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Computerized Shawnee Lime/Limestone Scrubbing Model Users Manual

Interagency Energy/Environment R&D Program Report

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Computerized Shawnee Lime/Limestone Scrubbing Model Users Manual

by

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ABSTRACT

This manual provides a general description of the Shawnee lime-limestone scrubbing computerized design - cost-estimate model and the detailed procedures for using it. It is a revision of an earlier manual (1979). All inputs and outputs are described along with the options available. Design and economic premises are included. The model is based on Shawnee Test Facility scrubbing data and includes a combination of material balance subsystems provided to the Tennessee Valley Authority (TVA) by Bechtel National, Inc., and capital investment - revenue requirement subsystems developed by TVA. As key features, the model provides estimates of capital investment and operating revenue requirements for a lime or limestone scrubbing facility. Also provided are a material balance, equipment list, and a breakdown of costs by processing areas. The primary uses of the model should be for projecting comparative economics of lime or limestone flue gas desulfurization processes (on the same basis as the model) or in the evaluation of system alternatives prior to the development of a detailed design.

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USERS MANUAL

INTRODUCTION

Since 1968 the U.S. Environmental Protection Agency (EPA) has sponsored a flue gas desulfurization (FGD) test facility at the Tennessee Valley Authority (TVA) coal-fired Shawnee Steam Plant near Paducah, Kentucky. TVA is the constructor and operator and Bechtel National, Inc., is the major contractor. The test facility originally consisted of three prototype-size scrubber units, each capable of processing about 30,000 aft^3/min (10 MW equivalent) of flue gas. One unit, a marble-bed absorber, was shut down in 1973 and converted to a cocurrent absorber in 1978. The other two units, a mobile-bed absorber (Turbulent Contact Absorber, or TCA) and a venturi - spray tower, have been operated under a variety of conditions since 1972.

A computer model capable of projecting comparative capital investment, and annual and lifetime revenue requirements for lime and limestone FGD scrubbing systems based on the Shawnee results has been under development since the mid-1970's. Only informal documentation for the model was available until 1979 when a formal users manual was published (Stephenson and Torstrick, 1979). Since that time the model has been expanded to include spray tower and venturi - spray tower absorbers; forced-oxidation systems; systems with absorber loop additives (MgO and adipic acid); revised design and economic premises; and many other miscellaneous changes reflecting process improvements and variations.

The primary purpose of the model is not to calculate the economics of an individual system to a high degree of accuracy, but to provide sufficient detail to allow projections of preliminary conceptual design and costs for various lime or limestone scrubbing case variations. The model permits the estimation of the relative economics of these systems for variations in process design alternatives such as limestone versus lime scrubbing, TCA versus spray tower, use of chemical additives such as MgO or adipic acid, or alternative waste disposal methods such as onsite ponding versus forced oxidation-landfill. The effect of variations in the values of independent design criteria such as absorber gas velocity, liquid-to-gas (L/G) ratio, alkali stoichiometry, slurry residence time, and reheat temperature, may also be assessed.

Initial development of the Shawnee computer economics model began in 1974, with the responsibility shared by Bechtel and TVA. Bechtel's major responsibility has been to develop models for calculating the overall material balance flow rates and stream compositions. TVA has been responsible for determining the sizes of the required equipment, accumulating cost data for the major equipment items, and developing both a subsystem for calculating equipment costs and a subsystem for projecting capital investment costs. TVA has also developed procedures to use the output of these models in a separate TVA subsystem that projects annual and lifetime revenue requirements.

The combined models should be useful to utility companies as well as architectural and engineering contractors who are involved in the selection and design of FGD facilities. It is intended to assist in the evaluation of system alternatives leading to the development of a detailed design rather than to project a final detailed design. It should also be useful for evaluating the potential effects of various process variables on economics as a guide for planning research and development activities. Although the model has not been validated as a method for comparing projected lime or limestone scrubbing economics with the economics of alternate processes, these comparisons should be valid if the assumptions for the alternate systems are equivalent to the model assumptions for lime or limestone systems.

The model has already been used for several applications other than those for which it was specifically developed. These include simulated industrial boiler applications, smelter off-gas desulfurization applications, and plant fuel optimization studies.

This revision of the users manual provides the updated information and procedures necessary to use the Shawnee lime and limestone computer model. It does not provide the concepts and background information basic to the model development. Presentations related to the model have been given at EPA industry briefings (Torstrick, 1976; and Stephenson and Torstrick, 1978, 1979) and FGD symposiums (Torstrick et al., 1978; and McGlamery et al., 1980). The publications associated with these presentations discuss the model in general, describe the process and program options, and show sample results. Copies of these publications should be used in conjunction with the manual. Process flowsheets and diagrams are included in Appendix A to provide the user with the equipment layouts. Design and economic premises in effect since December 1979 (and expanded and amplified in March 1980), which serve as guidelines for computer input, are described in Appendix B. These premises are used for TVA economic studies and contain specifications beyond the scope of the model.

GENERAL INFORMATION

CURRENT SCOPE

The present model projects a complete conceptual design package for either a lime or limestone scrubbing system. It is designed for a wide range of options that are applicable to new coal-fired power units. Currently six scrubbing options (each with either lime or limestone) and four separate waste disposal options are provided. Several other options are provided to allow different combinations of process variations and improvements such as MgO or adipic acid addition or forced oxidation-ponding. Equipment size and layout configurations are based on units that range in size from 100 to 1300 MW and for coal sulfur contents that range from 2% to 5%. Because extreme variations in equipment sizes and layout configurations can result from factors other than unit size and coal sulfur content, ranges for some of these variables have been defined as follows:

Absorber gas velocity (TCA)	8-12.5 ft/sec
Liquor recirculation rate	25-100 gal/kft^3
Slurry residence time in hold tank	2-25 minutes
Number of scrubbing trains	1-10
SO_2 concentration	1500-4000 ppm

The validity of results for operating conditions outside the ranges shown above has not been determined. However, results for intermediate-sized plants operating outside these boundaries may still be valid.

Several model runs may be required to fully analyze the combined effects of individual input factors, especially if the specified ranges are exceeded. The effect of variations in inputs (such as absorber gas velocity, degree of SO_2 removal, reheat temperature, alkali stoichiometry, or L/G ratio) can be assessed individually by varying one factor per model run, or the cumulative effect can be determined by varying several factors simultaneously.

FUTURE DEVELOPMENT

Further modifications to the model are expected to be made as test data from Shawnee become available. Options which are currently being considered are: (1) landfill of treated waste, including gypsum; (2) an expanded pond model to allow input options and variables for dike width, dike roads, diverter dikes, and pond layout; (3) multiple boiler applications with common feed preparation and waste disposal facilities; (4) cocurrent scrubbing; (5) dry particulate removal costs included with FGD capital investment and revenue requirements; (6) alternate reheating methods such as hot air injection, flue gas recycling, and regenerative reheat systems; (7) retrofit difficulty factors for projecting costs for existing units; and (8) expansion of the model to validate projections for SO_2 concentrations less than 1500 ppm. If future additions are made, revisions will be made to the users manual to reflect the changes.

AVAILABILITY

The model is available to the public through TVA under an information exchange agreement between EPA and TVA. Upon receipt of a written request, TVA provides a copy of the model suitable for loading onto an IBM 370 compatible computer system, along with FORTRAN program listings and the documentation required to execute the model. Under the same information exchange agreement, capabilities are provided for TVA to make model runs based on user-supplied input data. This allows users to analyze model capabilities with a minimum amount of investigation and investment.

TVA has also loaded the Shawnee Computer Model on the Control Data Corporation (CDC) CYBERNET system which is a nationwide, commercial data processing network. The program can be made available on this system after the appropriate authorization for use is cleared by TVA and billing arrangements have been made between the user and CDC. Updated versions of the program will be maintained on this system and made available based on user interest.

Model options and input variables are added and modified on a regular basis as the scrubbing facility test results become available. The latest version is usually supplied to users and is typically the basis for user runs made by TVA. Model and documentation availability are subject to limitations based on available funding and the costs that must be incurred in connection with a user request. Requests for copies of the computer model, model runs to be made by TVA, or additional information should be made to the authors at the following address: Energy Design and Operations, Tennessee Valley Authority, Muscle Shoals, Alabama 35660, telephone number (205) 386-2814 or (205) 386-2514.

MODEL DESCRIPTION

INPUT

The overall model requires a minimum of 15 lines of input. Additional input is required when a user-specified operating profile is chosen instead of the built-in profiles. A detailed FORTRAN variable list of the model input is shown in Table C-1 of Appendix C. The variables are defined in Table C-2 of Appendix C. Ranges for key variables to aid in establishing input data to the model are shown in Table 1.

As new options are incorporated, the required inputs are subject to change. When this occurs, the list of variables and the associated definitions will be updated and made available as necessary.

OUTPUT

The outputs of the Shawnee lime-limestone computer model provide a complete conceptual design package for lime or limestone scrubbing, consisting of: (1) a detailed material balance including properties of the major streams; (2) a detailed water balance itemizing water availability and water required; (3) specifications of the scrubbing system design; (4) a display of overall pond design and costs; (5) specifications and costs of the process equipment by major processing area; (6) a detailed breakdown of the projected capital investment; (7) an itemized breakdown of the projected levelized revenue requirements by component; (8) an optional itemized breakdown of the revenue requirements for the first year of operation of the system; (9) an optional lifetime revenue requirement analysis showing projected costs for each year of operation of the plant as well as lifetime cumulative and discounted costs and equivalent unit revenue requirements; and (10) a particulate removal cost table which lists operating conditions and itemizes capital investment and revenue requirements costs for a cold-side electrostatic precipitator (ESP), a hot-side ESP, a baghouse, and a wet scrubber. However, upstream particulate removal is independent of the FGD process and costs are not included in the FGD economic projections. These outputs are illustrated in the base case printout shown in Appendix D (p. D-17).

In addition to the outputs listed above, a diagnostic message file is generated each time the model is executed. This file contains informative messages related to processing such as data case number and title, possible conflicts between options, variable values that may be out of

TABLE 1. VARIABLE RANGES

Item	Description
Power plant	New, 100-1300 MW
Fuel sulfur content	2-5%
Absorber gas velocity	8-12.5 ft/sec
Liquor recirculation rate	25-100 gal/kft^3
Effluent hold tank residence time	2-25 minutes
Number of scrubbing trains	1-10
Number of spare scrubbing trains	0-10
Sulfur to overhead as SO_2 gas	0-100%
Ash to overhead as fly ash	0-100%
System pressure drop (TCA only)	Should not exceed 3 inches per stage
Investment year	Midpoint of project expenditure schedule
Revenue requirement year	First year of operation of plant

Note: The variable ranges were established for model development purposes. Values beyond these ranges are not necessarily invalid but the potential for error is greater when these ranges are exceeded.

range, and fatal conditions that terminate model execution. In typical model runs made by TVA the message file is listed between the printed output from the investment program and the printed output from the revenue programs, but this depends on the control language procedures used for execution. An example message file is shown in the base case printout in Appendix D (p. D-23).

OPTIONS

A detailed list of all of the model inputs is included in Tables C-1 and C-2 of Appendix C. These tables include a number of options for selecting process design and controlling model output. Types of options are listed below:

- Print
- Particulate collection device Reheat
- Reheat
- Bypass and partial scrubbing
- Coal-cleaning and input composition
- Particulate removal
- SO_2 removal
- Operating parameter calculation
- Scrubbing absorbent (lime or limestone)
- Chemical additive and forced-oxidation
- Fan and absorber
- Redundancy
- Waste disposal
- Pond design
- Pond liner
- Economics
- Pond capacity
- Operating profile

Some examples of the various options are shown on the pages that follow. For illustration purposes the appropriate input data line is shown and the particular option code is indicated. An explanation of each option and sample output resulting from its usage is provided where necessary. Values for all variables must be entered for each case even though a variable value is being calculated by the model as a result of a user-specified option. When this condition occurs, the calculated value will override the input value. A value of zero will be appropriate for many variables but the value cannot be omitted. Spaces cannot be used to take the place of variables which have a value equal to zero.

Some user-specified input values result in the use of default values of other variables for consistency in the calculations. For the options that allow defaults, the option code that must be input and the default values that are assumed are described. All model output listings used to illustrate individual options are derived from the base case data shown in Appendix D. Only the variables related to options being illustrated are changed from the base case unless otherwise noted.

Print Options

Line No.	Input data
1	1 1 1 1 1
2	1 1 1 1 1 1 1 1 1 1 1 1
3	1 1 1

The options on the first three lines of the input data control printed output from the model. These options are described in the input definition list in Appendix C, Table C-2. The only print option requiring further explanation is the first option on line 3. This option controls the printout of the capital investment and revenue requirement sections. The short form printout is shown in Table 2 and may be compared with the long printout of the base case example in Appendix D.

Particulate Collection Device Option

Line No.	Input data
5	2 500 9500 11700 39 300 2 1 0 0 0 0 0 0 175 470 751 ↓ XESP

The particulate collection device option is controlled by the XESP variable. The value of XESP may be 0, 1, or 2. A zero value is used if no particular removal device is to be considered. A value of 1 is used if a mechanical collector (33% efficient) is selected, and the code for upstream removal (line 6, ASHUPS, see Table C-2) should have an input value of 33 (% removal). If an XESP value of 2 is selected, a separate particulate removal cost model (Argonne, 1979) projects the capital

TABLE 2. EXAMPLE SHORT FORM PRINTOUT

RAW MATERIAL HANDLING AREA
--- -------- -------- ----

NUMBER OF REDUNDANT ALKALI PREPARATION UNITS = 1

ECONOMIC CHARACTERISTICS
-------- ---------------

1979 TVA-EPA ECONOMIC PREMISES

PROJECTED REVENUE REQUIREMENTS INCLUDE LEVELIZED OPERATING AND MAINTENANCE COSTS
RATE = 1.886 TIMES FIRST YEAR OPERATING AND MAINTENANCE COSTS

FREIGHT INCLUDED IN TOTAL INVESTMENT
FREIGHT RATE = 3.5 %

SALES TAX INCLUDED IN TOTAL INVESTMENT
SALES TAX RATE = 4.0 %

LABOR OVERTIME INCLUDED IN TOTAL INVESTMENT
OVERTIME RATE = 1.5

INFLATION RATE = 6.0 %

PROCESS MAINTENANCE = 8.0 %

POND MAINTENANCE = 3.0 %

POND DESIGN
---- ------

OPTIMIZED TO MINIMIZE TOTAL COST PLUS OVERHEAD

POND COSTS (THOUSANDS OF DOLLARS)
---- ----- ---------- -- --------

	LABOR	MATERIAL	TOTAL
SUBTOTAL DIRECT	14920.	302.	15222.
TAX AND FREIGHT		23.	23.
POND CONSTRUCTION	14920.	325.	15245.
LAND COST			2104.
POND SITE			17349.

(continued)

TABLE 2 (continued)

LIMESTONE SLURRY PROCESS -- BASIS: 500 MW UNIT, 1984 STARTUP

USER SHORT FORM PRINT CASE 012

PROJECTED CAPITAL INVESTMENT REQUIREMENTS

	INVESTMENT, THOUSANDS OF 1982 DOLLARS			
	RAW MATERIAL HANDLING AND PREPARATION	SCRUBBING	WASTE DISPOSAL	TOTAL
SUBTOTAL DIRECT INVESTMENT	7808.	35764.	17569.	61141.
TOTAL CAPITAL INVESTMENT	14229.	65133.	29652.	109014.

(continued)

TABLE 2 (continued)

PROJECTED FIRST YEAR REVENUE REQUIREMENTS - USER SHORT FORM PRINT

ANNUAL OPERATION KW-HR/KW = 5500

	REVENUE REQUIREMENT, $
SUBTOTAL RAW MATERIAL	1304000
SUBTOTAL CONVERSION COSTS	7854400
SUBTOTAL INDIRECT COSTS	2816500
LEVELIZED CAPITAL COSTS	16025000
FIRST YEAR ANNUAL REVENUE REQUIREMENTS	27999900

investment and revenue requirements for particulate removal. The results are listed in the output but are not included in the projected FGD costs. The percentage of particulate removal required for this option is specified by the ASHUPS variable. Example output showing the results of specifying mechanical collectors (XESP = 1) is shown in Table 3. Example output showing the results of using the built-in particulate removal cost model is shown in the base case printout in Appendix D (p. D-17).

Reheat Option

Line No.	Input data
5	2 500 9500 11700 39 300 2 1 0 0 0 0 0 0 175 470 751

```
Line No.                         Input data
   5      2 500 9500 11700 39 300 2 1 0 0 0 0 0 0 175 470 751
                                  ↓                     ↙   ↓
                                 XRH               TSTEAM HVS
```

The reheat option (XRH) allows for either an inline steam reheater for the scrubbed gas or for no reheating of the scrubbed gas. The inline steam reheater is the only type of reheater available in the current version of the model. When a reheater is specified (XRH = 2), the TSTEAM variable is used to specify the temperature of the reheater steam and the HVS variable is used to specify the heat of vaporization of the reheater steam. Example output showing the results of specifying an inline steam reheater is shown in the base case in Appendix D (p. D-10). When no reheating is specified (XRH = 0) the reheater section as shown in the base case printout is omitted.

Emergency Bypass Option

```
Line No.                         Input data
   5      2 500 9500 11700 39 300 2 1 0 0 0 0 0 0 175 470 751
                                    ↘
                                  KEPASS
```

The emergency bypass option (KEPASS) allows an emergency bypass around the FGD system for one-half of the gas normally scrubbed as specified in the premises used by TVA for comparative economic evaluations for EPA (Appendix B). An emergency bypass is allowed by the revised NSPS promulgated in 1979 (Federal Register, 1979) when spare FGD modules (trains) are provided. If only one operating scrubbing train is specified (line 9, NOTRAN) then the emergency bypass is sized for all of the gas normally scrubbed instead of only one-half. When both emergency bypass and partial scrubbing/bypass (line 5, KPASO2 and PSSO2X) are specified, the bypass duct is sized for 50% of the gas normally scrubbed (100% of the gas normally scrubbed if only one operating train) plus the partial bypass normally used for the unscrubbed gas (total cannot exceed 100%). The following values are used for the KEPASS option:

0 - No emergency bypass

1 - Emergency bypass

TABLE 3. MECHANICAL COLLECTOR COST ILLUSTRATION

SCRUBBING

INCLUDING 4 OPERATING AND 1 SPARE SCRUBBING TRAINS

ITEM	DESCRIPTION	NO.	MATERIAL	LABOR
MECHANICAL ASH COLLECTOR	33% PARTICULATE REMOVAL	1	654166.	112232.
I.D. FANS	7.5IN H2O, WITH 631. HP MOTOR AND DRIVE	5	3341982.	58581.
SHELL			1769029.	
RUBBER LINING			1766858.	
MIST ELIMINATOR			393850.	
SLURRY HEADER AND NOZZLES			853235.	
TOTAL SPRAY SCRUBBER COSTS		5	4782970.	449605.
REHEATERS		5	2647704.	168446.
SOOTBLOWERS	40 AIR-FIXED 20 AIR-RETRACTABLE	60	294910.	182512.
EFFLUENT HOLD TANK	343449.GAL, 38.8FT DIA, 38.8FT HT, FLAKEGLASS-LINED CS	5	373173.	301519.
EFFLUENT HOLD TANK AGITATOR	82.HP	5	505849.	207512.
COOLING SPRAY PUMPS	1388.GPM 100FT HEAD, 64.HP, 4 OPERATING AND 6 SPARE	10	104732.	32268.
ABSORBER RECYCLE PUMPS	15611.GPM, 100FT HEAD, 723.HP, 8 OPERATING AND 7 SPARE	15	1581896.	139397.
MAKEUP WATER PUMPS	3469.GPM, 200.FT HEAD, 292.HP, 1 OPERATING AND 1 SPARE	2	33169.	3742.
			---------	---------
TOTAL EQUIPMENT COST			14320518.	1655810.

Example output showing an emergency bypass specified is shown in the base case printout in Appendix D (p. D-7).

Partial Scrubbing/Bypass Option

Line No.	Input data
5	2 500 9500 11700 39 300 2 1 1 90 0 0 0 0 175 470 751

(1 → KPASO2; 90 → PSSO2X)

The partial scrubbing/bypass option (KPASO2) allows FGD systems to be projected for conditions where all of the flue gas does not have to be scrubbed to meet specified emission levels. The percent removal in the absorber is specified with the PSSO2X variable and the model will calculate the percentage of flue gas that can be bypassed (if any) and still meet the emission limit or overall removal percentage specified (line 7, ISO2 and XSO2). The appropriate ductwork and reheater adjustments are made as required depending on the amount of bypassed gas. When both partial scrubbing/bypass and emergency bypass (line 5, KEPASS) are specified the bypass duct is sized for the gas normally bypassed plus 50% of the gas normally scrubbed (100% if only one operating train; total cannot exceed 100%). Partial scrubbing/bypass is not allowed when SO_2 removal is calculated from scrubber operating parameters (line 7, XSR = 3). The following values are used for the KPASO2 option:

0 - No partial scrubbing/bypass

1 - Partial scrubbing/bypass

Example output showing partial scrubbing/bypass specified is shown in Table 4 and is based on an emission limit of 1.2 lb SO_2/MBtu.

Coal-Cleaning Option

Line No.	Input data
5	2 500 9500 11700 39 300 2 1 0 0 1 84.16 12.16 2.21 175 470 751

(1 → KCLEAN; 84.16 → WPRCVR; 12.16 → WPPSAC; 2.21 → WPPSRC)

The coal-cleaning option (KCLEAN) allows the model to be used in conjunction with physical coal cleaning. The model calculates the composition and firing rate of cleaned coal to the boiler based on the raw coal characteristics, the coal cleaning parameters, and boiler heat rate and megawatts. The corresponding composition of the flue gas to the scrubbing system is used for determining the degree of SO_2 removal required. The variables WPRCVR, WPPSAC, and WPPSRC are used to specify the required coal-cleaning parameters. The WPRCVR variable specifies the percent weight recovery (lb clean coal per lb of raw coal); the WPPSAC variable specifies the weight percent of pyritic sulfur plus ash in the cleaned coal; and the WPPSRC variable specifies the weight percent

TABLE 4. EXAMPLE RESULTS SHOWING PARTIAL SCRUBBING/BYPASS

EMERGENCY BY-PASS
--------- -------

EMERGENCY BY-PASS DESIGNED FOR 57.1 %

HOT GAS FROM BOILER
--- --- ---- ------

	MOLE PERCENT	LB-MOLE/HR	LB/HR
CO2	12.338	0.2255E+05	0.9923E+06
HCL	0.006	0.1145E+02	0.4175E+03
SO2	0.214	0.3914E+03	0.2508E+05
O2	5.560	0.1016E+05	0.3251E+06
N2	75.227	0.1375E+06	0.3852E+07
H2O	6.654	0.1216E+05	0.2191E+06

HOT GAS FLOW RATE = .1154E+07 SCFM (60. DEG F, 14.7 PSIA)
= .1687E+07 ACFM (300. DEG F, 14.7 PSIA)

CORRESPONDING COAL FIRING RATE = .4060E+06 LB/HR

HOT GAS HUMIDITY = 0.042 LB H2O/LB DRY GAS

WET BULB TEMPERATURE = 124. DEG F

HOT GAS TO BY-PASS
--- --- -- -------

	MOLE PERCENT	LB-MOLE/HR	LB/HR
CO2	12.338	0.3189E+04	0.1404E+06
HCL	0.006	0.1620E+01	0.5906E+02
SO2	0.214	0.5537E+02	0.3547E+04
O2	5.560	0.1437E+04	0.4599E+05
N2	75.227	0.1945E+05	0.5449E+06
H2O	6.654	0.1720E+04	0.3099E+05

HOT GAS BY-PASSED 14.1 %

HOT GAS FLOW RATE = .1633E+06 SCFM (60. DEG F, 14.7 PSIA)
= .2386E+06 ACFM (300. DEG F, 14.7 PSIA)

CORRESPONDING COAL FIRING RATE = .5743E+05 LB/HR

(continued)

TABLE 4 (continued)

HOT GAS TO SCRUBBER
--- --- -- --------

	MOLE PERCENT	LB-MOLE/HR	LB/HR
CO2	12.338	0.1936E+05	0.8519E+06
HCL	0.006	0.9832E+01	0.3585E+03
SO2	0.214	0.3361E+03	0.2153E+05
O2	5.560	0.8723E+04	0.2791E+06
N2	75.227	0.1180E+06	0.3307E+07
H2O	6.654	0.1044E+05	0.1881E+06

SO2 CONCENTRATION IN SCRUBBER INLET GAS = 2142. PPM
= 5.28 LBS / MILLION BTU

FLYASH EMISSION = 0.060 LBS/MILLION BTU
= 0.029 GRAINS/SCF (WET) OR 285. LB/HR

SOLUBLE CAO IN FLY ASH = 0. LB/HR
SOLUBLE MGO IN FLY ASH = 0.

HOT GAS FLOW RATE = .9910E+06 SCFM (60. DEG F, 14.7 PSIA)
= .1448E+07 ACFM (300. DEG F, 14.7 PSIA)

CORRESPONDING COAL FIRING RATE = .3486E+06 LB/HR

HOT GAS HUMIDITY = 0.042 LB H2O/LB DRY GAS

WET BULB TEMPERATURE = 124. DEG F

WET GAS FROM SCRUBBER
--- --- ---- --------

	MOLE PERCENT	LB-MOLE/HR	LB/HR
CO2	11.716	0.1967E+05	0.8657E+06
HCL	0.000	0.4916E+00	0.1792E+02
SO2	0.020	0.3361E+02	0.2153E+04
O2	5.169	0.8677E+04	0.2777E+06
N2	70.300	0.1180E+06	0.3307E+07
H2O	12.795	0.2148E+05	0.3870E+06

SO2 CONCENTRATION IN SCRUBBER OUTLET GAS = 200. PPM

FLYASH EMISSION = 0.030 LBS/MILLION BTU
= 0.016 GRAINS/SCF (WET) OR 143. LB/HR

TOTAL WATER PICKUP = 408. GPM
INCLUDING 9.7 GPM ENTRAINMENT

WET GAS FLOW RATE = .1060E+07 SCFM (60. DEG F, 14.7 PSIA)
= .1191E+07 ACFM (124. DEG F, 14.7 PSIA)

WET GAS SATURATION HUMIDITY = 0.087 LB H2O/LB DRY GAS of pyritic sulfur in the raw coal. When the revised NSPS (Federal Register, 1979) emission limit is automatically calculated by the model (line 7, ISO2 = 4), the appropriate credit for coal cleaning will also be automatically calculated by the model, on a raw coal basis. In all other cases, the emission limit or removal percentage (line 7, ISO2 and XSO2) must be specified on a cleaned coal basis or must be calculated by the model from scrubber operating parameters (line 7, XSR = 3). Coal cleaning is not allowed when the gas composition is specified directly (line 6, INPOPT = 2). The following values are used for the KCLEAN option.

0 - No coal cleaning

1 - Coal cleaning

Example output showing the results of specifying coal cleaning is shown in Table 5, and is based on 84.16% weight recovery, 12.16% pyritic sulfur plus ash in the cleaned coal, and 2.21% pyritic sulfur in the raw coal.

Input Composition Option

Line No.	Input data
	INPOPT ↗
6A	1 66.7 3.8 5.6 1.3 3.36 .1 15.1 4.0 92 80 2 .06 .03
or	
6B	2 12.338 .006 .214 5.560 75.227 6.654 1154000 47500 100 100 2 .06 .03
	↘ INPOPT

The input composition option (INPOPT) allows the flue gas composition to be specified directly instead of being calculated by the model from a coal composition. This allows the model to be used to project FGD systems for other than coal-fired boilers, such as smelter off-gas. The variables described for line 6A (C, H, O, N, S, Cl, ash, H_2O, etc.; see Table C-2) should be used when the coal composition is specified; the variables described for line 6B (CO_2, HCl, SO_2, O_2, N_2, H_2O, etc.; see Table C-2) should be used when the flue gas is specified directly. Coal cleaning (line 5, KCLEAN = 1) and the automatic calculation of revised NSPS emission levels (line 7, ISO2 = 4) are not allowed when the flue gas composition is specified directly. The following values are used for the INPOPT option:

1 - Coal composition is specified (line 6A)

2 - Flue gas composition is specified (line 6B)

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TABLE 5. EXAMPLE RESULTS SHOWING COAL CLEANING

PHYSICAL COAL CLEANING

STREAM COMPOSITIONS

COMPONENT	RAW COAL		CLEAN COAL		REFUSE	
	WEIGHT PERCENT	LB PER LB RAW COAL	WEIGHT PERCENT	LB PER LB RAW COAL	WEIGHT PERCENT	LB PER LB RAW COAL
CARBON	66.7000	0.7013	74.5248	0.6272	46.7830	0.0741
HYDROGEN	3.8000	0.0400	4.2458	0.0357	2.6653	0.0042
OXYGEN	5.6000	0.0589	6.2570	0.0527	3.9278	0.0062
NITROGEN	1.3000	0.0137	1.4525	0.0122	0.9118	0.0014
SULFUR (O)	1.1500	0.0121	1.2849	0.0108	0.8066	0.0013
PURE COAL	78.5500	0.8259	87.7650	0.7386	55.0945	0.0873
SULFUR (P)	2.2100	0.0221	1.5525	0.0131	5.7034	0.0090
ASH	15.1000	0.1510	10.6075	0.0893	38.9692	0.0617
ASH & S	17.3100	0.1731	12.1600	0.1023	44.6726	0.0708
CHLORINE	0.1000	0.0010	0.0750	0.0006	0.2328	0.0004
TOTAL	100.0000	1.0000	100.0000	0.8416	100.0000	0.1584
BTU/LB	12282.	12282.	13469.	11335.	9764.	1547.
PERCENT ORIGINAL BTU	1.0000		0.9229		0.1259	

When a coal composition is specified, a "BOILER CHARACTERISTICS" section is included in the output report. Example output showing the results of specifying a coal composition as input (INPOPT = 1) is shown in the base case printout in Appendix D (p. D-4). When a flue gas composition is specified, a "HOT GAS ANALYSIS" section is provided. Example output showing the results of specifying a flue gas composition as input is shown in Table 6.

Particulate Removal Option

Line No.	Input data
6A	1 66.7 3.8 5.6 1.3 3.36 .1 15.1 4.0 92 80 2 .06 .03
	IASH ASHUPS ASHSCR

The particulate removal variables are IASH, ASHUPS, and ASHSCR. The IASH option identifies the method for specifying particulate removal, i.e., as percent removal or as outlet emission in lb/MBtu. IASH may take values of 0, 1, 2, or 3. If IASH is equal to 0, upstream particulate removal (ASHUPS) and absorber particulate removal (ASHSCR) take default values of 33% and 99.2% removal respectively. If IASH equals 1, ASHUPS and ASHSCR are input as percent removal. If IASH equals 2, ASHUPS and ASHSCR are input particulate loadings in lb/MBtu at the outlet of the upstream particualte collector and the absorber respectively. If IASH equals 3, ASHUPS is input as percent removal and ASHSCR takes a default value of 75%. Regardless of the option chosen, the output listing provides the equivalent particulate emission as both percent removal and lb/MBtu. A summary of the options is shown below.

IASH = 0 ASHUPS default value = 33% removal

ASHSCR default value = 99.2% removal

IASH = 1 ASHUPS input value as percent removal

ASHSCR input value as percent removal

IASH = 2 ASHUPS input value as lb/MBtu to absorber

ASHSCR input value as lb/MBtu from absorber

IASH = 3 ASHUPS input value as percent removal

ASHSCR default value equals 75% removal

Example output showing the results of specifying particulate removal based on lb/MBtu (IASH = 2) is shown in the base case printout in Appendix D (pp. D-8, -10).

TABLE 6. EXAMPLE RESULTS SHOWING USER INPUT FLUE GAS COMPOSITION

```
                 *** INPUTS ***

HOT GAS ANALYSIS, MOLE PERCENT:

    CO2        CL        SO2        O2        N2        H2O
 12.3380    0.0006    0.2140    5.5600   75.2270    6.6540

SULFUR OVERHEAD = 100.0 PERCENT

ASH OVERHEAD = 100.0 PERCENT
```

SO_2 Removal Option

Line No.	Input data
7	90 0 0 10 25 4 0.0 10 1 0.0 1 0 .15 0 0 0 4.85 5 0 0

(4 → ISO2; 0.0 → XSO2)

The model has five methods for specifying SO_2 outlet concentrations or removal. The controlling variables are the ISO2 option and the actual value to be removed, XSO2. If ISO2 = 1, XSO2 is input as the percentage of SO_2 to be removed. (The percentage of SO_2 to be removed is used as the percent removal by the absorber except when partial scrubbing is specified with the KPASO2 option on line 5.) If ISO2 = 2, XSO2 is input as the absorber outlet emission expressed as pounds SO_2/MBtu. If ISO2 = 3, XSO2 is input as ppm SO_2 in the absorber outlet stream. If ISO2 = 4, XSO2 is automatically calculated by the model from the input coal composition based on the revised NSPS (Federal Register, 1979). Figure 1 illustrates the relationship between the SO_2 content of the raw coal and the controlled outlet emission levels used in the model for the revised NSPS. A fifth method for specifying SO_2 removal, SO_2 removal calculated, is described in the operating parameter options section (line 7, XSR = 3). Regardless of the option chosen, the equivalent SO_2 removal in all three units is displayed in the model output. The input value is indicated as having been specified and the other values are indicated as having been calculated. A summary of the input options is shown below.

ISO2 = 1 XSO2 is input as percent removal

ISO2 = 2 XSO2 is input as pounds SO_2/MBtu at the absorber outlet

ISO2 = 3 XSO2 is input as ppm SO_2 in the absorber outlet stream

ISO2 = 4 XSO2 will be automatically calculated by the model based on the revised NSPS (Federal Register, 1979)

Example output showing the results of specifying emission limits based on the revised NSPS is shown in the base case printout in Appendix D.

An important concept related to SO_2 removal calculations in the model should be emphasized here. The SO_2 removal options are based on long-term average removals and are not to be construed as 3-hour or 24-hour averages. When sizing an FGD facility the raw material handling, feed preparation, and scrubbing areas should be based on the maximum sulfur content of the coal rather than the long-term average. The waste disposal pond, however, should be sized on the long-term average sulfur content. This can be done by entering the weight percent sulfur as the maximum expected and then entering the pond capacity factor (line 14, PNDCAP) to adjust the total amount of waste generated back to the equivalent long-term average amount.

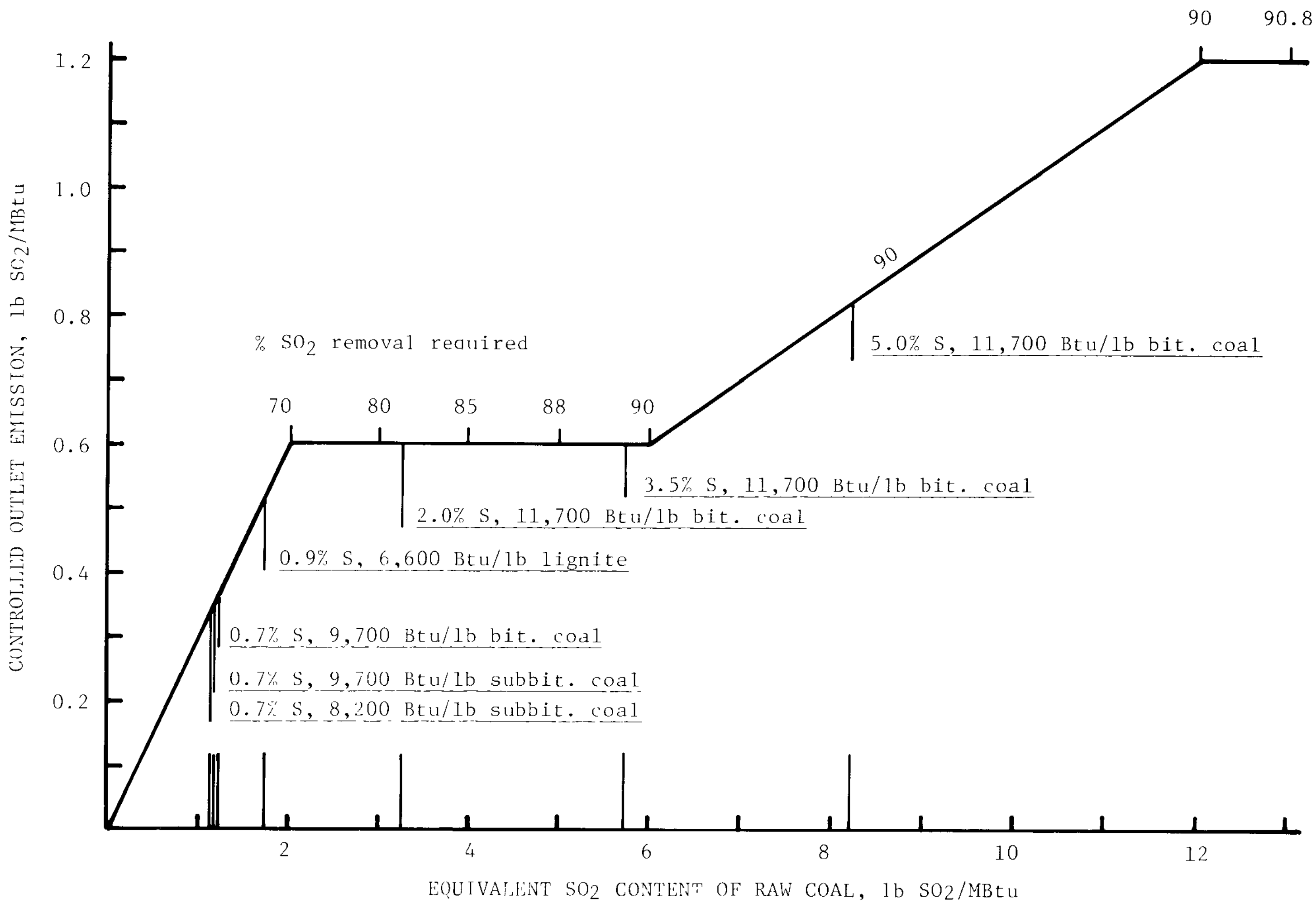

Figure 1. Controlled SO_2 emission requirements for 1979 NSPS. Premise coals, shown underlined, are based on premise boiler conditions.

Operating Parameter Calculation Option

Line No.	Input data
	XLG ↑ XSO2 ↑ XSR ↑ SRIN ↗
7	90 0 0 10 25 4 0.0 10 1 0.0 1 0 .15 0 0 0 4.85 5 0 0
8	15 40 .2 40 0 30 0.0 80 1.2 0.0 0 9 0 14.7 1
	↓ PHLIME

Four options are available in the model to allow either user input or model calculation of the major operating parameters which include L/G (expressed as absorber liquor recirculation rate in gallons of liquor recirculated per 1000 actual cubic feet of gas at the absorber outlet), stoichiometry (expressed as mols $CaCO_3$ or CaO added per mol of SO_2 absorbed), and SO_2 removal. The options differ slightly for the limestone scrubbing system and the lime scrubbing system so the description is divided into two sections.

First, for limestone scrubbing (line 7, XIALK = 1) the variables used are XSR, XLG, SRIN, and XSO2. XSR is the controlling option and takes values from 0 to 3. If XSR has an input value of 0, the L/G (XLG), stoichiometry (SRIN), and SO_2 removal (XSO2, units depend on ISO2) are all user input values. Specifying XSR = 0 is referred to as "force-through" because no program checks are made for validity or consistency among the three input variables to ensure that specified L/G and stoichiometry can result in the input degree of removal. If XSR is equal to 1, XLG and XSO2 are input and the model calculates stoichiometry. If XSR is equal to 2, SRIN and XSO2 are input and the model calculates XLG. When XSR is equal to 3, XLG and SRIN are input and the model calculates XSO2. Values of 1.01 or greater should be used for SRIN when it is specified as input. A summary of the various options for a limestone scrubbing system is shown below.

XSR = 0 XLG is input

XSO2 is input

SRIN is input

XSR = 1 XLG is input

XSO2 is input

SRIN is calculated

XSR = 2 XLG is calculated

XSO2 is input

SRIN is input

XSR = 3 XLG is input

XSO2 is calculated

SRIN is input

Example output showing the results of specifying XSR = 1 is shown in the base case printout in Appendix D (pp. D-5, -12).

Similar options are available in the lime scrubbing option (line 7, XIALK = 2). Except when XSR = 0, the variable PHLIME replaces SRIN because for lime scrubbing the model calculates the pH of the recirculation liquor instead of the lime stoichiometry. (When limestone is specified the value of PHLIME is ignored. When lime is specified SRIN is ignored except when XSR = 0 in which case PHLIME is ignored.) A summary of the options for a lime scrubbing system is shown below.

XSR = 0 XLG is input

XSO2 is input

SRIN is input

XSR = 1 XLG is input

XSO2 is input

PHLIME is calculated

XSR = 2 XLG is calculated

XSO2 is input

PHLIME is input

XSR = 3 XLG is input

XSO2 is calculated

PHLIME is input

The output listing for the lime scrubbing option is similar to that for the limestone option shown in Appendix D except that the stoichiometry is printed out for CaO instead of $CaCO_3$, as shown in Table 7. (An input value of 7.85 is used for PHLIME in this example.) For both the lime and limestone options, if input values are specified for the variables that are to be calculated by the model, the input values are ignored.

Scrubbing Absorbent Option (Lime or Limestone)

Line No.	Input data
7	90 0 0 10 25 4 0.0 10 1 0.0 1 0 .15 0 0 0 4.85 5 0 0

(The 1 following "0.0" is marked with an arrow: XIALK)

The alkali scrubbing absorbent option (XIALK) allows a choice of either lime or limestone. If XIALK = 1, limestone slurry is selected as the scrubbing medium. If XIALK = 2, lime slurry is selected. Example output showing the results of specifying limestone scrubbing (XIALK = 1) is shown in the base case printout in Appendix D. Table 8 shows how the lime option output differs from limestone in both the input display and the raw material preparation area equipment list.

Chemical Additive Option

Line No.	Input data
7	90 0 0 10 25 4 0.0 10 1 0.0 1 0 .15 0 0 0 4.85 5 0 0

(The 0 following "1" is marked with an arrow: IADD)

The chemical additive option (IADD) provides for the addition of either magnesium oxide (MgO) or adipic acid to the slurry stream to improve scrubber efficiency and SO_2 removal rates. The following values are used for the IADD option:

0 - No chemical additive

1 - MgO added

2 - Adipic acid added ("force-through" mode must be used for the adipic acid option; see the operating parameter calculation option, XSR, on line 7)

Example output showing the results of adding adipic acid is shown in Table 9.

TABLE 7. LIME SCRUBBING OUTPUT LISTING

```
SCRUBBER SYSTEM
-------- ------

TOTAL NUMBER OF SCRUBBING TRAINS (OPERATING+REDUNDANT) =  5

SO2 REMOVAL =  88.6 PERCENT

PARTICULATE REMOVAL IN SCRUBBER SYSTEM =  50.0 PERCENT

SPRAY TOWER PRESSURE DROP =  2.2 IN. H2O

TOTAL SYSTEM PRESSURE DROP =  7.5 IN. H2O

SPECIFIED   SPRAY TOWER L/G RATIO  =  90. GAL/1000 ACF(SATD)

LIME ADDITION = 0.2278E+05 LB/HR DRY LIME

CALCULATED LIME STOICHIOMETRY        =  1.10 MOLE CAO ADDED AS LIME
                                            PER MOLE (SO2+2HCL) ABSORBED

SOLUBLE CAO FROM FLY ASH =  0.0  MOLE PER MOLE (SO2+2HCL) ABSORBED

TOTAL SOLUBLE MGO          =  0.00 MOLE PER MOLE (SO2+2HCL) ABSORBED

TOTAL STOICHIOMETRY        =  1.10 MOLE SOLUBLE (CA+MG)
                                 PER MOLE (SO2+2HCL) ABSORBED

SCRUBBER INLET LIQUOR PH =  7.85

MAKE UP WATER =  720. GPM

CROSS-SECTIONAL AREA PER SCRUBBER =   577. SQ FT

SYSTEM SLUDGE DISCHARGE
------ ------ ---------
```

SPECIES	LB-MOLE/HR	LB/HR	SOLID COMP., WT %	LIQUID COMP., PPM
CASO3 .1/2 H2O	0.2428E+03	0.3135E+05	58.23	
CASO4 .2H2O	0.1029E+03	0.1771E+05	32.90	
CACO3	0.3523E+02	0.3527E+04	6.55	
INSOLUBLES	----------	0.1247E+04	2.32	
H2O	0.4440E+04	0.7999E+05		
CA++	0.5272E+01	0.2113E+03		2617.
MG++	0.1515E+01	0.3682E+02		456.
SO3--	0.1426E+00	0.1141E+02		141.
SO4--	0.1194E+01	0.1147E+03		1421.
CL-	0.1088E+02	0.3857E+03		4776.

```
TOTAL DISCHARGE FLOW RATE = 0.1346E+06 LB/HR
                          =   203.      GPM

TOTAL DISSOLVED SOLIDS IN DISCHARGE LIQUID =   9391. PPM

DISCHARGE LIQUID PH =  7.37
```

TABLE 8. LIME OPTION INPUTS AND RAW MATERIAL PREPARATION AREA

LIME SCRUBBING   CASE 007

*** INPUTS ***

BOILER CHARACTERISTICS

MEGAWATTS = 500.

