Premises for Electric Power Generating Systems" a fuel cost of $\$1/10^6$ Btu was used.

The other elements included in the annual operating costs were operation and maintenance, fixed and variable costs, and overhead. The base derivation of these costs were taken from the EPRI report entitled "Technical Assessment Guide," EPRI PS-866-SR, June 1978.

For those alternatives where the condensate was not returned to the system, the additional O&M costs incurred were included since significant additional water treatment expenditures were necessary.

2.F. CAPITAL COST DETERMINATION

The capital cost for each alternative was developed from the cycle performance parameters discussed previously. The calculation of the steam cycle yielded the boiler superheat outlet steam flow at 80 percent load. The flow was then scaled up to 100 percent load. This produced the capacity of the boiler and power plant based on steam flow alternative. From a base itemized cost list (Table E-3), for a similar 540 MW gross plant without process steam extraction, each alternative's capital costs were determined by scaling. The capital cost scaling factor used was the ratio of the flow rate of the alternative case to that of the base case raised to the 0.8 power. The base cost list was taken from the report "Coal-Fired Power Plant Capital Cost Estimates", EPRI AF-342. Cost for a FGD System is not included in the base itemized cost list.

All components of the base case were scaled except the turbine/generator which, along with the plant load, remained constant. In several cases,

TABLE E-3
CAPITAL COST BREAKDOWN, BASE CASE

	ITEM	10^6 \$ (7/1/76)
1	Steam Generator System	55.2
2	Turbine/Generator	25.2
3	Condenser and Auxiliaries	2.1
4	Other Rotating Equipment	6.5
5	Heaters and Exchangers	1.8
6	Tanks, Drums, Vessels	0.8
7	Water Treatment and Chemical Feed	1.3
8	Coal and Ash Handling	4.4
9	Electrostatic Precipitator	14.3
10	Stack with Lining and Lights	2.3
11	Miscellaneous Concrete	8.7
12	Miscellaneous Structural	7.9
13	Architecture and Finish	3.9
14	Earthwork	7.9
15	Piles and Caisson	4.0
16	Site Improvements	4.9
17	Miscellaneous Mechanical including Insulation and Lagging	4.2
18	HVAC	0.8
19	Piping	20.8
20	Instrumentation and Controls	5.2
21	Electrical including TR^S, Switchgear, MCC	5.2
22	Electrical including Conduit, Cable, Trays, Wire and Switchyard	16.8
23	Field Distributables	18.4
24	Engineering and Fees (@ 7% of Total)	20.8
25	Contingency (@ 12% of Total)	36.5
26	7% Other Costs (1 through 25)	19.6
	TOTAL (TPI - Total Plant Investment)	299.5

additional capital costs were added when a particular component increased in size out of proportion to the remainder of the plant. An example of this is those alternatives that do not return the condensate and therefore require additional water treatment capacity.

2.G. PRESENT WORTH ANALYSIS

In order to perform a meaningful cost comparison of the various methods of obtaining process steam, evaluations were made on a present worth (7-1-79 dollars) basis. Equations and economic factors used to perform this evaluation are presented below.

Design Start Date: 7-1-74
Operation Start Date: 7-1-79
Plant Life: 30 years
Escalation (except fuel): 60%
Escalation, Fuel: 6.2%
Investment Return (MAR): 10%

$$\begin{aligned} PW_{(7\text{-}1\text{-}79)} = {} & (TCR \times FCR \times SPWF) \\ & + (FYOM_{(1\text{-}1\text{-}78)} \times EF_1 \times PWSF_{6}) \\ & + (FYFL_{(7\text{-}1\text{-}78)} \times EF_2 \times PWSF_{6.2}) \end{aligned}$$

$$TCR = \frac{CI_{(7\text{-}1\text{-}76)}}{EF_3} \times ECE + AFDC + Land + Inventory$$

$$AFDC_{(7\text{-}1\text{-}79)} = \frac{CI_{(7\text{-}1\text{-}76)}}{EF_3} \times ECE \times AIDC$$

where

$PW_{(7\text{-}1\text{-}79)}$ = Total present worth cost, 7-1-79, \$
TCR = Total capital requirement, \$
SPWF = Series present worth factor, 10% for 30 years = 9.4270
FCR = Fixed charge rate = 0.18
$FYOM_{(1\text{-}1\text{-}78)}$ = First year operations and maintenance, 1-1-78, \$
EF_1 = Escalation factor to bring FYOM costs up to 7-1-79 = $(1.06)^{1.5}$
$FYFL_{(7\text{-}1\text{-}78)}$ = First year fuel costs, 7-1-78, \$
EF_2 = Escalation factor to bring FYFL costs up to 7-1-79 = 1.062
$PWSF_6$ = Present worth summation factor corresponding to an escalation rate of 6.0%. Similar to the series present worth factor except for escalation allowance = 17.7775

$PWSF_{6.2}$ = Present worth summation factor corresponding to an escalation rate of 6.2% = 18.2133

$CI_{(7-1-76)}$ = Capital investment 7-1-76, \$

EF_3 = Escalation factor to change the equivalent CI to 7-1-74 = $(1.06)^2$

ECE = A 21.27% escalation applied to a capital estimate of 7-1-74 which is escalated to 7-1-79 under a typical construction payment S-curve schedule = 1.2127

AFDC = Allowance for funds during construction, 7-1-79, \$

Land = \$5000/acre x 500 acres = \$2.5 x 10^6, 7-1-79

Inventory = \$5 x 10^6, 7-1-79. (Initial coal pile, etc.)

AIDC - A factor to account for the interest paid during construction which is accumulated by 7-1-79 = .1397 (Based on a typical construction payment S-curve schedule which corresponds to a cg of approximately 1.7 years).

2.H. PROCESS STEAM COST DETERMINATION

After evaluating the present worth cost differential for each of the alternates, it was desirable to convert the values to a 30-year levelized cost on a unit basis. The 30-year levelized process steam costs can be determined using the following equation and economic factors:

$$LSC = \frac{\Delta \ PW}{SPWF \times 8760 \times 0.7}$$

where

LSC = Thirty year levelized cost of steam, \$1000/lb. (7/1/1979-7/1/2009)

ΔPW = Increased present worth of a given alternate case over the base case, 7-1-79, \$

SPWF = Series present worth factor, 10% for 30 years = 9.4270

The preceding analysis determines the cost of steam excluding profit. If steam were sold to an outside user, profit would have to be considered when determining LSC.

