COAL UTILITY ENVIRONMENTAL COST (CUECost) WORKBOOK USER'S MANUAL
Version 1.0

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Abstract

The document is a user's manual for the Coal Utility Environmental Cost (CUECost) workbook (an interrelated set of spreadsheets), and documents its development and the validity of methods used to estimate installed capital and annualized costs. The CUECost workbook produces rough-order-of-magnitude (ROM) cost estimates (+/-30% accuracy) of the installed capital and annualized operating costs for air pollution control (APC) systems installed on coal-fired power plants to control emissions of sulfur dioxide, nitrogen oxides (NOx), and particulate matter. In general, system performance is an input requirement for the workbook user. The workbook was designed to calculate estimates of an integrated APC system or individual component costs for various APC technologies currently used in the utility industry. Nine technologies are currently in the workbook: Flue gas desulfurization—limestone with forced oxidation, lime spray drying, and limestone with dibasic acid; Particulate matter removal—electrostatic precipitators and fabric filters; and NOx control—selective catalytic reduction, selective non-catalytic reduction, natural gas reburning, and low-NOx burners.

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Note

In this manual, the indicated sum of a column of numbers may differ from the arithmetic sum by 1 or 2 in the last place; this is a rounding error, and the indicated sum is correct.

1.0 INTRODUCTION AND SUMMARY

1.1 OVERVIEW

This document serves as a User's Manual for the CUECost workbook (a workbook is an interrelated set of spreadsheets), and documents its development and the validity of the methods used to estimate installed capital and annualized costs. The CUECost economic analysis workbook produces rough-order-of-magnitude (ROM) cost estimates (+30%/-30% accuracy) of the installed capital and annualized operating costs for air pollution control (APC) systems installed on coal-fired power plants. Costs for utility APC systems are site-specific. These costs are subject to change with changes in technology, labor rates, and material costs. The costs estimated by the CUECost workbook come from a variety of sources. With that understanding, one may assume, but it is not guaranteed, that CUECost will produce estimates in the range of accuracy of ±30% of the actual cost, which was the goal of this project. In general system performance is an input requirement for the user of the workbook.

The CUECost spreadsheet was developed in Microsoft Excel workbook format to provide the user with complete insight into the equipment cost estimating methodology. All assumptions are readily accessible to the user by reviewing the specific equations and references for each cell in the spreadsheets. CUECost is slightly larger than one megabyte in size, so it can be saved onto one 3-1/2" diskette. It is composed of technology-specific spreadsheets with one common input spreadsheet for all technologies. This allows the workbook to be expanded to incorporate other technologies in the future.

Raytheon Engineers & Constructors, Inc. acted as the primary subcontractor to Eastern Research Group, Inc. (ERG) who held the prime contract directly with the Environmental Protection Agency (EPA). Raytheon provided the basic framework for the spreadsheet and constructed the user input, combustion calculations, flue gas desulfurization and particulate control technology spreadsheets. Eastern Research Group developed the nitrogen oxides control system spreadsheet.

1.2 BACKGROUND

The Air Pollution Prevention and Control Division (APPCD) of the National Risk Management Research Laboratory (NRMRL) contracted for development of a cost estimating workbook for APC systems on coal-fired power plants. It was developed in Excel 5.0 format to provide the user with more flexibility in modifying the spreadsheet and outputs to meet the user's needs for site-specific applications.

The workbook was designed to calculate estimates of an integrated APC system or individual component costs for various APC technologies currently used in the utility industry to reduce emissions of sulfur dioxide (SO_2), particulate matter (PM), and nitrogen oxides (NO_x) generated by conventional pulverized coal-fired boilers. Technologies currently in the workbook included:

Flue Gas Desulfurization (FGD) = Limestone with Forced Oxidation (LSFO)
Lime Spray Drying (LSD)

		Limestone with Dibasic Acid (LSDBA)
Particulate Matter Removal	=	Electrostatic Precipitator (ESP) Fabric Filter (FF)
Nitrogen Oxide Control	=	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Natural Gas Reburning (NGR) Low NO_x Burners (LNB)

Descriptions of these technologies can be found in Appendix B of this document.

1.3 WORKBOOK DESCRIPTION

A map of the CUECost workbook is shown in Figure 1-1. This design format allows the addition of future technologies by inserting new spreadsheets into the workbook. The workbook calculates both new and retrofit plant costs using a 1.0 factor for a new facility, a 1.3 factor for a moderately difficult retrofit, and a 1.6 factor for a difficult retrofit. The user is also given the option to input his own retrofit factor based on plant-specific information. Equipment sizing and variable operating costs are derived based on the calculated material balances for specific process criteria, including flue gas flow rate, pollutant removal rate, chemical consumption rate, waste production rate, etc.

The first sheet of the workbook contains all the inputs required for the economic analysis. The user enters general parameters that define the characteristics of the power plant. These plant criteria inputs are followed by economic factors required for the cost estimate. The remainder of the input requirements provide specific design criteria for each control technology. Default values are provided for all inputs. Also, seven default coals are included in the spreadsheet database. The user has the capability to run five different cases at once, allowing easy comparison of results when varying design parameters.

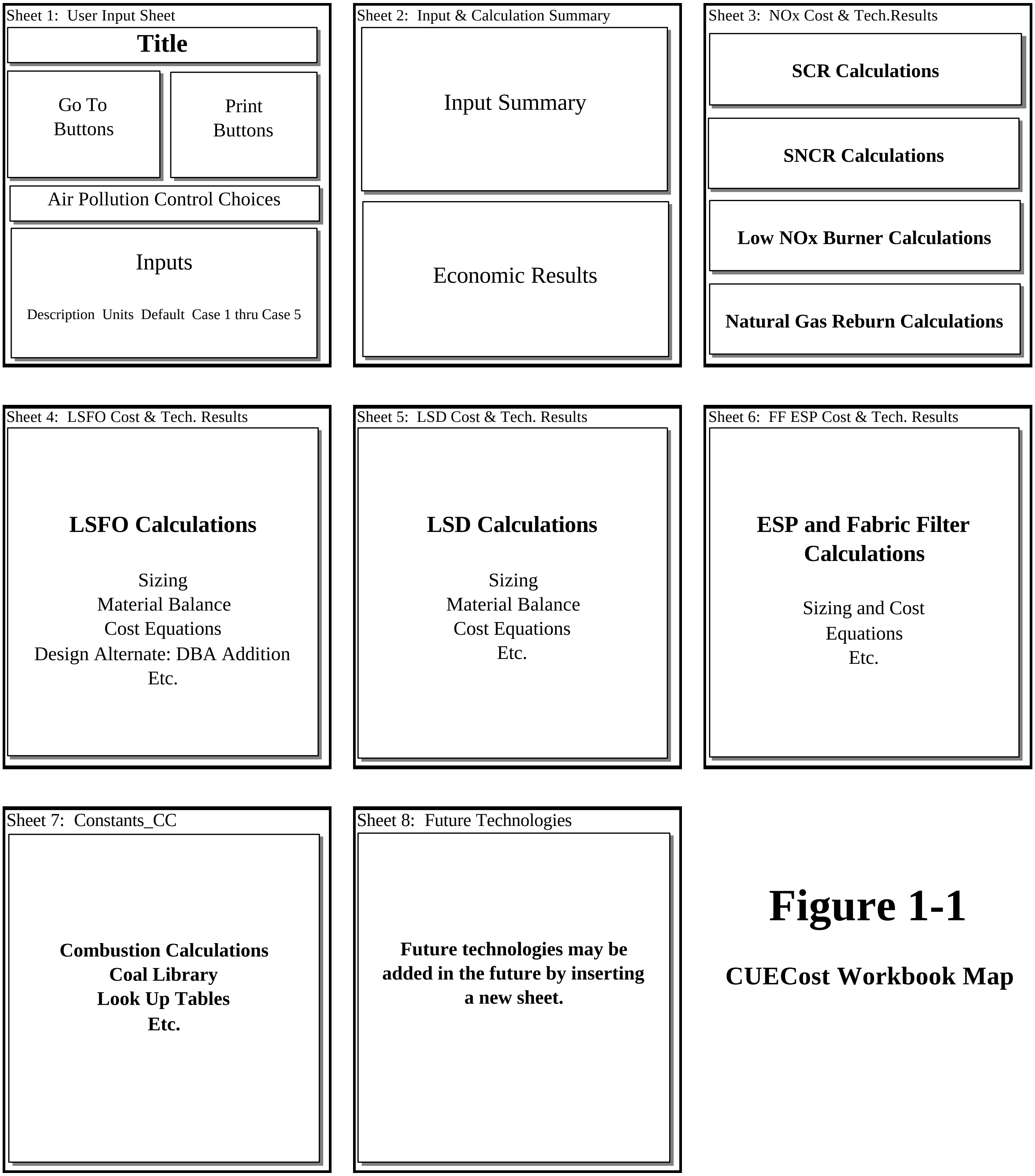

Figure 1-1

CUECost Workbook Map

1.4 USER'S MANUAL CONTENTS

This document consists of the following Sections:

<u>Section 1.0</u>: The Introduction/Summary states the purpose and content of this document.

<u>Section 2.0</u>: An itemized listing of requirements for the user's computer system is followed by a series of Installation Guidelines for use in installing the CUECost workbook to the user's hard disk. Instruction is also provided for the first-time user on how to get started producing a cost estimate using CUECost. This includes listings of the input sequence and other preliminary steps for the user to complete prior to using the CUECost workbook.

<u>Section 3.0</u> A detailed description of the contents of each spreadsheet and a layout diagram are provided in this section. It provides a technical description of the workbook and discusses how the spreadsheets are integrated to minimize user input. The cost estimating methodology is also described, including a logic diagram to illustrate the calculation sequence that is used to develop capital and annualized cost estimates.

<u>Section 4.0</u> This section of the user's manual provides a description of the input and output options available to the user for cost estimate development

<u>Section 5.0</u> The final section of the user's manual summarizes the validation procedure that was followed during development and subsequent testing of the CUECost workbook.

<u>Appendix A</u> Definitions of acronyms, abbreviations and terminology used in the text and spreadsheets are provided.

<u>Appendix B</u> Process criteria and technology descriptions of equipment included in each technology cost estimate are included in this appendix.

<u>Appendix C</u> This appendix presents tabulations of the primary assumptions that served as the estimate basis for the default values included in the spreadsheets. This includes both plant design and economic criteria.

<u>Appendix D</u> The data sources for the cost-versus-capacity algorithms are discussed in this appendix. Previous publications, vendor quotations, and costs from recent APC installations served as the basis for all cost-versus-capacity curves used in the spreadsheets.

<u>Appendix E</u> An example case study/tutorial demonstration of the spreadsheets is provided in this appendix to demonstrate how the workbook is used. Pictures of the actual Excel screens are provided for easy reference to those shown when running CUECost.

Appendix F Documentation for the entire workbook is found in this appendix, describing in detail the contents of each cell and providing a description of each area of the spreadsheets.

1.5 PROJECT APPROACH

The workbook design allows the user to review all of the assumptions and equations contained in each spreadsheet and to adjust any of them to fit the user's particular needs. A multi-spreadsheet format was selected to allow the addition of other technologies if future expansion of the workbook is desired. A separate input spreadsheet was assembled, along with technology-specific Excel spreadsheets for each APC system that perform equipment sizing and economic calculations.

For the FGD technologies, cost-versus-capacity equations were formulated based on the historical database of actual equipment costs incurred during Phase 1 of the utility Clean Air Act compliance programs, budgetary quotations for components as received from vendors during early 1998, and cost data obtained from industry database programs. These parametric equations serve as the basis for the FGD system capital costs calculated by CUECost. Operating cost equations were formulated based on the consumption rates estimated in the spreadsheets by the material balance calculations. A material balance is developed specifically for each FGD system, and provides the chemical consumption rates, wastes production rates, and flow rates through process equipment that are used to estimate the system power consumption. Operating labor requirements are based on a formula that relates plant size to the number of operating staff needed to run the FGD equipment, and maintenance costs are calculated as a percentage of the installed costs for the system.

The particulate matter control technology cost estimates are based on a previously constructed model formulated by Carnegie Mellon University (CMU) for the U. S. Department of Energy (DOE). This model was constructed based on a combination of theoretical equations for Electrostatic Precipitator (ESP) sizing. The theoretical equations were modified to incorporate the empirical data obtained from a series of ESP vendors for installations firing different coals. This frame work taken from the CMU model served as the basis for the CUECost ESP design portion of the spreadsheet. The CMU spreadsheet was further modified using a proprietary empirical model that is based on 150-200 actual installations firing a wider variety of fuels.

The CMU model used a modified version of the Deutsch-Anderson equation to relate removal efficiency to collection area and gas flowrate for various coals as part of the ESP sizing calculations. The original Deutsch-Anderson equation was found to be inaccurate for removal efficiencies above 95%. Various empirical models were developed to overcome this inaccuracy, and the CMU model chose to use the White version (White, 1977) of the modified Deutsch equation provided below:

$$h = 1 \exp \{-A/V\ H\ w_k\}^k$$

where
h = collector removal efficiency
A = collector area, ft^2
V = volumetric flue gas flow rate, acfm

w_k = precipitation rate parameter
k = constant varying with coal type

The w_k and k values used in the CMU ESP sizing equations were correlated with the calculated total ash resistivity (based on the ash analysis provided by the user or the one taken from the default coal database), and separate k curves were developed for groups of coals that have similar sulfur content. This modified sizing spreadsheet provides the expected specific collection area (SCA) for the ESP, and a new set of cost equations were developed to relate the ESP size (calculated from the SCA and the ESP inlet flue gas volumetric flowrate) to the expected cost for the installed system. Operating costs are calculated using the inlet-flowrate-versus-expected-power-consumption algorithms. Maintenance costs are calculated as a percentage of the installed equipment cost.

Fabric filter costs were also based on a new set of cost equations developed to relate the FF size (calculated as a function of the volumetric flue gas flowrate times the air-to-cloth ratio (A/C) selected by the user) and the FF inlet flue gas volumetric flowrate to determine the expected cost for the installed system. Operating costs are calculated using the inlet-flowrate-versus-expected-power-consumption algorithms. Maintenance costs are calculated as a percentage of the installed equipment cost.

NO_x control technology design and cost algorithms are based on research conducted for the EPA Acid Rain Division (ARD), the EPA Office of Research and Development (ORD) and the DOE Pittsburgh Energy Technology Center. Design parameter calculations for SCR, SNCR, and NGR are taken from the Integrated Air Pollution Control System (IAPCS) model. IAPCS is a computer model of utility air pollution control technologies. IAPCS has evolved over the years from a FORTRAN code model completed in 1983. Version 5.0 of IAPCS was published in 1995 (Gundappa et al., 1995). Minor revisions were made in 1997, which resulted in version 5a. CUECost is designed to update information in IAPCS using a spreadsheet approach. SCR capital cost components are based on algorithms developed for the DOE (Frey and Rubin, 1994) as part of the Integrated Environmental Control Model (IECM). For SNCR and NGR total capital equipment costs, Acid Rain Division research was used to update IAPCS methodology. The ARD cost data used to update IAPCS are presented in:

- "Cost Estimates for Selected Applications of NO_x Control Technologies on Stationary Combustion Boilers and Responses to Comments," U.S.Environmental Protection Agency, Washington, DC, 1998; and

- "Investigation of Performance and Cost of NO_x Controls as Applied to Group 2 Boilers," U.S.Environmental Protection Agency, Washington, DC, August 1997.

LNBT total plant costs are based on algorithms presented in another Acid Rain Division report (EPA, 1996). These reports are available to the public from EPA's Office of Air and Radiation, Acid Rain Division, Washington, DC, 20460 (202-564-9085). The cost estimates presented in the ARD reports are being used in the NO_x-related rulemaking and have been reviewed by stakeholders associated with the rulemaking process. O&M cost algorithms for all technologies use IAPCS equations from IAPCS 5.0.

Operating costs are estimated in the workbook based on simplified material balances calculated within CUECost based on the inputs supplied by the user. The ultimate coal analysis, including weight percent sulfur, carbon, hydrogen, oxygen, nitrogen, moisture and ash, serves as the primary input for the combustion calculations performed by the spreadsheet. The resulting gas flow is the basis for the remaining material balance calculations.

Economic criteria supplied by the user are then used to calculate the capital and annualized costs for the selected APC system. The user has the option to use the default values provided in the spreadsheet if some of the input data requested are not readily available.

1.6 DEFAULT PLANT CRITERIA

The workbook includes default values for all input parameters. These criteria are specific to a generic 500 MW coal-fired power plant located in Pennsylvania. The specific design and economic criteria used as defaults are provided in Appendix C for reference. A coal library is also included so that the user can select a coal similar to that actually burned at the plant if an actual ultimate analysis is not readily available.

1.7 RESULTS

The CUECost workbook provides rough-order-of-magnitude (ROM) cost estimates (+30%/-30% accuracy) for a wide variety of APC technology scenarios. Cost estimates for different combinations of FGD, particulate matter and NO_x control technologies can be easily compared in the results summaries presented in five parallel columns on the spreadsheets. Examples of the input sheets can be found in Appendix E.

This user's manual assumes that the user is already familiar with the use of IBM-compatible hardware and Excel software. The user should refer to the manuals supplied with their own hardware and software packages for questions regarding working with Excel spreadsheets in this environment. The actual input screens are shown in Appendix E to provide the user with some specific instructions on how to maneuver around the workbook and input the site-specific data.

CUECost is designed to produce ROM estimates for a wide range of plant sizes and coal types. However, appropriate ranges of plant size and operating conditions have been established based on the limits to the database used to construct the cost-versus-capacity algorithms. Range limits are provided in the spreadsheet for each input supplied by the user. The major criteria limitation for CUECost is the plant size range. Equipment algorithms are based on the assumption that they will be installed at a facility ranging from 100 to 2000 MW in net capacity. All other criteria are limited only by their technical validity. The suggested technical limits for each criterion are provided in the spreadsheets when applicable.

It should be noted that the cost estimates provided in this study and generated by CUECost are dependent upon the various underlying assumptions, inclusions, and exclusions utilized in developing them. Actual project costs will differ, and can be significantly affected by factors such as changes in the external environment, the manner in which the project is implemented, and other factors which impact the estimate basis or otherwise affect the project. Estimate accuracy ranges are only projections based upon cost estimating methods and are not guarantees of actual project costs.

EPA policy is to express all measurements in EPA documents in metric units. Values in this document are given in British units for the convenience of the engineers and other technical staff accustomed to using the British system. The following conversion factors presented in Table 1-1 can be used to provide metric equivalents.

Table 1-1. British to Metric Conversion Factors

To Convert British		Multiply By	To Obtain Metric(SI=Systems Intern)	
ac	acre	0.405	ha	hectare
Btu	British thermal unit	0.252	kcal	kilocalories
°F	deg. Fahrenheit - 32	0.5556	°C	degrees Centigrade
ft	feet	0.3048	m	meters
ft^2	square feet	0.0929	m^2	square meters
ft^3	cubic feet	0.02832	m^3	cubic meters
ft/m	feet per minute	0.00508	m/s	meters per second
ft^3/m	cubic feet per minute	0.000472	m^3/s	cubic meters/second
gal	gallons (U.S.)	3.785	L	liters
gpm	gallons per minute	0.06308	L/s	liters per second
gr	grains	0.0648	g	grams
gr/ft^3	grains per cubic foot	2.288	g/m^3	grams per cubic meter
hp	horsepower	0.746	kW	kilowatts
in.	inches	0.0254	m	meters
lb	pounds	0.4536	kg	kilograms
lb/ft^3	pounds per cubic foot	16.02	kg/m^3	kilograms/cubic meter
lb/hr	pounds per hour	0.126	g/s	grams per second
mi	miles	1609	m	meters
psi	pounds per square inch	6895	Pa	pascals (newton/m^2)
rpm	revolutions per minute	0.1047	rad/s	radians per second
scfm	standard (60 °F) cubic feet/minute	1.6077	nm^3/hr	normal cubic meters/hr
ton	short tons	0.9072	tonne	metric tons
t/hr	short tons per hour	0.252	kg/s	kilograms per second

2.0 GETTING STARTED/INSTALLATION GUIDELINES

2.1 HARDWARE AND SOFTWARE REQUIREMENTS/INTERNET ACCESS

The CUECost workbook is written in Microsoft Excel 5.0 format. An IBM-compatible computer is required with a minimum speed of 66 megahertz recommended to minimize spreadsheet recalculation time. Higher speed circuitry and later revisions of Excel are acceptable for running the CUECost software. The hardware and software requirements for CUECost and User's Manual are listed below:

Computer Hardware: IBM Compatible 386 or higher speed (66 megahertz minimum recommended - a math co-processor is recommended)

Hard Disk:	Any
Keyboard:	Any
Mouse:	Any
Modem:	Not required except for down-loading the spreadsheet from web site
Printer Compatibility:	Supports Laser Jet setup
Monitor Requirements:	Color monitor recommended

Operating System: Windows Version 3.1 or higher

Memory Requirements: 4 Megabyte minimum (8 MB recommended) free RAM
3 Megabyte on hard drive for download of CUECost workbook

Installation Requirements: Download from EPA's Technology Transfer Network (TTN) web site listed below:

www.epa.gov/ttn/catc

Click on CATC - Product Information, then click on Software (executables and manuals)
Search for CUECost
Download to hard drive

Commercial Support Software Required:
Microsoft Excel 5.0 or higher for Workbook
Microsoft Word 6.0 or higher for User's Manual

Development Contractor Data:

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2.2 GETTING STARTED

After accessing the workbook via the EPA web site and storing the files on the user's hard drive (note that the files may have to be decompressed using "Pkunzip"), the User's Manual may be called up in WordPerfect or Acrobat, depending upon the format downloaded, and then printed out for easy access. Each user should read the user's manual to become familiar with how CUECost works and where various input and technical data are provided within the workbook. After reviewing the user's manual, the user should then call up the workbook as an Excel file and begin review of the spreadsheets contained therein. The file will be active when called up from the web site (after decompression). The User should go to the Home site (cell A1) on the first sheet of the workbook to begin.

