DRAFT

DE-FC22-93PC92642

MILLIKEN CLEAN COAL TECHNOLOGY DEMONSTRATION PROJECT

PUBLIC DESIGN REPORT - DRAFT

NOVEMBER 1993

NEW YORK STATE ELECTRIC & GAS CORPORATION

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ABSTRACT

To comply with the Clean Air Act Amendments of 1990, New York State Electric & Gas Corporation (NYSEG) will demonstrate the reduction of SO_2 and NO_X emissions, without a significant decrease in plant efficiency, by installing a combination of innovative technologies and plant upgrades at Milliken Station located in Lansing, New York.

This Public Design Report (PDR) consolidates for public use all non-proprietary design information on the Milliken Clean Coal Technology Demonstration (MCCTD) project. The PDR is based on detailed design information and contains sufficient background information to provide an overview of the project and pertinent cost data. Since the scope of the report is limited to non-proprietary information, its content is not sufficient to provide a complete tool in designing a replicate plant. However, this report will serve as a reference for the design considerations involved in a commercial-scale facility.

This report includes an overview description of the MCCTD project which includes: a description of the technology and overall process performance requirements; plant location; plant facilities both existing and new with a process plant block flow diagram and material and energy balances; effluent stream components (e.g. SO_2, NO_X, toxics); products and by-products; process plant areas with detailed equipment specification lists and costs, utility and consumable requirements, etc.; environmental, health and safety considerations; project schedule; project cost information broken down by phases as well as by capital, startup, and fixed and variable operating costs; projected technical performance; and projected environmental performance.

At Milliken Station, NYSEG is working with the US Department of Energy in an environmentally responsible manner to demonstrate an approach to using coal wisely.

POINT OF CONTACT

For further information on the Milliken Clean Coal Technology Demonstration Project and/or the technologies being used, you may contact the following:

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LIST OF ABBREVIATIONS/ACRONYMS

ACET	Average cold end temperature
acfm	Actual cubic feet per minute
ACERC	Advanced Combustion Engineering Research Center
ANSI	American National Standards Institute
AQCR	Air Quality Control Region
Btu	British thermal unit
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
$CaCl_2$	Calcium chloride
$CaCO_3$	Calcium carbonate (limestone)
CAPCIS	Corrosion and Protection Centre Industrial Services
CCT	Clean Coal Technology
CO	Carbon monoxide
CO_2	Carbon dioxide
DOE	US Department of Energy
EPRI	Electric Power Research Institute
ERDA	New York State Energy Research and Development Authority
ESEERCO	Empire State Electric Energy Research Corporation
ESP	Electrostatic precipitator
FEGT	Furnace exit gas temperature
FGD	Flue gas desulfurization
G/C	Gilbert/Commonwealth, Inc.
GEP	Good engineering practice
gpd	Gallons per day
gpm	Gallons per minute
HSTC	High Sulfur Test Center
ID	Induced Draft (Fan)
kV	Kilovolt
kWh	Kilowatt hour
L/G	Liquid to gas ratio
LOI	Loss on ignition
lb/hr	Pounds per hour

ABBREVIATIONS/ACRONYMS (continued)

MCCTD	Milliken Clean Coal Technology Demonstration
MCR	Maximum continuous rating
MGD	Millions gallons per day
mg/l	Milligrams per liter
mmBtu	Million British thermal units
MW	Megawatt
MWe	Megawatt electric
NAAQS	National Ambient Air Quality Standards
NADP	National Atmospheric Deposition Program
NERC	North American Electric Reliability Council
NH_3	Ammonia
NMHC	Non-methane hydrocarbons
NO	Nitrogen oxide
NO_2	Nitrogen dioxide
NO_X	Oxides of nitrogen
NSPS	New Source Performance Standards
NYSDEC	New York State Department of Environmental Conservation
NYSEG	New York State Electric & Gas Corporation
Pb	Lead
PDR	Public Design Report
PFD	Process Flow Diagram
P&ID	Piping and Instrumentation Diagrams
PM_{10}	Particulate matter less than or equal to 10 micrometers
PON	Program Opportunity Notice
ppm	Parts per million
PSD	Prevention of Significant Deterioration
SCR	Selective catalytic reduction
S-H-U	Saarberg-Hölter Umwelttechnik GmbH
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
SPDES	State Pollutant Discharge Elimination System
STEBBINS	The Stebbins Engineering & Manufacturing Company
SWMF	Solid waste management facility
TEEM	Total Environmental & Energy Technology
TPO	Technical Project Officer
TSP	Total suspended particulates
TSS	Total suspended solids

ABBREVIATIONS/ACRONYMS (continued)

US	United States
$\mu g/m^3$	Micrograms per cubic meter
μm	Micrometers

LIST OF UNITS

acfm	Actual cubic feet per minute
Btu	British thermal unit
gpd	Gallons per day
gpm	Gallons per minute
kV	Kilovolt
kWh	Kilowatt hour
lb/hr	Pounds per hour
MCR	Maximum continuous rating
MGD	Millions gallons per day
mg/l	Milligrams per liter
mmBtu	Million British thermal units
MSL	Above mean sea level
MW	Megawatt
MWe	Megawatt electric
PM_{10}	Particulate matter less than or equal to 10 micrometers
ppm	Parts per million
TSP	Total suspended particulates
TSS	Total suspended solids
$\mu g/m^3$	Micrograms per cubic meter
μm	Micrometers

GLOSSARY OF TERMS

ACERC	Advanced Combustion Engineering Research Center
ACET	Average cold end temperature
AQCR	Air Quality Control Region
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
$CaCl_2$	Calcium chloride
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CAPCIS	Corrosion and Protection Centre Industrial Services
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ERDA	New York State Energy Research Development Authority
ESEERCO	Empire State Electric Energy Research Corporation
ESP	Electrostatic precipitator
FEGT	Furnace exit gas temperature
FGD	Flue gas desulfurization
G/C	Gilbert/Commonwealth, Inc.
GEP	Good engineering practice
HSTC	High Sulfur Test Center
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MCCTD	Milliken Clean Coal Technology Demonstration
NAAQS	National Ambient Air Quality Standards
NADP	National Atmospheric Deposition Program
NERC	North American Electric Reliability Council
NH_3	Ammonia
NMHC	Non-methane hydrocarbons
NO	Nitrogen oxide
NO_2	Nitrogen dioxide

GLOSSARY OF TERMS (continued)

NO_X	Oxides of nitrogen
NO_XOUT®	Process, by Nalco FuelTech, urea-based chemical and mechanical system for cost-effective NO_X reduction
NSPS	New Source Performance Standards
NYSDEC	New York State Department of Environmental Conservation
NYSEG	New York State Electric & Gas Corporation
Pb	Lead
PDR	Public Design Report
PFD	Process Flow Diagram
P&ID	Piping & Instrumentation Diagrams
PON	Program Opportunity Notice
PSC	New York State Public Service Commission
PSD	Prevention of Significant Deterioration
ROW	Right-of-way
SADCA	New York State Acid Deposition Control Act
SCR	Selective catalytic reduction
S-H-U	Saarberg-Hölter Umwelttechnik GmbH
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
SPDES	State Pollutant Discharge Elimination System
STEBBINS	The Stebbins Engineering & Manufacturing Co.
SWMF	Solid waste management facility
TEEM	Total Environmental & Energy Technology
TPO	Technical Project Officer
US	United States

EXECUTIVE SUMMARY

In May 1991 New York State Electric & Gas Corporation (NYSEG) applied to the US Department of Energy (DOE) for partial funding of the $159 million Milliken Clean Coal Technology Demonstration (MCCTD) Project from the Clean Coal Technology IV program. This program, a team effort between the federal government and coal users, will help ensure the nation uses this abundant domestic resource wisely and in an environmentally responsible manner. In September of 1991, the Milliken project was chosen as a successful applicant. The MCCTD was one of nine clean coal projects selected for funding by the DOE. A Cooperative Agreement was executed between NYSEG and the DOE on October 20, 1992 for the project (DE-FC22-93PC92642).

The Milliken Clean Coal Technology Demonstration Project is being constructed at NYSEG's Milliken Station located in Lansing, Tompkins County, New York. This plant is one of the top 20 most efficient steam electric generating stations operating in the United States. This project will achieve significant reductions in acid gas emissions with virtually no change in station efficiency by demonstrating a technology that is technically and economically viable in a retrofit application. It will provide cost and performance data from a commercial-scale application to demonstrate the viability of this technology for new boilers.

The major technology vendors that have joined NYSEG as an integrated team and their associated technologies are as follows:

- Saarberg-Hölter-Umwelttechnik (S-H-U) - FGD Process Design
- Stebbins Engineering and Manufacturing Company (Stebbins) - Tile Lined Absorber Design and Fabrication
- Nalco FuelTech - SNCR Design and Equipment Supply
- ABB Air Preheater, Inc. - Heat Pipe Air Heater Design and Fabrication
- DHR Technologies, Inc. - Design and Installation of Plant Economic Optimization Advisor (PEOA) expert computer system

This project will provide full-scale demonstration of a combination of innovative emission-reducing technologies and plant upgrades for the control of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions from a coal-fired steam generator, without a significant loss of efficiency.

The overall project goals are:

- to achieve 98% SO_2 removal efficiency using limestone while burning high-sulfur coal.
- To achieve up to 70% NO_X reductions using the NOxOUT® selective non-catalytic reduction (SNCR) technology in conjunction with combustion modifications.
- To minimize solid wastes by producing marketable by-products (commercial-grade gypsum, calcium chloride, and fly-ash).

- To achieve zero wastewater discharge.
- To maintain station efficiency by using a high efficiency heat pipe air heater system and a low power consuming scrubber system.

The Saarberg-Hölter Umwelttechnick (S-H-U) process will be used to reduce SO_2 emission by 98%. In the S-H-U process, the flue gas is scrubbed with a limestone slurry in an absorber vessel that does not contain packing or grid work. The lack of packing results in a low pressure drop across the absorber, which decreases energy requirements. The S-H-U slurry is maintained at a low pH by adding formic acid, which acts as a buffer, to the limestone slurry. A slipstream is processed for recovery and recycled to the process. This will be the first US demonstration of the S-H-U process and will include the innovative feature of a tile-lined, split-flow absorber constructed below the flues.

NO_X emissions will be reduced by a combination of combustion modifications and the installation of the NO_XOUT® urea injection technology. The NO_XOUT® technology is capable of reducing NO_X emissions without affecting the salability of the flyash.

In order to maintain plant efficiency, a high efficiency heat pipe air heater system will be installed. A heat pipe unit uses carefully selected liquids, sealed in tubes, as the heat transfer medium. One portion of each tube is in the flue gas stream and the rest of the tube is in the air stream. The liquid in the tube evaporates in the hot portion; then the vapor flows to the cold end, where it condenses; and the liquid flows back to the hot end. The need for special air seals and the associated potential for air heater leakage is eliminated with this design. Because of the high efficiency of these units, the temperature of the combustion air will be increased, which will increase the efficiency of the plant.

The S-H-U process is the only developed wet limestone flue gas desulfurization (FGD) process which is designed specifically to employ the combined benefits of low-pH operation; formic acid enhancement; single loop, cocurrent/countercurrent absorber; and in-situ forced oxidation. The unique cocurrent/countercurrent absorber does not include any packing or grid work. This significantly reduces the potential for plugging and erosion and reduces the energy consumption of the induced draft (ID) fans. This project will provide the first demonstration of the S-H-U process installed directly below the flues which saves considerable space. This design approach is advantageous for retrofit on existing plants where space is at premium. The S-H-U FGD process will be installed on both Units 1 and 2 with common auxiliary equipment.

The project will demonstrate the production of excellent and consistent quality gypsum for use in wallboard manufacturing and will produce marketable calcium chloride.

The project is installing combustion modifications on both units for primary NO_X emission control. Combustion modifications will reduce NO_X levels by about 20%. In addition, the NO_XOUT® technology will be installed on Unit 2 to provide a further reduction in NO_X emissions over that achieved by the combustion modifications alone. The NO_XOUT® process achieves NO_X reduction by the reaction of NO_X with urea injection into the post-combustion zones of the boiler.

The total project cost is $158,607,807. The DOE's share is $45,000,000. NYSEG has secured additional cofunding agreements with: CONSOL, Inc., Empire State Electric Energy Research Corporation (ESEERCO), Electric Power Research Institute (EPRI), and New York State Energy Development Authority (ERDA).

As of October 1993, the status of the MCCTD project is as follows:

- Engineering and Design - 90% Complete
- Equipment Procurement - 90% Complete
- FGD Building Construction - 50% Complete
- Equipment Installation - 5% Complete

In summary, NYSEG, together with the participant organizations, remains committed to the successful completion and demonstration of the Milliken Clean Coal Technology Demonstration Project.

MILLIKEN CLEAN COAL TECHNOLOGY

DEMONSTRATION PROJECT

SECTION 1.0

PROJECT OVERVIEW

DE-FC22-93PC92642

1.1 PURPOSE OF THE PUBLIC DESIGN REPORT

The purpose of the Public Design Report is to consolidate for public use all non-proprietary design information on the project. This report is based on detailed design information. The report contains sufficient background information to provide an overview of the project and pertinent cost data. Since the scope of the report is limited to non-proprietary information, its content is not sufficient to provide a complete tool in designing a replicate plant. However, this report will serve as a reference for the design considerations involved in a commercial-scale facility.

This report includes an overview description of the demonstration project which includes: a description of the technology and overall process performance requirements; plant location; plant facilities both existing and new with a process plant block flow diagram and material and energy balances; effluent stream components (e.g. SO_2, NO_X, toxics); products and by-products; process plant areas with detailed equipment specification lists and costs, utility and consumable requirements, etc.; environmental, health and safety considerations; project schedule; project cost information broken down by phases as well as by capital, startup, and fixed and variable operating costs; projected technical performance; projected environmental performance; projected economics, and conclusions.

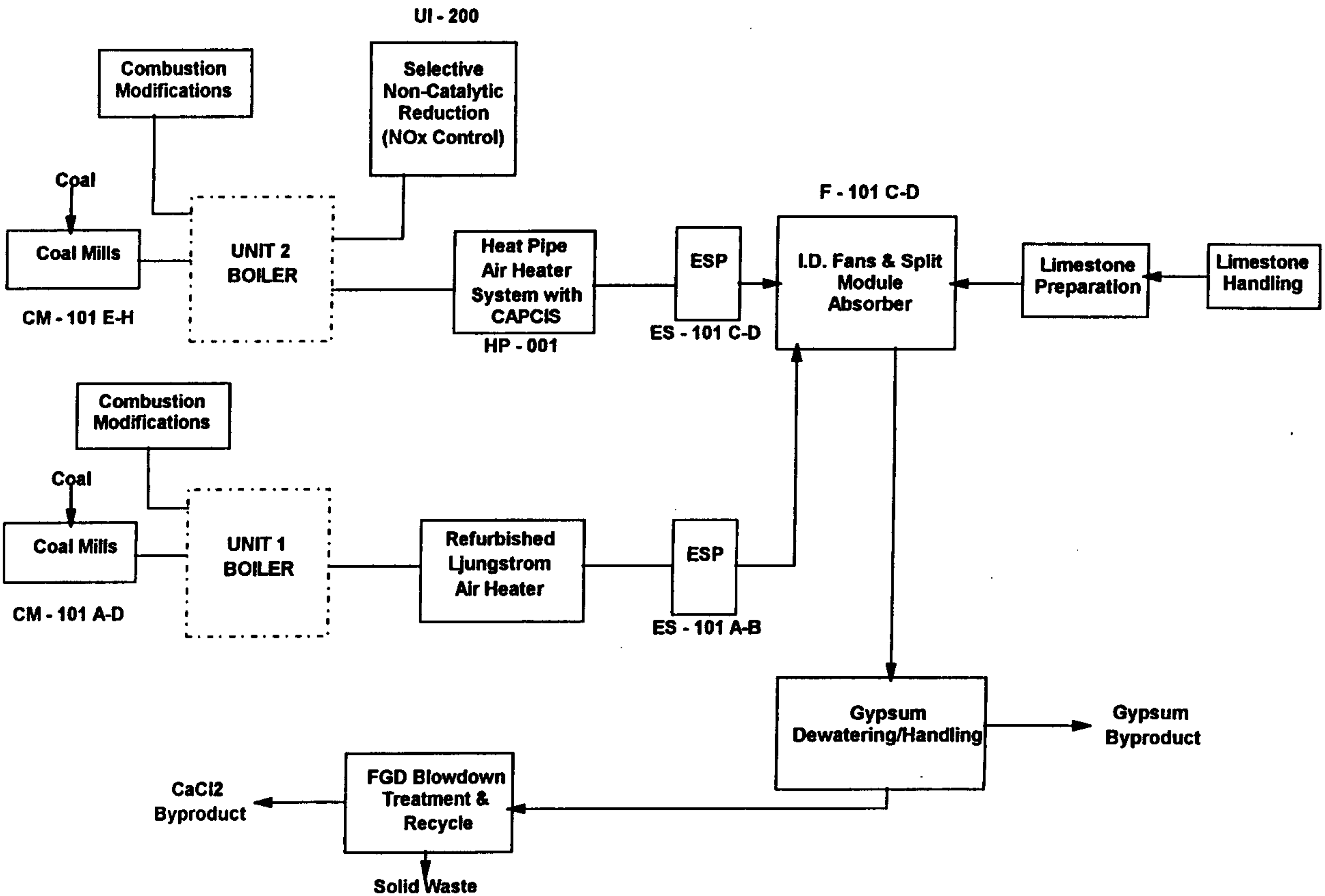
1.2 BRIEF DESCRIPTION OF THE PROJECT

Milliken Station, which is among the nation's most efficient and reliable generators of electricity, is one of seven coal-fired stations in the NYSEG generating system. To comply with the Clean Air Act Amendments of 1990, NYSEG is installing a sulfur dioxide (SO_2) removal system, also called a flue gas desulfurization (FGD) system or scrubber at Milliken. Additional changes are being made to bring the station into compliance with new nitrogen oxides (NO_X) limits (see FIGURE 1.2-1).

In May of 1991, New York State Electric & Gas Corporation (NYSEG) applied to the US Department of Energy for partial funding of the $159 million project from the Clean Coal Technology IV program. This program, a team effort between the federal government and coal users, will help ensure that the nation uses this abundant domestic resource wisely and in an environmentally responsible manner. In September of 1991, the Milliken project was chosen as a successful applicant. A Cooperative Agreement was executed between NYSEG and the DOE on October 20, 1992.

Project Title:	Milliken Clean Coal Technology Demonstration Project (MCCTD)
Proposer:	New York State Electric & Gas Corporation
Project Location:	Milliken Station Lansing, New York Tompkins County
Technology:	A combination of limestone scrubbing, combustion modifications, urea injection, and enhanced heat recovery to reduce SO_2 and NO_X emissions while maintaining efficiency.
Application:	SO_2 and NO_X emissions reductions in pulverized-coal-fired furnaces.
Type of Coal Used:	High-sulfur bituminous (Pittsburgh seam)
Product:	Pollution Control Technology
Project Size:	300 MWe
Project Start Date:	1992
Project End Date:	1998

FIGURE 1.2-1
PROCESS BLOCK DIAGRAM FOR MCCTD PROJECT



Estimated Project Cost: $158,607,807

Estimated Cost Distribution:	Participant Share (%)	DOE Share (%)
	71.63	28.37

NYSEG is hosting and cofunding the MCCTD project at Milliken Station which is also being cofunded by CONSOL, Inc., Empire State Electric Energy Research Corporation (ESEERCO), Electric Power Research Institute (EPRI), and New York State Energy Development Authority (ERDA). The major technology vendors that have joined NYSEG as an integrated team and their associated technologies are as follows:

- Saarberg-Hölter-Umwelttechnik (S-H-U) - FGD Process Design
- Stebbins Engineering and Manufacturing Company (Stebbins) - Tile Lined Absorber Design and Fabrication
- Nalco FuelTech - SNCR Design and Equipment Supply
- ABB Air Preheater, Inc. - Heat Pipe Air Heater Design and Fabrication
- DHR Technologies, Inc. - Design and Installation of Plant Economic Optimization Advisor (PEOA) expert computer system

As of October 1993, the status of the MCCTD project is as follows:

- Engineering and Design - 90% Complete
- Equipment Procurement - 90% Complete
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- Equipment Installation - 5% Complete

The demonstration phase of the MCCTD project is scheduled to begin in July of 1995. A brief description of the planned testing is as follows:

NYSEG plans to evaluate the impact of coal sulfur content, concentration of formic acid in the recycle slurry, and in-service spray header combinations on the S-H-U process performance. The S-H-U process variables are presented in TABLE 1.2-1. The goals of the S-H-U evaluation are to demonstrate 95-98% SO_2 removal while maintaining 95% FGD reliability; determine the impact of the FGD on net plant heat rate; and confirm limestone utilization and formic acid makeup requirements. Using the base coal, the project will also evaluate the impact of scrubber variables on SO_2 removal, by-product gypsum quality, and calcium chloride quality.