BOILER HEAT RATE = 9500. BTU/KWH

EXCESS AIR = 39. PERCENT, INCLUDING LEAKAGE

HOT GAS TEMPERATURE = 300. DEG F

COAL ANALYSIS, WT % AS FIRED :

C	H	O	N	S	CL	ASH	H2O
66.70	3.80	5.60	1.30	3.36	0.10	15.10	4.00

SULFUR OVERHEAD = 92.0 PERCENT

ASH OVERHEAD = 80.0 PERCENT

HEATING VALUE OF COAL = 11700. BTU/LB

FLYASH REMOVAL	EFFICIENCY, %	EMISSION, LBS/M BTU
UPSTREAM OF SCRUBBER	99.4	0.06
WITHIN SCRUBBER	50.0	0.03

COST OF UPSTREAM FLYASH REMOVAL EXCLUDED

ALKALI

LIME :

CAO = 95.00 WT % DRY BASIS
SOLUBLE MGO = 0.15
INERTS = 4.85
MOISTURE CONTENT : 5.00 LB H2O/100 LBS DRY LIME

FLY ASH :

SOLUBLE CAO = 0.0 WT %
SOLUBLE MGO = 0.0
INERTS = 100.00

(continued)

TABLE 8 (continued)

RAW MATERIAL HANDLING AND PREPARATION

INCLUDING 2 OPERATING AND 1 SPARE PREPARATION UNITS

ITEM	DESCRIPTION	NO.	MATERIAL	LABOR
CONVEYOR FROM CALCINATION PLANT	1500FT HORIZONTAL, 30HP	1	207327.	37741.
STORAGE SILO ELEVATOR	125.FT HIGH, 50 HP	1	62607.	4494.
CONCRETE STORAGE SILO	136674.FT3,48.8FT DIA , 73.2FT STRAIGHT SIDE STORAGE HT	1	177002.	375654.
STORAGE SILO HOPPER BOTTOM	60 DEGREE, CS	1	22252.	15214.
RECLAIM VIBRATING FEEDER	3.5HP	1	3813.	391.
RECLAIM BELT CONVEYOR	124.FT HORIZONTAL, 5HP	1	25788.	3392.
FEED BIN ELEVATOR	50FT HIGH, 50HP	1	37754.	2216.
FEED BELT CONVEYOR	50FT HORIZONTAL, 5HP	1	12076.	1043.
FEED CONVEYOR TRIPPER	30FPM, 1HP	1	18940.	6518.
FEED BIN	10FT DIA, 15FT STRAIGHT SIDE HT, COVERED, CS	3	14491.	9973.
BIN VIBRATING FEEDER	3.5HP	3	30508.	3911.
BIN WEIGH FEEDER	12FT, 12IN SCREW, 1HP	3	15635.	2347.
SLAKER	6.TPH, 10.HP	3	175997.	10433.
SLAKER PRODUCT TANK		3	15445.	12515.
SLAKER PRODUCT TANK AGITATOR	10HP	3	22881.	5475.
LIME SYSTEM DUST COLLECTORS	POLYPROPYLENE BAG TYPE 2200 CFM,7.5HP	5	38770.	14340.
SLAKER PRODUCT TANK SLURRY PUMPS	134.GPM, 60FT HEAD, 4.HP, 2 OPERATING AND 1 SPARES	3	11863.	3480.
SLURRY FEED TANK	141019.GAL, 28.8FT DIA, 28.8FT HT, FLAKEGLASS-LINED CS	1	35984.	29727.
SLURRY FEED TANK AGITATOR	50.HP	1	57120.	4686.
SLURRY FEED TANK PUMPS	67.GPM, 60 FT HEAD, 2.HP, 4 OPERATING AND 4 SPARE	8	22498.	7300.
			---------	---------
TOTAL EQUIPMENT COST			1008750.	550850.

TABLE 9. EXAMPLE RESULTS SHOWING THE ADDITION OF ADIPIC ACID

RAW MATERIAL HANDLING AND PREPARATION

INCLUDING 2 OPERATING AND 1 SPARE PREPARATION UNITS

ITEM	DESCRIPTION	NO.	MATERIAL	LABOR
CAR SHAKER AND HOIST	20HP SHAKER 7.5HP HOIST	1	71916.	13037.
CAR PULLER	25HP PULLER, 5HP RETURN	1	63050.	19555.
UNLOADING HOPPER	16FT DIA, 10FT STRAIGHT INCLUDES 6 IN SQ GRATING	1	15508.	5932.
UNLOADING VIBRATING FEEDER	3.5HP	1	5466.	521.
UNLOADING BELT CONVEYOR	20FT HORIZONTAL, 5HP	1	11440.	1434.
UNLOADING INCLINE BELT CONVEYOR	310FT, 50HP	1	85295.	4824.
UNLOADING PIT DUST COLLECTOR	POLYPROPYLENE BAGTYPE, INCLUDES DUST HOOD	1	11186.	5215.
UNLOADING PIT SUMP PUMP	60GPM, 70FT HEAD, 5HP	1	2415.	782.
STORAGE BELT CONVEYOR	200FT, 5HP	1	73092.	3911.
STORAGE CONVEYOR TRIPPER	30FPM, 1HP	1	27203.	9126.
MOBILE EQUIPMENT	SCRAPPER TRACTOR	1	141862.	0.
RECLAIM HOPPER	7FT WIDE, 4.25FT HT, 2FT WIDE BOTTOM, CS	2	2415.	1630.
RECLAIM VIBRATING FEEDER	3.5HP	2	10932.	1043.
RECLAIM BELT CONVEYOR	200FT, 5HP	1	40931.	2868.
RECLAIM INCLINE BELT CONVEYOR	193FT, 40HP	1	60253.	3650.
RECLAIM PIT DUST COLLECTOR	POLYPROPYLENE BAG TYPE	1	7754.	2607.
RECLAIM PIT SUMP PUMP	60GPM, 70FT HEAD, 5HP	1	2415.	782.
RECLAIM BUCKET ELEVATOR	90FT HIGH, 75HP	1	57838.	6649.
FEED BELT CONVEYOR	60.FT HORIZONTAL 7.5HP	1	20466.	1434.

(continued)

TABLE 9 (continued)

FEED CONVEYOR TRIPPER	30 FPM, 1HP	1	27203.	9126.
FEED BIN	13FT DIA, 21FT STRAIGHT SIDE HT, COVERED, CS	3	43283.	24052.
BIN WEIGH FEEDER	14FT PULLEY CENTERS, 2HP	3	49575.	2347.
GYRATORY CRUSHERS	75HP	3	297071.	6453.
BALL MILL DUST COLLECTORS	POLYPROPYLENE BAG TYPE 2200 CFM, 7.5HP	3	23262.	7822.
BALL MILL	12.5TPH, 714.HP	3	1699745.	120659.
MILLS PRODUCT TANK	5500 GAL 10FT DIA, 10FT HT, FLAKEGLASS LINED CS	3	13729.	10951.
MILLS PRODUCT TANK AGITATOR	10HP	3	22881.	5475.
MILLS PRODUCT TANK SLURRY PUMP	53.GPM, 60FT HEAD, 2.HP, 2 OPERATING AND 1 SPARES	3	8507.	2738.
ADIPIC ACID AND STORAGE SILO	6058.FT3, 17.3FT DIA 40.3FT HT 60 DEG CONE	1	24237.	16264.
PNEUMATIC CONVEYOR SYSTEM	10. HP	1	8580.	5345.
ADDITION FEED BIN	RUBBER LINED	1	5520.	3044.
SCREW FEEDER	30 FT LONG, 6 IN D, SS	1	4703.	521.
ADDITIVE DUST COLLECTOR	POLYPROPLENE BAG TYPE 450 CFM, 1.5 HP	1	3305.	261.
SLURRY FEED TANK	55651.GAL, 21.2FT DIA, 21.2FT HT, FLAKEGLASS-LINED CS	1	19361.	15995.
SLURRY FEED TANK AGITATOR	48.HP	1	41832.	3432.
SLURRY FEED TANK PUMPS	26.GPM, 60 FT HEAD, 1.HP, 4 OPERATING AND 4 SPARE	8	21553.	7300.
			---------	---------
TOTAL EQUIPMENT COST			3025779.	326782.

Forced-Oxidation Option

Line No.	Input data
8	15 40 .2 40 0 30 0.0 80 1.2 0.0 0 9 0 14.7 1

(Arrow from the fifth value, 0, points to: IFOX)

The forced-oxidation option (IFOX) provides for converting sulfite sludge (which chemically has an oxygen demand) to gypsum (which does not). Gypsum, in comparison with sulfite sludges, offers better disposal options such as easier dewatering, a higher settling rate, and a higher density of settled sludge. The following values are used for the IFOX option:

0 - No forced oxidation

1 - Forced oxidation in a single effluent tank (within the absorber loop)

2 - Forced oxidation in the first of two effluent tanks (within the absorber loop)

3 - Forced oxidation in the disposal feed tank (bleedstream from the absorber loop); the number of effluent tanks depends on the ISCRUB variable (line 9)

The number of effluent tanks specified by the forced-oxidation option must not conflict with the number of tanks indicated by the absorber option (ISCRUB, line 9). Example output showing the results of specifying forced oxidation in the first of two effluent tanks (IFOX = 2) is shown in Table 10. An example of one tank (IFOX = 1) is shown in Table 11.

Fan Option

Line No.	Input data
8	15 40 .2 40 0 30 0.0 80 1.2 0.0 0 9 0 14.7 1

(Arrow from the last value, 1, points to: IFAN)

The fan option (IFAN) allows either induced draft (ID) fans or forced draft (FD) fans to be specified. The following values are used:

0 - Forced draft fans

1 - Induced draft fans

Example output showing the results of specifying ID fans is shown in the base case printout in Appendix D (pp. D-5, -20). The format of the output is similar for the FD fan option; however, the fan costs are different.

TABLE 10. EXAMPLE RESULTS SHOWING FORCED OXIDATION, TWO EFFLUENT TANKS

SCRUBBING

INCLUDING 4 OPERATING AND 1 SPARE SCRUBBING TRAINS

ITEM	DESCRIPTION	NO.	MATERIAL	LABOR
I.D. FANS	7.5IN H2O, WITH 630. HP MOTOR AND DRIVE	5	3340693.	58558.
SHELL			1768270.	
RUBBER LINING			1766030.	
MIST ELIMINATOR			393580.	
SLURRY HEADER AND NOZZLES			852669.	
TOTAL SPRAY SCRUBBER COSTS		5	4780547.	449402.
REHEATERS		5	2646582.	168382.
SOOTBLOWERS	40 AIR-FIXED 20 AIR-RETRACTABLE	60	294910.	182512.
EFFLUENT HOLD TANK	343220.GAL, 38.8FT DIA, 38.8FT HT, FLAKEGLASS-LINED CS	5	373008.	301386.
EFFLUENT HOLD TANK AGITATOR	82.HP	5	505611.	207414.
RECIRCULATION TANK	171610.GAL 27.4FT DIA, 38.8FT HT, FLAKEGLASS-LINED CS	5	218513.	180603.
RECIRCULATION TANK AGITATOR	69.HP	5	309612.	127011.
COOLING SPRAY PUMPS	1387.GPM 100FT HEAD, 64.HP, 4 OPERATING AND 6 SPARE	10	104710.	32259.
RECIRCULATION PUMPS	15601.GPM, 100FT HEAD, 723.HP, 8 OPERATING AND 7 SPARE	15	1581315.	139356.
OXIDATION BLEED PUMPS	240.GPM, 60 FT HEAD 7.HP, 4 OPERATING AND 4 SPARE	8	34604.	11999.
OXIDATION AIR BLOWER	3264.SCFM, 344.HP	6	208405.	4693.
OXIDATION SPARGER	19.4 FT DIA RING	5	95155.	41619.
MAKEUP WATER PUMPS	3467.GPM, 200.FT HEAD, 292.HP, 1 OPERATING AND 1 SPARE	2	33153.	3740.
			---------	---------
TOTAL EQUIPMENT COST			14526781.	1908930.

TABLE 11. EXAMPLE RESULTS SHOWING FORCED OXIDATION, ONE EFFLUENT TANK

SCRUBBING

INCLUDING 4 OPERATING AND 1 SPARE SCRUBBING TRAINS

ITEM	DESCRIPTION	NO.	MATERIAL	LABOR
I.D. FANS	7.5IN H2O, WITH 630. HP MOTOR AND DRIVE	5	3340693.	58556.
SHELL			1768270.	
RUBBER LINING			1766030.	
MIST ELIMINATOR			393580.	
SLURRY HEADER AND NOZZLES			852669.	
TOTAL SPRAY SCRUBBER COSTS		5	4780547.	449402.
REHEATERS		5	2646582.	168382.
SOOTBLOWERS	40 AIR-FIXED 20 AIR-RETRACTABLE	60	294910.	182512.
EFFLUENT-OXIDATION HOLD TANK	343220.GAL, 38.8FT DIA, 38.8FT HT, FLAKEGLASS-LINED CS	5	373008.	301386.
EFFLUENT-OXIDATION HOLD TANK AGITATOR	82.HP	5	505611.	207414.
COOLING SPRAY PUMPS	1387.GPM 100FT HEAD, 64.HP, 4 OPERATING AND 6 SPARE	10	104710.	32259.
ABSORBER RECYCLE PUMPS	15601.GPM, 100FT HEAD, 723.HP, 8 OPERATING AND 7 SPARE	15	1581315.	139356.
OXIDATION BLEED PUMPS	240.GPM, 60 FT HEAD 7.HP, 4 OPERATING AND 4 SPARE	8	34604.	11999.
OXIDATION AIR BLOWER	3264.SCFM, 344.HP	6	208405.	4693.
OXIDATION SPARGER	19.4 FT DIA RING	5	95155.	41619.
MAKEUP WATER PUMPS	3467.GPM, 200.FT HEAD, 292.HP, 1 OPERATING AND 1 SPARE	2	33153.	3740.
TOTAL EQUIPMENT COST			13998669.	1601318.

Scrubbing Option

Line No.	Input data
9	1 0 0 0 35 .0000005 32 10 5.70 1 4 1 .1

(first value → ISCRUB)

The scrubbing option (ISCRUB) provides six separate scrubbing systems that can be projected. The ISCRUB values that can be used and corresponding scrubber systems are as follows:

1 - Spray tower (one effluent tank unless two tanks are specified by the forced-oxidation option, IFOX, on line 9)

2 - TCA (one effluent tank unless two tanks are specified by the forced-oxidation option, IFOX, on line 9)

3 - Venturi - spray tower with two effluent tanks (if forced oxida tion is specified by IFOX on line 9, IFOX must be equal to 2.

4 - Venturi - spray tower with one effluent tank (if forced oxida tion is specified by IFOX on line 9, the number of tanks must agree with the number specified here)

5 - Venturi - TCA with two effluent tanks (if forced oxidation is specified by IFOX on line 9, IFOX must be equal to 2.

6 - Venturi - TCA with one effluent tank (if forced oxidation is specified by IFOX on line 9, the number of tanks must agree with the number specified here)

There are no specific material balance models for the venturi - TCA scrubbing combination specified by options 5 and 6. These options are provided to allow comparative cost estimates for analysis and should normally be used only in "force-through" mode (see the operating parameter calculation option, XSR, on line 7). Example output showing the results of specifying a spray tower is shown in the base case printout in Appendix D. Example output showing the results of specifying a venturi - spray tower with two effluent tanks is shown in Table 12.

Redundancy Options

Line No.	Input data
9	1 0 0 0 35 .0000005 32 10 5.70 1 4 1 .1

(last four values: 1 → NSPREP, 4 → NOTRAN, 1 → NOREDN)

Options for redundancy in the model apply to the raw material preparation area and the scrubbing area. The controlling input variables are NSPREP, NOTRAN, and NOREDN. NSPREP specifies the number of spare

TABLE 12. VENTURI - SPRAY TOWER ABSORBER COST ILLUSTRATION

SCRUBBING

INCLUDING 4 OPERATING AND 1 SPARE SCRUBBING TRAINS

ITEM	DESCRIPTION	NO.	MATERIAL	LABOR
I.D. FANS	17.7IN H2O, WITH 1486. HP MOTOR AND DRIVE	5	4815075.	71922.
VENTURI		5	792785.	96702.
SHELL			1769029.	
RUBBER LINING			1766858.	
MIST ELIMINATOR			393850.	
SLURRY HEADER AND NOZZLES			853235.	
TOTAL SPRAY SCRUBBER COSTS		5	4782970.	449605.
REHEATERS		5	2531194.	158857.
SOOTBLOWERS	55 AIR-FIXED 20 AIR-RETRACTABLE	75	336858.	221621.
VENTURI HOLD TANK	85768.GAL 19.4FT DIA, 38.8FT HT, FLAKEGLASS-LINED CS	5	148579.	122847.
VENTURI HOLD TANK AGITATOR	58.HP	5	189533.	77751.
VENTURI RECYCLE PUMPS	6938.GPM 100 FT HEAD, 321.HP 4 OPERATING AND 6 SPARE	10	808850.	65200.
EFFLUENT HOLD TANK	343449.GAL, 38.8FT DIA, 38.8FT HT, FLAKEGLASS-LINED CS	5	373173.	301519.
EFFLUENT HOLD TANK AGITATOR	82.HP	5	505849.	207512.
ABSORBER RECYCLE PUMPS	15611.GPM, 100FT HEAD, 723.HP, 8 OPERATING AND 7 SPARE	15	1581896.	139397.
MAKEUP WATER PUMPS	3469.GPM, 200.FT HEAD, 292.HP, 1 OPERATING AND 1 SPARE	2	33169.	3742.
			---------	---------
TOTAL EQUIPMENT COST			16899872.	1916669.

preparation units (ball mills for limestone or slakers for lime) and may be given any realistic value, 0, 1, 2, 3, ... NOTRAN specifies the number of operating absorbers. The model automatically overrides the value of NOTRAN if the specified number requires an absorber larger than the maximum available size. NOREDN indicates the number of spare scrubbing trains. The base case equipment list in Appendix D (pp. D-18-20) shows the output for a limestone scrubbing system designed with redundancy in both ball mills and absorbers. For comparison, Table 13 shows similar output for a limestone system with no redundancy in the absorber area.

Waste Disposal Option

Line No.	Input data
10	1 0 9999 5000 0 25 5280 1 12 4.75

ISLUDG SDFEE

Four waste disposal options are provided in the model. The input variables are ISLUDG and SDFEE. ISLUDG may take the values 1, 2, 3, or 4. SDFEE specifies the cost per dry ton to fix or treat the sludge. When ISLUDG = 1 the model assumes an onsite ponding sludge disposal system. If ISLUDG = 2 a disposal system consisting of a gravity thickener and an onsite pond is assumed. For ISLUDG = 3 the disposal system includes costs for a gravity thickener and fixation. Total fixation and disposal costs are input at $/ton of dry waste to be fixed using the SDFEE variable. Option 4 is similar to option 3 except that a rotary vacuum filter is added to the system downstream from the thickener and before fixation. The fixation fee is applied in the same manner as for ISLUDG = 3; however, in this case the material being fixed is the filter cake. Typically, SDFEE will be zero for options 1 and 2 but an additional fee for fixation of the sludge in the pond can be included by setting SDFEE equal to the desired fee value. A summary of the ISLUDG options is as follows:

1 - Onsite ponding

2 - Gravity thickener and onsite ponding

3 - Gravity thickener and fixation (the SDFEE variable is used to specify the thickener underflow fixation fee expressed in $/ton of dry sludge to be fixed)

4 - Same as option 3 plus a rotary vacuum filter (the SDFEE variable is used to specify the filter cake fixation fee in $/ton of dry sludge to be fixed)

The base case printout in Appendix D (pp. D-16, -21) is an example of the onsite ponding option. Sample output for the other waste disposal options are shown in Tables 14-16. Annual revenue requirements corresponding to waste disposal option 3 are shown in Table 17.

TABLE 13. EXAMPLE RESULTS SHOWING NO REDUNDANCY

SCRUBBING

ITEM	DESCRIPTION	NO.	MATERIAL	LABOR
I.D. FANS	7.5IN H2O, WITH 631. HP MOTOR AND DRIVE	4	2673586.	46865.
SHELL			1415222.	
RUBBER LINING			1413486.	
MIST ELIMINATOR			315080.	
SLURRY HEADER AND NOZZLES			682588.	
TOTAL SPRAY SCRUBBER COSTS		4	3826376.	359684.
REHEATERS		4	2118163.	134757.
SOOTBLOWERS	32 AIR-FIXED 16 AIR-RETRACTABLE	48	235928.	146009.
EFFLUENT HOLD TANK	343449.GAL, 38.8FT DIA, 38.8FT HT, FLAKEGLASS-LINED CS	4	298538.	241215.
EFFLUENT HOLD TANK AGITATOR	82.HP	4	404679.	132807.
COOLING SPRAY PUMPS	1388.GPM 100FT HEAD, 64.HP, 4 OPERATING AND 4 SPARE	8	83786.	25814.
ABSORBER RECYCLE PUMPS	15611.GPM, 100FT HEAD, 723.HP, 8 OPERATING AND 4 SPARE	12	1265517.	111518.
MAKEUP WATER PUMPS	3469.GPM, 200.FT HEAD, 292.HP, 1 OPERATING AND 1 SPARE	2	33169.	3742.
			----------	----------
TOTAL EQUIPMENT COST			10939738.	1202409.

TABLE 14. EXAMPLE EQUIPMENT LIST FOR SLUDGE OPTION 2

WASTE DISPOSAL

ITEM	DESCRIPTION	NO.	MATERIAL	LABOR
ABSORBER BLEED RECEIVING TANK	85768.GAL, 19.4FT DIA, 38.8FT HT, FLAKGLASS-LINED CS	1	29716.	24569.
ABSORBER BLEED TANK AGITATOR	47.HP	1	34390.	2821.
POND FEED SLURRY PUMPS	473.GPM, 130.FT HEAD 30.HP, 1 OPERATING AND 1 SPARE	2	11542.	4030.
POND SUPERNATE PUMPS	501.GPM, 192.FT HEAD, 40.HP, 1 OPERATING AND 1 SPARE	2	12182.	1374.
THICKENER FEED PUMP	845.GPM, 60FT HEAD, 23.HP, 1 OPERATING AND 1 SPARE	2	15815.	5195.
THICKENER	14848.SQ.FT.,137.FT DIA, 8.1TANK FT HT 7. RAKE HP	1	324349.	344683.
THICKENER OVERFLOW PUMPS	349.GPM, 75.0FT HEAD, 11.HP, 1 OPERATING AND 1 SPARE	2	9703.	1095.
THICKENER OVERFLOW TANK	5752.GAL, 11.0FT DIA, 8.1FT HT	1	2395.	1638.
TOTAL EQUIPMENT COST			440091.	385407.

TABLE 15. EXAMPLE EQUIPMENT LIST FOR SLUDGE OPTION 3

WASTE DISPOSAL

ITEM	DESCRIPTION	NO.	MATERIAL	LABOR
ABSORBER BLEED RECEIVING TANK	85768.GAL, 19.4FT DIA, 38.8FT HT, FLAKGLASS-LINED CS	1	29716.	24569.
ABSORBER BLEED TANK AGITATOR	47.HP	1	34390.	2821.
THICKENER FEED PUMP	845.GPM, 60FT HEAD, 23.HP, 1 OPERATING AND 1 SPARE	2	15815.	5195.
THICKENER	23200.SQ.FT.,172.FT DIA, 9.2TANK FT HT 11. RAKE HP	1	453553.	492801.
THICKENER OVERFLOW PUMPS	558.GPM, 75.0FT HEAD, 18.HP, 1 OPERATING AND 1 SPARE	2	10337.	1166.
THICKENER OVERFLOW TANK	9213.GAL, 13.1FT DIA, 9.2FT HT	1	3261.	2230.
SLUDGE FIXATION FEED PUMP	263.GPM, 50FT HEAD, 7.HP, 1 OPERATING AND 1 SPARE	2	8717.	3121.
TOTAL EQUIPMENT COST			555788.	531904.

TABLE 16. EXAMPLE EQUIPMENT LIST FOR SLUDGE OPTION 4

WASTE DISPOSAL

ITEM	DESCRIPTION	NO.	MATERIAL	LABOR
ABSORBER BLEED RECEIVING TANK	85768.GAL, 19.4FT DIA, 38.8FT HT, FLAKGLASS-LINED CS	1	29716.	24569.
ABSORBER BLEED TANK AGITATOR	47.HP	1	34390.	2821.
THICKENER FEED PUMP	848.GPM, 60FT HEAD, 24.HP, 1 OPERATING AND 1 SPARE	2	15825.	5204.
THICKENER	23290.SQ.FT.,172.FT DIA, 9.2TANK FT HT 11. RAKE HP	1	454889.	494357.
THICKENER UNDERFLOW SLURRY PUMPS	264.GPM, 9.1FT HEAD, 1.HP , 1 OPERATING AND 1 SPARE	2	7798.	3126.
THICKENER OVERFLOW PUMPS	561.GPM, 75.0FT HEAD, 18.HP, 1 OPERATING AND 1 SPARE	2	10344.	1167.
THICKENER OVERFLOW TANK	9249.GAL, 13.1FT DIA, 9.2FT HT	1	3269.	2235.
FILTER FEED TANK	4359.GAL, 9.1FT DIA, 9.1FT HT, FLAKEGLASS-LINED CS	1	3545.	2929.

(continued)

TABLE 16 (continued)

FILTER FEED TANK AGITATOR	7.HP	1	5159.	423.
FILTER FEED SLURRY PUMP	132.GPM, 50FT HEAD, 4.HP, 2 OPERATING AND 1 SPARE	3	11837.	3463.
FILTER	350.SQ FT FILTRATION AREA, 44. VACUUM HP 2 OPERATING AND 1 SPARE	3	367249.	67579.
FILTRATE PUMP (PER FILTER)	88.GPM, 20.0FT HEAD, 1.HP, 2 OPERATING AND 2 SPARE	4	17195.	1940.
FILTRATE SURGE TANK	2891.GAL, 7.9FT DIA, 7.9FT HT	1	1573.	1075.
FILTRATE SURGE TANK PUMP	175.GPM, 85.0FT HEAD, 6.HP, 1 OPERATING AND 1 SPARE	2	9182.	1036.
FILTER CAKE CONVEYOR	75 FT. HORIZONTAL 100 FT. INCLINE 1.5 HP	1	37108.	3453.
			----------	----------
TOTAL EQUIPMENT COST			1009079.	615378.

TABLE 17. EXAMPLE REVENUE REQUIREMENTS FOR SLUDGE FIXATION ALTERNATIVE (SLUDGE OPTION 3)

LIMESTONE SLURRY PROCESS -- BASIS: 500 MW SCRUBBING UNIT - 500 MW GENERATING UNIT, 1984 STARTUP

PROJECTED REVENUE REQUIREMENTS - SLUDGE 3 CASE 004

DISPLAY SHEET FOR YEAR= 1
ANNUAL OPERATION KW-HR/KW = 5500

34.89 TONS PER HOUR DRY SLUDGE
TOTAL CAPITAL INVESTMENT 131600000

	ANNUAL QUANTITY	UNIT COST,$	TOTAL ANNUAL COST,$
DIRECT COSTS			
RAW MATERIAL			
LIMESTONE	153.4 K TONS	8.50/TON	1304000
SUBTOTAL RAW MATERIAL			1304000
CONVERSION COSTS			
OPERATING LABOR AND SUPERVISION	35620.0 MAN-HR	15.00/MAN-HR	534300
UTILITIES			
STEAM	546160.0 K LB	2.50/K LB	1365400
PROCESS WATER	235000.0 K GAL	0.14/K GAL	32900
ELECTRICITY	47403380.0 KWH	0.037/KWH	1753900
MAINTENANCE			
LABOR AND MATERIAL			5776300
ANALYSES	4940.0 HR	21.00/HR	103800
SUBTOTAL CONVERSION COSTS			9566600
SUBTOTAL DIRECT COSTS			10870600
INDIRECT COSTS			
OVERHEADS			
PLANT AND ADMINISTRATIVE (60.0% OF CONVERSION COSTS LESS UTILITIES)			3848600
SLUDGE DISPOSAL FEE	191900.0 TONS	10.00/TON	1919000
FIRST YEAR OPERATING AND MAINTENANCE COSTS			16638200
LEVELIZED CAPITAL CHARGES(14.70% OF TOTAL CAPITAL INVESTMENT)			19345200
FIRST YEAR ANNUAL REVENUE REQUIREMENTS			35983400
EQUIVALENT FIRST YEAR UNIT REVENUE REQUIREMENTS, MILLS/KWH (MW SCRUBBED)			13.08
LEVELIZED OPERATING AND MAINTENANCE (1.886 TIMES FIRST YEAR OPER. & MAIN.)			31379600
LEVELIZED CAPITAL CHARGES(14.70% OF TOTAL CAPITAL INVESTMENT)			19345200
LEVELIZED ANNUAL REVENUE REQUIREMENTS			50724800
EQUIVALENT LEVELIZED UNIT REVENUE REQUIREMENTS, MILLS/KWH (MW SCRUBBED)			18.45

HEAT RATE 9500. BTU/KWH - HEAT VALUE OF COAL 11700 BTU/LB - COAL RATE 1116500 TONS/YR

Pond Design Option

```
Line No.             Input data

   10      1 0 9999 5000 0 25 5280 1 12 4.75
                 ↙       ↙  ↘
            PSAMAX PDEPTH PMXEXC
```

The configuration for disposal ponds used in the model and shown in Figure 2 is assumed to be square with a diverter dike that is three-fourths the length of the sides. Based on this configuration and the volume of waste to be disposed of over the total life of the plant, the pond design option provides three different options for defining the relationships between pond land area, excavation depth, and depth of waste in the finished pond. These options are as follows:

Fixed depth pond

Optimum pond based on minimum investment costs, subject to specified area limits, excavation limits, or both

Optimum pond based on minimum investment costs

Three variables, PSAMAX, PDEPTH, and PMXEXC, determine which pond option is selected by the model. The PSAMAX variable specifies the maximum land area in acres available for the pond, the PDEPTH variable specifies the ultimate depth of waste in the finished pond, and the PMXEXC variable specifies the maximum depth of topsoil and subsoil (clay) that will be excavated and used for dike construction (excavation and dike construction calculations are based on the assumption that the excavated material compacts to 85% of the original volume). For a fixed depth pond, PSAMAX should be set to zero, PDEPTH should be set to the desired depth, and PMXEXC should be set to zero. For an optimum pond based on minimum investment costs but subject to area and excavation limits, PSAMAX should be set to the maximum area in acres available for pond construction, PDEPTH should be set to zero, and PMXEXC should be set to the maximum excavation depth allowed. The final option, optimum pond based on minimum investment costs (no area and excavation limits) is essentially the same as the second option except that the values specified for the area and excavation limits should be set high enough that they will not realistically limit the optimized values, for example, PSAMAX = 9999 and PMXEXC = 25. The following variable values illustrate each of the pond design options.

PSAMAX = 0, PDEPTH = 10, PMXEXC = 0 - Fixed depth pond (pond area and excavation depth will be calculated by the model).

PSAMAX = 250, PDEPTH = 0, PMXEXC = 3 - Optimum pond based on minimum investment costs, but pond area cannot exceed 250 acres and excavation depth cannot exceed three feet (if the optimum pond does not exceed the specified area and excavation limits, the values calculated by the model will be used, otherwise pond depth and the optimum value that is not exceeded will be adjusted as necessary).

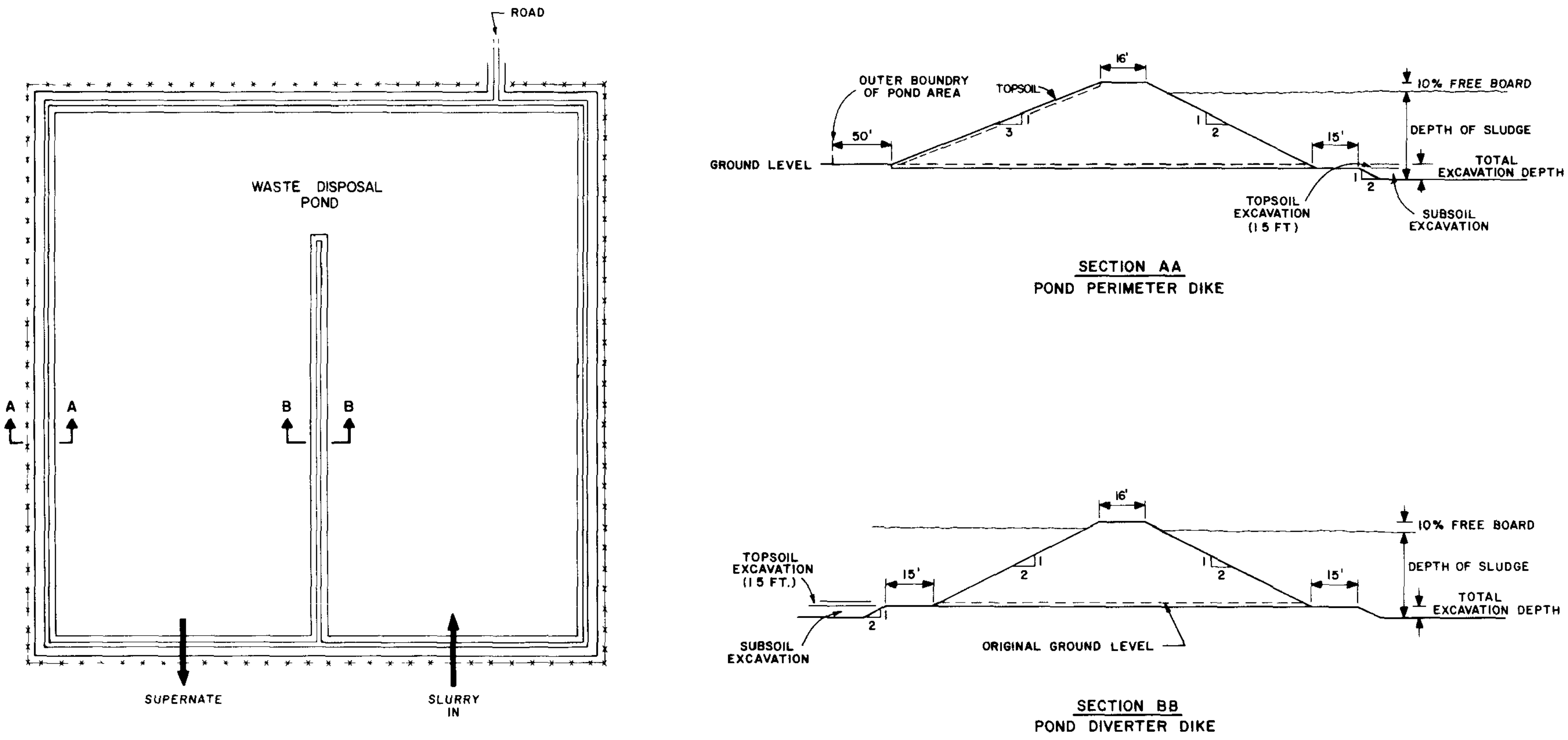

Figure 2. Pond construction configuration.

PSAMAX = 9999, PDEPTH = 0, PMXEXC = 25 - Optimum pond based on minimum investment costs (pond area, depth, and excavation depth will all be calculated by the model).

When pond design option two is used and calculations indicate that the total waste volume cannot be contained within the specified area and excavation limits, an error message is issued and the data case is terminated. Example output showing the results of specifying an optimum pond based on minimum investment costs is shown in the base case printout in Appendix D (p. D-16). Example output showing the results of specifying an area limitation of 270 acres is shown in Table 18.

Pond Liner Option

Line No.	Input data
10	1 0 9999 5000 0 25 5280 1 12 4.75

(1 → ILINER, 12 → XLINA, 4.75 → XLINB)

The pond liner option allows a choice of an unlined, clay-lined, or synthetic-lined pond. The input variables are ILINER, XLINA, and XLINB. ILINER specifies the type of lining in the pond as illustrated below.

1 = Clay liner

2 = Synthetic liner

3 = No liner

For a clay-lined pond (ILINER = 1), XLINA specifies the depth of clay in inches and XLINB specifies the clay lining installation cost (or the costs for reworking the clay subsoil into a lining) in $\$/yd^3$. For a synthetic-lined pond (ILINER = 2), XLINA specifies the liner material cost in $\$/yd^2$ and XLINB specifies the installation cost in $\$/yd^2$. For no liner (ILINER = 3), XLINA and XLINB should be set to zero.

Example output showing the results of specifying a clay pond liner is shown in the base case printout in Appendix D (p. D-16). Example output showing the results of specifying a synthetic pond liner is shown in Table 19. The input values for the synthetic liner were ILINER = 2, XLINA = 4.00, and XLINB = 1.50.

Economic Premises Option

Line No.	Input data
11	7 2 16 5 10 8 15.6 10 8 3 6 1 60 1.886 14.7 0.0

(6 → IECON, 1 → PCTOVR, 60 → XLEVEL, 1.886 → CAPCHG or PCTADM, 14.7 → PCTMKT or UNDCAP, 0.0 → PCTMKT or PCTINS)

IECON PCTOVR XLEVEL CAPCHG PCTMKT

or or or

PCTADM UNDCAP PCTINS

TABLE 18. EXAMPLE OF OPTIMUM POND SUBJECT TO AREA LIMITS

POND DESIGN

OPTIMIZED TO MINIMIZE TOTAL COST PLUS OVERHEAD

WITH POND SITE ACREAGE CONSTRAINT

POND DIMENSIONS

DEPTH OF POND	45.36	FT
DEPTH OF EXCAVATION	10.93	FT
LENGTH OF DIVIDER DIKE	2078.	FT
LENGTH OF POND PERIMETER DIKE	11804.	FT
LENGTH OF POND PERIMETER FENCE	13227.	FT
SURFACE AREA OF BOTTOM	756.	THOUSAND YD2
SURFACE AREA OF INSIDE WALLS	217.	THOUSAND YD2
SURFACE AREA OF OUTSIDE WALLS	173.	THOUSAND YD2
SURFACE AREA OF RECLAIM STORAGE	93.	THOUSAND YD2
LAND AREA OF POND	954.	THOUSAND YD2
LAND AREA OF PONC SITE	1307.	THOUSAND YD2
LAND AREA OF POND SITE	270.	ACRES
VOLUME OF EXCAVATION	3001.	THOUSAND YD3
VOLUME OF RECLAIM STORAGE	571.	THOUSAND YD3
VOLUME OF SLUDGE TO BE	12900.	THOUSAND YD3
DISPOSED OVER LIFE OF PLANT	7996.	ACRE FT

POND COSTS (THOUSANDS OF DOLLARS)

	LABOR	MATERIAL	TOTAL
CLEARING LAND	528.		528.
EXCAVATION	8998.		8998.
DIKE CONSTRUCTION	6335.		6335.
LINING(12. IN. CLAY)	1541.		1541.
SODDING DIKE WALLS	214.	135.	349.
ROAD CONSTRUCTION	27.	8.	35.
PERIMETER COSTS, FENCE	66.	132.	198.
RECLAMATION EXPENSE	710.		710.
MONITOR WELLS	4.	4.	8.
SUBTOTAL DIRECT	18422.	279.	18701.
TAX AND FREIGHT		21.	21.
POND CONSTRUCTION	18422.	300.	18722.
LAND COST			1350.
POND SITE			20072.
OVERHEAD			8894.
TOTAL			28966.

TABLE 19. SYNTHETIC POND LINER EXAMPLE

POND DESIGN

OPTIMIZED TO MINIMIZE TOTAL COST PLUS OVERHEAD

POND DIMENSIONS

DEPTH OF POND	33.06	FT
DEPTH OF EXCAVATION	6.27	FT
LENGTH OF DIVIDER DIKE	2434.	FT
LENGTH OF POND PERIMETER DIKE	13530.	FT
LENGTH OF POND PERIMETER FENCE	14717.	FT
SURFACE AREA OF BOTTOM	1080.	THOUSAND YD2
SURFACE AREA OF INSIDE WALLS	193.	THOUSAND YD2
SURFACE AREA OF OUTSIDE WALLS	148.	THOUSAND YD2
SURFACE AREA OF RECLAIM STORAGE	109.	THOUSAND YD2
LAND AREA OF POND	1256.	THOUSAND YD2
LAND AREA OF POND SITE	1612.	THOUSAND YD2
LAND AREA OF POND SITE	333.	ACRES
VOLUME OF EXCAVATION	2442.	THOUSAND YD3
VOLUME OF RECLAIM STORAGE	712.	THOUSAND YD3
VOLUME OF SLUDGE TO BE	12900.	THOUSAND YD3
DISPOSED OVER LIFE OF PLANT	7996.	ACRE FT

POND COSTS (THOUSANDS OF DOLLARS)

	LABOR	MATERIAL	TOTAL
CLEARING LAND	651.		651.
EXCAVATION	7322.		7322.
DIKE CONSTRUCTION	4511.		4511.
LINING(SYNTHETIC)	1908.	5089.	6997.
SODDING DIKE WALLS	114.	72.	186.
ROAD CONSTRUCTION	31.	9.	40.
PERIMETER COSTS. FENCE	74.	147.	221.
RECLAMATION EXPENSE	923.		923.
MONITOR WELLS	4.	4.	8.
SUBTOTAL DIRECT	15538.	5321.	20859.
TAX AND FREIGHT		399.	399.
POND CONSTRUCTION	15538.	5720.	21258.
LAND COST			1665.
POND SITE			22923.
OVERHEAD			10099.
TOTAL			33022.

The economic premises option (IECON) allows cost projections based on either the EPA-TVA economic premises adopted December 5, 1979 (and expanded and amplified in March 1980), or the old premises that were used prior to December 5, 1979. Appendix B contains a description of the revised premises. Four variables are used in conjunction with the economic premises option, and the meaning of these variables depends on which set of premises is selected (see Appendix B). If the revised premises are specified (IECON = 1), the PCTOVR variable specifies the plant administrative overhead rate, applied as a percent of conversion costs less utilities, the XLEVEL variable specifies the levelizing factor to be applied to first-year operating and maintenance costs to develop levelized operating and maintenance costs for the total life of the plant, the CAPCHG variable specifies levelized annual capital charges applied as a percent of total capital investment, and the PCTMKT variable specifies marketing costs applied as a percent of byproduct credit (applies only to processes with a salable byproduct). If the levelizing factor (XLEVEL) is set to zero then a lifetime revenue sheet is printed showing annual revenue requirements for each year of plant operation. If the old premises (used before December 1979) are specified (IECON = 0), the PCTOVR variable specifies the plant overhead rate, applied as a percent of conversion costs less utilities, the PCTADM variable specifies the administrative research and service overhead rate, applied as a percent of operating labor and supervision, the UNDCAP variable specifies the annual capital charge basis for undepreciated investment, and the PCTINS variable specifies the rate for insurance and interim replacements, applied as a percent of total capital investment. Example output showing the results of specifying the new economic premises (IECON = 1) and a nonzero levelizing factor (XLEVEL = 1.886) is shown in the base case printout in Appendix D (pp. D-22, -24). The results of specifying a zero levelizing factor are shown in the example revenue requirements in Table 20. The results of specifying the old economic premises are shown in the example revenue requirements in Table 21.