NOTE: The CUECost workbook can be modified by the user. To ensure its integrity, a copy of the original spreadsheet should be saved in a separate file in a new directory and all other copies saved under different file names.

The default values provided in the spreadsheet will allow the user to immediately run a test case and print output sheets to test the existing printer setup routine. Familiarity with Excel spreadsheet software is required to modify the workbook to correct printing problems.

The input requirements for the spreadsheet are itemized in Section 4 of this user's manual. The user should first obtain the necessary input data for all cases to be evaluated. Up to five cases can be run simultaneously for direct on-screen comparison of results. Up to eight site-specific coal analyses can be added to the eight columns available in the coal library for use in any series of estimating runs. This file can then be saved for use in the future. The existing default values can be deleted by entering values in the library cells, and then saving the new file for future use under a different file name. The input cells are colored blue for identification by the user.

When running the spreadsheet for the first time, it would be best to save your input data to a separate file on a regular basis (every 10-15 minutes is recommended). The spreadsheet provides the capability to select from a variety of system options, picking alternate control technologies and combinations of the component options provided.

In the future, an updated version of the workbook may be published. These future CUECost spreadsheets may contain additional APC technologies and/or modifications to the original workbook. They are expected to be accessible at the same internet site and will be issued as different versions or as add-on spreadsheets. The 5.0 version of Excel is stated to be Year 2000 (Y2K)-compatible by Microsoft except for a few minor bugs that should not impact the CUECost workbook performance. By saving the workbook as a later version of Excel, any potential problems due to Y2K should be eliminated.

3.0 WORKBOOK LAYOUT AND METHODOLOGY

3.1 WORKBOOK LAYOUT

Figure 1-1 found in Section 1.0 provides the basic layout of the various sheets currently included in the CUECost workbook. The following descriptions apply to the individual spreadsheets:

Sheet 1 = User Input - The input spreadsheet is described below:

a) This sheet provides the primary user interface and basic instructions on how to proceed. These consist of a series of GoTo buttons the user selects based on the technology cost estimates desired and the part of the workbook to be reviewed at that time.

b) Next to the GoTo buttons can be found a column of Print Buttons. These buttons allow the user to print sections of the workbook automatically using macros referenced to ranges of specific spreadsheets. A Print All option is also provided that produces a complete printout of the contents of the workbook.

c) This spreadsheet contains the Title block and the initial process selection alternatives. Here the user constructs the basis for the cost estimate, selecting the combination of technologies desired in the estimate.

d) The final portion of this spreadsheet contains all of the inputs required to define the parameters of the cost estimate. It should be noted that, for future additions to the workbook, the input requirements for each new technology would simply be added at the bottom of the input list and a new GoTo button included above. The user is allowed to input up to five cases (each with a different set of parameters) side by side. The results are available in this 5-column format, allowing direct comparison of the results and identification of where the major cost impacts occurred when changing a specific parameter.

e) The various columns in the spreadsheet are described below:

C Column A provides a text description of the cells in each row.

C Column B defines the units that should be used for the input to the cells in each row.

C Column C supplies a suggested range of input values based on technical limits or spreadsheet validity limitations.

C Column D is a listing of the default values included in the spreadsheet.

- Column E through I provide entry points for values specific to up to five simultaneous case evaluations.

Sheet 2 = Input and Calculation Summary - This sheet summarizes the inputs selected and extracts the calculated technical results from the rest of the workbook. The cost estimate is constructed on this spreadsheet using the economic input variables supplied by the user. This includes the annualized and capital cost estimates using information taken from the process-specific spreadsheets that follow. The one page output sheet is also formatted on this spreadsheet for printing by the user.

Sheet 3 = NO_x Cost and Technical Results - NO_x calculations are completed on this spreadsheet. The results of the combustion calculations provided on Sheet 7 are used to calculate the material balance for the NO_x systems. This material balance derives the expected usage rate for limestone, the gas flow entering the absorber module(s), the quantity of waste or byproduct being generated, etc. These values are then used to calculate the expected costs for the various cost areas using the algorithms developed for CUECost.

Sheets 4 = LSFO, 5 = LSD, and 6 = ESP and FF - These sheets perform the same function as Sheet 3 for the other APC technologies.

Sheet 7 = Constants - This spreadsheet contains all of the GoTo buttons, range name definitions, tables of constants used by the workbook (such as the molecular weights of compounds), and other macros used by CUECost. This spreadsheet also contains the coal library and the combustion calculation sequence used for all of the material balances performed in the other process-specific spreadsheets.

In general, the methodology employed in the workbook for cost development follows the format used by the IAPCS model, providing installed capital and operating costs for the selected technologies. The calculation sequence, documented in Appendix F, takes advantage of the vertical arrangement of the spreadsheet. In the documentation Appendix F, the content of each cell is identified. A series of tables present the equations (and all variables used in these equations) contained in each cell and the units of the calculated results. Descriptive material is included in the documentation to define the purpose and method employed within various subsections of the spreadsheets.

Output - The print buttons at the top of the Input spreadsheet allow the user to select alternative output options. A 1-page summary and a complete output of intermediate results plus inputs are two of the alternatives available. Alternate sections of the spreadsheets may be useful, and can be integrated into the output by selecting the print range desired (using the Excel icons) and printing that selection.

3.2 METHODOLOGY

The calculation sequence used in the spreadsheets to estimate APC capital and annualized costs is summarized in the following material. Additional details regarding the specific equations and interrelationships between sections of the spreadsheets can be found in the workbook documentation provided in Appendix F. This spreadsheet design will accommodate the addition of alternate APC technologies by inserting new spreadsheets for system cost estimation and technical calculations that will use the same input sections and common economic calculations. The cost spreadsheet allows the user to select the technologies of interest. It will then calculate the associated costs for each control system based on the data that the user enters to define site-specific conditions. Figure 3-1 is the logic diagram for the workbook and illustrates how the capital and annualized costs for APC equipment are calculated. The methodology and the calculation sequences used by CUECost are described below in the following material.

3.2.1 Step 1

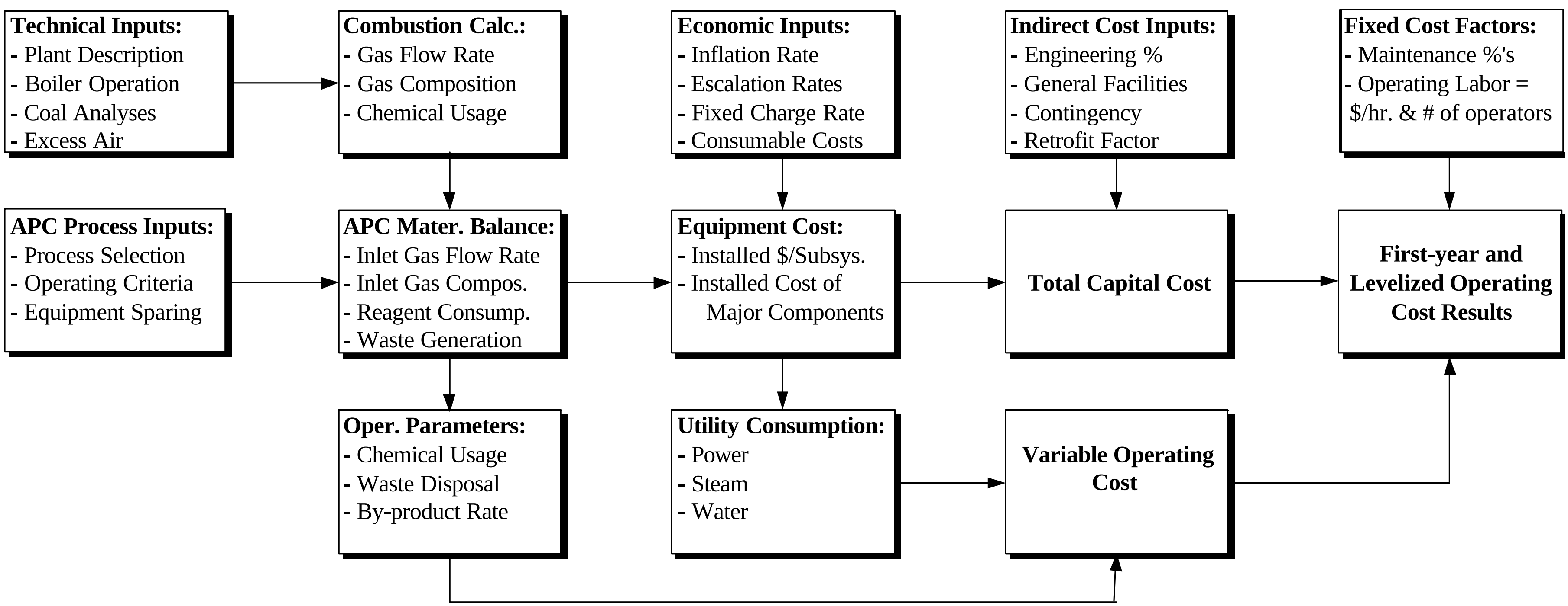
Beginning with the Input spreadsheet the user is first asked to select the desired combination of APC technologies. Following the initial process selection, the user enters the necessary technical and economic parameters specific to the project. Default values are provided for all inputs. The inputs are separated into the following distinct sections:

- General Plant Technical Inputs (boiler operation, coal analysis, excess air, etc.)
- Economic Inputs (inflation/discount/escalation/fixed charge rates, consum. costs)
- Indirect Cost Rates (engineering, general facilities, contingency, other)
- Fixed Cost Factors (maintenance %, operating labor)
- APC System-Specific Technical Inputs (operating criteria, equipment sparing)
- Retrofit Factor

3.2.2 Step 2

After the user has entered the technical inputs, the workbook performs the combustion calculations in the Constants spreadsheet. The flue gas flowrate and composition are calculated in this step. The results of these calculations are summarized in the Results spreadsheet, along with the inputs taken from the Inputs spreadsheet.

Figure 3-1. CUECost Logic Diagram



3.2.3 Step 3

Using the results of the combustion calculation and the APC-specific technical inputs, the necessary material balance calculations are performed. Reagent consumption and waste generation are calculated based on the inlet gas flow and composition (see APC technology spreadsheets).

3.2.4 Step 4

Following the calculation of the material balance, the equipment costs associated with the six specific equipment areas (APC spreadsheets) are calculated. The largest equipment components for each area (absorber, ID fan, etc.) are broken out and estimated separately. All capital costs are installed costs (i.e., they include all costs associated with the installation of the subsystem or component). These installation expenditures include the costs for:

- Earthwork
- Concrete
- Structural steel
- Piping
- Electrical
- Instrumentation and Controls
- Painting
- Insulation
- Buildings and Architectural

Costs for demolition are treated as an input, assuming that the user can provide the expected costs for any demolition that might be required at a specific site. The items listed above, when added to the bare equipment cost, are equivalent to "A" in the calculation sequence for the capital cost shown in Table 3-1.

3.2.5 Step 5

Adding the costs listed above to the uninstalled bare equipment costs results in the total direct field cost for the installed equipment (APC spreadsheets). The installed equipment costs (bare equipment cost multiplied by an installation factor composed of various cost accounts listed above -- earthwork, steel, piping, etc.) for each component include the typical indirect field costs, such as field staff and legalities, craft fringes and insurance, temporary facilities, construction equipment and tools, and an allowance for start-up and testing. Allowances for taxes are also included in the final installed cost for each subsystem. The Total Installed Cost then serves as the basis for the calculation of the engineering and general facilities cost components and the contingency cost associated with the project capital cost. Escalation of the capital cost is then performed using the CE Index (see Economic Indicators found on the last page of each issue of the *Chemical Engineering* magazine) for the year selected by the user as the basis for the cost estimate.

Table 3-1. Total Capital Requirement Calculation Method

Installed Process Capital Cost	=	A
General Facilities @ % of A	=	B
Engineering and Home Office Fees @ % of A	=	C
Contingency @ % of (A + B + C)	=	D
Total Plant Cost (TPC)	=	A+B+C+D
Total Cash Expended (TCE)	=	TPC x Adjustment Factor*
Allowance for Funds During Construction (AFDC)	=	AFDC % (input) x TPC
Total Plant Investment (TPI)	=	TCE + AFDC
Preproduction Costs	=	F
Inventory Capital	=	G
Total Capital Requirement	=	TPI + F + G

* Adjustment Factor is based on the years of construction and the inflation rate. Reduces the cost of the capital investment due to the purchase of components prior to the completion of the construction period, allowing the TCR to be expressed in a single year dollar value.

For most equipment areas and components, a cost algorithm is supplied to relate installed component cost to the component capacity. The spreadsheet was constructed to allow the user to generate cost estimates for plants ranging from 100 MW to 2000 MW and for facilities firing almost any coal.

3.2.6 Step 6

In addition to the equipment costs, the APC spreadsheets also calculate operating parameters (chemical usage, waste disposal, by-product rate, etc.) after the calculation of the material balances (APC spreadsheets). The usage and production rates serve as the basis for the calculation of the variable operating cost components. The workbook uses the operating parameters and the calculated utility consumption (electrical energy, steam, water, etc.) to calculate the variable operating costs for the project. The annualized cost calculation method is summarized in Table 3-2.

3.2.7 Step 7

Finally, the total capital and operating costs are used to calculate the levelized and first-year annualized costs. These costs are summarized in the Summary spreadsheet for direct comparison of case cost estimates and printing of output summaries.

Table 3-2. Annualized Cost Calculation Method

Fixed O&M Costs =

Operating Labor	=	Labor Rate x 8760 x Number of Operators Added	=	A
Maintenance Labor/Materials	=	Maintenance Factor x Installed Capital Cost	=	B
Administrative/Support Labor	=	0.3 x (Operating Labor + Maintenance Labor)	=	C

Variable Operating Cost =

Chemicals	=	Chemical Cost x Consumption Rate/Year	=	D
Solids Disposal	=	Waste Disposal Cost x Waste Production Rate/Year	=	E
Water Cost	=	Water Cost x Water Consumption Rate	=	F
Power	=	Power Cost x Power Consumption Rate	=	G
Steam	=	Steam Cost x Steam Consumption Rate	=	H

Fixed Charges =

Fixed Capital Charges	=	Total Capital Requirement x Fixed Charge Rate	=	I

$/Year (First-Year) = A+B+C+I+ [(D+E+F+G+H) x Capacity Factor]

Levelized/Annualized Cost (Mills/kWh) = Levelization factors multiplied times first-year costs

4.0 INPUT AND OUTPUT OPTIONS

4.1 INPUT DATA

The CUECost workbook was constructed so that all “normal” user inputs are entered into the Input spreadsheet. The various other spreadsheets then access data and use them to calculate the case study cost estimates. The term “normal” inputs is used to describe those data that are required to obtain the standard results from the spreadsheet. These cells are typically colored blue for those users who are using a color monitor. The Excel spreadsheet format allows the user to modify some of the internal assumptions and algorithms contained in the spreadsheet if the user feels that his/her own information will provide a more accurate assessment of the site-specific costs.

Columns E through I of the Input spreadsheet are provided for the user input data. Each column is specific to an individual case. Duplicate data for each case can simply be copied over into the remaining columns rather than entered individually for each case. The input spreadsheet is divided into various sections. To obtain any type of site-specific cost estimate, both the General Plant and Economic Criteria input sections should be completed. The user is not required to enter any information into those spreadsheets that do not apply to technologies being considered in the current case study (i.e., if only FGD costs are of interest, then inputs are not required for the NO_x or particulate matter control systems). The input spreadsheet sections are listed below with a brief description of the content of each:

1. Air Pollution Control system definition - Here the user selects the various APC technologies that should be included in the various cases. As was previously noted, the user can run up to five simultaneous cases and get the results for all five side-by-side for direct comparison. Each case can contain one or all of the APC subsystems.

2. Plant Technical Inputs - These criteria define the operating conditions at the facility under investigation. Fuel characteristics, heat rate, location conditions, etc., are requested in this section. These data are then used as the basis for the combustion calculations and definition of the plant ambient conditions, and the retrofit factor is used in the capital cost estimate development.

3. Economic Criteria - These economic data define the basis for the cost estimates that are produced, including the basis year, inflation rates, escalation rates, operating labor rates, chemical costs, and utility costs.

4. Limestone with Forced Oxidation FGD Process Definition - This section provides a series of inputs that define the operating conditions for the scrubber system. In this section the user can define conditions that are specific to vendor data that they might have received in the past, or the default values can be used to determine the generic costs for the FGD system. The option to use a dibasic acid (DBA) additive is also provided. The DBA acts as a buffer in the SO_2 absorption reaction, potentially reducing the operating costs for the FGD system and improving performance at some sites.

5. Lime Spray Dryer FGD Process (a.k.a. Dry Scrubbing) Definition - The data input on this spreadsheet are similar to the inputs for the LSFO spreadsheet. Once again the process operating conditions are defined for each case being considered.

6. Particulate Matter Control System Definition - All data required to define the particulate matter control system are entered in this section. The user also selects the type of control system that is desired, whether it be an ESP or a FF, and what type of fabric filter is selected.

7. Nitrogen Oxides Control System Definition - All data required to define the NO_x control system are requested in this section. The user also selects the type of control system that is desired: selective catalytic reduction (SCR), selective non-catalytic reduction, natural gas reburn (NGR) technology, or low-NO_x burner technology (LNBT) (including low NO_x burners [LNB] for pulverized coal boilers, and low-NO_x concentric firing systems [LNCFS] for tangentially fired boilers).

4.2 OUTPUT OPTIONS

The input values are then summarized in the Input and Calculation Summary spreadsheet. This spreadsheet also compiles the results generated by the other technology-specific spreadsheets. The tables are constructed for use in printing the output sheets. A 1-page summary table is available in the Results spreadsheet. This summary table provides the cost estimates generated for all of the control technologies selected for each case. More detailed breakdowns of each technology cost estimate are also generated in the technology-specific spreadsheets to identify the components of the estimates. To obtain outputs from the workbook, the user can return to the User Input Sheet, ensure that the workbook has been recalculated by pressing the F9 button, and then click on any one of the Print buttons provided. The User can also enter any spreadsheet of interest and click on the print icon. The workbook is set up to automatically print all of the material in each spreadsheet.

The workbook also allows the user to select any specific portion of the individual spreadsheet that is of interest and print out that material only. A specific range can be selected and that section printed using the standard Excel methodology.

NOTE: The user should not save the spreadsheet after selecting a portion of the spreadsheet for printing unless specifically seeking to delete the print range associated with the entire spreadsheet.

5.0 SPREADSHEET VALIDATION

The CUECost workbook was constructed to allow the user to have the maximum flexibility to modify it to generate site-specific cost estimates without requiring an extensive amount of input data. The four technology spreadsheets were developed using different sets of cost and design data. The basis for each set of parametric design and cost equations is described in the following section.

5.1 FGD SPREADSHEETS - LSFO and LSD Technologies

The equipment design parameters and cost data are based on a combination of recent vendor quotes and a historical database of installed power projects. Cost-versus-capacity curves were constructed based on this historical information combined with recent vendor quotations from both installed FGD systems and budgetary quotes received specifically for this project. Many of the sources of information that were used in this development of the FGD system costs are not available to the public due to the proprietary nature of the information and the project-specific sensitivity of the cost data.

This equipment cost database was assembled over the last ten years based on the experience gained at FGD installations for 10-15 plants ranging in size from 300 to 2000 MW. Equipment cost data is a compilation of data taken from these actual installations, vendor quotations for construction contracts, as well as budgetary quotations obtained in 1998 specifically to support this project. The budgetary quotes for large equipment items were received from one to six vendors depending on the component. This document validates the accuracy of the cost data by comparing the results generated by the model to published cost data for many of the Phase 1 FGD systems installed in response to acid rain regulations. The validation of the data used in the development of these algorithms is described in Appendix D of this user's manual.