The NO_X control test program is divided into two parts: the Low NO_X concentric firing system with the boiler thermal efficiency advisor software; and the NO_XOUT® process. As shown in TABLE 1.2-2, the low NO_X burner test program variables include economizer O_2 level, secondary air split between overfire air ports and concentric air, and angle between fuel air and secondary air. The goal of the low NO_X burner test program is to maximize the NO_X reduction with acceptable water wall slagging, tube corrosion, and carbon carryover in the fly ash.

The NO_XOUT® test program goals are: 1) to increase NO_X removal by an additional 30% above the LNCFS III removal while maintaining ammonia slip below 2 ppm in the flue gas; and 2) to evaluate the impact of the NO_XOUT®process on the air heater, ESP and scrubber performance; and on the bottom ash,fly ash, gypsum, and calcium chloride quality. The NO_XOUT® process variables include reagent/NO_X molar ratio, reagent injection location, reagent concentration and boiler load. The variables and variable ranges are presented in TABLE 1.2-3.

The balance of plant variables are presented in TABLE 1.2-4. The heat pipe air heater study will optimize the net plant heat rate with minimal impact on plant availability. The plant particulate control efficiency will be evaluated across the ESP and across the S-H-U scrubber. The ESP is designed to maintain the scrubber inlet particulate flow rate at 120-145 lb/hr per boiler. The low particulate rate is required to produce saleable gypsum.

Associated with the demonstration program, a trace element/air toxics balance will be conducted around Milliken Station. The goal of the evaluation is to determine the effectiveness of the upgraded ESP and the S-H-U process in reducing trace element emissions.

An overview of the project schedule can be seen on FIGURE 1.2-2.

Also included in this section as FIGURES 1.2-3 through 1.2-9 are 3-D representations of the scrubber facility.

TABLE 1.2-1
S-H-U PROCESS VARIABLES

Variable	Variable Range	Goal
Coal sulfur content	1.5, 2.9, 4.0 wt % sulfur	Up to 98% SO_2 removal, 95% reliability, minimize FGD energy requirement. Evaluate Impact of FGD on net plant heat rate. Confirm calcium and formic acid makeup rate.
Formic acid concentration	Proprietary	
In-service spray header combinations	Various spray header combinations	

TABLE 1.2-2
LOW NO_x BURNER TEST PROGRAM

Variable	Variable Range	Goal
Economizer O_2 level	2.0 to 5.0%	Maximize NO_x reduction with acceptable waterwall slagging, tube corrosion, and carbon carryover in fly ash
Secondary air split between OFA ports and concentric air	0 to 30% OFA	
Angle between concentric air and coal stream	-15 to +15° yaw -30 to +30° verticle tilt	

TABLE 1.2-3
NO_xOUT® PROCESS VARIABLES

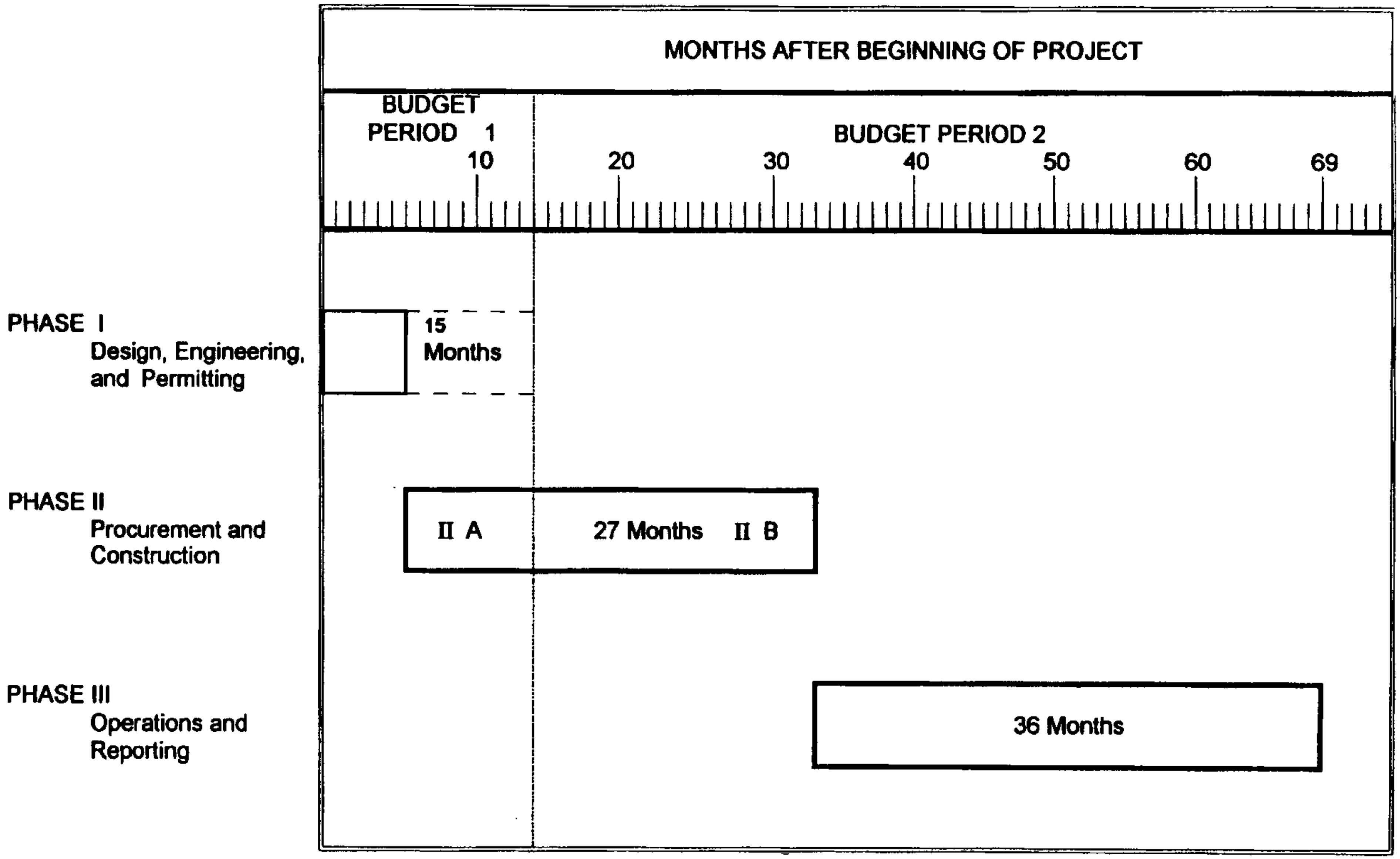
Variable	Variable Range	Goal
Urea/NO_x molar ratio	0.15 to 1.5	Up to 30% additional NO_x removal Evaluate impact on air heater, ESP, FGD, and by-product quality No urea or ammonia contamination of by-products
Urea injection location	up to 3 locations	
Urea concentration	5 to 15 wt % solution	
Boiler load	75 to 100% capacity	

TABLE 1.2-4
BALANCE OF PLANT VARIABLES

Area	Variable	Variable Range	Goal
Air Heater	Air heater gas exit temperature	240 to 300°F	Optimize net plant heat rate with minimal adverse effect on plant operations
	Economizer O_2 level	2.0 to 5% O_2	Determine impact on boiler efficiency and fly ash LOI
Particulate Control	Coal Sulfur content	1.5, 2.9, 4.0 wt % sulfur	0.1 lb/MM Btu particulates at scrubber inlet
	ESP power		0.05 lb/MM Btu particulates at scrubber outlet

FIGURE 1.2.-2

OVERALL PROJECT SCHEDULE FOR MCCTD PROJECT



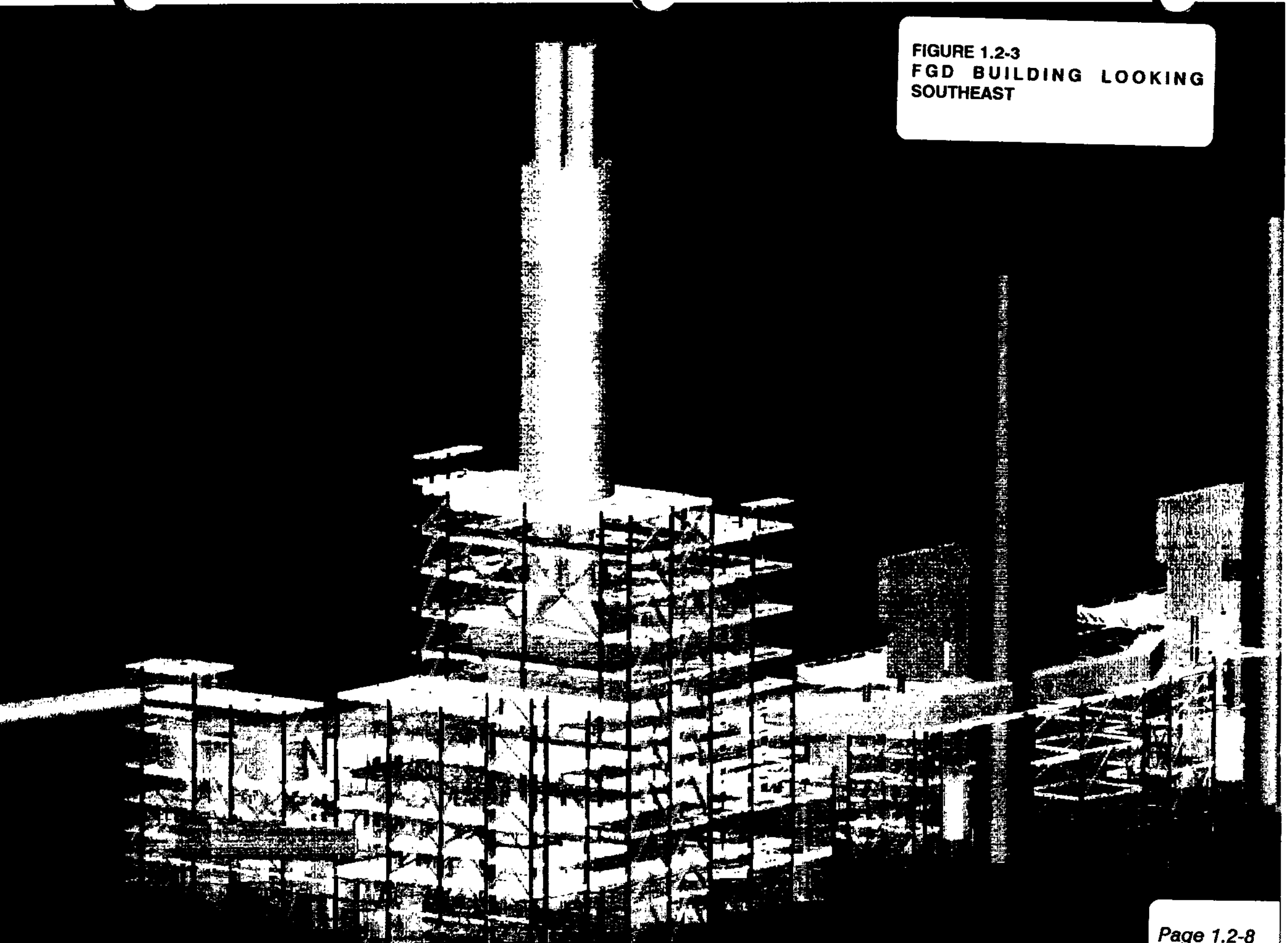


FIGURE 1.2-3
FGD BUILDING LOOKING SOUTHEAST

FIGURE 1.2-4
GYPSUM DEWATERING AREA

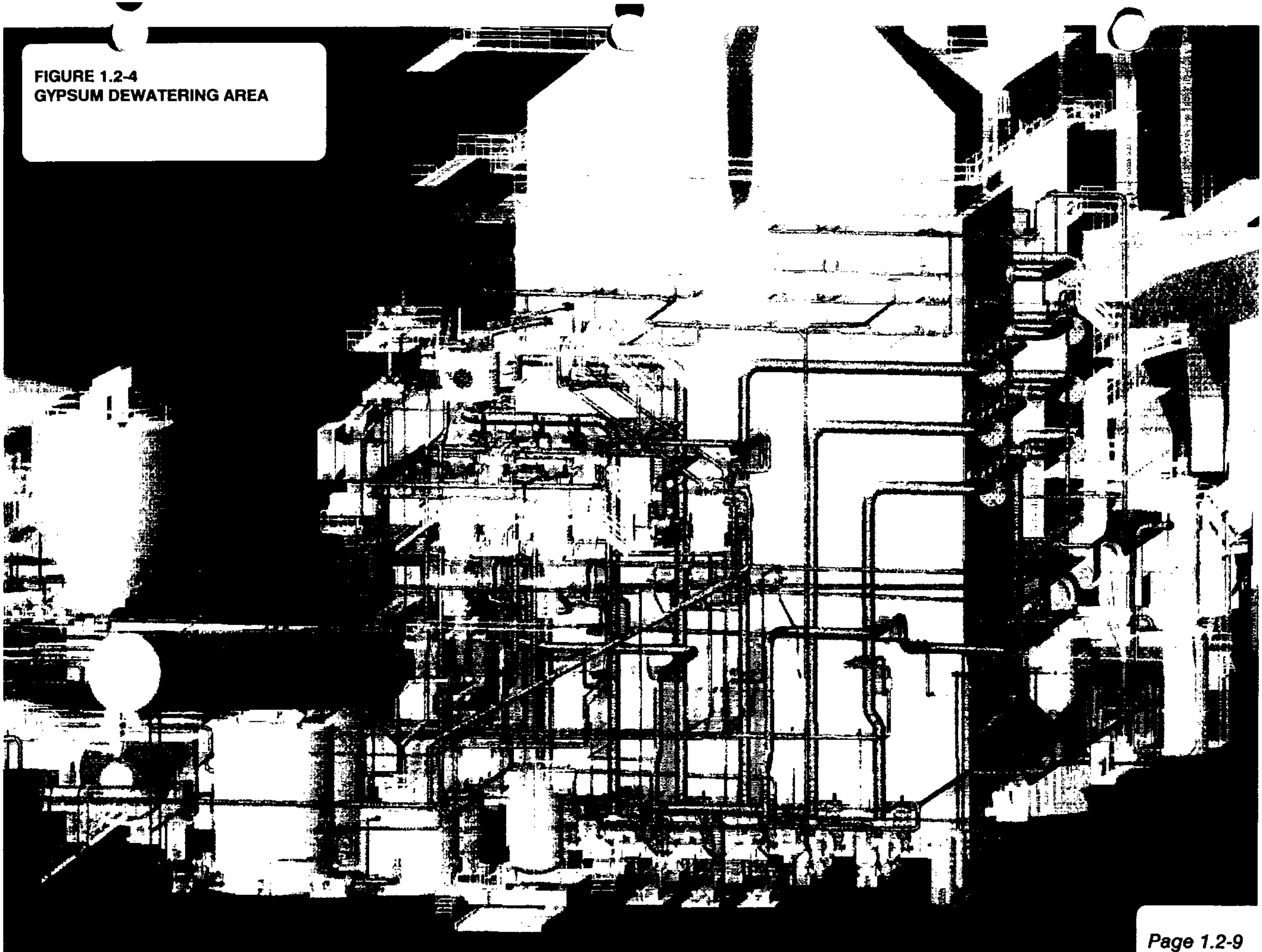
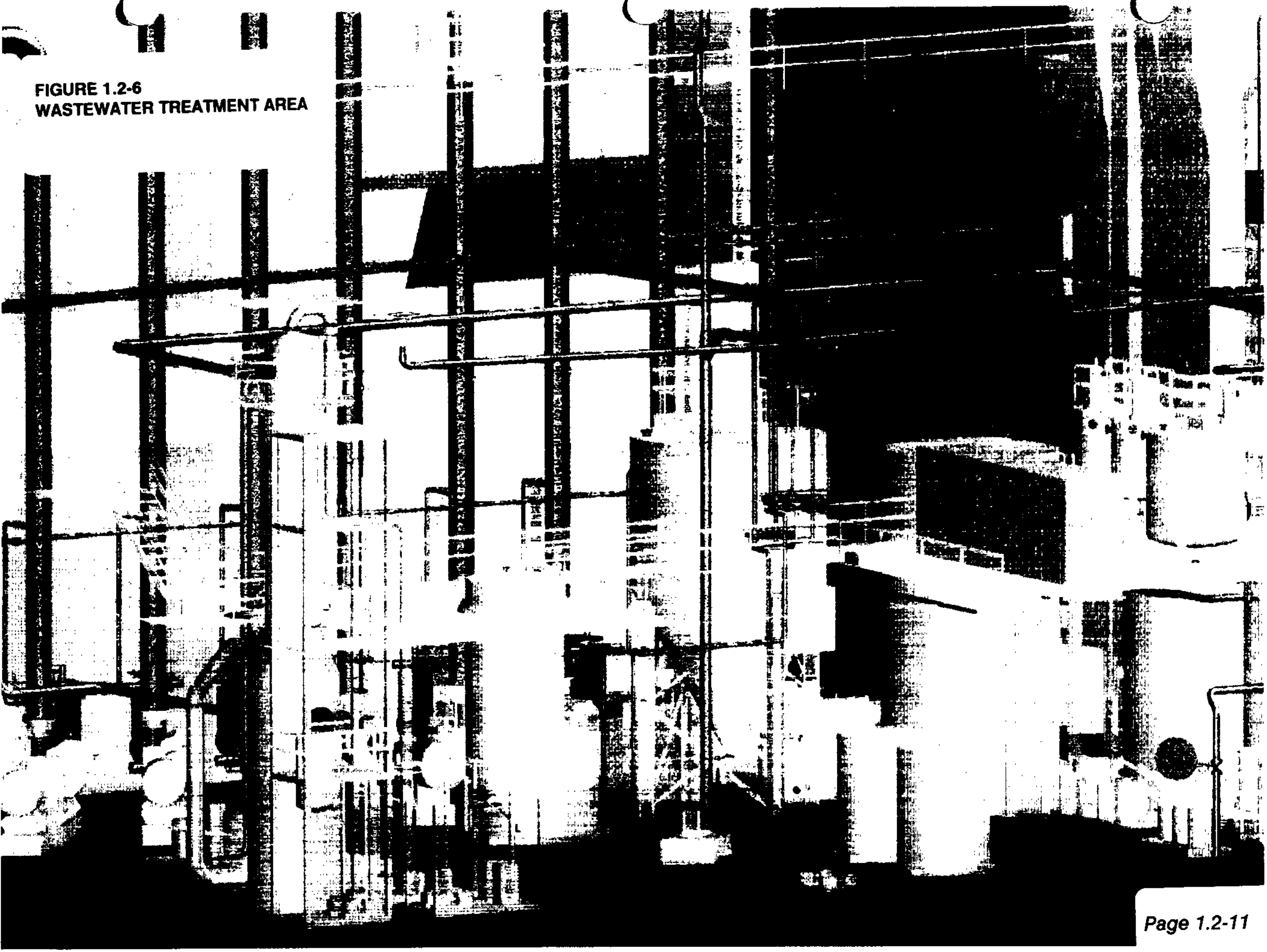