Sales Tax and Freight Option

Line No.	Input data
12	1 4 3.5 6 0 1 1.5 1 2 1 8 5 10 0

```
1 → ITAXFR   4 → TXRATE   3.5 → FRRATE
```

The sales tax and freight option (ITAXFR) allows sales tax and freight to be applied as a percentage of material costs. The sales tax rate is specified with the variable TXRATE, and the freight rate is specified with the FRRATE variable. When ITAXFR is set to 1, the specified rates are applied to material costs and included in the capital investment summary printout; when ITAXFR is set to zero sales tax and freight are excluded. Example output showing the results of specifying sales tax and freight is shown on the capital investment summary sheet in the base case printout in Appendix D (p. D-22). An example investment summary sheet showing sales tax and freight excluded is shown in Table 22.

TABLE 20. EXAMPLE REVENUE REQUIREMENTS USING THE NEW ECONOMIC PREMISES WITH NO LEVELIZING

LIMESTONE SLURRY PROCESS -- BASIS: 500 MW SCRUBBING UNIT - 500 MW GENERATING UNIT, 1984 STARTUP

PROJECTED REVENUE REQUIREMENTS - ZERO LEVAL CASE 008

DISPLAY SHEET FOR YEAR= 1
ANNUAL OPERATION KW-HR/KW = 5500

34.89 TONS PER HOUR DRY SLUDGE
TOTAL CAPITAL INVESTMENT 109013000

	ANNUAL QUANTITY	UNIT COST,$	TOTAL ANNUAL COST,$
DIRECT COSTS			
RAW MATERIAL			
LIMESTONE	153.4 K TONS	8.50/TON	1304000
SUBTOTAL RAW MATERIAL			1304000
CONVERSION COSTS			
OPERATING LABOR AND SUPERVISION	30680.0 MAN-HR	15.00/MAN-HR	460200
UTILITIES			
STEAM	546160.0 K LB	2.50/K LB	1365400
PROCESS WATER	259930.0 K GAL	0.14/K GAL	36400
ELECTRICITY	47526160.0 KWH	0.037/KWH	1758500
MAINTENANCE			
LABOR AND MATERIAL			4130100
ANALYSES	4940.0 HR	21.00/HR	103800
SUBTOTAL CONVERSION COSTS			7854400
SUBTOTAL DIRECT COSTS			9158400
INDIRECT COSTS			
OVERHEADS			
PLANT AND ADMINISTRATIVE (60.0% OF CONVERSION COSTS LESS UTILITIES)			2816500
FIRST YEAR OPERATING AND MAINTENANCE COSTS			11974900
LEVELIZED CAPITAL CHARGES(14.70% OF TOTAL CAPITAL INVESTMENT)			16025000
FIRST YEAR ANNUAL REVENUE REQUIREMENTS			27999900
EQUIVALENT FIRST YEAR UNIT REVENUE REQUIREMENTS, MILLS/KWH (MW SCRUBBED)			10.18

HEAT RATE 9500. BTU/KWH - HEAT VALUE OF COAL 11700 BTU/LB - COAL RATE 1116500 TONS/YR

(continued)

TABLE 20 (continued)

LIMESTONE SLURRY PROCESS -- BASIS: 500 MW SCRUBBING UNIT - 500 MW GENERATING UNIT, 1984 STARTUP

PROJECTED LIFETIME REVENUE REQUIREMENTS - ZERO LEVAL CASE 008

TOTAL CAPITAL INVESTMENT: $ 109014000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR /KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BYPRODUCT RATE, EQUIVALENT TONS/YEAR DRY SLUDGE	SLUDGE FIXATION FEE $/TON DRY SLUDGE	ADJUSTED GROSS ANNUAL REVENUE REQUIREMENT EXCLUDING SLUDGE FIXATION COST, $/YEAR	TOTAL ANNUAL SLUDGE FIXATION COST, $/YEAR	NET ANNUAL INCREASE IN TOTAL REVENUE REQUIREMENT, $	CUMULATIVE NET INCREASE IN TOTAL REVENUE REQUIREMENT, $
1	5500	26125000	1116500	30600	191900	0.0	27999900	0	27999900	27999900
2	5500	26125000	1116500	30600	191900	0.0	28718500	0	28718500	56718400
3	5500	26125000	1116500	30600	191900	0.0	29479900	0	29479900	86198300
4	5500	26125000	1116500	30600	191900	0.0	30287200	0	30287200	116485500
5	5500	26125000	1116500	30600	191900	0.0	31142800	0	31142800	147628300
6	5500	26125000	1116500	30600	191900	0.0	32050100	0	32050100	179678400
7	5500	26125000	1116500	30600	191900	0.0	33011400	0	33011400	212689800
8	5500	26125000	1116500	30600	191900	0.0	34030700	0	34030700	246720500
9	5500	26125000	1116500	30600	191900	0.0	35110900	0	35110900	281831400
10	5500	26125000	1116500	30600	191900	0.0	36256200	0	36256200	318087600
11	5500	26125000	1116500	30600	191900	0.0	37470100	0	37470100	355557700
12	5500	26125000	1116500	30600	191900	0.0	38756700	0	38756700	394314400
13	5500	26125000	1116500	30600	191900	0.0	40120700	0	40120700	434435100
14	5500	26125000	1116500	30600	191900	0.0	41566600	0	41566600	476001700
15	5500	26125000	1116500	30600	191900	0.0	43099100	0	43099100	519100800
16	5500	26125000	1116500	30600	191900	0.0	44723300	0	44723300	563824100
17	5500	26125000	1116500	30600	191900	0.0	46445100	0	46445100	610269200
18	5500	26125000	1116500	30600	191900	0.0	48270500	0	48270500	658539700
19	5500	26125000	1116500	30600	191900	0.0	50205300	0	50205300	708745000
20	5500	26125000	1116500	30600	191900	0.0	52256200	0	52256200	761001200
21	5500	26125000	1116500	30600	191900	0.0	54429800	0	54429800	815431000
22	5500	26125000	1116500	30600	191900	0.0	56734200	0	56734200	872165200
23	5500	26125000	1116500	30600	191900	0.0	59176800	0	59176800	931342000
24	5500	26125000	1116500	30600	191900	0.0	61765800	0	61765800	993107800
25	5500	26125000	1116500	30600	191900	0.0	64510200	0	64510200	1057618000
26	5500	26125000	1116500	30600	191900	0.0	67419300	0	67419300	1125037300
27	5500	26125000	1116500	30600	191900	0.0	70503100	0	70503100	1195540400
28	5500	26125000	1116500	30600	191900	0.0	73771700	0	73771700	1269312100
29	5500	26125000	1116500	30600	191900	0.0	77236500	0	77236500	1346548600
30	5500	26125000	1116500	30600	191900	0.0	80909400	0	80909400	1427458000
TOT	165000	783750000	33495000	918000	5757000		1427458000	0	1427458000	
LIFETIME AVERAGE INCREASE IN UNIT REVENUE REQUIREMENT										
DOLLARS PER TON OF COAL BURNED							42.62	0.0	42.62	
MILLS PER KILOWATT-HOUR							17.30	0.0	17.30	
CENTS PER MILLION BTU HEAT INPUT							182.13	0.0	182.13	
DOLLARS PER TON OF SULFUR REMOVED							1554.97	0.0	1554.97	
REVENUE REQUIREMENT DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							351898600	0	351898600	
LEVELIZED INCREASE IN UNIT REVENUE REQUIREMENT EQUIVALENT TO DISCOUNTED REQUIREMENT OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							33.43	0.0	33.43	
MILLS PER KILOWATT-HOUR							13.57	0.0	13.57	
CENTS PER MILLION BTU HEAT INPUT							142.89	0.0	142.89	
DOLLARS PER TON OF SULFUR REMOVED							1219.75	0.0	1219.75	

UNIT COSTS INFLATED AT 6.00% PER YEAR

TABLE 21. EXAMPLE REVENUE REQUIREMENTS USING THE OLD ECONOMIC PREMISES

LIMESTONE SLURRY PROCESS -- BASIS: 500 MW SCRUBBING UNIT - 500 MW GENERATING UNIT, 1984 STARTUP

PROJECTED REVENUE REQUIREMENTS - OLD PREMISE — CASE 009

DISPLAY SHEET FOR YEAR= 1
ANNUAL OPERATION KW-HR/KW = 5500

34.89 TONS PER HOUR DRY SLUDGE
TOTAL CAPITAL INVESTMENT 99172000

	ANNUAL QUANTITY	UNIT COST,$	TOTAL ANNUAL COST,$
DIRECT COSTS			
RAW MATERIAL			
LIMESTONE	153.4 K TONS	8.50/TON	1304000
SUBTOTAL RAW MATERIAL			1304000
CONVERSION COSTS			
OPERATING LABOR AND SUPERVISION	30680.0 MAN-HR	15.00/MAN-HR	460200
UTILITIES			
STEAM	546160.0 K LB	2.50/K LB	1365400
PROCESS WATER	259970.0 K GAL	0.14/K GAL	36400
ELECTRICITY	47526120.0 KWH	0.037/KWH	1758500
MAINTENANCE			
LABOR AND MATERIAL			3299600
ANALYSES	4380.0 HR	21.00/HR	92000
SUBTOTAL CONVERSION COSTS			7012100
SUBTOTAL DIRECT COSTS			8316100
INDIRECT COSTS			
DEPRECIATION			3175700
COST OF CAPITAL AND TAXES, 17.20% OF UNDEPRECIATED INVESTMENT			17057700
INSURANCE & INTERIM REPLACEMENTS, 1.17% OF TOTAL CAPITAL INVESTMENT			1160300
OVERHEAD			
PLANT, 50.0% OF CONVERSION COSTS LESS UTILITIES			1925900
ADMINISTRATIVE, RESEARCH, AND SERVICE, 10.0% OF OPERATING LABOR AND SUPERVISION			46000
SUBTOTAL INDIRECT COSTS			23365600
TOTAL ANNUAL REVENUE REQUIREMENT			31681700
EQUIVALENT UNIT REVENUE REQUIREMENT, MILLS/KWH			11.52

HEAT RATE 9500. BTU/KWH - HEAT VALUE OF COAL 11700 BTU/LB - COAL RATE 1116500 TONS/YR

(continued)

TABLE 21 (continued)

LIMESTONE SLURRY PROCESS -- BASIS: 500 MW SCRUBBING UNIT - 500 MW GENERATING UNIT, 1984 STARTUP

PROJECTED LIFETIME REVENUE REQUIREMENTS - OLD PREMISE

CASE 009

TOTAL CAPITAL INVESTMENT: $ 99172000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR /KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BYPRODUCT RATE, EQUIVALENT TONS/YEAR DRY SLUDGE	SLUDGE FIXATION FEE $/TON DRY SLUDGE	ADJUSTED GROSS ANNUAL REVENUE REQUIREMENT EXCLUDING SLUDGE FIXATION COST, $/YEAR	TOTAL ANNUAL SLUDGE FIXATION COST, $/YEAR	NET ANNUAL INCREASE IN TOTAL REVENUE REQUIREMENT, $	CUMULATIVE NET INCREASE IN TOTAL REVENUE REQUIREMENT, $
1	5500	26125000	1116500	30600	191900	0.0	31681700	0	31681700	31681700
2	5500	26125000	1116500	30600	191900	0.0	31135400	0	31135400	62817100
3	5500	26125000	1116500	30600	191900	0.0	30589200	0	30589200	93406300
4	5500	26125000	1116500	30600	191900	0.0	30043000	0	30043000	123449300
5	5500	26125000	1116500	30600	191900	0.0	29496800	0	29496800	152946100
6	5500	26125000	1116500	30600	191900	0.0	28950600	0	28950600	181896700
7	5500	26125000	1116500	30600	191900	0.0	28404300	0	28404300	210301000
8	5500	26125000	1116500	30600	191900	0.0	27858100	0	27858100	238159100
9	5500	26125000	1116500	30600	191900	0.0	27311900	0	27311900	265471000
10	5500	26125000	1116500	30600	191900	0.0	26765700	0	26765700	292236700
11	5500	26125000	1116500	30600	191900	0.0	26219500	0	26219500	318456200
12	5500	26125000	1116500	30600	191900	0.0	25673200	0	25673200	344129400
13	5500	26125000	1116500	30600	191900	0.0	25127000	0	25127000	369256400
14	5500	26125000	1116500	30600	191900	0.0	24580800	0	24580800	393837200
15	5500	26125000	1116500	30600	191900	0.0	24034600	0	24034600	417871800
16	5500	26125000	1116500	30600	191900	0.0	23488400	0	23488400	441360200
17	5500	26125000	1116500	30600	191900	0.0	22942100	0	22942100	464302300
18	5500	26125000	1116500	30600	191900	0.0	22395900	0	22395900	486698200
19	5500	26125000	1116500	30600	191900	0.0	21849700	0	21849700	508547900
20	5500	26125000	1116500	30600	191900	0.0	21303500	0	21303500	529851400
21	5500	26125000	1116500	30600	191900	0.0	20757300	0	20757300	550608700
22	5500	26125000	1116500	30600	191900	0.0	20211000	0	20211000	570819700
23	5500	26125000	1116500	30600	191900	0.0	19664800	0	19664800	590484500
24	5500	26125000	1116500	30600	191900	0.0	19118600	0	19118600	609603100
25	5500	26125000	1116500	30600	191900	0.0	18572400	0	18572400	628175500
26	5500	26125000	1116500	30600	191900	0.0	18026200	0	18026200	646201700
27	5500	26125000	1116500	30600	191900	0.0	17479900	0	17479900	663681600
28	5500	26125000	1116500	30600	191900	0.0	16933700	0	16933700	680615300
29	5500	26125000	1116500	30600	191900	0.0	16387500	0	16387500	697002800
30	5500	26125000	1116500	30600	191900	0.0	15841300	0	15841300	712844100
TOT	165000	783750000	33495000	918000	5757000		712844100	0	712844100	

LIFETIME AVERAGE INCREASE IN UNIT REVENUE REQUIREMENT			
DOLLARS PER TON OF COAL BURNED	21.28	0.0	21.28
MILLS PER KILOWATT-HOUR	8.64	0.0	8.64
CENTS PER MILLION BTU HEAT INPUT	90.95	0.0	90.95
DOLLARS PER TON OF SULFUR REMOVED	776.52	0.0	776.52
REVENUE REQUIREMENT DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	256559500	0	256559500
LEVELIZED INCREASE IN UNIT REVENUE REQUIREMENT EQUIVALENT TO DISCOUNTED REQUIREMENT OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	24.38	0.0	24.38
MILLS PER KILOWATT-HOUR	9.90	0.0	9.90
CENTS PER MILLION BTU HEAT INPUT	104.17	0.0	104.17
DOLLARS PER TON OF SULFUR REMOVED	889.29	0.0	889.29

TABLE 22. EXAMPLE INVESTMENT SUMMARY SHEET WITH SALES TAX AND FREIGHT EXCLUDED

LIMESTONE SLURRY PROCESS -- BASIS: 500 MW SCRUBBING UNIT - 500 MW GENERATING UNIT, 1984 STARTUP
PROJECTED CAPITAL INVESTMENT REQUIREMENTS - NO TAX OR FREIGHT

CASE 002

	INVESTMENT, THOUSANDS OF 1982 DOLLARS				DISTRIBUTION
	RAW MATERIAL PREPARATION	SCRUBBING	WASTE DISPOSAL	TOTAL	DOLLARS PER KW
EQUIPMENT					
MATERIAL	3049.	13666.	95.	16810.	33.62
LABOR	307.	1544.	34.	1884.	3.77
PIPING					
MATERIAL	416.	5152.	1058.	6627.	13.25
LABOR	192.	918.	352.	1461.	2.92
DUCTWORK					
MATERIAL	0.	3042.	0.	3042.	6.08
LABOR	0.	2723.	0.	2723.	5.45
FOUNDATIONS					
MATERIAL	341.	172.	20.	534.	1.07
LABOR	883.	374.	42.	1299.	2.60
STRUCTURAL					
MATERIAL	196.	372.	2.	570.	1.14
LABOR	142.	648.	3.	794.	1.59
ELECTRICAL					
MATERIAL	262.	813.	146.	1221.	2.44
LABOR	757.	1567.	318.	2641.	5.28
INSTRUMENTATION					
MATERIAL	148.	814.	13.	975.	1.95
LABOR	22.	131.	9.	162.	0.32
BUILDINGS					
MATERIAL	147.	0.	0.	147.	0.29
LABOR	163.	0.	0.	163.	0.33
TOTAL PROCESS CAPITAL	7024.	31937.	2092.	41053.	82.11
SERVICES AND MISCELLANEOUS (6.0 %)	421.	1916.	126.	2463.	4.93
TOTAL DIRECT PROCESS INVESTMENT	7445.	33854.	2218.	43517.	87.03
POND CONSTRUCTION MATERIAL	0.	0.	303.	303.	0.61
POND CONSTRUCTION LABOR	0.	0.	14917.	14917.	29.83
TOTAL DIRECT POND INVESTMENT	0.	0.	15219.	15219.	30.44
TOTAL DIRECT INVESTMENT	7445.	33854.	17437.	58736.	117.47
ENGINEERING DESIGN AND SUPERVISION (7.0 %)	521.	2370.	155.	3046.	6.09
ARCHITECT AND ENGINEERING CONTRACTOR (2.0 %)	149.	677.	44.	870.	1.74
CONSTRUCTION EXPENSES (16.0 %)	1191.	5417.	355.	6963.	13.93
CONTRACTOR FEES (5.0 %)	372.	1693.	111.	2176.	4.35
CONTINGENCY (10.0 %)	968.	4401.	288.	5657.	11.31
POND INDIRECTS (2.0, 1.0, 8.0, 5.0, 10.0 %)	0.	0.	4201.	4201.	8.40
SUBTOTAL FIXED INVESTMENT	10647.	48411.	22591.	81649.	163.30
STARTUP & MODIFICATION ALLOWANCE (8.0, 0.0 %)	852.	3873.	254.	4978.	9.96
INTEREST DURING CONSTRUCTION (15.6 %)	1661.	7552.	3524.	12737.	25.47
ROYALTIES (0.0 %)	0.	0.	0.	0.	0.0
LAND	10.	4.	2120.	2134.	4.27
WORKING CAPITAL	401.	1825.	940.	3166.	6.33
TOTAL CAPITAL INVESTMENT	13571.	61665.	29429.	104665.	209.33

Overtime Option

Line No.	Input data
12	1 4 3.5 6 0 1 1.5 1 2 1 8 5 10 0

(Arrows point from 1 to IOTIME and from 1.5 to OTRATE.)

The overtime option (IOTIME) allows an overtime labor rate (OTRATE) to be applied to 7% of total labor as defined in the new TVA-EPA premises (Appendix B). When IOTIME is set to 1, the specified overtime rate is applied to 7% of all applicable labor costs; when IOTIME is set to zero no overtime labor adjustments are made. The added costs for overtime labor are not shown separately in the model output, but a message is printed in the listing of the model inputs to indicate if overtime is specified as shown in the base case printout in Appendix D (p. D-6).

Separate Pond Construction Indirect Investment Factors Option

Line No.	Input data
12	1 4 3.5 6 0 1 1.5 1 2 1 8 5 10 0

(Arrows point from 1 to INDPND, 2 to PENGIN, 1 to PARCH, 8 to PFLDEX, 5 to PFEES, 10 to PCONT and 0 to PSTART.)

The separate pond construction indirect investment factors option (INDPND) allows pond construction indirect investment to be calculated separately from process indirect investment. Pond construction is in general less complex than the scrubbing process and therefore indirect investment factors are usually lower. Six variables are used in conjunction with the separate pond indirect investment option. They correspond one-for-one with the process indirect investment factors (line 11: ENGIN, ARCTEC, FLDEXP, FEES, CONT, and START). The PENGIN variable specifies pond engineering design and supervision costs, applied as a percentage of total direct pond investment. The PARCH variable specifies pond architectural and engineering contractor costs, applied as a percentage of total direct pond investment. The PFLDEX variable specifies pond construction field expenses, applied as a percentage of total direct pond investment. The PFEES variable specifies pond contractor fees, applied as a percentage of total direct pond investment. The PCONT variable specifies pond contingencies, but the way it is applied depends on the economic premises option (line 11, IECON). If the new economic premises are specified (IECON = 1) then pond contingency is applied as a percentage of total direct pond investment plus each of the preceding four pond indirect investment costs. If the old economic premises are specified (IECON = 0) then pond contingency is applied as a percentage of total direct pond investment only. The PSTART variable specifies the allowance for pond startup and modification, applied as a percentage of total fixed pond investment. Example output showing the results of specifying separate indirect investment factors for pond construction (INDPND = 1) is shown on the investment summary sheet in the base case printout in Appendix D (p. D-22). Example output showing the results of using common indirect investment factors for both the FGD process and pond construction (INDPND = 0) is shown in Table 23.

Pond Capacity Option

Line No.	Input data
14	4 1 5 .8 1.0 3 .65 1 1 1.10 1982 297.9

(The second value, 1, is PNDCAP.)

The pond capacity option provides the capability to design the raw material and scrubbing areas based on maximum sulfur content of coal (high sulfur content fluctuation) but, at the same time, to design the pond based on an average sulfur content. For example, on a long-term basis, the coal being used may be expected to average 2.0% sulfur. However, at times the sulfur content may be as high as 3%. The raw material preparation area and the scrubbing area should be sized for the maximum coal sulfur content that is expected to be encountered. In this case a value of 3% must be considered for design of the feed preparation and absorber units, but the model also calculates the sludge production rate based on the input sulfur content and sizes the pond based on that amount. The PNDCAP option is included in the model to allow the projected waste disposal pond size to be modified to account for the difference between average and maximum sulfur content (ordinarily PNDCAP will be in the range of 0.5-1.0). In the preceding example, by specifying PNDCAP equal to 0.67, the waste disposal pond would be sized based on a 2% sulfur coal, whereas the other facilities would be designed for fluctuations in coal sulfur content of up to 3%.

If the user wishes to specify an oversized pond to cover contingencies in sulfur content, or to specify an undersized pond for applications in which the initial pond is not designed for the full life of the plant, an appropriate PNDCAP factor, i.e., greater than or less than 1.0, can be specified.

Operating Profile Option

Line No.	Input data
14	3 1 5 .8 1.0 3 .65 1 1 1.10 1982 297.9
15	30

(The first value on line 14, 3, is IOPSCH; the value on line 15, 30, is IYROP.)

One of the most important variables affecting the economics of a power plant and an associated FGD system is the operating profile (number of years of operation and the hours of operation per year) over the life of the unit. The effects of the year-by-year profile on investment and

TABLE 23. EXAMPLE INVESTMENT SUMMARY SHEET WITH COMMON INDIRECT INVESTMENT FACTORS FOR PROCESS AND POND

LIMESTONE SLURRY PROCESS -- BASIS; 500 MW SCRUBBING UNIT - 500 MW GENERATING UNIT, 1984 STARTUP
PROJECTED CAPITAL INVESTMENT REQUIREMENTS - COMMON INDIRECTS

CASE 003

	INVESTMENT, THOUSANDS OF 1982 DOLLARS				DISTRIBUTION
	RAW MATERIAL PREPARATION	SCRUBBING	WASTE DISPOSAL	TOTAL	DOLLARS PER KW
EQUIPMENT					
MATERIAL	3049.	13666.	95.	16810.	33.62
LABOR	307.	1544.	34.	1884.	3.77
PIPING					
MATERIAL	416.	5152.	1058.	6626.	13.25
LABOR	192.	918.	352.	1461.	2.92
DUCTWORK					
MATERIAL	0.	3042.	0.	3042.	6.08
LABOR	0.	2723.	0.	2723.	5.45
FOUNDATIONS					
MATERIAL	341.	172.	20.	534.	1.07
LABOR	883.	374.	42.	1299.	2.60
STRUCTURAL					
MATERIAL	196.	372.	2.	570.	1.14
LABOR	142.	648.	3.	794.	1.59
ELECTRICAL					
MATERIAL	262.	813.	146.	1221.	2.44
LABOR	757.	1566.	318.	2641.	5.28
INSTRUMENTATION					
MATERIAL	148.	814.	13.	975.	1.95
LABOR	22.	131.	9.	162.	0.32
BUILDINGS					
MATERIAL	147.	0.	0.	147.	0.29
LABOR	163.	0.	0.	163.	0.33
SALES TAX (4.0 %) AND FREIGHT (3.5 %)	342.	1802.	100.	2244.	4.49
TOTAL PROCESS CAPITAL	7366.	33740.	2192.	43298.	86.60
SERVICES AND MISCELLANEOUS (6.0 %)	442.	2024.	132.	2598.	5.20
TOTAL DIRECT PROCESS INVESTMENT	7808.	35764.	2324.	45896.	91.79
POND CONSTRUCTION MATERIAL	0.	0.	303.	303.	0.61
POND CONSTRUCTION LABOR	0.	0.	14905.	14905.	29.81
POND SALES TAX (4.0 %) AND FREIGHT (3.5 %)	0.	0.	23.	23.	0.05
TOTAL DIRECT POND INVESTMENT	0.	0.	15231.	15231.	30.46
TOTAL DIRECT INVESTMENT	7808.	35764.	17555.	61127.	122.25
ENGINEERING DESIGN AND SUPERVISION (7.0 %)	547.	2504.	1229.	4279.	8.56
ARCHITECT AND ENGINEERING CONTRACTOR (2.0 %)	156.	715.	46.	918.	1.84
CONSTRUCTION EXPENSES (16.0 %)	1249.	5722.	2809.	9780.	19.56
CONTRACTOR FEES (5.0 %)	390.	1788.	878.	3056.	6.11
CONTINGENCY (10.0 %)	1015.	4649.	2252.	7916.	15.83
SUBTOTAL FIXED INVESTMENT	11165.	51143.	24768.	87076.	174.15
STARTUP & MODIFICATION ALLOWANCE (8.0 %)	893.	4091.	1981.	6966.	13.93
INTEREST DURING CONSTRUCTION (15.6 %)	1742.	7978.	3864.	13584.	27.17
ROYALTIES (0.0 %)	0.	0.	0.	0.	0.0
LAND	10.	4.	2137.	2152.	4.30
WORKING CAPITAL	418.	1917.	941.	3276.	6.55
TOTAL CAPITAL INVESTMENT	14229.	65133.	33692.	113054.	226.11

revenue requirements are determined by the economic premises option (line 11, IECON), the operating and maintenance cost levelizing factor (line 11, XLEVEL) used with the new economic premises, and the waste disposal option (line 10, ISLUDG). The model provides four options for specifying this profile. The input variable for these options is IOPSCH. If IOPSCH = 1 the program uses the TVA-developed operating schedule shown in Figure 3 which is based on the profile assumed in Detailed Cost Estimates for Advanced Effluent Desulfurization Processes (G. G. McGlamery et al., 1975). If IOPSCH = 2 the operating schedule is based on historical Federal Energy Regulatory Commission (FERC, previously FPC) data as shown in Figure 4. If IOPSCH = 3 the user must input the operating profile as shown below. If IOPSCH = 4 a levelized operating profile of 5500 hours per year is used (see Appendix D). A 30-year operating life is assumed unless a year-by-year operating profile is provided by the user. When the operating profile is specified by the user (IOPSCH = 3), the IYROP variable on line 15 specifies the projected operating life in years and cannot exceed 50. Beginning on line 16, the total number of hours-per-year entries must be equal to the value of IYROP. The number of entries per line must not exceed 10. Less than 10 entries are allowed on the last line only, depending on the number of years required. An example of using 25 years is shown below.

Line No.	Input data
14	3 1 5 .8 1.0 3 .65 1 1 1.10 1982 297.9
15	25
16	5000 5000 6000 6000 7000 7000 7000 7000 7000 7000
17	7000 7000 7000 7000 7000 7000 7000 7000 6000 6000
18	6000 5000 5000 5000 4000
19	END

If levelized operating and maintenance costs under the new premises are being used, a levelizing factor (line 11, XLEVEL) that corresponds to the operating profile should be used.

Example output resulting from the Figure 3 operating profile (IOPSCH = 1) is shown in Table 24. Table 25 illustrates the results of the Figure 4 FERC data operating profile (IOPSCH = 2). Example output resulting from a user-supplied operating profile (IOPSCH =3) is shown in Table 26. The base case printout in Appendix D (p. D-24) shows the results of specifying a levelized operating profile of 5,500 hours per year.

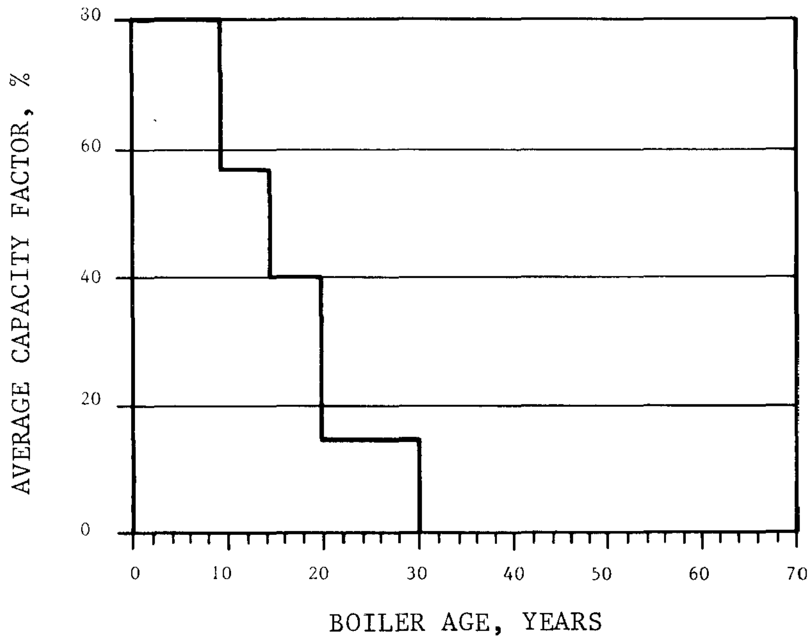

Figure 3. Operating profile assumed for IOPSCH = 1 based on old TVA premises.

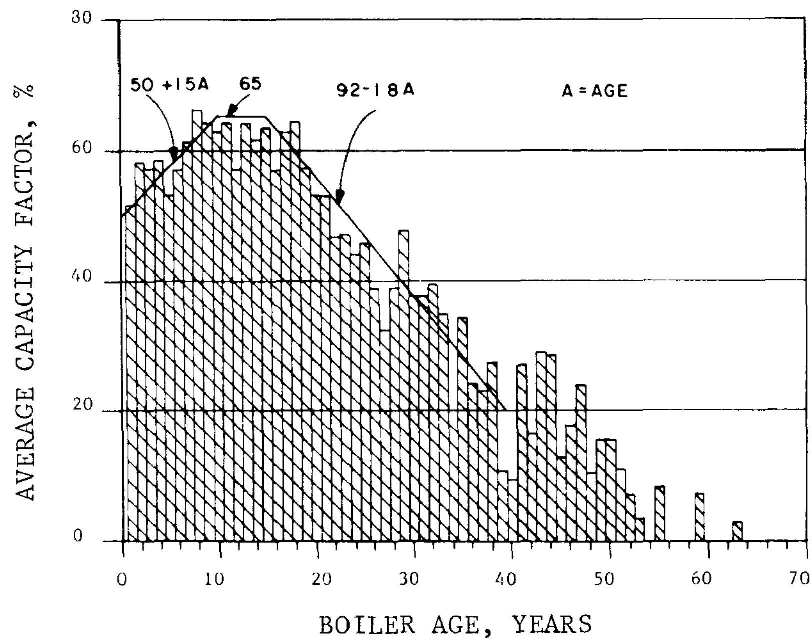

Figure 4. Operating profile assumed for IOPSCH = 2 based on historical Federal Energy Regulatory Commission data.

TABLE 24. EXAMPLE LIFETIME REVENUE REQUIREMENTS USING THE OLD TVA PREMISES OPERATING PROFILE

LIMESTONE SLURRY PROCESS -- BASIS: 500 MW SCRUBBING UNIT - 500 MW GENERATING UNIT, 1984 STARTUP

PROJECTED LIFETIME REVENUE REQUIREMENTS - FIVE PROCESS PROFILE

CASE 010

TOTAL CAPITAL INVESTMENT: $ 104679000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR /KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BYPRODUCT RATE, EQUIVALENT TONS/YEAR DRY SLUDGE	SLUDGE FIXATION FEE $/TON DRY SLUDGE	ADJUSTED GROSS ANNUAL REVENUE REQUIREMENT EXCLUDING SLUDGE FIXATION COST, $/YEAR	TOTAL ANNUAL SLUDGE FIXATION COST, $/YEAR	NET ANNUAL INCREASE IN TOTAL REVENUE REQUIREMENT, $	CUMULATIVE NET INCREASE IN TOTAL REVENUE REQUIREMENT, $
1	7000	33250000	1420900	38900	244200	0.0	28564600	0	28564600	28564600
2	7000	33250000	1420900	38900	244200	0.0	29355300	0	29355300	57919900
3	7000	33250000	1420900	38900	244200	0.0	30193400	0	30193400	88113300
4	7000	33250000	1420900	38900	244200	0.0	31081700	0	31081700	119195000
5	7000	33250000	1420900	38900	244200	0.0	32023300	0	32023300	151218300
6	7000	33250000	1420900	38900	244200	0.0	33021400	0	33021400	184239700
7	7000	33250000	1420900	38900	244200	0.0	34079700	0	34079700	218319400
8	7000	33250000	1420900	38900	244200	0.0	35201100	0	35201100	253520500
9	7000	33250000	1420900	38900	244200	0.0	36389800	0	36389800	289910300
10	7000	33250000	1420900	38900	244200	0.0	37649900	0	37649900	327560200
11	5000	23750000	1015000	27800	174400	0.0	33631600	0	33631600	361191800
12	5000	23750000	1015000	27800	174400	0.0	34726400	0	34726400	395918200
13	5000	23750000	1015000	27800	174400	0.0	35886900	0	35886900	431805100
14	5000	23750000	1015000	27800	174400	0.0	37116700	0	37116700	468921800
15	5000	23750000	1015000	27800	174400	0.0	38420500	0	38420500	507342300
16	3500	16625000	710500	19400	122100	0.0	34069700	0	34069700	541412000
17	3500	16625000	710500	19400	122100	0.0	35190600	0	35190600	576602600
18	3500	16625000	710500	19400	122100	0.0	36378600	0	36378600	612981200
19	3500	16625000	710500	19400	122100	0.0	37638300	0	37638300	650619500
20	3500	16625000	710500	19400	122100	0.0	38973100	0	38973100	689592600
21	1500	7125000	304500	8300	52300	0.0	28898000	0	28898000	718490600
22	1500	7125000	304500	8300	52300	0.0	29708400	0	29708400	748199000
23	1500	7125000	304500	8300	52300	0.0	30567900	0	30567900	778766900
24	1500	7125000	304500	8300	52300	0.0	31478600	0	31478600	810245500
25	1500	7125000	304500	8300	52300	0.0	32443900	0	32443900	842689400
26	1500	7125000	304500	8300	52300	0.0	33467500	0	33467500	876156900
27	1500	7125000	304500	8300	52300	0.0	34552200	0	34552200	910709100
28	1500	7125000	304500	8300	52300	0.0	35702100	0	35702100	946411200
29	1500	7125000	304500	8300	52300	0.0	36921000	0	36921000	983332200
30	1500	7125000	304500	8300	52300	0.0	38212800	0	38212800	1021545000
TOT	127500	605625000	25881500	708000	4447500		1021545000	0	1021545000	
LIFETIME AVERAGE INCREASE IN UNIT REVENUE REQUIREMENT										
DOLLARS PER TON OF COAL BURNED							39.47	0.0	39.47	
MILLS PER KILOWATT-HOUR							16.02	0.0	16.02	
CENTS PER MILLION BTU HEAT INPUT							168.68	0.0	168.68	
DOLLARS PER TON OF SULFUR REMOVED							1442.86	0.0	1442.86	
REVENUE REQUIREMENT DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							311206100	0	311206100	
LEVELIZED INCREASE IN UNIT REVENUE REQUIREMENT EQUIVALENT TO DISCOUNTED REQUIREMENT OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							27.94	0.0	27.94	
MILLS PER KILOWATT-HOUR							11.34	0.0	11.34	
CENTS PER MILLION BTU HEAT INPUT							119.41	0.0	119.41	
DOLLARS PER TON OF SULFUR REMOVED							1021.02	0.0	1021.02	

UNIT COSTS INFLATED AT 6.00% PER YEAR

TABLE 25. EXAMPLE LIFETIME REVENUE REQUIREMENTS USING THE HISTORICAL FERC/FPC OPERATING PROFILE

LIMESTONE SLURRY PROCESS -- BASIS: 500 MW SCRUBBING UNIT - 500 MW GENERATING UNIT, 1984 STARTUP

PROJECTED LIFETIME REVENUE REQUIREMENTS - FPC/FERC PROFILE CASE 010

TOTAL CAPITAL INVESTMENT: $ 106672000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR /KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BYPRODUCT RATE, EQUIVALENT TONS/YEAR DRY SLUDGE	SLUDGE FIXATION FEE $/TON DRY SLUDGE	ADJUSTED GROSS ANNUAL REVENUE REQUIREMENT EXCLUDING SLUDGE FIXATION COST, $/YEAR	TOTAL ANNUAL SLUDGE FIXATION COST, $/YEAR	NET ANNUAL INCREASE IN TOTAL REVENUE REQUIREMENT, $	CUMULATIVE NET INCREASE IN TOTAL REVENUE REQUIREMENT, $
1	4512	21432000	915900	25100	157400	0.0	26703200	0	26703200	26703200
2	4643	22054300	942500	25800	162000	0.0	27612300	0	27612300	54315500
3	4775	22681300	969300	26500	166600	0.0	28590900	0	28590900	82906400
4	4906	23303500	995900	27300	171200	0.0	29640600	0	29640600	112547000
5	5037	23925800	1022500	28000	175700	0.0	30767900	0	30767900	143314900
6	5169	24552800	1049300	28700	180300	0.0	31981300	0	31981300	175296200
7	5300	25175000	1075900	29400	184900	0.0	33281200	0	33281200	208577400
8	5432	25802000	1102600	30200	189500	0.0	34679500	0	34679500	243256900
9	5563	26424300	1129200	30900	194100	0.0	36177800	0	36177800	279434700
10	5694	27046500	1155800	31600	198700	0.0	37785500	0	37785500	317220200
11	5695	27051300	1156000	31600	198700	0.0	39114800	0	39114800	356335000
12	5695	27051300	1156000	31600	198700	0.0	40520900	0	40520900	396855900
13	5695	27051300	1156000	31600	198700	0.0	42011500	0	42011500	438867400
14	5695	27051300	1156000	31600	198700	0.0	43591100	0	43591100	482458500
15	5695	27051300	1156000	31600	198700	0.0	45265600	0	45265600	527724100
16	5537	26300800	1124000	30800	193200	0.0	46394100	0	46394100	574118200
17	5379	25550300	1091900	29900	187700	0.0	47547000	0	47547000	621665200
18	5221	24799800	1059800	29000	182100	0.0	48723200	0	48723200	670388400
19	5064	24054000	1027900	28100	176700	0.0	49926200	0	49926200	720314600
20	4906	23303500	995900	27300	171200	0.0	51143500	0	51143500	771458100
21	4748	22553000	963800	26400	165600	0.0	52377900	0	52377900	823836000
22	4591	21807300	931900	25500	160200	0.0	53631900	0	53631900	877467900
23	4433	21056800	899900	24600	154700	0.0	54890400	0	54890400	932358300
24	4275	20306300	867800	23800	149100	0.0	56155100	0	56155100	988513400
25	4118	19560500	835900	22900	143700	0.0	57428000	0	57428000	1045941400
26	3960	18810000	803800	22000	138200	0.0	58690100	0	58690100	1104631500
27	3802	18059500	771800	21100	132600	0.0	59941700	0	59941700	1164573200
28	3645	17313800	739900	20300	127200	0.0	61184600	0	61184600	1225757800
29	3487	16563300	707800	19400	121700	0.0	62393200	0	62393200	1288151000
30	3329	15812800	675800	18500	116100	0.0	63566400	0	63566400	1351717400
TOT	146001	693505700	29636800	811100	5093900		1351717400	0	1351717400	

LIFETIME AVERAGE INCREASE IN UNIT REVENUE REQUIREMENT			
DOLLARS PER TON OF COAL BURNED	45.61	0.0	45.61
MILLS PER KILOWATT-HOUR	18.52	0.0	18.52
CENTS PER MILLION BTU HEAT INPUT	194.91	0.0	194.91
DOLLARS PER TON OF SULFUR REMOVED	1666.52	0.0	1666.52
REVENUE REQUIREMENT DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	346396900	0	346396900
LEVELIZED INCREASE IN UNIT REVENUE REQUIREMENT EQUIVALENT TO DISCOUNTED REQUIREMENT OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	35.83	0.0	35.83
MILLS PER KILOWATT-HOUR	14.55	0.0	14.55
CENTS PER MILLION BTU HEAT INPUT	153.14	0.0	153.14
DOLLARS PER TON OF SULFUR REMOVED	1309.63	0.0	1309.63

UNIT COSTS INFLATED AT 6.00% PER YEAR

TABLE 26. EXAMPLE LIFETIME REVENUE REQUIREMENTS USING A USER-SUPPLIED OPERATING PROFILE

LIMESTONE SLURRY PROCESS -- BASIS: 500 MW SCRUBBING UNIT - 500 MW GENERATING UNIT, 1984 STARTUP

PROJECTED LIFETIME REVENUE REQUIREMENTS - USER INPUT SCHEDULE CASE 013

TOTAL CAPITAL INVESTMENT: $ 108027000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR /KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BYPRODUCT RATE, EQUIVALENT TONS/YEAR DRY SLUDGE	SLUDGE FIXATION FEE $/TON DRY SLUDGE	ADJUSTED GROSS ANNUAL REVENUE REQUIREMENT EXCLUDING SLUDGE FIXATION COST, $/YEAR	TOTAL ANNUAL SLUDGE FIXATION COST, $/YEAR	NET ANNUAL INCREASE IN TOTAL REVENUE REQUIREMENT, $	CUMULATIVE NET INCREASE IN TOTAL REVENUE REQUIREMENT, $
1	5000	23750000	1015000	27800	174400	0.0	27379300	0	27379300	27379300
2	5000	23750000	1015000	27800	174400	0.0	28069400	0	28069400	55448700
3	6000	28500000	1217900	33300	209300	0.0	30678500	0	30678500	86127200
4	6000	28500000	1217900	33300	209300	0.0	31566400	0	31566400	117693600
5	7000	33250000	1420900	38900	244200	0.0	34548200	0	34548200	152241800
6	7000	33250000	1420900	38900	244200	0.0	35668300	0	35668300	187910100
7	7000	33250000	1420900	38900	244200	0.0	36855700	0	36855700	224765800
8	7000	33250000	1420900	38900	244200	0.0	38114100	0	38114100	262879900
9	7000	33250000	1420900	38900	244200	0.0	39448200	0	39448200	302328100
10	7000	33250000	1420900	38900	244200	0.0	40862300	0	40862300	343190400
11	7000	33250000	1420900	38900	244200	0.0	42361300	0	42361300	385551700
12	7000	33250000	1420900	38900	244200	0.0	43950000	0	43950000	429501700
13	7000	33250000	1420900	38900	244200	0.0	45634400	0	45634400	475136100
14	7000	33250000	1420900	38900	244200	0.0	47419600	0	47419600	522555700
15	7000	33250000	1420900	38900	244200	0.0	49312200	0	49312200	571867900
16	7000	33250000	1420900	38900	244200	0.0	51318100	0	51318100	623186000
17	7000	33250000	1420900	38900	244200	0.0	53444200	0	53444200	676630200
18	7000	33250000	1420900	38900	244200	0.0	55697900	0	55697900	732328100
19	6000	28500000	1217900	33300	209300	0.0	53473400	0	53473400	785801500
20	6000	28500000	1217900	33300	209300	0.0	55729000	0	55729000	841530500
21	6000	28500000	1217900	33300	209300	0.0	58120000	0	58120000	899650500
22	5000	23750000	1015000	27800	174400	0.0	54973500	0	54973500	954624000
23	5000	23750000	1015000	27800	174400	0.0	57319100	0	57319100	1011943100
24	5000	23750000	1015000	27800	174400	0.0	59805400	0	59805400	1071748500
25	4000	19000000	812000	22200	139600	0.0	55387400	0	55387400	1127135900
TOT	157000	745750000	31869100	872300	5476900		1127135900	0	1127135900	

LIFETIME AVERAGE INCREASE IN UNIT REVENUE REQUIREMENT			
DOLLARS PER TON OF COAL BURNED	35.37	0.0	35.37
MILLS PER KILOWATT-HOUR	14.36	0.0	14.36
CENTS PER MILLION BTU HEAT INPUT	151.14	0.0	151.14
DOLLARS PER TON OF SULFUR REMOVED	1292.14	0.0	1292.14
REVENUE REQUIREMENT DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	350801100	0	350801100
LEVELIZED INCREASE IN UNIT REVENUE REQUIREMENT EQUIVALENT TO DISCOUNTED REQUIREMENT OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	30.19	0.0	30.19
MILLS PER KILOWATT-HOUR	12.26	0.0	12.26
CENTS PER MILLION BTU HEAT INPUT	129.03	0.0	129.03
DOLLARS PER TON OF SULFUR REMOVED	1103.15	0.0	1103.15

UNIT COSTS INFLATED AT 6.00% PER YEAR

USAGE OF THE MODEL

As previously discussed, a copy of the model can be made available for independent user execution; or TVA, under an information-exchange agreement with EPA, can make specific runs of the model based on user-supplied input data. This section is provided for potential users who wish to obtain the model for independent use.