CUECost validation was accomplished in a number of ways. The cost estimates generated were compared to the results generated by more detailed estimating spreadsheets available to more limited groups. These included the comparison of FGD cost estimates to the results generated by the Electric Power Research Institute's FGDCOST model. This model has been used throughout the utility industry for the last seven years and has demonstrated its ability to estimate site-specific costs well within ROM accuracy requirements. The CUECost estimates were found to compare well with the results generated by the FGDCOST model when allowance was made for the changes in the technology that have occurred since the FGDCOST model was constructed, escalation, and the reduced level of design data that is required by the CUECost workbook.

CUECost was also used to calculate cost estimates for many of the Phase 1 FGD systems. Actual installed cost data have been published in various sources for these systems. These data were compared to the estimates generated by the CUECost workbook and it was found that CUECost reproduced these actual costs within an accuracy of ±15%. Table 5-1 provides the results of this comparative analysis for previously installed FGD systems.

Table 5-1. CUECost FGD Cost Comparisons for Phase 1 Acid Rain Installations

Unit	MW	%S	Rem. Eff. %	Pub $/kW	CUECost $/kW	%Differ.
Petersburg	657	3.50	95	317	291	-8.20
Cumberland	2600	4.00	95	200	187	-6.50
Conemaugh	1700	2.80	95	195	179	-8.20
Ghent	511	3.50	90	215	229	+6.5
Gibson	668	3.50	91	247	218	-11.70
Bailly	600	4.50	95	180	196	+8.9
Milliken	316	3.20	98	348	362	+4.0
Navajo	2250	0.75	92	236	213	-9.75

Table 5-2. Comparison of CUECost ESP Sizing Estimates with Other Sources

Coal	% S	Rem.Eff.,%	Rayth. SCA*	CUECost SCA*	% Differ.
Indiantown	1.09	99.4	385	429	+11.43
WV-EPRI	0.66	99.2	418	375	-10.29
LoSulfBituminous	0.97	99.4	403	424	+5.21
Keystone	1.09	99.3	393	386	-1.78
India	0.5	99.9	965	883	-8.50
Logan, WV	0.89	99.7	569	502	-11.78
ND Lignite	0.94	99.4	376	411	+9.31
UT-EPRI	0.53	99.5	446	442	-0.90
UT-Alternate	0.66	99.6	435	482	+10.80
Rosebud, MT	0.56	99.5	482	459	-4.77
WY-PRB	0.37	99.3	558	558	0
Test Coal	2	99.1	287	283	-1.39
Pitts 8	2.13	99.2	272	285	+4.78
Carneys	2	99.1	288	281	-2.43
TX Lignite	1.16	99.8	549	549	0
OH Alternate	4.7	99.6	247	259	+4.86
IL #6	3.25	99.5	276	261	-5.43
Armstrong, PA	2.6	99.3	277	274	-1.08
Jefferson, OH	3.43	99.6	321	326	1.56

* SCA = square feet of plate area per 1000 actual cubic feet per minute of flue gas flow

5.2 PARTICULATE MATTER CONTROL SPREADSHEET

The particulate matter control sizing equations were based on previously published correlations developed by Carnegie Mellon University (CMU). This development process is described in Appendix D. The CMU model was constructed using design information supplied by multiple vendors. The ESP equations provided in this CMU model were reviewed and compared to the expected ESP sizes in terms of Specific Collection Area (SCA), evaluating the various types of coals listed in Table 5-2. The "Rayth." SCA data provided in Table 5-2 were calculated using a series of parametric equations developed by Raytheon. These equations were derived from SCA data for utility coal-fired installations over the past 25 years obtained by Raytheon and incorporated into a proprietary model used for confirmation of vendor data and specification preparation. As can be seen in Table 5-2, the CUECost workbook calculates SCA values that are within 15% of the values generated by the Raytheon model.

The ESP cost algorithms were derived from the Raytheon cost database for more than 100 units installed across the country. The costs generated by these algorithms were compared to the current IAPCS results for the same plant sizes and coals. The current model produced cost results within 30% of the IAPCS cost estimating model over a range of SCA values from 300 to 600. The FF cost algorithms (one for pulse jet design and one for reverse gas) were developed from 10 to 12 recent (1992-1997) firm price quotations for each FF design. The coal-fired boilers in this database ranged in size from 50 to 500 MW.

5.3 NO_x CONTROL SPREADSHEET

For NO_x control technologies, CUECost results were compared to cost data reported by the EPA Acid Rain Division for NO_x controls applied to utility boilers. The Acid Rain Division reports are based on an EPA national database of boilers. The 1990 Clean Air Act Amendments required the EPA to examine NO_x control technology costs, and the resulting Acid Rain Division studies were used and reviewed during the rule-making process. A comparison was made for four cases with various boiler types, boiler sizes (100 to 400 MW) and coals burned. The boiler design and operating parameters for each case were input into CUECost to obtain capital and operating and maintenance costs.

Different approaches were taken to verify or validate the costs predicted by CUECost for the various NO_x control technologies. For SCR, SNCR and NGR, design parameters used for the Acid Rain Division study cases were used to calculate preliminary operating parameters and costs with CUECost. Algorithms for SCR in CUECost were compared to the ARD study costs to validate the algorithms. However, the ARD data were incorporated into the algorithms for SNCR and NGR. As a result, the cost comparisons for these technologies were conducted to benchmark the algorithms and evaluate how well they track the ARD data. The percent differences found for the four boiler cases are presented in Table 5-3. Differences range in magnitude from 0 to 11 percent for total plant costs and from 0 to 22 percent for operating and maintenance costs.

The algorithms used to estimate costs for LNBT in CUECost were taken from an Acid Rain Division study (EPA, 1996). The cost data upon which the algorithms were based represent actual LNBT retrofit cases. The capital cost comparison shows 0 percent difference, as expected, because the algorithms are based solely on ARD data. A comparison is not presented for operating and maintenance costs because these costs are highly boiler specific.

Table 5-3. Percent Difference Between CUECost and Acid Rain Division Studies for Retrofit Cases*

	Cyclone-Fired		Wet-Bottom	
			Vertical-Fired	Wall- Fired
	Midwestern Bituminous		Eastern Bituminous	
	Boiler Size (MW)			
	150	400	100	259
Total Plant Costs				
Selective Catalytic Reduction (50 percent removal)	4%	0%	8%	-4%
Selective Noncatalytic Reduction (50 percent removal)	-7%	7%	-15%	6%
Natural Gas Reburning (35 percent removal)	11%	6%	0%	2%
Low NO_x Burner Technology	0%	0%	0%	0%
O&M Costs				
Selective Catalytic Reduction (50 percent removal)	-12%	-18%	-16%	-22%
Selective Noncatalytic Reduction (50 percent removal)	8%	0%	12%	4%
Natural Gas Reburning (35 percent removal)	-11%	-7%	-12%	-12%

* Note: Percent Difference = (Acid Rain Costs - CUECost Results) x 100 /Acid Rain Costs

5.4 VALIDATION SUMMARY

Costs for utility APC systems are site-specific. These costs are subject to change with changes in technology, labor rates, and material costs. The costs estimated by the CUECost workbook come from a variety of sources. With that understanding, one may assume, but it is not guaranteed, that CUECost will produce estimates in the range of accuracy of ±30% of the actual cost, which was the goal of this project. The operating cost estimates are more straightforward than the capital cost estimates, relying more on the accuracy of the input data supplied by the user. The calculation sequences for these estimates have been verified on a cell-by-cell basis during the course of the workbook development. The documentation provided in Appendix F also allows any user to verify a specific calculation sequence that might be in question at some point in the future. The economic calculation methods used have been well established for many years throughout the utility industry, and have been documented in the EPRI Technical Assessment Guide (Ramachandran, 1989).

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APPENDIX A

TERMINOLOGY DEFINITIONS, ABBREVIATIONS, ACRONYMS, AND RANGE NAMES

A.1 DEFINITION OF TERMS

Allowance for Funds Used During Construction (AFUDC or AFDC) - Represents the time value of money during the construction period. AFUDC is calculated based on the weighted cost of capital, compounded on an annual basis throughout the period, and applied to all funds spent during each year. This cost is added to the Total Cash Expended to obtain TPI. See Table 3-1 for the use of the AFDC factor. The AFDC factor is input by the user, and is a function of the years of construction and the discount rate.

Ammonia Slip = The unreacted ammonia that exits an SCR or SNCR process, and exits the stack with the flue gas. It is expressed as a concentration n the exit gas or as a percentage of the mass of ammonia input to the process.

Battery Limits = The boundary limits within a plant used to define the equipment components contained in a subsystem.

Capacity Factor (CF) - Equivalent to the ratio of the total energy output over a time period divided by the total gross energy generating capacity of the unit. Typically the CF is input as the expected average value over the remaining plant life.

Carrying Charge Factor (CCF) - Amount of revenue per dollar of investment that must be collected from customers in order to pay the carrying charges on that investment. The CCF is expressed as a decimal that is multiplied by the original investment to obtain a carrying charge in terms of dollars. The carrying charge rate can be a present value or levelized quantity over a specified period of time (up to the book life), or an annual quantity in a specific year of life. The factor includes the return on debt, return on equity, income and property taxes, book depreciation, rate of return to shareholders, and insurance.

Constant Dollar - Cost estimate presented in terms of the base year dollars without including the impact of inflation over the plant life. However, real escalation is included in the calculation of future year costs. Constant dollar analysis requires the use of a discount rate that does not include inflation.

Contingency - A capital cost included in the estimate to cover the costs for additional equipment or other costs that are expected to be incurred during a project after the detailed design is completed. These are funds that are expected to be spent during implementation of the final project. The contingency is factored as a percent of process capital plus engineering, home office and general facilities.

Current Dollar - A cost analysis that includes the effects of inflation and real escalation. The discount rate used for current dollar analyses is equivalent to the return required to attract investment capital and is equivalent to the weighted average of the return on equity and return on debt.

Engineering and Home Office Costs - Derived as a percentage of the total direct capital cost. This indirect cost includes the costs for architectural/engineering company and for home office engineering expenses by the user's company. This value typically ranges from 5 to 20% of the Process Capital, with the percentage varying based on the level of complexity for equipment installation (e.g., a new plant might have a value of 5 to 10% while a retrofit might experience engineering costs closer to 15-20%).

General Facilities - Includes costs for items such as roads, office buildings, maintenance shops, and laboratories. The indirect cost for these facilities typically ranges from 5 to 20% of the Process Capital.

Heat Rate - Equivalent to the fuel energy content (Btu) required to produce 1 kWh of electric energy. Fuel energy content is typically based on the higher heating value of the fuel.

Inflation Rate - Equivalent to the rise in prices caused by an increase in the available currency and credit without a proportionate increase in available of goods and services of equal quality. The inflation rate does not include the effects of real escalation.

Operating Costs - Operating costs for each technology are expressed in terms of both $/kW-year and mills/kWhr. The $/kW-year costs are considered to be an expression of annual costs and, therefore, include the capacity factor in the calculation. The mills/kWhr values are considered instantaneous values, and, therefore, do not include the capacity factor in their calculation.

Present Value (PV) - Monetary equivalent to the amount of money at a point in time other than that at which it is paid or received.

Process Capital - Total installed cost of all process equipment.

Total Capital Requirement (TCR) - Equivalent to the Total Plant Cost, AFUDC, plant startup costs, and inventory capital.

Total Plant Cost (TPC) - Equivalent to the total installed cost for all plant equipment, including all direct and indirect construction costs, engineering, overheads, fees, and contingency.

A.2 ABBREVIATIONS, ACRONYMS AND RANGE NAMES

A/C = Air to Cloth ratio used for fabric filter equipment sizing. Calculated by dividing the flue gas volumetric flowrate by the collection surface area of the fabric filter media.

ACFM = Actual Cubic Feet per Minute

APC = Air Pollution Control equipment

ARD = Acid Rain Division

CMU = Carnegie Mellon University

CUECost = The name assigned to the APC cost estimating spreadsheets, Coal Utility Environmental Cost workbook

DBA = Dibasic Acid, used as a buffering agent in LSFO scrubbing systems. A mixture of three organic acids.

EPA = United States Environmental Protection Agency

ESP = Electrostatic Precipitator

FF = Fabric Filter

FGD = Flue Gas Desulfurization system

IAPCS = Integrated Air Pollution Control System

k = Exponential constant used to related coal type, removal efficiency and ash resistivity to ESP size in terms of the Specific Collection Area (SCA)

LNB = Low NO_x Burners

LNBT = Low NO_x Burner Technology

LSFO = Limestone FGD system with Forced Oxidation

LSD = Lime Spray Drying FGD system

NGR = Natural Gas Reburn

OFA = Over-fire air used to complete coal combustion in some LNBT applications

ppm = parts per million

RLCS = Rubber-Lined Carbon Steel

SCA = Specific Collecting Area; refers to ESP size in terms of plate area (ft^2)/1000 acfm

SCR = Selective Catalytic Reduction

SNCR = Selective Non-catalytic Reduction

$\underline{w_k}$ = Precipitation rate parameter used in calculation of removal efficiency for an ESP

The following table lists the range and variable names used in the model. The sheet and cell location, description, and associated value of the variables are listed in the table.

VARIABLE / RANGE NAME	SHEET / CELL LOCATION	DESCRIPTION	VALUE
Air_MolWt	=Constants_CC!$D$134	Molecular weight of Air	28.8555
APC	='User Input Sheet'!$A$41:$I$51	Summary of Control Technology Choices	NA
Ash_MolWt	=Constants_CC!$D$141	Molecular weight of Ash	1
C_MolWt	=Constants_CC!$D$136	Molecular weight of Carbon	12.01115
Ca_MolWt	=Constants_CC!$D$143	Molecular weight of Calcium	40.08
Ca_OH_2_MolWt	=Constants_CC!$D$154	Molecular weight of Calcium Hydroxide	74.0947
CaCl2_MolWt	=Constants_CC!$D$161	Molecular weight of Calcium Chloride	110.99
CaCO3_MolWt	=Constants_CC!$D$151	Molecular weight of Calcium Carbonate	100.0894
CaO_MolWt	=Constants_CC!$D$153	Molecular weight of Calcium Oxide (Lime)	56.0794
CaSO3halfH2O_MolWt	=Constants_CC!$D$155	Molecular weight of Calcium Sulfite	129.1499
CaSO4_2H2O_MolWt	=Constants_CC!$D$156	Molecular weight of Calcium Sulfate Dihydrate	172.1723
CaSO4_MolWt	=Constants_CC!$D$152	Molecular weight of Calcium Sulfate	136.1416
CH4_MolWt	=Constants_CC!$D$160	Molecular weight of Methane	16.043
Cl2_MolWt	=Constants_CC!$D$139	Molecular weight of Chlorine	70.906
CO2_MolWt	=Constants_CC!$D$145	Molecular weight of Carbon Dioxide	44.01
Coal_Library	=Constants_CC!$B$10:$K$48	Library of Coals	NA
Combustion	=Constants_CC!$B$306:$I$521	Combustion Calculations	NA
CostSummary	='Input & Calculation Summary'!$A$256:$G$404	Summary of Capital and O&M Costs	NA
cubft_60	=Constants_CC!$D$272	Cubic Feet per Mole at 60 degrees F	379.63
cubft_69	=Constants_CC!$D$273	Cubic Feet per Mole at 69 degrees F	386
cubft_70	=Constants_CC!$D$274	Cubic Feet per Mole at 70 degrees F	386.704
Def_AFUDC	='User Input Sheet'!$D$93	Default Allowance for Funds During Construction Rate	0.108
Def_AHLeak	='User Input Sheet'!$D$64	Default Air Heater In-leakage	0.12
Def_AHoutPress	='User Input Sheet'!$D$68	Default Air Heater Outlet Pressure	-12
Def_AHOutTemp	='User Input Sheet'!$D$65	Default Air Heater Outlet Temperature	300
Def_AirH2O	='User Input Sheet'!$D$69	Default Moisture in Air	0.013
Def_AmbPress	='User Input Sheet'!$D$67	Default Ambient Pressure	29.4
Def_BagDia	='User Input Sheet'!$D$214	Default Fabric Filter Bag Diameter	6
Def_BagLength	='User Input Sheet'!$D$215	Default Fabric Filter Bag Length	20
Def_BagLife	='User Input Sheet'!$D$218	Default Fabric Filter Bag Life	5
Def_BagReach	='User Input Sheet'!$D$216	Default Fabric Filter Bag Reach	3
Def_BotAsh	='User Input Sheet'!$D$72	Default Percent Bottom Ash	0.2
Def_Cap_ER	='User Input Sheet'!$D$104	Default Capital Escalation Rate	0.03
Def_Cap_Esc	='User Input Sheet'!$D$102	Default Answer to CE Index Question	Yes
Def_CapFact	='User Input Sheet'!$D$62	Default Capacity Factor	0.65
Def_CEIndex	='User Input Sheet'!$D$103	Default Chemical Engineering Index (Jan. 1998)	388
Def_CnstrLabor	='User Input Sheet'!$D$105	Default Construction Labor Rate	35
Def_Coal	='User Input Sheet'!$D$76	Default Coal	1
Def_CostBasis	='User Input Sheet'!$D$89	Default Cost Basis Year	1998
Def_DiscRate	='User Input Sheet'!$D$92	Default Discount Rate	0.092

VARIABLE / RANGE NAME	SHEET / CELL LOCATION	DESCRIPTION	VALUE
Def_Esc_Cap	='User Input Sheet'!$D$103	Default Chemical Engineering Index (Jan. 1998)	388
Def_Esc_Consum	='User Input Sheet'!$D$100	Default Consumables Escalation Rate	0.03
Def_ESPCont	='User Input Sheet'!$D$229	Default Percent Contingency for ESP	0.2
Def_ESPEng	='User Input Sheet'!$D$231	Default Percent Engineering for ESP	0.1
Def_ESPGenFac	='User Input Sheet'!$D$230	Default Percent General Facilities for ESP	0.1
Def_ESPMaint	='User Input Sheet'!$D$228	Default Percent Maintenance for ESP	0.05
Def_FabType	='User Input Sheet'!$D$212	Default Fabric for Bags (Nomex)	2
Def_FF	='User Input Sheet'!$D$210	Default Fabric Filter Type (Pulse Jet)	2
Def_FFCont	='User Input Sheet'!$D$220	Default Percent Contingency for FF	0.2
Def_FFEng	='User Input Sheet'!$D$222	Default Percent Engineering for FF	0.1
Def_FFGenFac	='User Input Sheet'!$D$221	Default Percent General Facilities for FF	0.1
Def_FFMaint	='User Input Sheet'!$D$219	Default Percent Maintenance for FF	0.05
Def_FFSparing	='User Input Sheet'!$D$217	Default Percentage of Compartments Out of Service	0.1
Def_FGD	='User Input Sheet'!$D$45	Default Flue Gas Desulfurization Process (LSFO)	1
Def_FlyAsh	='User Input Sheet'!$D$71	Default Percent Fly Ash	0.8
Def_FYCC_const	='User Input Sheet'!$D$96	Default First Year Carrying Charge Rate (Constant $)	0.157
Def_FYCC_curr	='User Input Sheet'!$D$94	Default First Year Carrying Charge Rate (Current $)	0.223
Def_GastoCloth	='User Input Sheet'!$D$211	Default Fabric Filter Gas to Cloth Ratio	3.5
Def_InAirTemp	='User Input Sheet'!$D$66	Default Inlet Air Temperature	80
Def_LCC_const	='User Input Sheet'!$D$97	Default Levelized Carrying Charge Rate (Constant $)	0.117
Def_LCC_curr	='User Input Sheet'!$D$95	Default Levelized Carrying Charge Rate (Current $)	0.169
Def_MAR	='User Input Sheet'!$D$91	Default Inflation Rate	0.03
Def_MW	='User Input Sheet'!$D$60	Default MW Equivalent of Flue Gas to Control System	500
Def_NOx	='User Input Sheet'!$D$49	Default NOx Control Process (SCR)	1
Def_NPHR	='User Input Sheet'!$D$61	Default Net Plant Heat Rate	10500
Def_OperLabor	='User Input Sheet'!$D$107	Default Operating Labor Rate	30
Def_PartControl	='User Input Sheet'!$D$47	Default Particulate Control Process (FF)	1
Def_PartLimit	='User Input Sheet'!$D$207	Default Outlet PM Emission Limit (lbs/MMBtu)	0.03
Def_PCMarkup	='User Input Sheet'!$D$106	Default Percent Prime Contractors Markup	0.03
Def_Plate_Ht	='User Input Sheet'!$D$226	Default ESP Plate Height	36
Def_Plate_Space	='User Input Sheet'!$D$225	Default ESP Plate Spacing	12
Def_PowerCost	='User Input Sheet'!$D$108	Default Power Cost	25
Def_PRB	='User Input Sheet'!$D$77	Default Answer to Powder River Basin Coal Question	Yes
Def_RetroFact	='User Input Sheet'!$D$74	Default Retrofit Factor	1.3
Def_SalesTax	='User Input Sheet'!$D$98	Default Sales Tax Percentage	0.06
Def_SeisZone	='User Input Sheet'!$D$73	Default Seismic Zone	1
Def_SerLife	='User Input Sheet'!$D$90	Default Service Life	30
Def_State	='User Input Sheet'!$D$59	Default Location (State) of Plant	PA
Def_SteamCost	='User Input Sheet'!$D$109	Default Steam Cost	3.5
Def_TotAir	='User Input Sheet'!$D$63	Default Percent Excess Air in Boiler	1.2
degK	=Constants_CC!$D$268	Conversion for degrees Kelvin	273
Del_ESP_EFS	='User Input Sheet'!$D$224	Default ESP Electric Field Strength	10
Economic_Inputs	='User Input Sheet'!$A$87:$I$109	Summary of Economic Inputs	NA
ESP_Calcs	='FF ESP Cost & Tech. Results'!$A$100:$H$241	ESP Calculations	NA
ESP_PDrop	='User Input Sheet'!$D$227	Default ESP Pressure Drop	3
FF_Calcs	='FF ESP Cost & Tech. Results'!$A$20:$H$98	Fabric Filter Calculations	NA
FF_PDrop	='User Input Sheet'!$D$209	Default Fabric Filter Pressure Drop	6