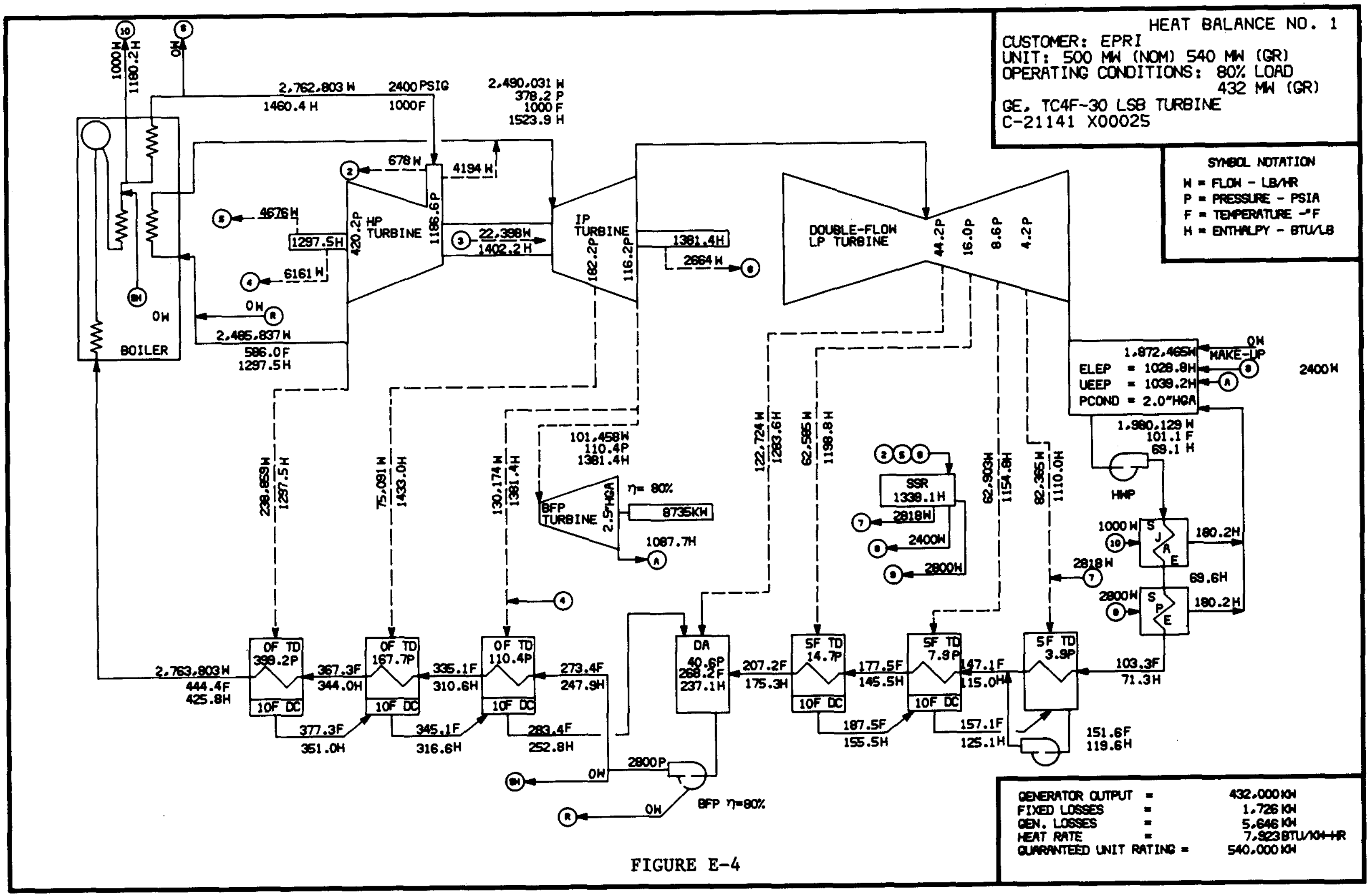

HEAT BALANCE NO. 1
CUSTOMER: EPRI
UNIT: 500 MW (NOM) 540 MW (GR)
OPERATING CONDITIONS: 80% LOAD
432 MW (GR)
GE, TC4F-30 LSB TURBINE
C-21141 X00025
SYMBOL NOTATION
W = FLOW - LB/HR
P = PRESSURE - PSIA
F = TEMPERATURE -°F
H = ENTHALPY - BTU/LB
GENERATOR OUTPUT = 432,000 KW
FIXED LOSSES = 1,726 KW
GEN. LOSSES = 5,646 KW
HEAT RATE = 7,923 BTU/KW-HR
GUARANTEED UNIT RATING = 540,000 KW
1000 W
1180.2 H
0 W
2,762,803 W
1460.4 H
2400 PSIG
1000 F
2,490,031 W
378.2 P
1000 F
1523.9 H
678 W
4194 W
HP TURBINE
420.2P
1186.6P
4676 W
1297.5 H
6161 W
22,398 W
1402.2 H
IP TURBINE
182.2P
116.2P
1381.4 H
2664 W
DOUBLE-FLOW LP TURBINE
44.2P
16.0P
8.6P
4.2P
0 W
BOILER
2,485,837 W
586.0 F
1297.5 H
1,872,465 W
0 W MAKE-UP
ELEP = 1028.8 H
UEEP = 1039.2 H
PCOND = 2.0"HGA
2400 W
1,980,129 W
101.1 F
69.1 H
HWP
238,853 W
1297.5 H
75,091 W
1433.0 H
130,174 W
1381.4 H
101,458 W
110.4 P
1381.4 H
BFP TURBINE
2.5"HGA
η= 80%
8735 KW
1087.7 H
122,724 W
1283.6 H
62,585 W
1198.8 H
SSR
1338.1 H
2818 W
2400 W
2800 W
62,903 W
1154.8 H
82,365 W
1110.0 H
1000 W
SJAE
180.2 H
69.6 H
2818 W
2800 W
SPE
180.2 H
2,763,803 W
444.4 F
425.8 H
OF TD
399.2P
10F DC
367.3F
344.0 H
OF TD
167.7P
10F DC
377.3F
351.0 H
335.1F
310.6 H
OF TD
110.4P
10F DC
345.1F
316.6 H
273.4F
247.9 H
283.4F
252.8 H
DA
40.6P
268.2F
237.1 H
207.2F
175.3 H
5F TD
14.7P
10F DC
177.5F
145.5 H
187.5F
155.5 H
5F TD
7.9P
10F DC
147.1F
115.0 H
157.1F
125.1 H
5F TD
3.9P
103.3F
71.3 H
151.6F
119.6 H
2800 P
0 W
0 W
BFP η=80%

FIGURE E-4

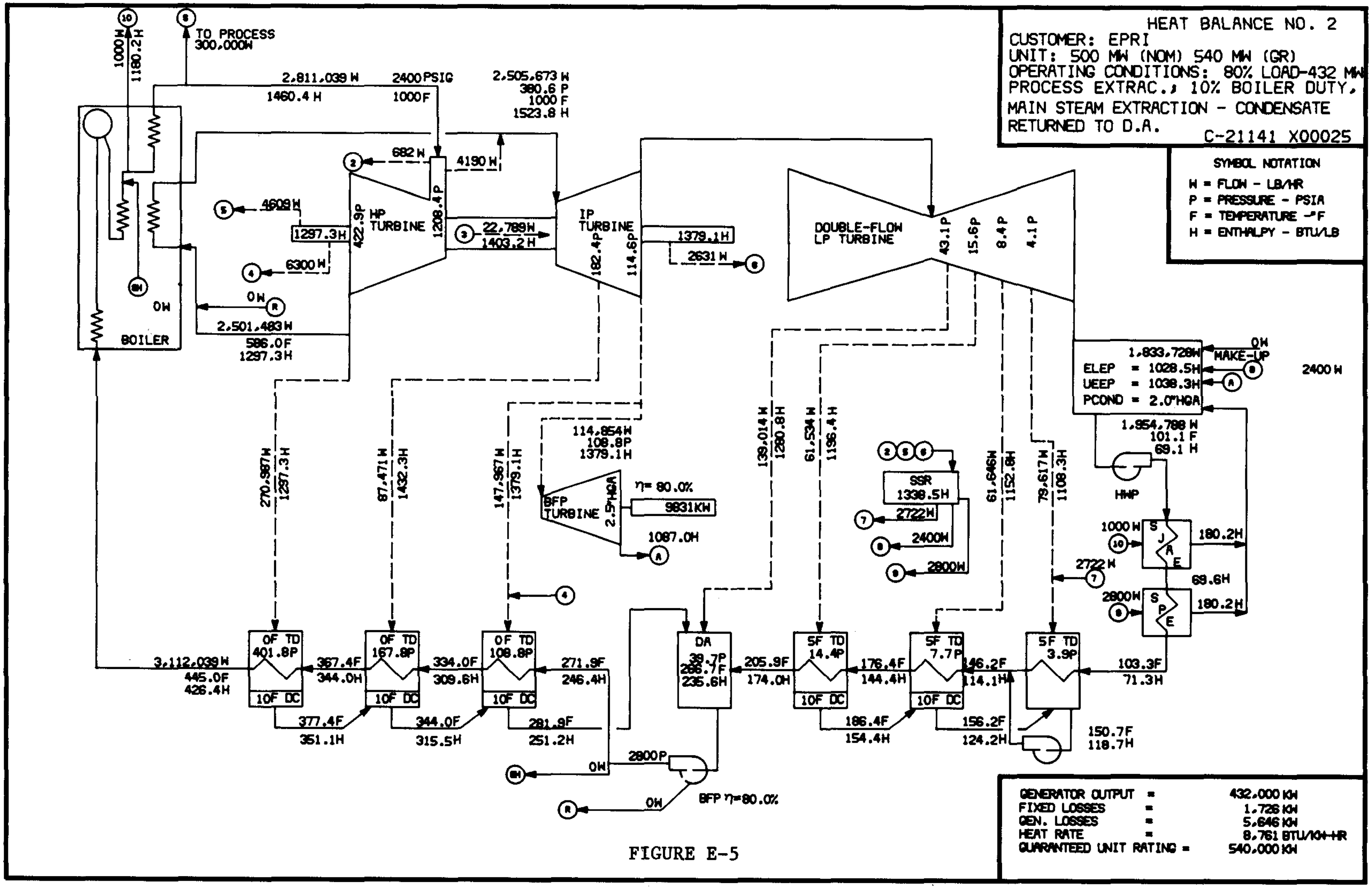
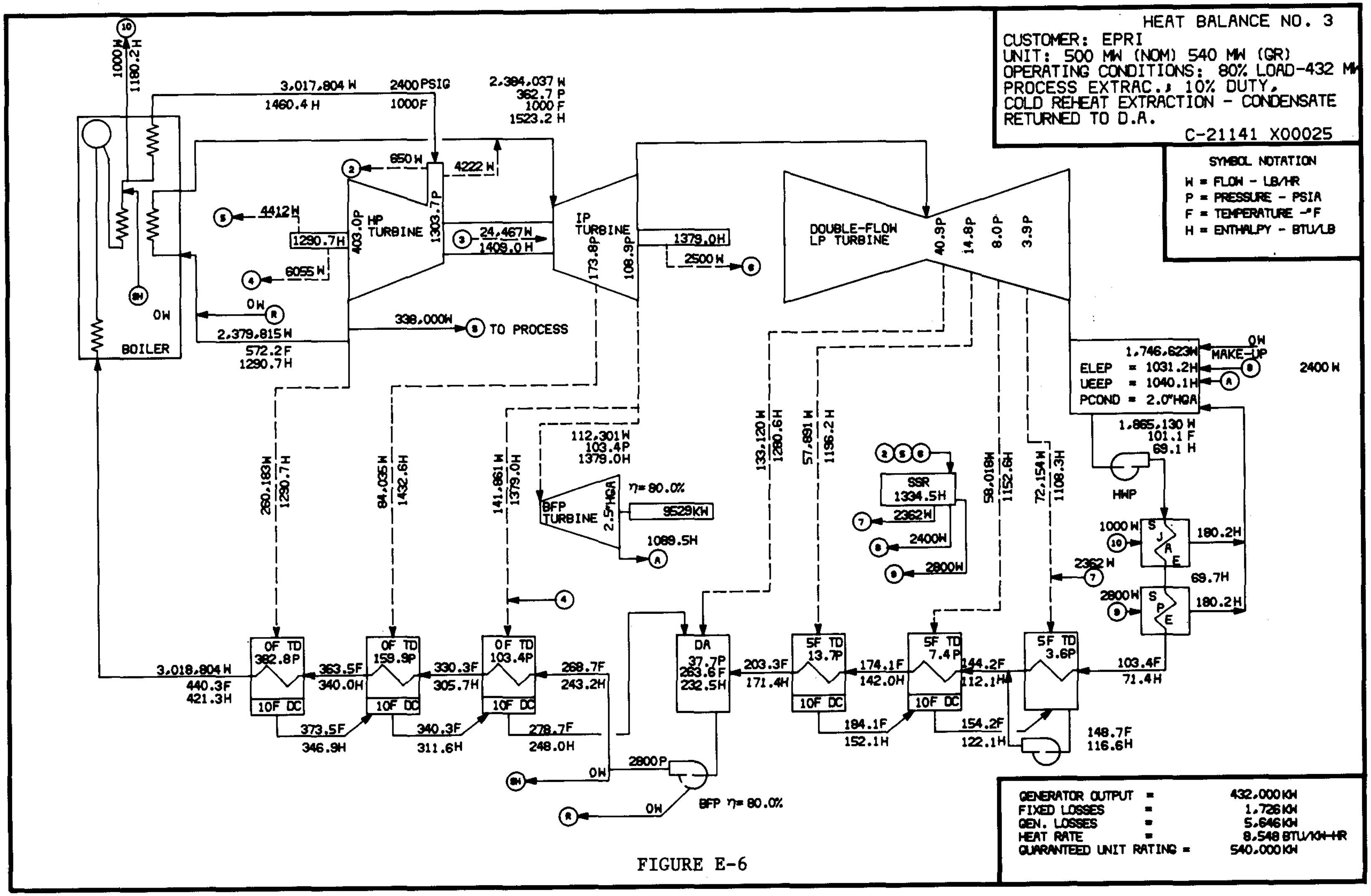