The model was developed for, and is executed on, the TVA in-house IBM 370 compatible computer system. The current model consists of two FORTRAN programs that are compiled using either the IBM G1 or H extended compiler. The first program, which calculates investment costs, is relatively large; it contains over 10,000 lines of source code. The second program, which calculates revenue requirements, contains about 2,000 lines.

Core storage requirements for the first program are about 300,000 bytes; the use of overlays can reduce this requirement to about 150,000 bytes. The second program executes within 150,000 bytes of core storage with no overlays. In addition to the core storage required for program execution, temporary online storage (disk) is also required for intermediate files and the transfer of data between the two programs. The only input data required for model execution are the user input data; all other data for default assumptions and option-related calculations are assigned the necessary values internally within the program. Temporary online storage requirements depend on the number of cases run but typically do not exceed 200,000 bytes.

The model is executed in both interactive and batch modes. The input data can be provided in three different ways depending on the mode of execution. For batch execution (typically remote batch) the input data variables are punched on cards and inserted in a model execution run deck. The second method of providing data applies to interactive model execution. Input is solicited at the terminal during actual model execution and the user must respond with the appropriate values. The third method is used for both interactive and batch execution. A data file is created interactively (typically using a text editor); all variable values (including the options selected) are examined and corrected if necessary; then the model is executed (either interactively or a batch run is submitted from the interactive terminal) and the input is processed as a standard data file.

The third method of providing input data has been found to be preferable in most cases. When separate but similar model runs are required, the data file containing the input is copied to a second file, variables and options are modified as necessary, and a second model run is submitted. This reduces both input preparation time and the number of input data errors because only the variables and options that differ from a previous run must be modified.

The job control language (JCL) required to execute the model in batch mode is stored in a catalogued procedure file. An example procedure file is shown in Table 27. The catalogued procedure uses a system utility program, IEBGENER, which can be replaced if necessary by a user program to copy from input card data to disk storage and from disk storage to an output print file. The overall procedure consists of four steps to (1) copy the input data to a temporary online storage file (disk), (2) copy the input data to an output print file, (3) execute the first program of the model, and (4) execute the second program. The programs are executed from load modules to avoid recompiling each time they are executed.

The remaining JCL required to execute the model in batch mode is shown in Table 28. If the input data have been prepared on cards, a card deck similar to example one in Table 28 would be submitted with the data cards following the //LOAD.DATA DD * ... card. In example two, the catalogued procedure (Table 27) is executed and the required input is read from a previously created data file. The JCL examples shown in Tables 27 and 28 generally apply whether the job is submitted interactively or with a card deck.

Table 29 shows two example interactive procedures for model execution. Example 1 in Table 29 shows an example procedure for directly entering the data during model execution. Example 2 shows a procedure for interactive execution using a previously created data file.

The amount of computer time required for model execution is a function of the number of cases of input data and the particular computer system. On the TVA system (Amdahl V8 with JES3) the average CPU time required per case is about .5 second but some cases have exceeded 2 seconds.

The model is usually distributed on magnetic tape for independent usage. A fairly wide range of tape format options is available but typically the tape is unlabeled, the density is 1600, the block size is 4,000 characters (50 records, 80 characters per record), and the tape contains two files, one for each program.

TABLE 27. EXAMPLE PROCEDURE FOR EXECUTING THE MODEL IN BATCH MODE

```
//SHAWNEE    PROC   PRTFMS=A
//LOAD       EXEC   PGM=IEBGENER
//SYSPRINT   DD     SYSOUT=A
//SYSIN      DD     DUMMY
//SYSUT1     DD     DDNAME=DATA
//SYSUT2     DD     UNIT=SYSCR, SPACE=(TRK,(1,1),RLSE),DISP=(NEW,PASS),
//                  DCB=(RECFM=FB,LRECL=8Ø,BLKSIZE=4ØØ)
//LIST       EXEC   PGM=IEBGENER
//SYSPRINT   DD     SYSOUT=A
//SYSIN      DD     DUMMY
//SYSUT1     DD     DSN=*.LOAD.SYSUT2,DISP=(OLD,PASS)
//SYSUT2     DD     SYSOUT=&PRTFMS,DCB=(RECFM=F,LRECL=8Ø,BLKSIZE=8Ø)
//INVEST     EXEC   PGM=INV,REGION=400
//STEPLIB    DD     DSN=CHM.SHAWNEE.LOAD,DISP=SHR
//FTØ2FØØ1   DD     UNIT=SYSCR,SPACE=(TRK,(1,1),RLSE),DISP=(NEW,PASS),
//                  DCB=(LRECL=4Ø4,BLKSIZE=4Ø8,RECFM=VBS)
//FTØ3FØØ1   DD     SYSOUT=A
//FTØ5FØØ1   DD     DSN=*.LOAD.SYSUT2,DISP=(OLD,DELETE,DELETE)
//FTØ6FØØ1   DD     SYSOUT=&PRTFMS
//REVENUE    EXEC   PGM=REV,REGION=15ØK,COND=(COND=(Ø,LT,INVEST)
//STEPLIB    DD     DSN=CHM.SHAWNEE.LOAD,DISP=SHR
//FTØ2FØØ1   DD     DSN=*.INVEST.FTØ2FØØ1,DISP=(OLD,DELETE,DELETE)
//FTØ6FØØ1   DD     SYSOUT=&PRTFMS
```

TABLE 28. EXAMPLE BATCH RUN TO EXECUTE THE MODEL USING A PROCEDURE FILE

(Example 1)

```
//TXSHAWNE     JOB 123456,PRGMER.R501CEBM.2513,MSGLEVEL=1,CLASS=K,
//                 NOTIFY=CHM
/*MAIN ORG=RGROUP03
//PROCLIB  DD  DSN=CHM.PROCLIB,DISP=SHR
//SHAWNEE  EXEC SHAWNEE,PRTFMS=A
//LOAD.DATA    DD *        (INPUT DATA CARDS FOLLOW THIS CARD)
//
```

(Example 2)

```
//TXSHAWNE      JOB 123456,PRGMER.R501CEBM.2513,MSGLEVEL=1,CLASS=K,
//                  NOTIFY=CHM
/*MAIN ORG=RGROUP03
//PROCLIB  DD  DSN=CHM.PROCLIB,DISP=SHR
//SHAWNEE  EXEC SHAWNEE,PRTFMS=A
//LOAD.DATA    DD DISP=SHR,DSN=CHM.PART2.DATA
//
```

TABLE 29. SAMPLE PROCEDURE FOR EXECUTING THE MODEL INTERACTIVELY

(Example 1)

```
FREEALL
TERM LINESIZE(132)
FREE FILE (FT02F001,FT03F001,FT05F001,FT06F001)
ALLOC FI(FT02F001)  NEW BLOCK(13030)  SPACE(10,5)
ALLOC FI(FT03F001)  DA(*)
ALLOC FI(FT05F001)  DA(*)
ALLOC FI(FT06F001)  DA(*)
CALL 'CHM.SHAWNEE.LOAD(INV)'
CALL 'CHM.SHAWNEE.LOAD(REV)'
FREEALL
```

(Example 2)

```
FREEALL
TERM LINESIZE(132)
FREE DA('CHM.PART2.DATA')
FREE FILE(FT02F001,FT03F001,FT05F001,FT06F001)
ALLOC FI(FT02F001)  NEW BLOCK(13030)  SPACE(10,5)
ALLOC FI(FT03F001)  DA(*)
ALLOC FI(FT05F001)  DA('CHM.PART2.DATA')
ALLOC FI(FT06F001)  DA(*)
CALL 'CHM.SHAWNEE.LOAD(INV)'
CALL 'CHM.SHAWNEE.LOAD(REV)'
FREEALL
```

REFERENCES

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APPENDIX A

PROCESS FLOWSHEETS AND LAYOUTS

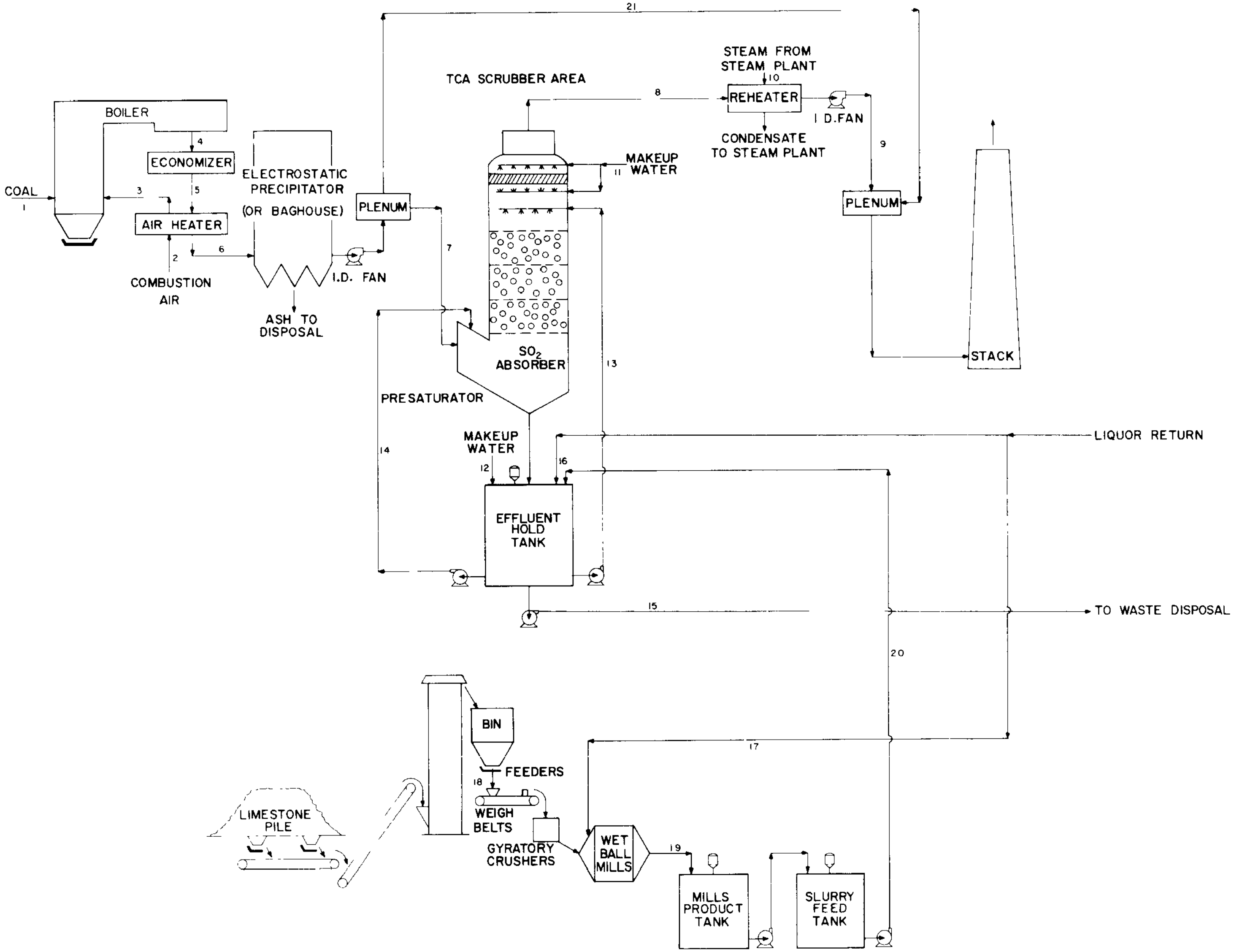


Figure A-1. Limestone scrubbing process utilizing TCA absorber.

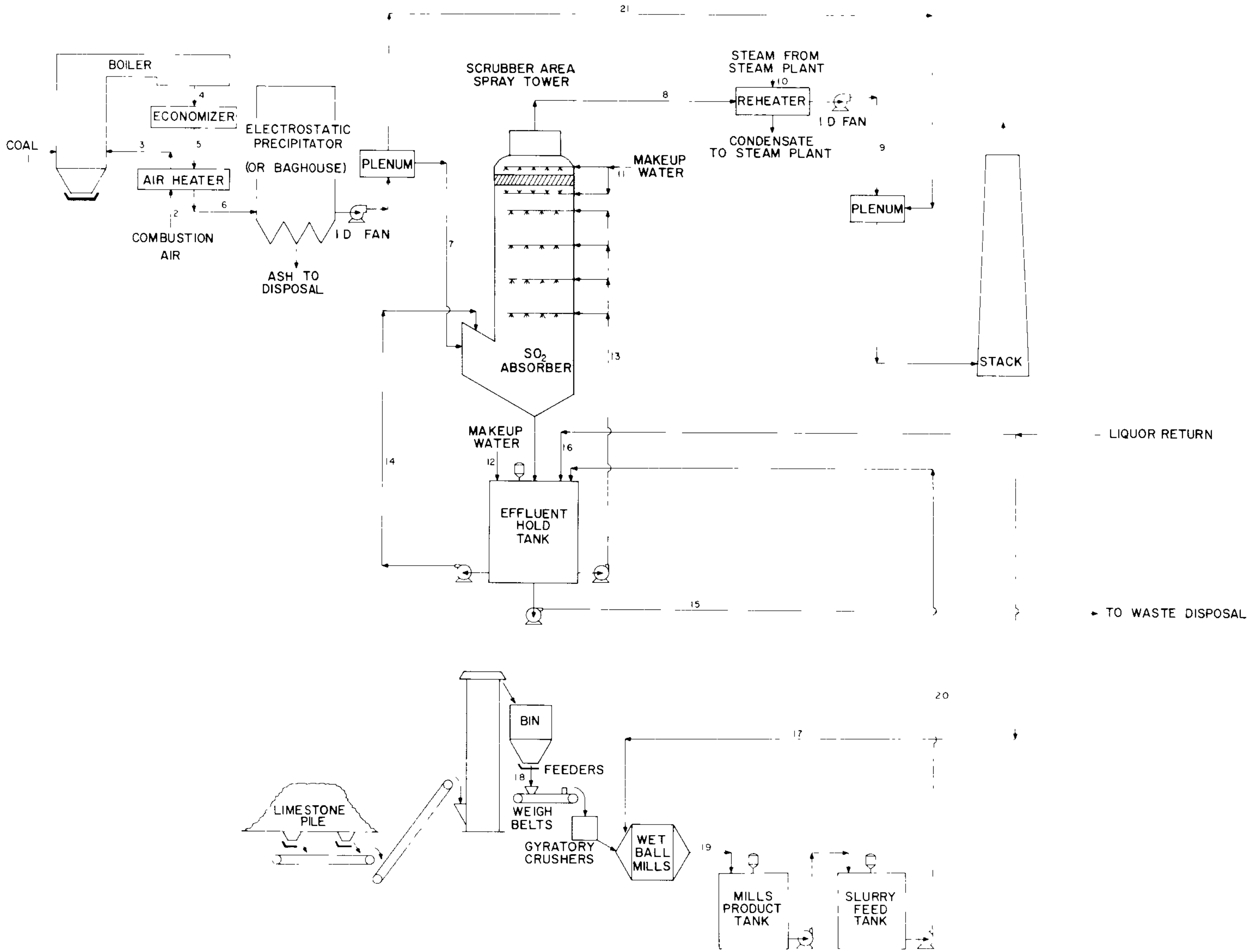


Figure A-2. Limestone scrubbing process utilizing a spray tower.

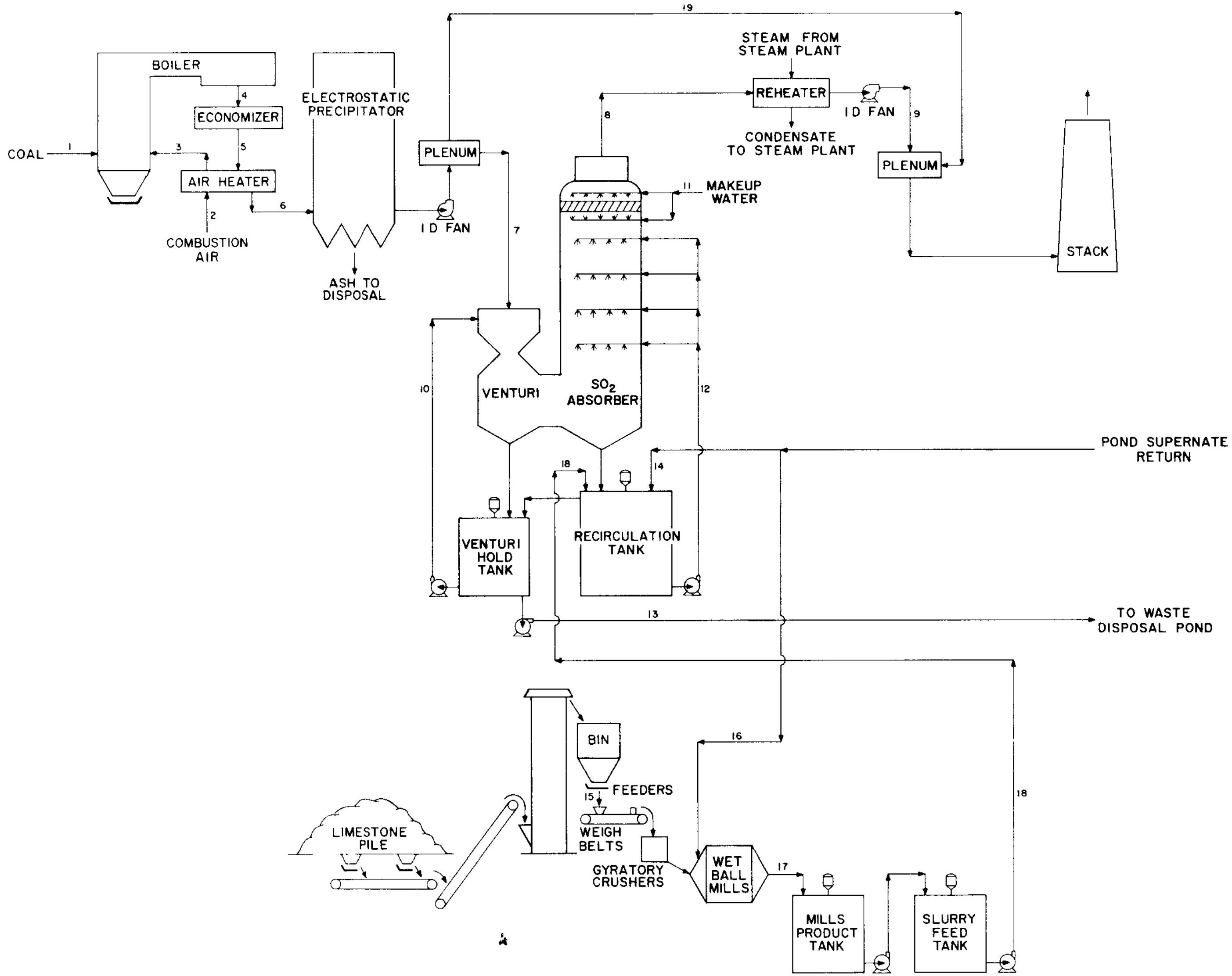


Figure A-3. Limestone scrubbing process utilizing a venturi - spray tower.

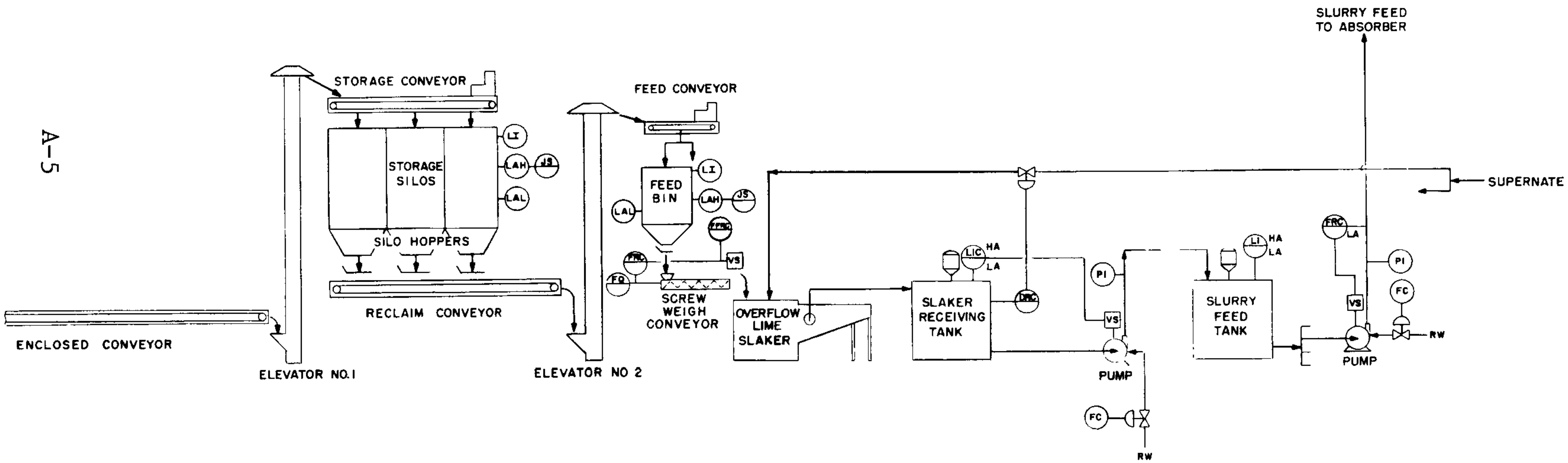


Figure A-4. Lime handling and preparation area for lime scrubbing option.

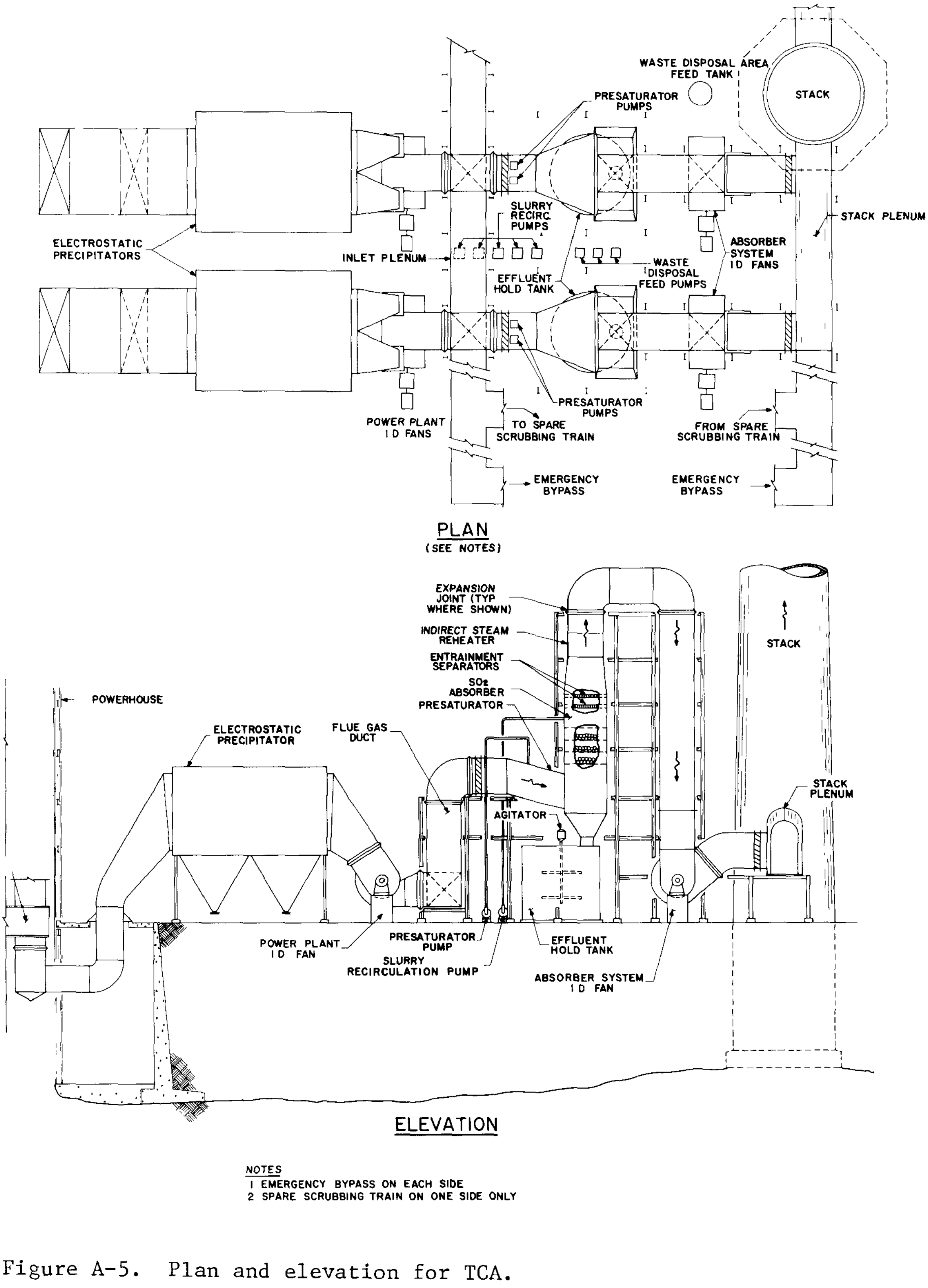


Figure A-5. Plan and elevation for TCA.

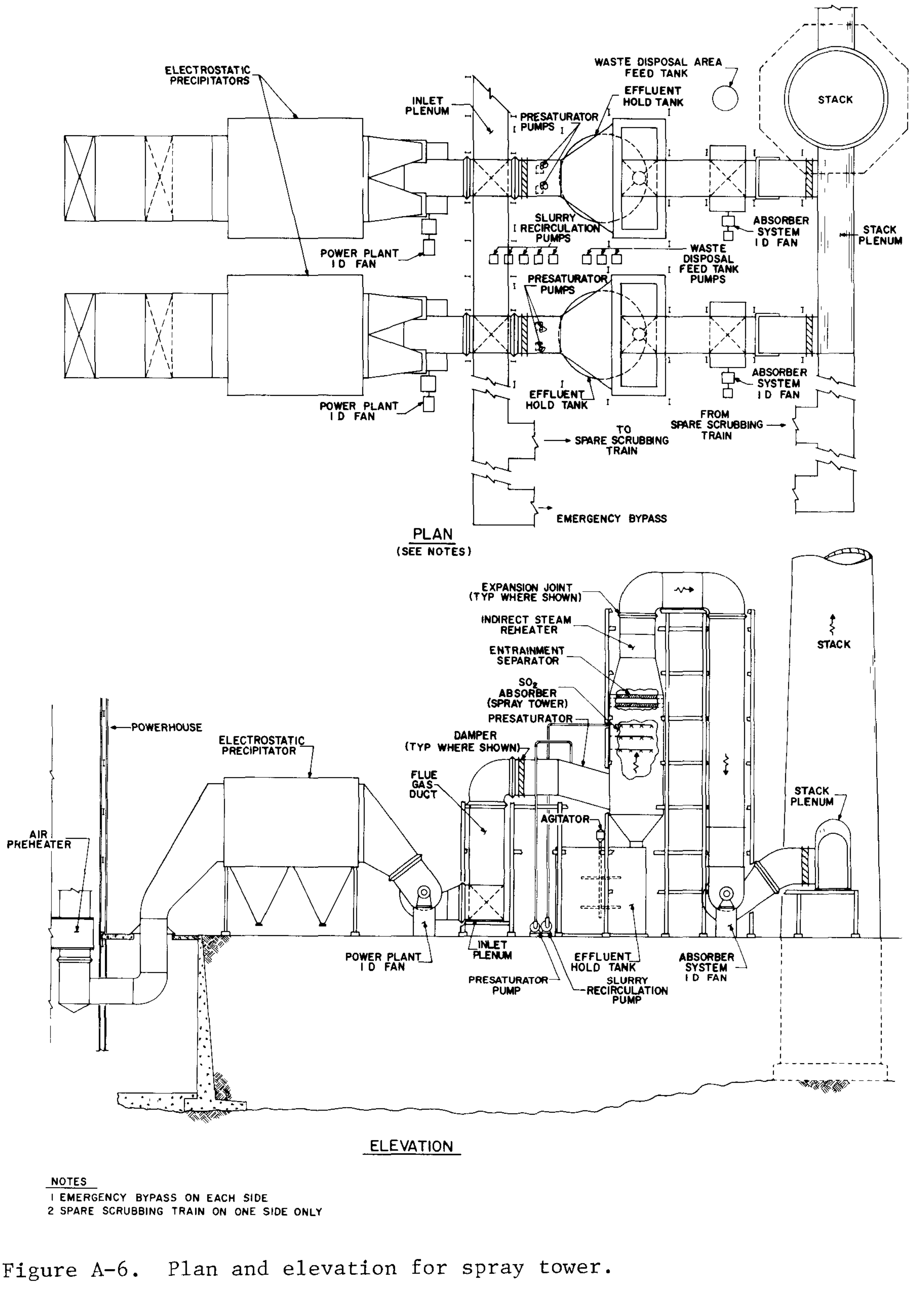


Figure A-6. Plan and elevation for spray tower.

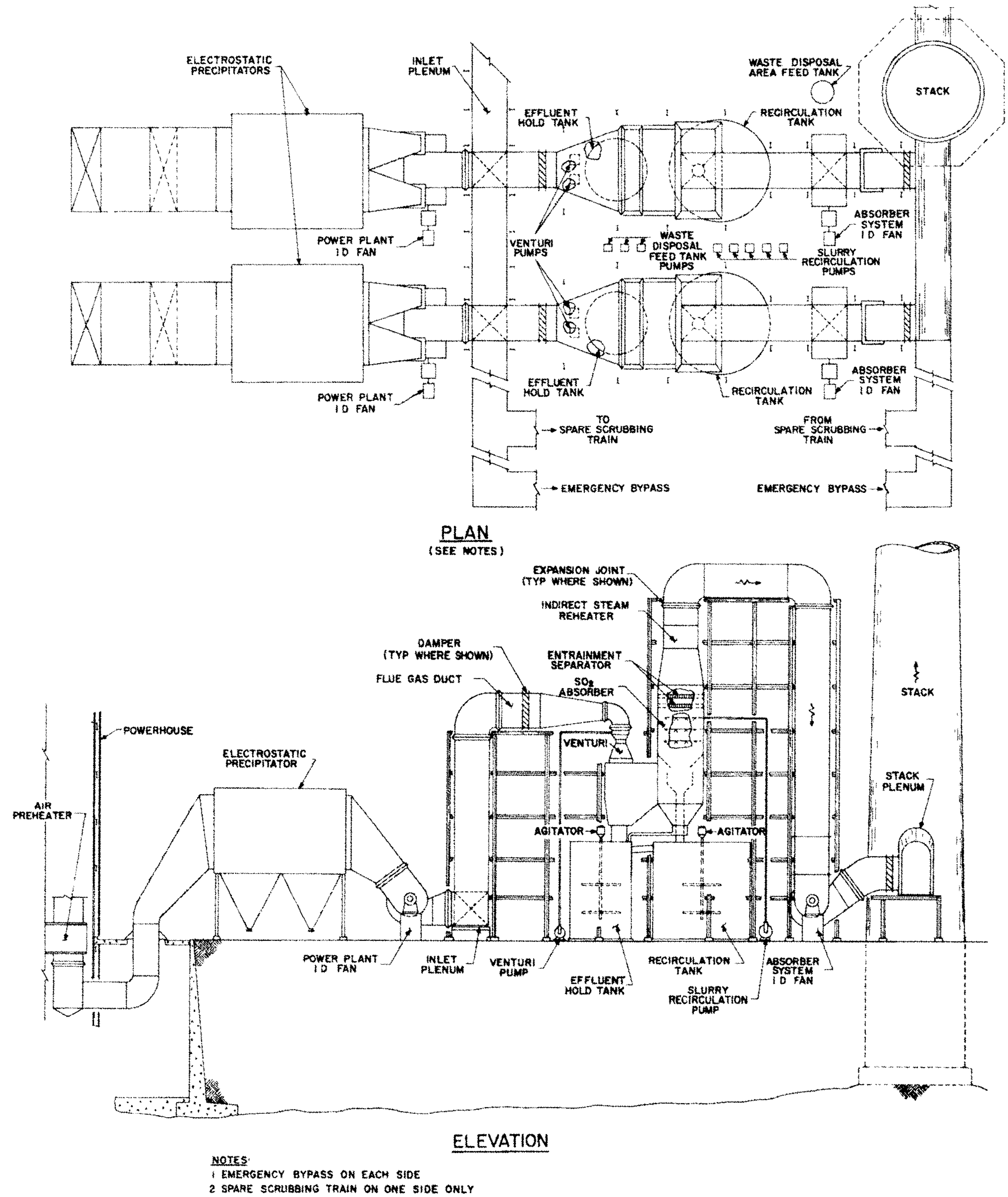
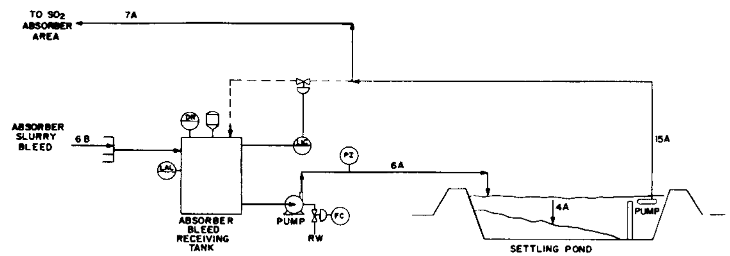
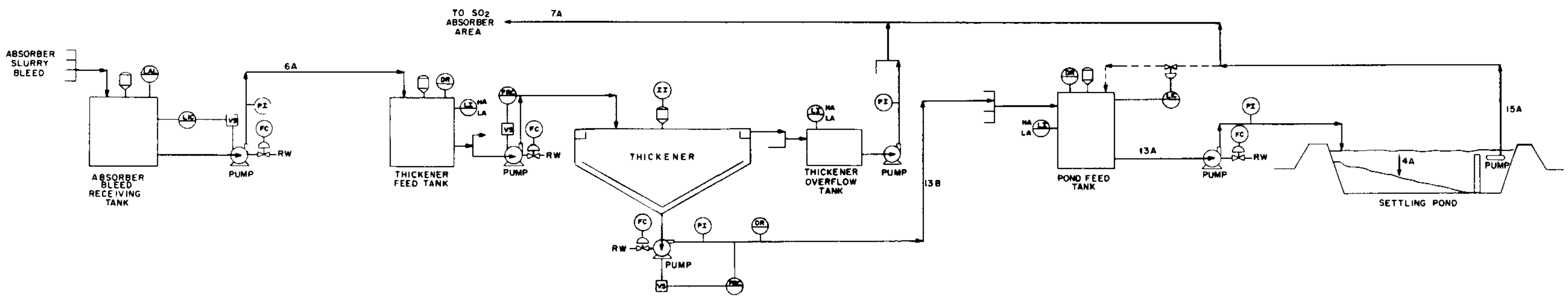


Figure A-7. Plan and elevation for venturi - spray tower.

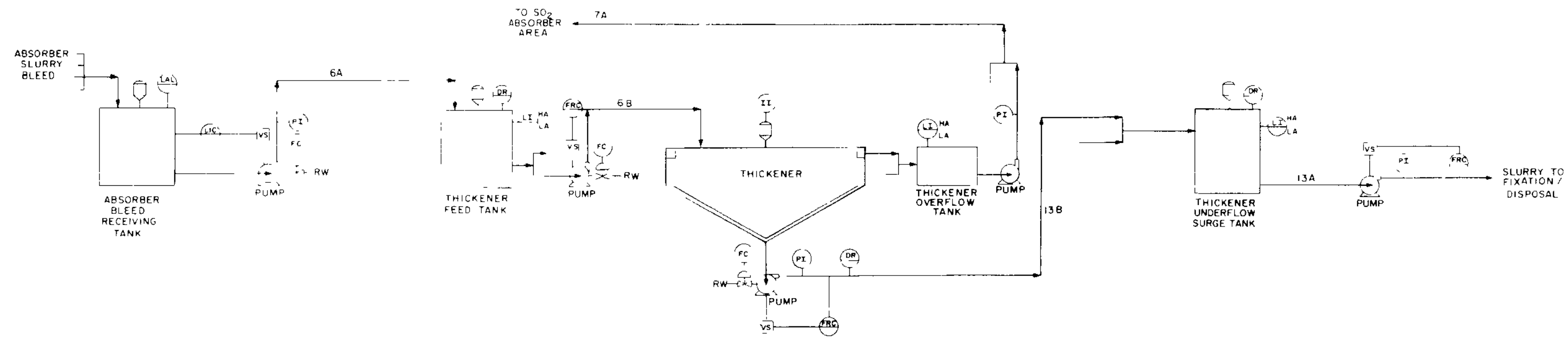


Onsite ponding (Option 1)

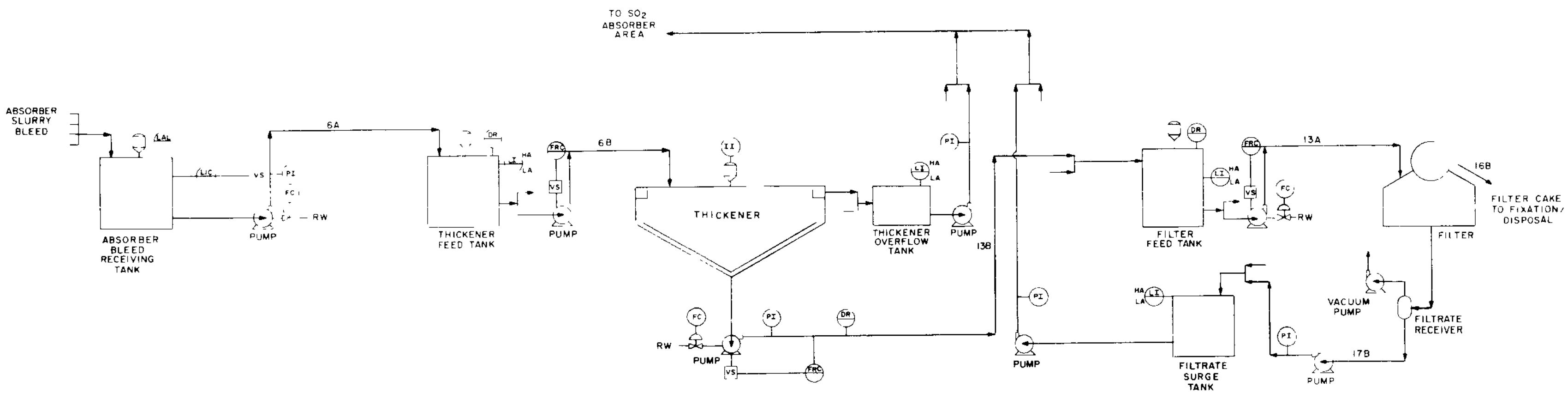


Thickener ponding (Option 2)

Figure A-8. Waste disposal options 1 and 2.



Thickener - Fixation (Option 3)



Thickener - Filter - Fixation (Option 4)

Figure A-9. Waste disposal options 3 and 4.

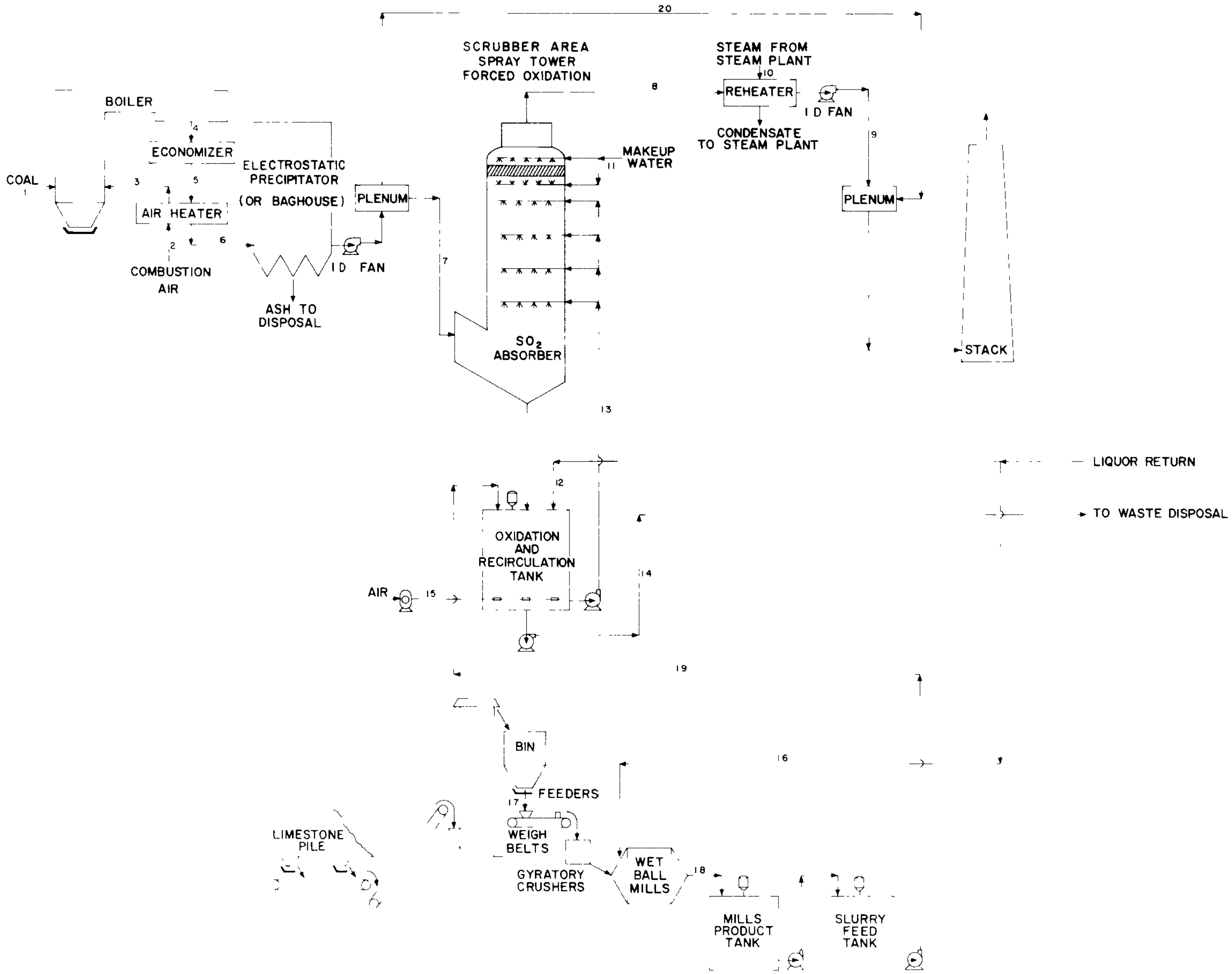


Figure A-10. Single tank oxidation loop.