VARIABLE / RANGE NAME	SHEET / CELL LOCATION	DESCRIPTION	VALUE
GeneralPlantInputs	='User Input Sheet'!$A$53:$I$86	Summary of General Plant Inputs	NA
H2_MolWt	=Constants_CC!$D$137	Molecular weight of Hydrogen	2.01594
H2O_MolWt	=Constants_CC!$D$135	Molecular weight of Water	18.01534
H2SO4_MolWt	=Constants_CC!$D$159	Molecular weight of Sulfuric Acid	98.0775
HCl_MolWt	=Constants_CC!$D$148	Molecular weight of Hydrochloric Acid	36.461
inH2O_inHg	=Constants_CC!$D$269	Conversion Factor for Pressure	13.615
Input_Summary	='Input & Calculation Summary'!$A$2:$G$242	Summary of Inputs	NA
kW_Hp	=Constants_CC!$D$275	Conversion Factor from kW to Hp	0.746
LibraryCoal	=Constants_CC!$D$13:$K$48	Library of Coal Analyses	NA
LNB_Calcs	='NOX Cost & Tech. Results'!$A$116:$H$135	NOx Control Calculations	NA
LSD_AbsorbMatl	='User Input Sheet'!$D$174	Default Absorber Material for LSD Process	1
LSD_AdSat	='User Input Sheet'!$D$164	Default Adiabatic Saturation Temperature	127
LSD_ApptoSat	='User Input Sheet'!$D$165	Default Approach to Saturation	20
LSD_Calcs	='LSD Cost & Tech. Results'!$A$20:$H$351	Lime Spray Dryer Calculations / Material Balances	NA
LSD_Conting1	='User Input Sheet'!$D$187	LSD Default Contingency for Reagent Feed Area	0.2
LSD_Conting2	='User Input Sheet'!$D$188	LSD Default Contingency for SO2 Removal Area	0.2
LSD_Conting3	='User Input Sheet'!$D$189	LSD Default Contingency for Flue Gas Handling Area	0.2
LSD_Conting4	='User Input Sheet'!$D$190	LSD Default Contingency for Waste/Byproduct Handling Area	0.2
LSD_Conting5	='User Input Sheet'!$D$191	LSD Default Contingency for Support Equipment	0.2
LSD_Costs	='LSD Cost & Tech. Results'!$A$221:$H$350	Lime Spray Dryer Costs	NA
LSD_DelP	='User Input Sheet'!$D$176	LSD Default Pressure Drop	5
LSD_DispCost	='User Input Sheet'!$D$179	LSD Default Waste Disposal Cost	30
LSD_EngHO1	='User Input Sheet'!$D$199	LSD Default Engineering & Home Office Fees for Reagent Feed Area	0.1
LSD_EngHO2	='User Input Sheet'!$D$200	LSD Default Engineering & Home Office Fees for SO2 Removal Area	0.1
LSD_EngHO3	='User Input Sheet'!$D$201	LSD Default Engineering & Home Office Fees for Flue Gas Handling Area	0.1
LSD_EngHO4	='User Input Sheet'!$D$202	LSD Default Engineering & Home Office Fees for Waste/Byproduct Handling Area	0.1
LSD_EngHO5	='User Input Sheet'!$D$203	LSD Default Engineering & Home Office Fees for Support Equipment	0.1
LSD_Facil1	='User Input Sheet'!$D$193	LSD Default General Facilities for Reagent Feed Area	0.1
LSD_Facil2	='User Input Sheet'!$D$194	LSD Default General Facilities for SO2 Removal Area	0.1
LSD_Facil3	='User Input Sheet'!$D$195	LSD Default General Facilities for Flue Gas Handling Area	0.1
LSD_Facil4	='User Input Sheet'!$D$196	LSD Default General Facilities for Waste/Byproduct Handling Area	0.1
LSD_Facil5	='User Input Sheet'!$D$197	LSD Default General Facilities for Support Equipment	0.1
LSD_Inputs	='User Input Sheet'!$A$161:$I$203	Lime Spray Dryer Input Area	NA
LSD_Maint1	='User Input Sheet'!$D$181	LSD Default Maintenance Factor for Reagent Feed Area	0.05
LSD_Maint2	='User Input Sheet'!$D$182	LSD Default Maintenance Factor for SO2 Removal Area	0.05
LSD_Maint3	='User Input Sheet'!$D$183	LSD Default Maintenance Factor for Flue Gas Handling Area	0.05

VARIABLE / RANGE NAME	SHEET / CELL LOCATION	DESCRIPTION	VALUE
LSD_Maint4	='User Input Sheet'!$D$184	LSD Default Maintenance Factor for Waste/Byproduct Handling Area	0.05
LSD_Maint5	='User Input Sheet'!$D$185	LSD Default Maintenance Factor for Support Equipment	0.05
LSD_MB	='LSD Cost & Tech. Results'!$A$20:$H$220	Lime Spray Dryer Material Balance Area	NA
LSD_NoAbsorb	='User Input Sheet'!$D$172	LSD Default Number of Absorbers	2
LSD_OutTemp	='User Input Sheet'!$D$166	LSD Default Spray Dryer Outlet Temperature	147
LSD_ReagCost	='User Input Sheet'!$D$178	LSD Default Reagent Cost	65
LSD_ReagRatio	='User Input Sheet'!$D$167	LSD Default Reagent Feed Ratio	0.9
LSD_ReagStor	='User Input Sheet'!$D$177	LSD Default Number of Days for Reagent Storage	60
LSD_Recycle	='User Input Sheet'!$D$169	LSD Default Recycle Rate	30
LSD_RecycleConc	='User Input Sheet'!$D$171	LSD Default Recycle Slurry Solids Concentration	0.35
LSD_SO2Rem	='User Input Sheet'!$D$163	LSD Default SO2 Removal Efficiency	0.9
LSFO_AbsorbDelP	='User Input Sheet'!$D$127	LSFO Default Absorber Pressure Drop	6
LSFO_AbsorbMatl	='User Input Sheet'!$D$125	LSFO Default Absorber Material	1
LSFO_AdSat	='User Input Sheet'!$D$117	LSFO Default Adiabatic Saturation Temperature	127
LSFO_Calcs	='LSFO Cost & Tech. Results'!$A$20:$H$373	LSFO Calculation and Material Balances	NA
LSFO_Conting1	='User Input Sheet'!$D$143	LSFO Default Contingency for Reagent Feed Area	0.2
LSFO_Conting2	='User Input Sheet'!$D$144	LSFO Default Contingency for SO2 Removal Area	0.2
LSFO_Conting3	='User Input Sheet'!$D$145	LSFO Default Contingency for Flue Gas Handling Area	0.2
LSFO_Conting4	='User Input Sheet'!$D$146	LSFO Default Contingency for Waste/Byproduct Handling Area	0.2
LSFO_Conting5	='User Input Sheet'!$D$147	LSFO Default Contingency for Support Equipment	0.2
LSFO_Costs	='LSFO Cost & Tech. Results'!$A$182:$H$340	Limestone Forced Oxidation Costs	NA
LSFO_DBA	='User Input Sheet'!$D$115	LSFO Default DBA Question	2
LSFO_Disposal	='User Input Sheet'!$D$121	LSFO Default Type of Waste Disposal	1
LSFO_EngHO1	='User Input Sheet'!$D$155	LSFO Default Engineering & Home Office Fees for Reagent Feed Area	0.1
LSFO_EngHO2	='User Input Sheet'!$D$156	LSFO Default Engineering & Home Office Fees for SO2 Removal Area	0.1
LSFO_EngHO3	='User Input Sheet'!$D$157	LSFO Default Engineering & Home Office Fees for Flue Gas Handling Area	0.1
LSFO_EngHO4	='User Input Sheet'!$D$158	LSFO Default Engineering & Home Office Fees for Waste/Byproduct Handling Area	0.1
LSFO_EngHO5	='User Input Sheet'!$D$159	LSFO Default Engineering & Home Office Fees for Support Equipment	0.1
LSFO_Facil1	='User Input Sheet'!$D$149	LSFO Default General Facilities for Reagent Feed Area	0.1
LSFO_Facil2	='User Input Sheet'!$D$150	LSFO Default General Facilities for SO2 Removal Area	0.1
LSFO_Facil3	='User Input Sheet'!$D$151	LSFO Default General Facilities for Flue Gas Handling Area	0.1
LSFO_Facil4	='User Input Sheet'!$D$152	LSFO Default General Facilities for Waste/Byproduct Handling Area	0.1
LSFO_Facil5	='User Input Sheet'!$D$153	LSFO Default General Facilities for Support Equipment	0.1
LSFO_GypsumCredit	='User Input Sheet'!$D$135	LSFO Default Credit for Gypsum Byproduct	2

VARIABLE / RANGE NAME	SHEET / CELL LOCATION	DESCRIPTION	VALUE
LSFO_Inputs	='User Input Sheet'!$A$111:$I$159	LSFO Input Area	NA
LSFO_LandfillCost	='User Input Sheet'!$D$133	LSFO Default Landfill Cost	30
LSFO_LGRatio	='User Input Sheet'!$D$114	LSFO Default L/G Ratio	125
LSFO_Maint1	='User Input Sheet'!$D$137	LSFO Default Maintenance Factor for Reagent Feed Area	0.05
LSFO_Maint2	='User Input Sheet'!$D$138	LSFO Default Maintenance Factor for SO2 Removal Area	0.05
LSFO_Maint3	='User Input Sheet'!$D$139	LSFO Default Maintenance Factor for Flue Gas Handling Area	0.05
LSFO_Maint4	='User Input Sheet'!$D$140	LSFO Default Maintenance Factor for Waste/Byproduct Handling Area	0.05
LSFO_Maint5	='User Input Sheet'!$D$141	LSFO Default Maintenance Factor for Support Equipment	0.05
LSFO_MB	='LSFO Cost & Tech. Results'!$A$20:$H$181	LSFO Material Balance Area	NA
LSFO_NoAbsorb	='User Input Sheet'!$D$123	LSFO Default Number of Absorbers	1
LSFO_ReagCost	='User Input Sheet'!$D$132	LSFO Default Reagent Cost	15
LSFO_ReagRatio	='User Input Sheet'!$D$118	LSFO Default Reagent Feed Ratio	1.05
LSFO_ReagStor	='User Input Sheet'!$D$131	LSFO Default Number of Days for Reagent Storage	60
LSFO_Reheat	='User Input Sheet'!$D$128	LSFO Default Answer to Reheat Question	1
LSFO_ReheatTemp	='User Input Sheet'!$D$130	LSFO Default Amount of Reheat Required	25
LSFO_ScrubSlurry	='User Input Sheet'!$D$120	LSFO Default Scrubber Slurry Solids Concentration	0.15
LSFO_SO2Rem	='User Input Sheet'!$D$113	LSFO Default SO2 Removal Efficiency	0.95
LSFO_StackCost	='User Input Sheet'!$D$134	LSFO Default Gypsum Stacking Cost	6
Mg_MolWt	=Constants_CC!$D$144	Molecular weight of Magnesium	24.312
N2_MolWt	=Constants_CC!$D$138	Molecular weight of Nitrogen	28.02
Na_MolWt	=Constants_CC!$D$157	Molecular weight of Sodium	22.99
Na2CO3_MolWt	=Constants_CC!$D$158	Molecular weight of Sodium Carbonate	105.9894
NGR_Calcs	='NOX Cost & Tech. Results'!$A$136:$H$181	Natural Gas Reburn Calculation Area	NA
NO_MolWt	=Constants_CC!$D$147	Molecular weight of Nitrogen Oxide	30.0094
NO2_MolWt	=Constants_CC!$D$146	Molecular weight of Nitrogen Peroxide	46.0088
NOx_Cals	='NOX Cost & Tech. Results'!$A$5:$H$182	NOx Control Calculation Area	NA
NOx_Inputs	='User Input Sheet'!$A$233:$I$289	NOx Control Inputs	NA
O2_MolWt	=Constants_CC!$D$142	Molecular weight of Oxygen	31.9988
Particulate_Calcs	='FF ESP Cost & Tech. Results'!$A$20:$H$241	Particulate Control Calculation Area	NA
Particulate_Inputs	='User Input Sheet'!$A$205:$I$231	Particulate Control Inputs	NA
S_MolWt	=Constants_CC!$D$140	Molecular weight of Sulfur	32.064
SAPress_inHg	=Constants_CC!$D$270	Standard Atmospheric Pressure (inches Hg)	29.92
SATemp_degF	=Constants_CC!$D$271	Standard Atmospheric Temperature (degrees F)	70
SCR_Calcs	='NOX Cost & Tech. Results'!$A$5:$H$60	SCR Calculation Area	NA
SNCR_Calcs	='NOX Cost & Tech. Results'!$A$61:$H$115	SNCR Calculation Area	NA
SO2_MolWt	=Constants_CC!$D$149	Molecular weight of Sulfur Dioxide	64.0628
SO3_MolWt	=Constants_CC!$D$150	Molecular weight of Sulfur Trioxide	80.0622

APPENDIX B

TECHNOLOGY DESCRIPTIONS/CRITERIA

B.1 LIMESTONE FORCED OXIDATION DESIGN CRITERIA

In a limestone with forced oxidation (LSFO) system, the flue gas is contacted with a slurry containing approximately 15% calcium carbonate and sulfate solids. The aqueous sulfite formed by SO_2 absorption is oxidized to sulfate by forced air injection in the tower recirculation tank. This produces a slurry with essentially 100% conversion of calcium sulfite to sulfate. The series of chemical reactions that occur in an LSFO absorber and reaction tank are described in the following equations (a process flow diagram for the LSFO system is shown in Figure B-1):

SO_2 Reaction: $CaCO_3\ (s) + SO_2\ (g) + 1/2\ H_2O \rightarrow CaSO_3 \bullet 1/2\ H_2O + CO_2$

Sulfite Oxidation: $CaSO_3 \bullet 1/2\ H_2O + 1/2\ O_2 + 3/2\ H_2O \rightarrow CaSO_4 \bullet 2\ H_2O$

The current model requires that the user input new values for the slurry recycle rate (Liquid to Gas Ratio = L/G) whenever the SO_2 removal efficiency across the FGD system is changed versus the current 95% removal rate included as the base case default value. Typically the increase in removal efficiency above this 95% level will require significant increases in the recycle rate. A value of 140 gallons/1000 actual cubic feet (L/G) would be typical for a 97% removal system versus the 125 value for a 95% system. Therefore, the pump sizes and power consumption required in the FGD system would increase significantly. Values for the limestone feed rate (stoichiometric feed ratio default = 1.05 moles of $CaCO_3$ per mole of SO_2 removed) also remain constant with changes in the removal efficiency, but can be modified by the user if additional vendor information is available.

The slurry produced by the FGD system can be thickened and pumped directly to a gypsum stack for final disposal, vacuum filtered or centrifuged for landfill disposal, or washed and dewatered for commercial wallboard production.

The LSFO system incorporates five specific equipment areas:

- Reagent Feed - Receiving, Storage, Grinding
- SO_2 Removal - Absorbers, Tanks, Pumps
- Flue Gas Handling - Ductwork and I.D.Fan
- Waste / Byproduct Handling - Dewatering, Disposal/Storage, Washing
- Support Equipment - Electrical, Water, Air

Each area is designed to compare to typical vendor package scope of supply for a standard FGD system installation project. Within various cost areas, the largest equipment component costs will be broken out and the cost estimate calculated for these items. In the

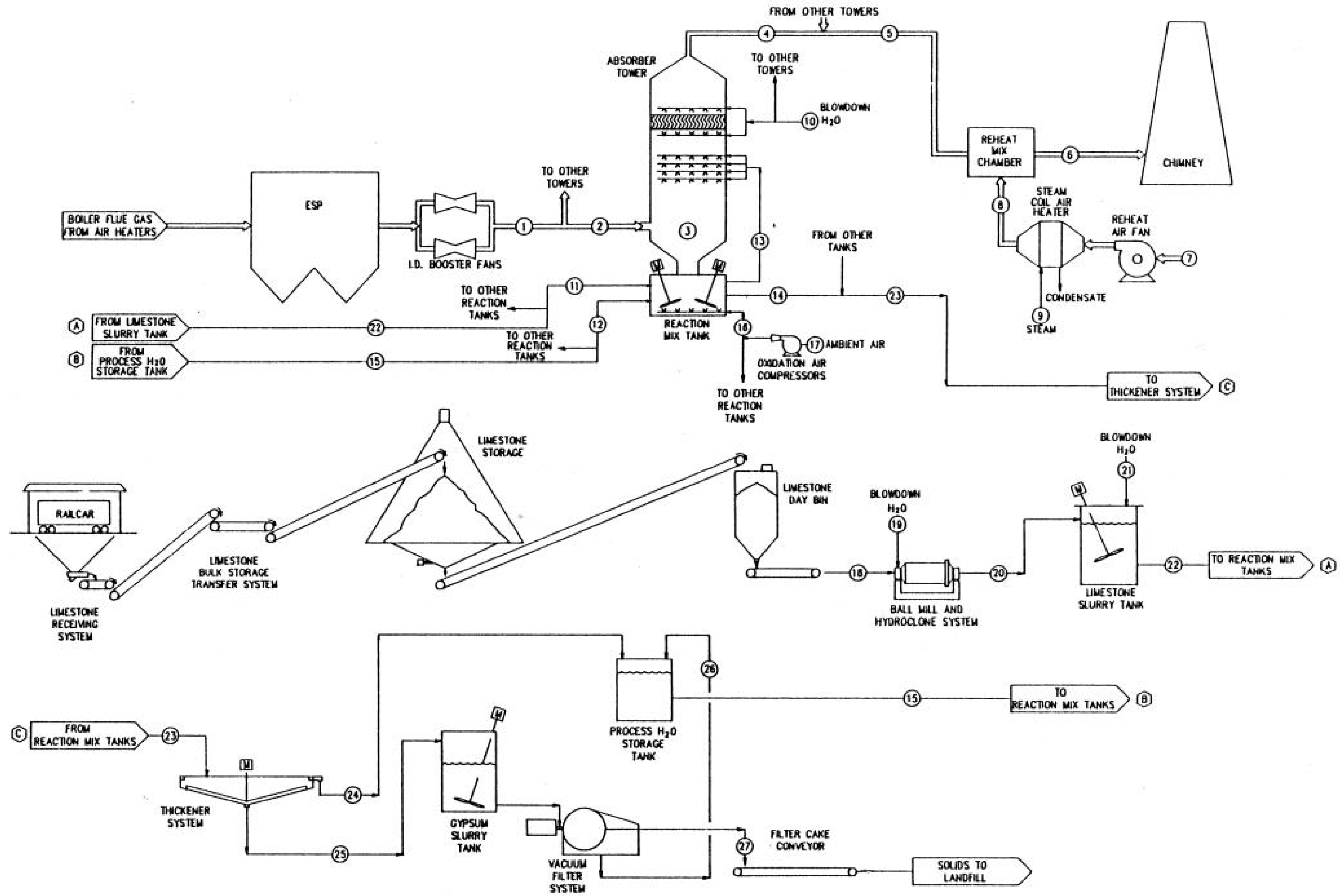

Figure B-1. LSFO Process Flow Diagram

Reagent Feed System, the ball mill cost will be provided. In the FGD system, the absorber costs will be calculated. The I.D. Fans will be broken out of the Flue Gas Handling System. The item selected from the Waste/Byproduct System will be based on the type of back-end processing equipment selected by the user.

An alternative design option is provided in the LSFO system to include the addition of dibasic organic acid (DBA). This additive helps to buffer the SO_2 absorption reaction, increasing the available alkalinity in the slurry. This allows the system to be designed with lower recycle rates, and potentially a lower limestone feed rate while maintaining the removal efficiency.