HEAT BALANCE NO. 2
CUSTOMER: EPRI
UNIT: 500 MW (NOM) 540 MW (GR)
OPERATING CONDITIONS: 80% LOAD-432 MW
PROCESS EXTRAC., 10% BOILER DUTY,
MAIN STEAM EXTRACTION - CONDENSATE
RETURNED TO D.A.
C-21141 X00025
SYMBOL NOTATION
W = FLOW - LB/HR
P = PRESSURE - PSIA
F = TEMPERATURE -°F
H = ENTHALPY - BTU/LB
10
1000 W
1180.2 H
8
TO PROCESS
300,000W
2,811,039 W
1460.4 H
2400 PSIG
1000 F
2,505,673 W
380.6 P
1000 F
1523.8 H
682 W
4190 W
2
4609 W
5
1297.3 H
6300 W
4
HP TURBINE
422.9P
1208.4P
3
22,789 W
1403.2 H
IP TURBINE
182.4P
114.6P
1379.1 H
2631 W
6
DOUBLE-FLOW LP TURBINE
43.1 P
15.6 P
8.4 P
4.1 P
SH
0 W
0 W
R
2,501,483 W
586.0 F
1297.3 H
BOILER
1,833,728 W
ELEP = 1028.5 H
UEEP = 1038.3 H
PCOND = 2.0"HGA
0 W
MAKE-UP
8
A
2400 W
1,954,788 W
101.1 F
69.1 H
HWP
270,987 W
1297.3 H
87,471 W
1432.3 H
147,967 W
1379.1 H
114,854 W
108.8P
1379.1 H
BFP TURBINE
2.5"HGA
η= 80.0%
9831 KW
1087.0 H
A
4
139,014 W
1280.8 H
61,534 W
1196.4 H
2 5 6
SSR
1338.5 H
7
2722 W
8
2400 W
9
2800 W
61,646 W
1152.8 H
79,617 W
1108.3 H
1000 W
10
SJAE
180.2 H
2722 W
7
69.6 H
2800 W
9
SPE
180.2 H
3,112,039 W
445.0 F
426.4 H
0F TD
401.8P
10F DC
367.4 F
344.0 H
0F TD
167.8P
10F DC
334.0 F
309.6 H
0F TD
108.8P
10F DC
271.9 F
246.4 H
377.4 F
351.1 H
344.0 F
315.5 H
281.9 F
251.2 H
DA
39.7P
266.7 F
235.6 H
205.9 F
174.0 H
5F TD
14.4P
10F DC
176.4 F
144.4 H
5F TD
7.7P
10F DC
146.2 F
114.1 H
5F TD
3.9P
103.3 F
71.3 H
186.4 F
154.4 H
156.2 F
124.2 H
150.7 F
118.7 H
2800 P
0 W
SH
0 W
R
BFP η=80.0%
GENERATOR OUTPUT = 432,000 KW
FIXED LOSSES = 1,726 KW
GEN. LOSSES = 5,646 KW
HEAT RATE = 8,761 BTU/KW-HR
GUARANTEED UNIT RATING = 540,000 KW

FIGURE E-5



HEAT BALANCE NO. 3

CUSTOMER: EPRI
UNIT: 500 MW (NOM) 540 MW (GR)
OPERATING CONDITIONS: 80% LOAD-432 MW
PROCESS EXTRAC.; 10% DUTY,
COLD REHEAT EXTRACTION - CONDENSATE
RETURNED TO D.A.

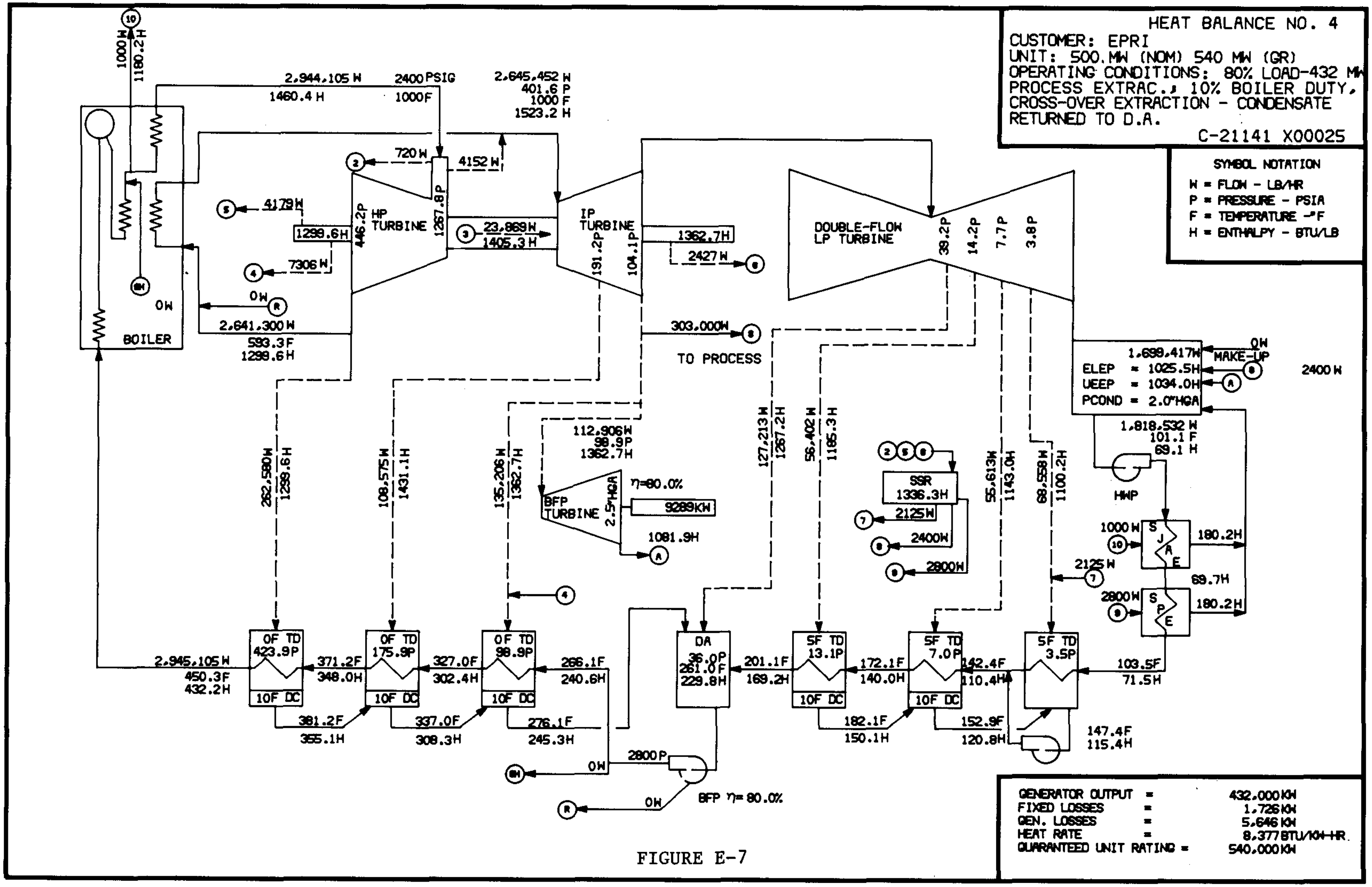
C-21141 X00025

SYMBOL NOTATION

W = FLOW - LB/HR
P = PRESSURE - PSIA
F = TEMPERATURE -°F
H = ENTHALPY - BTU/LB

GENERATOR OUTPUT	=	432,000 KW
FIXED LOSSES	=	1,726 KW
GEN. LOSSES	=	5,646 KW
HEAT RATE	=	8,548 BTU/KW-HR
GUARANTEED UNIT RATING	=	540,000 KW