FIGURE 1.2-5
INTERNAL ABSORBER HEADERS

FIGURE 1.2-6
WASTEWATER TREATMENT AREA



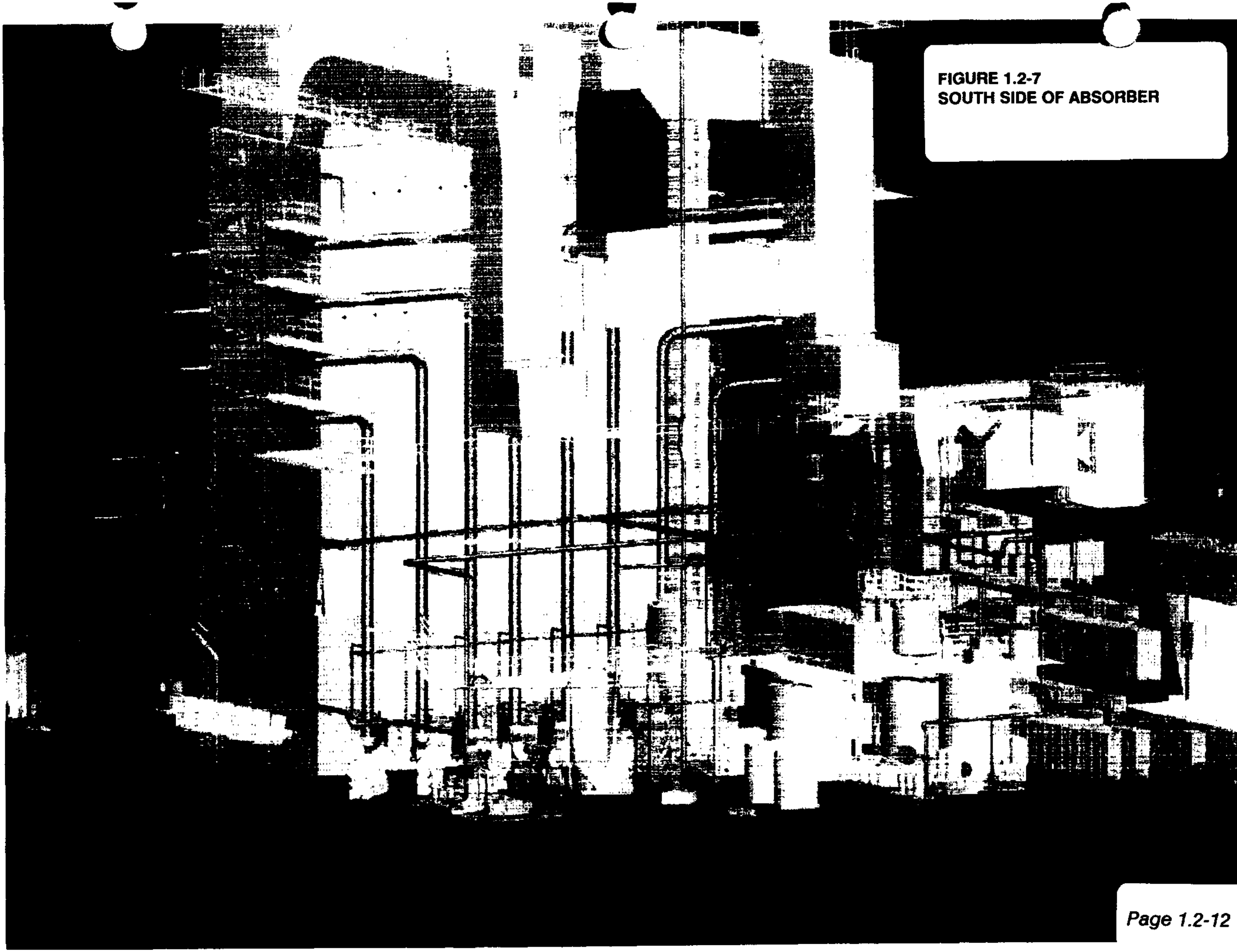


FIGURE 1.2-7
SOUTH SIDE OF ABSORBER

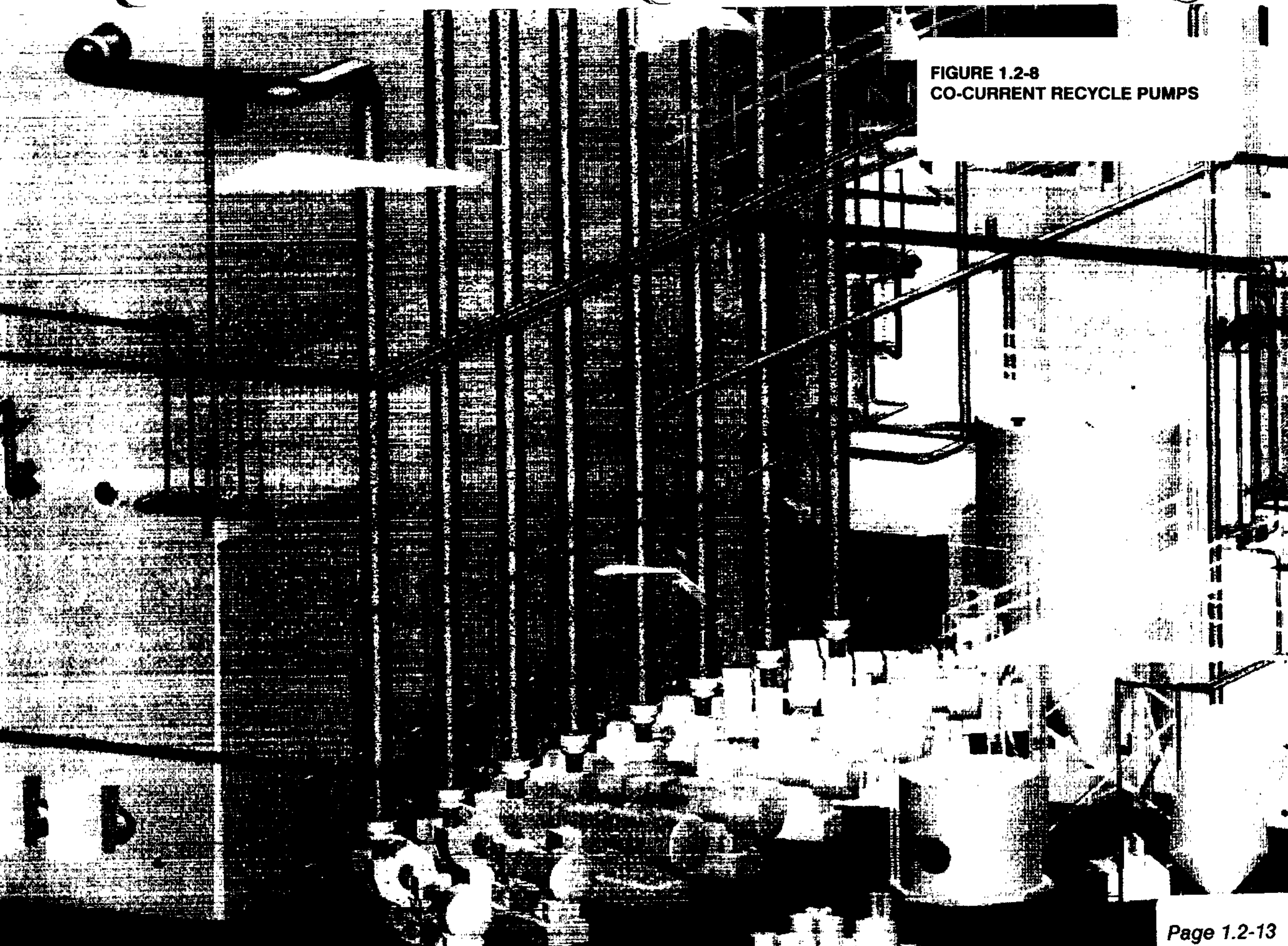


FIGURE 1.2-8
CO-CURRENT RECYCLE PUMPS

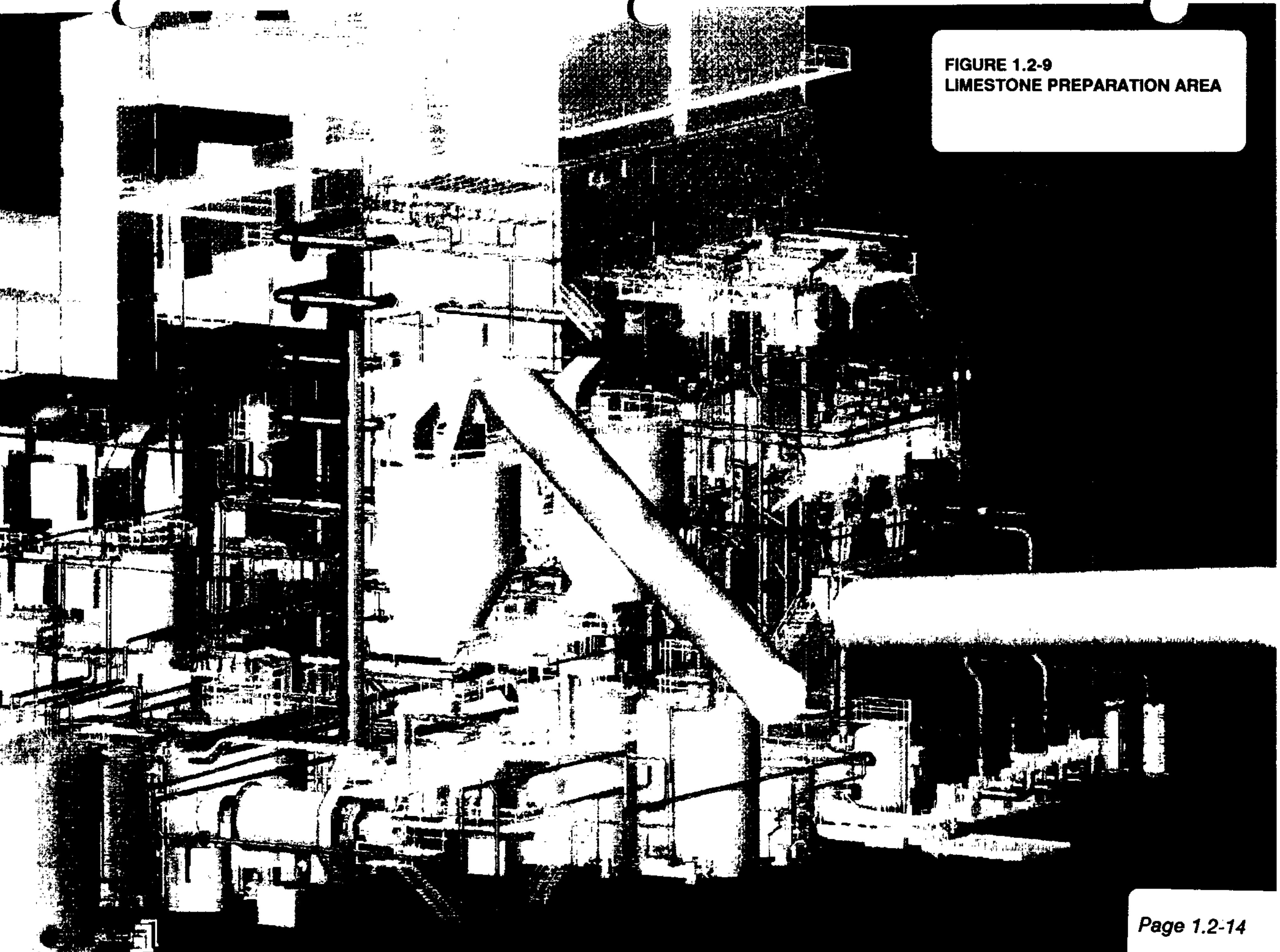


FIGURE 1.2-9
LIMESTONE PREPARATION AREA

1.3 OBJECTIVES OF THE PROJECT

NYSEG will demonstrate the reduction of SO_2 and NO_X emissions without a significant decrease in plant efficiency by installing a combination of innovative technologies and plant upgrades. These include the Saarberg-Hölter Umwelttechnick (S-H-U) process for SO_2 reduction, combustion modifications and the NO_XOUT® process for NO_X reduction, and a high efficiency heat pipe air heater system plus other energy-saving modifications to maintain efficiency. This project will be the first US demonstration of the S-H-U process, which will include the first demonstration of a tile-lined, split-flow absorber below the flues. This project will also be the first demonstration of the NO_XOUT® process in a utility furnace firing high-sulfur coal-fired furnace.

The overall project goals are:

- To achieve 98% SO_2 removal from the flue gas, using limestone, while burning high-sulfur coal.
- To achieve up to 70% NO_X reduction using the NO_XOUT® selective non-catalytic reduction (SNCR) technology in combination with combustion modifications.
- To minimize solid wastes by producing marketable by-products (commercial-grade gypsum, calcium chloride, and flyash).
- To achieve zero wastewater discharge.
- To maintain station efficiency by using a high efficiency heat pipe air heater system and a scrubber system with low power requirements.

The S-H-U process is the only developed wet limestone flue gas desulfurization (FGD) process which is designed specifically to employ the combined benefits of low-pH operation; formic acid enhancement; single loop, cocurrent/-countercurrent absorption; and in-situ forced oxidation. The unique cocurrent/countercurrent absorber does not include any packing or grid work. This significantly reduces the potential for plugging and erosion and reduces the energy consumption of the induced draft (ID) fans.

This project will demonstrate the following features of the S-H-U FGD process:

- up to 98% SO_2 removal efficiency with limestone,
- low limestone reagent consumption,

- excellent stability and easy operation during load changes and transients,
- low production of scrubber blowdown,
- freedom from scaling and plugging,
- high availability,
- low maintenance,
- production of wallboard-grade gypsum and commercially usable calcium chloride by-products, and
- improved energy efficiency compared with conventional FGD technologies.

This project will provide the first demonstration of the S-H-U process installed directly below the flues. This design approach saves considerable space on site and is advantageous for existing plants, where space for retrofitting an FGD process is at a premium.

The S-H-U FGD process will be installed on both Units 1 and 2 with common auxiliary equipment. A single split absorber will be used. This innovation features an absorber vessel that is divided into two sections to provide a separate absorber module for each unit. This design allows for more flexibility in power plant operations than a single absorber, while saving space and being cheaper than two separate absorbers.

An additional feature to be demonstrated is the use of a tile-lined absorber. The tile lining has superior abrasion and corrosion resistance, when compared with rubber and alloy linings, and is expected to last the life of the plant. In addition, the tile is easily installed at existing sites, where space for construction is at a premium, making it ideal for use in retrofit projects.

Unlike some competing processes that produce gypsum, the S-H-U by-product gypsum will be of excellent and consistent quality, regardless of the plant load level or flue gas sulfur dioxide level. To provide a more marketable product, the gypsum will be agglomerated for easy transportation of the purchaser.

This project will also be the first demonstration of the production and marketing of by-product calcium chloride. The brine concentration system will allow the S-H-U blowdown stream to be purified and recycled to the plant as FGD make-up water. The calcium chloride produced from the brine concentration system will be a commercially marketable product and will be sold as a solution or spray dried and sold as a powder, depending on the needs of the purchaser.

The project is installing combustion modifications on both units for primary NO_X emission control. Combustion modifications are an integral part of the project, since they reduce NO_X levels by about 20%. In addition, the NO_XOUT® technology will be installed on Unit 2 to provide a further reduction in NO_X emissions over that achieved by the combustion modifications alone. The NO_XOUT® process achieves NO_X reduction by the reaction of NO_X with urea injected into the post-combustion zones of the boiler.

The installation of the NO_XOUT® technology will allow this project:

- To demonstrate a NO_X emissions reduction of 30% or more over that achieved with combustion modifications alone.
- To demonstrate cost effectiveness for NO_X reduction.
- To determine the effect of these NO_X reduction technologies on air heater, electrostatic precipitator (ESP), and scrubber operations and on fly ash quality.

Another component of the project is the addition of a high efficiency heat pipe air heater system, along with other equipment modifications, to maintain the station efficiency, while SO_2 and NO_X emissions are significantly reduced. The CAPCIS corrosion monitoring system will be used in conjunction with the high efficiency air heater system to control flue gas discharge temperature and prevent acid corrosion due to condensation.

1.4 SIGNIFICANCE OF THE PROJECT

Public Law 101-549, (The 1990 Clean Air Act Amendment (CAAA) recently passed by Congress) requires existing coal-burning power plants to reduce sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions. Considering the technology options which are commercially available today, it appears that these existing plants will have to rely heavily on wet flue gas desulfurization (FGD) and NO_x mitigation upgrades to reach the levels of sulfur and NO_x required by legislation.

Flue gas desulfurization is a commercialized technology that has been applied to both new and existing coal-fired utility boilers in the United States for the past 15 years. As of February 1989, there were 149 FGD-equipped boilers in commercial service representing 63,289 MW of installed generating capacity. Another 18 FGD-equipped boilers, representing 7,726 MW of capacity, are planned for future service. The majority of these FGD processes were installed in response to the New Source Performance Standards (NSPS) of December 1971 and June 1979 which mandated SO_2 emission limitations of 1.2 lb per million Btu (heat input to the boiler) and a sliding scale of 0.6 to 1.2 lb per million Btu (70 to 90 percent removal), respectively. The remainder of these FGD processes are retrofit applications (38 boilers, amounting to 12,531 MW of capacity) that were installed to meet state or local environmental regulations. As such, the status of FGD technology as applied to the United States utility industry is one directed primarily toward new source applications and FGD retrofit to existing plants in response to the recently passed clean air legislation.

Emissions of nitrogen oxides from coal fired boilers have typically been controlled through combustion modification technology. This technology will not ensure that the mandated reductions are complied with. This is evident in the regulatory exception provided in the CAAA for those units where combustion technology fails to meet the emission limits. While the first phase of the CAAA will allow continuation of this practice, stricter guidelines set forth in 1997 will be required to be based on the best available technology taking in to account the costs and energy and environmental impacts. Therefore, control technologies which can demonstrate compliance with emission goals on a cost effective basis will be commercially desired.

FGD For New Boilers. FGD technology development and application has been largely driven by the new boiler market. Consequently, the typical FGD process design philosophy uses small (up to 150 MWe plant size) absorber towers, a spare absorber tower, and liberal sparing of primary and auxiliary components. Moreover, conventional FGD designs require large amounts of space for waste disposal.

FGD Retrofit To Existing Boilers. Retrofit to an existing plant presents problems that are much more difficult than for new plants. Often, the space available for the FGD system is limited, and accessibility for installing the FGD system, maintaining that equipment, or removing old equipment is difficult. Lack of space to retrofit an FGD system at an existing site leads to concerns that include:

- The placement of a number of small absorber towers plus spares becomes difficult or impossible.
- Sparing of primary and auxiliary components becomes difficult.
- Available space for waste disposal is at a premium.
- Accessibility for operation and maintenance becomes difficult.

The net result is a retrofit FGD process that is more expensive, less reliable, difficult to maintain, and incapable of performance levels associated with a comparable new system. Generally, this situation becomes more acute for older, smaller existing boilers. All other things being equal, older and smaller plants are more difficult to retrofit than newer and larger plants. This situation occurs because in older boilers, space is usually limited in the beginning. It is further complicated by the fact that older plants are generally modified over time to accommodate new technology. For example, many plants have added or replaced their existing particulate control equipment with additional or new electrostatic precipitators. This reduces the area that might normally be used for an FGD retrofit. This situation is especially acute for existing coal-fired utility boilers in the eastern U.S. where the average age of utility boilers is 25 years.