The following are LSFO specific design criteria. The default values provided in the spreadsheet are considered typical for operating FGD systems recently installed in the U.S. Reagent costs are typically based on the costs stated in the *Chemical Marketing Reporter*:

Description	Units	Range	Default Value
SO_2 Removal Required	%	90-98	95
Liquid/Gas Ratio (L/G)	gal/1000 acf	95-160	125
Adiabatic Saturation Temperature	° F	100-170	127
Reagent Feed Ratio (Stoichiometric Feed Rate)	Mole $CaCO_3$ / Mole SO_2 removed	1.0-1.25	1.05
Scrubber Slurry Solids Concentration	Wt. %	10-30	15
Stacking, Landfill, Wallboard (1 = stacking, 2 = landfill, 3 = wallboard byproduct)	integer	1,2,3	1
Number of Absorbers (Maximum Capacity = 700 MW per absorber module)	integer	1-6	1
Absorber Material [1 = alloy, 2 = Rubber-lined Carbon Steel (RLCS)]	integer	1 or 2	1
Absorber Pressure Drop	in. H_2O	Not limited	6
Reagent Cost (delivered)	$/ton	Not limited	15
Reagent Bulk Storage	days	Not limited	60
Landfill Disposal Cost	$/ton	Not limited	30
Stacking Disposal Cost	$/ton	Not limited	6
Credit for Gypsum Byproduct	$/ton	Not limited	2
DBA Feed Rate	lbs/ton SO_2	Not limited	20
DBA Cost	$/ton	Not limited	360

	Maintenance Factor, %	Contingency, %	General Facilities, %	Engineer.& H.O.* Fees, %
Reagent Feed	5	20	10	10
SO_2 Removal	5	20	10	10
Flue Gas Handling	5	20	10	10
Waste / Byproduct	5	20	10	10
Support Equipment	5	20	10	10

*H.O. = Home Office overhead fees which include the owner's administrative overhead, project management, and in-house engineering costs.

B.2 LIME SPRAY DRYER DESIGN CRITERIA

In a lime spray dryer (LSD) process the flue gas exiting the air heaters enters a spray dryer vessel. Within the vessel, an atomized slurry of lime and recycled solids contacts the flue gas stream. The sulfur oxides in the flue gas react with the lime and fly ash alkali to form calcium salts.

A process flow diagram for the LSD system is shown for reference in Figure B-2. The chemical reactions associated with the SO_2 removal from the flue gas are provided below:

Lime Hydration:	$CaO + H_2O \rightarrow Ca(OH)_2$
SO_x Reactions:	$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 \bullet 1/2\ H_2O + 1/2\ H_2O$
	$Ca(OH)_2 + SO_3 + H_2O \rightarrow CaSO_4 \bullet 2\ H_2O$
Sulfite Oxidation	$Ca(OH)_2 + SO_2 + H_2O + 1/2\ O_2 \rightarrow CaSO_4 \bullet 2\ H_2O$

The water entering with the slurry vaporizes, lowering the temperature and raising the moisture content of the scrubbed gas. A particulate matter control device downstream of the spray dryer removes the dry solids and fly ash that did no fall out in the vessel. A portion of the collected reaction products and fly ash solids is recycled to the slurry feed system. The remaining solids are transported to a landfill for disposal.

The CUECost workbook responds to changes in the removal efficiency and any other parameter by using the input values entered by the user and recalculating the material balance on that new basis. No other changes in the spreadsheet are done automatically in response to changes in parameters. The model does modify the solids recycle rate as the coal sulfur content is modified. This is done by using a look-up tabulation of recycle values associated with various coal sulfur percentages.

The LSD system incorporates five specific equipment areas:

- Reagent Feed System - Receiving, Storage, Grinding
- SO_2 Removal - Spray Dryers, Tanks, Pumps
- Flue Gas Handling - Ductwork and I.D.Fan
- Waste / Byproduct Handling - Disposal, Storage
- Support Equipment - Electrical, Water, Air

Each area is designed to compare to typical vendor package scope of supply for a standard FGD system installation project. Within various cost areas, the largest equipment component costs will be broken out and the cost estimate calculated for these items. In the Reagent Feed System, the ball mill slaker cost will be provided. In the FGD system, the spray dryer costs will be calculated. The I.D. Fans will be broken out of the Flue Gas Handling System. The item selected from the Waste/Byproduct System will be based on the type of back-end processing equipment selected by the user. The following are LSD specific design criteria:

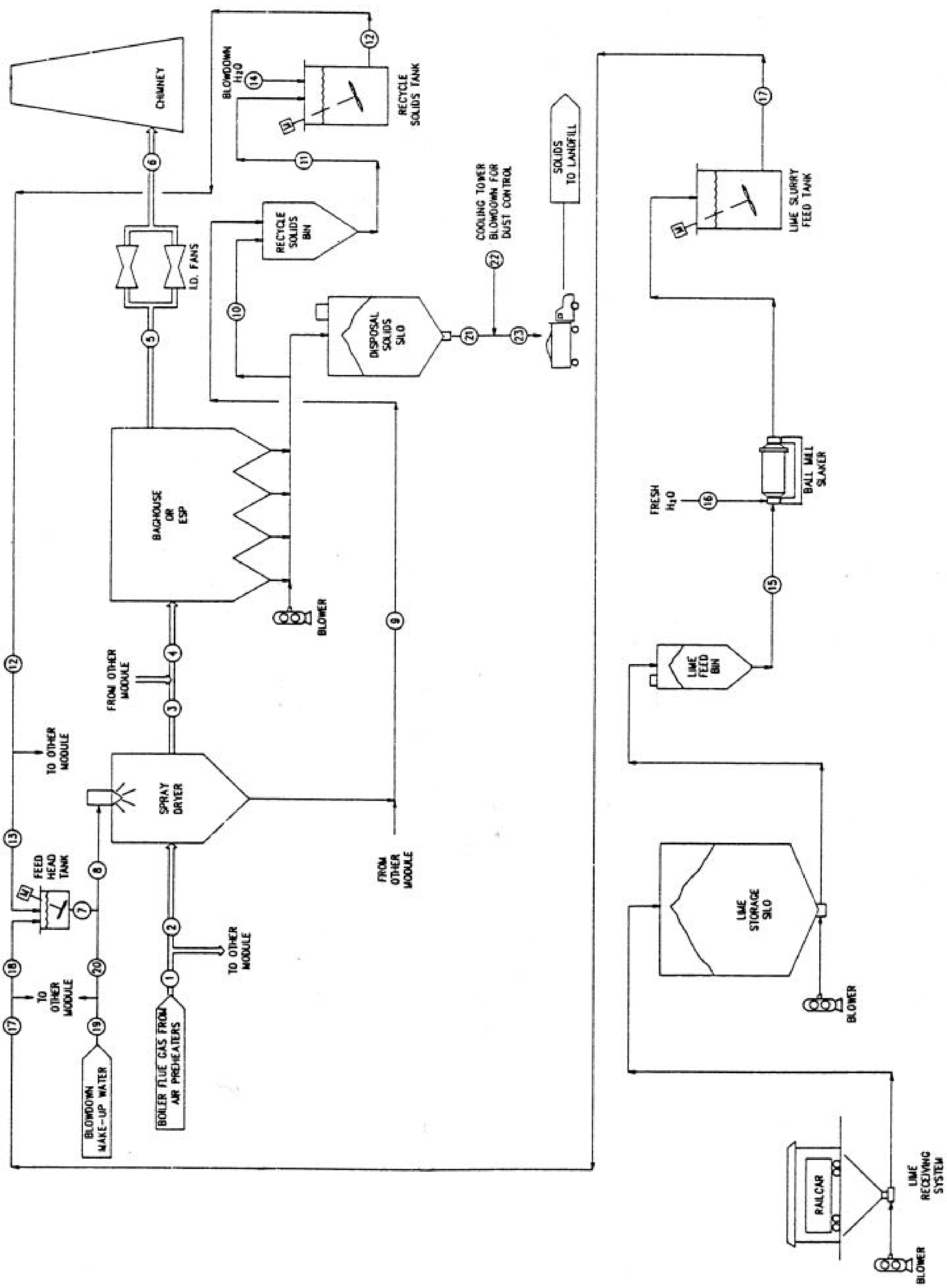

Figure B-2. LSD Process Flow Diagram

Description	Units	Range	Value
SO_2 Removal Required	%	85-95	90
Adiabatic Saturation Temp.	° F	100-170	127
Approach to Saturation	F °	10-50	20
Reagent Ratio (stoichiometry)	Mole CaO / Mole inlet SO_2	1.1-2.0	1.2
Recycle Rate	Lb.recycle / Lb.lime feed	10-30	17
Recycle Slurry Solids Concentration	Wt. %	10-50	35
Number of Spray Dryers (Max Capacity = 300 MW/spray dryer module)	Integer	1-7	2
Spray Dryer Material (1=alloy,2=RLCS)	Integer	1 or 2	1
Spray Dryer Pressure Drop	In. H_2O	Not limited	5
Reagent Cost (delivered)	$/ton	Not limited	65.00
Reagent Bulk Storage	days	Not limited	60
Dry Waste Disposal Cost	$/ton	Not limited	30.00

		Indirect Cost Factors		
	Maintenance Factor, %	Contingency, %	General Facilities, %	Engin.& H.O.* Fees, %
Reagent Feed	5	20	10	10
SO_2 Removal	5	20	10	10
Flue Gas Handling	5	20	10	10
Waste / Byproduct	5	20	10	10
Support Equipment	5	20	10	10

*H.O. = Home Office overhead fees which include the owner's administrative overhead, project management, and in-house engineering costs.

The annual Maintenance (component of the operating cost), additional General Facilities, and Engineering factors provided in the table above are multiplied by the installed equipment capital cost to obtain an estimate of these costs to the utility. The Contingency factor is applied to the total bottom line cost (Equipment Installed Cost plus Site Facilities and Engineering) and represents an estimate of the capital that will be expended, but that is not accounted for in the estimate due to the level of detail included in the system design for this cost spreadsheet.

B.3 PARTICULATE MATTER CONTROL DESIGN CRITERIA

In a particulate control system, the flue gas exiting the air heaters enters an ESP or FF through the inlet manifold. In an ESP, the particulate matter is electrically charged by the electric fields generated in the ESP. This charge helps to move the particles to the collecting plates surfaces, and hold them in place until the collected material can be discharged into the collecting hoppers. ESP's are available in a wide variety of designs, varying materials of construction; collecting plate design, size and spacing; electrode design; etc. These variations in design between vendors are not addressed in this spreadsheet, and are not expected to drive the final system cost estimates beyond the stated ROM estimate accuracy. The dry fly ash material is then typically conveyed to final disposal silos by a pneumatic conveying system.

Within the FF, the particulate matter is collected on filter bags suspended vertically within the FF vessel. The particulate matter is physically removed from the gas as it passes through the filter bags, by impacting both the bag fibers and the filter cake that collects on the surface of the bags. Periodically, individual FF compartments are mechanically cleaned by reversing the gas flow or using a pulse jet design that uses pressurized air to force the collected fly ash off the bags and into the collection hoppers. The two design options (reverse gas and pulse jet) are available as options in the spreadsheet. The air-to-cloth ratio (square feet of cloth required per 1000 actual cubic feet per minute of flue gas flow) identifies the size of the FF required, quantifying the amount of cloth area required to treat a given gas flowrate. Once again, the ash is typically conveyed to the waste silo by a pneumatic conveying system.

The CUECost workbook responds to changes in the removal efficiency and any other parameter by using the input values entered by the user and recalculating the material balance on that new basis. No other changes in the spreadsheet are done automatically in response to changes in parameters. The model does modify the solids collection rate as the coal ash content is modified.

Specific design criteria associated with particulate matter control are summarized below:

Description	Units	Value
Outlet Part. Matter Emission Limit	Lbs/10^6 Btu	0.03
Particulate Matter Control Process (1 = Fabric Filter, 2 = ESP)	Integer	1

B.3.1 Fabric Filter:

Description	Units	Value
Fabric Filter Type (1 = Reverse Gas, 2 = Pulse Jet)	Integer	2
Gas-to-Cloth Ratio	ACFM/ft^2	1.8
Bag Life	Years	5

B.3.2 Electrostatic Precipitator:

Description	Units	Value
Specific Collection Area (SCA)	Ft^2 Collecting Plate / 1000 ACFM Gas	Calculated based on ash composition and collection efficiency.

B.4 NO_x CONTROL TECHNOLOGY CRITERIA

Four NO_x control technologies are included in CUECost:

Selective Catalytic Reduction (SCR)
Non-Selective Catalytic Reduction (SNCR)
Natural Gas Reburning (NGR)
Low NO_x Burners (LNB)

The process design criteria and assumptions that serve as defaults within the spreadsheet are described in the following material:

B.4.1 Selective Catalytic Reduction Design Criteria

Selective catalytic reduction is a post-combustion nitrogen oxides (NO_x) reduction process where NO_x in the flue gas is reduced to nitrogen (N_2) and water (H_2O) using ammonia (NH_3) as a reductant. The reduction occurs in the presence of a catalyst at reaction temperatures between 600 and 750 °F. SCR systems are typically based on one of two designs. The first design is a hot-side, high-dust SCR where the SCR system is located between the economizer and air preheater. The second design is a cold-side, low-dust SCR where the SCR is typically located downstream of the air heater and particulate control device. In a variation of this design, the SCR system can be located further downstream, after the flue gas desulfurization (FGD) system. This is often called a tail-end SCR system. The CUECost algorithms estimate costs for hot-side, high-dust systems, because hot-side systems have been used on most SCR applications (EPA, 1996).

An SCR system reduces NO_x concentrations in the flue gas using ammonia as the reducing agent in a series of gas-phase reactions in the presence of a catalyst to form nitrogen and water. The chemical reactions for these reduction reactions are provided below:

$$4\,NH_3 + 4\,NO + O_2 \rightarrow 4\,N_2 + 6\,H_2O$$

$$4\,NH_3 + 2\,NO_2 + O_2 \rightarrow 3\,N_2 + 6\,H_2O$$

Small fractions of the ammonia can also be oxidized to alternate forms of nitrogen oxides:

$$2\,NH_3 + 2\,O_2 \rightarrow N_2O + 3\,H_2O$$

Some of the residual ammonia will also react with trace concentrations of the sulfur oxides in the flue gas. These reactions are described below:

$$NH_3 + SO_2 + 1/2\,O_2 + H_2O \rightarrow NH_4HSO_4$$
$$2\,NH_3 + SO_3 + H_2O \rightarrow (NH_4)_2SO_4$$

The solids formed in this reaction can contribute to catalyst fouling and contamination of flyash.

The key operating parameters that affect the performance and, consequently, the capital and operating cost of SCR systems include the allowable NH_3 slip emissions, the space velocity, the

NO_x reduction efficiency, and the NH_3/NO_x molar ratio. For SCR systems these parameters are interrelated, and their values depend on the type of SCR application (high-dust or tail-end) and the desired performance levels. Ammonia slip emissions are controlled by the SCR system design. Typically SCR catalyst suppliers provide a guarantee of 2 ppm over the catalyst life. Since the 2 ppm NH_3 slip is guaranteed at the end of the catalyst's life, the initial NH_3 slip emissions will be very low (<1 ppm). For this reason, ammonia slip does not affect the catalyst volume calculations in CUECost.

The space velocity is the primary parameter used to specify catalyst volume. If the user does not input a value for space velocity, CUECost calculates it based on the NO_x reduction efficiency and the NH_3/NO_x molar ratio. For SCR, NO_x reduction efficiency can range from approximately 60 to 95%, but systems are typically designed to achieve 70 to 90% removal. The NH_3/NO_x molar ratio generally ranges from about 0.7 to 1.0. Ammonia can be injected at a greater than 1:1 stoichiometric ratio to increase NO_x reduction efficiency, but NH_3 slip would also increase significantly.

CUECost estimates capital costs for reactor housing, initial catalyst, ammonia storage and injection system, flue gas handling including ductwork and induced draft fan modifications, air preheater modifications and miscellaneous direct costs, including ash handling and water treatment additions that typically are modified due to the increased concentrations of ammonium salts in the collected flyash.

Operating and maintenance costs include NH_3, catalyst replacement and disposal, electricity, steam, labor and maintenance costs. Annual catalyst replacement costs are based on the catalyst life. For example, if the catalyst life is 3 years and there are three catalyst sections, then one-third of the catalyst is replaced each year. The catalyst disposal cost reflects the cost of disposing of the spent catalyst. A typical value of 48 lb/cubic foot was used for the catalyst density to calculate the mass of the spent catalyst.

Default input values for SCR are presented below. The default inputs were taken from EPA’s Acid Rain Division (ARD) studies (EPA, 1996) where available. Unit costs are escalated from 1995 dollars to 1998 dollars using *Chemical Engineering Magazine* cost indices.

Default Input Parameters for SCR

Parameter	Units	Default	Range	Source
NH_3/NO_x Stoichiometric Ratio	mol NH_3 / mol NO_x	0.9	0.7 - 1.0	Engineering judgement
NOx Reduction Efficiency	%	70	60 - 95	EPA, 1996
Inlet NOx	lbs/10^6 Btu	0.8		EPA, 1996
Overall Catalyst Life	years	3	2-5	EPA, 1996
Ammonia Cost (anhydrous)	$/ton	206	Not Limited	EPA, 1996
Catalyst Cost	$/ft^3	356	Not Limited	EPA, 1996
Solid Waste Disposal Cost	$/ton	11.48	Not Limited	EPA, 1996
Maintenance (% of installed cost)	%	1.5		EPA, 1996
Contingency (% of installed cost)	%	20		EPA, 1996
General Facilities (% of installed cost)	%	5		EPA, 1996
Engineering Fees (% of installed cost)	%	10		EPA, 1996
Number of Reactors	integer	2		EPA, 1996
Number of Air Preheaters	integer	1		Engineering judgement

B.4.2 Selective Non-catalytic Reduction Design Criteria

The selective non-catalytic reduction (SNCR) process involves injection of a nitrogen-bearing chemical (usually NH_3 or urea) into boiler flue gases within a prescribed temperature range (typically 1600 to 2000 °F). The NH_3 or urea [$CO(NH_2)_2$] selectively reacts with NO_x in the flue gas to convert it to N_2. For the NH_3-based SNCR process, either aqueous or anhydrous NH_3 is injected into the flue gas where the temperature is between 1600 and 1900 °F. Most of the NH_3 reacts with NO and oxygen in the gas stream to form N_2 and H_2O. For the $CO(NH_2)_2$-based SNCR process, an aqueous solution of $CO(NH_2)_2$ is injected into the flue gas at one or more locations in the upper furnace and/or convective pass. The $CO(NH_2)_2$ reacts with NO_x in the flue gas to form N_2, H_2O, and carbon dioxide (CO_2). The chemical reactions for this conversion process are not well defined, consisting of a series of dissociation reactions at the elevated gas temperatures in the boiler gas path. The following summary equation describes the overall reaction that is occurring, while the actual reaction mechanism is a long series of dissociation and chemical reactions between various free radicals:

Urea Reaction: $$CO(NH_2)_2 + 2\ NO + 1/2\ O_2 \rightarrow 2\ N_2 + CO_2 + 2\ H_2O$$

Ammonia Reactions $$4\ NH_3 + 4\ NO + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

$$4\ NH_3 + 2\ NO_2 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

CUECost allows the user to select either $CO(NH_2)_2$ or NH_3 as the SNCR reagent. The user is asked to specify the NO_x reduction efficiency and the stoichiometric molar ratio of reagent to NO_x. SNCR can achieve NO_x-reduction efficiencies ranging from 30 to 70%. Approximately 50% reduction is typical. The SNCR process requires stoichiometric reagent:NO_x ratios of greater than 1:1 to achieve significant NO_x removal. The ratio can range from about 0.5 to 2.5, but will typically fall within the range of 1 to 2. The NH_3 and $CO(NH_2)_2$ injection rates are then calculated based on the stoichiometric ratio, inlet NO_x and boiler heat input.

For the $CO(NH_2)_2$-based SNCR process, the user chooses wall injectors, lances, or both. Wall injectors are nozzles installed in the upper furnace waterwalls. In-furnace lances protrude into the upper furnace or convective pass and allow better mixing of the reagent with the flue gas. In-furnace lances require either an air- or water-cooling circulation system. If the user enters values for both wall injectors and lances, then costs include both lances and wall injectors. If wall injectors are to be used alone, then the user enters zero for both the number of lance levels and the number of lances. Similarly, if lances are to be used alone, the user enters zero for both the number of injector levels and the number of wall injectors. CUECost uses input parameters for the number of injectors and lances unless the user wants these parameters to be calculated from the number of levels. If the user inputs zero for the number of injectors and also inputs the number of injector levels, CUECost will calculate the number of injectors. Similarly, if the user inputs zero for the number of lances, the number of lances will be calculated from the number of lance levels. For the NH_3-based SNCR process, the user can choose either steam or air as the atomizing medium. Based on the user's choice, an annual operating cost for steam or electricity usage is calculated.

The main equipment areas in the battery limits for SNCR include the reagent receiving area, storage tanks, and recirculation system; the injection system, including injectors, pumps, valves, piping, and distribution system; the control system; and air compressors. In addition, NH_3-based SNCR systems use electrically powered vaporizers to vaporize the NH_3 prior to injection.