FIGURE E-6

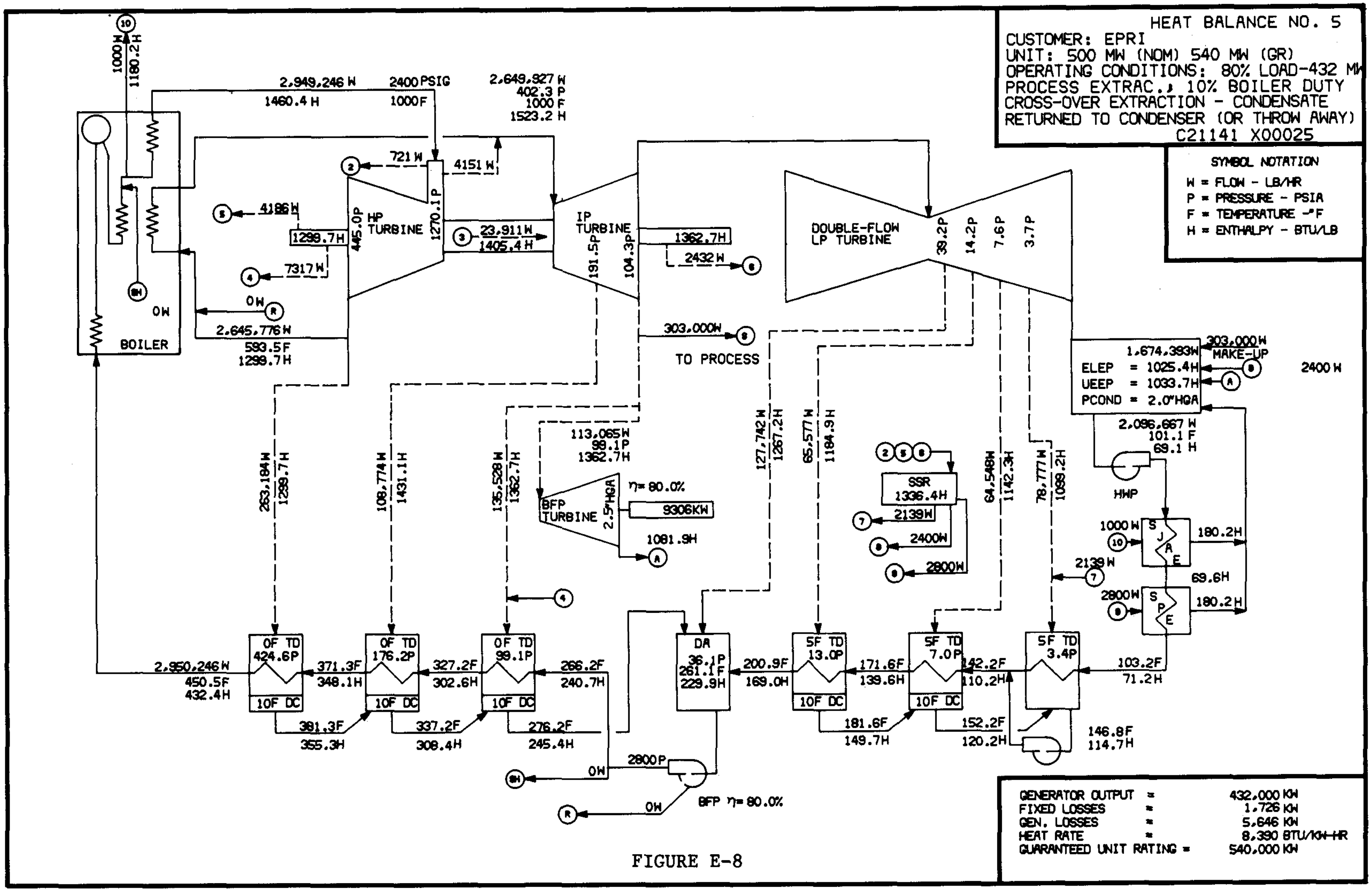


HEAT BALANCE NO. 4
CUSTOMER: EPRI
UNIT: 500.MW (NOM) 540 MW (GR)
OPERATING CONDITIONS: 80% LOAD-432 MW
PROCESS EXTRAC., 10% BOILER DUTY,
CROSS-OVER EXTRACTION - CONDENSATE
RETURNED TO D.A.
C-21141 X00025

SYMBOL NOTATION
W = FLOW - LB/HR
P = PRESSURE - PSIA
F = TEMPERATURE -°F
H = ENTHALPY - BTU/LB

GENERATOR OUTPUT = 432,000 KW
FIXED LOSSES = 1,726 KW
GEN. LOSSES = 5,646 KW
HEAT RATE = 8,377 BTU/KW-HR.
GUARANTEED UNIT RATING = 540,000 KW

FIGURE E-7



HEAT BALANCE NO. 5
CUSTOMER: EPRI
UNIT: 500 MW (NOM) 540 MW (GR)
OPERATING CONDITIONS: 80% LOAD-432 MW
PROCESS EXTRAC., 10% BOILER DUTY
CROSS-OVER EXTRACTION - CONDENSATE
RETURNED TO CONDENSER (OR THROW AWAY)
C21141 X00025

SYMBOL NOTATION
W = FLOW - LB/HR
P = PRESSURE - PSIA
F = TEMPERATURE -°F
H = ENTHALPY - BTU/LB

GENERATOR OUTPUT	=	432,000 KW
FIXED LOSSES	=	1,726 KW
GEN. LOSSES	=	5,646 KW
HEAT RATE	=	8,390 BTU/KW-HR
GUARANTEED UNIT RATING	=	540,000 KW

FIGURE E-8

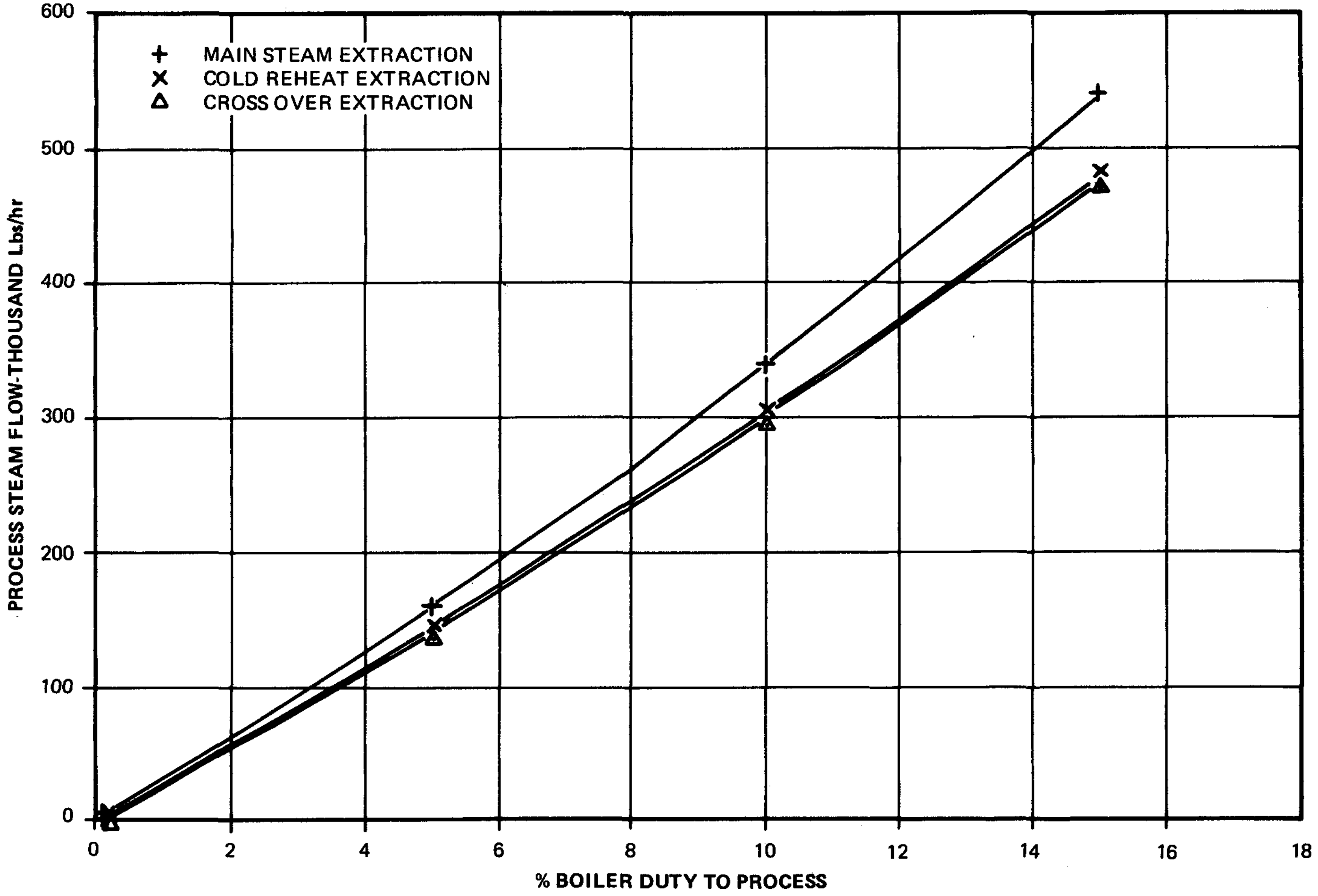
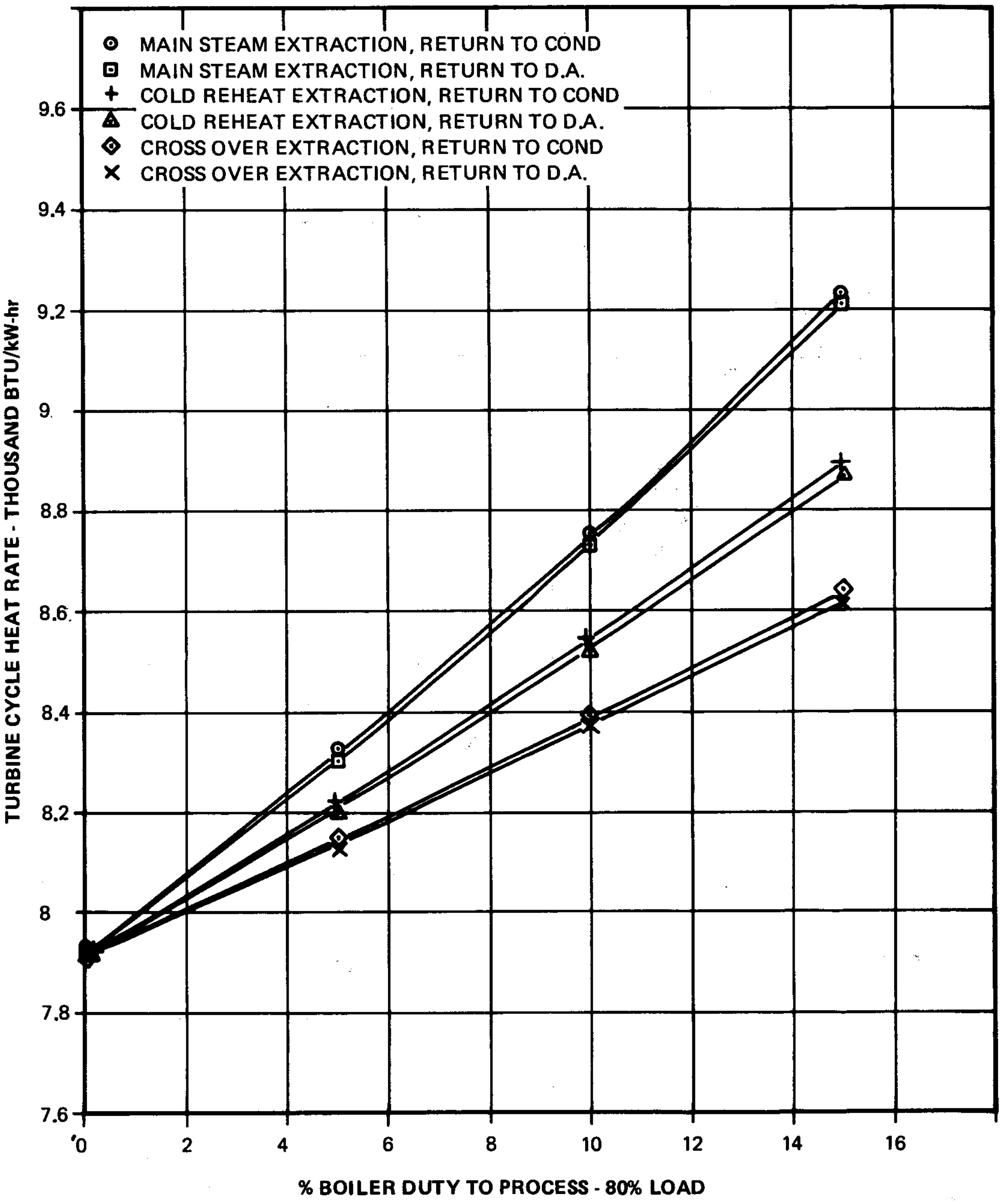