The S-H-U Wet FGD Process

The process for NYSEG's Milliken Station is the Saarberg-Hölter Umwelttechnik GmbH (S-H-U) wet limestone flue gas desulfurization process. The S-H-U process can be implemented as a separate facility, or as an integral part of the stack to conserve site space. Because the S-H-U design consists of a below-stack absorber, this demonstration project would greatly enhance the acceptance of S-H-U technology as a retrofit option to a large number of existing plants with similar space restrictions as Milliken Station. FGD processes, such as S-H-U, which offer below-stack designs will fit at existing sites where another type of FGD system would otherwise have to find expansion room that often is unavailable. Construction costs at constricted sites are higher: there are design compromises and construction is difficult.

Therefore, site-specific retrofit FGD cost is lower for below-stack designs than those designs which do not allow below-stack absorbers.

As a result of the FGD evaluations conducted by NYSEG at Milliken Station, NYSEG found the S-H-U process to be one of the most flexible, reliable, and cost-competitive FGD processes available. Moreover, NYSEG believes that successful demonstration of the innovative design changes summarized below will significantly reduce the cost of the S-H-U process and enhance its attractiveness for retrofit.

S-H-U Low pH and Formic Acid Buffering Advantages. The S-H-U FGD process was developed in Germany, where one of S-H-U's parent companies is a German electric utility. The S-H-U process is unique among wet limestone processes in that it was designed to take advantage of the benefits available from low pH operation by adding small amounts of formic acid to the recycle slurry. The formic acid improves the SO_2 removal efficiency of the wet limestone process, eliminates scaling and plugging, and acts as a buffer to control the pH drop of the recycle slurry. Other suppliers have at times attempted the use of an organic acid to improve the performance of their FGD system processes which did not in some way meet performance requirements. However, no other supplier except S-H-U offers a system designed at the onset to take full advantage of the many inherent benefits of formic acid buffering.. Unless the FGD system is initially designed to use an organic acid, the many benefits of buffering are lost. The system will not be properly configured to take full advantage of low pH absorption unless specifically designed for it.

The formic acid buffering of the S-H-U process offers the following benefits:

a. Control over the pH drop of the recycle slurry, allowing low pH absorption that eliminates the formation of sulfite ions which are responsible for scaling and plugging; this lowers maintenance costs and improves the availability for the FGD system.

b. Increased system stability results due to formic acid buffering which permits substantial changes in SO_2 inlet concentration without affecting either SO_2 emissions or operating pH. Unlike many other competing processes, the S-H-U stability exists regardless of whether the system SO_2 concentration transients are upward or downward. In FIGURE 1.4-1, the impact of inlet SO_2 variation on outlet SO_2 concentration is shown for a conventional limestone scrubber (without formic acid) and for the S-H-U process. With formic acid addition, the SO_2 emissions remain constant while the inlet SO_2 concentration varies by over a factor of two.

c. Enhanced SO_2 removal efficiency, due to formic acid increasing limestone dissolution and reducing the required scrubber liquid-to-gas ratio. This reduces purchased reagent costs, pump size and cost, and pump power requirements.

d. Increased solubility of limestone in the presence of formic acid permits a coarser grind to be used. This reduces the required mill size and cost, and reduces grinding power requirements.

e. Improved oxidation of the recycle slurry directly to gypsum. Because the system operates in the bisulfite pH region, chemical kinetics favor the oxidation to gypsum.

f. Desirable barrel-shaped gypsum crystals are formed while minimizing the production of undesirable fines. (In some competing FGD processes, detrimental fines hamper the gypsum dewatering process, which require the added cost associated with their separation, and the consequent loss of revenue from the lower yield of marketable gypsum product.) In the S-H-U process, all of the gypsum is of high quality. Unlike many of its competitors, the S-H-U gypsum quality and yield is maintained regardless of plant load or flue gas sulfur content.

g. The cocurrent/countercurrent flow of flue gas with respect to the slurry spray permits the unit to operate in the low pH range, eliminating sulfite scale formation and the need to remove it. See FIGURE 1.4-1

h. The S-H-U process is well suited for high-chloride coals because of the buffering effect of the formic acid additive, as shown in FIGURE 1.4-2. The need for a prescrubber is eliminated and FGD blowdown volume can be reduced. The process accepts up to 50,000 ppm chloride in the recycle slurry without a detrimental effect on SO_2 removal performance. Hence, unlike some competitors, the S-H-U technology can be used on high chloride U.S. coals.

In addition to the above inherent process advantages, there is also the following advantage for the below-stack design chosen at Milliken Station:

i. It employs a design that is fully enclosed, which promotes good sound attenuation and noise control on and off the site.

Commercial Gypsum Production. The S-H-U process can produce commercial wallboard grade gypsum, or disposal gypsum suited for landfill. At the Milliken site, commercial grade gypsum will be marketed.

FIGURE 1.4-1

SO_2 ABSORPTION EFFICIENCY WITH/WITHOUT FORMIC ACID ADDITION, UNLIKE MANY COMPETING PROCESSES, THE S-H-U PROCESS IS INHERENTLY STABLE DURING LOAD SWING TRANSIENTS, WIDE CHANGES IN COAL CHLORIDE LEVEL, OR WIDE CHANGES IN SO_2 CONCENTRATION. THIS SIGNIFICANTLY REDUCES MAINTENANCE PROBLEMS.

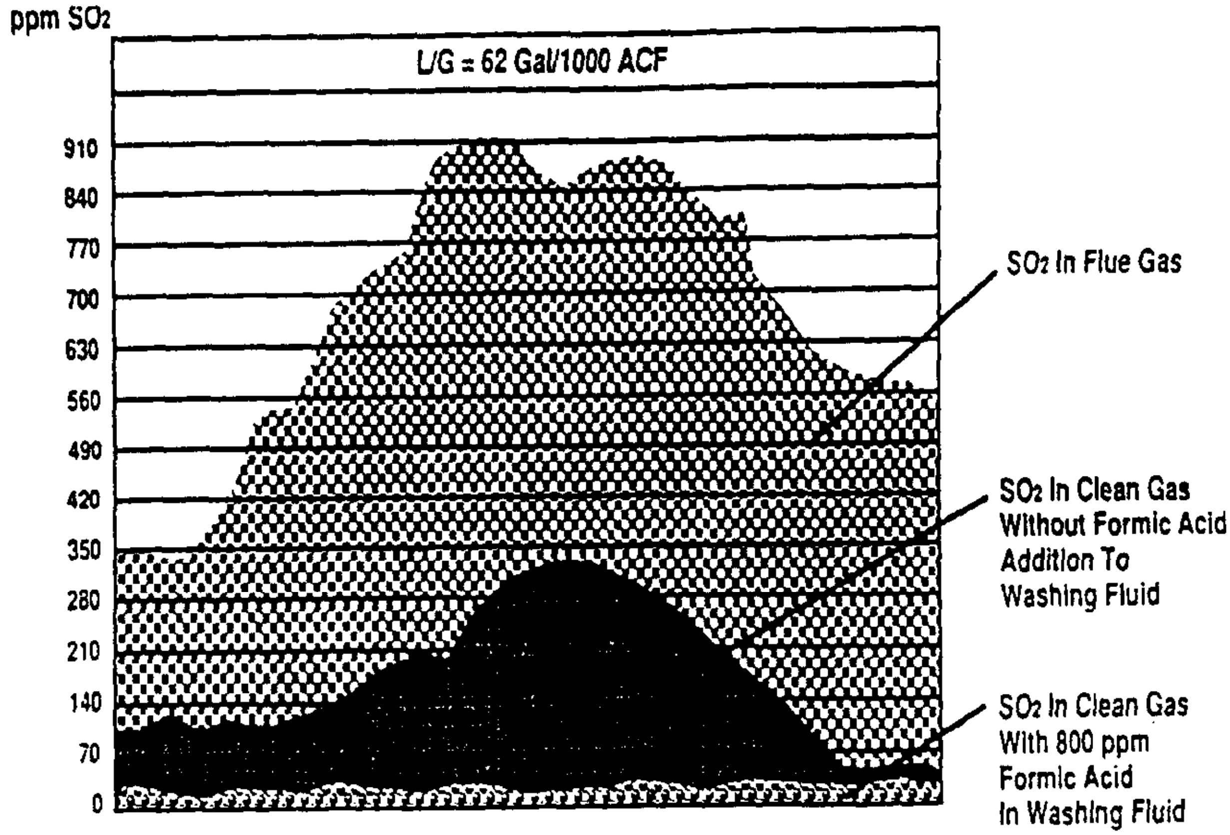
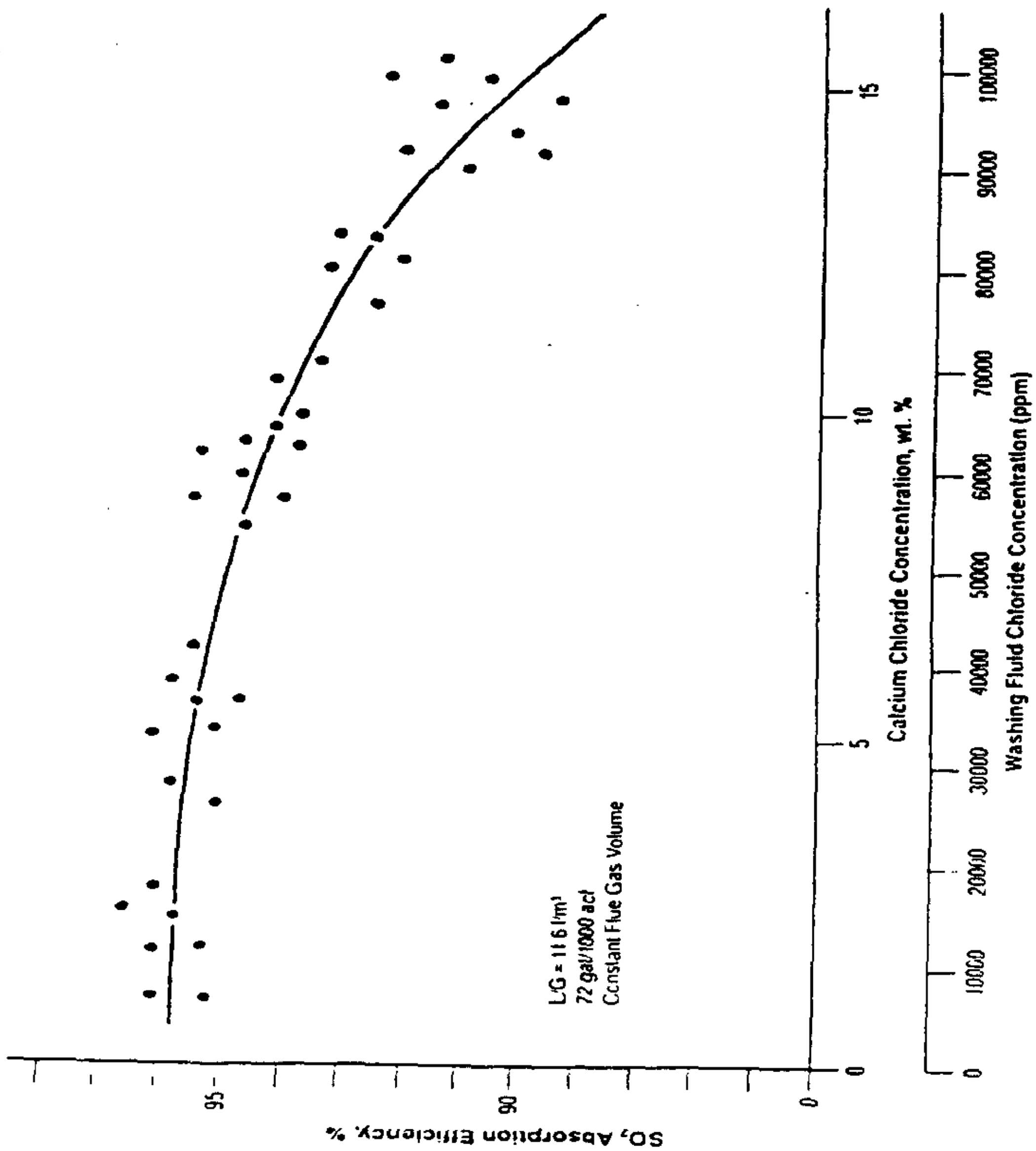


FIGURE 1.4-2

FORMIC ACID BUFFERING DRAMATICALLY REDUCES THE IMPACT OF CHLORIDE ON THE SO_2 ABSORPTION REACTIONS. THIS ALLOWS OPERATION AT HIGHER CONCENTRATIONS, REDUCING WASTE FLOWS.



The Production of Commercial Grade Gypsum. The S-H-U process adds the *additional benefit in that commercial, as opposed to disposable gypsum, can* be produced simply by washing the gypsum for chloride and formic acid removal during dewatering. The waste disposal problem can be significantly reduced since the low pH process produces 100 percent yield of high quality gypsum crystals suitable for the wallboard or cement industries.

S-H-U experience has shown that in flue gas desulfurization, the sulfite phase of the scrubbing process is best avoided in preference to the bisulfite process, in order to achieve high scrubber availability and straightforward gypsum production. As shown in FIGURE 1.4-3, pH determines the sulfur-containing ion formed during the absorption process.

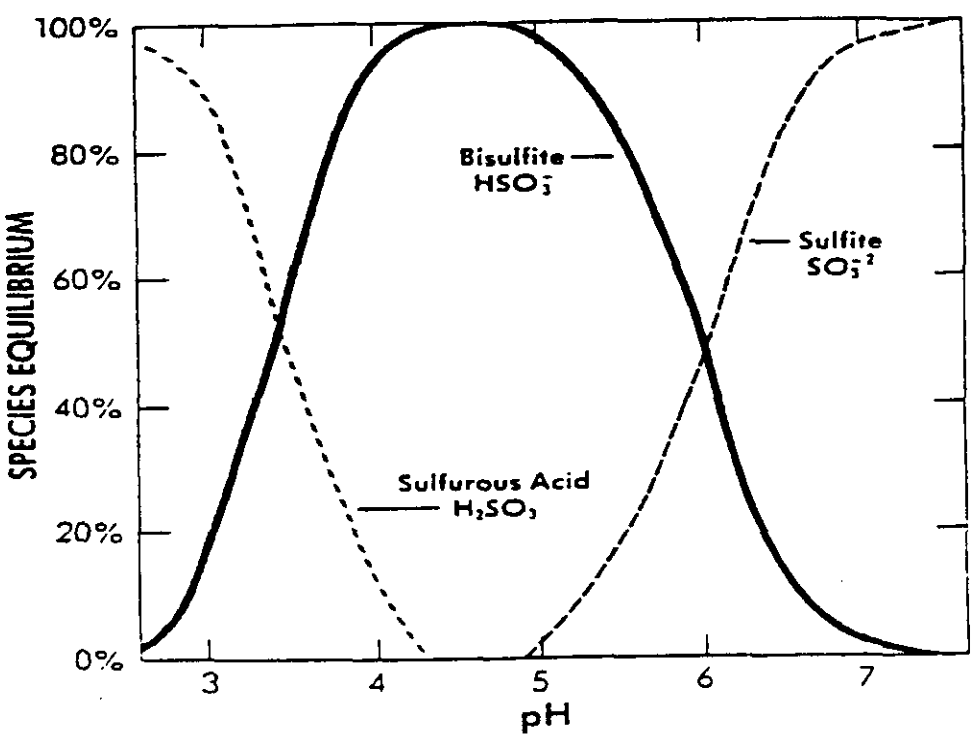
For example, at a pH of 5.5, approximately 20 percent of the SO_2 absorbed is present as sulfite and 80 percent is present as bisulfite. In the pH range between 4.0 and 5.0, the S-H-U operating range, virtually all ions formed are bisulfite. Sulfite ions are not formed in this pH range. Therefore, calcium sulfite production is precluded, and susceptibility to sulfite scaling is eliminated.

In addition, the pH range between 4.0 and 5.0 is ideal for straight-forward oxidation of bisulfite to sulfate. Higher pH processes oxidize a combination of bisulfite and sulfite. Sulfite is more difficult to oxidize, resulting in higher oxidation air requirements and/or sulfite inclusions in the gypsum. Gypsum produced in the S-H-U process is easy to dewater.

Landfilled Gypsum (Not Proposed) Could Have Been Considered Instead. *Some competing processes landfill their solid waste.* The S-H-U process can be compared on an equivalent basis, since it can be configured to produce gypsum intended for landfill disposal. The calcium sulfite waste produced by conventional FGD processes is significantly inferior to the S-H-U landfill grade gypsum. Calcium sulfite waste is mechanically unstable and must either be ponded or mixed with dry fly ash and lime for landfill disposal. If calcium sulfite is ponded, three to five times the land area needed for gypsum disposal is required. For example, during a 30-year life of two 500 MW units firing 2.5 percent sulfur coal, disposal of ponded calcium sulfite would require 400 to 700 acres of land, depending on pond depth. Only 130 acres would be required for gypsum disposal (by stacking). If calcium sulfite were landfilled along with fly ash, space requirements would be greater than those for stacked gypsum. In addition, operation of a stabilized sulfite sludge landfill is more complex and costly than for gypsum stacking. Landfilling calcium sulfite would require thickeners, vacuum filters, dry ash handling equipment, pug mills for sludge/lime/ fly ash mixing to fixate the sludge mixture, truck transportation to the landfill, and placement

FIGURE 1.4-3

THE S-H-U PROCESS OPERATES IN THE pH RANGE THAT PRODUCES ONLY BISULFITE - THE SPECIES THAT AVOIDS SCALING AND OXIDIZES EASILY



and compaction at the landfill site. Fly ash would no longer be available for sale if it were required for mixing with the calcium sulfite material.

Factors Affecting the FGD Market. A key factor in the commercialization of FGD technology is that the market is driven by the rate of growth in the electric power industry and by the demands of the regulatory environment. Passage of the Clean Air Act Amendments by Congress along with recent changes in the NSPS for SO_2 emissions from electric utility and industrial boilers will require nationwide reductions in SO_2 emissions. The SO_2 emissions credit trading feature of the Clean Air Act Amendments places greater emphasis on ultra-high cost effective SO_2 removal capability. The S-H-U process is capable of up to 98 percent SO_2 removal; with this ultra-high SO_2 removal, the S-H-U process possesses a significant selling feature.

The demonstration is compatible with the timing of these regulatory changes. This program will be complete and all its information publicly available by 1999. Information will begin to be available in 1996. The S-H-U process is a highly cost competitive FGD process. After this demonstration project's expected cost savings are proven, the S-H-U process will capture a large share of FGD market due to requirements for retrofit or new plant SO_2 emission controls. Preliminary evaluations by an industry research institute have indicated that S-H-U technology may be the most cost competitive of the FGD processes for achieving high SO_2 removal rates with a limestone-based system.

A New U.S. FGD Vendor will be Established. While Saarberg-Hölter Umwelttechnik GmbH, a German company, owns the S-H-U process license and will supply the basic process engineering, a majority of detailed design services and all equipment will be supplied by U.S. companies. This will aid in the development of the U.S. manufacturing base that will be supplying the process to the U.S. power industry.

Stebbins Tile-Lined Split Module Absorber is also Proposed
The construction of the FGD absorber for Milliken Station is the Stebbins Reinforced Concrete/Ceramic Tile system. The Stebbins construction can be implemented as a separate structure for new or retrofit installations or implemented as here as an below-stack absorber to save space. It can also be implemented as a single module or implemented here as a split module absorber. In addition, the construction can be implemented for virtually any of the currently available wet lime or limestone FGD process designs as well as for the S-H-U process.