Operating labor costs are based on 2 person-hours required per 8-hour shift of operation. The annual cost of the reagent is the major operating cost item for the process and is calculated as the product of the reagent usage in tons/year and the cost in dollars per ton of pure reagent. Electricity, water, and steam requirements are based on vendor information. The cost of steam or air for atomization of reagent is included as an operating cost.

Default input values for SNCR are presented below. The default inputs were taken from studies by EPA’s Acid Rain Division (EPA, 1996) where available. Unit costs are escalated from 1995 dollars to 1998 dollars using *Chemical Engineering Magazine* cost indices.

Default Input Parameters for SNCR

Parameter	Units	Default	Range	Source
Number of Injector Levels	integer	3	Not limited	EPA, 1996
Number of Injectors	integer	18	Not limited	EPA, 1996
Number of Lance Levels	integer	0	Not limited	EPA, 1996
Number of Lances	integer	0	Not limited	EPA, 1996
NO_x Reduction Efficiency	%	50	30-70	EPA, 1996
NH_3/NO_x Stoichiometric Ratio	$\frac{\text{mole } NH_3}{\text{mole } NO_x}$	1.2	0.8-2	Engineering judgement
Urea/NO_x Stoichiometric Ratio	mole NH_2 mole NO_x	1.2	0.8-2	EPA, 1996
Urea Cost (50% solution)	$/ton	225	Not Limited	EPA, 1996
Ammonia Cost (anhydrous)	$/ton	206	Not Limited	EPA, 1996
Water Cost	$/1,000 gal	0.41	Not Limited	EPA, 1996
Maintenance	% of inst. cost	1.5		EPA, 1996
Contingency	% of inst. cost	20		EPA, 1996
General Facilities	% of inst. cost	5		EPA, 1996
Engineering Fees	% of inst. cost	10		EPA, 1996

B.4.3 Natural Gas Reburning Design Criteria

Natural gas reburning (NGR) involves substituting natural gas for a portion of the pulverized coal supplied to the primary combustion zone and injecting it downstream of the primary combustion zone to form a reducing zone in which NO_x compounds are reduced to N_2. Combustion air for the reburning fuel (natural gas) is injected further downstream. Because the main combustion zone of furnaces employing this technology operates in its normal manner, gas reburning is applicable to a wide range of wall, tangential, and cyclone-fired boilers.

Boiler modifications for gas reburning involve installation of additional fuel injectors and associated piping and control valves. In the burnout zone, key components include overfire air (OFA) ports, a windbox, ductwork, and control dampers. Installation of the gas injectors and OFA ports require waterwall modifications. Adequate residence time must be available both in the reburn zone and the burnout zone to maximize NO_x reduction and to minimize unburned carbon losses. Consequently, for retrofit applications, adequate space between the top burner row and the furnace exit must be available for appropriately locating the reburn fuel injectors and OFA ports.

The fraction of boiler heat input contributed by natural gas combustion (reburn fraction) depends on the desired NO_x removal efficiency. The relationship between the reburn fraction and

NO_x reduction efficiency applies for NO_x reduction efficiencies from 55 to 65 percent and corresponding reburn fractions from 0.08 to 0.20. In CUECost, these are the valid input ranges for the NO_x removal efficiency and reburn fraction. If the user inputs both parameters within the valid ranges, the input values are used for cost calculations. If only one parameter is outside of the valid range, that parameter is calculated using the other parameter. If both input values are outside of the valid ranges, a default reburn fraction of 0.15 is used with a corresponding 61 percent NO_x removal efficiency.

The installed costs of gas injectors, OFA ports, and related equipment are included in the NGR cost spreadsheet. Also included is the cost associated with piping natural gas to the boiler from the metering station located at the utility plant fence-line.

In general, natural gas reburning reduces the boiler operating costs associated with coal- and ash-handling process areas, including maintenance, electricity, and ash disposal. Fuel costs are generally higher, because the price of natural gas is typically higher than the price of coal. Maintenance costs for operating the NGR system are estimated at 2 percent of the total plant cost, plus a maintenance credit for operating the coal handling process at reduced coal feed rates. Savings from reduced fly ash disposal are estimated only for retrofit applications. The incremental fuel cost for firing gas is estimated by multiplying the amount of gas burned by the fuel price difference between gas and coal

Default values for NGR input parameters are presented below. The default inputs were taken from ARD studies (EPA, 1996) where available. Unit costs are escalated from 1990 dollars to 1998 dollars using *Chemical Engineering Magazine* cost indices.

Default Input Parameters for NGR

Parameter	Units	Default	Range	Source
NO_x Reduction Efficiency	%	61	55-65	Gundappa et al., 1995
Gas Reburn Fraction	fraction	0.15	0.08-0.20	Gundappa et al., 1995
Waste Disposal Rate	$/ton	11.48	Not Limited	EPA, 1996
Natural Gas Rate	$/MMBtu	2.31	Not Limited	EPA, 1996
Maintenance (% of installed cost)	%	1.5		EPA, 1996
Contingency (% of installed cost)	%	20		EPA, 1996
General Facilities (% of installed cost)	%	2		EPA, 1996
Engineering Fees (% of installed cost)	%	10		EPA, 1996

B.4.4 Low-NO_x Burner Technology Design Criteria

Low-NO_x burner technology (LNBT) limits NO_x formation by controlling both the stoichiometric and temperature profiles of the combustion process in each burner flame envelope. This control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding one or more of the following conditions:

- Reduced O_2 in the primary combustion zone, which limits fuel NO_x formation;
- Reduced flame temperature, which limits thermal NO_x formation; and
- Reduced residence time at peak temperature, which limits thermal NO_x formation.

Low NO_x burner designs for wall-fired boilers can be divided into two general categories: "delayed combustion" and "internally staged." Delayed combustion LNBT is designed to decrease flame turbulence (thus delaying fuel/air mixing) in the primary combustion zone, thereby establishing a fuel-rich condition in the initial stages of combustion. Internally staged LNBT is designed to create stratified fuel-rich and fuel-lean conditions in or near the burner. In the fuel-rich regions, combustion occurs under reducing conditions, promoting the conversion of fuel nitrogen to N_2 and inhibiting fuel NO_x formation. In the fuel-lean regions, combustion is completed at lower temperatures, thus inhibiting thermal NO_x formation.

Conventional tangentially fired boilers consist of corner-mounted vertical burner assemblies from which fuel and air are injected into the furnace. The fuel and air nozzles are directed tangent to an imaginary circle in the center of the furnace, generating a rotating fireball in the center of the boiler. Each corner has it own windbox that supplies primary air through the air compartments located above and below each fuel compartment. For tangentially fired boilers, LNBT changes the air flow through the windbox by decreasing the amount of primary air and directing secondary air away from the fireball and toward the furnace wall.

Default input parameters for LNBT and suggested ranges are presented below. The user selects the boiler type and the retrofit difficulty. CUECost calculates total capital cost as a function of boiler size. The NO_x reduction efficiency input does not affect the capital cost estimate, but is used to estimate emissions reduction.

Default Values for LNBT Input Parameters

Parameter	Units	Default	Range	Source
NO_x Reduction Efficiency	%	35	15 - 60	Gundappa et al., 1995
Boiler Type	T=Tang.Fired W = Wall Fired	N/A	Not Limited	N/A
Retrofit Difficulty	L=Low,A=Aver., H=High	N/A	Not Limited	N/A
Maint.Labor (% of inst.cost)	%	0.8	Not Limited	Gundappa et al., 1995
Maint.Mater. (% of inst.cost)	%	1.2	Not Limited	Gundappa et al., 1995

REFERENCES

Gundappa, M., L. Gideon, and E. Soderberg, 1995, "Integrated Air Pollution Control System (IAPCS), version 5.0, Volume2: Technical Documentation, Final" EPA, Air and Energy Engineering Research Laboratory, Research Triangle Park, NC, EPA-600/R-95-169b (NTIS PB96-157391).

EPA, 1996, "Cost-effectiveness of Low-NO_x Burner Technology Applied to Phase I, Group 1 Boilers," prepared by Acurex Environmental Corporation for EPA Acid Rain Division. This report is available to the public from EPA's Office of Air and Radiation, Acid Rain Division, Washington, DC 20460 (202-564-9085).

APPENDIX C

DESIGN/ECONOMIC CRITERIA

C.1 GENERAL PLANT DESIGN CRITERIA

The plant design and operating default values provided below were taken from the criteria established by EPA's Integrated Air Pollution Control System (IAPCS) model and from Raytheon's design experience. The user can override any default value as long as the value input is within the stated range of the spreadsheet.

Description	Units	Range	Default Input
Location (state)	Abbrev.	All States	PA
Total Net Plant Output	MW	100-2000	500
Net Plant Heat Rate	Btu/kWhr	Not limited	10,500
Plant Capacity Factor	%	0-100	65
Number of Boilers	Integer	1-4	1
Excess Air Downstream of Economizer	%	Not limited	120
Air Heater In-Leakage	%	Not limited	12
Air Heater Outlet Gas Temp.	° F	Not limited	300
Inlet Air Temp.	° F	Not limited	80
Ambient Absolute Pressure	In. Hg Abs.	Not limited	29.4
Pressure After Air Heater	In. H_2O,gage	Not limited	-12
Moisture in Air	Lb/lb dry air	Not limited	0.013
Ash Split:			
Fly Ash	%	Not limited	80
Bottom Ash	%	Not limited	20
Seismic Zone/Risk Factor (Figure C-1)	Integer	1-5	1
Retrofit Factor	Integer	1.0-3.0	1.3
(1.0 = new, 1.3 = medium, 1.6 = difficult)			

Coals Included (enter index number) See Table C-1 for Available Coals

Table C-1. Coal Analysis Library

COAL ANALYSIS LIBRARY									
Index Number		1	2	3	4	5	6	7	8
Coal Name		Wyoming PRB	Armstrong, PA	Jefferson, OH	Logan, WV	No. 6 Illinois	Rosebud, MT	Lignite, ND	"User Specified"
Coal Cost	$/MMBtu	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
PROXIMATE ANALYSIS (ASTM, as rec'd)									
Moisture - Enter below in Ultimate Analysis									
Volatile Matter	wt%	**31.39**	**36.20**	**37.20**	**35.40**	**33.00**	**36.40**	**42.00**	**0.00**
Fixed Carbon	wt%	**33.05**	**48.70**	**44.80**	**43.00**	**39.00**	**30.30**	**20.10**	**0.00**
Ash - Enter below in Ultimate Analysis									
COAL ULTIMATE ANALYSIS (ASTM, as rec'd)									
Moisture	wt%	**30.24**	**6.00**	**5.00**	**5.00**	**12.00**	**25.20**	**32.00**	**0.00**
Carbon	wt%	**48.18**	**71.55**	**65.72**	**65.99**	**55.35**	**51.52**	**45.06**	**0.00**
Hydrogen	wt%	**3.31**	**4.88**	**4.53**	**4.75**	**4.00**	**3.29**	**2.80**	**0.00**
Nitrogen	wt%	**0.70**	**1.40**	**1.21**	**0.70**	**1.08**	**0.69**	**1.50**	**0.00**
Chlorine	wt%	**0.01**	**0.00**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.00**
Sulfur	wt%	**0.37**	**2.60**	**3.43**	**0.89**	**4.00**	**0.56**	**0.94**	**0.00**
Ash	wt%	**5.32**	**9.10**	**13.00**	**16.60**	**16.00**	**8.15**	**5.90**	**0.00**
Oxygen	wt%	**11.87**	**4.47**	**7.01**	**5.97**	**7.47**	**10.49**	**11.70**	**0.00**
TOTAL	wt%	100.00	100.00	100.00	100.00	100.00	100.00	100.00	0.00
Mod Mott Spooner HHV (Btu/lb) - ***calc***	Btu/lb	8,227	13,100	11,922	12,058	10,100	8,789	7,500	0
COAL ASH ANALYSIS (ASTM, as rec'd)									
SiO2	wt%	**35.51**	**46.92**	**51.35**	**50.68**	**50.82**	**27.00**	**29.80**	**0.00**
Al2O3	wt%	**17.11**	**21.00**	**30.00**	**29.00**	**19.06**	**19.00**	**10.00**	**0.00**
TiO2	wt%	**1.26**	**2.40**	**1.80**	**1.70**	**0.83**	**1.08**	**0.40**	**0.00**
Fe2O3	wt%	**6.07**	**20.20**	**9.00**	**9.00**	**20.00**	**9.00**	**9.00**	**0.00**
CaO	wt%	**26.67**	**3.25**	**4.50**	**5.50**	**3.43**	**18.50**	**21.40**	**0.00**
MgO	wt%	**5.30**	**2.65**	**2.00**	**1.00**	**3.07**	**2.40**	**10.50**	**0.00**
Na2O	wt%	**1.68**	**0.90**	**0.40**	**0.40**	**0.60**	**2.80**	**4.40**	**0.00**
K2O	wt%	**2.87**	**0.30**	**0.20**	**0.90**	**0.37**	**0.45**	**0.49**	**0.00**
P2O5	wt%	**0.97**	**0.00**	**0.16**	**0.60**	**0.17**	**0.42**	**0.00**	**0.00**
SO3	wt%	**1.56**	**1.38**	**0.59**	**1.22**	**1.22**	**18.85**	**14.01**	**0.00**
Other Unaccounted for	wt%	**1.00**	**1.00**	**0.00**	**0.00**	**0.43**	**0.50**	**0.00**	**0.00**
TOTAL	wt%	100.00	100.00	100.00	100.00	100.00	100.00	100.00	0.00

Zone 0 - No Damage
Zone 1 - Minor Damage
Zone 2 - Moderate Damage
Zone 3 - Major Damage
Zone 4 - Areas Within Zone 3 Close To Major Fault Systems

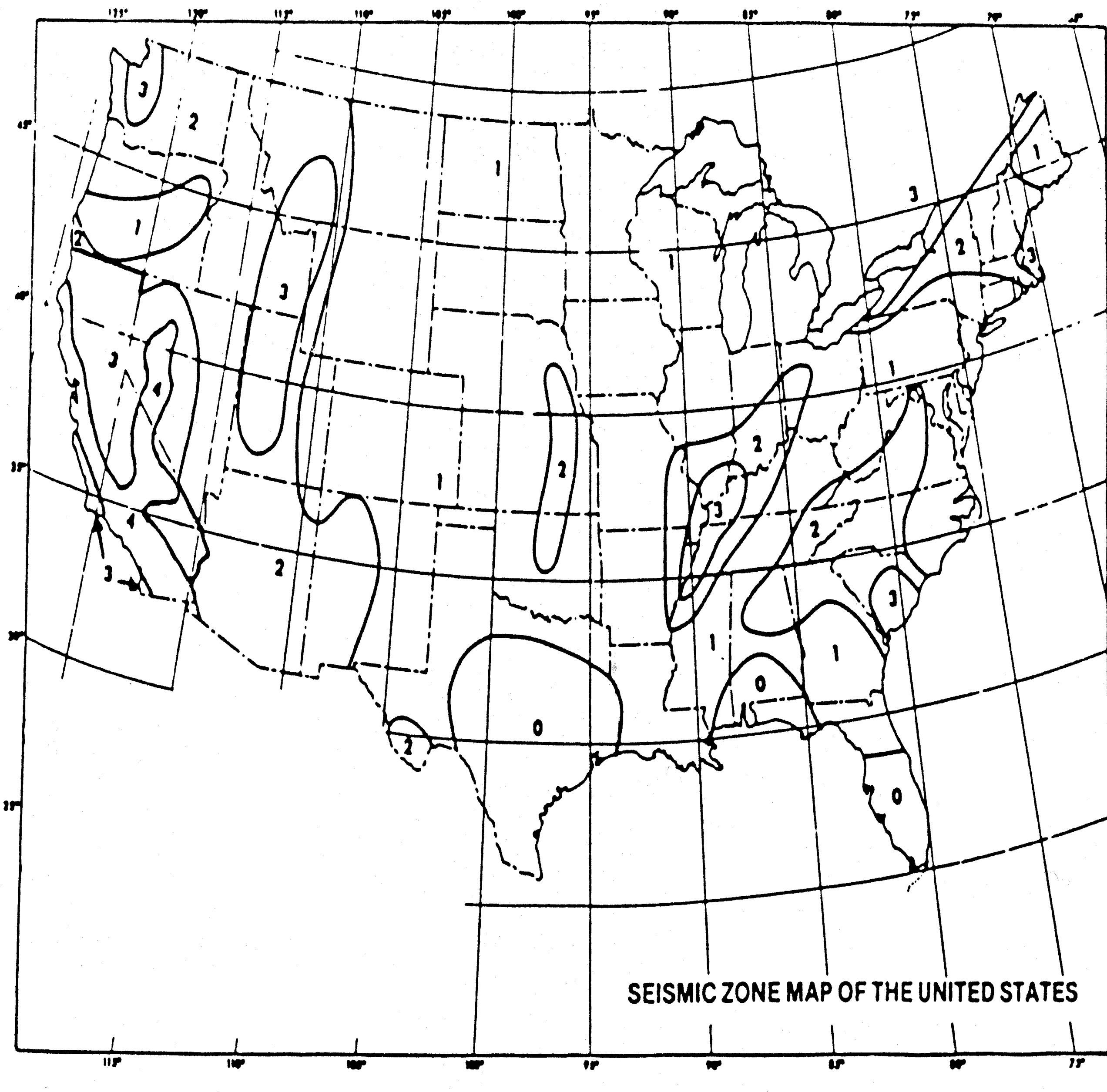

Figure C-1. Seismic Risk Factors

C.2 ECONOMIC CRITERIA

Description	Units	Value
Cost Basis - Year Dollars	Year	1998
Inflation Rate	%	3.00
After Tax Discount Rate (current $'s)	%	9.20
AFUDC Rate (current $'s)	%	10.80
Service Life (levelization period)	Years	30
First-year Carrying Charge* (current $'s)	%	22.30
Levelized Carrying Charge* (current $'s)	%	16.90
First Year Carrying Charge* (constant $'s)	%	15.70
Levelized Carrying Charge* (constant $'s)	%	11.70

* Carrying charge factors are based on:

Discount Rate or Weighted Cost of Capital; Constant $ = 6.2%, Current $ = 11.5%
Book Life = 30 years
Tax Life = 15 years
Inflation Rate = 5%
Federal and State Income Tax = 38%
Property Tax and Insurance = 2% per year
These values were calculated using the EPRITAG™ methodologies.
The user may substitute values for specific analyses.

Description	Units	Value
Multiple Unit Factor (economy of scale):		
Two Units/Boilers	Factor	1.90
Three Units/Boilers	Factor	2.75
Land Costs	$/acre	0
Sales Tax	%	6.0
Escalation Rates:		
Consumables (O&M)	%	3.0
Capital Costs	Year $'s CE* Annual Plant Index Value	
	End of Year 1997 CE Index = 388	
Construction Labor Rate	$/hr	35
Prime Contractor's Markup	%	10.0
Operating Labor Rate	$/hr	30
Power Cost	Mills/kWh	25
Limestone Cost	$/ton	15**
Lime Cost	$/ton	60**
Ammonia Cost	$/ton	220**

*CE = *Chemical Engineering Magazine* - Plant Index updated in each issue. This is the user input value for the year selected. The model divides the input value by the January 1998 index value to determine the escalation factor that is needed.

**CMR = *Chemical Marketing Reporter*, July 1998

APPENDIX D

COST ALGORITHM DEVELOPMENT/VALIDATION/SOURCES

D.1 SELECTIVE CATALYTIC REDUCTION

D.1.1 Performance Parameters

The key operating parameters that affect the performance and, consequently, the capital and operating costs of SCR systems include the allowable NH_3 slip emissions, the space velocity, the NO_x reduction efficiency, and the NH_3/NO_x molar ratio. For SCR systems these parameters are interrelated, and their values depend on the type of SCR application (high-dust or tail-end) and the desired performance levels. Ammonia slip emissions are controlled by the SCR system design. Typically SCR catalyst suppliers provide a guarantee of 2 ppm over the catalyst life. Since the 2 ppm NH_3 slip is guaranteed at the end of the catalyst's life, the initial NH_3 slip emissions will be very low (<1 ppm). Ammonia slip is not taken into consideration in the catalyst volume determination. The space velocity is the primary parameter used to specify catalyst volume. If the user does not input a value for space velocity, CUECost calculates it based on the NO_x reduction efficiency and the NH_3/NO_x molar ratio (molecular weight of NO_X = molecular weight of NO_2):

Space Velocity

$$SV = 6131.06 / 3 * (n)^{-0.241} * (NH_3:NO_x\ ratio)^{-2.306}$$

where:
- SV = space velocity, 1/hr
- n = NO_x reduction efficiency, fraction
- $NH_3:NO_x$ ratio = stoichiometric ratio of NH_3 to NO_x
- * = multiply

The NO_x reduction efficiency (n) and molar ratio of NH_3 to NO_x (NH_3/NO_x ratio) are user input values. The gross catalyst volume and NH_3 injection rate are determined from the following equations taken from IAPCS:

Ammonia Injection Rate

$$NH_3 = 3.702 \times 10^{-4} * NH_3:NO_x\ ratio * BSIZE * HTR * NO_x$$

Gross Catalyst Volume

$$CV = Q / SV$$

where:
- NH_3 = Ammonia injection rate, lb/hr
- BSIZE = boiler size, MW
- HTR = net heat rate, Btu/kWh
- $NH_3:NO_x$ ratio = stoichiometric ratio of ammonia to NO_x
- NO_x = inlet NO_x emissions, lb/10^6 Btu
- CV = gross catalyst volume, ft^3

Q = flue gas volume flow rate, SCFH

D.1.2 Capital Costs

CUECost estimates capital costs for reactor housing, initial catalyst, ammonia storage and injection system, flue gas handling including ductwork and induced draft fan modifications, air preheater modifications and miscellaneous direct costs, including ash handling and water treatment additions. CUECost equations for SCR direct capital costs are shown below.