FIGURE E-9

PERCENT BOILER DUTY TO PROCESS vs. PROCESS STEAM FLOW



EPRI - 540MW GROSS, MODEL PLANT
HEAT RATE vs. BOILER DUTY TO PROCESS - 80% LOAD

FIGURE E-10

PERCENT BOILER DUTY TO PROCESS vs. TURBINE CYCLE HEAT RATE

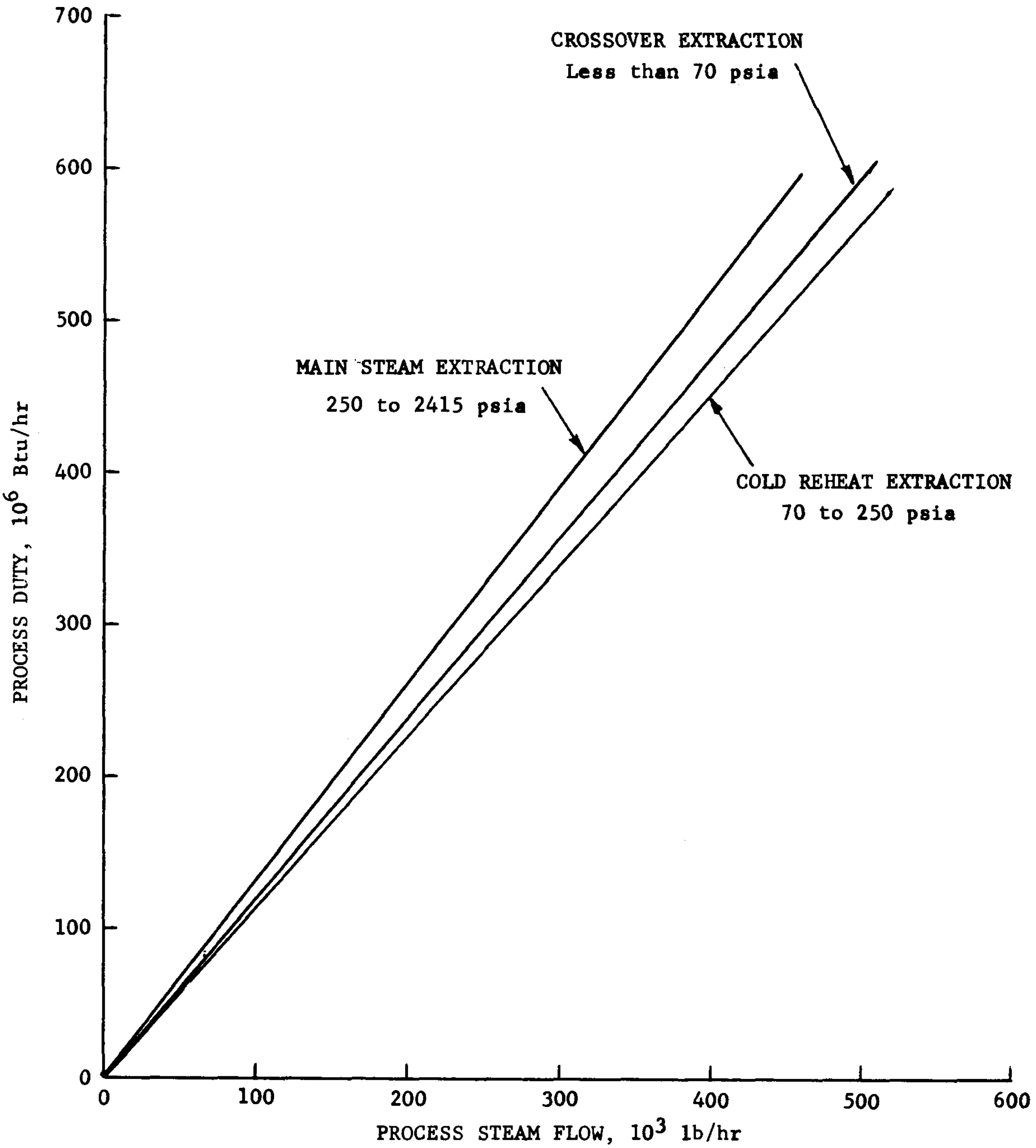


FIGURE E-11

PROCESS STEAM FLOW VS. PROCESS HEAT DUTY

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Appendix F

FLUE GAS DESULFURIZATION EVALUATION STANDARD

A proposed evaluation standard for economic assessment of flue gas desulfurization (FGD) systems is presented here in two sections. The first section (Part 1) defines the various components of capital and operating costs and presents a standardized format for their development and presentation. The second section (Part 2) details a standard specification for a base-case nonproprietary limestone slurry FGD system with provision for consistent adaptation for other cases or processes.

Part 1

STANDARD FOR FGD CAPITAL AND OPERATING COST PRESENTATION AND ECONOMIC EVALUATION

This portion of the standard is contained in the following amended EPRI document Economic Premises for Electric Power Generations Systems — Complete Plant Utility Financing (July 26, 1978) FGD Amendment (September 1978).

ECONOMIC PREMISES FOR
ELECTRIC POWER GENERATING SYSTEMS

COMPLETE PLANT UTILITY FINANCING

(REFERENCE DATE: JULY 26, 1978)

FLUE GAS DESULFURIZATION AMENDMENT JUNE 1979

A. CAPITAL REQUIREMENTS

(An example format for presenting projected capital requirements is shown in Table A-1.)

1. <u>Total Plant Investment</u>

The total plant investment is the sum of:

(a) Process (or On-Site) Capital
(b) General Facilities (or Off-Site) Capital
(c) Engineering and Home Office Fees
(d) Project Contingency
(e) Process Contingency

These items are discussed below.

Process Capital

Process capital is the total constructed cost of all onsite FGD and related facilities, including all direct and indirect construction costs. Utility capital for items such as FGD water makeup treatment will be included along with prorata capital distribution for power plant items such as ID fans (for that portion of their load required for the FGD system).

All sales taxes should be included. When possible, the process capital costs should be broken down by major plant section (e.g., raw materials receipt, storage, and preparation, gas path systems, and waste separation and placement). The specific section breakdown should be agreed upon with the EPRI project manager. The capital cost detail should break down the total process capital into factory materials (equipment), field materials, and field labor.

The process design basis, the scope definition for the FGD system, and an indication of the quality of the mechanical design (materials of construction, equipment redundancy) must be referenced.

General Facilities or Offsite Capital

The capital cost of the offsite facilities is to be given explicitly in the report. The offsite facilities include a prorata share of roads, office buildings, shops, laboratories, etc., and generally are in the range of 5 to 20 percent of the onsite capital cost. Raw material and byproduct storage systems are not to be included in the onsite capital costs and are not part of the offsite facilities. The cost basis for the offsites will be established by the contractor with the concurrence of the EPRI project manager. Sales taxes should be included where applicable.

Engineering and Home Office Overhead Including Fee

The contractor will include an estimate of the engineering and home office overhead and fee that are considered representative of this type of plant. These fees may be included in the process capital and general facility capital costs if the contractor's cost-estimating system incorporates estimates of these fees as a part of the equipment costs. The capital cost summary table must indicate where these fees have been included (10 to 15 percent of the process capital is typical for these fees).

Project Contingency

A capital cost contingency factor should be developed by the contractor for each segregated portion of the FGD system. This is a project contingency factor that is intended to cover additional equipment or other costs that would result from a more detailed design of a definitive project at an actual site. Table A-5 at the end of this appendix presents guidelines for relating the project contingency to the level of design/estimating effort. Thus, by specifying the project contingency, the level of design/estimating effort and precision can be inferred. The contingency factors developed for each plant section should be explicitly shown in the report.

Process Contingency

This is a capital cost contingency applied to new technology in an effort to quantify the uncertainty in the design and cost of the commercial-scale equipment. The following guidelines are provided to aid in assigning process contingency allowances to various sections of the plant.

State of Technology Development	Percentage of Installed Section Cost
New concept with limited data	25% and up
Concept with bench-scale data available	15-25%
Small pilot plant data (e.g., 1-10 MW size) available	10-15%
A full-size module (100 MW) has been successfully operated for a period of one year	5-10%
The process is used commercially in similar or identical service to that proposed	0-5%

The process contingency should be shown separately for each major plant section.

2. Total Capital Requirement

The total capital requirement for a regulated utility includes all capital necessary to complete the entire project. These items include:

(a) Total Plant Investment
(b) Prepaid Royalties
(c) Preproduction (or startup) Costs
(d) Inventory Capital
(e) Initial Chemical and Catalyst Charge
(f) Allowance for Funds During Construction (AFDC)
(g) Land

These items are discussed below.

Total Plant Investment

Defined in Item 1, above.

Prepaid Royalties

See Table A-4 at the end of this appendix for definition

Preproduction Costs

The preproduction costs are intended to cover operator training, equipment checkout, major changes in plant equipment, extra maintenance, and inefficient use of fuel and other materials during plant startup. The preproduction costs are estimated as follows:

(a) One month of fixed operating costs (fixed operating costs are operating and maintenance labor, administrative and support labor, and maintenance materials).