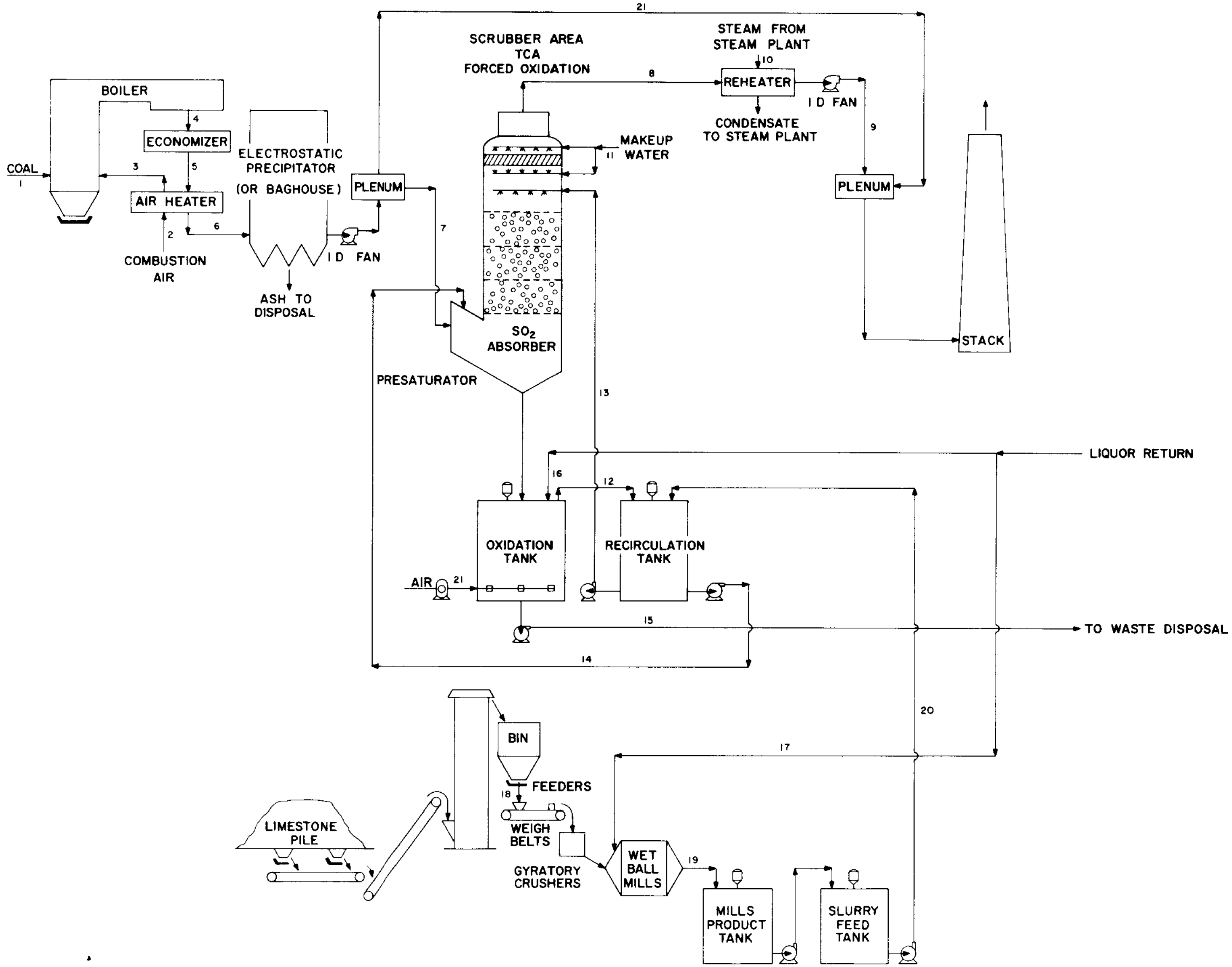


Figure A-11. Double tank oxidation loop.

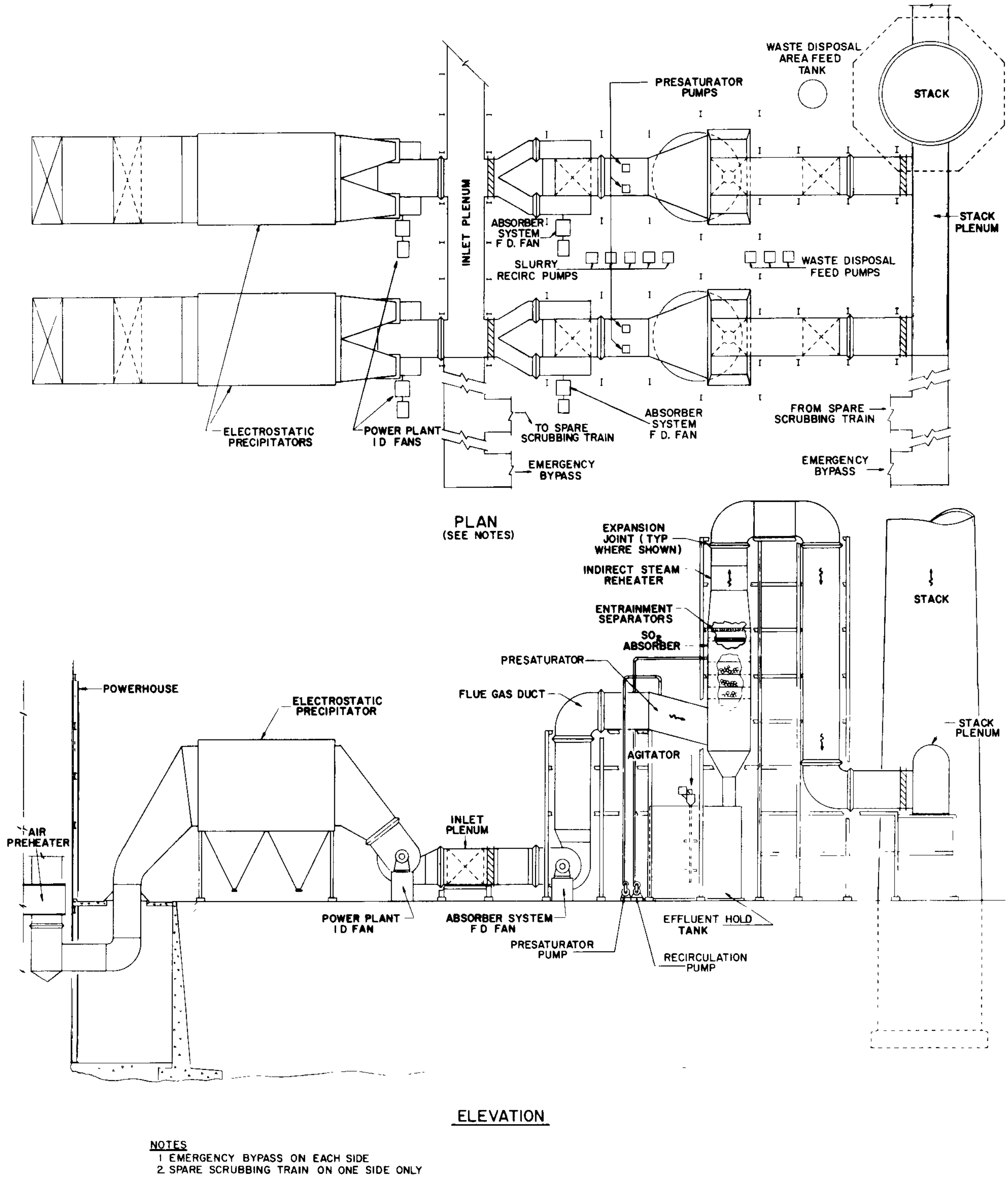


Figure A-12. Plan and elevation for TCA utilizing forced-draft fans.

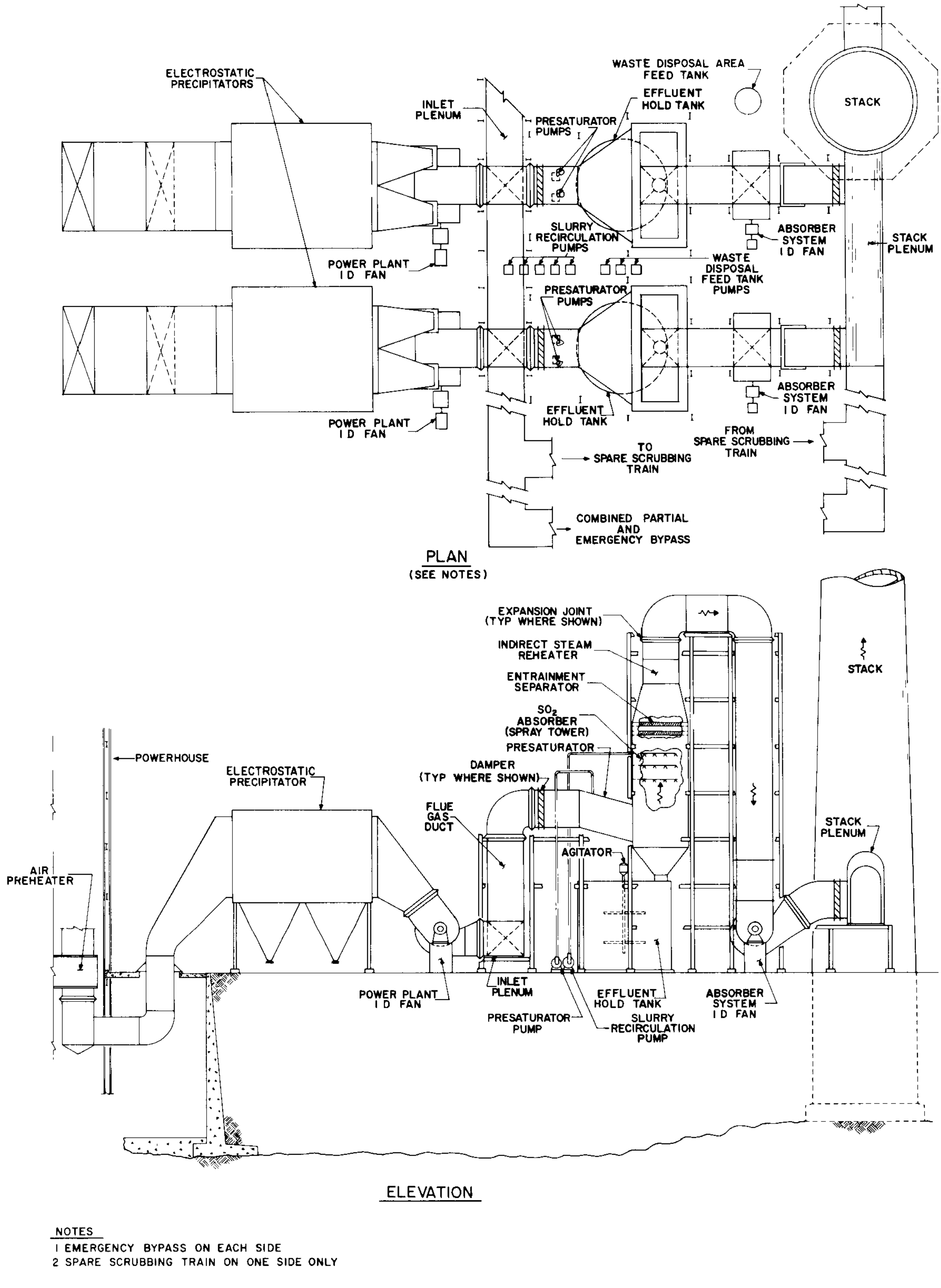


Figure A-13. Plan and elevation for partial scrubbing with bypass duct.

APPENDIX B

DESIGN AND ECONOMIC PREMISES

INTRODUCTION

In December 1979, new design and economic premises for comparative economic evaluations of emission control processes were adopted for emission control studies done by TVA for EPA. These premises were expanded and amplified in March 1980 and applicable portions have been incorporated into the Shawnee model. The economic premises can be selected by the economic premises option, IECON, on line 11 of the model input data. Separate options were established for the design premises to allow them to be selected independently. The old premises used for earlier versions of the model (Tomlinson et al., 1979, and Stephenson and Torstrick, 1979) can still be selected if required. The referenced publications provide complete details on the old economic premises so only a brief overview is presented here.

Separate input options are used to provide for differences between the old and new premises in the calculation of total capital investment except for working capital and contingency. Under the old premises, working capital is calculated as three weeks of raw material costs, seven weeks of direct costs, and seven weeks of overhead costs. Contingency is calculated as a percentage of direct investment. Under the new premises working capital is calculated as one month of raw material costs, one and one-half months of conversion costs, one and one-half months of plant and administrative overhead costs, and three percent of total direct investment to cover spare parts, accounts receivable, and monies on deposit for taxes and accounts payable. Contingency under the new premises is calculated as a percentage of the sum of direct investment, engineering design and supervision, architectural and engineering contractor costs, construction field expenses, and contractor fees. The remaining differences between the old and new premises in the calculation of capital investment are controlled by separate input options and variables. They include separate indirect investment factors for pond construction, sales tax and freight on materials, overtime labor, emergency bypass, inflation, royalties, and a constant lifetime operating profile.

There are also differences between the old and new premises in the calculation of both indirect costs for annual revenue requirements and in lifetime revenue requirements. Under the old premises, indirect costs are based on depreciation, cost of capital and taxes as a percentage of undepreciated investment, insurance and interim replacements as a percentage of total capital investment, plant overhead as a percentage of conversion costs less utilities, and administrative, research, and service overheads as a percentage of operating labor and supervision. Under the new premises, indirect costs are based on plant and administrative overheads as a percentage of conversion costs less utilities, and levelized capital charges as a percentage of total capital investment. For processes that result in a salable byproduct, marketing costs are applied as a percentage of byproduct credit under the new premises.

Lifetime revenue requirements under the old premises are based on annual revenue requirements calculated for each individual year of the projected plant life. A lifetime revenue requirements report is printed showing year-by-year projections. Under the new premises, a levelized operating and maintenance factor is applied to first-year operating and maintenance instead of calculating year-by-year requirements. However, for comparative analysis and flexibility, if a levelizing factor of zero is used in conjunction with the new premises, a year-by-year revenue requirements report based on the lifetime operating profile that is specified can still be generated.

Example output from the model illustrating the differences between the old and new premises are shown in the model description section and in the base case printout in Appendix D. Additional comparisons between the old and new premises that illustrate the individual effects of the changes are described in a paper presented at the 1980 EPA FGD symposium (McGlamery et al., 1980). The descriptions of the individual input options in the model description section provide additional information. However, the references cited previously for the old premises and the remainder of this appendix for the new premises must be used for comprehensive details and background information. The same cost indexes and projections are used for both the old and new premises. It should be noted that the new premises that follow contain specifications beyond the scope of the model.

DESIGN AND ECONOMIC PREMISES EFFECTIVE DECEMBER 1979

INTRODUCTION

These premises provide criteria for comparative economic evaluations of emission control processes for electric utility coal-fired power plants. The design premises define representative coal and power unit conditions and standard design practices for emission control systems. The economic premises are based on regulated utility economics. They prescribe procedures for determining capital investment and annual revenue requirements. The premises are directly applicable to economic evaluations of coal cleaning, flue gas desulfurization (FGD), nitrogen oxides (NO_x) emission control, waste disposal, and particulate matter emission control.

The economic evaluations are always based on a conceptual design developed from the design premises and engineering data such as flow diagrams, material balances, and equipment costs. Depending on the specified degree of accuracy of the cost estimate, some costs are either scaled or developed from detailed design and operating data.

Normally a base-case new 500-MW power unit burning 3.5% sulfur, 16% ash bituminous coal, and complying with 1979 new source performance standards (NSPS) (1) is used as the basis of comparison. Case variations are developed as necessary to illustrate their effects on the economics of the processes evaluated. For FGD evaluations a limestone scrubbing process using a spray tower, forced oxidation, and gypsum landfill disposal serves as the standard of comparison.

The current premises are based on 1982 costs for capital investment and 1984 costs for annual revenue requirements. These and other premise criteria are updated as necessary. Established criteria are not usually revised on a piecemeal basis, however, as this would complicate their use and reduce the comparability and applicability of evaluations made over a period of time. All necessary premise changes are made at one time, usually every one to three years.

DESIGN PREMISES

Coal Premises

The premise coals consist of four eastern bituminous coals containing 5.0%, 3.5%, 2.0%, and 0.7% sulfur; a 0.7% sulfur western bituminous coal; a 0.7% sulfur western subbituminous coal; and a 0.9% sulfur North

Dakota lignite. They are based on analyses of U.S. steam coals representative of the types in current use (2,3). The analysis data for each of these coals are summarized in Table B-1 and a fly ash analysis for each coal is shown in Table B-2.

TABLE B-2. FLY ASH COMPOSITIONS

Component	Bituminous fly ash, wt %	Subbituminous fly ash, wt %	Lignite fly ash, wt %
SiO_2	50.8	39.7	23.0
Al_2O_3	20.6	21.5	11.5
TiO_2	2.5	1.1	0.5
Fe_2O_3	16.9	7.4	8.6
CaO	2.0	20.0	21.6
MgO	1.0	4.7	6.0
Na_2O	0.4	1.7	5.9
K_2O	2.6	0.5	0.5
SO_3	2.4	2.3	19.2
P_2O_5	-	1.0	0.4
Other	0.8	0.1	2.8
Total	100.0	100.0	100.0

As-fired coal refers to the coal entering the coal-cleaning plant or power plant. This coal is supplied in a 3-inch top size after large rocks and trash have been removed from the run-of-mine coal. Broken coal is assumed to have the particle size distributions represented by the Bennett form of the Rosin and Rammler equation,

$$R = 100e^{-(x/\bar{x})^n}$$

which can be plotted on special graph paper devised by the U.S. Bureau of Mines (4) as shown in Figure B-1. In the equation,

x = particle diameter or width of screen aperture in millimeters. It is the abscissa in Figure B-1.

$\bar{x}$ = a size constant, in millimeters, that is specific to each distribution line of particle size. In Figure B-1, it is the value of x when R = 36.79%; in turn R = 36.79% when $\bar{x}$ = x in the Rosin and Rammler equation.

n = a size distribution constant. In Figure B-1, it is the arithmetical slope of a distribution line. Parallel distribution lines have the same value of n.

TABLE B-1. COMPOSITION OF PREMISE COALS

(As-Fired Basis)

Coal	Sulfur: Total, %	Sulfur: Pyritic, %	Sulfur: Sulfatic, %	Sulfur: Organic, %	Ash, %	Moisture, %	Heat content, Btu/lb	Ultimate analysis: C, %	H, %	O, %	N, %	Cl, %
Eastern bituminous, 5.0% S	4.80	3.17	0.05	1.58	15.10	4.0	11,700	65.2	4.0	5.5	1.3	0.1
Eastern bituminous, 3.5% S	3.36	2.21	0.05	1.10	15.14	4.0	11,700	66.7	3.8	5.6	1.3	0.1
Eastern bituminous, 2.0% S	1.92	1.25	0.04	0.63	15.08	4.0	11,700	67.8	3.7	6.0	1.4	0.1
Eastern bituminous, 0.7% S	0.67	0.44	0.01	0.22	15.13	4.0	11,700	68.8	3.6	6.3	1.4	0.1
Western bituminous, 0.7% S	0.59	0.20	0.01	0.38	9.71	16.0	9,700	57.0	3.9	11.5	1.2	0.1
Western subbituminous, 0.7% S (Powder River Basin)	0.48	0.16	0.01	0.31	6.30	29.3	8,200	49.0	3.5	10.7	0.7	0.02
North Dakota lignite, 0.9% S	0.57	0.19	0.01	0.37	7.22	36.3	6,600	40.1	2.8	12.4	0.6	0.01

(Moisture-Free Basis)

Coal	Sulfur: Total, %	Sulfur: Pyritic, %	Sulfur: Sulfatic, %	Sulfur: Organic, %	Ash, %	Moisture, %	Heat content, Btu/lb	Ultimate analysis: C, %	H, %	O, %	N, %	Cl, %
Eastern bituminous, 5.0% S	5.00	3.30	0.05	1.65	15.7			67.9	4.2	5.7	1.4	0.1
Eastern bituminous, 3.5% S	3.50	2.30	0.05	1.15	15.7			69.5	4.0	5.8	1.4	0.1
Eastern bituminous, 2.0% S	2.00	1.31	0.04	0.65	15.7			70.6	3.9	6.3	1.4	0.1
Eastern bituminous, 0.7% S	0.70	0.46	0.01	0.23	15.7			71.7	3.8	6.6	1.4	0.1
Western bituminous, 0.7% S	0.70	0.24	0.01	0.45	11.6			67.9	4.6	13.7	1.4	0.1
Western subbituminous, 0.7% S (Powder River Basin)	0.68	0.23	0.01	0.44	8.9			69.3	5.0	15.1	1.0	0.02
North Dakota lignite, 0.9% S	0.89	0.30	0.01	0.58	11.3			63.0	4.4	19.5	0.9	0.01

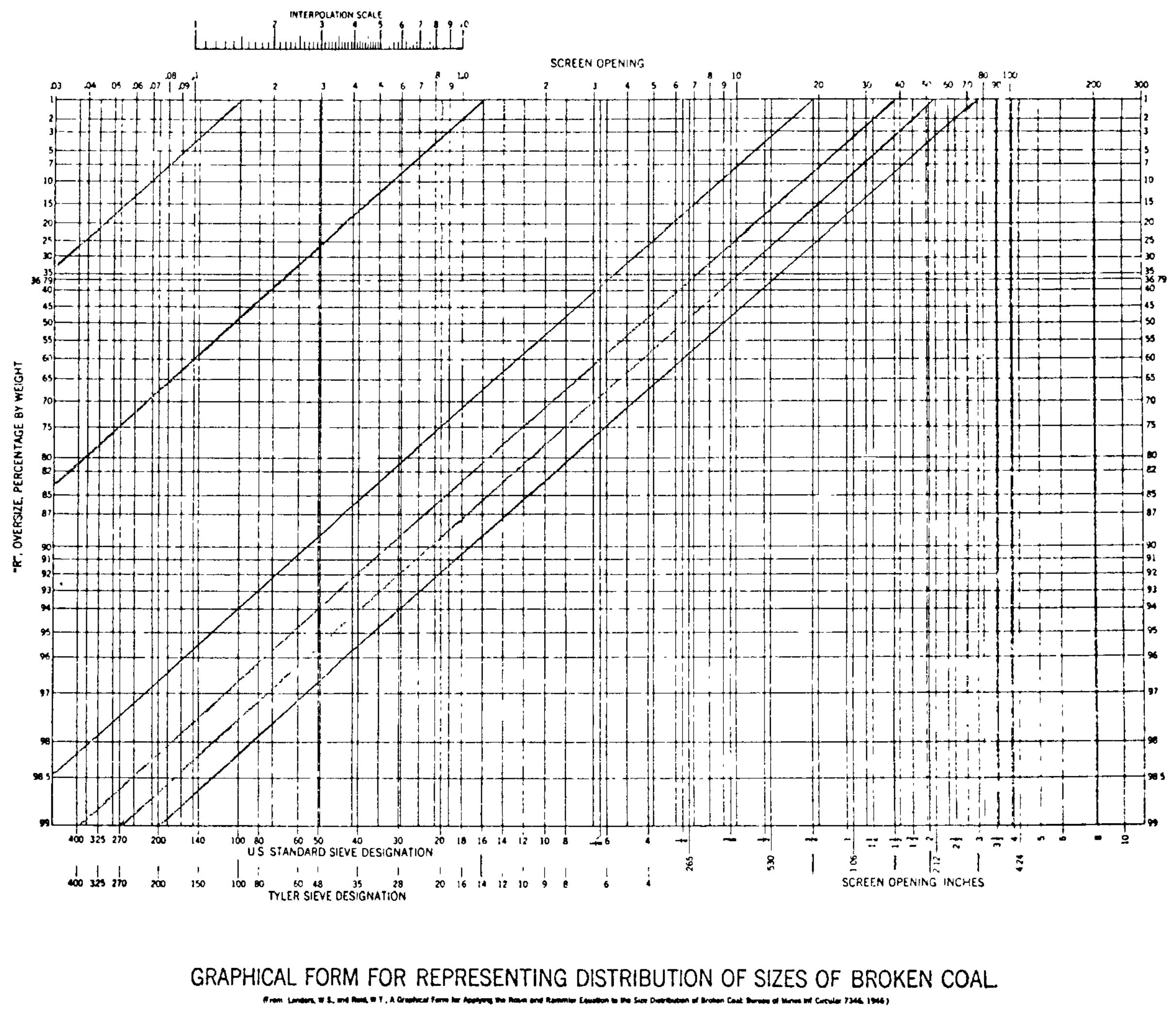


Figure B-1. Rosin-Rammler plots of premise coal sizes.

e = the base of the natural logarithm.

R = the weight percentage of coal retained on a screen whose aperture is x. R expresses cumulative oversize and is the ordinate in Figure B-1.

For all distribution lines in Figure B-1, the value of n is 0.8840. Values of $\bar{x}$ for selected size distributions are given below.

Nominal top sizes	Actual aperture size (Tyler $\sqrt{2}$ Series) in.	mm	$\bar{x}$ mm
3 in.	2.970	75.43	13.40
2 in.	2.100	53.34	9.478
1-1/2 in.	1.485	37.71	6.702
3/4 in.	0.742	18.86	3.351
3/8 in.	0.371	9.429	1.676
3 mesh	0.093	2.357	0.4189
14 mesh	0.046	1.179	0.2094
28 mesh	0.023	0.589	0.1047

Power Plant

The power plant site is assumed to be in the north-central region (Illinois, Indiana, Ohio, Michigan, Kentucky, and Wisconsin). The location represents an area in which coal-fired power plants burning coals of diverse type and source are situated (5,6). The design is based on standard design practices (7,8) and current trends in utility boiler construction (9,10). The base-case power unit is a new, single 500-MW, balanced-draft, horizontally fired, dry-bottom boiler burning pulverized coal. The steam pressure is 2,400 psi. The superheat and reheat temperatures are 1,000°F.

Power unit size case variations consist of similar 200-MW and 1,000-MW units. For new units the systems being evaluated are assumed to be installed during construction of the power plant. New units are assumed to have a 30-year life and to operate at full load for 5,500 hours a year. For case variations, identical existing units with 20 years of remaining life at 5,500 hours/year of full-load operation are used. Heat rates are based on coal type, unit size, and unit age. Power plant heat rates are shown in Table B-3. To provide for equitable comparisons, the power units are not derated for energy consumption by the systems evaluated. Instead the energy requirements are charged as independently purchased commodities. Normally cost estimates are based on a single power unit independent of other units at the site. In cases in which a plant-wide process or system is evaluated, a plant capacity of 2,000 MW is used.

TABLE B-3. POWER UNIT REMAINING LIFE, OPERATING TIME, AND HEAT RATE

	New			Existing		
Power unit size, MW:	200	500	1,000	200	500	1,000
Remaining life, years	30	30	30	20	20	20
Full load, hr/yr	5,500	5,500	5,500	5,500	5,500	5,500
Heat rate, Btu/kWh						
Bituminous coal	9,700	9,500	9,200	9,900	9,700	9,500
Subbituminous coal	10,700	10,500	10,200	11,000	10,700	10,500
Lignite	11,200	11,000	10,700	11,400	11,200	11,000

Flue Gas Compositions

Flue gas compositions are based on combustion of pulverized coal assuming a total air rate equivalent to 139% of the stoichiometric requirement (defined as air for combustion of carbon, hydrogen, and sulfur). This includes 20% excess air to the boiler and 19% additional air leakage to the flue gas in the air heater. It is assumed that 80% of the ash present in all coals is emitted as fly ash. Sulfur emitted as SO_x is dependent on the coal type; 92% of the sulfur in all eastern coals and 85% of the sulfur in all western coals and lignite is emitted as SO_x. The remaining sulfur is removed in the bottom ash and fly ash. No loss of sulfur in the pulverizers is assumed. Three percent of the sulfur emitted as SO_x is SO_3 and the remainder is SO_2.

A flow diagram around the boiler is shown in Figure B-2 and detailed boiler material balances and flue gas composition summaries for stream 8, for each premise coal, are shown in Tables B-4 through B-17. The streams shown in the material balances have excess significant digits for cases in which higher accuracy is needed. All streams balance to a net of ±10 lb/hr. These numbers are not to be published without rounding to four significant digits, no more - no less.

Environmental Regulations

Emissions from new coal-fired utility plants are regulated by the new source performance standards, which are issued under authority of Section 111 of the Clean Air Act as amended in 1970 and 1977. This section requires the Environmental Protection Agency (EPA) to set Federal emission limitations which reflect the degree of control that can be achieved by using the best available control technology (BACT). On December 23, 1971, EPA issued NSPS to limit emissions of SO_2, NO_x, and particulate matter from utility power plants (11). In 1979 EPA chose to revise the NSPS (1) which are shown in Table B-18. The controlled outlet SO_2 emission and SO_2 removal efficiencies for premise coals are shown in Figure B-3 and tabulated in Table B-19.

TABLE B-4. BOILER MATERIAL BALANCE

EASTERN BITUMINOUS COAL, 5% SULFUR

	Stream No.	1	2	3
	Description	Coal to boiler	Total air to air heater	Combustion air to boiler
1	Total stream, lb/hr	405,983	5,047,807	4,357,819
2	Flow rate, sft^3/min @ 60^oF		1,115,166	962,733
3	Temperature, ^oF		80	
4	N_2 (C) lb/hr	(264,701)	3,829,456	3,306,006
5	O_2 (H) lb/hr	(16,239)	1,153,571	995,888
6	CO_2 (O) lb/hr	(22,329)		
7	SO_2 (N) lb/hr	(5,278)		
8	SO_3 (Cl) lb/hr	(406)		
9	NO (S) lb/hr	(19,487)		
10	NO_2 lb/hr			
11	HCl lb/hr			
12	H_2O lb/hr	16,239	64,799	55,925
13	Ash lb/hr	61,303		

	Stream No.	4	5	6
	Description	Bottom ash	Gas to economizer	Gas to air heater
1	Total stream, lb/hr	12,572	4,751,230	4,751,230
2	Flow rate, sft^3/min @ 60^oF		999,502	999,502
3	Temperature, ^oF			
4	N_2 (C) lb/hr		3,310,415	3,310,415
5	O_2 (H) lb/hr		164,941	164,941
6	CO_2 (O) lb/hr		969,982	969,982
7	SO_2 (N) lb/hr		34,748	34,748
8	SO_3 (Cl) lb/hr		1,343	1,343
9	NO (S) lb/hr		1,766	1,766
10	NO_2 lb/hr		142	142
11	HCl lb/hr		418	418
12	H_2O lb/hr		217,184	217,184
13	Ash lb/hr	12,572	50,291	50,291

	Stream No.	7	8	
	Description	Air inleakage	Gas to electrostatic precipitator	
1	Total stream, lb/hr	689,988	5,441,218	
2	Flow rate, sft^3/min @ 60^oF	152,433	1,151,935	
3	Temperature, ^oF			
4	N_2 (C) lb/hr	523,451	3,833,866	
5	O_2 (H) lb/hr	157,682	322,623	
6	CO_2 (O) lb/hr		969,982	
7	SO_2 (N) lb/hr		34,748	
8	SO_3 (Cl) lb/hr		1,343	
9	NO (S) lb/hr		1,766	
10	NO_2 lb/hr		142	
11	HCl lb/hr		418	
12	H_2O lb/hr	8,855	226,039	
13	Ash lb/hr		50,291	

TABLE B-5. FLUE GAS COMPOSITION

FOR 5% SULFUR EASTERN BITUMINOUS COAL

(Stream 8; gas to electrostatic precipitator)

Component	Volume, %	Lb-mol/hr	Lb/hr
N_2	75.13	136,900	3,834,000
O_2	5.53	10,080	322,600
CO_2	12.10	22,040	970,000
SO_2	0.30 (2,976 ppm)	542	34,750
SO_3	0.01 (93 ppm)	17	1,343
NO	0.03 (324 ppm)	59	1,766
NO_2	0.00 (16 ppm)	3	142
HCl	0.01 (66 ppm)	12	418
H_2O	6.89	12,550	226,000
	100.00	182,200	5,391,000
Fly ash[a]			50,290
Total			5,441,000

Sft^3/min (60°F) = 1,152,000
Aft^3/min (300°F) = 1,684,000

Fly Ash Loading

	Gr/sft^3
Wet	5.09
Dry	5.47

Sulfuric acid dew point temperature: 316°F

a. See Table B-2 for fly ash composition.

TABLE B-6. BOILER MATERIAL BALANCE

EASTERN BITUMINOUS COAL, 3.5% SULFUR

	Stream No.		1	2	3
	Description		Coal to boiler	Total air to air heater	Combustion air to boiler
1	Total stream, lb/hr		405,983	5,071,690	4,378,438
2	Flow rate, sft^3/min @ 60°F			1,120,442	967,288
3	Temperature, °F			80	
4	N_2 (C)	lb/hr	(270,791)	3,847,575	3,321,648
5	O_2 (H)	lb/hr	(15,427)	1,159,029	1,000,601
6	CO_2 (O)	lb/hr	(22,735)		
7	SO_2 (N)	lb/hr	(5,278)		
8	SO_3 (Cl)	lb/hr	(406)		
9	NO (S)	lb/hr	(13,641)		
10	NO_2	lb/hr			
11	HCl	lb/hr			
12	H_2O	lb/hr	16,239	65,086	56,189
13	Ash	lb/hr	61,466		

	Stream No.		4	5	6
	Description		Bottom ash	Gas to economizer	Gas to air heater
1	Total stream, lb/hr		12,511	4,771,910	4,771,910
2	Flow rate, sft^3/min @ 60°F			1,002,880	1,002,880
3	Temperature, °F				
4	N_2 (C)	lb/hr		3,326,058	3,326,058
5	O_2 (H)	lb/hr		165,726	165,726
6	CO_2 (O)	lb/hr		992,298	992,298
7	SO_2 (N)	lb/hr		24,324	24,324
8	SO_3 (Cl)	lb/hr		940	940
9	NO (S)	lb/hr		1,766	1,766
10	NO_2	lb/hr		142	142
11	HCl	lb/hr		418	418
12	H_2O	lb/hr		210,192	210,192
13	Ash	lb/hr	12,511	50,046	50,046

	Stream No.		7	8	
	Description		Air inleakage	Gas to electrostatic precipitator	
1	Total stream, lb/hr		693,252	5,465,162	
2	Flow rate, sft^3/min @ 60°F		153,154	1,156,034	
3	Temperature, °F				
4	N_2 (C)	lb/hr	525,927	3,851,985	
5	O_2 (H)	lb/hr	158,428	324,154	
6	CO_2 (O)	lb/hr		992,298	
7	SO_2 (N)	lb/hr		24,324	
8	SO_3 (Cl)	lb/hr		940	
9	NO (S)	lb/hr		1,766	
10	NO_2	lb/hr		142	
11	HCl	lb/hr		418	
12	H_2O	lb/hr	8,879	219,089	
13	Ash	lb/hr		50,046	

TABLE B-7. FLUE GAS COMPOSITION

FOR 3.5% SULFUR EASTERN BITUMINOUS COAL

(Stream 8; gas to electrostatic precipitator)

Component	Volume, %	Lb-mol/hr	Lb/hr
N_2	75.22	137,500	3,852,000
O_2	5.54	10,130	324,200
CO_2	12.33	22,550	992,300
SO_2	0.21 (2,079 ppm)	380	24,320
SO_3	0.01 (66 ppm)	12	940
NO	0.03 (323 ppm)	59	1,766
NO_2	0.00 (16 ppm)	3	142
HCl	0.01 (66 ppm)	12	418
H_2O	6.65	12,160	219,100
	100.00	182,800	5,415,000
Fly ash[a]			50,050
Total			5,465,000

Sft^3/min (60°F) = 1,156,000
Aft^3/min (300°F) = 1,690,000

Fly Ash Loading

	Gr/sft^3
Wet	5.05
Dry	5.41

Sulfuric acid dew point temperature: 308°F

a. See Table B-2 for fly ash composition.

TABLE B-8. BOILER MATERIAL BALANCE

EASTERN BITUMINOUS COAL, 2.0% SULFUR

	Stream No.	1	2	3
	Description	Coal to boiler	Total air to air heater	Combustion air to boiler
1	Total stream, lb/hr	405,983	5,081,446	4,386,860
2	Flow rate, sft^3/min @ 60°F		1,122,597	969,149
3	Temperature, °F		80	
4	N_2 (C) lb/hr	(275,256)	3,854,977	3,328,038
5	O_2 (H) lb/hr	(15,021)	1,161,258	1,002,525
6	CO_2 (O) lb/hr	(24,359)		
7	SO_2 (N) lb/hr	(5,684)		
8	SO_3 (Cl) lb/hr	(406)		
9	NO (S) lb/hr	(7,795)		
10	NO_2 lb/hr			
11	HCl lb/hr			
12	H_2O lb/hr	16,239	65,211	56,297
13	Ash lb/hr	61,223		

	Stream No.	4	5	6
	Description	Bottom ash	Gas to economizer	Gas to air heater
1	Total stream, lb/hr	12,369	4,780,474	4,780,474
2	Flow rate, sft^3/min @ 60°F		1,004,532	1,004,532
3	Temperature, °F		800	705
4	N_2 (C) lb/hr		3,332,854	3,332,854
5	O_2 (H) lb/hr		166,047	166,047
6	CO_2 (O) lb/hr		1,008,662	1,008,662
7	SO_2 (N) lb/hr		13,899	13,899
8	SO_3 (Cl) lb/hr		537	537
9	NO (S) lb/hr		1,766	1,766
10	NO_2 lb/hr		142	142
11	HCl lb/hr		418	418
12	H_2O lb/hr		206,672	206,672
13	Ash lb/hr	12,369	49,477	49,477

	Stream No.	7	8	
	Description	Air inleakage	Gas to electrostatic precipitator	
1	Total stream, lb/hr	694,586	5,475,060	
2	Flow rate, sft^3/min @ 60°F	153,449	1,157,981	
3	Temperature, °F	535	300	
4	N_2 (C) lb/hr	526,939	3,859,793	
5	O_2 (H) lb/hr	158,733	324,780	
6	CO_2 (O) lb/hr		1,008,662	
7	SO_2 (N) lb/hr		13,899	
8	SO_3 (Cl) lb/hr		537	
9	NO (S) lb/hr		1,766	
10	NO_2 lb/hr		142	
11	HCl lb/hr		418	
12	H_2O lb/hr	8,914	215,586	
13	Ash lb/hr		49,477	

TABLE B-9. FLUE GAS COMPOSITION

FOR 2% SULFUR EASTERN BITUMINOUS COAL

(Stream 8; gas to electrostatic precipitator)

Component	Volume, %		Lb-mol/hr	Lb/hr
N_2	75.24		137,800	3,860,000
O_2	5.54		10,100	324,800
CO_2	12.52		22,920	1,009,000
SO_2	0.12	(1,185 ppm)	217	13,900
SO_3	0.00	(38 ppm)	7	537
NO	0.03	(322 ppm)	59	1,766
NO_2	0.00	(16 ppm)	3	142
HCl	0.01	(66 ppm)	12	418
H_2O	6.54		11,970	215,600
	100.00		183,100	5,426,000
Fly ash[a]				49,480
Total				5,475,000

Sft^3/min (60°F) = 1,158,000
Aft^3/min (300°F) = 1,692,000

Fly Ash Loading

	Gr/sft^3
Wet	4.98
Dry	5.33

Sulfuric acid dew point temperature: 297°F

a. See Table B-2 for fly ash composition.

TABLE B-10. BOILER MATERIAL BALANCE

EASTERN BITUMINOUS COAL, 0.7% SULFUR

	Stream No.	1	2	3
	Description	Coal to boiler	Total air to air heater	Combustion air to boiler
1	Total stream, lb/hr	405,983	5,091,465	4,395,510
2	Flow rate, sft^3/min @ 60^oF		1,124,811	971,060
3	Temperature, ^oF		80	
4	N_2 (C) lb/hr	(279,316)	3,862,577	3,334,599
5	O_2 (H) lb/hr	(14,616)	1,163,548	1,004,502
6	CO_2 (O) lb/hr	(25,577)		
7	SO_2 (N) lb/hr	(5,684)		
8	SO_3 (Cl) lb/hr	(406)		
9	NO (S) lb/hr	(2,720)		
10	NO_2 lb/hr			
11	HCl lb/hr			
12	H_2O lb/hr	16,239	65,340	56,409
13	Ash lb/hr	61,425		

	Stream No.	4	5	6
	Description	Bottom ash	Gas to economizer	Gas to air heater
1	Total stream, lb/hr	12,329	4,789,164	4,789,164
2	Flow rate, sft^3/min @ 60^oF		1,006,060	1,006,060
3	Temperature, ^oF		800	705
4	N_2 (C) lb/hr		3,339,415	3,339,415
5	O_2 (H) lb/hr		166,376	166,376
6	CO_2 (O) lb/hr		1,023,540	1,023,540
7	SO_2 (N) lb/hr		4,850	4,850
8	SO_3 (Cl) lb/hr		188	188
9	NO (S) lb/hr		1,766	1,766
10	NO_2 lb/hr		142	142
11	HCl lb/hr		418	418
12	H_2O lb/hr		203,155	203,155
13	Ash lb/hr	12,329	49,314	49,314

	Stream No.	7	8	
	Description	Air inleakage	Gas to electrostatic precipitator	
1	Total stream, lb/hr	695,955	5,485,119	
2	Flow rate, sft^3/min @ 60^oF	153,751	1,159,811	
3	Temperature, ^oF	535	300	
4	N_2 (C) lb/hr	527,978		
5	O_2 (H) lb/hr	159,046		
6	CO_2 (O) lb/hr		1,023,540	
7	SO_2 (N) lb/hr		4,850	
8	SO_3 (Cl) lb/hr		188	
9	NO (S) lb/hr		1,766	
10	NO_2 lb/hr		142	
11	HCl lb/hr		418	
12	H_2O lb/hr	8,931	212,086	
13	Ash lb/hr		49,314	

TABLE B-11. FLUE GAS COMPOSITION

FOR 0.7% SULFUR EASTERN BITUMINOUS COAL

(Stream 8; gas to electrostatic precipitator)

Component	Volume, %	Lb-mol/hr	Lb/hr
N_2	75.27	138,100	3,867,000
O_2	5.55	10,170	325,400
CO_2	12.68	23,260	1,024,000
SO_2	0.04 (414 ppm)	76	4,850
SO_3	0.00 (11 ppm)	2	188
NO	0.03 (322 ppm)	59	1,766
NO_2	0.00 (16 ppm)	3	142
HCl	0.01 (65 ppm)	12	418
H_2O	6.42	11,770	212,100
	100.00	183,400	5,436,000
Fly ash[a]			49,310
Total			5,485,000

Sft^3/min (60°F) = 1,160,000
Aft^3/min (300°F) = 1,695,000

Fly Ash Loading

	Gr/sft^3
Wet	4.96
Dry	5.30

Sulfuric acid dew point temperature: 273°F

a. See Table B-2 for fly ash composition.