For all items except flue gas handling, cost algorithms are based on regression models developed for the Integrated Environmental Control Model (IECM) (Frey, C.H. and E.S. Rubin, 1994). The IECM regression models were developed from cost data for 12 coal-fired power plants (Robie and Ireland, 1991). The flue gas handling cost algorithm is taken from the Integrated Air Pollution Control System (IAPCS) model, version 5.0 (Gundappa et al., 1995). Costs derived from the IAPCS equations for flue gas handling were found to be on the same order of magnitude as costs reported by the Acid Rain Division study. IECM equations were used for the other direct capital cost items because they are based on more current cost data than IAPCS. Installation costs for items such as structural supports, foundations, concrete, earthwork are accounted for in the cost data used to develop the IECM and IAPCS equations and, therefore, are not a separate item in CUECost. Plant cost indices from *Chemical Engineering Magazine* are included in the equations to update direct capital costs.

Direct Capital Costs for Hot-side SCR (Installed equipment costs)

Reactor Housing

$DC_r = 18.65 * N_{r,tot} * (CV / N_{r,tot})$^0.489 * 1000 * RF * PCI / 357.3

Ammonia Storage and Injection System

DC_{NH3} = 50.8 * (NH3)^0.482 * 1000 * RF * PCI / 357.3

Flue Gas Handling: Ductwork and Fans

DC_{fgh} = 143.66 *[G_{fg} * (750+460) / (70+460)]^0.694 * RF * PCI / 314.0

Air Preheater Modifications

$DC_{aph,mod} = 1370 * N_{t,aph} * (UA_{t,aph} / 4.4 / 10$^6 / $N_{t,aph})$^0.8 * 1000 * RF * PCI / 357.3

Miscellaneous Direct Costs

DC_{misc} = [100 + 300 * (BSIZE / 550)^0.6] * 1000 * RF * PCI / 357.3

Where:
G_{fg} = flue gas volumetric flow rate for SCR ductwork, SCFM
$N_{r,tot}$ = Number of SCR reactors
$N_{t,aph}$ = total number of air preheaters
RF = retrofit factor
PCI = chemical engineering plant cost index from *Chemical Engineering Magazine*
= 388 for 1998 dollars, 314.0 for 1982 dollars and 357.3 for IECM base year dollars
$UA_{t,aph}$ = product of universal heat transfer coefficient and heat exchanger surface area

$$= \frac{q_{aph}}{dT_{LM, aph}}, \quad Btu/°R$$

q_{aph} = heat transfer

$$= \frac{\text{Flue gas SCFM} * 60 * 7.9 * (T_{flue\ gas,\ out} - T_{flue\ gas,\ in})}{0.7302 * 530}$$

$dT_{LM, aph}$ = log-mean temperature difference

$$= \frac{(T_{flue\ gas,\ in} - T_{air,\ out}) - (T_{flue\ gas,\ out} - T_{air,\ in})}{LN[(T_{flue\ gas,\ in} - T_{air,\ out}) / (T_{flue\ gas,\ out} - T_{air,\ in})]}$$

The flue gas inlet temperature ($T_{flue\ gas,\ in}$) and the air outlet temperature ($T_{flue\ gas,\ out}$) are assumed to be the respective typical values of 725 and 600 ^oF.

Capital costs for instruments and controls, sales tax and freight are calculated from percentages of the equipment cost subtotal. The equipment cost subtotal is the sum of the equations listed above. For instruments and controls and freight, the respective default percentages are 2% and 5%. The sales tax rate is a user input value. The total direct cost is determined by applying the retrofit factor to the capital equipment cost subtotal, which is the sum of the equipment costs listed above and instruments and controls, sales tax and freight. The retrofit factor is a user input value that ranges from one for new applications to three for the most difficult retrofit cases. Equations for indirect capital costs are given below.

Indirect Capital Costs for Hot-side SCR

General Facilities = Total Direct Cost with Retrofit * General Facilities (% of installed cost)

Engineering fees = Total Direct Cost with Retrofit * Engineering Fees (% of installed cost)

Contingency = Total Direct Cost with Retrofit * Contingency (% of installed cost)

Total Plant Investment = Sum of Total Direct Cost with Retrofit, General Facilities, Engineering fees, Contingency taking into account allowance for funds during construction

Preproduction = Total Plant Investment * 0.02 + One month fixed operating costs + One month variable operating costs (@ full capacity)

Initial Ammonia (60 days) = $NH_3 * 24 * CF * 60 * UC_{NH3} / 2000$

Initial Catalyst = $CV * UC_{CAT}$

Where: CF = capacity factor, fraction

UC_{NH3} = ammonia cost rate, \$/ton

UC_{CAT} = unit cost of catalyst, \$/ft^3

D.1.3 Operating and Maintenance Costs

Operating and maintenance costs include NH_3, catalyst replacement and disposal, electricity, steam, labor and maintenance costs. The CUECost operating and maintenance cost equations presented below are based on IAPCS equations. IAPCS equations were selected instead of IECM equations for operating and maintenance costs because the level of detail required for IAPCS input parameters was closer to that of other CUECost inputs. Additionally, the parameters affecting operating and maintenance costs are not likely to have changed significantly since the IAPCS equations were developed. With the exception of catalyst replacement costs, the equations from IAPCS were derived from data reported by TVA (Maxwell, J. D., and L. R. Humphries, 1985) for the high-dust system. Annual catalyst replacement costs are based on the catalyst life. For example, if the catalyst life is 3 years, then one-third of the catalyst is replaced each year. The catalyst disposal cost reflects the cost of disposing of the spent catalyst. Catalyst disposal is typically included in the purchase cost of the catalyst. As a result, the recommended default for this line item is zero. However, an equation is included to allow the user to estimate a disposal cost, if applicable. A typical value of 48 lb/cubic foot was used for the catalyst density to calculate the mass of the spent catalyst.

Operating and Maintenance Cost Equations for SCR ($/year)

$$\text{Ammonia Cost} = (8{,}760/2{,}000) * (NH_3 * CF * UC_{NH3})$$

$$\text{Catalyst Replacement Cost} = CV/N * UC_{CAT}$$

$$\text{Catalyst Disposal Cost} = \frac{48 * \text{Catalyst Replacement Cost} * UC_{WASTE}}{2{,}000 * UC_{CAT}}$$

$$\text{Electricity} = (-545{,}133 + 5.801*G) * (CF / 0.628) * UC_{ELEC}$$

$$\text{Steam} = (-14.91 + 33.29 * NH_3 *CF) * UC_{STEAM}$$

$$\text{Operating Labor} = (1{,}341 + 5.363 * BSIZE) * UC_{OL}$$

$$\text{Maintenance Costs} = \text{Maintenance (\%)} * TPC$$

Where:

G	=	flue gas flow rate, ACFM
N	=	overall catalyst life, years
Maintenance (%)	=	annual maintenance cost as a percent of total plant cost
TPC	=	total direct and indirect capital costs, $
UC_{ELEC}	=	electricity rate, $/kWh
UC_{OL}	=	operating labor wage, $/person-hr
UC_{STEAM}	=	steam rate, $/MMBtu
UC_{WASTE}	=	solid waste disposal rate, $/ton

D.1.4 CUECost Validation

Total plant costs and operating and maintenance costs estimated by CUECost algorithms were compared to current cost data developed and validated by EPA's Acid Rain Division (ARD). Cost and design information for four applications of SCR on various boiler types, boiler sizes and coals was taken from a 1996 ARD study (Tables D-1 and D-2). The design information for these SCR applications was used to evaluate equations from CUECost. Total plant cost capital costs include the reactor housing, initial catalyst, ammonia storage and injection system, flue gas handling including ductwork and induced draft fan modifications, air preheater modifications and miscellaneous direct costs, including ash handling and water treatment additions. Other direct capital costs for taxes, freight, instruments and controls and initial inventory are included in the comparison of direct capital costs. The total plant cost includes direct costs listed above as well as indirect capital costs for engineering, general facilities and contingencies. Chemical engineering plant cost indices from *Chemical Engineering Magazine* were used to normalize costs in consistent year dollars.

The percent difference between ARD study costs and the CUECost estimates for total plant costs ranged from -4 percent to +8 percent for the cases evaluated. Operation and maintenance costs estimated by CUECost are 23 to 31 percent lower than those estimated by the ARD study. The largest difference appears to be the catalyst replacement cost.

Table D-1: CUECost with Acid Rain Division Study Design for SCR (1990 dollars)

		Cyclone-Fired		Wet-Bottom Vertical-Fired	Wet-Bottom Wall-Fired
		Midwestern		Eastern Bituminous	
		Boiler Size (MW)			
Selective Catalytic Reduction		**150**	**400**	**100**	**259**
CUECost with Acid Rain Division Design Parameters					
Input Parameters Taken from Acid Rain Division Study					
NO_x Reduction Efficiency	fraction	0.50	0.50	0.50	0.50
NH_3/NO_x Molar Ratio	fraction	0.50	0.50	0.50	0.51
Inlet NO_x	lbs/MMBtu	1.4	1.3	0.95	0.92
Design Parameters Calculated by CUECost					
Ammonia Injection Rate	lb/hr	340	884	155	399
Gross Catalyst Volume	ft^3	1,385	3,883	935	2,485
Flue Gas at Air Heater Outlet	SCFM	273,571	766,250	182,280	482,464
Capital Costs Using Acid Rain Division Design Parameters ($ 1000)					
Reactor Housing and Installation		1,188	1,967	981	1,582
Ammonia Handling and Injection		1,097	1,739	752	1,185
Flue Gas Handling:Ductwork and Fans		2,238	4,574	1,689	3,318
Air Preheater Modifications		481	1,096	348	757
Misc. Other Direct Capital Costs		309	453	270	379
Initial Catalyst		485	1,359	327	870
Total Capital Equipment Cost		5,798	11,188	4,367	8,090
Freight, Sales Tax and Inst. & Controls		691	1,278	525	939
Total Plant Cost (TPC)		8,590	16,353	6,489	11,884
TPC ($/kW)		57.3	40.9	64.9	45.9
% Difference from Acid Rain Division Study		4%	0%	8%	-4%
O&M Costs using Acid Rain Division Design Parameters ($1000/year)					
Ammonia		157	407	72	184
Catalyst Replacement		162	453	109	290
Catalyst Disposal		0.10	0.28	0.07	0.18
Electricity		112	366	66	220
High-dust SCR Steam		34	88	15	40
Maintenance		122	225	92	165
O&M Total		586	1,539	354	899
% Difference from Acid Rain Division Study		-23%	-24%	-31%	-30%

Table D-2: Acid Rain Division Study: SCR Applications

Selective Catalytic Reduction		Cyclone-Fired		Wet-Bottom Vertical-Fired	Wet-Bottom Wall-Fired
		Midwestern Bituminous		Eastern Bituminous	
		Boiler Size (MW)			
		150	400	100	259
Acid Rain Division Costs and Design Parameters					
Design Parameters from Acid Rain Division					
NO_x Reduction Efficiency	fraction	0.50	0.50	0.50	0.50
NH_3/NO_x Molar Ratio	fraction	0.50	0.50	0.50	0.51
Inlet NO_x	lbs/MMBtu	1.4	1.3	0.95	0.92
Ammonia Injection Rate	lb/hr	339	882	155	398
Gross Catalyst Volume	ft^3	3,690	10,020	2,571	6,675
Flue Gas at Air Heater Outlet	SCFM	292,924	821,164	191,279	498,215
Acid Rain Division Capital Costs ($ 1000)					
SCR Reactors/Ammonia Storage		3,180	7,040	2,150	4,921
Piping/Ductwork		945	1,600	860	1,528
Electrical/PLC		450	720	460	803
Draft Fans		1,065	1,760	650	1,166
Platform/Insulation/Enclosure		180	440	100	285
Air Preheater Modifications		285	520	250	466
Total Capital Equipment Cost		6,105	12,080	4,470	9,169
Total Plant Cost (TPC)		8,242	16,308	6,035	12,378
TPC ($/kW)		55.05.0	40.8	60.4	47.8
Acid Rain Division O&M Costs ($ 1000/year)					
Power Consumption		56	200	55	140
Ammonia Consumption		156	408	72	184
Catalyst Consumption		430	1,168	300	779
General Maintenance		123	246	89	183
O&M Total		764	2,023	516	1,286

D.2 SELECTIVE NONCATALYTIC REDUCTION

D.2.1 Performance Parameters

The CUECost workbook allows the user to select either urea [$CO(NH_2)_2$] or ammonia [NH_3] as the SNCR reagent. The user is asked to specify the NO_x reduction efficiency and the stoichiometric ratio of reagent to NO_x (molecular weight of NO_x = molecular weight of NO_2). The NH_3 and $CO(NH_2)_2$ injection rates in pounds of pure reagent per hour are then calculated based on the stoichiometric ratio, inlet NO_x and boiler heat input:

Urea Injection Rate

$$\text{Urea} = 6.5 * 10^{-4} * \text{UREA:NO}_x \text{ ratio} * \text{BSIZE} * \text{HTR} * \text{NO}_x$$

Ammonia Injection Rate

$$\text{NH}_3 = 3.702 * 10^{-4} * \text{NH}_3\text{:NO}_x \text{ ratio} * \text{BSIZE} * \text{HTR} * \text{NO}_x$$

Where:

Urea	=	$CO(NH_2)_2$ injection rate, lb/hr
NH_3	=	NH_3 injection rate, lb/hr
BSIZE	=	boiler size, MW
HTR	=	net heat rate, Btu/kWh
NH_3:NO_x ratio	=	stoichiometric ratio of NH_3 to NO_x
NO_x	=	inlet NO_x emissions, lb/10^6 Btu
UREA:NO_x	=	normalized stoichiometric ratio of $CO(NH_2)_2$ to NO_x (i.e., moles of reagent nitrogen to moles of uncontrolled NO_x)

For the $CO(NH_2)_2$-based SNCR process, the user may select to use wall injectors, lances, or both. Wall injectors are nozzles installed in the upper furnace waterwalls. In-furnace lances protrude into the upper furnace or convective pass and allow better mixing of the reagent with the flue gas. In-furnace lances require either an air- or water-cooling circulation system. Additionally, since the location of the temperature window changes with load, multiple levels of injectors and/or lances will be required for effective NO_x reduction over the operating load range of the boiler. If the user specifies a number of injector lance levels, but inputs zero for the number of injectors or lances, CUECost calculates the number of injectors or lances using the equations below:

$$N_I = (8.6 + 0.03 * \text{BSIZE} - 0.013 * \text{Red}) * N_{IL}$$

$$N_L = (2 + 0.013\ \text{BSIZE}) * N_{LL}$$

Where:

N_I	=	number of wall injectors
Red	=	NO_x reduction efficiency, %
N_{IL}	=	number of injector levels
N_L	=	number of lances
N_{LL}	=	number of lance levels

If the user enters values for both wall injectors and lances, then costs include both lances and wall injectors. If wall injectors are to be used alone, then the user enters zero for both the number of lance levels and the number of lances. Similarly if lances are to be used alone, the user enters zero for both the number of injector levels and wall injectors. For the NH_3-based SNCR process, the user can choose either steam or air as the atomizing medium. Based on the user's choice, an annual operating cost for steam and/or electricity usage is calculated.

D.2.2 Capital Costs

The main equipment areas in the battery limits for SNCR include the reagent receiving area, storage tanks, and recirculation system; the injection system, including injectors, pumps, valves, piping, and distribution modules; the control system; and air compressors. In addition, NH_3-based SNCR systems use vaporizers to vaporize the NH_3 prior to injection. The capital costs are estimated using modified equations from IAPCS v.5.0. The IAPCS equations were modified to incorporate the extensive, current cost data developed and validated by EPA's Acid Rain Division (ARD). IAPCS is a computer model developed for the EPA NRMRL-RTP (formerly the Air and Energy Engineering Research Laboratory) to estimate costs and performance for emission control systems applied to coal-fired utility boilers. IAPCS was developed in the 1980's and has been updated over the years. Documentation for the latest revision to IAPCS, completed in 1995, presents equations in 1982 dollars, with adjustments made using cost indices to normalize costs to other-year dollars.

Cost and design information was available in a 1996 ARD study for six applications of urea-based (50% solution) SNCR on various boiler types and sizes. The design information for these cases was input to the IAPCS model, and the capital cost estimates from IAPCS were compared to the ARD study estimates. The ratio of the ARD study costs to costs calculated using IAPCS equations was determined for each case. The ratios were then averaged, and the resulting average ratio was incorporated into each IAPCS capital cost equation. It should be noted that the ratios were determined for Total Direct Capital Cost. Itemization of equipment in major equipment areas varied between IAPCS and the ARD study so that unique ratios could not be established for each equipment area. As a result, the same ratio was added to each equipment cost equation. This approach was applied for both urea- and ammonia-based SNCR, because the capital costs do not vary significantly between the two processes (EPA, 1996). The algorithms for SNCR direct capital costs are presented below. Plant cost indices from *Chemical Engineering Magazine* are included in the equations to update direct capital costs.

Direct Capital Costs for SNCR (Installed equipment costs)

Urea-Based SNCR Process

Urea Storage & Handling $= 38{,}143 * (\text{Urea}/8.7)^{0.417} * 0.915 * \text{PCI} / 357.6$

Urea Injection $= (117{,}809 + 10{,}477 * N_I + 53{,}111 * N_L) * 0.915 * \text{PCI} / 357.6$

Misc. $= (96{,}082 + 106 * \text{BSIZE} + 898 * N_I + 2{,}433 * N_L) * 0.915 * \text{PCI} / 357.6$

Air Heater Modifications $= 11.2 * (\text{ACFM})^{0.772} * 0.915 * \text{PCI} / 357.6$

Ammonia-Based SNCR Process

Ammonia Storage, Handling, Injection, Controls = 63,822* $(BSIZE)^{0.6}$ * 0.655 * PCI / 357.6

Air Heater Modifications = 11.2* $(ACFM)^{0.772}$ * 0.655 * PCI / 357.6

Where: Urea = urea injection rate, lb/hr
N_I = number of wall injectors
N_L = number of lances
ACFM = flue gas volumetric flow rate at air heater inlet, ft^3/min

Capital costs for instruments and controls, sales tax and freight are assumed to be included in the algorithms listed above because they are updated with ARD costs that include these items. The total direct cost with retrofit is determined by applying the retrofit factor to the capital equipment cost subtotal, which is the sum of the equipment costs listed above. The retrofit factor is a user input value that ranges from one for new applications to three for the most difficult retrofit cases. Equations for indirect capital costs are given below.

Indirect Capital Costs for SNCR

General Facilities = Total Direct Cost with Retrofit * General Facilities (% of installed cost)

Engineering fees= Total Direct Cost with Retrofit * Engineering Fees (% of installed cost)

Contingency = Total Direct Cost with Retrofit * Contingency (% of installed cost)

Total Plant Investment = Sum of Total Direct Cost with Retrofit, General Facilities, Engineering fees, Contingency taking into account allowance for funds during construction

Preproduction = Total Plant Investment * 0.02+ One Month Fixed Operating Costs + One Month Variable Operating Costs (@ full capacity)

Initial Ammonia (60 days) = NH_3 * 24 * CF * 60 * UC_{NH3} /2000

Initial Urea (60 days) = NH_3 * 24 * CF * 60 * UC_{UREA} /2000

Where: CF = capacity factor, fraction
UC_{NH3} = ammonia cost rate, \$/ton
UC_{UREA} = $CO(NH_2)_2$ cost rate, \$/ton

D.2.3 **Operating and Maintenance Costs**

The operating and maintenance cost equations for SNCR, taken from IAPCS v.5.0, are shown below. Equations for the urea- and ammonia-based processes are shown separately in the table. As in IAPCS, the operating labor costs are based on 2 person-hours required per 8-hour shift of operation. The default for maintenance labor and materials costs is 4% of the total direct and indirect capital cost. The annual cost of the reagent is the major operating cost item for the process and is calculated as the product of the reagent usage in tons/year and the cost in dollars per ton of pure reagent. Electricity, water, and steam requirements are based on vendor information. The increase in the energy requirement for steam or air atomization are included in the operating cost algorithms.