(b) One month of variable operating costs at full capacity (these variable operating costs include chemicals, water, and other consumables and waste disposal charges).

(c) Five percent of total plant investment (this charge covers expected changes and modifications to equipment that will be needed to bring the plant up to full capacity).

Inventory Capital

The value of inventories of raw materials, other consumables, and byproducts is capitalized and included in the inventory capital account. The inventory capital is estimated as follows:

(a) One month's supply of raw materials based on full-capacity operation

(b) One month's supply of other consumables (excluding water) based on full-capacity operation

Initial Chemicals and Catalyst Charge

The initial cost of any catalyst or chemicals that are contained in the process equipment (other than that in storage, and thus covered in inventory capital) is also included.

Allowance for Funds During Construction (AFDC)

An AFDC charge is computed based on the time period from the center of gravity (cg) of expenditures until the plant is in commercial operation. The interest rate is eight percent per year. The AFDC is then calculated from the total plant investment (TPI) as shown below:

$$\text{AFDC} = [(1.08)^{cg} - 1]\ (\text{TPI})$$

<u>Numerical Example</u>

$\text{TPI} = \$100$

$cg = 2$ years

$$\text{AFDC} = [(1.08)^{2} - 1]\ (100) = \$16.6$$

The center of gravity time period (cg) is to be estimated by the contractor. Representative centers of gravity for several types of power plants are shown in the following table:

Type of Plant	Total Design-Construction Time	cg
Pulverized Coal Fired (1000 MW)	5 years	2 years
Oil Fired Combined Cycle (500 MW)	3 years	1 year
Combustion Turbine Unit (75 MW)	2 years	0.5 year

Since the AFDC charge is to be expressed in the same year dollars as the total plant investment, cost escalation (inflation) is not included. The particular year used must be specified. It will normally be the first year of operation. Table A-6 at the end of this appendix gives an example of an AFDC calculation based on a construction cash flow schedule.

Land

Land costs are site-specific and variable. See Table A-4 for a land cost.

B. CAPACITY FACTOR

For EPRI evaluation purposes, the following capacity factors (CF) are suggested as design values:

Type of Plant	Design Capacity Factor
Base	70%
Intermediate	30%
Peaking	10%

A design capacity factor of 70 percent is normally used as indicated in Table A-4. The CF is assumed to be constant over the life of the plant (i.e., levelized).

C. OPERATING COST BASIS

The operating costs are to be estimated on a first operating year basis. The costs will also be presented on a 30-year levelized basis (details are given in the following section.

The operating costs are divided into fixed and variable costs. The fixed costs are essentially independent of capacity factor and are generally expressed in \$/kW-yr based on design capacity. The variable costs are directly proportional to the amount of power produced (capacity factor) and are generally expressed in mills/kWh.

An example format for presenting first year operating costs is presented in Table A-2.

1. Fixed Operating Costs

Fixed operating costs include the following:

(a) Operating Labor
(b) Maintenance (may also have a variable component)
(c) Overhead Charges

These items are discussed below.

Operating Labor

The contractor will estimate the number of operating jobs (OJ) that are required to operate the plant. The operating labor charges (OLC) are then computed using the average labor rate (ALR) as follows:

$$\text{OLC} = \frac{(\text{OJ}) \times (\text{ALR}) \times (8760\ \text{hr/yr})}{(\text{Full capacity of plant in kW})}$$

The average labor rate includes payroll burden and is given in Table A-4 at the end of this appendix.

Maintenance Costs

Annual maintenance costs for new technologies are often estimated as a percentage of the installed capital cost of the pertinent facilities. The percentage varies widely depending on the nature of the processing conditions and the type of design. Maintenance costs in the ranges shown below are representative.

Type of Processing Conditions	Maintenance Percentage of Process (or offsite) Capital Cost/Yr
Corrosive (fouling and abrasive slurries)	6.0 - 10 (& higher)
Severe (solids handling high temperature)	4.0 - 6 (& higher)
Clean (noncorrosive or fouling liquids and gases only)	2.0 - 4
Offsite facilities & steam/electrical systems	1.5

The maintenance costs will be developed by the contractor with concurrence of the EPRI project manager.

The maintenance costs should be separately expressed as maintenance labor and maintenance materials. A maintenance labor/materials ratio of 40/60 may be used for this breakdown if other information is not available.

Overhead Charges

The only overhead charge included in the power plant studies is a charge for administrative and support labor, which is taken as 30 percent of the operating and maintenance labor.

General and administrative expenses are not included.

2. Variable Operating Costs

Consumables

Variable operating costs includes fuel, water, chemicals, waste disposal, etc. The first-year values to use for these items are given in Table A-4 at the end of this appendix.

Variable Maintenance Charges

A variable component of the maintenance cost should be included if there is a basis for estimating how maintenance costs vary with capacity factor.

3. Byproduct Credits

Byproduct credits (if any) are based on values given in Table A-4.

4. Levelized Operating Costs

Inflation will tend to increase the operating costs (in current dollars) over the life of the plant. In EPRI analyses, a long-term inflation rate of six percent per year is assumed in estimating the cost of capital (discussed in a following section) and in estimating the life-cycle revenue requirements for other expenses. To represent these varying revenue requirements for fixed and variable costs (including fuel), a single "levelized" value is computed using the "present worth" concept of money. Based on the following assumptions,

Inflation rate = 6%/year
Discount rate = 10%/year,

the 30-year levelization factor (LF) for operating and maintenance (O&M) costs (excluding fuel) is 1.886 (see Chapter V of the EPRI Technical Assessment Guide [TAG] for further detail).

30-year levelized O&M = 1.886 x (1st year O&M)

The 30-year LF for fuel is given in Table A-4.

D. COST OF CAPITAL

The cost of capital is based on an assumed six percent per year inflation rate and the following assumptions:

Debt/Equity Ratio	50/50
Debt Cost	8%/yr
Preferred Stock Ratio	15%
Preferred Stock Cost	8.5%/yr
Common Stock Ratio	35%
Common Stock Cost	13.5%/yr
Weighted Cost of Capital	10%/yr
Federal + State Income Tax Rate	50%
Property Taxes and Insurance	2%/yr
Investment Tax Credit	0
Book Life	30 yr
Tax Life	20 yr
Iowa Type S_1 Retirement Dispersion	

The 30-year levelized fixed charge rate (LFCR) calculated from the above assumptions is eighteen percent per year. For more information see Chapter V of the Technical Assessment Guide (TAG).

Levelized Fixed Charges (30-year plant)

The levelized fixed charges (LFC) are based on the total capital requirement (TCR) and are computed as follows:

$$\text{LFC} = \frac{(\text{LFCR})\ (\text{TCR})}{(\text{plant size in kW})} = \$/\text{kW-yr}$$

Where LFCR = 0.18

Levelized Fixed Charges (interim replacements)

If major portions of the plant have a short life (5 to 10 years), and would have to be capitalized as interim replacements, a fixed-charge rate consistent with the shorter life must be applied to these capital items. The contractor should obtain the proper fixed-charge rate in this case from the EPRI project manager.

E. EFFECT OF FGD ON POWER COST

The component of FGD cost in the cost of electricity from a power plant is not a single value but varies with the plant capacity factor. Therefore, the power cost should be presented in the form of a "Power Cost Sensitivity Curve" plot as defined below.

Power Cost Sensitivity Curve

Vertical axis = FGD component of electric power cost (mills/kWh).

Horizontal axis = capacity factor (0 to 100%)

Thirty-year levelized costs are used. An example is shown in Figure A-1. The contractor will prepare this curve for the power generation option being evaluated.

The range of capacity factors for which the design/ cost estimate are reasonably valid should be represented by a solid curve. A dashed curve can be used to indicate the cost trends outside the design range.

Numerical Power Cost

For convenience of discussion, a levelized cost of power for the design capacity factor will be calculated, using the 30-year levelized fixed charges, O&M charges, and fuel charges. A sample format for presenting this cost calculation is shown in Table A-3.

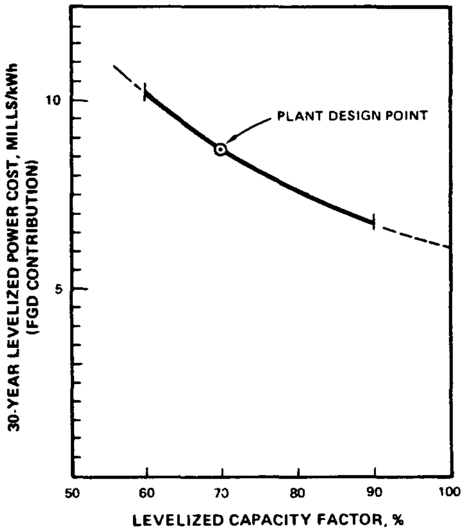

Figure A-1
SENSITIVITY OF FGD CONTRIBUTION TO POWER COST TO CHANGES IN CAPACITY FACTOR

Table A-1

XYZ PROCESS

PROJECTED CAPITAL REQUIREMENTS

Unit size (MW net):
Capacity factor:
Coal (sulfur content):
Pricing level:
SO_2 emission limit:

	$/kW
Raw Material Receiving & Storage	
Feed Preparation & Storage	
Flue Gas Treatment	
Flue Gas Reheat	
Waste Separation	
Waste Disposal	
SO_2 Regeneration	
Flue Gas Supply	
SO_2 Reduction	
Product Storage	
Total Process Capital	
General Facilities	
Engineering & H.O., Fees	
Project Contingency	
Process Contingency	
Total Plant Investment	
Royalty Allowance	
Preproduction Cost	
Inventory & Initial Chemicals	
Interest during Construction	
Land	
TOTAL CAPITAL REQUIREMENT	

Levelized fixed charges - mills/kWh

Table A-2

XYZ PROCESS

PROJECTED FIRST YEAR OPERATING COST

Basis:
Unit size (MW net):
Capacity factor:
Coal (sulfur content):
Pricing level:
SO_2 emission limit:

	Unit	Unit Rate ($)	Annual Quantity	Annual Cost ($x1000)
Operating Labor	Manhour			
Maintenance Labor				
Maintenance Material				
Admin./Support				
Total Fixed O&M Cost				
Utilities				
Steam	10^6 Btu			
Water	10^3 gal			
Electricity	kWh			
Fuel Oil	gal			
Natural Gas	10^3 ft^3			
Chemicals-Limestone	ton			
Lime	"			
Soda Ash	"			
Magnesium Oxide	"			
Coke	"			
Anthracite	"			
Antioxidant	lb			
Other Consumables				
Waste Disposal	ton			
Total Variable O&M Cost				
TOTAL FIRST YEAR OPERATING COST				

Levelized Operating Cost - mills/kWh

Table A-3

XYZ PROCESS

LEVELIZED REVENUE REQUIREMENTS

Basis:
Unit size (MW net):
Capacity factors:
Coal (Sulfur content):
Pricing level:
SO_2 emission limit:

	Levelized mills/kWh
Process Capital General Facilities Engineering, H.O., Fees Contingency Total Capital Requirement Preproduction Inventory & Misc. AFDC Land	
Total Plant Investment Operating & Admin Labor Maintenance Labor & Mat.	
Total Fixed O&M Cost Utilities Steam Water Electricity Chemicals & Consumables Waste Disposal	
Total Variable O&M Cost	
TOTAL LEVELIZED REVENUE REQUIREMENTS	

Table A-4

ECONOMIC VARIABLES

Design Capacity Factor

70% for Base Load, 30% for Intermediate Load, 10% for Peak Load

Capital Investment Items

Paid-up Royalties: 0.5% of Process Capital

Operating Labor (Mid 1978 $)

First Year: $12.50/manhour (This labor rate is based on a direct labor charge of $9.25/hr plus a 35% payroll burden.)

Labor Inflation Rate: 6%/year

Purchased Materials (Delivered Cost), Chicago Area

	Mid-1978 $	Price Escalation Rate/Yr (Including Inflation)	30-Year Levelization Factor (LF)
Coal	$1.00/10^6 Btu	-	-
Fuel Oil (No.6)	$0.40/gal	6.1%	1.909
Steam	$2.50/10^6 Btu	6.1%	1.909
Electric Power	$0.03/kWh	6.1%	1.909
Process Water	$0.40/10^3 gal(a)	6.0%	1.886
Cooling Water	$0.10/10^3 gal	6.0%	1.886
Natural Gas	$4.00/10^3 ft^3	6.1%	1.909
Coke	$35.00/ton	6.0%	1.886
Anthracite	$56.85/ton	6.0%	1.886
Lime	$34.00/ton	6.0%	1.886
Limestone	$10.00/ton	6.0%	1.886
Soda Ash	$65.00/ton	6.0%	1.886
Magnesium Oxide	$250.00/ton	6.0%	1.886
Citric Acid, 50%	$800.00/ton	6.0%	1.886

Disposal Charges

Sludge	$8.50/ton (dry basis)	6.0%	1.886
Dry, Granular Solids	$4.00/ton	6.0%	1.886

Byproduct Credits

Sulfuric Acid	No credit	----	----
Sulfur	No credit	----	----

Land Cost

$5000/acre

(a) This is a raw water acquisition charge only. Intake structures, treating, and pumping costs are to be included in plant capital and O&M.

Table A-5

DESIGN AND COST ESTIMATE CLASSIFICATIONS

Item	Design/ Estimate Description	Project Contingency Range	Design Information Required	Cost Estimate Basis		
				Major Equipment	Other Materials	Labor
Class I	Simplified	20% to 30%	General site conditions, geographic location and plant layout. Process flow/operation block diagram. Product output capacities.	By overall project or section-by-section based on capacity/cost graphs, ratio methods, and comparison with similar work completed by the contractor, with material adjusted to current cost indices and labor adjusted to site conditions.		
Class II	Preliminary	15% to 20%	As for Type Class I plus engineering specifics, e.g.: Major equipment specifications. Preliminary P&I flow diagrams.	Recent purchase costs (including freight) adjusted to current cost index.	By ratio to major equipment costs on plant parameters	Labor/material ratios for similar work, adjusted for site conditions and using expected average labor rates.
Class III	Detailed	10% to 15%	Complete process design. Engineering design usually 20% - 40% complete. Project construction schedule. Contractual conditions and local labor conditions. Actual site defined	Firm quotations adjusted for possible price escalation with some critical items committed. Pertinent taxes and freight included.	Firm unit cost quotes or current billing costs) based on detailed quantity takeoff.	Estimated man-hour units (including assessment) using expected labor rate for each job classification.
Class IV	Finalized	5% to 10%	As for Class III - with engineering essentially complete.	As for Class III - with most items committed.	As for Class III - with material on approximately 100% firm basis.	As for Class III - some actual field labor productivity may be available.

Table A-6

EXAMPLE OF AFDC CALCULATION FROM THE CONSTRUCTION PERIOD CASH FLOW

Example

Total Plant Investment (TPI) = \$100 (year 1 \$)

Construction Expenditure Schedule (Assumed)

Year	\$ (year 1 \$)
1	5
2	15
3	30
4	35
5	15

Assuming expenditures are uniform over a given year, the effective interest rate for the first year is one-half the annual interest rate (using annual end-of-year compounding).

Annual Interest Rate = 8%

Calculation of AFDC

$$\begin{array}{lcr}
5 \times (1.04)\ (1.08)^4 & = & 7.07 \\
15 \times (1.04)\ (1.08)^3 & = & 19.65 \\
30 \times (1.04)\ (1.08)^2 & = & 36.39 \\
35 \times (1.04)\ (1.08) & = & 39.31 \\
15 \times (1.04) & = & \underline{15.60} \\
\text{Total (TPI + AFDC)} & & 118.02
\end{array}$$

$$\text{Center of Gravity (cg)} = \frac{\log \left(\frac{\text{AFDC}}{\text{TPI}} + 1\right)}{\log\ (1.08)}$$

$$\text{cg} = \frac{\log \left(\frac{18.02}{100} + 1\right)}{\log\ (1.08)} = 2.15 \text{ years}$$

Therefore, 2.15 years is the center of gravity (cg) for the construction expenditure schedule shown above.

Appendix G

COMMENTS OF PROCESS SUPPLIERS

Prior to publication of this report, the suppliers and developers of the processes presented in sections 4 through 7 of the report were given an opportunity to review the process description and cost estimate of their particular process. The process descriptions were subsequently revised to reflect changes requested by the process suppliers.

In some cases, the process suppliers did not fully agree with the cost estimates presented herein for their particular process. However, the cost estimates were not changes because such changes would have meant that the estimates were no longer representative of a consistent, comparative methodology. Instead, each process supplier was given an opportunity to present their cost estimate comments, if any, in this Appendix.

COMMENTS OF TENNESSEE VALLEY AUTHORITY

General TVA comments concerning the draft report "Economics of Four FGD Systems" prepared by Stearns-Roger Engineering Corporation for EPRI.

Process Design

1. Both the cocurrent and the conventional limestone systems are designed with 100% redundancy in the limestone preparation area, 33-1/3% scurbber redundancy and provisions for full bypass. The need for this degree of grinding redundancy and bypass are questionable. In contrast, recirculation pumps are not spared.

2. Scrubber layout for the systems is not conventional. Although the report states that the arrangement is consistent for all processes evaluation, it is in general a more costly arrangement, particularly for the conventional limestone and cocurrent limestone processes. This arrangement essentially eliminates the advantages of cocurrent scrubbing in regard to layout of ductwork and simplicity of reheater design (ground level).

3. Scrubber heights of 110' and 120' for conventional and cocurrent limestone scrubbers appear to be out of line with normal practices.

4. Separate slurry recirculation pumps are indicated for each slurry distribution point for the conventional and cocurrent limestone processes. A more conventional less expensive design uses a single header feeding all slurry distribution locations.

5. Limestone systems designed for forced oxidation within the scrubber loop produce a disposable gypsum by-product which is preferable to blended sludge. This by-product is comparable to the by-product from the CT-121 process.

6. Storage of limestone slurries at a concentration of 20% solids may be more difficult than storage at 60% solids.

7. The following data related to limestone consumption and waste disposal are given in the report:

Process	Stoichiometry	Solids concentration % by wieght Thickener underflow	 dewatered sludge	Waste disposal rate, tph
Conventional limestone scrubbing	1.15	25	45	140
Cocurrent limestone scrubbing	1.30	25	60	122.5

A stoichiometry of 1.15 for 90% SO_2 removal using conventional limestone scrubbing is optimistic based on results at Shawnee. Also, based on Shawnee results, there is no significant difference in dewatering characteristics of cocurrent and conventional limestone sludges.

Economics

1. It would have been valuable to include additional tables in the report displaying the projected breakdowns for the cost sensitivity variations in the same format as Tables 4-3 through 4-5. It would also have been helpful to display the projected field material costs (piping, foundation, structure, etc.) for each area.

2. Relative Total Process Capital and Total Capital Requirement costs for the conventional and cocurrent limestone processes are reversed solely as a result of using different project and process contingency factors for the two processes.

3. Recent TVA in-house evaluations comparing economics of conventional limestone scrubbing using forced oxidation, cocurrent limestone scrubbing using forced oxidation, and Chiyoda 121 processes result in the following relative ranking in order of increasing revenue requirements: (1) Cocurrent (2) Chiyoda CT-121, and (3) conventional scrubbing.

DAVY McKEE COMMENTS

Davy McKee Corporation must take exception to the economic analysis presented in this report. The economics of the Wellman-Lord process have been reported from several independent sources in recent years, and while we have not always concurred with all of the details and methodology, we have been able to identify and reconcile these results with our own analysis. We have not been able to do so in this report.

We recognize that in preparing studies of this kind, differences in criteria, methodology, and reporting format are to be expected. We also recognize that these differences make direct comparisons between different studies difficult. The Total Capital Requirement estimated in this report is so much greater than any previously reported independent study and our own estimates, however, that the differences cannot be attributed to criteria, methodology or format.