Suitability to Construction in a Congested Area. Because the Stebbins Tile, split module absorber design consists of a below-stack absorber this demonstration project will greatly enhance the acceptance of Stebbins technology as a retrofit option to a large number of existing plants with problems similar to that of the Milliken Station: limited site space. Absorber construction systems such as Stebbins Tile which offer below-stack designs will fit at existing sites where another type of construction would otherwise have to find expansion room that is often unavailable. Construction costs at constricted sites are higher and therefore there are design compromises and construction is difficult. Site-specific retrofit FGD cost is lower for below-stack designs than for those designs which do not allow below-stack absorbers. The constricted site advantages of Stebbins Tile construction are not limited to below-stack designs. Limited construction access is necessary to implement the reinforced concrete/tile lined system. This asset enables a utility company to retrofit a Stebbins Absorber between existing structures without having to provide space for cranes to lift large sections of steel or alloy absorber shell.

Superior Corrosion and Abrasion Resistance. Demonstration of the Stebbins Tile construction in conjunction with the S-H-U FGD process design further enhances the acceptance of Stebbins technology as a retrofit option and as a new plant option. The S-H-U process operates at lower pH and at higher chloride concentrations than other wet lime/limestone processes, and presents a potential more corrosive environment in the absorber. Additionally, the S-H-U process with its cocurrent/countercurrent design required an interior wall with both sides exposed to the process. Successful demonstration of the Stebbins tile system in this application will enhance its acceptance as a construction option.

On Line Repairs. Conventional lined carbon steel and alloy absorber constructions require that the absorber module be shutdown in order to repair leaks in the absorber walls. A valuable asset of the Stebbins Tile construction is that leaks in exterior walls can be repaired from outside the absorber vessel, with the absorber in operation. This advantage of the Stebbins Tile system further enhances absorber availability and further reduces the need for a spare absorber module, saving plot space and capitol cost, important considerations for a utility company selecting an absorber construction.

Ability to Withstand Higher Temperature or Temperature Excursions. A significant detriment to the availability of conventional absorber designs is their susceptibility to damage when exposed to high temperature flue gas. Such exposure can occur due to an air preheater failure or due to a power outage that interrupts the absorber quench and recycle sprays. The Stebbins Tile construction is able to withstand these upset conditions without damage to the tile lining, obviating the need for extensive relining outages, thereby enhancing absorber availability. This enhanced availability further reduces the need for a spare absorber module, presenting utility companies with significant plot space and cost savings.

Heat Pipe Air Heater System
Since FGD retrofits consume auxiliary power, capacity is lost during retrofit. In this project, a major upgrade, the retrofit of a heat pipe air heater and other performance enhancing changes will also be demonstrated that will restore much of the lost power and improve overall performance. As discussed earlier, the S-H-U process also has a number of features that help conserve energy, in addition to the energy saved by the heat pipe air heater. With improved energy conservation, fewer tons of coal need to be burned to produce the electric power demanded. This reduces the input pollutants in need of control, and also reduces the amount of CO_2 gas that is produced.

The direct benefit is a reduction in air leakage across the air heater from 16% of the entering air to zero. This represents a horsepower savings of 452 BHP (based on Milliken Station flow rates for one unit) as well as a thermal efficiency improvement of approximately 0.5% due to a 20°F (approximately) lower uncorrected gas exit temperature. With the integration of an advanced technology corrosion monitoring system (CAPCIS), the flue gas exit temperature may be further reduced to 25°F (from 280°F to 255°F) which will result in an overall boiler efficiency improvement of approximately 0.6%.

$NO_xOUT^{®}$ Injection (SNCR) The Milliken project will include the demonstration of the Nalco Fuel Tech $NO_xOUT^{®}$ technology as a control for NO_x emissions on Unit 2. The system is a selective non-catalytic reduction (SNCR) process which utilizes urea injection in the furnace to reduce NO_x. NYSEG believes this technology, used by itself or in combination with combustion modification technologies, will provide an increase in the overall reduction of NO_x.

Improved NO_x Reduction Advantage. Since the injection of the $NO_xOUT^{®}$ solution does not impact the combustion process, the $NO_xOUT^{®}$ system can be applied in conjunction with all combustion modification technologies to improve reductions in NO_x. $NO_xOUT^{®}$ used in this fashion is expected to reduce NO_x by up to 30%. This further reduction is important in that combustion modifications are not expected to be able to reduce NO_x emissions to the 0.45 lb/MM Btu level in all applications. Also, local or regional regulators may require stricter emission limits than the CAAA. These lower limits would only be possible through the utilization of combined control technologies such as is feasible with the $NO_xOUT^{®}$ system.

Low Capital Cost Requirements. The $NO_xOUT^{®}$ system is a low capital cost NO_x reduction method. The only capital equipment included in this process is a pumping skid, urea storage tank, injection piping and nozzles, and control systems. These costs provide substantial advantage over the cost of selective catalytic reduction technology which can be an order of magnitude higher.

Enhanced Temperature Characteristics. The NO_xOUT^{*} enhanced urea solution provides enhanced temperature characteristics as compared to urea alone. Addition of proprietary chemical enhancers to the solution has succeeded in broadening and/or shifting the optimum temperature at which the solution is effective. This has allowed increased reductions of NO_x through staging of the chemical injection at different levels in the boiler. Also since the location becomes somewhat less critical it is expected that no additional injection points would be required on a boiler besides the original inspection ports.

Low Ammonia Slip. The chemical enhancers included in the NO_xOUT^{*} urea solution also allows ammonia slip to be maintained below 2 ppm. Typically, a simple urea injection will have significant levels of ammonia being formed as a side reaction to the NO_x reaction. The ammonia can result in increased air heater plugging or can collect on the fly ash collected in the ESP and prevent the commercial sale of the fly ash. By maintaining the ammonia slip to such a low concentration these problems are avoided.

Commercialization Aspects. Nalco Fuel Tech believes that this project will provide key impetus for the further commercialization and acceptance of the NO_xOUT^{*} system. This belief is supported by several key criteria which will be demonstrated by this project. These criteria are:

- **U.S. Utility Application**: The demonstration of the technology on a U.S. utility will provide the credibility required to establish a technology as a commercially viable option in this market. The U.S. utility market is close knit in which successful application of a product in the market is highly regarded. Utilities use different sources of information from research organizations such as EPRI or computer information exchanges to research previous utility applications of a technology prior to acceptance of that technology. A successful demonstration project at Milliken Station will provide the base required to become accepted in this market.

- **Compliance with Emission Goals**: The project will demonstrate the economical reduction of NO_x to below the 0.45 lb/MM Btu limit prior to the 1997 deadline for the establishment of new regulatory limits on NO_x emissions. Since this new limit will be based on the best available technology with consideration for costs and energy and environmental impacts, this demonstration will provide the baseline by which this technology can be compared.

- **High Sulfur Application**: Demonstration of this technology on high sulfur coal is provided by this project. While this technology has been demonstrated on low sulfur coal (0.5%) at the Kerr Mcgee Argus plant beginning in June 1989, the demonstration of this technology on a high sulfur application, as provided by this project, is critical to wide spread commercialization of the $NO_xOUT^{®}$ process.

1.4.1 Commercialization Timetable and Milestone Chart

Commercialization Of The S-H-U Advanced Technology
The individual equipment components will be available from U.S. manufacturers at the scale required to be used in the proposed project. This condition has the effect of reducing the steps necessary in commercializing the technology.

Based on this, the steps required for the commercialization of the S-H-U process in the U.S. are:

a. Demonstration at a scale large enough to establish user confidence in a U. S. utility environment.

b. Prototype testing at a large (300 MW) operating utility power plant.

c. Establishing U.S. utility confidence in the technical and economic worth of the approach.

All of the above will be demonstrated by the project. Following that demonstration, the final step becomes possible.

d. Widespread commercial application.

Several critical factors normally affecting commercialization of a particular product or process are not applicable to the proposed project. For example, financing to develop the equipment and manufacturing of the equipment need not be addressed, since the process engineering and major equipment have been previously developed.

Commercialization will be initiated during the demonstration and will be ongoing throughout the project. In 1999 it will be fully implemented.

The Stebbins Experience Base Means Faster Commercialization Of The Ceramic Tile Absorber Construction. The approach to commercialization of the Stebbins Tile Absorber Construction requires a different path to commercialization than normally associated with a new product, as outlined above. As a result, the difficulties and schedule to commercialize are greatly reduced.

Early commercial introduction in the U.S. FGD absorber market is possible because the Stebbins Semplate Tile Reinforced Concrete construction system has fully proven itself in similar applications in the pulp and paper, chemical and mining industries; because this construction system is familiar to the utility industry through its use in auxiliary scrubber related power plant tankage; and because the tile and grout portion of the Stebbins system has proven its corrosion/abrasion resistance as a replacement for failed liners in several FGD absorber and flue gas duct applications. Additionally, this technology has been used in conjunction with the M. W. Kellogg Horizontal Weir Absorber process design since 1982 at the Big Rivers Electric D. B. Wilson station.

Based on this, the steps required for the commercialization of the Stebbins Semplate Tile Reinforced Concrete Absorber Construction in the U.S. are:

a. Demonstration at a scale large enough to establish user confidence in the available savings in plot space, construction access and construction costs.

b. Prototype testing at a large (300 MW) operating utility power plant.

c. Establishing U.S. utility confidence in the technical and economic worth of the approach.

All of the above will be demonstrated by the proposed project. After that demonstration, the final step becomes possible:

d. Widespread commercial application.

Several critical factors normally affecting commercialization of a particular product or process are not applicable to the proposed project. For example, financing to develop the technology and manufacturing of the technology need not be addressed, since the process engineering and major components and construction methods have been previously developed.

On an annual basis Stebbins Engineering and Manufacturing Company constructs approximately 10-15 large ($2-$10 per million) installations utilizing the proposed construction methods and materials of construction. When considering all projects and specifications, they completed nearly 1,300 projects in 1990 alone.

Stebbins Has An Extensive Field Crew Of Qualified Masons. Stebbins is the only North American corrosion resistant lining company with a field crew of brick masons of over 140. In addition to being capable of installing Stebbins' brick/tile lining systems, the majority of Stebbins' field crew are capable superintendents. As a superintendent, they are responsible for managing the entire labor force for a project.

Furthermore, due to its affiliation with the International Mason Contractor's Association, Stebbins has available from local union halls throughout North

America approximately three times the number of brick masons shown above, all of which are of "Stebbins qualified." To ensure quality, however, it is required that masons hired from union halls must work with a Stebbins supervisory mason.

Stebbins Has Proven Project Management Capability. For projects in the northeastern United States, Stebbins' project management personnel are supplied out of their corporate headquarters in Watertown, New York.

Stebbins and subsidiaries have, in North America, several projects in the million dollar plus range at any given time.

Furthermore, Stebbins recently completed two Gold Pressure Leach Autoclave Projects in Nevada which entailed the design, supply and installation of complex lining systems, steel vessels and titanium internals in nine (9) Autoclave Vessels (12' Ø x 90' OAL) and 32 associated vessels. As is typical with all of Stebbins' lining projects they utilized their own field crew of brick masons to complete this project. The total value of these projects was over $25 million.

Stebbins Lining Experience Dates from 1884. Stebbins' lining experience dates back to 1884 with the complete design and installation of Pulp and Paper Mills. Their corrosion resistant lining experience and capabilities have grown considerably over the 107 years of their existence due to diversification from the Pulp and Paper Industry into the Mining, Chemical and Power Industries.

Among their client list in the Chemical and Mining Industry are such major companies as INCO, American Barrick, DuPont, Oxychem and Kerr McGee. The continual growth of their client list has been due to their premium quality lining installations, superior service capabilities, and their excellent reputation for standing behind the work they complete.

Quality Control And Technical Services. Stebbins has developed internal systems to maintain a reputation of high quality lining design and installations. Following are several of these key internal systems:

Field Crew Training: In addition to the extensive field experience that Stebbins' brick mason personnel have, Stebbins continually holds training seminars and meetings to review lining installation techniques for existing and new materials.

Job Specifications/Instructions:
For each lining project, Stebbins develops job instructions which specifically outline the installation details of the lining system. Also included with these job instructions are detailed lining drawings which assists the job superintendent in

assuring consistent quality installations.

Research and Development (Tech Services) Services:
Stebbins has a Research and Development Department (Tech Services) which is capable of answering any material or installation technique questions for the field crew. On major lining projects, it is not uncommon for one of Stebbins' technical service personnel to visit the job site several times to support the field crew from a technical standpoint.

Stebbins' Tech Services is continually testing existing materials to confirm their operating limitations. This group also completes ongoing material tests of all of the materials, regardless of source, used in their lining systems to ensure quality control prior to installation.

Stebbins' Tech Services is comprised of three chemical engineers with over 50 years of combined lining design experience with Stebbins, along with a research chemist, and a lab technician. In addition to the responsibilities outlined above for this group, they are also continually developing new materials to replace inferior products or to improve existing materials to replace inferior products or modifications.

In addition, Stebbins' Tech Services personnel are commonly called on by clients to perform annual lining inspections for a nominal fee. This service is an added benefit Stebbins is able to offer its clients.

With over 100 years of experience in corrosion resistant lining, engineering and installation in various industries, Stebbins is a leading company in this field of work. Their full service, turnkey approach to projects has enabled them to satisfy thousands of clients since their beginning in 1884, and has allowed them continual growth over the years.

Commercialization of the Stebbins Semplate Tile Reinforced Concrete Absorber Construction will be initiated during the demonstration and ongoing throughout the project. It will be fully commercialized by 1999.

Commercialization of Heat Pipe Air Heater System
There are three milestones which are essential in the commercialization of the heat pipe air heater system, consisting of the air heater and CAPCIS corrosion monitor controls. These milestones are:

a. Issuance of a purchase order for the air heaters at the Milliken demonstration facility.

b. Completion of demonstration of the success of the air heater technology for the demonstration project.

c. Completion of the development of a strategic marketing plan.

It is expected that the issuance of the purchase order itself will promote acceptance of the technology and therefore spawn commercialization of this technology system.

Demonstration of the technology should be completed within one year of plant startup. The development of the strategic marketing plan would parallel the demonstration of the technology and would be completed within a year after demonstration of the technology.

The infrastructure for commercialization of heat pipe air heaters is already in place for the smaller size units which have been commercialized for other applications of the heat pipe technology. The scaleup to the demonstration facility size is not significantly different (from a manufacturing viewpoint) than the present commercial sizes because of the modular construction concept and similarity of individual parts (e.g., the tube diameter for the smaller scale version is the same as on the larger scale, the tube materials, quantity, lengths and fin design will change instead).

Commercialization Of $NO_xOUT^{\bullet}$ Injection

The commercialization of the Nalco Fuel Tech $NO_xOUT^{\bullet}$ non-selective catalytic reduction technology will proceed quickly based on the successful completion of this project. The demonstration of this technology to successfully achieve emission reductions below 0.45 lb/mmBtu on a high sulfur, pulverized coal utility plant will provide the catalyst for commercialization of this technology. Similar utility plants requiring reductions beyond that provided by combustion modifications alone or those plants that want to avoid the problems of combustion modifications when used alone will utilize the $NO_xOUT^{\bullet}$ technology.

NO_x regulatory requirements to be re-established in 1997, will have an impact on the commercialization of the technology. Establishment of this technology as a low cost impact with minimal energy and environmental concerns should lead to this technology being chosen as the basis for compliance. If so established, this process will be required for many old plants as a retrofit and for new plants.

Commercialization of this technology will also be assisted by Nalco Fuel Tech's strong support in the commercialization of this project. Steps have been taken to already contract U.S. licensees of the project that will be able to provide the $NO_xOUT^{\bullet}$ chemical in the U.S. These licensees are UNOCAL, CARGILL, ARCADIAN, NITROCHEM, and W. H. SHURTLEFF. The availability of these licensees demonstrate the impact that this technology will have on the U.S. chemical industry and the ease at which commercialization will be established.

The only other requirement to complete commercialization of this technology is demonstration of the technology on a cyclone fired unit. This demonstration is required to establish the viability of $NO_xOUT^®$ on this type of boiler. Nalco Fuel Tech is currently under negotiations for a site for such a demonstration. Therefore it is expected that this area of the market will soon be established also.

These factors lead to the conclusion that the Nalco Fuel Tech $NO_xOUT^®$ process will be fully commercialized by the year 1997.

1.4.2 Market Analysis

A large market is expected for the S-H-U FGD process. Initially, this market will be stimulated by electric utility power plants that require FGD retrofit to enable compliance with recently passed Clean Air Act Amendment legislation. Plants will have to respond to this legislation with applications starting in 1995. It is assumed that the retrofits will continue for a finite period, 15 years. As a result of the proposed project, the technology will have been fully commercialized by 1999. As a result, the S-H-U process is expected to be able to penetrate the new United States power plant market by 1996.

It is S-H-U's intent that the Milliken Station, as the first S-H-U plant in the U.S., serve as a "showcase" installation for site visits of potential clients. The high efficiency and flexibility of the process as demonstrated at Milliken should dramatically increase the attractiveness of the technology to U.S. utilities. Data collected during the demonstration will validate the applicability of the technology on a wider range of coals and sulfur levels than already demonstrated in Europe.

The demonstration in conjunction with the other advanced concepts outlined will increase interest in the process above that generated by demonstration of the process by itself. S-H-U experience at the Model Power Station Völklingen with the FGD unit inside the cooling tower along with fluidized bed combustors for coal tailings, has given a tremendous increase in interest in the technology as evidenced by the tens of thousands of visitors to the plant. S-H-U feels that its rise to the second leading supplier of FGD equipment in Germany can be traced in large measure to the successful demonstration at Völklinger.

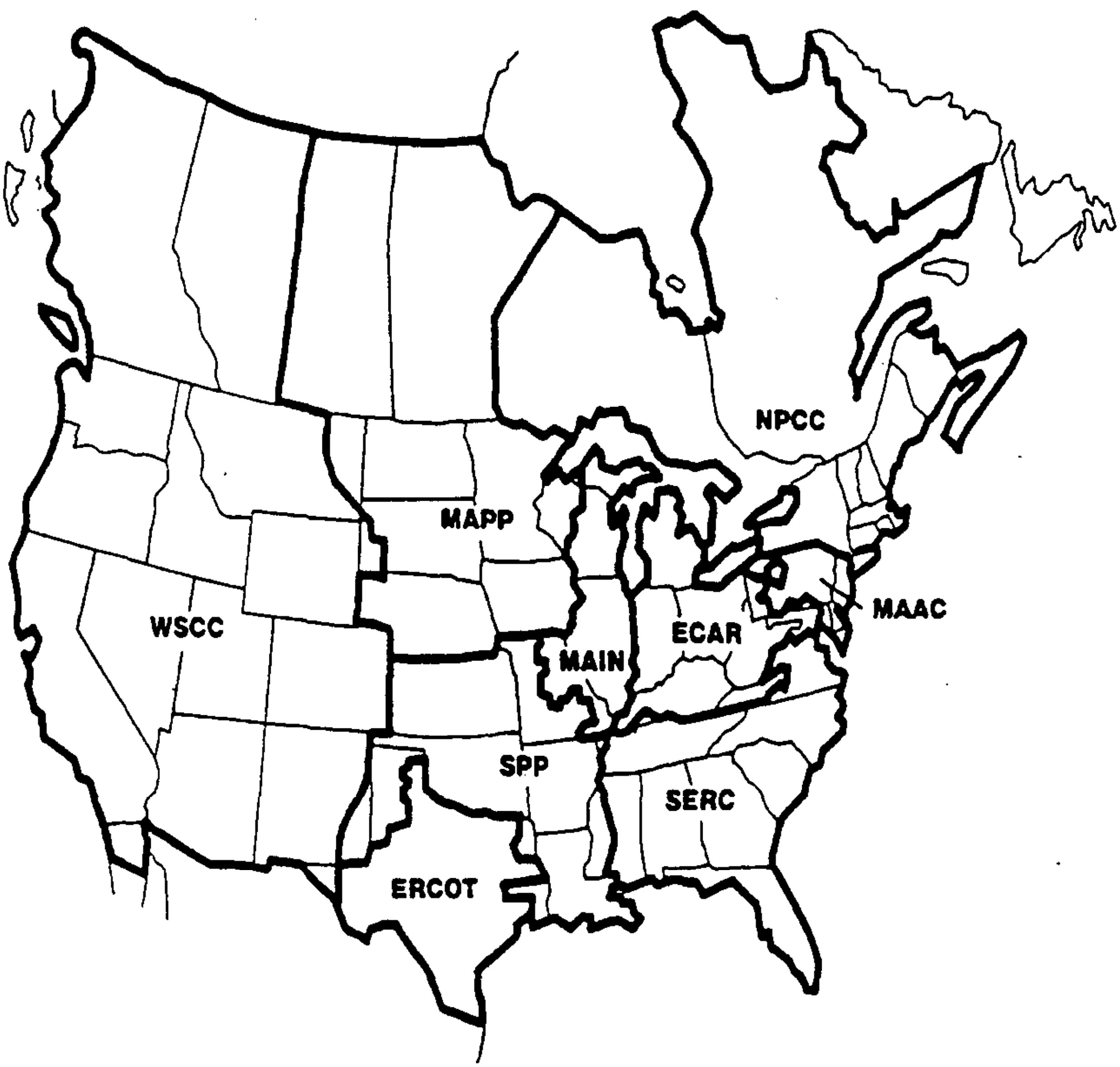
S-H-U expects the same type of response to a successful demonstration at Milliken Station.