TABLE B-12. BOILER MATERIAL BALANCE

WESTERN BITUMINOUS COAL, 0.7% SULFUR

	Stream No.		1	2	3
	Description		Coal to boiler	Total air to air heater	Combustion air to boiler
1	Total stream, lb/hr		489,691	5,117,371	4,417,874
2	Flow rate, sft^3/min @ 60^oF			1,130,534	976,000
3	Temperature, ^oF			80	
4	N_2 (C)	lb/hr	(279,124)	3,882,231	3,351,566
5	O_2 (H)	lb/hr	(19,098)	1,169,468	1,009,613
6	CO_2 (O)	lb/hr	(56,314)		
7	SO_2 (N)	lb/hr	(5,876)		
8	SO_3 (Cl)	lb/hr	(490)		
9	NO (S)	lb/hr	(2,889)		
10	NO_2	lb/hr			
11	HCl	lb/hr			
12	H_2O	lb/hr	(78,351)	65,672	56,695
13	Ash	lb/hr	(47,549)		

	Stream No.		4	5	6
	Description		Bottom ash	Gas to economizer	Gas to air heater
1	Total stream, lb/hr		9,596	4,897,968	4,897,968
2	Flow rate, sft^3/min @ 60^oF			1,045,965	1,045,965
3	Temperature, ^oF				
4	N_2 (C)	lb/hr		3,356,574	3,356,574
5	O_2 (H)	lb/hr		167,228	167,228
6	CO_2 (O)	lb/hr		1,022,834	1,022,834
7	SO_2 (N)	lb/hr		4,760	4,760
8	SO_3 (Cl)	lb/hr		184	184
9	NO (S)	lb/hr		1,766	1,766
10	NO_2	lb/hr		142	142
11	HCl	lb/hr		504	504
12	H_2O	lb/hr		305,590	305,590
13	Ash	lb/hr	9,596	38,386	38,386

	Stream No.		7	8	
	Description		Air inleakage	Gas to electrostatic precipitator	
1	Total stream, lb/hr		699,498	5,597,466	
2	Flow rate, sft^3/min @ 60^oF		154,534	1,200,499	
3	Temperature, ^oF				
4	N_2 (C)	lb/hr	530,666	3,887,240	
5	O_2 (H)	lb/hr	159,855	327,083	
6	CO_2 (O)	lb/hr		1,022,834	
7	SO_2 (N)	lb/hr		4,760	
8	SO_3 (Cl)	lb/hr		184	
9	NO (S)	lb/hr		1,766	
10	NO_2	lb/hr		142	
11	HCl	lb/hr		504	
12	H_2O	lb/hr	8,977	314,567	
13	Ash	lb/hr		38,386	

TABLE B-13. FLUE GAS COMPOSITION

FOR 0.7% SULFUR WESTERN BITUMINOUS COAL

(Stream 8; gas to electrostatic precipitator)

Component	Volume, %	Lb-mol/hr	Lb/hr
N_2	73.10	138,800	3,887,000
O_2	5.38	10,220	327,100
CO_2	12.24	23,240	1,023,000
SO_2	0.04 (390 ppm)	74	4,760
SO_3	0.00 (10 ppm)	2	184
NO	0.03 (311 ppm)	59	1,766
NO_2	0.00 (16 ppm)	3	142
HCl	0.01 (74 ppm)	14	504
H_2O	9.20	17,460	314,600
	100.00	189,800	5,559,000
Fly ash[a]			38,390
Total			5,597,000

Sft^3/min (60°F) = 1,200,000
Aft^3/min (300°F) = 1,755,000

Fly Ash Loading

	Gr/sft^3
Wet	3.73
Dry	4.11

Sulfuric acid dew point temperature: 278°F

a. See Table B-2 for fly ash composition.

TABLE B-14. BOILER MATERIAL BALANCE

WESTERN SUBBITUMINOUS COAL, 0.7% SULFUR

	Stream No.		1	2	3
	Description		Coal to boiler	Total air to air heater	Combustion air to boiler
1	Total stream, lb/hr		640,244	5,765,154	4,977,111
2	Flow rate, sft^3/min @ 60^{o}F			1,273,643	1,099,548
3	Temperature, ^{o}F			80	
4	N_2 (C)	lb/hr	(313,720)	4,373,663	3,775,824
5	O_2 (H)	lb/hr	(22,409)	1,317,506	1,137,415
6	CO_2 (O)	lb/hr	(68,506)		
7	SO_2 (N)	lb/hr	(4,482)		
8	SO_3 (Cl)	lb/hr	(128)		
9	NO (S)	lb/hr	(3,073)		
10	NO_2	lb/hr			
11	HCl	lb/hr			
12	H_2O	lb/hr	187,591	73,985	63,872
13	Ash	lb/hr	40,335		

	Stream No.		4	5	6
	Description		Bottom ash	Gas to economizer	Gas to air heater
1	Total stream, lb/hr		8,159	5,609,196	5,609,196
2	Flow rate, sft^3/min @ 60^{o}F			1,215,098	1,215,098
3	Temperature, ^{o}F				
4	N_2 (C)	lb/hr		3,779,506	3,779,506
5	O_2 (H)	lb/hr		188,611	188,611
6	CO_2 (O)	lb/hr		1,149,608	1,149,608
7	SO_2 (N)	lb/hr		5,063	5,063
8	SO_3 (Cl)	lb/hr		196	196
9	NO (S)	lb/hr		1,627	1,627
10	NO_2	lb/hr		131	131
11	HCl	lb/hr		132	132
12	H_2O	lb/hr		451,685	451,685
13	Ash	lb/hr	8,159	32,637	32,637

	Stream No.		7	8	
	Description		Air inleakage	Gas to electrostatic precipitator	
1	Total stream, lb/hr		788,043	6,397,239	
2	Flow rate, sft^3/min @ 60^{o}F		174,095	1,389,193	
3	Temperature, ^{o}F				
4	N_2 (C)	lb/hr	597,839	4,377,345	
5	O_2 (H)	lb/hr	180,091	368,702	
6	CO_2 (O)	lb/hr		1,149,608	
7	SO_2 (N)	lb/hr		5,063	
8	SO_3 (Cl)	lb/hr		196	
9	NO (S)	lb/hr		1,627	
10	NO_2	lb/hr		131	
11	HCl	lb/hr		132	
12	H_2O	lb/hr	10,113	461,798	
13	Ash	lb/hr		32,637	

TABLE B-15. FLUE GAS COMPOSITION

FOR 0.7% SULFUR WESTERN SUBBITUMINOUS COAL

(Stream 8; gas to electrostatic precipitator)

Component	Volume, %	Lb-mol/hr	Lb/hr
N_2	71.13	156,300	4,377,000
O_2	5.25	11,520	368,700
CO_2	11.89	26,120	1,150,000
SO_2	0.04 (360 ppm)	79	5,063
SO_3	0.00 (9 ppm)	2	196
NO	0.02 (246 ppm)	54	1,627
NO_2	0.00 (14 ppm)	3	131
HCl	0.00 (18 ppm)	4	132
H_2O	11.67	25,630	461,800
	100.00	219,700	6,365,000
Fly ash[a]			32,640
Total			6,397,000

Sft^3/min (60°F) = 1,389,000
Aft^3/min (300°F) = 2,030,000

Fly Ash Loading

	Gr/sft^3
Wet	2.74
Dry	3.10

Sulfuric acid dew point temperature: 280°F

a. See Table B-2 for fly ash composition.

TABLE B-16. BOILER MATERIAL BALANCE

NORTH DAKOTA LIGNITE, 0.9% SULFUR

Stream No.		1	2	3
Description		Coal to boiler	Total air to air heater	Combustion air to boiler
1	Total stream, lb/hr	833,333	5,938,178	5,126,485
2	Flow rate, sft^3/min @ 60^oF		1,311,867	1,132,547
3	Temperature, ^oF		80	
4	N_2 (C) lb/hr	(334,167)	4,504,926	3,889,145
5	O_2 (H) lb/hr	(23,333)	1,357,047	1,171,551
6	CO_2 (O) lb/hr	(103,333)		
7	SO_2 (N) lb/hr	(5,000)		
8	SO_3 (Cl) lb/hr	(83)		
9	NO (S) lb/hr	(4,750)		
10	NO_2 lb/hr			
11	HCl lb/hr			
12	H_2O lb/hr	302,500	76,205	65,789
13	Ash lb/hr	60,167		

Stream No.		4	5	6
Description		Bottom ash	Gas to economizer	Gas to air heater
1	Total stream, lb/hr	12,176	5,947,642	5,947,642
2	Flow rate, sft^3/min @ 60^oF		1,296,872	1,296,872
3	Temperature, ^oF		800	
4	N_2 (C) lb/hr		3,893,140	3,893,140
5	O_2 (H) lb/hr		194,053	194,053
6	CO_2 (O) lb/hr		1,224,537	1,224,537
7	SO_2 (N) lb/hr		7,825	7,825
8	SO_3 (Cl) lb/hr		302	302
9	NO (S) lb/hr		2,045	2,045
10	NO_2 lb/hr		165	165
11	HCl lb/hr		86	86
12	H_2O lb/hr		576,786	576,786
13	Ash lb/hr	12,176	48,703	48,703

Stream No.		7	8	
Description		Air inleakage	Gas to electrostatic precipitator	
1	Total stream, lb/hr	811,693	6,759,335	
2	Flow rate, sft^3/min @ 60^oF	179,320	1,476,192	
3	Temperature, ^oF			
4	N_2 (C) lb/hr	615,780	4,508,920	
5	O_2 (H) lb/hr	185,496	379,549	
6	CO_2 (O) lb/hr		1,224,537	
7	SO_2 (N) lb/hr		7,825	
8	SO_3 (Cl) lb/hr		302	
9	NO (S) lb/hr		2,045	
10	NO_2 lb/hr		165	
11	HCl lb/hr		86	
12	H_2O lb/hr	10,417	587,203	
13	Ash lb/hr		48,703	

TABLE B-17. FLUE GAS COMPOSITION

FOR 0.9% SULFUR NORTH DAKOTA LIGNITE

(Stream 8; gas to electrostatic precipitator)

Component	Volume, %		Lb-mol/hr	Lb/hr
N_2	68.95		161,000	4,509,000
O_2	5.08		11,860	379,500
CO_2	11.92		27,820	1,225,000
SO_2	0.05	(524 ppm)	122	7,825
SO_3	0.00	(17 ppm)	4	302
NO	0.03	(291 ppm)	68	2,045
NO_2	0.00	(17 ppm)	4	165
HCl	0.00	(9 ppm)	2	86
H_2O	13.97		32,600	587,200
	100.00		233,400	6,711,000
Fly ash[a]				48,700
Total				6,759,000

Sft^3/min (60°F) = 1,476,000
Aft^3/min (300°F) = 2,158,000

Fly Ash Loading

	Gr/sft^3
Wet	3.85
Dry	4.47

Sulfuric acid dew point temperature: 295°F

a. See Table B-2 for fly ash composition.

TABLE B-18. 1979 REVISED NSPS EMISSION STANDARDS

<u>SO_2</u>
70% SO_2 removal (minimum) to a maximum SO_2 emission of 0.6 lb SO_2/MBtu
0.6 lb SO_2/MBtu maximum emission up to 90% SO_2 removal
90% SO_2 removal (minimum) to a maximum SO_2 emission of 1.2 lb SO_2/MBtu
1.2 lb SO_2/MBtu maximum emission
<u>NO_x</u>
Bituminous coal - 0.6 equivalent lb NO_2/MBtu
Subbituminous coal - 0.5 equivalent lb NO_2/MBtu
Lignite - 0.6 equivalent lb NO_2/MBtu
<u>Particulate</u>
0.03 lb/10^6 Btu

Reference 1

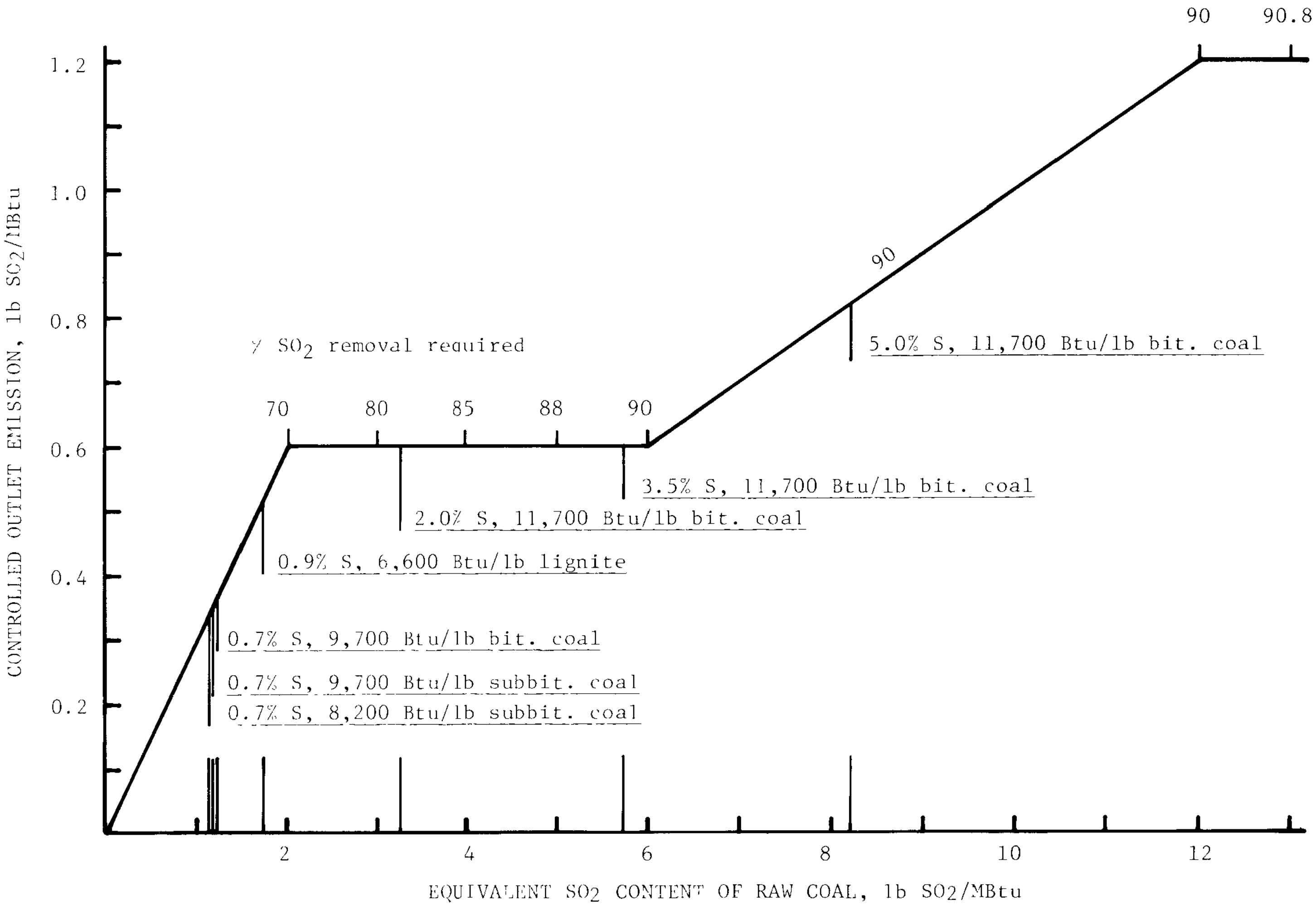


Figure B-3. Controlled SO_2 emission requirements for 1979 NSPS. Premise coals, shown underlined, are based on premise boiler conditions.

TABLE B-19. PREMISE COAL EMISSION STANDARDS

Coal	Equivalent SO_2 content of coal, lb SO_2/MBtu	Overall equivalent SO_2 removal efficiency, %	Equivalent SO_2 removal required in FGD system, %[a]	Controlled outlet emission, lb SO_2/MBtu
Eastern bit., 5.0% S	8.21	90.0	89.1	0.82
Eastern bit., 3.5% S	5.74	89.6	88.7	0.60
Eastern bit., 2.0% S	3.28	81.7	80.1	0.60
Eastern bit., 0.7% S	1.15	70.0	67.4	0.34
Western bit., 0.7% S	1.22	70.0	64.7	0.36
Western subbit., 0.7% S	1.17	70.0	64.7	0.35
N.D. lignite, 0.9% S	1.73	70.0	64.7	0.52

a. Based on FGD system as the only SO_2 control device and the previously defined sulfur retention in the ash.

Equation to determine equivalent SO_2 content of coal:

$$E = (S/H)(2 \times 10^4)$$

where: S = % sulfur in coal, as fired
H = heat content of coal, as fired
E = equivalent SO_2 content of coal as fired, lb equivalent SO_2/MBtu

Equations to determine overall % sulfur removal required:

$E < 2.0$

70% equivalent SO_2 removal required

$2.0 < E < 6.0$

% equivalent SO_2 removal required = ((E - 0.6)/E)(100)

$6.0 < E < 12.0$

90% equivalent SO_2 removal required

$E > 12.0$

% equivalent SO_2 removal required = ((E - 1.2)/E)(100)

Equation to determine equivalent SO_2 removal required in FGD system:

% equivalent SO_2 removal required = ((A - B)/(1.0 - B))(100)

where: A = overall removal efficiency, decimal fraction
B = decimal fraction of S removed with ash: (1.0 - decimal fraction of sulfur emitted as SO_x)

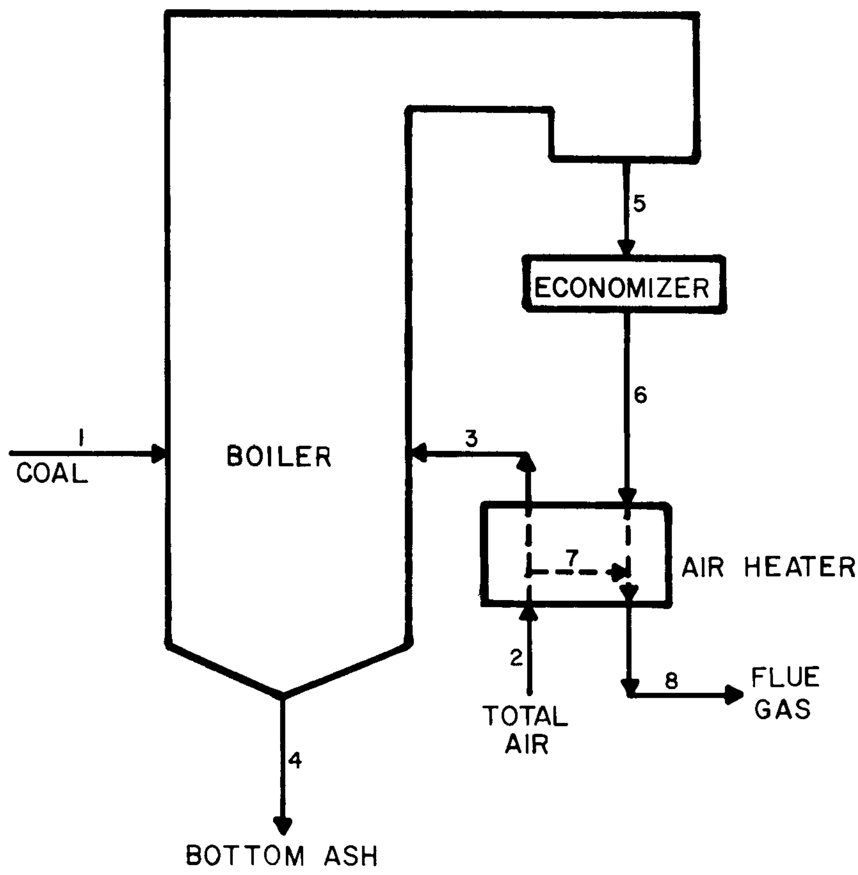


Figure B-2. Boiler flow diagram.

Particulate Matter

Cold-side (post-air heater) ESP's sized to meet the 0.03 lb/MBtu standard are normally assumed for particulate matter control. In some evaluations cyclones, fabric filter baghouses, or hot-side (pre-air heater) ESP's may be required. The costs for ash collection and disposal may or may not be included in the economic evaluations, depending on the particular processes being evaluated. In some processes ash may be an intrinsic part of the process. In such processes, or in evaluations in which comparison with such processes may be anticipated, provisions for ash control costs are included.

Flue Gas Desulfurization

The conceptual design of the FGD system meets applicable emission standards and reflects a practical operating approach. FGD systems are close-coupled to the power unit by a plenum into which the power plant ID fans discharge. The plenum allows the scrubbing systems to be designed for a different number of trains than the number of power plant ducts (to account for limitations in the available size of individual scrubbing units), and it facilitates the use of redundant scrubbing trains. To minimize flow control problems which can result from this design, separate fans are provided on each side of the plenum. Conventional power plant ID fans operating balanced draft in respect to the boiler are used upstream from the plenum to overcome the pressure drop of the boiler and associated downstream flue gas ductwork. These fans are generally designed to overcome a static head of about 15 in. H_2O. Since they are required even if FGD units are not installed, the installation and resulting operating costs are not included in the costs of the FGD system. Separate fans are provided downstream from the plenum to overcome the pressure drop attributed to the scrubber and the ductwork which is required solely as a result of installing FGD facilities.

The FGD costs include FGD-related ductwork and associated equipment between the power plant ID fans and the stack plenum. All ductwork between the power plant ID fan and the stack plenum is charged to the flue gas treatment system. This is done on the assumption that without the flue gas treatment system the boiler ID fan would discharge directly into the stack plenum. Unless specific process requirements dictate otherwise, scrubbing trains are sized for a maximum of 125 MW of flue gas up to a maximum of 513,000 sft^3/min (60^oF). Thus, the 500-MW base case requires four operating trains and the 200-MW and 1,000-MW case variations require two (100-MW) and eight (125-MW) operating trains respectively. Furthermore, any boiler generating more than 340,000 aft^3/min (about 100 MW) is provided with a minimum of two operating scrubber trains. It is assumed that the annual availability of a scrubbing train is 85% and that no scrubbing time is lost during startup. Spare scrubbing trains are provided as described below.

Emergency Bypass--

Because the 1979 NSPS allow emergency bypass around the FGD system under some conditions if spare scrubbing capacity is provided, redundancy in the form of spare scrubbing trains and provision for bypass of 50% of the gas that would normally be scrubbed are included in all FGD economic evaluations. The 1,000-MW case variation with eight operating scrubbing trains is provided with two spare trains. Units on smaller boilers are provided with one spare train. An emergency bypass of 50% of the scrubbed gas is assumed to be an economic balance between the higher cost of providing additional bypass and the small likelihood of multiple scrubbing train failures making higher bypass rates necessary. The bypass is installed as two identical ducts from each end of the inlet plenum to the plenum downstream from the scrubbing trains. Particulate collection equipment is not bypassed.

Partial Scrubbing--

In some cases, depending on the sulfur content of the coal and SO_x removal requirements, scrubbing a portion of the flue gas at a high SO_x removal efficiency and combining it with the remaining flue gas may be more economical than scrubbing all of the flue gas at a lower SO_x removal efficiency. In such cases the bypassed gas duct requirements and the emergency bypass capability are combined in the same duct. The ducts are sized to handle both the flue gas normally bypassed and the emergency bypass of 50% of the gas normally scrubbed. Depending on sulfur in the coal for the 500-MW power unit, partial scrubbing could involve scrubbing as little as 375 MW of flue gas. Three operating scrubbing trains and one spare scrubbing train are provided for this case.

Ductwork--

Square ductwork with 2-inch insulation (in standard cases) is used for the inlet plenum and scrubbing trains. To prevent ash settling, a gas velocity of 50 ft/sec is used for the inlet plenum, all ductwork, and the emergency bypass. A gas velocity of 25 ft/sec is used for the reheater section. Duct material is usually 3/16-inch Cor-Ten® steel when the gas temperature is higher than 150°F and 3/16-inch stainless steel when the gas temperature is lower than 150°F.

Removal Efficiencies--

It is assumed that 50% of the SO_3, 95% of the HCl, 0% of the NO_x, and 50% of the remaining fly ash in the flue gas are removed in the FGD system. For systems requiring a presaturator or humidifier, it is assumed that 5% of the SO_2 is removed in the presaturator and that the remaining SO_2 removal takes place in the FGD absorber.

Spare Equipment--

Equipment is spared in accordance to general field practice. For most processes the following equipment is spared:

- Crushing and grinding equipment: A spare train of crushing and grinding equipment
- Slakers
- Sludge filters
- Pumps
- Scrubbing trains: A spare scrubbing train or trains

Mist Eliminator--

The mist eliminator is a zigzag-chevron-baffle type. The mist eliminator reduces entrained moisture to a maximum level of 0.1% (by weight) of the flue gas. This maximum level is assumed for calculation of the amount of stack gas reheat required.

Stack Gas Reheat--

Indirect steam reheat is provided for processes that cool the flue gas below 175°F. This stack gas reheat is considered necessary both to evaporate entrained water droplets not removed by the mist eliminator and to increase plume buoyancy. Necessary information for calculating the steam requirement and reheater surface area is given in Table B-20 and a sample calculation is shown in Table B-21.

One-half of the reheater tubes are made of Inconel 625 and one-half of Cor-Ten. Inconel 625 is highly resistant to corrosion and is used

TABLE B-21. SAMPLE REHEATER CALCULATIONS

Gas to Reheater

	lb/hr
CO_2	1,008,000
HCl	21
SO_2	2,850
O_2	319,800
N_2	3,852,000
H_2O (vapor)	444,873
Total gas	5,627,544
H_2O (liquid entrainment)	5,627
Total	5,633,171

Reheater Heat Duty

	lb/hr	x	Cp^m(Btu/lb)[b]	=	Btu/hr
CO_2	1,008,000	x	10.8		10,886,400
HCl	21	x	9.5		200
SO_2	2,850	x	7.9		22,515
O_2	319,800	x	11.2		3,581,760
N_2	3,852,000	x	12.5		48,150,000
H_2O (vapor)	444,873	x	22.6		10,054,130
Total					72,695,005
H_2O (liquid entrainment)	5,627	x	1,043.2[b]		5,870,090
Total					78,565,095 Btu/hr

Steam Requirement

78,565,095 Btu/hr ÷ 751.9 Btu/lb = 104,489 lb/hr

Reheater Area

78,565,095 Btu/hr ÷ 4 operating reheaters ÷ 20.8 Btu/ft^2-hr-^{o}F ÷ 319^{o}F[a,b] = 2,960 ft^2

a. Log mean temperature difference (ΔT_L) = $(T_1 - T_2)/(\ln(T_1/T_2))$

T_1 = Tsteam - Tgas in = 470 - 125 = 345
T_2 = Tsteam - Tgas out = 470 - 175 = 295
ΔT_L = (345 - 295)/(ln(345/295))

b. For a temperature change from 125^{o}F to 175^{o}F only.

TABLE B-20. REHEATER DATA

Compound	Cp^m (Btu/lb)[a]
CO_2	10.8
HCl	9.5
SO_2	7.9
SO_3	8.2
O_2	11.2
N_2	12.5
NO	12.0
NO_2	10.2
H_2O (vapor)	22.6

Steam:
saturated at 470°F (500 psig), heat of vaporization 751.9 Btu/lb

Reheater overall heat transfer coefficient:
20.8 Btu/ft²-hr-°F

Entrained water enthalpy:
liquid at T = 125°F: 92.9 Btu/lb
vapor at T = 175°F: 1136.1 Btu/lb
∴ ΔH^a = 1043.2 Btu/lb

a. For a temperature change from 125°F to 175°F only.

for the first bank of tubes, which increases the flue gas temperature to 150°F. The Cor-Ten tubes follow directly after, raising the temperature of the gas at the exit to 175°F. For the partial bypass case, the gas may not be heated to 175°F because of the smaller percentage of scrubbed (cool) gas. In these cases, the percentage of Inconel 625 tubes increases to as much as 100% (for reheat to 150°F or less).

Raw Materials and Byproducts--

Raw materials and byproduct storage capacity is normally 30 days unless process or industry practice differ. Standard raw material characteristics are shown in Table B-22.

NO_x Control

Processes that remove only NO_x are combined with a limestone spray tower, forced-oxidation FGD system with landfill waste disposal for comparison with processes that remove both NO_x and SO_2.

Redundancy is included in the NO_x control processes to ensure that removal efficiencies used in each particular economic study are met. For wet NO_x control processes the availability is the same as for FGD

TABLE B-22. RAW MATERIAL CHARACTERISTICS

	Size as received	Ground size	Analysis[a]	Bulk density, lb/ft^3
Limestone	0 x 1-1/2 inch Fineness of grind index factor = 5.7 Hardness of work index factor = 10	90% to pass 325 mesh	95% $CaCO_3$ 0.15% MgO 4.85% inerts 5 lb H_2O/100 lb dry limestone	95
Lime (pebble)	3/4 x 1-1/4 inch	-	95% CaO 0.15% MgO 4.85% inerts 5 lb H_2O/100 lb dry lime	55
MgO	Crystalline powder	-	98% MgO 2% inerts	30 (virgin) 15 (regenerated)
Soda ash	100% to pass 100 mesh	-	99.8% Na_2CO_3 (58.4% Na_2O) 0.15% NaCl 0.02% inerts 0.03% H_2O	35
Adipic acid	Crystalline powder	-	99.8% $(CH_2)_4(COOH)_2$ 0.2% inerts	49

a. Limestone and lime analysis on a dry basis. H_2O is based on pounds of dry limestone or lime.

systems. When the number of trains is the same as FGD for the same boiler size, the redundancy for wet NO_x control process trains is the same as for an FGD system.

For dry catalytic processes, catalyst replacement occurs during boiler outages and does not affect boiler on-stream time. A sufficient quantity of catalyst is included to ensure that the desired removal efficiency is maintained during the entire guaranteed life of the catalyst load. Redundancy and the number of trains for all dry processes are based on NO_x removal system module availability and the required NO_x removal efficiency. Redundancy is achieved through sparing NO_x removal system trains or sparing vital equipment such as NH_3 vaporization and injection equipment.

Solids Disposal

For FGD processes producing a solid waste, either ponding or landfill disposal at a site one mile from the FGD facilities is used. Sufficient land is provided for disposal during the remaining life of the FGD facility. Fly ash disposal is not included unless fly ash collection or use is an integral part of the FGD process. The disposal site is assumed to be an area of low relief with sufficient soil for dike construction or landfill requirements.

Pond--

Disposal ponds are square, earthen-diked enclosures with a median diverter dike. Dikes are constructed from material removed from the impoundment area as shown in Figure B-4. The entire impoundment area is lined with 12 inches of clay (assumed available onsite). Pond size and depth are adjusted to minimize the sum of land and construction costs. Pond costs include a 6-foot security fence around the perimeter dike, security lighting, a topsoil storage area, and one upstream and three downstream ground water monitoring wells.

Landfill--

Landfills are an area-type landfill having a square configuration with a single 20-foot lift and a 2-degree cap, as shown in Figure B-5. After topsoil removal the landfill area is lined with 12 inches of clay (assumed available onsite) and 24 inches of bottom ash. This bottom ash layer allows the water to drain into a catchment ditch around the perimeter. The ditch drains into a catchment basin for pH adjustment before discharging into the river. Land requirements include the landfill, catchment basin, equipment storage area, topsoil storage area, and a 50-foot perimeter of undisturbed land. Costs for access roads, a 6-foot security fence around the total landfill area, security lighting, and topsoil stripping, replacement, and revegetation are included. One upstream and three downstream ground water monitoring wells are also included.

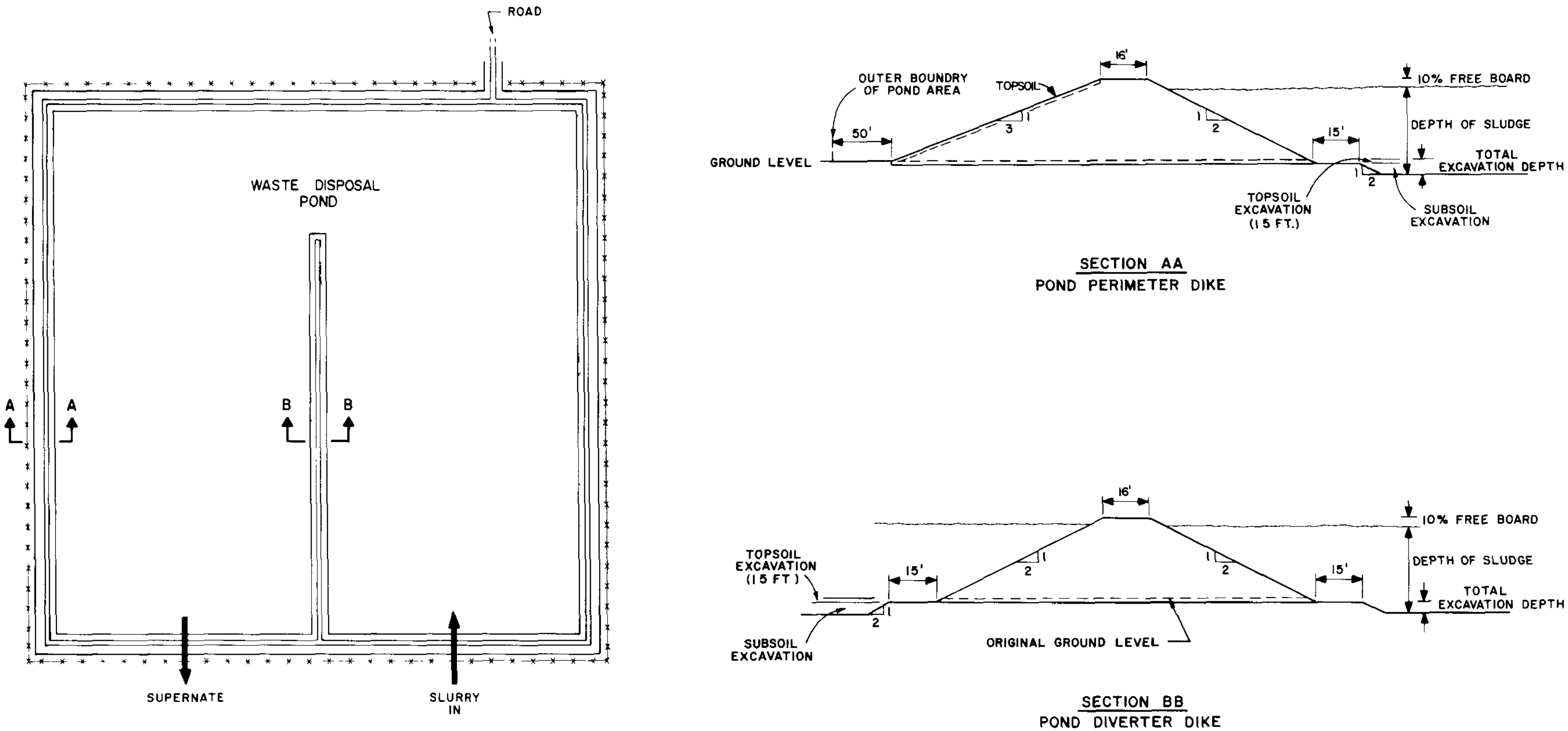


Figure B-4. Pond plan and dike construction details.

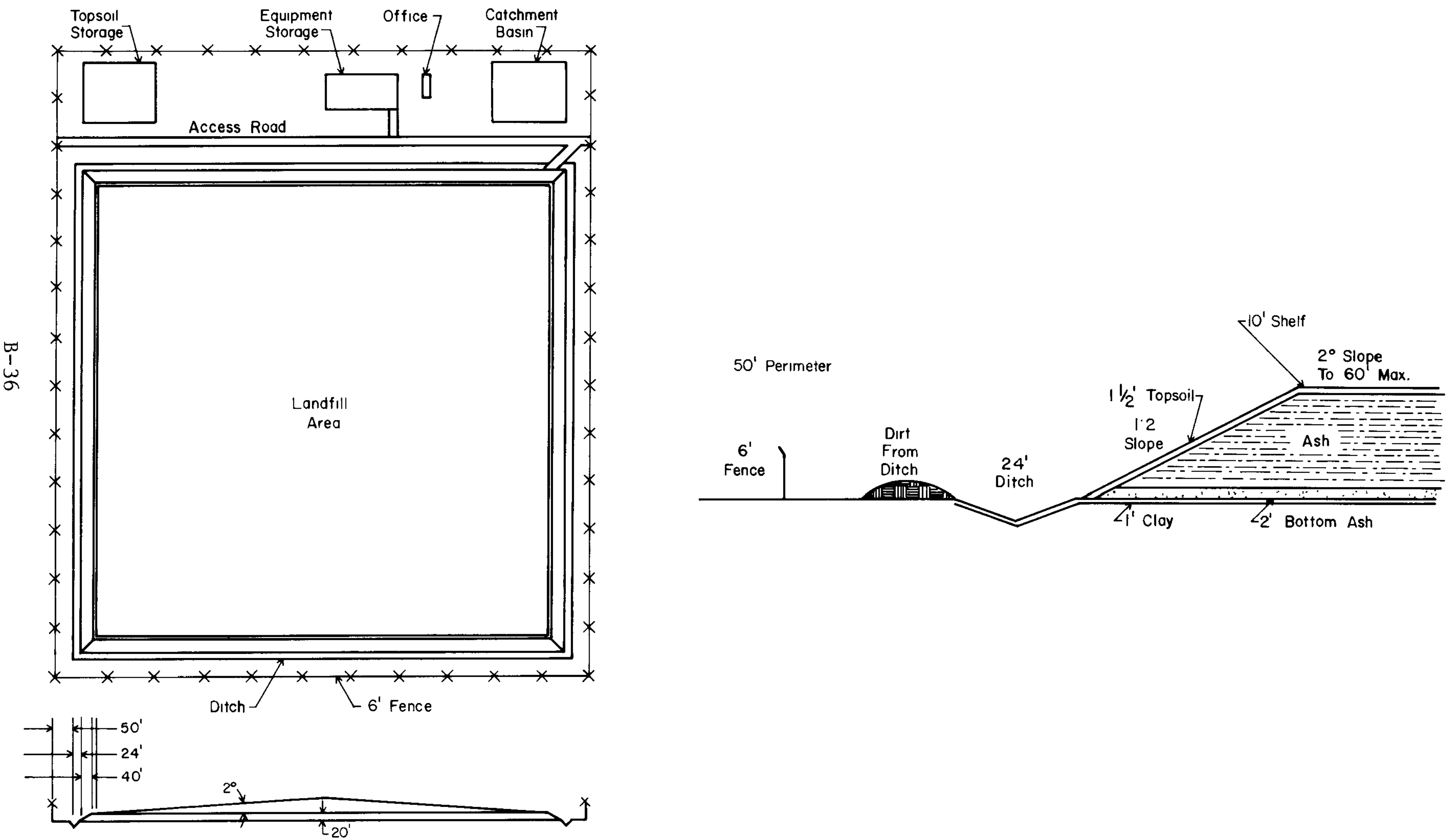


Figure B-5. Landfill plan and construction details.

ECONOMIC PREMISES

Schedule and Cost Factors

The construction schedule used as a cost basis is shown in Figure B-6. A three-year construction period, from early 1981 to late 1983, is used. Mid-1982 costs are used for capital investment. Mid-1984 costs are used for annual revenue requirements. These costs represent the midpoint of construction expenditures in 1982 and the midpoint of the first-year of operation in 1984. Costs are projected from *Chemical Engineering* cost indexes (12), as shown in Table B-23. Frequently used costs are shown in Table B-24.

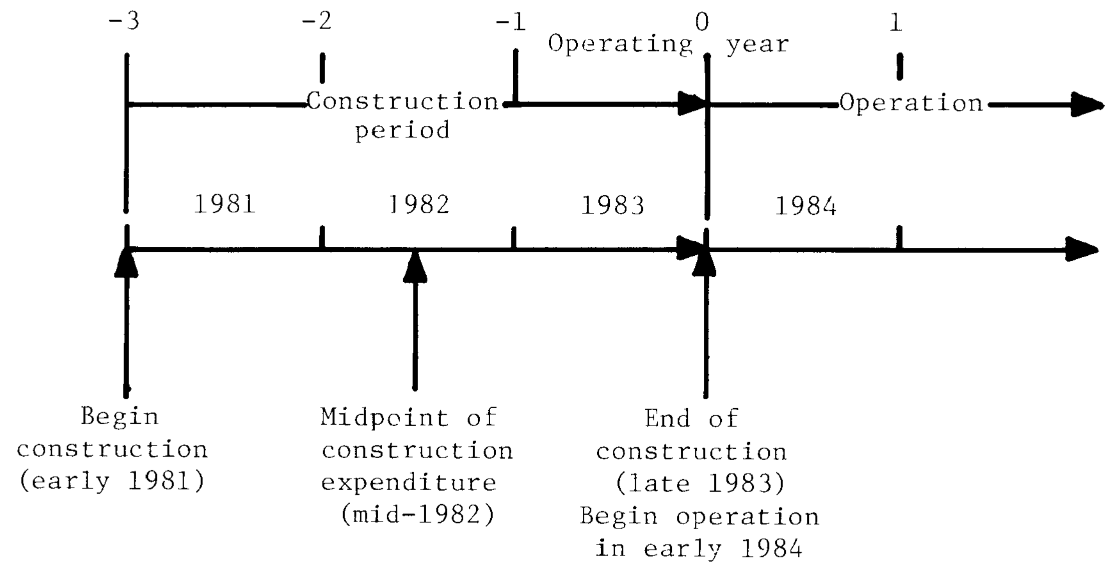


Figure B-6. Construction schedule.

TABLE B-23. COST INDEXES AND PROJECTIONS

Year:	1978	1979	1980[a]	1981[a]	1982[a]	1983[a]	1984[a]
Plant	218.8	238.7	257.8	277.1	297.9	320.2	342.6
Material[b]	240.6	264.4	288.2	311.2	336.1	363.0	388.4
Labor[c]	185.9	194.9	210.5	227.3	245.5	265.2	283.7

a. TVA projections.
b. Same as "equipment, machinery, supports" *Chemical Engineering* index.
c. Same as "construction labor" *Chemical Engineering* index.

TABLE B-24. COST FACTORS

Project Timing	
Start	January 1981
End	December 1983
Midpoint	Mid-1982
First-year operation	1984
1984 Utility Costs	
Electricity	\$0.037/kWh
Steam	\$2.50/klb; \$3.30/MBtu
Eastern bit. coal (<1% S)	\$53.35/ton; \$2.30/MBtu
Eastern bit. coal (>1% S)	\$43.30/ton; \$1.85/MBtu
Western bit. coal (0.7% S)	\$55.70/ton; \$2.90/MBtu
Western subbit. coal (0.7% S)	\$30.00/ton; \$1.80/MBtu
N.D. lignite (0.9% S)	\$15.00/ton; \$1.15/MBtu
Fuel oil No. 6	\$8.33/MBtu
Diesel fuel[a]	\$1.60/gal
Natural gas	\$4.29/MBtu
Filtered river water	\$0.14/kgal (up to 0.6 Ggal)
	\$0.12/kgal (0.6 - 2 Ggal)
	\$0.10/kgal (2-5 Ggal)
	\$0.08/kgal (over 5 Ggal)
1984 Labor Costs	
FGD	\$15.00/man-hr
Waste disposal	\$21.00/man-hr
Analysis	\$21.00/man-hr
1984 Raw Material Costs	
Limestone	\$8.50/ton (95% $CaCO_3$, dry basis)
Lime	\$75.00/ton (pebble, 95% CaO, dry basis)
Ammonia	\$155.00/ton
Soda ash	\$160.00/ton (99.8% Na_2CO_3)
Adipic acid	\$1,200.00/ton
MgO	\$460.00/ton
1982 Land Cost	
	\$5,000/acre

These cost factors are based on a north-central plant location.

a. Cost is based on wholesale price of barge-load quantities. Road taxes are not included.

Capital Cost Estimates

Four grades of capital cost estimates are prepared depending upon the intended use and the amount of information available. The grades, in increasing order of accuracy, are (1) order of magnitude, (2) study, (3) preliminary, and (4) definitive. The two grades normally used are the study and preliminary grades. The purpose, information required, and predicted accuracy are listed in Table B-25.

A typical capital investment sheet is shown in Table B-26. The capital investment sheet is divided into three major sections: direct investment, indirect investment, and other capital investment.

Direct Investment--

Direct investment consists of total process capital; services, utilities, and miscellaneous; and waste disposal investment. Total process capital can be determined when an equipment list has been organized. Using standard estimating techniques (13,14) and the average annual Chemical Engineering cost indexes and projections shown in Table B-23, the equipment cost and installation costs of each area are estimated. These installation costs include charges for all piping, foundations, excavations, structural steel, electrical equipment, instruments, ductwork (all included in gas handling area), paint, buildings, taxes, freight, and a premium for 7% overtime construction labor as shown in Figure B-7. The total process area costs are summed on the Area Summary Sheet shown in Figure B-8 to give the total process capital.

Service facilities such as maintenance shops, stores, communications, security, offices, and road and railroad facilities are estimated or allocated on the basis of process requirements. Included in the utilities investment are necessary electrical substations, conduit, steam, process water, fire and service water, instrument air, chilled water, inert gas, and compressed air distribution facilities. Services, utilities, and miscellaneous are estimated to be in the range of 4% to 8% of the total process capital. For most cases 6% is to be used, higher for processes only and lower for ponds only. The base case limestone and lime scrubbing processes are charged 6% for services, utilities, and miscellaneous.

All equipment and direct construction costs associated with waste disposal are included in waste disposal costs. For ponds, this includes pond construction costs from the computer pond model. For landfills, mobile equipment and construction costs are included. All mobile equipment involved in loading and transporting the waste from the in-process storage area, as well as working the landfill, are included in solids disposal equipment. The landfill construction cost, as calculated from the landfill model, is listed separately from the solids disposal equipment. The sum of total process capital; services, utilities, and miscellaneous; and the waste disposal cost is the total direct investment.