Our major concern lies in the reported Total Process Capital. We have estimated the base case system using the study criteria and the most recent equipment quotations obtained from purchases made for current projects and in the preparation of lump sum proposals for other projects. We have used the sulfuric acid case for comparative purposes, and estimate the Total Process Capital to be $105/KW as compared to the $170.9/KW contained in this report.

Applying the factors assumed by EPRI to develop Total Plant Investment and Total Capital Requirement results in a Total Capital Requirement of $166.6/KW as compared to the $267.4/KW reported by EPRI.

While some differences in basic criteria exist such as a slightly lower sulfur content in the coal (3.5% vs. 4.0%) and higher allowable emission levels (1.2#/MBtu vs. .79#/MBtu), we call attention to the data published in the paper "Economics and Energy Requirements of Sulfur Oxides Control Processes," by G.G. McGlamery, T.W. Tarkington and S.V. Tomlinson of TVA. This paper was presented at the March 1979 Flue Gas Desulfurization Symposium in Las Vegas. In this analysis a Total Capital Investment of $71,448,000 is reported, or $142.9/KW as compared to the $267.4/KW reported in the EPRI study. We do not believe the aforementioned criteria differences account for the Capital Investment differences.

In brief, we believe the capital cost estimates are high by at least 60%. This difference is, of course, further reflected in the levelized busbar cost data.

In an attempt to reconcile this large difference in Total Process Capital estimates we have noted several departures in design features from what we would consider a preferred design.

1. The design used in this report includes extensive treatment of the pre-scrubber effluent by neutralization with lime, the addition of fly ash and chemical fixative to produce a sludge similar to that of the limestone throwaway effluent for disposal. While this option is technically feasible, and consistent with the treatment of throwaway process sludge, our experience has been that other options are available requiring less extensive treatment facilities. In none of the Wellman-Lord systems installed or in design at this time has such extensive treatment been required.

2. For all existing utility installations to date, Davy McKee has selected a square tile lined concrete design for the absorbers incorporating common walls between units. This decision has been reviewed in detail as each installation was designed, and in every case proven to be the most economical design as compared to other options, including the carbon steel shell with rubber lining design proposed in this study.

3. The general arrangement of the absorbers shown in Fig. 7-4 is not typical of existing or planned projects. This fact was noted in our comments to the contractor on our initial review of the first draft of the report, and a more typical layout was proposed. We believe our arrangement results in better gas distribution, reduced land requirements and lower costs.

We note two specific items in the economic data which we feel require comment.

1. The costs given for area 07 and 10 for the sulfuric acid option we believe are inconsistent with the costs presented for the sulfur option. We find reasonable agreement with the sulfur option costs, but our experience has indicated that the acid option has always been lower in cost than the sulfur option. We believe the indicated acid option costs are high by a factor of 2.

2. No by-product credit is given for the sulfate salt cake produced in the Wellman-Lord crystallizer section. We recognize that the value of this credit is somewhat more difficult to establish than the sulfur or acid product, but operators of existing Wellman-Lord plants have all been successful in marketing this material. We suggest that $25/ton can be reasonably expected.

In conclusion, we do not believe that the incorporation of the specific design and economic details outlined in these comments will resolve the large difference between our analysis, other independent studies and the analysis in this report. We do not take exception to the economic premises and parameters selected by EPRI in preparing this report, as we believe the knowledgeable reader recognizes the need for a reasonable degree of commonality in making comparative reviews, and that such commonality limits to some extent the economic and technical options available to the purchaser and designer of a specific plant. In the area of equipment and erection costs (represented in this study as Total Process Capital), however, we believe our experience in the purchase and erection of similar plants qualifies our exception to the analysis presented in this report.

We regret that time and resources to fully resolve the apparent differences have not been available to us. We appreciate the opportunity to present our concerns and wish it were not necessary to do so. Our only interest is that the economics of our Wellman-Lord process be reasonably presented, and do not believe this report does so.

CHIYODA INTERNATIONAL CORPORATION'S COMMENTS

At the request of EPRI, Chiyoda International Corporation has reviewed Sections 3 and 6 of this report and offers the following comments in an effort to ensure an accurate representation of the Chiyoda Thoroughbred 121 (CT-121) Flue Gas Desulfurization technology and to bring to the reader's attention any discrepancies between the CT-121 technology presented herein and the CT-121 technology currently being offered commercially to the electric utility industry. For the reader's convenience the page number and paragraph of the subject matter for which the comments are directed are identified.

Page 3-13, Paragraphs D and E

CT-121 is being offered commercially to the electric utility industry on a lump sum competitive bid basis. We, therefore, believe that there can be no more uncertainty in CT-121's cost as opposed to any of the systems evaluated in this report. We, therefore, believe it is inappropriate to assign a higher contingency to CT-121. We believe that a contingency may be justified and applicable to a system under development, but not a system such as CT-121 which is fully developed with a fixed design.

Page 6-2, Paragraph 3

It should be noted that CT-121 by-product gypsum, in addition to its use in the manufacture of wallboard, is also suitable for use as a retarder in the manufacture of Portland cement or as a fertilizer or soil conditioner. These additional uses can be important market outlets, especially for smaller power plants or in cases in which transportation costs of the by-product gypsum rules out its use in the manufacture of wallboard. It should also be noted that although transportation costs make the sale of gypsum site specific, there are still considerable opportunities for its sale.

Page 6-3, Figure 6-1

Figure 6-1 illustrates the use of a filter splitter box and progressive cavity pumps for gypsum slurry service for the Gypsum Stacking and Mechanical Dewatering alternates. Although this can be considered a viable application, our preference, based on our commercial experience, is to use a splitter pipe header and centrifugal pumps.

Page 6-7, Paragraph 1

"Gypsum stacking" is an ultimate disposal technique which takes full advantage of the rapid settling and inherent stability of the CT-121 by-product gypsum. This method of disposal was developed by industry to eliminate the need for mechanical dewatering equipment, trucking costs, and to reduce land requirements to minimize overall disposal costs. The phosphate industry which produces huge quantities of gypsum, as well as other industries such as the nonferrous smelter (tailings), and sugar refining (limestone precipitate) industries which also produce huge quantities of solid waste, all use the "stacking" disposal technique which consists of pumping the solid wastes in slurry form to the ultimate disposal site where solid wastes settle out and the process liquors recycled to the process. Therefore, we do not visualize "gypsum stacking" merely as a means to dewater gypsum as presented herein, but rather an ultimate disposal method which takes full advantage of the rapid settling and stability of CT-121 gypsum to minimize overall disposal costs. For all of these industries, the "stacking" method of disposal has been determined the most cost effective means of permanently disposing huge quantities of by-product solid waste.

Page 6-8, Table 6-2

Table 6-2 shows power consumption as 2.2 percent of net generating capacity. This compares with our estimate of 1.8 percent.

Page 6-10, Paragraph 4

In paragraph 4 it is mentioned that the pH and slurry concentrations in the Jet Bubbling Reactor are maintained in the range of 3 to 5 and 10 to 30 weight percent, respectively. We believe that some misunderstanding may result from this description of how these parameters are controlled. For both of these parameters, a single and optimum control point will be specified depending on site specific design criteria. We believe the report intended to describe the relative insensitivity of pH and slurry concentration.

Page 6-11, Paragraph 1

One of the major points to be considered in a technical evaluation pertains to the ease in which the FGD system by-product can be dewatered. Therefore, we believe that it is important that the dewatering characteristics of CT-121 by-product gypsum be clarified, particularly with respect to how these characteristics impact on the size and operability of filtration equipment.

The crystal size and configuration and the high settling and cake forming rates of CT-121 gypsum permits the use of a rotary vacuum filter designed specifically for free filtering materials. We have experienced filtration rates of up to 5,600 pounds per hour per square foot for sludges produced by conventional lime or limestone scrubbing systems. This high filtration rate impacts greatly on the size of filtration equipment. A conservative sizing criteria of 2,000 pounds per hour per square foot results in a drum size of four feet diameter by four feet wide for the 500 MW application considered in this report. This compares with a conventional filter which would require a drum size of fourteen feet diameter by twelve feet wide. In addition to a significant reduction is size, the filter itself is greatly simplified compared with conventional rotary drum vacuum filters. This is especially true with respect to internal piping. For rotary vacuum filters designed for free filtering materials, such as CT-121 gypsum, the internal piping is reduced to a single pipe. The result is a considerably higher effective vacuum across the filter cake.

Page 6-13, Table 6-3

We are not in a position to comment on the accuracy of the estimated capital requirement as the information provided was not intended for such an analysis and the estimated costs developed for the individual processes are not intended to reflect the absolute costs, but rather relative costs to be used for comparison purposes only. However, we can make some general observations: (1) the Total Process Capital compared with actual and similar commercial offerings is very high: (2) project and process contingencies are high compared to other systems under consideration (refer to our comment for page 3-13, paragraphs D and E): (3) the costs included in this report are based on information which was available in February 1979. As such, they do not reflect recent and significant refinements to the technology which impact favorably on total system cost.

Page 6-14, Table 6-4

As for total capital requirements discussed above, we are not in a position to comment on the accuracy of the operating costs presented in Table 6-4. However, we can make the following general observations: (1) Operating and maintenance labor is excessive. We would expect that operating and maintenance costs for CT-121 would be considerably less than for the other systems considered due to simplicity of design and operation (no slurry recycle pump, thickeners and ancillary equipment) and improved process chemistry (complete oxidation of sulfite and sulfate and high limestone utilization) made possible by operation at a slightly lower pH and the use of gypsum seed crystals. Lower operating and maintenance costs is one of the most significant cost advantages of the CT-121 technology. (2) We would expect the "gypsum stack" alternate to be the least costly method of disposal based on pumping gypsum slurry directly to the disposal site as opposed to dewatering by "gypsum stacking" and then trucking to the disposal site which is the basis on which the disposal costs presented are based. The disposal costs presented in Table 6-4 for the "gypsum stack" alternate are essentially inflated by the costs incurred in handling and transporting the dewatered gypsum to the disposal site. Based on our "gypsum stacking" experience, we visualize only a part-time job for operation of a "gypsum stack" for the 500 MW application under study. Even for very large "gypsum stacking" operations, such as in the phosphate industry, only one or two men per day shift are required.