The total electric utility market available to the S-H-U process can be divided into two segments - retrofit capacity and new capacity. Although the technology is applicable to industrial boilers, these were not included here. Additionally, over 80 percent of coal production is used to generate electricity. The total market in each segment is limited by technology boundary conditions that are later described.

Some of the market assessment comments made here refer to the markets in various regions of the United States. FIGURE 1.4-4 shows the North American Electric Reliability Council (NERC) regions used here, which are referred to by their respective names in the subsections that follow. For those regions that cross into Canada, only the U.S. portion is included in the market assessments below.

FIGURE 1.4-4

NAMES OF U.S. REGIONS EVALUATED IN THE MARKET ANALYSIS: ONLY THE U.S. PORTIONS OF THE REGIONS ARE USED



Ref: "1989 Electric Supply & Demand for 1989-1998," NERC.

The NERC regions used for the regional discrimination of potential market share that are identified in the remainder of this subsection as indicated in TABLE 1.4-1, which follows:

TABLE 1.4-1
ACRONYMS USED TO IDENTIFY U.S. REGIONS

Acronym	NERC Region Identified For Regional Market Analysis
ECAR	East Central Area Reliability Coordination Agreement
ERCOT	Electric Reliability Council Of Texas
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network
MAPP	U.S. portion of Mid-Continent Area Power Pool
NPCC	U.S. portion of Northeast Power Coordinating Council
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
WSCC	U.S. portion of Western Systems Coordinating Council

Summary Of Results. A summary breakdown of the firm and planned capacity market shares on absolute and relative bases that are expected for the S-H-U process are presented in TABLE 1.4-2 and TABLE 1.4-3. These two tables summarize the results of a sophisticated market assessment that show appreciable success for the S-H-U technology between 1995 and 2030 for those units that have yet to select FGD technology, should the Milliken demonstration prove as successful as projected.

The market share for heat pipe air heaters, Stebbins tile absorber, and NO_xOUT® urea injection was estimated in a similar fashion. This summary is shown in TABLE 1.4-4 and TABLE 1.4-5.

The subsections that follow below detail the basis for these market penetration estimates.

TABLE 1.4-2

MARKET ASSESSMENT SUMMARY: RETROFIT CAPACITY MARKET PENETRATION FOR ADVANCED S-H-U TECHNOLOGY FROM YEAR 1995 THROUGH 2030

	Estimated S-H-U Penetration (MW)	Relative* Penetration (%of Market)
1996-2000	607	2.0%
2001-2005	1188	3.5%
2006-2010	1600	5.9%
2011-2015	1348	9.7%
2016-2020	583	15.6%
2021-2025	186	23.9%
2026-2030	154	34.8%

* Relative to total population

TABLE 1.4-3

MARKET ASSESSMENT SUMMARY: NEW CAPACITY MARKET PENETRATION FOR ADVANCED S-H-U TECHNOLOGY FROM YEAR 1995 THROUGH 2030

	Estimated S-H-U Penetration (MW)	Relative* Penetration (% of Market)
1996-2000	1314	1.9%
2001-2005	3059	3.3%
2006-2010	5824	5.3%
2011-2015	12146	8.5%
2016-2020	21612	13.3%
2021-2025	27323	20.3%
2026-2030	24960	30.0%

TABLE 1.4-4

MARKET ASSESSMENT SUMMARY: RETROFIT CAPACITY MARKET PENETRATION FOR STEBBINS TILE, HEAT PIPE AIR HEATER SYSTEMS, AND NOxOUT® INJECTION AVERAGE - 1991 THROUGH 2030

	Estimated Penetration (MW)	Relative[a] Penetration (% of Market)
Stebbins Tile Absorber	4,235	9.1%
Heat Pipe Air Heater System	4,805	10.2%
NO_xOUT® Injection	4,624	9.8%

[a] Relative to total population

TABLE 1.4-5

MARKET ASSESSMENT SUMMARY: NEW CAPACITY MARKET PENETRATION FOR STEBBINS TILE, HEAT PIPE AIR HEATER SYSTEMS, AND NO_xOUT® INJECTION AVERAGE - 1991 THROUGH 2030

	Estimated Penetration (MW)	Relative[a] Penetration (% of Market)
Stebbins Tile Absorber	72004	9.1%
Heat Pipe Air Heater System	109578	10.2%
NO_xOUT® Injection	105582	9.8%

[a] Relative to total population

1.4.2.1 Technology Boundary Conditions

Technology boundary conditions represent technology applicability factors and features of the boiler population that define the maximum market segment.

<u>S-H-U Technology</u>
For retrofit FGD technology, the total market is limited to all pre-NSPS coal-fired boilers that are presently in commercial service, and are not equipped with SO_2 control (i.e., FGD, physical coal cleaning, atmospheric fluidized-bed combustion repowering, or compliance low-sulfur coal). The comparison of the S-H-U FGD process against advanced technology concepts such as coal gasification, fluidized bed combustion, fuel cells, or other concepts was not addressed due to the multitude of assumptions which would have to be made.

<u>Stebbins Tile</u>
The technology boundary conditions for the use of Stebbins tile in the FGD absorber was assumed to be the same as that for the S-H-U FGD technology.

<u>Heat Pipe Air Heater System</u>
The technology boundary conditions for the heat pipe air heater system is not limited to units which will require SO_2 reduction technologies. Therefore, the potential market is only limited to coal fired units currently in service which will not be retired before 2030.

<u>$NO_xOUT^{®}$ Injection</u>
The technology boundary conditions for the $NO_xOUT^{®}$ injection is larger than that for the S-H-U FGD technology since, in addition to coal fired units, this process can be used with oil and gas fired plants. Therefore, the potential market is only limited to fossil units currently in service which will not be retired before 2030.

1.4.2.2 Total Potential Coal-Fired Market and Geographic Distribution

The projection of the total electric generation requirements anticipated in the U.S. is a necessary prerequisite to identify market potential for clean coal technologies. Further, to allow recognition of regional factors which can influence the potential for market penetration, it is appropriate that perceived requirements for electric capacity be disaggregated to a level that is regionally meaningful.

As discussed above, NERC regions were selected for this analysis, as shown earlier in FIGURE 1.4-4. These regions are referenced in the following paragraphs. NERC is essentially established on the basis of system inter-ties; however, NERC areas generally coincide with other regional characterizations as well. For purposes of this analysis, although several NERC regions extend into Canada, only the U.S. portion of such areas have been included in the data presented.

Adequacy and Regional Characteristics of Present Generating Capability
While presently available generating capability represents, in the composite, a slight margin over uniformly prevailing summer peak demands for electricity, there is some diversity in regional reserve status as evidenced in the TABLE 1.4-6 reflecting actual 1984 data.

There is also a distinctively regional character in the mix of generating facility types available to meet system requirements. The makeup of summer 1984 generating capability for each region is summarized in TABLE 1.4-7.

TABLE 1.4-6
REGIONAL RESERVE GENERATION CAPABILITY STATUS

Actual			Reserve	
NERC Region	Peak Demand, MW	Capability, MW	Margin, MW	% of Peak
ECAR	65,851	90,115	24,264	36.8%
ERCOT	36,851	44,056	7,205	19.6%
MAAC	35,442	46,183	10,741	30.3%
MAIN	35,186	41,608	6,422	18.3%
MAPP	20,666	28,161	7,495	36.3%
NPCC	38,144	51,312	13,168	34.5%
SERC	93,400	127,562	34,162	36.6%
SPP	45,562	60,389	14,827	32.5%
WSCC	80,048	114,854	34,806	43.5%
TOTAL	451,150	604,240	153,090	33.9%

TABLE 1.4-7

SUMMER GENERATING CAPABILITY

Region of the United States (see FIGURE 1.4-4)										
Peak	ECAR	ERCOT	MAAC	MAIN	U.S. Portion MAPP	U.S. Portion NPCC	SERC	SPP	U.S. Portion WSCC	U.S. TOTAL
Nuclear	4,593	0	8,367	7,318	3,708	7,940	28,714	1,694	4,741	62,075
Hydro & P.S.	3,377	236	2,134	871	3,062	7,937	13,841	2,650	49,540	83,646
Coal	76,545	11,121	12,695	27,007	17,999	6,291	62,459	22,746	25,423	262,286
Oil/Gas										
SteamTurbines	2,299	30,889	14,973	3,887	417	23,831	12,160	29,520	25,100	146,076
Other	3,301	1,810	8,014	2,525	2,975	5,313	10,388	3,777	10,050	48,153
Total	90,115	44,056	46,183	41,606	28,161	51,312	127,562	60,389	114,854	604,240

Collectively, coal, oil, and gas fired steam turbine plants represent almost 70 percent of summer capability, despite the emergence of nuclear power. Coal plants, while accounting for better than 43 percent of the capability on a national scale, vary from approximately 12 percent of installed capability in the northeast (NPCC) to 85 percent in the east central area (ECAR).

Additional Generating Capacity Under Construction or Committed
Over the ten year period from 1985 to 1994, NERC statistics indicate that plants either presently under construction or under advanced stages of planning represent an increase (net of planned additions less projected plant retirements) of 107.4 GW, consisting of the components by estimated year in service shown in TABLE 1.4-8.

On the basis of this data, it may be seen that coal-fired capacity is anticipated to maintain its relative position to the projected generation mix through 1994. As indicated in TABLE 1.4-9, the same circumstance essentially applies on a regional basis.

It is obvious that among the most critical of these projections would be a regional forecast of coincident peak demands. Since, with two exceptions, actual 1984 peak demands occurred in the summer months, projections by regions, peak summer demands and available summer capabilities are uniformly applied to measure future adequacy. As indicated in TABLE 1.4-10, recognition of regional economic and other factors results in a different growth projection for individual regions.

Projected Reserve Margins to 1994
In their Electric Power Supply and Demand report, NERC summarizes forecasts developed by individual utility members of the regional Reliability Councils.

Correlation of projected peak demands with existing and planned system capabilities permits development of reserve margins and measurements of relative status as reflected for each region in TABLE 1.4-11.

TABLE 1.4-8

CAPACITY COMMITTED OR UNDER CONSTRUCTION

	Nuclear	Hydro & P.S.	Steam Turbines Coal	Steam Turbines Other	All Other	Total
1985	9,213	(3,727)	9,145	(2,498)	414	12,547
1986	13,653	1,454	6,379	(1,374)	1,824	21,936
1987	11,978	235	4,492	(1,782)	1,071	15,994
1988	5,045	1,897	2,094	(769)	1,108	9,375
1989	2,738	562	4,529	(1,475)	1,742	8,096
1990	950	567	1,108	(943)	2,113	3,795
1991	3,392	1,615	5,692	(973)	1,302	11,028
1992	1,365	777	4,050	(1,711)	2,268	6,749
1993	0	1,045	6,766	350	2,375	10,536
1994	1,250	36	5,070	(780)	1,763	7,339
Total	**49,584**	**4,461**	**49,325**	**(11,955)**	**15,980**	**107,395**
Percent	**46.2**	**4.2**	**45.9**	**(11.1)**	**14.9**	
1994 Capability	**111,659**	**88,109**	**311,613**	**136,121**	**64,133**	**711,645**
Percent	**15.7**	**12.4**	**43.8**	**19.1**	**9.0**	

TABLE 1.4-9

PROJECTED TOTAL AND COAL-FIRED CAPABILITY, AND COAL-FIRED AS PERCENT OF TOTAL

Year	ECAR	ERCOT	MAAC	MAIN	U.S. Portion MAPP	U.S. Portion NPCC	SERC	SPP	U.S. Portion WSCC	U.S. TOTAL
TOTAL SUMMER CAPABILITY-GW										
ACTUAL 1984	90.1	44.1	46.2	41.6	28.2	51.3	127.6	60.4	114.9	604.2
PROJECTED 1985	93.1	44.4	46.3	45.7	28.6	51.1	130.1	64.9	112.7	616.8
1986	97.7	46.8	47.5	45.7	29.1	53.1	133.3	66.8	118.9	638.7
1987	97.8	50.5	48.5	48.8	29.1	55.1	136.9	66.5	121.5	654.7
1988	98.9	51.8	48.5	49.9	29.8	55.0	139.6	66.6	124.0	664.1
1989	100.0	53.3	48.2	50.0	29.8	54.9	144.2	66.4	125.5	672.2
1990	101.0	54.9	48.2	50.0	29.9	54.9	144.3	66.7	126.1	676.0
1991	101.1	56.6	49.1	50.0	29.7	55.3	148.4	68.7	128.0	687.0
1992	102.6	58.2	49.6	49.9	29.8	55.2	149.1	69.2	130.2	693.8
1993	103.9	60.6	50.2	49.9	29.7	56.1	151.8	71.1	131.1	704.3
1994	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
COAL-FIRED CAPABILITY-GW										
ACTUAL 1984	76.5	11.1	12.7	27.0	18.0	6.3	62.5	22.7	25.4	262.3
										0.0
PROJECTED 1985	78.5	11.2	12.7	27.8	18.5	6.6	65.2	24.5	26.5	271.4
1986	80.4	11.9	12.7	27.8	19.0	6.7	65.3	25.7	28.5	277.8
1987	80.5	13.1	12.7	27.8	19.2	7.3	66.9	25.6	29.3	282.3
1988	80.4	13.6	12.7	27.8	20.0	7.8	67.3	25.6	29.2	284.4
1989	82.2	13.6	12.7	27.8	20.0	8.2	69.3	25.6	29.5	288.9
1990	82.2	14.2	12.7	27.8	20.0	8.2	69.2	26.1	29.6	290.0
1991	82.2	16.0	12.7	27.8	20.0	8.2	70.6	26.9	31.3	295.7
1992	83.6	17.3	13.4	27.7	20.0	8.1	70.6	27.1	32.1	299.8
1993	84.4	18.8	14.0	27.7	19.9	8.1	70.5	28.9	32.3	304.5
1994	85.0	20.1	14.0	27.7	20.3	8.2	73.2	30.4	32.8	311.6
COAL-FIRED CAPABILITY AS % OF TOTAL										
ACTUAL 1984	84.9%	25.2%	27.5%	64.9%	63.9%	12.3%	49.0%	37.7%	22.1%	43.4%
PROJECTED 1985	84.3%	25.1%	27.4%	60.9%	64.6%	12.9%	50.1%	37.8%	23.5%	44.0%
1986	82.3%	25.4%	26.8%	60.8%	65.3%	12.6%	49.0%	38.4%	23.9%	43.5%
1987	82.3%	25.9%	26.2%	56.9%	65.9%	13.3%	48.9%	38.5%	24.1%	43.1%
1988	81.3%	26.2%	26.2%	55.6%	67.2%	14.2%	48.2%	38.4%	23.5%	42.8%
1989	82.2%	25.5%	26.4%	55.6%	67.2%	14.9%	48.1%	38.6%	23.5%	43.0%
1990	81.4%	25.9%	26.4%	55.6%	67.0%	14.9%	47.9%	39.2%	23.5%	42.9%
1991	81.4%	28.2%	25.9%	55.6%	67.2%	14.8%	47.5%	39.2%	24.5%	43.0%
1992	81.4%	29.8%	26.9%	55.5%	67.3%	14.7%	47.3%	39.1%	24.6%	43.2%
1993	81.2%	31.0%	27.8%	55.5%	67.2%	14.5%	46.5%	40.6%	24.6%	43.2%
1994	81.2%	32.1%	27.9%	55.5%	67.6%	14.6%	47.9%	41.9%	24.6%	43.8%

TABLE 1.4-10

REGIONAL LOAD GROWTH

NERC Region	Summer Peak Demand, GW 1984	1989	1994	Compound Growth Rate 1984-89	1989-94	1984-94
ECAR	65.9	74.2	81.2	2.4%	1.8%	2.1%
ERCOT	39.6	43.9	52.5	3.5	3.6	3.6
MAAC	35.4	37.2	39.3	1.0	1.1	1.1
MAIN	35.2	37.4	40.5	1.2	1.6	1.4
MAPP	20.7	24.0	26.5	3.0	2.0	2.5
NPCC	38.1	41.9	45.5	1.9	1.7	1.8
SERC	93.4	108.0	121.9	2.9	2.5	2.7
SPP	45.6	52.4	59.4	2.8	2.5	2.7
WSCC	80.0	89.6	100.1	2.3	2.2	2.3
Total	**451.7**	**508.5**	**566.8**	**2.4**	**2.2**	**2.3**

TABLE 1.4-11

PROJECTED PEAK DEMANDS, GENERATING CAPABILITY, AND RESERVE MARGINS

Year	ECAR	ERCOT	MAAC	MAIN	U.S. Portion MAPP	U.S. Portion NPCC	SERC	SPP	U.S. Portion WSCC	U.S. TOTAL
SUMMER PEAK DEMANDS-GW										
1988	72.5	42.3	36.7	36.8	23.4	41.3	105.3	51.0	87.6	497.2
1989	74.1	43.9	37.1	37.3	23.9	41.9	108.0	52.4	89.5	508.5
1990	75.5	45.4	37.5	37.9	24.5	42.5	110.8	53.7	91.6	519.8
1991	76.9	46.9	37.9	38.6	24.9	43.3	113.4	55.2	93.5	530.9
1992	78.3	48.6	38.3	39.2	25.4	44.1	116.1	56.6	95.7	542.5
1993	79.7	50.6	38.8	39.8	25.9	44.6	119.0	57.9	97.8	554.4
1994	81.1	52.4	39.3	40.4	26.5	45.5	121.8	59.3	100.1	566.8
EXISTING & PLANNED SUMMER CAPABILITY-GW										
1988	98.8	51.7	48.4	49.9	29.8	54.9	139.6	66.6	123.9	664.0
1989	100.0	53.2	48.2	49.9	29.8	54.9	144.1	66.3	125.4	672.1
1990	100.9	54.8	48.2	49.9	29.8	54.9	144.3	66.7	126.1	675.9
1991	101.0	56.6	49.0	49.9	29.7	55.3	148.4	68.7	128.0	687.0
1992	102.5	58.2	49.5	49.8	29.7	55.2	149.1	69.2	130.1	693.7
1993	103.8	60.5	50.2	49.8	29.6	56.0	151.8	71.0	131.0	704.2
1994	104.6	62.4	50.0	49.8	30.0	55.9	152.7	72.3	133.4	711.6
RESERVE MARGIN AS A PERCENT OF PEAK DEMAND										
1988	36.3%	22.2%	31.8%	35.7%	27.4%	33.0%	32.5%	30.6%	41.4%	33.5%
1989	34.8%	21.3%	29.8%	33.6%	24.4%	31.1%	33.4%	26.6%	40.1%	32.2%
1990	33.7%	20.8%	28.4%	31.6%	21.8%	29.2%	30.2%	24.0%	37.6%	30.0%
1991	31.4%	20.5%	29.4%	29.5%	19.2%	27.7%	30.9%	24.3%	36.9%	29.4%
1992	31.0%	19.7%	29.3%	27.1%	17.0%	25.1%	28.4%	22.3%	36.0%	27.9%
1993	30.3%	19.7%	29.4%	25.2%	14.1%	25.5%	27.6%	22.7%	33.9%	27.0%
1994	29.0%	19.1%	27.3%	23.1%	13.3%	22.9%	25.3%	21.9%	33.2%	25.5%

As can be seen, with the exception of ERCOT (Texas) and MAIN (mid-America) where the 1984 reserve margin was the lowest, the combination of existing capacity, planned capacity, and capacity under construction results in a uniform deterioration of reserve margins. While in some cases initial reserve margins may be considered overly adequate, the assumption of a 20 percent reserve criteria would indicate, notably in the MAPP region (mid-continent), a necessity for additional capacity as soon as the early to mid 1990's.