Indirect Investment--

Indirect capital costs cover fees for engineering design and supervision, architect and engineering contractor, construction expense,

TABLE B-25. CAPITAL COST ESTIMATE CLASSIFICATION

Grade	Purpose	Minimum information required	Predicted accuracy +%	Predicted accuracy -%
Order of magnitude (ratio estimate)	Preliminary feasibility study to determine whether continued investigation is merited. Rough comparison of alternatives.	General design basis,[a] flowsheet and material balance, heat and energy balance. For the order of magnitude estimates this information is of a tenative nature, developed from a preliminary process concept.	>50	>50
Study (factored estimate)	Comparison of alternatives. Preliminary screening. Preliminary budget preparation. Authorization for funding for an engineering study or for development of additional information.	All of the above on a firm rather than tentative basis plus overall layout of manufacturing and nonmanufacturing facilities, sized equipment and instrument lists, and performance data sheets.	40	20
Preliminary (initial budget or scope estimate)	Preliminary budget approval. More accurate comparison of alternatives. Followup of an order of magnitude or study estimate.	All of the study estimate requirements plus process control diagrams, process piping sketches with sizes, plan and elevation drawings, offsite descriptions including sizes and capacities.	30	15
Definitive (project control estimate)	Final capital authorization. Project cost control. Followup on order of magnitude, study, or preliminary estimates for more accurate information. Generally reserved for a real construction project with a known site.	All of the preliminary estimate requirements plus piping plan and elevation drawings integrated with the equipment plan and elevation drawings, electrical layout single line drawings, detailed piping and instrumentation flowsheets, layout of nonmanufacturing facilities, design sketches for unusual equipment items, and specific site data including utilities and transportation availability, soil bearing, wind and snow loads.	20	10

a. General design basis includes product, product specifications, plant capacity, storage requirements, operating stream time, provisions for expansion, raw materials and their storage requirements.

TABLE B-26. CAPITAL INVESTMENT SHEET

TABLE ADVANCED LIMESTONE PROCESS CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 3.5% S in coal; 88.6% SO_2 removal; onsite solids disposal)

	Investment, k$
Direct Investment	
Materials handling	
Feed preparation	
Gas handling	
SO_2 absorption	
Stack gas reheat	
Oxidation	
Solids separation	
Total process capital	
Services, utilities, and miscellaneous	
Total direct investment excluding landfill	
Solids disposal equipment	
Landfill construction	
Total direct investment	
Indirect Investment	
Engineering design and supervision	
Architect and engineering contractor	
Construction expense	
Contractor fees	
Contingency	
Disposal area indirects	
Total fixed investment	
Other Capital Investment	
Allowance for startup and modifications	
Interest during construction	
Royalties	
Land	
Working capital	
Total capital investment	
Dollars of total capital per kW of generating capacity	

Basis: North-central plant location represents project beginning early 1981, ending late 1983; average cost basis for scaling, mid-1982.
Redundant scrubber train, 50% emergency bypass, spare pumps.
Landfill located one mile from power plant.
FGD process investment begins at power plant ID fans. Stack plenum and stack excluded.

Area	% of process equipment	Material	Labor[a]	Total
Process equipment	X			
Piping and insulation				
Concrete foundations				
Excavations, site preparation, roads, etc.				
Structural				
Electrical				
Instrumentation				
Ducts, chutes, expansion joints, etc.				
Paint and miscellaneous				
Buildings				
Trucks and earthmoving equipment				
Subtotal				
Freight (3.5% of process equipment material)			X	
Tax (4% of material subtotal)			X	
Total process area cost				

a. Includes premium for 7% overtime, i.e., labor is 0.93 (straight time labor) + (0.07)(1.5)(straight time labor) or 1.035 (straight time labor).

Figure B-7. Process area cost summary sheet.

Area	Description	Total process area cost, $	Total process capital, $
1	Materials handling		
2	Feed preparation		
3	Gas handling		
4	SO_2 absorption		
5	Stack gas reheat		
6	Oxidation		
7	Solids separation and disposal		

Figure B-8. Area summary sheet.

contractor fees, and contingency. Listed in Table B-27 are the ranges to be used to calculate the process and waste disposal indirect investments. The base percentages are normally used while the low and high ranges are used in cases where the process being studied is either much more complex than the typical system (the higher percentage factors are used) or much less complex (the lower percentage factors are used). Under most conditions the base values are used for typical systems. The limestone and lime scrubbing processes use the low percentages for a 1,000-MW unit, base percentages for a 500-MW unit, and the high percentages for a 200-MW unit. Contingency is included to compensate for unforeseen expenses. The contingency varies depending on the process and the waste disposal method, as shown in Table B-28. The limestone and lime scrubbing processes are assessed a contingency of 10% for the process and 20% for the landfill.

Other Capital Investment--

The allowance for startup and modifications is applied as a percentage of the total fixed investment. Since the startup and modification costs for the waste disposal area are assumed to be negligible, this allowance is calculated as a percentage of the total process fixed investment only. The values used are shown in Table B-29. The limestone and lime scrubbing processes are assessed at a rate of 8% for this charge.

The cost of borrowed funds (interest) during construction is 15.6% of the total fixed investment (both process and waste disposal). This factor is based on an assumed three-year construction schedule and is calculated with a 10% weighted cost of capital with 25% of the construction expenditures in the first year, 50% in the second year, and 25% in the third year of the project construction schedule. Expenditures in a given year are assumed uniform over that year. Startup costs are assumed to occur late enough in the project schedule that there are no charges for the use of money to pay startup costs. Table B-30 illustrates the calculation of the interest during construction for three- through six-year construction schedules.

Most processes will include a one-time royalty charge using either an actual royalty obtained from the vendor or 1% of the total process capital involved. Processes exempt from royalties due to their generic design are limestone and lime processes, including those with forced oxidation or adipic acid or both, and the magnesia process.

Land--

All land associated with the process and waste disposal area is charged to the process. The cost of land is $5,000 per acre.

Working Capital--

Working capital is the total amount of money invested in raw materials, supplies, finished products, accounts receivable, and money on deposit for payment of operating expenses. For these premises, working capital is defined as the equivalent cost of 1 month's raw material cost, 1.5 months' conversion cost, 1.5 months' plant and administrative overhead costs (all of the above are found on the annual revenue

TABLE B-27. RANGE OF INDIRECT INVESTMENTS

Indirect Investment, Process

	% of total direct investment excluding waste disposal investment		
	Low	Base	High
Engineering design and supervision	6	7	8
Architect and engineering contractor	1	2	3
Construction expense	14	16	18
Contractor fees	4	5	6
Total	25	30	35

Waste Disposal Indirects FGD Pond, FGD Landfill, or Ash Pond

	% of total direct waste disposal investment[a]		
	Low	Base	High
Engineering design and supervision	2	2	2
Architect and engineering contractor	1	1	1
Construction expense	7	8	9
Contractor fees	4	5	6
Total	14	16	18

Ash Landfill

	% of total direct waste disposal investment[a]
	Base
Engineering design and supervision	6
Architect and engineering contractor	3
Construction expense	10
Contractor fees	6
Total	25

a. Pond (or landfill construction) only.

TABLE B-28. CONTINGENCY

Process Contingency

	% of total direct investment excluding waste disposal plus process indirect investment
Limestone and lime slurry	10
Limestone and lime - forced oxidation	10
Limestone and lime - forced oxidation with adipic acid	10
All others	20

Waste Disposal Contingency

	% of total waste disposal direct investment plus waste disposal indirect investment
FGD pond	10
Ash pond	10
FGD landfill	20
Ash landfill	10

TABLE B-29. ALLOWANCE FOR STARTUP AND MODIFICATIONS

Process

	% of total fixed investment for process only
Limestone and lime (generic[a])	8
All other processes	10

Waste Disposal

	% of total fixed investment for waste disposal only
Ponds and landfills	0

a. Excludes Chiyoda, double alkali, etc., which have unique designs and are not as yet proven technology.

TABLE B-30. INTEREST DURING CONSTRUCTION ILLUSTRATION

Three-Year Construction Schedule

Years from startup	Compound amount factor[a]		Fraction of total plant investment		
3-2	1.2686	x	0.250	=	0.317
2-1	1.1533	x	0.500	=	0.577
1-0	1.0484	x	0.250	=	0.262

Total fixed investment plus interest during construction: 1.156

Interest during construction = 1.156 - 1.000 = 0.156 or 15.6%

Four-Year Construction Schedule

Years from startup	Compound amount factor[a]		Fraction of total plant investment		
4-3	1.3955	x	0.150	=	0.209
3-2	1.2686	x	0.300	=	0.381
2-1	1.1533	x	0.350	=	0.404
1-0	1.0484	x	0.200	=	0.210

Total fixed investment plus interest during construction: 1.204

Interest during construction = 1.204 - 1.000 = 0.204 or 20.4%

Five-Year Construction Schedule

Years from startup	Compound amount factor[a]		Fraction of total plant investment		
5-4	1.5349	x	0.10	=	0.154
4-3	1.3955	x	0.20	=	0.279
3-2	1.2686	x	0.30	=	0.381
2-1	1.1533	x	0.25	=	0.288
1-0	1.0484	x	0.15	=	0.157

Total fixed investment plus interest during construction: 1.259

Interest during construction = 1.259 - 1.000 = 0.259 or 25.9%

(continued)

TABLE B-30 (continued)

Six-Year Construction Schedule

Years from startup	Compound amount factor[a]		Fraction of total plant investment		
6-5	1.6886	x	0.10	=	0.169
5-4	1.5349	x	0.15	=	0.230
4-3	1.3955	x	0.25	=	0.349
3-2	1.2686	x	0.25	=	0.317
2-1	1.1533	x	0.15	=	0.173
1-0	1.0484	x	0.10	=	0.105

Total fixed investment plus interest during construction: 1.343

Interest during construction = 1.343 - 1.000 = 0.343 or 34.3%

a. Present worth and compound amount factor using the 10% cost of capital with continuous compounding (13).

Years from startup	Uniform expenditure present worth (13)	Compound amount factor (13)
7-6	0.5384	1.8574
6-5	0.5922	1.6886
5-4	0.6515	1.5349
4-3	0.7166	1.3955
3-2	0.7883	1.2686
2-1	0.8671	1.1533
1-0	0.9538	1.0484

requirements sheet), and 3% of the total direct capital investment (from the capital investment sheet). One month is defined as 1/12 of annual costs. The equation is shown below:

Working capital = 1/12 (total raw materials cost) +
(1.5) (1/12) (total conversion cost) +
(1.5) (1/12) (plant and administrative overhead) +
0.03 (total direct investment)

Battery Limits--

Since battery limits costs typically include most of the associated indirect investments, battery limits costs have their own indirect investment factors as shown below:

	% of battery limits cost
Engineering design and supervision	6
Architect and engineering contractor	1
Construction expense	14
Contractor fees	0
Contingency	10

Retrofit Factor--

For existing plant cases a retrofit factor is assigned to cover the additional investment required. Each of the area investments (i.e., material handling, etc.) is multiplied by the retrofit factor. Retrofit factors vary widely depending on the process and the site involved. For emission control processes which are close coupled to the boiler, the following retrofit factors are used:

Process	Retrofit factor	Reason
Limestone scrubbing	1.3	These scrubbing systems are add-on in that they require no boiler modifications. This factor for the retrofit cases is due to the need to fit the equipment into available space.
Spray dryer	1.5	These scrubbing systems require relatively minor modifications to the boiler and ESP ductwork. This factor also includes the expense of fitting the equipment into the available space.
NO_x FGT (SCR)	1.7	These control systems require extensive modifications to the boiler economizers and air heaters and the associated ductwork. This factor also includes the expense of locating the equipment in the available space.

It is assumed that most FGD systems will be of the add-on type and therefore use the 1.3 retrofit factor.

Annual Revenue Requirements

Annual revenue requirements in these premises consist of various direct and indirect operating and maintenance costs and capital charges. Annual revenue requirements normally vary from year to year as operating and maintenance costs change and capital charges decline. Thus no single year is necessarily representative of the lifetime costs, nor can single-year undistorted comparisons be made among processes with different ratios of operating costs to capital charges. In addition it is necessary to take into account the effect of time on the value of money (i.e., for inflation, the future earning power of money spent, and other factors).

Frequently these factors are accounted for by levelizing (15). Levelization converts all the varying annual revenue requirements to a constant annual value, such that the sum of the present worths of the levelized annual revenue requirements equals the sum of the present worths of the actual annual revenue requirements. The levelized value is calculated by multiplying the revenue requirements for each year by the appropriate present worth factor and summing the present worth values. Then the single present worth value is converted to equal annual values by multiplying the result by the capital recovery factor.

In these premises the operating and maintenance costs are levelized by multiplying the first-year operating and maintenance cost by a levelizing factor. The levelized capital charges are determined by levelizing the percentage of capital investment applied yearly as capital charges. The levelizing factor includes a discount factor reflecting the time-value of money and an inflation factor reflecting the effects of inflation during the operating life of the system. The discount rate used is 10% and the inflation rate used is 6%. The levelizing factor produced varies with the remaining life of the system. Calculation of the levelizing factor for operating and maintenance costs and of levelized capital charges is discussed below.

A typical annual revenue requirement tabulation is shown in Table B-31. Direct costs consist of raw material and conversion costs. These, combined with overheads, are the operating and maintenance costs. For processes that produce a salable byproduct, byproduct sales are applied as a credit to the operating and maintenance costs. Levelized capital charges are calculated as a percentage of the capital investment and added to the operating and maintenance costs to provide the first-year annual revenue requirements. The levelized annual revenue requirements are determined by multiplying the operating and maintenance costs by the levelizing factor and adding the product to the same levelized capital charges used in the first-year annual revenue requirements.

Operating and Maintenance Costs--

Frequently used raw material costs and standard conversion costs were shown previously in Table B-24. Other costs are obtained from vendors or published information. These costs are converted to 1984 costs using the cost indexes in Table B-23 or industry projections.

TABLE B-31. ANNUAL REVENUE REQUIREMENTS SHEET

TABLE ADVANCED LIMESTONE PROCESS ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 3.5% S in coal; 88.6% SO_2 removal; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, k$
Direct Costs - First-Year			
Raw materials			
Limestone	tons	/ton	
Total raw materials cost			
Conversion Costs			
Operating labor and supervision			
FGD	man-hr	/man-hr	
Solids disposal	man-hr	/man-hr	
Utilities			
Process water	kgal	/kgal	
Electricity	kWh	/kWh	
Steam	klb	/klb	
Maintenance			
Labor and material			
Analysis	man-hr	/man-hr	
Total conversion costs			
Total direct costs			
Indirect Costs - First-Year			
Overheads			
Plant and administrative			
Marketing (10% of byproduct sales)			
Byproduct Credit	tons	$/ton	
Total first-year operating and maintenance costs			
Levelized Capital Charges (% of total capital investment)			
Total first-year annual revenue requirements			
Levelized First-Year Operating and Maintenance Costs (first-year O and M)			
Levelized Capital Charges (% of total capital investment)			
Levelized annual revenue requirements			

	M$	Mills/kWh
First-year annual revenue requirements		
Levelized annual revenue requirements		

Basis: One-year, 5,500-hour operation of the system described in the capital investment sheet; 1984 cost basis.

Raw materials--Consumables required for their chemical or physical properties, other than fuel for the production of heat, are classified as raw materials. Raw material costs are determined as necessary from vendor quotations or published sources and escalated to 1984 costs. All costs are delivered costs.

Operating labor and supervision--Unit labor costs for 1984 were shown in Table B-24. The allocation of operating labor and supervision depends on the process complexity, number of process areas, labor intensity of the process, and operating experience.

Utilities--Services used, such as steam, electricity, process water, fuel oil, and heat credits, are charged under the utilities heading. Unit 1984 costs were shown in Table B-24. Costs for steam and electricity are based on the assumption that the required energy is purchased from another source. This simplifying assumption eliminates the need to derate the utility plant. Process water requirements are defined as any water used by the process being evaluated and are usually determined by the material balance. Steam requirements are for stack gas steam reheat and process requirements. Electrical power requirements are determined from the installed horsepower of operating electrical equipment (excluding the horsepower of spared equipment). Each motor in operation is assumed to be operating at rated capacity although this results in higher power consumptions than would actually occur. Electrical requirements are obtained from the equipment list where the motor horsepower is identified, plus an additional amount for functions such as lighting. A sample calculation is shown in Table B-32.

Maintenance--Process maintenance costs are 3% to 10% of the total direct process investment depending on process complexity, process equipment, materials handled, process areas, and unit size. The percentages shown in Table B-33 are used under most circumstances. For specific FGD processes the maintenance percentages shown in Table B-34 are used. For example, a 500-MW limestone and lime scrubbing process normally has a maintenance factor of 8%.

Waste disposal maintenance costs are estimated from the appropriate model and are typically 3% of the waste disposal site construction costs. Maintenance costs for waste disposal are not shown separately. If, and only if, it is required and no other information is available, the maintenance material-to-labor ratio is 60:40.

Analysis--Analysis costs are based on process complexity and are listed as a single entry.

Plant and administrative overhead--Plant and administrative overheads include plant services such as safety, cafeteria, and medical facilities; plant protection and personnel; general engineering (excluding maintenance), interplant communications and transportation; and the expenses connected with management activities. Plant and administrative overheads for the FGD process are 60% of the total conversion costs less utilities.

Marketing overhead--This is calculated as 10% of byproduct sales income.

TABLE B-32. SAMPLE ELECTRICAL REQUIREMENT CALCULATION

Electricity requirements are determined by summing the horsepower of all operating electrical equipment and multiplying by a factor of 0.7457 kW/hp. It is assumed that the instantaneous load factor and the power load factor are equal and thus cancel out. Additional electricity is added for functions such as lighting. For the limestone and lime processes 100 kW is added. For other processes more or less electricity, depending on the process type, size, and complexity, may be necessary.

Sample Calculation

Area		Total operating hp
1	Materials handling	70.5
2	Feed preparation	797.5
3	Gas handling	3,580.0
4	SO_2 absorption	6,189.0
5	Stack gas reheat	0.0
6	Oxidation	4,903.0
7	Solids disposal	71.0
	Total	15,611.0

15,611 hp x 0.7457 kW/hp = 11,641 kW

\+ 100 kW

11,741 kW

11,741 kW x 5,500 hr = 64,575,500 kWh

TABLE B-33. MAINTENANCE FACTORS

Process conditions	% of total direct investment excluding waste disposal		
	Low	Base	High
Corrosive or abrasive slurry	6	8	10
Solids, high pressure, or high temperature	4	5	6
Liquids and gases	3	4	5

TABLE B-34. MAINTENANCE FACTORS FOR SPECIFIC FGD PROCESSES

	Maintenance, % of total direct investment			
	FGD system			
	200 MW	500 MW	1000 MW	Waste disposal
Limestone and lime (generic)	9	8	7	3
Double alkali	7	6	5	3
Wellman-Lord	7	6	5	-
Magnesia	8	7	6	-
Lime spray dryer (including baghouse)	7	6	5	3

Byproduct sales--Total revenue from the sale of byproducts is applied as a credit to processes in which a byproduct is salable.

Capital Charges--

Capital charges are those costs incurred by construction of the facility that must be recovered during its life. They consist of returns on equity and debt (discount rate), depreciation, income taxes, and other costs such as insurance and local taxes. In keeping with common practice for investor-owned utilities the weighted cost of capital is used as the discount rate (16). Depreciation is stated as a sinking fund factor to simplify calculations. An allowance for interim replacement is included to compensate for possible early retirement of the facility. Credits are also included for tax preference allowances. The capital charges are shown in Table B-35 and discussed below. In keeping with standard practice, book, tax, and economic lives are used in the following calculations. In these premises, however, all three are assumed to be equal.

TABLE B-35. LEVELIZED ANNUAL CAPITAL CHARGES

	% of total capital investment remaining life, years			
	15	20 (existing plant)	25	30 (new plant)
Weighted cost of capital	10.00	10.00	10.00	10.00
Depreciation (sinking fund factor)	3.15	1.75	1.02	0.61
Annual interim replacement	0.72	0.67	0.62	0.56
Levelized accelerated tax depreciation	(1.44)	(1.43)	(1.40)	(1.36)
Levelized investment tax credit	(2.39)	(2.14)	(2.00)	(1.93)
Levelized income tax	3.96	4.08	4.20	4.31
Insurance and property taxes	2.50	2.50	2.50	2.50
Levelized annual capital charge	16.5[a]	15.4[a]	14.9[a]	14.7[a]

a. Rounded to three significant figures.

The capital structure is assumed to be 35% common stock, 15% preferred stock, and 50% long-term debt. The cost of capital is assumed to be 11.4% for common stock, 10.0% for preferred stock, and 9.0% for long-term debt. The weighted cost of capital (WCC) is 10.0%. The discount rate (r) is equal to the weighted cost of capital.

Other economic factors used in financial calculations are a 10% investment tax credit rate, 50% State plus Federal income taxes, 2.5% property tax and insurance, and an annual inflation rate of 6%. Salvage value is assumed to be less than 10% and equal to removal cost.

Weighted cost of capital is calculated as follows:

WCC = (fraction long-term debt)(long-term debt cost, %) +
(fraction preferred stock)(preferred stock cost, %) +
(fraction common stock)(common stock cost, %)

The sinking fund factor method of depreciation is used since it is equivalent to straight line depreciation levelized for the economic life of the facility using the weighted cost of capital. The use of the sinking fund factor does not suggest that regulated utilities commonly use sinking fund depreciation. All factors and rates are expressed as decimals. The equation is:

$$SFF = (WCC)/((1 + WCC)^{N_e} -1)$$

where: SFF = sinking fund factor

WCC = weighted cost of capital

N_e = economic life in years

An annual interim replacement (retirement dispersion) allowance of 0.56% for new plants and 0.67% for existing plants is also included as an adjustment to the depreciation account to ensure that the initial investment will be recovered within the actual rather than the forecasted life of the facility. Since power plant retirements occur at different ages, an average service life is estimated. The type S-1 Iowa State (17) retirement dispersion pattern is used in these premises. The S-1 pattern is symmetrical with respect to the average-life axis and the retirements are represented to occur at a low rate over many years. The interim replacement allowance does not cover replacement of individual items of equipment since these are covered by the maintenance charge.

Tax preference allowances are incentives designed to encourage investment as a stimulus to the overall economy. The basic accounting method used is the flow through method which passes the tax advantage to revenue requirements as soon as they occur.

Using the sum of the years digits method, which allocates costs early in the life of the facility, the accelerated tax depreciation (ATD) is calculated as follows:

$$ATD = (2)(CRF_e)(N_t - (1/CRF_t))/(N_t)(N_t + 1)(WCC)$$

where: CRF_e = capital recovery factor (WCC + SFF) for the economic life

CRF_t = capital recovery factor (WCC + SFF) for the tax life

N_t = tax life in years

Levelized accelerated tax depreciation is calculated as follows:

$$LATD = (ATD - SLD)(ITR)/(1 - ITR)$$

where: SLD = straight line depreciation

$= 1/N_b$

N_b = book life in years

ITR = income tax rate

The levelized investment tax credit is calculated as follows:

$$LITC = (CRF_e)(\text{investment tax credit rate})/(1 + WCC)(1 - ITR)$$

The levelized income tax is calculated as follows:

$$LIT = (CRF_b + AIR - SLD)(1 - ((\text{debt ratio} \times \text{debt cost})/WCC))$$
$$(ITR)/(1 - ITR)$$

where: LIT = levelized income tax

AIR = annual interim replacement

The capital charges are applied as a percentage of the total capital investment, including land and working capital. Although land and most of working capital cannot be depreciated and are not subject to investment tax credit, their inclusion has an insignificant effect on capital charges.

Levelized Operating and Maintenance Costs--

Assuming a constant inflation rate, the levelized operating and maintenance costs are determined by multiplying the first-year operating and maintenance costs by an appropriate levelizing factor, L_f. The levelizing factor is calculated as follows:

$$L_f = CRF_e\ (K + K^2 + K^3 + --- + K^N)$$
$$= CRF_e\ (K(1 - K^N))/(1 - K)$$

where: CRF_e = capital recovery factor (WCC + SFF) for the economic life (see the discussion of capital charges)

K = (1 + i)/(1 + r); present worth of an inflationary value

i = inflation rate

r = discount rate

N_b = book life in years

An inflation rate of 6% (i = 0.06) and a discount rate of 10% (d = 0.10) are used for new units. Values of L_f for power units with a remaining life of 15, 20, 25, and 30 (new unit) years are shown in Table B-36. The first-year operating and maintanance costs are multiplied by the appropriate L_f to obtain the levelized operating and maintenance costs.

TABLE 36. LEVELIZING FACTORS

Book[a] life, N_b	$K = \frac{1 + i}{1 + r}$	$\frac{K (1 - K^{Nb})}{1 - K}$	CRF_B[b] (r, N_b)	Levelizing factor, L_f
15	0.96364	11.2965	0.13147	1.485
20	0.96364	13.8669	0.11746	1.629
25	0.96364	16.0028	0.11017	1.763
30[c]	0.96364	17.7775	0.10608	1.886

a. Same as economic life (N_e) and tax life (N_t).
b. Discount rate (r) of 10%.
c. New units.

SI SYSTEM NOTATION

The SI system of metric units is not used as the primary numerical system in these premises because of the widespread use of traditional units in correlative and supportive literature and general practice. Use of the SI system is not standardized in the utility industry although steps in this direction are being made (18). The SI system specifies a number of rules of usage, form, and style in addition to the numerical standards. These too are part of the SI system and should be followed when using it. Detailed procedures for use of SI conventions in the primary data or conversion to SI convention are readily available in the literature. A detailed general guide to SI convention is available in ASTM E 380 79 (19). To provide uniformity in the comparison of data developed from these premises such a guide should be consulted in using the SI system.

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APPENDIX C

DETAILED DESCRIPTIONS OF MODEL INPUT VARIABLES

TABLE C-1. MODEL INPUTS - FORTRAN VARIABLE NAMES

Line	
1	XINPUT XBC XALK XSSV XSRHT
2	OUTPUT XHGAS XWGAS XRAIR XRGAS XSRHO XSKGAS XSSO XDIS XSTR XGPM XIT
3	IRPT IEQPR IWTBAL
4	Case identification (up to 72 alphanumeric characters)
5	XESP MW BHR HVC EXSAIR THG XRH KEPASS KPASO2 PSSO2X KCLEAN WPRCVR WPPSAC WPPSRC TSK TSTEAM HVS
6A	INPOPT WPC WPH WPO WPN WPSUL WPCL WPASH WPH2O SULO ASHO IASH ASHUPS ASHSCR
6B	INPOPT VCO2 VHCL VSO2 VO2 VN2 VH2O SCFM WASH SULO ASHO IASH ASHUPS ASHSCR
7	XLG VLG VTR V VRH ISO2 XSO2 TR XSR SRIN XIALK IADD WPMGO XMGOAD AD ADDC WPI WPM ASHCAO ASHMGO
8	WPS PSD RS PSC IFOX OX SRAIR PSF FILRAT PHLIME IVPD VPD DELTAP PRES IFAN
9	ISCRUB XNS XNG HS RAIN SEEPRT EVAPRT WINDEX HPTONW NSPREP NOTRAN NOREDN PCNTRN
10	ISLUDG SDFEE PSAMAX ACRE$ PDEPTH PMXEXC DISTPD ILINER XLINA XLINB
11	ENGIN ARCTEC FLDEXP FEES CONT START CONINT XINT PCTMNT PDMNTP XINFLA IECON PCTOVR XLEVEL/PCTADM CAPCHG/UNDCAP PCTMKT/PCTINS
12	ITAXFR TXRATE FRRATE SERVRT ROYALT IOTIME OTRATE INDPND PENGIN PARCH PFLDEX PFEES PCONT PSTART
13	UC(1) - UC(9) MINDEX LINDEX YRINV YRREV
14	IOPSCH PNDCAP BAGDLP BAGRAT BGCOST BGLIFE EFFPS ESPDLP RESIST SCARAT ICEPYE CHPIOX
15	IYROP
16	IA(1) - IA(10)
17	IA(11) - IA(20)
18	IA(21) - IA(30)
19	END or NEXT

Note: Lines 15-18 are needed only if IOPSCH = 3. The number of entries required on lines 16-18 depends on the number of years specified with the IYROP variable on line 15. Although 30 years is normally used as a maximum plant life, up to 50 years are allowed and up to two additional lines may be used for IA(31) - IA(50).

TABLE C-2. MODEL INPUT VARIABLE DEFINITIONS

Line No.	Variable	Definition	Units or values
1	XINPUT	Option to control the printing of input data variables. If a value of zero is selected, no input data variables are printed; the options to individually control the printing of input variables are ignored.	0 = no input data printed 1 = print input variables according to individual input print options
1	XBC	Controls the printing of boiler characteristics input variables.	0 = no print 1 = print
1	XALK	Controls the printing of alkali input variables.	0 = no print 1 = print
1	XSSV	Controls the printing of scrubber system input variables.	0 = no print 1 = print
1	XSRHT	Controls the printing of steam reheater input variables.	0 = no print 1 = print
2	OUTPUT	Option to control the printing of model output. If a value of zero is selected, no output listings are printed and the options to individually control the printing of output listings are ignored.	0 = no output data printed 1 = print output listings according to individual output print options
2	XHGAS	Controls the printing of calculated properties of hot gas to scrubber.	0 = no print 1 = print
2	XWGAS	Controls the printing of calculated properties of wet gas from scrubber.	0 = no print 1 = print
2	XRAIR	Controls the printing of calculated properties of reheater air.	0 = no print 1 = print
2	XRGAS	Controls the printing of calculated properties of reheater gas (oil-fired reheater only).	0 = no print 1 = print
2	XSRHO	Controls the printing of calculated properties of inline steam reheater.	0 = no print 1 = print
2	XSKGAS	Controls the printing of calculated properties of stack gas.	0 = no print 1 = print

(continued)

TABLE C-2 (continued)

Line No.	Variable	Definition	Units or values
2	XSSO	Controls the printing of calculated scrubber system parameters.	0 = no print 1 = print
2	XDIS	Controls the printing of calculated properties of system discharge stream.	0 = no print 1 = print
2	XSTR	Controls the printing of calculated properties of scrubber system internal streams (excluding sludge discharge and makeup water). This option does not affect the printout of total stream flow rate.	0 = no print 1 = print
2	XGPM	Controls printing of total flow rates (gpm and lb/hr) of internal streams (excluding sludge discharge and makeup water).	0 = no print 1 = print
2	XIT	For the iterative calculation of stoichiometry, this option controls the printing of the iteration number and of the current and the preceding stoichiometry values.	0 = no print 1 = print
3	IRPT	Option to select either a short-form printout (totals only) or a long-form printout.	0 = short print 1 = long print
3	IEQPR	Controls the printing of the equipment list.	0 = no print 1 = print
3	IWTBAL	Controls the printing of calculated properties of water balance.	0 = no print 1 = print
4	CASEID	Case identification - this field is free form and may be up to 72 characters in length.	
5	XESP	Particulate collection option No mechanical collector available Mechanical collector available Print internal model examples (costs are not included in FGD costs)	 0 1 2
5	MW	Electric power output	megawatts
5	BHR	Boiler heat rate	Btu/kWh
5	HVC	Heating value of coal	Btu/lb
5	EXSAIR	Excess air	percent
5	THG	Temperature of hot gas to scrubber	^{o}F

(continued)

TABLE C-2 (continued)

Line No.	Variable	Definition	Units or values
5	XRH	Reheat option	
		No reheat	0
		Inline steam reheater (XRH value = 2) is the only type of reheat available at this time.	2
5	KEPASS	Emergency bypass option	
		No emergency bypass	0
		Emergency bypass	1
5	KPASO2	Partial scrubbing/bypass option	
		No partial scrubbing/bypass	0
		Partial scrubbing/bypass	1
5	PSSO2X	Percent SO_2 removal in the scrubber when partial scrubbing/bypass is specified	percent removal
5	KCLEAN	Coal cleaning option	
		No coal cleaning	0
		Coal cleaning	1
5	WPRCVR	Percent weight recovery (lb clean coal per lb raw coal) when coal cleaning is specified	percent
5	WPPSAC	Weight percent of pyritic sulfur plus ash in cleaned coal when coal cleaning is specified	weight percent
5	WPPSRC	Weight percent of pyritic sulfur in raw coal when coal cleaning is specified	weight percent
5	TSK	Temperature of stack gas	^oF
5	TSTEAM	Temperature of reheater steam	^oF
5	HVS	Heat of vaporization of reheater steam	Btu/lb
		The composition input specified on either line 6A or 6B depends on the composition option, INPOPT. If a coal composition will be input (INPOPT = 1) then line 6A is used. If a flue gas composition will be input (INPOPT = 2) then line 6B is used.	
6A	INPOPT	Composition input option	
		Coal composition will be input using line 6A	1

(continued)

TABLE C-2 (continued)

Line No.	Variable	Definition	Units or values
6A	WPC }		
6A	WPH }		
6A	WPO }		
6A	WPN } --	Amount of component (C, H, O, N, S, Cl, ash, H_2O) in coal. WPSUL is the total of both organic sulfur and pyritic sulfur.	weight percent
6A	WPSUL }		
6A	WPCL }		
6A	WPASH }		
6A	WPH2O }		
6A	SULO	Sulfur to overhead as SO_2 gas (remainder goes to bottom ash).	weight percent
6A	ASHO	Ash to overhead as particulates (remainder goes to bottom ash).	weight percent
6A	IASH	Unit of measure option for particulate removal	
		Default to model assumptions	0
		Percent removal	1
		Pounds particulates per MBtu	2
		Upstream removal (percent) with scrubber default	3
		(The actual values for particulate removal are provided by the ASHUPS and ASHSCR variables that immediately follow.)	
6A	ASHUPS	Value for particulate removal upstream from scrubber (Unit of measure is indicated by the IASH option above.)	
6A	ASHSCR	Value for particulate removal within scrubber (Unit of measure is indicated by the IASH option above.)	

(continued)

TABLE C-2 (continued)

Line No.	Variable	Definition	Units or values
6B	INPOPT	Composition input option Flue gas composition will be input using line 6B	 2
6B	VCO2 }		
6B	VHCL }		
6B	VSO2 } ---	Amount of component (CO_2, HCl, SO_2, O_2, N_2, and H_2O) in flue gas	volume percent
6B	VO2 }		
6B	VN2 }		
6B	VH2O }		
6B	SCFM	Standard cubic feet per minute (60^oF), gas from boiler	scfm
6B	WASH	Pounds of ash per hour in hot gas from boiler	lb/hr
6B	SULO	Should be set to 100 when flue gas composition is input	
6B	ASHO	Should be set to 100 when flue gas composition is input	
6B	IASH	See line 6A	
6B	ASHUPS	See line 6A	
6B	ASHSCR	See line 6A	
7	XLG	L/G ratio in scrubber (Refer to the XSR option on the following page.)	gal /kft^3
7	VLG	L/G ratio in venturi	gal /kft^3
7	VTR	Venturi/oxidation hold tank residence time. This variable is used to specify residence time in the second effluent tank when two tanks are specified. Two tanks may be specified by the forced oxidation option (IFOX, line 8), the scrubber option (ISCRUB, line 9), or both. VTR should be set to zero when only one effluent tank is used (see the TR variable below).	minute

(continued)

TABLE C-2 (continued)

Line No.	Variable	Definition	Units or values
7	V	Scrubber gas velocity (superficial)	ft/sec
7	VRH	Superficial gas velocity through reheater (face velocity)	ft/sec
7	ISO2	Unit of measure option for SO_2 removal	
		SO_2 to be removed is a percent value	1
		SO_2 emission concentration is a pounds SO_2/MBtu value	2
		SO2 emission concentration is a ppm value	3
		(The actual value for SO_2 removal is provided by the XSO2 variable that immediately follows.)	
		Revised NSPS (1978 Federal Register)	4
7	XSO2	Value for SO_2 to be removed. Unit of measure is indicated by the ISO2 option above; refer to the XSR option below for additional requirements. The value for XSO2 is automatically calculated when ISO2 = 4 and any input value will be ignored.	
7	TR	Recirculation/oxidation hold tank residence time. This variable is used to specify residence time in the effluent tank when only one tank is specified. If two tanks are specified, TR specifies residence time in the first tank (see the VTR variable above).	minute
7	XSR	Stoichiometry, L/G in scrubber, and SO_2 removal option. This option controls model processing of the stoichiometry value, SRIN, below; the L/G ratio in the scrubber, XLG, on the preceding page; and the SO_2 to be removed, XSO2, above (if XSO2 is required then ISO2 is also required).	
		SRIN, XLG, and XSO2 (also ISO2) will be processed as input variables. (No checks are made for validity or consistency among the specified values.)	0
		XLG and XSO2 (also ISO2) will be processed as input variables and SRIN will be calculated by the model.	1

(coninued)

TABLE C-2 (continued)

Line No.	Variable	Definition	Units or values
		SRIN and XSO2 (also ISO2) will be processed as input variables and XLG will be calculated by the model.	2
		SRIN and XLG will be processed as input variables; the value for SO_2 to be removed (XSO2) will be calculated by the model; and all three units of measure (ISO2) will be provided in the calculated results. Any user input values for ISO2 and XSO2 will be ignored.	3
7	SRIN	Value for stoichiometry (refer to the XSR option above)	mols $CaCO_3$ added as limestone per mol SO_2 absorbed
7	XIALK	Alkali addition option	
		Limestone	1
		Lime	2
7	IADD	Chemical additive option	
		No chemical additive	0
		MgO added	1
		Adipic acid added	2
7	WPMGO	Soluble MgO in limestone or lime	weight percent dry basis
7	XMGOAD	Soluble MgO added to system (used only when MgO added, see IADD above)	pound soluble MgO/100 pound limestone
7	AD	Adipic acid added to system (used only when adipic acid added, see IADD above)	ppm
7	ADDC	Adipic acid degradation constant (used only when adipic acid added, see IADD above)	
7	WPI	Insolubles in limestone-lime additive	weight percent dry basis
7	WPM	Moisture in limestone-lime additive	lb/100 pound dry additive
7	ASHCAO	Soluble CaO in particulates	weight percent

(continued)

TABLE C-2 (continued)

Line No.	Variable	Definition	Units or values
7	ASHMGO	Soluble MgO in particulates	weight percent
8	WPS	Solids in recycle slurry to scrubber	weight percent
8	PSD	Solids in sludge discharge	weight percent
8	RS	Clarifier solids settling rate	ft/hr
8	PSC	Percent solids in clarifier underflow	weight percent
8	IFOX	Forced oxidation option	
		No forced oxidation	0
		Forced oxidation in a single effluent tank	1
		Forced oxidation in the first of two effluent tanks	2
		Forced oxidation in the disposal feed tank	3
8	OX	Oxidation of sulfite in scrubber system	mol percent
8	SRAIR	Air stoichiometry value	g-atoms O/g-mol SO_2 absorbed
8	PSF	Percent solids in filter cake	percent
8	FILRAT	Filtration rate	tons/ft^2/day
8	PHLIME	Recirculation liquor pH for lime system (value is ignored for limestone system)	
8	IVPD	Venturi ΔP option	
		ΔP is input in inches H_2O	0
		Throat velocity (ft/sec) is input and the corresponding VPD is calculated	1
8	VPD	Value for either ΔP or throat velocity indicated by the IVPD option above	inch H_2O or (ft/sec)
8	DELTAP	Override ΔP for entire system	inch H_2O
8	PRES	Scrubber pressure	psia
8	IFAN	Fan option	
		Forced draft fans	0
		Induced draft fans	1

(continued)

TABLE C-2 (continued)

Line No.	Variable	Definition	Units or values
9	ISCRUB	Scrubbing option	
		Spray tower	1
		TCA	2
		Venturi-spray tower, two effluent tanks	3
		Venturi-spray tower, one effluent tank	4
		Venturi-TCA, two effluent tanks	5
		Venturi-TCA, one effluent tank	6
9	XNS	Number of TCA stages	
9	XNG	Number of TCA grids	
9	HS	Height of spheres per stage	inch
9	RAIN	Annual rainfall	in./yr
9	SEEPRT	Seepage rate	cm/sec
9	EVAPRT	Annual evaporation	in./yr
9	WINDEX	Limestone hardness work index factor value 5-15. (Example: 10)	wi
9	HPTONW	Fineness of grind index factor (see Table C-3)	hp/ton
9	NSPREP	Number of spare preparation units	(0-9)
9	NOTRAN	Number of operating scrubber trains	
9	NOREDN	Number of spare scrubber trains	
9	PCNTRN	Entrainment level as percentage of wet gas from scrubber. (Example: 0.1)	weight percent
10	ISLUDG	Sludge disposal option	
		Onsite ponding	1
		Thickener - ponding	2
		Thickener - fixation (fee)	3
		Thickener - filter - fixation (fee)	4
10	SDFEE	Sludge disposal fee. (Either an actual value or a zero value must be provided; refer to the ISLUDG option above.)	$/ton dry sludge

(continued)

TABLE C-2 (continued)

Line No.	Variable	Definition	Units or values
10	PSAMAX	Total available land for construction of pond	acres
10	ACRE$	Land cost	$/acre
10	PDEPTH	Final depth of sludge in pond	feet
10	PMXEXC	Maximum excavation depth	feet
10	DISTPD	Distance from scrubber area to pond	feet
10	ILINER	Pond lining option Clay liner Synthetic liner No liner (Refer to the XLINA and XLINB variables that immediately follow.)	 1 2 3
10	XLINA	If ILINER = 1, XLINA = clay depth If ILINER = 2, XLINA = material unit cost If ILINER = 3, XLINA = 0	inch $\$/yd^2$
10	XLINB	If ILINER = 1, XLINB = clay cost If ILINER = 2, XLINB = labor unit cost If ILINER = 3, XLINB = 0	$\$/yd^3$ $\$/yd^2$
11	ENGIN	Engineering design and supervision	percent
11	ARCTEC	Architect and engineering contractor	percent
11	FLDEXP	Construction field expenses	percent
11	FEES	Contractor fees	percent
11	CONT	Contingency	percent
11	START	Allowance for startup and modifications	percent
11	CONINT	Interest during construction	percent
11	XINT	Cost of capital	percent

(continued)

TABLE C-2 (continued)

Line No.	Variable	Definition	Units or values
11	PCTMNT	Maintenance rate, applied as percent of direct investment excluding pond cost	percent
11	PDMNTP	Pond maintenance rate, applied as percent of direct pond investment	percent
11	XINFLA	Inflation factor (used only when unlevelized lifetime revenue requirements are calculated, see Appendix B)	percent
11	IECON	Economic premises option (see the Model Description Section and Appendix B)	
		TVA/EPA economic premises beginning 12/5/79	1
		TVA/EPA economic premises prior to 12/5/79	0
11	PCTOVR	Plant overhead rate, applied as percent of conversion costs less utilities	percent
11	XLEVEL/ PCTADM	The use of this variable depends on the economic premises specified (IECON, line 11). If new premises are specified (IECON = 1), XLEVEL specifies the levelizing factor to be applied to first-year operating and maintenance costs to obtain levelized lifetime costs. If XLEVEL is set to zero there is no levelizing and a lifetime revenue sheet is generated. If old premises are specified (IECON = 0), PCTADM specifies the administrative research and service overhead rate, applied as a percent of operating labor and supervision.	percent
11	CAPCHG/ UNDCAP	If new premises are specified (IECON = 1) CAPCHG specifies levelized annual capital charges applied as a percent of total capital investment. If old economic premises are specified (IECON = 0) UNDCAP specifies the annual capital charge basis for undepreciated investment.	percent
11	PCTMKT/ PCTINS	If new premises are specified (IECON = 1) PCTMKT specifies marketing costs applied as a percent of byproduct credit (applies only to processes with a salable byproduct). If old economic premises are specified (IECON = 0) PCTINS specifies the rate for insurance and interim replacements applied as a percent of total capital investment.	percent
12	ITAXFR	Sales tax and freight option	
		No sales tax or freight	0
		Sales tax and freight rates applied based on TXRATE and FRRATE below	1

(continued)

TABLE C-2 (continued)

Line No.	Variable	Definition	Units or values
12	TXRATE	Sales tax rate (applied only when ITAXFR above set to 1)	percent
12	FRRATE	Freight rate (applied only when ITAXFR above set to 1)	percent
12	SERVRT	Services, utilities, and miscellaneous, applied as a percent of total process capital	percent
12	ROYALT	Royalties, applied as a percent of total process capital	percent
12	IOTIME	Overtime labor option	
		No overtime labor	0
		Overtime labor on 7% of total labor based on the OTRATE rate below	1
12	OTRATE	Overtime labor rate (applied to 7% of total labor) Example: 1.5	
12	INDPND	Separate indirect investment factors option for pond construction	
		No separate indirect factors for pond construction (same as process indirects)	0
		Separate indirects for pond construction specified by PENGIN, PARCH, PFLDEX, PFEES, PCONT, and PSTART below	1
12	PENGIN	Pond construction engineering design and supervision (applied only when INDPND above set to 1)	percent
12	PARCH	Pond construction architect and engineering contractor (applied only when INDPND above set to 1)	percent
12	PFLDEX	Pond construction field expenses (applied only when INDPND above set to 1)	percent
12	PFEES	Pond construction contractor fees (applied only when INDPND above set to 1)	percent
12	PCONT	Pond construction contingency (applied only when INDPND above set to 1)	percent
12	PSTART	Allowance for pond startup and modification (applied only when INDPND above set to 1)	percent

(continued)

TABLE C-2 (continued)

Line No.	Variable	Definition	Units or values
13	UC (1)	Limestone unit cost	\$/ton
13	UC (2)	Lime unit cost	\$/ton
13	UC (3)	MgO unit cost	\$/ton
13	UC (4)	Adipic acid unit cost	\$/ton
13	UC (5)	Operating labor and supervision unit cost	\$/man-hr
13	UC (6)	Steam unit cost	\$/klb
13	UC (7)	Process water unit cost	\$/kgal
13	UC (8)	Electricity unit cost	\$/kWh
13	UC (9)	Analyses unit cost	\$/hr
13	MINDEX	*Chemical Engineering* material cost index (see Table B-23)	
13	LINDEX	*Chemical Engineering* labor cost index (see Table B-23)	
13	YRINV	Investment year cost basis	year
13	YRREV	Revenue requirement year cost basis	year
14	IOPSCH	Operating profile option	
		TVA profile	1
		FERC profile	2
		User input profile (Refer to the IYROP and IA(n) options on lines 15-18.)	3
		Levelized operating profile, 5500 hr/yr	4
14	PNDCAP	Expected pond capacity (controls pond design capacity; if 100% of sludge is to be ponded over the life of the unit, input 1.0; if 80% of sludge is to be ponded, input 0.80.)	
14	BAGDLP	Baghouse pressure drop	inches H_2O
14	BAGRAT	Baghouse ratio (typically = 0.8)	$\frac{\text{open ft}^2}{\text{actual ft}^2}$
14	BGCOST	Bag cost	\$/ft^2

(continued)

TABLE C-2 (continued)

Line No.	Variable	Definition	Units or values
14	BGLIFE	Bag life	years
14	EFFPS	ESP rectification efficiency (Example - .65)	decimal
14	ESPDLP	ESP pressure drop	inches H_2O
14	RESIST	Resistivity option (high or low)[a] Assume ω = 20 ft/min Assume ω = 30	 1 2
14	SCARAT	SCA ratio Contingency or safety factor (fractional) to apply to calculated collected area	
14	ICEPYE	<u>Chemical Engineering</u> plant index year	year
14	CHPIOX	<u>Chemical Engineering</u> plant index (see Table B-1)	
15	IYROP	Years remaining life (lines 15 through 18 are needed only if the IOPSCH variable, line 14, is set to 3. Although only 30 years are shown, up to 50 years may be used and up to two additional lines are used for IA(31) - IA(50)	
16	IA(1) - IA(10)	Operating hr/yr (input only 10 years per line)	
17	IA(11) - IA(20)	Operating hr/yr (input only 10 years per line)	
18	IA(21) - IA(30)	Operating hr/yr (input only 10 years per line)	
19	END or NEXT	"END" terminates further execution. "NEXT" execution will continue with the next group of input variables. (If variable IOPSCH on line 14 is not equal to 3, line 15 will be the "END" or "NEXT" line.)	

a. Required for sizing hot ESP. Drift velocity (ω) is related to percent sulfur in the cold ESP model, but is an input for the hot ESP model.