Annual Operating and Maintenance Costs for SNCR

Urea-Based SNCR Process ($/year)

Operating and Supervisory Labor = $0.25 * 8{,}760 * UC_{OL}$

Maintenance Labor and Materials = Maintenance (%) * TPC

Reagent Requirement = $Urea * 8760 * CF/2{,}000 * UC_{UREA}$

Electricity Requirement = $(5.97 + 0.29 * N_I + 0.87 * N_L) * 8760 * CF * UC_{ELEC}$

Water Requirement = $(1.0 * N_I + 2.5 * N_L) * 60 * 8760 * CF/1{,}000 * UC_{H2O}$

Ammonia-Based SNCR Process ($/year)

Operating and Supervisory Labor Requirement = $0.25 * 8{,}760 * UC_{OL}$

Maintenance Labor and Materials Cost = Maintenance (%) * TPC

Reagent Requirement = $NH_3 * 8760 * CF/2{,}000 * UCNH3$

Steam Requirement (for steam atomization) = $BSIZE * 99.2 * 8{,}760 * CF/1{,}000 * UC_{STEAM}$

Electricity Requirement (for steam atomization) = $BSIZE * 0.12 * 8{,}760 * CF * UC_{ELEC}$

Electricity Requirement (for air atomization) = $BSIZE * 4.23 * 8{,}760 * CF * UC_{ELEC}$

Where:
TPC = total direct and indirect capital costs, $ (see Table 3-1)
UC_{ELEC} = electricity rate, $/kWh
UC_{H2O} = unit cost water, $/1,000 gallon
UC_{NH3} = NH_3 cost rate, $/ton
UC_{STEAM} = steam rate, $/MMBtu
UC_{UREA} = $CO(NH_2)_2$ cost rate, $/ton

D.2.4 <u>CUECost Validation</u>

To determine how successfully the IAPCS algorithms were modified using the ARD data, CUECost was run using the design information upon which the ARD cases were based. Total plant costs and operating and maintenance costs estimated using CUECost were compared to the costs developed by ARD. Results from this comparison are presented in Tables D-3 and D-4.

Total plant costs presented below include reagent storage and handling, injection system, air heater modifications, and miscellaneous direct capital costs. Total plant costs also include indirect capital costs such as engineering, general facilities and contingencies. *Chemical Engineering Magazine* plant cost indices were used to report costs in consistent year dollars. The percent difference between ARD study costs and the CUECost estimates for total plant costs ranged from -15 percent to +7 percent for the cases evaluated. Operation and maintenance costs estimated by CUECost are 0 to 12 percent greater than those estimated by the ARD study.

Table D-3: CUECost with Acid Rain Division Study Cases for SNCR (1990 dollars)

		Cyclone-Fired		Wet-Bottom Vertical-Fired	Wet-Bottom Wall-Fired
		Midwestern Bituminous		Eastern Bituminous	
		Boiler Size (MW)			
Selective Noncatalytic Reduction		**150**	**400**	**100**	**259**
CUECost with Acid Rain Division Design Parameters					
Default Input Parameters					
Number of Injectors	integer	18	36	18	36
Number of Lances	integer	0	0	0	0
Urea/NOX Stoichiometric Ratio	fraction	0.90	0.90	0.90	0.90
Design Parameters calculated by CUECost					
Urea Injection Rate	lb/hr	2,139	5,297	973	2,439
Air Heater Inlet ACFM	ACFM	611,455	1,712,635	407,633	1,078,935
Capital Costs using Acid Rain Division Design Parameters ($ 1000)					
Urea Storage & Handling		451	658	324	476
Urea Injection		364	589	364	589
Controls/Miscellaneous		152	203	146	185
Air Heater Modifications		391	865	286	605
Total Capital Equipment Cost		1,358	2,314	1,120	1,855
Total Plant Cost (TPC)		1,833	3,124	1,513	2,505
TPC ($/kW)		12.2	7.81	15.1	9.67
% Difference from Acid Rain Division Cost Study		-7	7	-15	6
O&M Costs using Acid Rain Division Design Parameters ($1000/year)					
Operating and Supervisory Labor		46	46	46	46
Maintenance Labor and Materials		27	47	23	38
Reagent		1,102	2,730	501	1,257
Electricity		3	5	3	5
Water		2	5	2	5
O&M Total		1,181	2,832	575	1,350
% Difference from Acid Rain Division Cost Study		8	0	12	4

Table D-4: Acid Rain Division Study: SNCR Applications (1990 dollars)

		Cyclone-Fired		Wet-Bottom Vertical-Fired	Wet-Bottom Wall-Fired
		Midwestern Bituminous		Eastern Bituminous	
		Boiler Size (MW)			
Selective Noncatalytic Reduction		**150**	**400**	**100**	**259**
Acid Rain Division Costs and Design Parameters					
Design Parameters from Acid Rain Division					
Number of Injectors	integer	18	36	18	36
Number of Lances	integer	0	0	0	0
Urea/NOX Stoichiometric Ratio	fraction	0.90	0.90	0.90	0.90
Economizer Outlet	ACFM	648,029	1,812,657	416,969	1,085,858
Acid Rain Division Capital Costs ($ 1000)					
Tanks, Pumps & Injectors		615	1,000	480	673
Pipes/Valves/Heat Tracing		510	680	530	725
Electrical/PLC		180	160	180	155
Platform/Insulation/Enclosure		135	280	90	155
Total Capital Equipment Cost		1,440	2,120	1,280	1,709
Total Plant Cost (TPC)		1,980	2,920	1,770	2,357
TPC ($/kW)		13.2	7.3	17.7	9.1
Acid Rain Division O&M Costs ($ 1000/year)					
Coal Consumption		74	198	36	97
Power consumption		19	59	7	31
Ash Disposal		3	7	1	3
General Maintenance		31	48	27	37
Urea Consumption		961	2,494	437	1,119
Water Consumption		7	18	3	7
O&M Total		1,094	2,824	512	1,295

D.3 NATURAL GAS REBURNING

D.3.1 Performance Parameters

The fraction of boiler heat input contributed by natural gas (reburn fraction) depends on the desired NO_x removal efficiency. The relationship between the reburn fraction and NO_x reduction efficiency, taken from IAPCS v.5.0, is based on vendor information and review of NGR performance data:

$$RBFRAC = (NO_xEFF - 0.48)/0.86$$

Where: RBFRAC = boiler heat input contributed by natural gas (fraction)
NOx EFF = NO_x reduction efficiency (fraction)

The relationship applies for NO_x reduction efficiencies from 55 to 65 percent and yields reburn fractions from 0.08 to 0.20. In CUECost, these are the valid input ranges for the NO_x removal efficiency and reburn fraction. If the user inputs both parameters within the valid ranges, the input values are used for cost calculations. If only one parameter is outside of the valid range, that parameter is calculated using the other parameter. If both input values are outside of the valid ranges, a default reburn fraction of 0.15 is used with a corresponding 61 percent NOx removal efficiency.

D.3.2 Capital Costs

Direct capital cost equations for NGR are presented below. The first equation includes the installed costs of gas injectors, OFA ports, and related equipment. This equation was developed by modifying the IAPCS equation for the same equipment area [Cost = 6,644,400*(BSIZE/500)^0.214] to reflect recent cost estimates from an ARD study (EPA, 1996). The ARD study estimated NGR costs for four different boiler sizes. To bring the IAPCS model up to date, the constant in the equation (6,644,400) was replaced with a variable. Then the equation was set equal to each of the ARD cost cases, and the equation was solved to determine a new constant. The results showed that the new "constant" varied linearly with boiler size. Therefore, the constant in the IAPCS equation was replaced with an expression that is a function of boiler size (BSIZE*3238 +1504675).

The second equation shown includes the costs associated with piping natural gas to the boiler from the metering station located at the utility plant fence line. The equation was derived by fitting an exponential curve to ARD costs for natural gas piping. Plant cost indices from *Chemical Engineering Magazine* are included in the equations to update direct capital costs.

Direct Capital Costs for NGR (Installed equipment cost)

Fuel injectors, overfire air ports, associated piping, valves, windbox, and control dampers $= (BSIZE*3238 + 1504675) * (BSIZE/500)^{0.214\,e} * PCI / 357.6$

Gas pipeline from fence line to boiler $= 372 * \exp(2.64 \times 10^{-3} * BSIZE) * PCI / 357.6$

Where: BSIZE = Boiler capacity (MW)

PCI = chemical engineering plant cost index from *Chemical Engineering Magazine*
= 388 for 1998 dollars and 357.6 for 1990 dollars

Capital costs for instruments and controls, sales tax and freight are assumed to be included in the algorithms listed above because they are updated with ARD costs that include these items. The total direct cost with retrofit is determined by applying the retrofit factor to the capital equipment cost subtotal, which is the sum of the equipment costs listed above. The retrofit factor is a user input value that ranges from 1 for new applications to 3 for the most difficult retrofit cases. Equations for indirect capital costs are given below.

Indirect Capital Costs for NGR

General Facilities = Total Direct Cost with Retrofit * General Facilities (% of installed cost)

Engineering fees = Total Direct Cost with Retrofit * Engineering Fees (% of installed cost)

Contingency = Total Direct Cost with Retrofit * Contingency (% of installed cost)

Total Plant Investment = Sum of Total Direct Cost with Retrofit, General Facilities, Engineering fees, Contingency taking into account allowance for funds during construction

Preproduction = Total Plant Investment * 0.02+ One Month Fixed Operating Costs + One Month Variable Operating Costs (@full capacity)

D.3.3 **Operating and Maintenance Costs**

In general, natural gas reburning reduces the boiler operating costs associated with coal- and ash-handling process areas, including maintenance, electricity, and ash disposal. Fuel costs are generally higher, because the price of natural gas is typically higher than the price of coal per unit of energy. The equations used by CUECost and taken from IAPCS for estimating operating costs and savings are given below. The electricity requirement for coal- and ash-handling processes decreases in proportion to the amount of reburn fuel used. The default for maintenance costs for operating the NGR system is 1.5 percent of the total plant cost. The empirical equation for estimating waste disposal savings includes a reduction of bottom and fly ash as a result of firing gas. As in IAPCS, savings from reduced fly ash disposal are estimated only for retrofit applications. The incremental fuel cost for firing gas is estimated by multiplying the amount of gas burned by the fuel price difference between gas and coal.

Annual Operating and Maintenance Costs and Savings for NGR

Electrical Consumption Savings ($/year)

$ELEC = 9.51 * 10^7 * Q_{in} * CF * RBFRAC/HHV * UC_{ELEC}$

Maintenance Cost ($/year)

$MAINT = Maintenance\ (\%) * TPC - 1387.5 * RBFRAC * (BSIZE/500)^{0.6}$

Waste Disposal Savings ($/year)

$WASTE = [BA * RBFRAC + (NR - 1) * 4.336 * RBFRAC * PPHPRT * CF] * UC_{WASTE}$

Natural Gas Consumption Cost ($/year)

$GAS = Q_{in} * RBFRAC * 8{,}760 * CF * (UC_{GAS} - UC_{COAL})$

Where:	Qin	= boiler heat input, MMBtu/hr
	CF	= capacity factor, dimensionless
	HHV	= higher heating value of coal, Btu/lb
	UC_{ELEC}	= electricity rate, $/kWh
	TPC	= total plant capital costs, $
	BA	= bottom ash rate, tons/year estimated from:
	BA	=BAF * ASH *, 500/HHV * Qin * 8,760 * CF/2,000 where, BAF = bottom ash factor, dimensionless ASH = percent ash in coal, wt. %
	NR	= retrofit status, 1 for new "grass root" installation (retrofit factor =1) and 2 for retrofit application (retrofit factor >1)
	PPHPRT	= fly ash rate, lb/hr
	UC_{WASTE}	= waste disposal rate, $/ton
	UC_{GAS}	= gas rate, $/MMBtu
	UC_{COAL}	= cost for coal, $/MMBtu

D.3.4 CUECost Validation

Total plant costs and operating and maintenance costs estimated by CUECost algorithms were compared to current cost data developed and validated by EPA's Acid Rain Division (ARD) (See Tables D-5 and D-6). Four applications of NGR for various boiler types, boiler sizes and coals were evaluated with CUECost. The design information provided by ARD for the four NGR applications was used to evaluate the direct capital cost equations from CUECost.
Total plant costs presented below include the fuel injectors, overfire air ports, associated piping, valves, windbox, and control dampers and the gas pipeline from the fence line to boiler. The total plant costs include direct costs listed above as well as indirect capital costs for engineering, general facilities and contingencies. *Chemical Engineering Magazine* plant cost indices were used to report costs in consistent year dollars.

The percent difference between ARD study costs and the CUECost estimates for total plant costs ranged from 0 percent to 11 percent for the cases evaluated. Operation and maintenance costs estimated by CUECost are 7 to 12 percent lower than those estimated by the ARD study.

Table D-5: CUECost with Acid Rain Division Study Cases for NGR (1990 dollars)

	Cyclone-Fired		Wet-Bottom Vertical-Fired	Wet-Bottom Wall-Fired
	Midwestern Bituminous		Eastern Bituminous	
	Boiler Size (MW)			
Natural Gas Reburning	**150**	**400**	**100**	**259**
CUECost with Acid Rain Division Design Parameters				
Design Parameters from Acid Rain Division				
Gas Reburn Fraction	0.16	0.16	0.16	0.16
Capital Costs using Acid Rain Division Design Parameters ($ 1000)				
Gas Pipeline from Fenceline to Boiler	720	1,393	631	960
Fuel Injectors, Overfire Air Ports and Associated Piping, Valves, Windbox and Control Dampers	2,000	3,470	1,684	2,646
Total Capital Equipment Cost	2,720	4,863	2,315	3,606
Total Plant Cost (TPC)	3,590	6,419	3,056	4,760
TPC($/kW)	23.9	16.1	30.6	18.4
% Difference from Acid Rain Division Cost Study	11	6	0	2
O&M Costs using Acid Rain Division Design Parameters ($1000/year)				
Electrical Consumption Savings	(54)	(152)	(34)	(89)
Maintenance	54	96	46	71
Waste Disposal Savings	(43)	(122)	(23)	(61)
Natural Gas Consumption	1,467	4,110	866	2,290
O&M	1,423	3,933	855	2,212
% Difference from Acid Rain Division Cost Study	-11	-7	-12	-12

Table D-6: Acid Rain Division Study: NGR Applications (1990 dollars)

	Cyclone-Fired		CHAPTER 2 Vertical-Fired	WET-Wall-Fired
	Midwestern Bituminous		Eastern Bituminous	
	Boiler Size (MW)			
Natural Gas Reburning	**150**	**400**	**100**	**259**
Acid Rain Division Costs and Design Parameters				
Design Parameters from Acid Rain Division				
Gas Reburn Fraction	0.16	0.16	0.16	0.16
Acid Rain Division Capital Costs ($ 1000)				
Fuel Piping System	510	1040	500	803
Burners/OFA	585	1840	540	1191
Electrical/BMS Modifications	735	1000	750	907
Windbox/Duct/Modifications	165	120	60	104
Platform/Insulation/Demolition	405	520	410	466
Total Capital Equipment Cost	2,400	4,520	2,260	3,471
Total Plant Cost (TPC)	3,225	6,080	3,050	4,662
TPC ($/kW)	21.5	15.2	30.5	18.0
Acid Rain Division O&M Costs ($ 1000/year)				
Coal Consumption	(1,630)	(4,564)	(1,201)	(3,184)
Ash Disposal	(50)	(141)	(27)	(71)
General Maintenance	50	93	47	71
Natural Gas Consumption	3,239	8,848	2,150	5,694
O&M Total	1,607	4,236	969	2,510

D.4 LOW-NO_X BURNER TECHNOLOGY

D.4.1 Capital Costs

CUECost estimates capital costs for retrofitting tangentially fired and wall-fired boilers with LNBT. The cost algorithms are based on a study of LNBT by ARD (EPA, 1996). The study obtained information from 56 boilers--35 wall-fired and 21 tangentially fired. The information provided for these retrofit cases was used to develop empirical equations that estimate total capital cost for LNBT retrofits as a function of boiler size. CUECost only addresses retrofit installations because most new boilers include LNBT in their base design.

The "bottom-line" costs include direct capital costs and indirect costs such as engineering, general facilities, and contingencies. The scope of direct costs collected for the ARD study includes 1) for the burner portion: burners or air and coal nozzles, burner throat and waterwall modifications, and windbox modifications; 2) for applicable combustion air staging: waterwall modifications or panels, windbox modifications, and ductwork; and 3) scope adders or supplemental equipment such as replacement or additional fans, dampers, or ignitors necessary for the LNBT. The scope of installed LNBT retrofit capital costs includes materials, construction and installation labor, engineering, and overhead costs (40 CFR, Part 76, Appendix B).

The ARD study found that capital costs vary greatly depending on the scope of the retrofit and the degree of modification necessary. As a result, the cost data were statistically separated into subsets of high and low cost cases for each boiler type. Cost equations were then developed by ARD for the high and low cost subsets, as well as for the entire set of cost data. The CUECost user selects from any of the three ARD cost equations based on the estimated retrofitting difficulty: high, average or low. The equations are given in 1995 dollars and include the user input *Chemical Engineering Magazine* plant cost index (PCI) to escalate to the desired cost year.

Total Capital Costs for LNBT Retrofit

Tangential-fired Boilers

High Cost: 57.04 * (300/BSIZE)^0.679 * 1000 * BSIZE * PCI / 357.6
Average Cost: 21.20 * (300/BSIZE)^0.35 * 1000 * BSIZE * PCI / 357.6
Low Cost: 11.71 * 1000 * BSIZE * PCI / 357.6

Wall-fired Boilers

High Cost: 27.72 * (300/BSIZE)^0.573 * 1000 * BSIZE * PCI / 357.6
Average Cost: 15.37 * (300/BSIZE)^0.35 * 1000 * BSIZE * PCI / 357.6
Low Cost: 6.53 * (300/BSIZE)^0.857 * 1000 * BSIZE * PCI / 357.6

Where: BSIZE = boiler size, MW
PCI = *Chemical Engineering* Plant Cost Index for desired cost basis year

A cost comparison between CUECost and IAPCS cost algorithms was not possible because design and economic parameters were not given in the ARD study of NGRT.

D.4.2 Operating and Maintenance Costs

The only direct operating costs associated with LNBT are for maintenance labor and materials. No energy penalty is assumed to be incurred with this technology. Costs for the controls, administration and support labor, including overhead, are 30 percent of the maintenance labor costs.

Annual Operating and Maintenance Costs for LNBT ($/year)

Maintenance Labor = TPC ($) * Maintenance Labor (0.8%)
Maintenance Materials = TPC ($) * Maintenance Materials (1.2%)
Administration/Overhead = Maintenance Labor ($/year)* 30%

Where: Maintenance Labor = Annual maintenance labor cost, $/year
Maintenance Materials = Annual maintenance materials cost, $/year
Administration/Overhead = Annual costs, $/year
TPC = Total Plant Costs ($)

D.4.3 CUECost Validation

Total plant costs estimated by CUECost for the four boiler sizes examined for the other NO_x technologies are shown in Table D-7. The CUECost algorithm for total plant cost is identical to the cost function presented by the ARD study of LNBT (EPA, 1996). A comparison is not presented for operating and maintenance costs because these costs are highly boiler specific.

Table D-7: CUECost with Acid Rain Division Study Cases for LNBT (1990 dollars)

Low NO_x Burner Technology	Boiler Size (MW) 150	400	100	259
	Average Case			
CUECost Total Plant Cost ($ 1000)				
Wall-Fired	2,938	5,559	2,258	4,191
T-Fired	4,053	7,668	3,114	5,781
% Difference from Acid Rain Division Study				
Wall-Fired	0	0	0	0
T-Fired	0	0	0	0

D.5 FGD AND PARTICULATE CONTROL SYSTEM COST ALGORITHM DEVELOPMENT

The cost algorithms associated with the flue gas desulfurization processes were developed based on historical data and new equipment quotations received during 1998 for some of the major equipment items. Algorithm development began with derivations from an in-house historical database by running a series of results on in-house economic models. These data sets were then modified by adding the additional data points from the new budgetary quotations, and then deriving new equations to represent the costs for equipment areas and for specific large pieces of equipment.

Performance data were sent to multiple vendors for one or two of the major equipment components identified in each cost area. These vendor contacts included a minimum of four vendors in each case. Responses to cost data requests were received from a minimum of one and normally three or more of the vendors solicited. Where vendor responses were limited due to refusals or delayed responses, additional data sources were obtained from recent projects to add to the data base of cost information for specific components. The cost data requests were made over the expected range of component sizes that could be used in the CUECost estimating workbook. The major equipment components, for which individual cost algorithms are provided, are listed below:

- FGD Absorbers and Spray Dryers
- New Stack
- Recycle Pumps
- Induced Draft Fans
- Limestone and Lime Slaking Ball Mills
- Thickeners
- Baghouses
- Electrostatic Precipitators

The user can find the specific algorithms derived for each equipment area and major component by referring to the specific capital cost development sections in Appendix F or by reviewing the contents of the CUECost spreadsheets for each technology. Operating cost algorithms can also be referenced in the same manner.

REFERENCES

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