Extrapolation of NERC Data to Year 2030

Since the investigation of the potential market penetration is to extend over the period through 2030, and the S-H-U process would not be considered commercial in the U.S. until the end of the proposed project, data previously referenced from source documents has been extrapolated to provide a basis for determining total potential generation capacity requirements through that date.

The extrapolation was accomplished in three phases:

1. Examining correlation of total NERC projected regional energy requirements and peak demands through 1994.

2. Extrapolating energy requirements through 2030.

3. Projecting peak demands on the basis of the correlations previously established.

This process is detailed in TABLEs 1.4-12, 1.4-13, and 1.4-14 respectively.

While projections of total national energy requirements through 2030 were already directly available from material contained in Appendix L of the PON, the express purpose of this rather limited analysis was to permit identification of future requirements on a regional basis.

Preliminary Determination of Total Capacity Requirements

Accepting as a criterion the maintenance of a minimum reserve capacity of 20 percent of annual peak demand, a determination of gross capacity requirements may be derived from the projected relationships established above. However, to do this on a national basis would be misleading

TABLE 1.4-12

RATIO OF PEAK DEMANDS TO ANNUAL ELECTRIC REQUIREMENTS

Year	ECAR	ERCOT	MAAC	MAIN	U.S. Portion MAPP	U.S. Portion NPCC	SERC	SPP	U.S. Portion WSCC	U.S. TOTAL
SUMMER PEAK DEMANDS - GW										
1984	65.8	36.8	35.4	35.1	20.6	38.1	93.4	45.5	80.0	451.1
1985	68.2	38.4	35.6	35.1	21.8	39.6	97.3	47.5	81.3	465.1
1986	69.5	39.6	36.0	35.6	22.3	40.3	100.0	48.5	83.1	475.4
1987	70.8	40.8	36.3	36.2	22.8	40.6	101.9	49.6	85.8	485.2
1988	72.5	42.3	36.7	36.8	23.4	41.3	105.3	51.0	87.6	497.2
1989	74.1	43.9	37.1	37.3	23.9	41.9	108.0	52.4	89.5	508.5
1990	75.5	45.4	37.5	37.9	24.5	42.5	110.8	53.7	91.6	519.8
1991	76.9	46.9	37.9	38.6	24.9	43.3	113.4	55.2	93.5	530.9
1992	78.3	48.6	38.3	39.2	25.4	44.1	116.1	56.6	95.7	542.5
1993	79.7	50.6	38.8	39.8	25.9	44.6	119.0	57.9	97.8	554.4
1994	81.1	52.4	39.3	40.4	26.5	45.5	121.8	59.3	100.1	566.8
AVERAGE ANNUAL DEMANDS - GW										
1984	43.7	21.2	21.2	19.5	12.0	24.8	57.4	25.8	53.5	279.1
1985	44.5	22.1	21.5	19.9	12.5	25.2	59.0	26.0	54.4	285.1
1986	45.4	22.8	21.9	20.3	12.8	25.7	60.6	26.6	56.0	292.1
1987	46.3	23.3	22.0	20.7	13.1	26.0	62.1	27.2	57.6	298.3
1988	47.6	24.2	22.4	21.1	13.4	26.4	64.4	28.0	58.9	306.4
1989	48.6	25.2	22.9	21.5	13.8	26.7	66.1	28.8	60.2	313.8
1990	49.5	26.2	23.3	21.9	14.1	27.1	68.1	29.6	61.6	321.4
1991	50.4	27.2	23.8	22.3	14.5	27.6	69.7	30.4	62.9	328.8
1992	51.3	28.2	24.2	22.7	14.8	28.2	71.4	31.3	64.4	336.5
1993	52.2	29.3	24.6	23.2	15.2	28.6	73.0	32.1	65.7	343.9
1994	53.1	30.4	25.1	23.6	15.5	29.2	74.7	32.9	67.1	351.6
RATIO OF PEAK DEMANDS TO AVERAGE DEMANDS, PERCENT										
1984	150.7%	173.8%	167.2%	180.4%	172.2%	153.8%	162.7%	176.6%	149.6%	161.6%
1985	153.3%	174.0%	165.6%	176.7%	174.5%	157.3%	164.9%	182.7%	149.6%	163.1%
1986	153.3%	174.0%	164.6%	175.7%	175.0%	156.9%	165.2%	182.6%	148.5%	162.8%
1987	153.0%	175.1%	165.2%	174.9%	174.6%	156.5%	164.1%	182.7%	149.0%	162.7%
1988	152.5%	175.1%	164.2%	174.4%	174.7%	156.6%	163.6%	182.2%	148.8%	162.3%
1989	152.7%	174.3%	162.2%	173.9%	173.7%	157.0%	163.5%	182.0%	148.8%	162.1%
1990	152.5%	173.5%	161.1%	173.4%	174.0%	156.9%	162.7%	181.7%	148.8%	161.7%
1991	152.6%	172.7%	159.3%	173.1%	172.1%	157.0%	162.7%	181.9%	148.7%	161.5%
1992	152.6%	172.6%	158.4%	172.8%	172.0%	156.5%	162.6%	180.9%	148.7%	161.2%
1993	152.7%	172.7%	157.7%	171.8%	170.9%	156.2%	163.1%	180.6%	149.0%	161.2%
1994	152.9%	172.4%	156.6%	171.6%	171.2%	155.9%	163.2%	180.4%	149.2%	161.2%

TABLE 1.4-13

PROJECTION OF ANNUAL ELECTRIC ENERGY REQUIREMENTS TO YEAR 2030

Year	ECAR	ERCOT	MAAC	MAIN	U.S. Portion MAPP	U.S. Portion NPCC	SERC	SPP	U.S. Portion WSCC	U.S. TOTAL
NET ELECTRICITY REQUIRED - GWH $(10)^3$										
1984	382.8	185.7	185.7	170.8	105.1	217.2	502.8	226.0	468.6	2444.9
1985	389.8	193.5	188.3	174.3	109.5	220.7	516.8	227.7	476.5	2497.4
1986	397.7	199.7	191.8	177.8	112.1	225.1	530.8	233.0	490.5	2558.7
1987	405.5	204.1	192.7	181.3	114.7	227.7	543.9	238.2	504.5	2613.1
1988	416.9	211.9	196.2	184.8	117.3	231.2	564.1	245.2	515.9	2684.0
1989	425.7	220.7	200.6	188.3	120.8	233.8	579.0	252.2	527.3	2748.8
1990	433.6	229.5	204.1	191.8	123.5	237.3	596.5	259.2	539.6	2815.4
1991	441.5	238.2	208.4	195.3	127.0	241.7	610.5	266.3	551.0	2880.2
1992	449.3	247.0	211.9	198.8	129.6	247.0	625.4	274.1	564.1	2947.7
1993	457.2	256.6	215.4	203.2	133.1	250.5	639.4	281.1	575.5	3012.5
1994	465.1	266.3	219.8	206.7	135.7	255.7	654.3	288.2	587.7	3080.0
COMPOUND GROWTH RATE										
1984-1994	1.0197	1.0367	1.0170	1.0193	1.0259	1.0165	1.0267	1.0246	1.0229	1.0234
1985-1994	1.0198	1.0317	1.0186	1.0201	1.0240	1.0198	1.0271	1.0231	1.0294	1.0246
1986-1994	1.0198	1.0219	1.0046	1.0197	1.0234	1.0117	1.0248	1.0226	1.0286	1.0212
1987-1994	1.0198	1.0386	1.0182	1.0193	1.0229	1.0154	1.0370	1.0294	1.0226	1.0272
1988-1994	1.0184	1.0413	1.0223	1.0190	1.0299	1.0114	1.0264	1.0286	1.0221	1.0242
1989-1994	1.0179	1.0397	1.0175	1.0186	1.0217	1.0150	1.0303	1.0278	1.0233	1.0242
1990-1994	1.0177	1.0382	1.0215	1.0183	1.0284	1.0185	1.0235	1.0270	1.0211	1.0230
1991-1994	1.0175	1.0368	1.0168	1.0179	1.0207	1.0217	1.0244	1.0296	1.0238	1.0234
1992-1994	1.0174	1.0390	1.0165	1.0220	1.0270	1.0142	1.0224	1.0256	1.0202	1.0220
1993-1994	1.0172	1.0375	1.0203	1.0172	1.0197	1.0210	1.0233	1.0249	1.0213	1.0224
COMPOSITE	1.0175	1.0376	1.0180	1.0184	1.0218	1.0209	1.0226	1.0254	1.0211	1.0223

(continued)

TABLE 1.4-13 (continued)

PROJECTION OF ANNUAL ELECTRIC ENERGY REQUIREMENTS TO YEAR 2030

Year	ECAR	ERCOT	MAAC	MAIN	U.S. Portion MAPP	U.S. Portion NPCC	SERC	SPP	U.S. Portion WSCC	U.S. TOTAL
PROJECTED GWH $(10)^3$										
1995	473.3	276.3	223.8	210.5	138.7	261.1	669.2	295.5	600.2	3148.7
1996	481.6	286.7	227.9	214.4	141.8	266.6	684.3	303.0	612.9	3219.1
1997	490.0	297.5	232.0	218.4	144.9	272.2	699.7	310.7	625.8	3291.1
1998	498.6	308.7	236.1	222.4	148.0	277.9	715.6	318.6	639.0	3364.8
1999	507.3	320.3	240.4	226.5	151.2	283.7	731.7	326.6	652.5	3440.2
2000	516.2	332.3	244.7	230.6	154.5	289.6	748.3	334.9	666.2	3517.4
2001	525.2	344.8	249.1	234.9	157.9	295.6	765.2	343.4	680.3	3596.5
2002	534.4	357.8	253.6	239.2	161.3	301.8	782.5	352.1	694.7	3677.4
2003	543.8	371.2	258.2	243.6	164.9	308.1	800.2	361.0	709.3	3760.3
2004	553.3	385.2	262.8	248.1	168.5	314.6	818.2	370.2	724.3	3845.1
2005	563.0	399.7	267.5	252.6	172.1	321.1	836.7	379.6	739.6	3932.0
2006	572.8	414.7	272.4	257.3	175.9	327.9	855.6	389.2	755.2	4020.9
2007	582.8	430.3	277.3	262.0	179.7	334.7	875.0	399.1	771.1	4112.0
2008	593.0	446.5	282.3	266.9	183.6	341.7	894.8	409.2	787.4	4205.3
2009	603.4	463.3	287.3	271.8	187.6	348.8	915.0	419.5	804.0	4300.8
2010	614.0	480.7	292.5	276.8	191.7	356.1	935.7	430.2	821.0	4398.7
2011	624.7	498.8	297.8	281.9	195.9	363.6	956.8	441.1	838.3	4498.8
2012	635.7	517.5	303.1	287.0	200.2	371.2	978.4	452.3	856.0	4601.4
2013	646.8	537.0	308.6	292.3	204.5	378.9	1000.5	463.7	874.0	4706.4
2014	658.1	557.2	314.1	297.7	209.0	386.9	1023.2	475.5	892.5	4814.1
2015	669.6	578.1	319.8	303.2	213.6	394.9	1046.3	487.5	911.3	4924.3
2016	681.3	599.8	325.6	308.8	218.2	403.2	1069.9	499.9	930.5	5037.3
2017	693.3	622.4	331.4	314.4	223.0	411.6	1094.1	512.6	950.2	5152.9
2018	705.4	645.8	337.4	320.2	227.8	420.2	1118.8	525.6	970.2	5271.5
2019	717.7	670.1	343.5	326.1	232.8	429.0	1144.1	538.9	990.7	5392.9
2020	730.3	695.3	349.6	332.1	237.9	438.0	1170.0	552.6	1011.6	5517.3
2021	743.1	721.4	355.9	338.2	243.1	447.1	1196.4	566.6	1032.9	5644.7
2022	756.1	748.5	362.3	344.5	248.4	456.5	1223.5	580.9	1054.7	5775.3
2023	769.3	776.7	368.9	350.8	253.8	466.0	1251.1	595.7	1077.0	5909.2
2024	782.8	805.9	375.5	357.2	259.3	475.8	1279.4	610.8	1099.7	6046.3
2025	796.5	836.2	382.3	363.8	265.0	485.7	1308.3	626.2	1122.9	6186.8
2026	810.4	867.6	389.1	370.5	270.7	495.8	1337.9	642.1	1146.6	6330.8
2027	824.6	900.3	396.1	377.3	276.6	506.2	1368.1	658.4	1170.8	6478.4
2028	839.0	934.1	403.3	384.3	282.7	516.8	1399.0	675.1	1195.5	6629.7
2029	853.7	969.2	410.5	391.3	288.8	527.6	1430.6	692.2	1220.7	6784.8
2030	868.6	1005.7	417.9	398.5	295.1	538.6	1463.0	709.7	1246.5	6943.7

TABLE 1.4-14

PROJECTION OF ANNUAL SUMMER PEAK DEMANDS TO YEAR 2030

Year	ECAR	ERCOT	MAAC	MAIN	U.S. Portion MAPP	U.S. Portion NPCC	SERC	SPP	U.S. Portion WSCC	U.S. TOTAL
PROJECTED AVERAGE DEMAND - GW (GWH/8760)										
1995	54.0	31.5	25.6	24.0	15.8	29.8	76.4	33.7	68.5	3148.7
1996	55.0	32.7	26.0	24.5	16.2	30.4	78.1	34.6	70.0	3219.0
1997	55.9	34.0	26.5	24.9	16.5	31.1	79.9	35.5	71.4	3291.0
1998	56.9	35.2	27.0	25.4	16.9	31.7	81.7	36.4	72.9	3364.7
1999	57.9	36.6	27.4	25.9	17.3	32.4	83.5	37.3	74.5	3440.1
2000	58.9	37.9	27.9	26.3	17.6	33.1	85.4	38.2	76.1	3517.4
2001	60.0	39.4	28.4	26.8	18.0	33.7	87.3	39.2	77.7	3596.4
2002	61.0	40.8	29.0	27.3	18.4	34.5	89.3	40.2	79.3	3677.4
2003	62.1	42.4	29.5	27.8	18.8	35.2	91.3	41.2	81.0	3760.2
2004	63.2	44.0	30.0	28.3	19.2	35.9	93.4	42.3	82.7	3845.1
2005	64.3	45.6	30.5	28.8	19.6	36.7	95.5	43.3	84.4	3931.9
2006	65.4	47.3	31.1	29.4	20.1	37.4	97.7	44.4	86.2	4020.9
2007	66.5	49.1	31.7	29.9	20.5	38.2	99.9	45.6	88.0	4112.0
2008	67.7	51.0	32.2	30.5	21.0	39.0	102.1	46.7	89.9	4205.2
2009	68.9	52.9	32.8	31.0	21.4	39.8	104.4	47.9	91.8	4300.7
2010	70.1	54.9	33.4	31.6	21.9	40.7	106.8	49.1	93.7	4398.5
2011	71.3	56.9	34.0	32.2	22.4	41.5	109.2	50.4	95.7	4498.7
2012	72.6	59.1	34.6	32.8	22.9	42.4	111.7	51.6	97.7	4601.3
2013	73.8	61.3	35.2	33.4	23.3	43.3	114.2	52.9	99.8	4706.4
2014	75.1	63.6	35.9	34.0	23.9	44.2	116.8	54.3	101.9	4814.0
2015	76.4	66.0	36.5	34.6	24.4	45.1	119.4	55.7	104.0	4924.3
2016	77.8	68.5	37.2	35.2	24.9	46.0	122.1	57.1	106.2	5037.2
2017	79.1	71.0	37.8	35.9	25.5	47.0	124.9	58.5	108.5	5152.9
2018	80.5	73.7	38.5	36.6	26.0	48.0	127.7	60.0	110.8	5271.4
2019	81.9	76.5	39.2	37.2	26.6	49.0	130.6	61.5	113.1	5392.8
2020	83.4	79.4	39.9	37.9	27.2	50.0	133.6	63.1	115.5	5517.2
2021	84.8	82.4	40.6	38.6	27.7	51.0	136.6	64.7	117.9	5644.7
2022	86.3	85.5	41.4	39.3	28.4	52.1	139.7	66.3	120.4	5775.3
2023	87.8	88.7	42.1	40.0	29.0	53.2	142.8	68.0	122.9	5909.1
2024	89.4	92.0	42.9	40.8	29.6	54.3	146.0	69.7	125.5	6046.2
2025	90.9	95.5	43.6	41.5	30.2	55.4	149.3	71.5	128.2	6186.8
2026	92.5	99.0	44.4	42.3	30.9	56.6	152.7	73.3	130.9	6330.8
2027	94.1	102.8	45.2	43.1	31.6	57.8	156.2	75.2	133.7	6478.4
2028	95.8	106.6	46.0	43.9	32.3	59.0	159.7	77.1	136.5	6629.7
2029	97.5	110.6	46.9	44.7	33.0	60.2	163.3	79.0	139.4	6784.7
2030	99.2	114.8	47.7	45.5	33.7	61.5	167.0	81.0	142.3	6943.7

(continued)

TABLE 1.4-14 (continued)