TABLE C-3. LIMESTONE FINENESS OF GRIND INDEX FACTOR

Ground limestone product size distribution			Index factor (HPTONW)
80%- micron	% -200 mesh	% -325 mesh	hp/ton
129	60		1.11
113	65		1.22
98	70		1.35
85	75		1.51
74	80		1.72
62	85		2.04
58	86	70	2.19
51	90	75	2.54
44	93	80	3.04
40	95		3.40
37		85	3.64
31		90	4.44
24		95	5.70 Base

Data from KVS Rock Talk Manual, Kennedy Van Saun Corporation, Danville, Pennsylvania, 1974. Total ballmill horsepower is calculated using the limestone hardness work index factor, wi, and the fineness of grind index factor as follows: hp = (tons/hr limestone)(wi)(fineness of grind index factor).

APPENDIX D

BASE CASE INPUT AND PRINTOUT

TABLE D-1. BASE CASE PRINTOUT

```
1 1 1 1 1
1 1 1 1 1 1 1 1 1 1 1 1
1 1 1
BASE MANUAL
2 500 9500 11700 39 300 2 1 0 0 0 0 0 0 175 470 751
1 66.7 3.8 5.6 1.3 3.36 0.1 15.1 4.0 92 80 2 .06 .03
90 0 0 10 25 4 0.0 10 1 0.0 1 0 0.15 0 0 0 4.85 5 0 0
15 40 0.2 40 0 30 0.0 80 1.2 0.0 0 9 0 14.7 1
1 0 0 0 35 .0000005 32 10 5.70 1 4 1 .1
1 0 9999 5000 0 25 5280 1 12 4.75
7 2 16 5 10 8 15.6 10 8 3 6 1 60 1.886 14.7 0.0
1 4 3.5 6 0 1 1.5 1 2 1 8 5 10 0
8.50 75.00 460 1200 15 2.5 0.14 0.037 21.00 336.1 245.5 1982 1984
4 1 5 .8 1.0 3 .65 1 1 1.1 1982 297.9
END
```

(continued)

TABLE D-1 (continued)

TENNESSEE VALLEY AUTHORITY
SHAWNEE LIMESTONE OR LIME SCRUBBING PROCESS
COMPUTERIZED DESIGN-COST ESTIMATE MODEL

REVISION DATE DECEMBER 10, 1980

(continued)

TABLE D-1 (continued)

BASE MANUAL CASE 1

*** INPUTS ***

BOILER CHARACTERISTICS

MEGAWATTS = 500.

BOILER HEAT RATE = 9500. BTU/KWH

EXCESS AIR = 39. PERCENT, INCLUDING LEAKAGE

HOT GAS TEMPERATURE = 300. DEG F

COAL ANALYSIS, WT % AS FIRED :

C	H	O	N	S	CL	ASH	H2O
66.70	3.80	5.60	1.30	3.36	0.10	15.10	4.00

SULFUR OVERHEAD = 92.0 PERCENT

ASH OVERHEAD = 80.0 PERCENT

HEATING VALUE OF COAL = 11700. BTU/LB

FLYASH REMOVAL	EFFICIENCY, %	EMISSION, LBS/M BTU
UPSTREAM OF SCRUBBER	99.4	0.06
WITHIN SCRUBBER	50.0	0.03

COST OF UPSTREAM FLYASH REMOVAL EXCLUDED

ALKALI

LIMESTONE :

CACO3 = 95.00 WT % DRY BASIS
SOLUBLE MGO = 0.15
INERTS = 4.85
MOISTURE CONTENT = 5.00 LB H2O/100 LBS DRY LIMESTONE
LIMESTONE HARDNESS WORK INDEX FACTOR = 10.00
LIMESTONE DEGREE OF GRIND FACTOR = 5.70

FLY ASH :

SOLUBLE CAO = 0.0 WT %
SOLUBLE MGO = 0.0
INERTS = 100.00

(continued)

TABLE D-1 (continued)

RAW MATERIAL HANDLING AREA
--- -------- -------- ----

NUMBER OF REDUNDANT ALKALI PREPARATION UNITS = 1

SCRUBBER SYSTEM VARIABLES
-------- ------ ---------

NUMBER OF OPERATING SCRUBBING TRAINS = 4

NUMBER OF REDUNDANT SCRUBBING TRAINS = 1

SPRAY TOWER LIQUID-TO-GAS RATIO = 90. GAL/1000 ACF(SATD)

SPRAY TOWER GAS VELOCITY = 10.0 FT/SEC

INDUCED DRAFT SCRUBBER FAN OPTION

SCRUBBER PRESSURE = 14.7 PSIA

SO2 CONCENTRATION IN SCRUBBER OUTLET GAS TO BE CALCULATED FOR NSPS

STOICHIOMETRY RATIO TO BE CALCULATED

ENTRAINMENT LEVEL = 0.10 WT %

EHT RESIDENCE TIME = 10.0 MIN

SO2 OXIDIZED IN SYSTEM = 30.0 PERCENT

SOLIDS IN RECIRCULATED SLURRY = 15.0 WT %

SOLIDS DISPOSAL SYSTEM
------ -------- ------

COST OF LAND = 5000.00 DOLLARS/ACRE

SOLIDS IN SYSTEM SLUDGE DISCHARGE = 40.0 WT %

MAXIMUM POND AREA = 9999. ACRES

MAXIMUM EXCAVATION = 25.00 FT

DISTANCE TO POND = 5280. FT

POND LINED WITH 12.0 INCHES CLAY

(continued)

TABLE D-1 (continued)

STEAM REHEATER (IN-LINE)
----- -------- ---------

SATURATED STEAM TEMPERATURE = 470. DEG F

HEAT OF VAPORIZATION OF STEAM = 751. BTU/LB

OUTLET FLUE GAS TEMPERATURE = 175. DEG F

SUPERFICIAL GAS VELOCITY (FACE VELOCITY) = 25.0 FT/SEC

ECONOMIC CHARACTERISTICS
-------- ---------------

1979 TVA-EPA ECONOMIC PREMISES

PROJECTED REVENUE REQUIREMENTS INCLUDE LEVELIZED OPERATING AND MAINTENANCE COSTS
RATE = 1.806 TIMES FIRST YEAR OPERATING AND MAINTENANCE COSTS

FREIGHT INCLUDED IN TOTAL INVESTMENT
FREIGHT RATE = 3.5 %

SALES TAX INCLUDED IN TOTAL INVESTMENT
SALES TAX RATE = 4.0 %

LABOR OVERTIME INCLUDED IN TOTAL INVESTMENT
OVERTIME RATE = 1.5

INFLATION RATE = 6.0 %

PROCESS MAINTENANCE = 8.0 %

POND MAINTENANCE = 3.0 %

IT	SR	SROLD
1	1.51	1.50
2	1.51	1.51

(continued)

TABLE D-1 (continued)

BASE MANUAL CASE 1

*** OUTPUTS ***

EMERGENCY BY-PASS

EMERGENCY BY-PASS DESIGNED FOR 50.0 %

HOT GAS TO SCRUBBER

	MOLE PERCENT	LB-MOLE/HR	LB/HR
CO2	12.338	0.2255E+05	0.9923E+06
HCL	0.006	0.1145E+02	0.4175E+03
SO2	0.214	0.3914E+03	0.2508E+05
O2	5.560	0.1016E+05	0.3251E+06
N2	75.227	0.1375E+06	0.3852E+07
H2O	6.654	0.1216E+05	0.2191E+06

SO2 CONCENTRATION IN SCRUBBER INLET GAS = 2142. PPM
= 5.28 LBS / MILLION BTU

FLYASH EMISSION = 0.060 LBS/MILLION BTU
= 0.029 GRAINS/SCF (WET) OR 285. LB/HR

SOLUBLE CAO IN FLY ASH = 0. LB/HR
SOLUBLE MGO IN FLY ASH = 0.

HOT GAS FLOW RATE = .1154E+07 SCFM (60. DEG F, 14.7 PSIA)
= .1687E+07 ACFM (300. DEG F, 14.7 PSIA)

CORRESPONDING COAL FIRING RATE = .4060E+06 LB/HR

HOT GAS HUMIDITY = 0.042 LB H2O/LB DRY GAS

WET BULB TEMPERATURE = 124. DEG F

(continued)

TABLE D-1 (continued)

WET GAS FROM SCRUBBER

	MOLE PERCENT	LB-MOLE/HR	LB/HR
CO2	11.713	0.2291E+05	0.1008E+07
HCL	0.000	0.5726E+00	0.2088E+02
SO2	0.023	0.4449E+02	0.2850E+04
O2	5.169	0.1011E+05	0.3235E+06
N2	70.300	0.1375E+06	0.3852E+07
H2O	12.795	0.2502E+05	0.4508E+06

SO2 CONCENTRATION IN SCRUBBER OUTLET GAS = 228. PPM

FLYASH EMISSION = 0.030 LBS/MILLION BTU
= 0.013 GRAINS/SCF (WET) OR 143. LB/HR

TOTAL WATER PICKUP = 475. GPM
INCLUDING 11.3 GPM ENTRAINMENT

WET GAS FLOW RATE = .1235E+07 SCFM (60. DEG F, 14.7 PSIA)
= .1388E+07 ACFM (124. DEG F, 14.7 PSIA)

WET GAS SATURATION HUMIDITY = 0.087 LB H2O/LB DRY GAS

(continued)

TABLE D-1 (continued)

FLUE GAS TO STACK

	MOLE PERCENT	LB-MOLE/HR	LB/HR
CO2	11.695	0.2291E+05	0.1008E+07
HCL	0.000	0.3726E+00	0.2088E+02
SO2	0.023	0.4449E+02	0.2850E+04
O2	5.161	0.1011E+05	0.3235E+06
N2	70.187	0.1375E+06	0.3852E+07
H2O	12.934	0.2533E+05	0.4564E+06

CALCULATED SO2 REMOVAL EFFICIENCY = 88.7 %

CALCULATED SO2 EMISSION = 0.60 POUNDS PER MILLION BTU

CALCULATED SO2 CONCENTRATION IN STACK GAS = 227. PPM

CALCULATED HCL CONCENTRATION IN STACK GAS = 3. PPM

SO2 REMOVAL CALCULATED FROM SCRUBBER OPERATING
PARAMETERS ANY SPECIFIED REMOVAL/EMISSION VALUES ARE IGNORED

FLYASH EMISSION = 0.030 LBS/MILLION BTU
= 0.013 GRAINS/SCF (WET) OR 143. LB/HR

STACK GAS FLOW RATE = .1237E+07 SCFM (60. DEG F, 14.7 PSIA)
= .1511E+07 ACFM (175. DEG F, 14.7 PSIA)

(continued)

STEAM REHEATER (IN-LINE)

SUPERFICIAL GAS VELOCITY (FACE VELOCITY) = 25.0 FT/SEC

SQUARE PIPE PITCH = 2 TIMES ACTUAL PIPE O.D.

SATURATED STEAM TEMPERATURE = 470. DEG F

OUTLET FLUE GAS TEMPERATURE = 175. DEG F

REQUIRED HEAT INPUT TO REHEATER = 0.7458E+08 BTU/HR

STEAM CONSUMPTION = 0.9930E+05 LBS/HR

OUTSIDE PIPE DIAMETER, IN.	PRESSURE DROP IN. H2O	HEAT TRANSFER COEFFICIENT, BTU/HR FT2 DEG F	NUMBER OF PIPES PER BANK PER TRAIN
1.00	0.75	0.2096E+02	91

	REHEATER OUTSIDE PIPE AREA, SQ FT PER TRAIN	NUMBER OF BANKS (ROWS) PER TRAIN
INCONEL	0.1533E+04	4
CORTEN	0.1235E+04	3
TOTAL	0.2768E+04	7

OUTLET SCRUBBER DUCTS ARE CORTEN

(continued)

TABLE D-1 (continued)

WATER BALANCE INPUTS
----- ------- ------

RAINFALL(IN/YEAR)	35.
POND SEEPAGE(CM/SEC)*10**8	50.
POND EVAPORATION(IN/YEAR)	32.

WATER BALANCE OUTPUTS
----- ------- -------

WATER AVAILABLE

RAINFALL	620. GPM	309789. LB/HR
ALKALI	6. GPM	2789. LB/HR
TOTAL	625. GPM	312579. LB/HR

WATER REQUIRED

HUMIDIFICATION	464. GPM	231707. LB/HR
ENTRAINMENT	11. GPM	5630. LB/HR
DISPOSAL WATER	208. GPM	103836. LB/HR
HYDRATION WATER	12. GPM	5876. LB/HR
CLARIFIER EVAPORATION	0. GPM	0. LB/HR
POND EVAPORATION	609. GPM	304255. LB/HR
SEEPAGE	110. GPM	54947. LB/HR
TOTAL WATER REQUIRED	1413. GPM	706251. LB/HR

NET WATER REQUIRED	788. GPM	393672. LB/HR

(continued)

TABLE D-1 (continued)

SCRUBBER SYSTEM
-------- ------

TOTAL NUMBER OF SCRUBBING TRAINS (OPERATING+REDUNDANT) = 5

SO2 REMOVAL = 88.6 PERCENT

PARTICULATE REMOVAL IN SCRUBBER SYSTEM = 50.0 PERCENT

SPRAY TOWER PRESSURE DROP = 2.2 IN. H2O

TOTAL SYSTEM PRESSURE DROP = 7.5 IN. H2O

SPECIFIED SPRAY TOWER L/G RATIO = 90. GAL/1000 ACF(SATD)

LIMESTONE ADDITION = 0.5578E+05 LB/HR DRY LIMESTONE

CALCULATED LIMESTONE STOICHIOMETRY = 1.50 MOLE CACO3 ADDED AS LIMESTONE PER MOLE (SO2+2HCL) ABSORBED

SOLUBLE CAO FROM FLY ASH = 0.0 MOLE PER MOLE (SO2+2HCL) ABSORBED

TOTAL SOLUBLE MGO = 0.01 MOLE PER MOLE (SO2+2HCL) ABSORBED

TOTAL STOICHIOMETRY = 1.51 MOLE SOLUBLE (CA+MG) PER MOLE (SO2+2HCL) ABSORBED

SCRUBBER INLET LIQUOR PH = 5.68

MAKE UP WATER = 788. GPM

CROSS-SECTIONAL AREA PER SCRUBBER = 578. SQ FT

SYSTEM SLUDGE DISCHARGE
------ ------ ---------

SPECIES	LB-MOLE/HR	LB/HR	SOLID COMP, WT %	LIQUID COMP, PPM
CASO3 .1/2 H2O	0.2428E+03	0.3134E+05	44.92	
CASO4 .2H2O	0.1024E+03	0.1762E+05	25.25	
CACO3	0.1795E+03	0.1796E+05	25.75	
INSOLUBLES	----------	0.2846E+04	4.08	
H2O	0.5764E+04	0.1038E+06		
CA++	0.5287E+01	0.2119E+03		2024.
MG++	0.2075E+01	0.5044E+02		482.
SO3--	0.1934E+00	0.1548E+02		148.
SO4--	0.1725E+01	0.1657E+03		1583.
CL-	0.1088E+02	0.3857E+03		3685.

TOTAL DISCHARGE FLOW RATE = 0.1744E+06 LB/HR
= 263. GPM

TOTAL DISSOLVED SOLIDS IN DISCHARGE LIQUID = 7905. PPM

DISCHARGE LIQUID PH = 7.42

(continued)

TABLE D-1 (continued)

SCRUBBER SLURRY BLEED

SPECIES	LB-MOLE/HR	LB/HR
CASO3 .1/2 H2O	0.2428E+03	0.3134E+05
CASO4 .2H2O	0.1024E+03	0.1762E+05
CACO3	0.1795E+03	0.1796E+05
INSOLUBLES	----------	0.2848E+04
H2O	0.2177E+05	0.3923E+06
CA++	0.1997E+02	0.8005E+03
MG++	0.7839E+01	0.1906E+03
SO3--	0.7305E+00	0.5849E+02
SO4--	0.6515E+01	0.6258E+03
CL-	0.4110E+02	0.1457E+04
AD=	0.0	0.0

TOTAL FLOW RATE = 0.4652E+06 LB/HR
= 845. GPM

TOTAL SUPERNATE RETURN

SPECIES	LB-MOLE/HR	LB/HR
H2O	0.1329E+05	0.2394E+06
CA++	0.1219E+02	0.4885E+03
MG++	0.4784E+01	0.1163E+03
SO3--	0.4459E+00	0.3570E+02
SO4--	0.3976E+01	0.3820E+03
CL-	0.2508E+02	0.8893E+03
AD=	0.0	0.0

TOTAL FLOW RATE = 0.2413E+06 LB/HR
= 483. GPM

SUPERNATE TO WET BALL MILL

SPECIES	LB-MOLE/HR	LB/HR
H2O	0.1910E+04	0.3442E+05
CA++	0.1752E+01	0.7023E+02
MG++	0.6878E+00	0.1672E+02
SO3--	0.6409E-01	0.5131E+01
SO4--	0.5716E+00	0.5491E+02
CL-	0.3606E+01	0.1278E+03
AD=	0.0	0.0

TOTAL FLOW RATE = 0.3469E+05 LB/HR
= 69. GPM

(continued)

TABLE D-1 (continued)

LIMESTONE SLURRY FEED

SPECIES	LB-MOLE/HR	LB/HR
CACO3	0.5294E+03	0.5300E+05
SOLUBLE MGO	0.2076E+01	0.8368E+02
INSOLUBLES	----------	0.2706E+04
H2O	0.2048E+04	0.3690E+05
CA++	0.1752E+01	0.7023E+02
MG++	0.6878E+00	0.1672E+02
SO3--	0.6409E-01	0.5131E+01
SO4--	0.5716E+00	0.5491E+02
CL-	0.3606E+01	0.1278E+03
AD*	0.0	0.0

TOTAL FLOW RATE = 0.9297E+05 LB/HR
= 117. GPM

SUPERNATE RETURN TO SCRUBBER OR EHT

SPECIES	LB-MOLE/HR	LB/HR
H2O	0.1138E+05	0.2050E+06
CA++	0.1044E+02	0.4183E+03
MG++	0.4097E+01	0.9959E+02
SO3--	0.3818E+00	0.3056E+02
SO4--	0.3405E+01	0.3270E+03
CL-	0.2148E+02	0.7614E+03
AD*	0.0	0.0

TOTAL FLOW RATE = 0.2066E+06 LB/HR
= 413. GPM

RECYCLE SLURRY TO SPRAY TOWER

SPECIES	LB-MOLE/HR	LB/HR
CASO3 .1/2 H2O	0.3589E+05	0.4633E+07
CASO4 .2H2O	0.1514E+05	0.2605E+07
CACO3	0.2653E+05	0.2656E+07
INSOLUBLES	----------	0.4210E+06
H2O	0.3219E+07	0.5799E+08
CA++	0.2952E+04	0.1183E+06
MG++	0.1159E+04	0.2817E+05
SO3--	0.1080E+03	0.8646E+04
SO4--	0.9631E+03	0.9251E+05
CL-	0.6076E+04	0.2154E+06
AD*	0.0	0.0

TOTAL FLOW RATE = 0.6876E+08 LB/HR
= 124890. GPM

(continued)

TABLE D-1 (continued)

FLUE GAS COOLING SLURRY

SPECIES	LB-MOLE/HR	LB/HR
CASO3 .1/2 H2O	0.1595E+04	0.2059E+06
CASO4 .2H2O	0.6727E+03	0.1158E+06
CACO3	0.1179E+04	0.1180E+06
INSOLUBLES	----------	0.1871E+05
H2O	0.1431E+06	0.2577E+07
CA++	0.1312E+03	0.5259E+04
MG++	0.5150E+02	0.1252E+04
SO3--	0.4800E+01	0.3843E+03
SO4--	0.4280E+02	0.4112E+04
CL-	0.2700E+03	0.9573E+04
AD=	0.0	0.0

TOTAL FLOW RATE = 0.3056E+07 LB/HR
= 5551. GPM

(continued)

TABLE D-1 (continued)

POND DESIGN

OPTIMIZED TO MINIMIZE TOTAL COST PLUS OVERHEAD

POND DIMENSIONS

DEPTH OF POND	24.41	FT
DEPTH OF EXCAVATION	4.06	FT
LENGTH OF DIVIDER DIKE	2833.	FT
LENGTH OF POND PERIMETER DIKE	15537.	FT
LENGTH OF POND PERIMETER FENCE	15572.	FT
SURFACE AREA OF BOTTOM	1497.	THOUSAND YD2
SURFACE AREA OF INSIDE WALLS	174.	THOUSAND YD2
SURFACE AREA OF OUTSIDE WALLS	133.	THOUSAND YD2
SURFACE AREA OF RECLAIM STORAGE	131.	THOUSAND YD2
LAND AREA OF POND	1659.	THOUSAND YD2
LAND AREA OF POND SITE	2037.	THOUSAND YD2
LAND AREA OF POND SITE	421.	ACRES
VOLUME OF EXCAVATION	2193.	THOUSAND YD3
VOLUME OF RECLAIM STORAGE	908.	THOUSAND YD3
VOLUME OF SLUDGE TO BE	12900.	THOUSAND YD3
DISPOSED OVER LIFE OF PLANT	7996.	ACRE FT

POND COSTS (THOUSANDS OF DOLLARS)

	LABOR	MATERIAL	TOTAL
CLEARING LAND	823.		823.
EXCAVATION	6576.		6576.
DIKE CONSTRUCTION	3350.		3350.
LINING(12. IN. CLAY)	2647.		2647.
SODDING DIKE WALLS	194.	122.	316.
ROAD CONSTRUCTION	35.	10.	46.
PERIMETER COSTS, FENCE	83.	166.	249.
RECLAMATION EXPENSE	1208.		1208.
MONITOR WELLS	4.	4.	8.
SUBTOTAL DIRECT	14920.	302.	15222.
TAX AND FREIGHT		23.	23.
POND CONSTRUCTION	14920.	325.	15245.
LAND COST			2104.
POND SITE			17349.
OVERHEAD			7242.
TOTAL			24591.

(continued)

TABLE D-1 (continued)

BASE MANUAL CASE 1

PARTICULATE REMOVAL INVESTMENT AND OPERATING COST

WPSUL CONTENT (%):	3.36
ASH CONTENT (%):	15.10
BTU RATING:	11700
BOILER TYPE:	DRY PULVERIZED COAL
NO. OF SCRUBBERS:	4
SCRUBBER VELOCITY (FT/M):	600.0
PLANT SIZE (MW):	500
OPERATING HRS/YR:	5500
PUMPING RATE (GAL/1000 ACF):	0.0
SCA RATIO: (ACTUAL SQ.FT./CALC. SQ.FT.)	1.100

PARTICULATE EMISSION REGULATION (LB ASH/MILLION BTU):	0.06
FLUE GAS TEMPERATURE (COLD) (F):	300.0
FLUE GAS TEMPERATURE (HOT) (F):	700.0
COST OF ELECTRICITY ($/KWHR):	0.04
COST OF STEAM ($/THOUSAND LB):	2.50
FIRST YEAR CAPITAL CHARGE FACTOR:	0.180
BAGHOUSE RATIO (OPER. SQ.FT./ACTUAL SQ.FT.):	0.80
BAG COST ($/SQ.FT.):	1.00
BAG LIFE(YEARS):	3.00
FLUE GAS REHEAT TEMPERATURE (F):	175.
CHEMICAL ENGINEERING PLANT INDEX:	297.9

	ELECTROSTATIC PRECIPITATORS COLD	ELECTROSTATIC PRECIPITATORS HOT	BAGHOUSE FABRIC FILTERS	SCRUBBERS
REQUIRED REMOVAL EFFICIENCY (%):	99.42	99.42	99.42	99.42
DRIFT VELOCITY (FT/M):	27.19	20.00		
SPECIFIC COLLECTION AREA (SQ.FT./ACFM):	208.27	283.14		
COLLECTION AREA (SQ.FT.):	351361.2	729084.4	767553.4	
TOTAL CORONA POWER (KW):	459.3	701.0		
AUXILIARY POWER (KW):	296.0	665.1	490.2	
FAN POWER (KW):	264.0	403.0	1320.1	8466.4
PUMP POWER (KW):				5347.2
TOTAL POWER (KW):	1019.4	1769.1	1810.3	13813.6
OPERATING AIR/CLOTH RATIO:			2.7	
INSTALLED AIR/CLOTH RATIO:			2.2	
REQUIRED PRESSURE DROP (INCHES):	1.0	1.0	5.0	32.1
DIAMETER (FEET):				34
REQUIRED REHEAT (BTU/HR):				64268960.0
STEAM SUPPLY/YR (THOUSAND LB):				392754.7
INSTALLED COST (1982 DOLLARS):	$ 5720140	$ 10603756	$ 16575926	$ 25555104
FIRST YEAR CAPITALIZED COST:	$ 1031532	$ 1912210	$ 2989191	$ 4608436
ANNUAL POWER COST:	$ 207440	$ 360008	$ 368398	$ 2811071
ANNUAL OPERATING AND MAINTENANCE COST (1982 DOLLARS):	$ 108140	$ 162274	$ 82881	$ 1507497
REPLACEMENT COST (1982 DOLLARS):			$ 377317	
ANNUAL REHEAT COST:				$ 981887
TOTAL ANNUAL COST:	$ 1347112	$ 2434492	$ 3817787	$ 9908891
ANNUALIZED COST OF POWER(MILLS/KWHR):	0.49	0.89	1.39	3.60

(continued)

TABLE D-1 (continued)

RAW MATERIAL HANDLING AND PREPARATION

INCLUDING 2 OPERATING AND 1 SPARE PREPARATION UNITS

ITEM	DESCRIPTION	NO.	MATERIAL	LABOR
CAR SHAKER AND HOIST	20HP SHAKER 7.5HP HOIST	1	71916.	13037.
CAR PULLER	25HP PULLER, 5HP RETURN	1	63050.	19555.
UNLOADING HOPPER	16FT DIA, 10FT STRAIGHT INCLUDES 5 IN SQ GRATING	1	15508.	5932.
UNLOADING VIBRATING FEEDER	3.5HP	1	5466.	521.
UNLOADING BELT CONVEYOR	20FT HORIZONTAL, 5HP	1	11440.	1434.
UNLOADING INCLINE BELT CONVEYOR	310FT, 50HP	1	85295.	4824.
UNLOADING PIT DUST COLLECTOR	POLYPROPYLENE BAGTYPE, INCLUDES DUST HOOD	1	11186.	5215.
UNLOADING PIT SUMP PUMP	60GPM, 70FT HEAD, 5HP	1	2415.	782.
STORAGE BELT CONVEYOR	200FT, 5HP	1	73092.	3911.
STORAGE CONVEYOR TRIPPER	30FPM, 1HP	1	27203.	9126.
MOBILE EQUIPMENT	SCRAPPER TRACTOR	1	141862.	0.
RECLAIM HOPPER	7FT WIDE, 4.25FT HT, 2FT WIDE BOTTOM, CS	2	2415.	1630.
RECLAIM VIBRATING FEEDER	3.5HP	2	10932.	1043.
RECLAIM BELT CONVEYOR	200FT, 5HP	1	40931.	2866.
RECLAIM INCLINE BELT CONVEYOR	193FT, 40HP	1	60253.	3650.
RECLAIM PIT DUST COLLECTOR	POLYPROPYLENE BAG TYPE	1	7754.	2607.
RECLAIM PIT SUMP PUMP	60GPM, 70FT HEAD, 5HP	1	2415.	782.
RECLAIM BUCKET ELEVATOR	90FT HIGH, 75HP	1	57[illegible]38.	664[illegible].

(continued)

TABLE D-1 (continued)

FEED BELT CONVEYOR	60.FT HORIZONTAL 7.5HP	1	20466.	1434.
FEED CONVEYOR TRIPPER	30 FPM, 1HP	1	27203.	9126.
FEED BIN	13FT DIA, 21FT STRAIGHT SIDE HT, COVERED, CS	3	43283.	24052.
BIN WEIGH FEEDER	14FT PULLEY CENTERS, 2HP	3	49575.	2347.
GYRATORY CRUSHERS	75HP	3	297071.	6453.
BALL MILL DUST COLLECTORS	POLYPROPYLENE BAG TYPE 2200 CFM, 7.5HP	3	23262.	7822.
BALL MILL	13.9TPH, 795.HP	3	1763928.	124619.
MILLS PRODUCT TANK	5500 GAL 10FT DIA, 10FT HT, FLAKEGLASS LINED CS	3	13729.	10951.
MILLS PRODUCT TANK AGITATOR	10HP	3	22881.	5475.
MILLS PRODUCT TANK SLURRY PUMP	59.GPM, 60FT HEAD, 2.HP, 2 OPERATING AND 1 SPARES	3	8583.	2738.
SLURRY FEED TANK	61977.GAL, 21.9FT DIA, 21.9FT HT, FLAKEGLASS-LINED CS	1	20802.	17185.
SLURRY FEED TANK AGITATOR	51.HP	1	45143.	3704.
SLURRY FEED TANK PUMPS	29.GPM, 60 FT HEAD, 1.HP, 4 OPERATING AND 4 SPARE	8	21711.	7300.
			----------	----------
TOTAL EQUIPMENT COST			3048605.	306769.

(continued)

TABLE D-1 (continued)

SCRUBBING

INCLUDING 4 OPERATING AND 1 SPARE SCRUBBING TRAINS

ITEM	DESCRIPTION	NO.	MATERIAL	LABOR
I.D. FANS	7.5IN H2O, WITH 631. HP MOTOR AND DRIVE	5	3341982.	58581.
SHELL			1769029.	
RUBBER LINING			1766858.	
MIST ELIMINATOR			393850.	
SLURRY HEADER AND NOZZLES			853235.	
TOTAL SPRAY SCRUBBER COSTS		5	4782970.	449605.
REHEATERS		5	2647704.	168446.
SOOTBLOWERS	40 AIR-FIXED 20 AIR-RETRACTABLE	60	294910.	182512.
EFFLUENT HOLD TANK	343449.GAL, 38.8FT DIA, 38.8FT HT, FLAKEGLASS-LINED CS	5	373173.	301519.
EFFLUENT HOLD TANK AGITATOR	82.HP	5	505849.	207512.
COOLING SPRAY PUMPS	1388.GPM 100FT HEAD, 64.HP, 4 OPERATING AND 6 SPARE	10	104732.	32268.
ABSORBER RECYCLE PUMPS	15611.GPM, 100FT HEAD, 723.HP, 8 OPERATING AND 7 SPARE	15	1581896.	139397.
MAKEUP WATER PUMPS	3469.GPM, 200.FT HEAD, 292.HP, 1 OPERATING AND 1 SPARE	2	33169.	3742.
			----------	----------
TOTAL EQUIPMENT COST			13666374.	1543578.

(continued)

TABLE D-1 (continued)

WASTE DISPOSAL

ITEM	DESCRIPTION	NO.	MATERIAL	LABOR
ABSORBER BLEED RECEIVING TANK	85768.GAL, 19.4FT DIA, 38.8FT HT, FLAKGLASS-LINED CS	1	29716.	24569.
ABSORBER BLEED TANK AGITATOR	47.HP	1	34390.	2821.
POND FEED SLURRY PUMPS	845.GPM, 130.FT HEAD 51.HP, 1 OPERATING AND 1 SPARE	2	18550.	5195.
POND SUPERNATE PUMPS	483.GPM, 192.FT HEAD, 39.HP, 1 OPERATING AND 1 SPARE	2	12053.	1360.
			---------	---------
TOTAL EQUIPMENT COST			94708.	33946.

(continued)

TABLE D-1 (continued)

LIMESTONE SLURRY PROCESS -- BASIS: 500 MW SCRUBBING UNIT - 500 MW GENERATING UNIT, 1984 STARTUP
PROJECTED CAPITAL INVESTMENT REQUIREMENTS - BASE MANUAL

CASE 1

	INVESTMENT, THOUSANDS OF 1982 DOLLARS				DISTRIBUTION
	RAW MATERIAL PREPARATION	SCRUBBING	WASTE DISPOSAL	TOTAL	DOLLARS PER KW
EQUIPMENT					
MATERIAL	3049.	13666.	95.	16810.	33.62
LABOR	307.	1544.	34.	1884.	3.77
PIPING					
MATERIAL	416.	5152.	1058.	6627.	13.25
LABOR	192.	918.	352.	1461.	2.92
DUCTWORK					
MATERIAL	0.	3042.	0.	3042.	6.08
LABOR	0.	2723.	0.	2723.	5.45
FOUNDATIONS					
MATERIAL	341.	172.	20.	534.	1.07
LABOR	883.	374.	42.	1299.	2.60
STRUCTURAL					
MATERIAL	196.	372.	2.	570.	1.14
LABOR	142.	648.	3.	794.	1.59
ELECTRICAL					
MATERIAL	262.	813.	146.	1221.	2.44
LABOR	757.	1567.	318.	2641.	5.28
INSTRUMENTATION					
MATERIAL	148.	814.	13.	975.	1.95
LABOR	22.	131.	9.	162.	0.32
BUILDINGS					
MATERIAL	147.	0.	0.	147.	0.29
LABOR	163.	0.	0.	163.	0.33
SALES TAX (4.0 %) AND FREIGHT (3.5 %)	342.	1802.	100.	2244.	4.49
TOTAL PROCESS CAPITAL	7366.	33740.	2192.	43298.	86.60
SERVICES AND MISCELLANEOUS (6.0 %)	442.	2024.	132.	2598.	5.20
TOTAL DIRECT PROCESS INVESTMENT	7808.	35764.	2324.	45896.	91.79
POND CONSTRUCTION MATERIAL	0.	0.	302.	302.	0.60
POND CONSTRUCTION LABOR	0.	0.	14920.	14920.	29.84
POND SALES TAX (4.0 %) AND FREIGHT (3.5 %)	0.	0.	23.	23.	0.05
TOTAL DIRECT POND INVESTMENT	0.	0.	15245.	15245.	30.49
TOTAL DIRECT INVESTMENT	7808.	35764.	17569.	61141.	122.28
ENGINEERING DESIGN AND SUPERVISION (7.0 %)	547.	2504.	163.	3213.	6.43
ARCHITECT AND ENGINEERING CONTRACTOR (2.0 %)	156.	715.	46.	918.	1.84
CONSTRUCTION EXPENSES (16.0 %)	1249.	5722.	372.	7343.	14.69
CONTRACTOR FEES (5.0 %)	390.	1788.	116.	2295.	4.59
CONTINGENCY (10.0 %)	1015.	4649.	302.	5966.	11.93
POND INDIRECTS (2.0, 1.0, 8.0, 5.0, 10.0 %)	0.	0.	4208.	4208.	8.42
SUBTOTAL FIXED INVESTMENT	11165.	51143.	22775.	85083.	170.17
STARTUP & MODIFICATION ALLOWANCE (8.0, 0.0 %)	893.	4091.	266.	5250.	10.50
INTEREST DURING CONSTRUCTION (15.6 %)	1742.	7978.	3553.	13273.	26.55
ROYALTIES (0.0 %)	0.	0.	0.	0.	0.0
LAND	10.	4.	2116.	2130.	4.26
WORKING CAPITAL	418.	1917.	942.	3277.	6.55
TOTAL CAPITAL INVESTMENT	14229.	65133.	29652.	109014.	218.03

(continued)

TABLE D-1 (continued)

TENNESSEE VALLEY AUTHORITY
SHAWNEE LIMESTONE OR LIME SCRUBBING PROCESS
COMPUTERIZED DESIGN-COST ESTIMATE MODEL

REVISION DATE DECEMBER 10, 1980

MESSAGE FILE

BASE MANUAL CASE 1

(continued)

TABLE D-1 (continued)

LIMESTONE SLURRY PROCESS -- BASIS: 500 MW SCRUBBING UNIT - 500 MW GENERATING UNIT, 1984 STARTUP

PROJECTED REVENUE REQUIREMENTS - BASE MANUAL CASE 1

DISPLAY SHEET FOR YEAR= 1
ANNUAL OPERATION KW-HR/KW = 5500

34.89 TONS PER HOUR DRY SLUDGE
TOTAL CAPITAL INVESTMENT 109013000

	ANNUAL QUANTITY	UNIT COST,$	TOTAL ANNUAL COST,$
DIRECT COSTS			
RAW MATERIAL			
LIMESTONE	153.4 K TONS	8.50/TON	1304000
SUBTOTAL RAW MATERIAL			1304000
CONVERSION COSTS			
OPERATING LABOR AND SUPERVISION	30680.0 MAN-HR	15.00/MAN-HR	460200
UTILITIES			
STEAM	546160.0 K LB	2.50/K LB	1365400
PROCESS WATER	259930.0 K GAL	0.14/K GAL	36400
ELECTRICITY	47526160.0 KWH	0.037/KWH	1758500
MAINTENANCE			
LABOR AND MATERIAL			4130100
ANALYSES	4940.0 HR	21.00/HR	103800
SUBTOTAL CONVERSION COSTS			7854400
SUBTOTAL DIRECT COSTS			9158400
INDIRECT COSTS			
OVERHEADS			
PLANT AND ADMINISTRATIVE (60.0% OF CONVERSION COSTS LESS UTILITIES)			2816500
FIRST YEAR OPERATING AND MAINTENANCE COSTS			11974900
LEVELIZED CAPITAL CHARGES(14.70% OF TOTAL CAPITAL INVESTMENT)			16025000
FIRST YEAR ANNUAL REVENUE REQUIREMENTS			27999900
EQUIVALENT FIRST YEAR UNIT REVENUE REQUIREMENTS, MILLS/KWH (MW SCRUBBED)			10.18
LEVELIZED OPERATING AND MAINTENANCE (1.886 TIMES FIRST YEAR OPER. & MAIN.)			22584700
LEVELIZED CAPITAL CHARGES(14.70% OF TOTAL CAPITAL INVESTMENT)			16025000
LEVELIZED ANNUAL REVENUE REQUIREMENTS			38609700
EQUIVALENT LEVELIZED UNIT REVENUE REQUIREMENTS, MILLS/KWH (MW SCRUBBED)			14.04

HEAT RATE 9500. BTU/KWH - HEAT VALUE OF COAL 11700 BTU/LB - COAL RATE 1116500 TONS/YR

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO.	2.	3. RECIPIENT'S ACCESSION NO.
EPA-600/8-81-008		

4. TITLE AND SUBTITLE	5. REPORT DATE
Computerized Shawnee Lime/Limestone Scrubbing Model Users Manual	March 1981
	6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S)	8. PERFORMING ORGANIZATION REPORT NO.
W.L. Anders and R.L. Torstrick	TVA/OP/EDT-81/15
9. PERFORMING ORGANIZATION NAME AND ADDRESS	10. PROGRAM ELEMENT NO.
TVA, Office of Power Division of Energy Demonstrations and Technology Muscle Shoals, Alabama 35660	CAAN1D
	11. CONTRACT/GRANT NO.
	EPA-IAG-79-D-X0511
12. SPONSORING AGENCY NAME AND ADDRESS	13. TYPE OF REPORT AND PERIOD COVERED
EPA, Office of Research and Development Industrial Environmental Research Laboratory Research Triangle Park, NC 27711	Users Manual; 1979-80
	14. SPONSORING AGENCY CODE
	EPA/600/13

15. SUPPLEMENTARY NOTES IERL-RTP project officer is Michael A. Maxwell, Mail Drop 61, 919/541-2578. This manual supplements EPA-600/7-79-210.

16. ABSTRACT The manual gives a general description of a computerized model for estimating design and cost of lime or limestone scrubber systems for flue gas desulfurization (FGD). It supplements EPA-600/7-79-210 by extending the number of scrubber options which can be evaluated. It includes spray tower and venturi/spray-tower absorbers, forced oxidation systems, systems with absorber loop additives (MgO or adipic acid), revised design and economic premises, and other changes reflecting process improvements and variations. It describes all inputs and outputs, along with detailed procedures for using the model and all its options. The model is based on prototype scrubber data from the EPA/Shawnee test facility and should be useful to utility companies, as well as to architectural and engineering contractors who are involved in selecting and designing FGD facilities. As key features, the model provides estimates of capital investment and operating revenue requirements. It also provides a material balance, equipment list, and a breakdown of costs by processing areas. The primary uses of the model are to project comparative economics of lime and limestone FGD processes and to evaluate system alternatives prior to the development of a detailed design.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Mathematical Models	Pollution Control	13B	12A
Desulfurization	Engineering Costs	Stationary Sources	07A, 07D	14A
Gas Scrubbing	Material Balance		13H	14G
Flue Gases	Equipment		21B	
Calcium Oxides	Industrial Processes		07B	
Calcium Carbonates				

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