PROJECTION OF ANNUAL SUMMER PEAK DEMANDS TO YEAR 2030

Year	ECAR	ERCOT	MAAC	MAIN	U.S. Portion MAPP	U.S. Portion NPCC	SERC	SPP	U.S. Portion WSCC	U.S. TOTAL
RATIO PEAK TO AVERAGE DEMAND										
1994	1.5287	1.7239	1.5657	1.7160	1.7121	1.5588	1.6318	1.8045	1.4922	
GROWTH	0.9997	0.9988	0.9944	0.9973	0.9979	0.9992	0.9990	0.9989	0.9997	
PROJECTED RATIO										
1995	1.5283	1.7219	1.5570	1.7114	1.7085	1.5575	1.6301	1.8025	1.4917	
1996	1.5279	1.7198	1.5482	1.7068	1.7048	1.5562	1.6285	1.8005	1.4912	
1997	1.5275	1.7177	1.5395	1.7022	1.7012	1.5549	1.6269	1.7985	1.4907	
1998	1.5271	1.7156	1.5309	1.6976	1.6976	1.5536	1.6253	1.7965	1.4902	
1999	1.5267	1.7135	1.5223	1.6930	1.6940	1.5523	1.6237	1.7945	1.4897	
2000	1.5263	1.7114	1.5138	1.6884	1.6904	1.5510	1.6221	1.7925	1.4892	
2001	1.5259	1.7093	1.5053	1.6839	1.6868	1.5497	1.6205	1.7905	1.4887	
2002	1.5255	1.7072	1.4969	1.6794	1.6832	1.5484	1.6189	1.7885	1.4882	
2003	1.5251	1.7052	1.4885	1.6749	1.6796	1.5471	1.6173	1.7865	1.4877	
2004	1.5247	1.7032	1.4802	1.6704	1.6760	1.5458	1.6157	1.7845	1.4872	
2005	1.5243	1.7012	1.4719	1.6659	1.6724	1.5445	1.6141	1.7825	1.4867	
2006	1.5239	1.6992	1.4637	1.6614	1.6688	1.5432	1.6125	1.7805	1.4862	
2007	1.5235	1.6972	1.4555	1.6569	1.6652	1.5419	1.6109	1.7785	1.4857	
2008	1.5231	1.6952	1.4473	1.6524	1.6616	1.5406	1.6093	1.7765	1.4852	
2009	1.5227	1.6932	1.4392	1.6480	1.6580	1.5393	1.6077	1.7745	1.4847	
2010	1.5223	1.6912	1.4311	1.6436	1.6545	1.5380	1.6061	1.7725	1.4842	
2011	1.5219	1.6892	1.4231	1.6392	1.6510	1.5367	1.6045	1.7705	1.4837	
2012	1.5215	1.6872	1.4151	1.6348	1.6475	1.5354	1.6029	1.7685	1.4832	
2013	1.5211	1.6852	1.4072	1.6304	1.6440	1.5341	1.6013	1.7665	1.4827	
2014	1.5207	1.6832	1.3993	1.6260	1.6405	1.5328	1.5997	1.7645	1.4822	
2015	1.5203	1.6812	1.3915	1.6216	1.6370	1.5315	1.5981	1.7625	1.4817	
2016	1.5199	1.6792	1.3837	1.6172	1.6335	1.5302	1.5965	1.7605	1.4812	
2017	1.5195	1.6772	1.3760	1.6128	1.6300	1.5289	1.5949	1.7585	1.4807	
2018	1.5191	1.6752	1.3683	1.6085	1.6265	1.5276	1.5933	1.7565	1.4802	
2019	1.5187	1.6732	1.3606	1.6042	1.6230	1.5263	1.5917	1.7545	1.4797	
2020	1.5183	1.6712	1.3530	1.5999	1.6195	1.5250	1.5901	1.7525	1.4792	
2021	1.5179	1.6692	1.3454	1.5956	1.6160	1.5237	1.5885	1.7505	1.4787	
2022	1.5175	1.6672	1.3379	1.5913	1.6125	1.5224	1.5869	1.7485	1.4782	
2023	1.5171	1.6652	1.3304	1.5870	1.6090	1.5211	1.5853	1.7465	1.4777	
2024	1.5167	1.6632	1.3229	1.5827	1.6056	1.5198	1.5837	1.7445	1.4772	
2025	1.5163	1.6612	1.3155	1.5784	1.6022	1.5185	1.5821	1.7425	1.4767	
2026	1.5159	1.6592	1.3081	1.5742	1.5988	1.5172	1.5805	1.7405	1.4762	
2027	1.5155	1.6572	1.3008	1.5700	1.5954	1.5159	1.5789	1.7386	1.4757	
2028	1.5151	1.6552	1.2935	1.5658	1.5920	1.5146	1.5773	1.7367	1.4752	
2029	1.5147	1.6532	1.2863	1.5616	1.5886	1.5133	1.5757	1.7348	1.4747	
2030	1.5143	1.6512	1.2791	1.5574	1.5852	1.5120	1.5741	1.7329	1.4742	

(continued)

TABLE 1.4-14 (continued)

PROJECTION OF ANNUAL SUMMER PEAK DEMANDS TO YEAR 2030

Year	ECAR	ERCOT	MAAC	MAIN	U.S. Portion MAPP	U.S. Portion NPCC	SERC	SPP	U.S. Portion WSCC	U.S. TOTAL
PROJECTED PEAK DEMAND - GW										
1995	82.5	54.2	39.9	41.1	27.0	46.4	124.5	60.7	102.2	578.8
1996	84.0	56.2	40.3	41.8	27.6	47.3	127.2	62.3	104.4	591.0
1997	85.4	58.4	40.8	42.4	28.1	48.4	130.0	63.8	106.4	603.6
1998	86.9	60.4	41.3	43.1	28.7	49.2	132.8	65.4	108.6	616.4
1999	88.4	62.7	41.7	43.8	29.3	50.3	135.6	66.9	111.0	629.6
2000	89.9	64.9	42.2	44.4	29.8	51.3	138.5	68.5	113.3	643.0
2001	91.6	67.3	42.8	45.1	30.4	52.2	141.5	70.2	115.7	656.7
2002	93.1	69.7	43.4	45.8	31.0	53.4	144.6	71.9	118.0	670.8
2003	94.7	72.3	43.9	46.6	31.6	54.5	147.7	73.6	120.5	685.2
2004	96.4	74.9	44.4	47.3	32.2	55.5	150.9	75.5	123.0	699.9
2005	98.0	77.6	44.9	48.0	32.8	56.7	154.1	77.2	125.5	714.9
2006	99.7	80.4	45.5	48.8	33.5	57.7	157.5	79.1	128.1	730.3
2007	101.3	83.3	46.1	49.5	34.1	58.9	160.9	81.1	130.7	746.1
2008	103.1	86.5	46.6	50.4	34.9	60.1	164.3	83.0	133.5	762.2
2009	104.9	89.6	47.2	51.1	35.5	61.3	167.8	85.0	136.3	778.7
2010	106.7	92.8	47.8	51.9	36.2	62.6	171.5	87.0	139.1	795.6
2011	108.5	96.1	48.4	52.8	37.0	63.8	175.2	89.2	142.0	812.8
2012	110.5	99.7	49.0	53.6	37.7	65.1	179.0	91.3	144.9	830.5
2013	112.3	103.3	49.5	54.5	38.3	66.4	182.9	93.4	148.0	848.6
2014	114.2	107.1	50.2	55.3	39.2	67.7	186.8	95.8	151.0	867.1
2015	116.2	111.0	50.8	56.1	39.9	69.1	190.8	98.2	154.1	886.1
2016	118.2	115.0	51.5	56.9	40.7	70.4	194.9	100.5	157.3	905.5
2017	120.2	119.1	52.0	57.9	41.6	71.9	199.2	102.9	160.7	925.3
2018	122.3	123.5	52.7	58.9	42.3	73.3	203.5	105.4	164.0	945.7
2019	124.4	128.0	53.3	59.7	43.2	74.8	207.9	107.9	167.4	966.5
2020	126.6	132.7	54.0	60.6	44.1	76.3	212.4	110.6	170.8	987.8
2021	128.7	137.5	54.6	61.6	44.8	77.7	217.0	113.3	174.3	1009.6
2022	131.0	142.5	55.4	62.5	45.8	79.3	221.7	115.9	178.0	1031.9
2023	133.2	147.7	56.0	63.5	46.7	80.9	226.4	118.8	181.6	1054.8
2024	135.6	153.0	56.8	64.6	47.5	82.5	231.2	121.6	185.4	1078.2
2025	137.8	158.6	57.4	65.5	48.4	84.1	236.2	124.6	189.3	1102.2
2026	140.2	164.3	58.1	66.6	49.4	85.9	241.3	127.6	193.2	1126.7
2027	142.6	170.4	58.8	67.7	50.4	87.6	246.6	130.7	197.3	1151.9
2028	145.1	176.4	59.5	68.7	51.4	89.4	251.9	133.9	201.4	1177.6
2029	147.7	182.8	60.3	69.8	52.4	91.1	257.3	137.0	205.6	1204.0
2030	150.2	189.6	61.0	70.9	53.4	93.0	262.9	140.4	209.8	1231.0

since regional circumstances would be diluted in the aggregate and since national demands are developed as the total of regional peak demands which are not necessarily coincident.

As previously indicated, reserve levels drop below the 20 percent criteria as early as 1991 in the mid-continent (MAPP) region. Typical relationships, depicted for the East Central (ECAR) and Texas Reliability Council (ERCOT) Regions are shown in FIGURE 1.4-5. In the same manner, total preliminary regional capability requirements were established as detailed in TABLE 1.4-15.

Replacement Capacity

It is important to estimate the amount of power plant retirements since this lost capacity must either be replaced by new power generation, or offset by reduced demand from conservation efforts. Thus, retired capacity that is not offset by conservation represents a potential market for the S-H-U process.

The U.S. generating facilities are aging. According to the Environmental Directory of U.S. Steam Electric Power Plants, the average age (by plant number) of all the coal, oil, gas and nuclear units in the U.S. is 25 years. FIGURE 1.4-6 shows the U.S. fleet power generation capability, which indicates when the capacity of the plants that are currently generating electricity were initially brought into service.

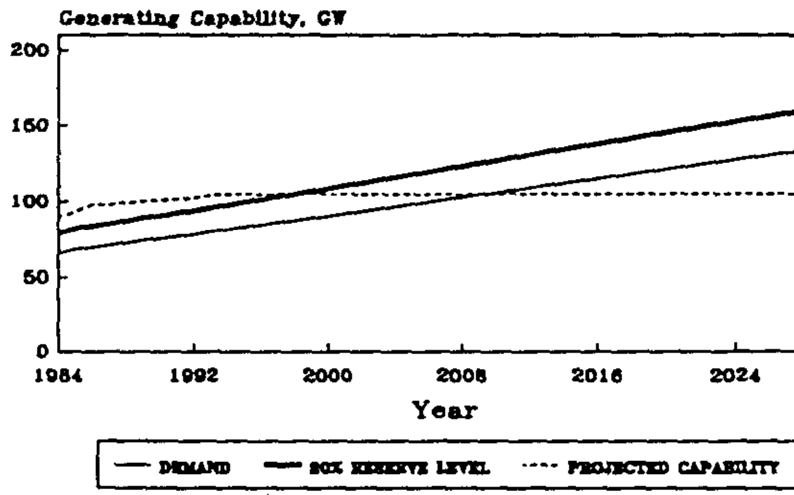
In order to forecast retirements, an assumption must be made as to how long the currently installed electric generation fleet can remain in economical repair. Smock notes that it is relatively easy to decide to retire obviously obsolete technology however, the capacity now crossing the 30 year point is, generally, not obsolete.

Whereas many plants were designed to have a 30 year life, comparatively economical plant upgrades and modernizations, forced by the high cost of new capacity, can extend that life for another 15 to 30 years. EPRI has stated that the trend toward life extension will "cause the average age of fossil fuel plants to increase by five years in the next decade." Nonetheless, plants, and boilers, in particular, eventually enter a wear-out phase in which component failure rates climb sharply. At this point, the cost of maintenance for continued life extension becomes impractical, and a unit is retired from service.

FIGURE 1.4-5

REPRESENTATIVE PEAK DEMAND COMPARISON FOR THE EAST CENTRAL AREA AND THE TEXAS AREA

PEAK DEMAND, CAPABILITY & RESERVE
East Central Area



PEAK DEMAND, CAPABILITY & RESERVE
Texas Area

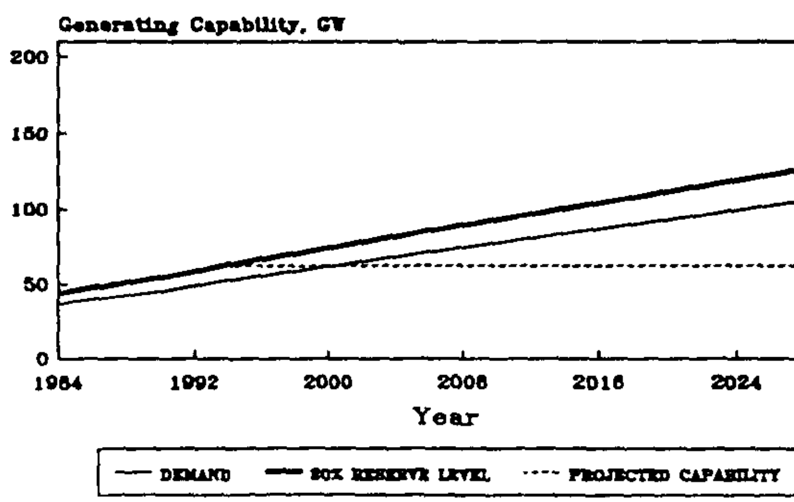


TABLE 1.4-15

PRELIMINARY PROJECTION OF ANNUAL CAPACITY REQUIREMENTS TO YEAR 2030

Year	ECAR	ERCOT	MAAC	MAIN	U.S. Portion MAPP	U.S. Portion NPCC	SERC	SPP	U.S. Portion WSCC	U.S. TOTAL
PEAK DEMAND WITH A 20% RESERVE MARGIN										
1992	93.96	58.3	46.0	47.0	30.5	52.9	139.3	67.9	114.8	651.1
1993	95.6	60.7	46.5	47.8	31.1	53.6	142.8	69.5	117.4	665.3
1994	97.4	62.8	47.1	48.5	31.8	54.6	146.2	71.2	120.1	680.1
1995	99.2	64.7	47.6	49.2	32.5	55.5	149.6	72.9	122.5	694.0
1996	101.0	66.6	48.0	49.8	33.2	56.3	153.1	74.5	124.9	707.9
1997	102.9	68.4	48.5	50.5	33.9	57.2	156.5	76.2	127.3	721.8
1998	104.7	70.3	49.0	51.1	34.6	58.1	159.9	77.8	129.7	735.7
1999	106.6	72.2	49.4	51.7	35.3	59.0	163.3	79.5	132.2	749.5
2000	108.4	74.0	49.9	52.4	36.0	59.9	166.7	81.1	134.6	763.4
2001	110.2	75.9	50.4	53.0	36.7	60.8	170.2	82.8	137.0	777.3
2002	112.1	77.8	50.8	53.7	37.4	61.7	173.6	84.5	139.4	791.2
2003	113.9	79.6	51.3	54.3	38.1	62.5	177.0	86.1	141.8	805.1
2004	115.8	81.5	51.7	54.9	38.8	63.4	180.4	87.8	144.2	818.9
2005	117.6	83.4	52.2	55.6	39.6	64.3	183.8	89.4	146.6	832.8
2006	119.4	85.2	52.7	56.2	40.3	65.2	187.3	91.1	149.0	846.7
2007	121.3	87.1	53.1	56.8	41.0	66.1	190.7	92.7	151.4	860.6
2008	123.1	89.0	53.6	57.5	41.7	67.0	194.1	94.4	153.8	874.5
2009	124.9	90.8	54.1	58.1	42.4	67.8	197.5	96.0	156.2	888.4
2010	126.8	92.7	54.5	58.8	43.1	68.7	200.9	97.7	158.7	902.2
2011	128.6	94.6	55.0	59.4	43.8	69.6	204.4	99.4	161.1	916.1
2012	130.5	96.4	55.4	60.0	44.5	70.5	207.8	101.0	163.5	930.0
2013	132.3	98.3	55.9	60.7	45.2	71.4	211.2	102.7	165.9	943.9
2014	134.1	100.2	56.4	61.3	45.9	72.3	214.6	104.3	168.3	957.8
2015	136.0	102.0	56.8	61.9	46.6	73.2	218.0	106.0	170.7	971.6
2016	137.8	103.9	57.3	62.6	47.3	74.0	221.5	107.6	173.1	985.5
2017	139.7	105.8	57.8	63.2	48.0	74.9	224.9	109.3	175.5	999.4
2018	141.5	107.6	58.2	63.9	48.7	75.8	228.3	111.0	177.9	1013.3
2019	143.3	109.5	58.7	64.5	49.4	76.7	231.7	112.6	180.3	1027.2
2020	145.2	111.4	59.2	65.1	50.1	77.6	235.1	114.3	182.7	1041.0
2021	147.0	113.2	59.6	65.8	50.8	78.5	238.5	115.9	185.2	1054.9
2022	148.8	115.1	60.1	66.4	51.5	79.3	242.0	117.6	187.6	1068.8
2023	150.7	117.0	60.5	67.0	52.2	80.2	245.4	119.2	190.0	1082.7
2024	152.5	118.8	61.0	67.7	52.9	81.1	248.8	120.9	192.4	1096.6
2025	154.4	120.7	61.5	68.3	53.6	82.0	252.2	122.6	194.8	1110.4
2026	156.2	122.6	61.9	69.0	54.3	82.9	255.6	124.2	197.2	1124.3
2027	158.0	124.5	62.4	69.6	55.1	83.8	259.1	125.9	199.6	1138.2
2028	159.9	126.3	62.9	70.2	55.8	84.7	262.5	127.5	202.0	1152.1
2029	161.7	128.2	63.3	70.9	56.5	85.5	265.9	129.2	204.4	1166.0
2030	163.6	130.1	63.8	71.5	57.2	86.4	269.3	130.8	206.8	1179.8

(continued)

TABLE 1.4-15 (continued)

PRELIMINARY PROJECTION OF ANNUAL CAPACITY REQUIREMENTS TO YEAR 2030

Year	ECAR	ERCOT	MAAC	MAIN	U.S. Portion MAPP	U.S. Portion NPCC	SERC	SPP	U.S. Portion WSCC	U.S. TOTAL
1992	102.6	58.2	49.6	49.9	29.8	55.2	149.1	69.2	130.2	693.8
1993	103.9	60.6	50.2	49.9	29.7	56.1	151.8	71.1	131.1	704.3
1994	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
1995	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
1996	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
1997	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
1998	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
1999	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2000	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2001	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2002	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2003	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2004	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2005	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2006	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2007	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2008	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2009	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2010	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2011	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2012	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2013	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2014	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2015	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2016	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2017	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2018	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2019	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2020	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2021	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2022	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2023	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2024	104.7	62.4	50.0	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2025	104.7	62.4	50	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2026	104.7	62.4	50	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2027	104.7	62.4	50	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2028	104.7	62.4	50	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2029	104.7	62.4	50	49.9	30.1	55.9	152.8	72.4	133.4	711.6
2030	104.7	62.4	50	49.9	30.1	55.9	152.8	72.4	133.4	711.6

(continued)

TABLE 1.4-15 (continued)

PRELIMINARY PROJECTION OF ANNUAL CAPACITY REQUIREMENTS TO YEAR 2030

Year	ECAR	ERCOT	MAAC	MAIN	U.S. Portion MAPP	U.S. Portion NPCC	SERC	SPP	U.S. Portion WSCC	U.S. TOTAL
TOTAL SUMMER PEAK SHORTFALL-MegaWatts										
1992	0.0	0.2	0.0	0.0	0.8	0.0	0.0	0.0	0.0	0.9
1993	0.0	0.1	0.0	0.0	1.5	0.0	0.0	0.0	0.0	1.7
1994	0.0	0.4	0.0	0.0	1.8	0.0	0.0	0.0	0.0	2.2
1995	0.0	2.3	0.0	0.0	2.5	0.0	0.0	0.5	0.0	5.3
1996	0.0	4.2	0.0	0.0	3.2	0.4	0.3	2.2	0.0	10.3
1997	0.0	6.0	0.0	0.6	3.9	1.3	3.7	3.8	0.0	19.5
1998	0.1	7.9	0.0	1.3	4.6	2.2	7.2	5.5	0.0	28.7
1999	1.9	9.8	0.0	1.9	5.3	3.1	10.6	7.1	0.0	39.7
2000	3.8	11.6	0.0	2.6	6.0	4.0	14.0	8.8	1.2	51.9
2001	5.6	13.5	0.4	3.2	6.7	4.9	17.4	10.4	3.6	65.7
2002	7.4	15.4	0.8	3.8	7.4	5.7	20.8	12.1	6.0	79.6
2003	9.3	17.2	1.3	4.5	8.1	6.6	24.3	13.8	8.4	93.5
2004	11.1	19.1	1.7	5.1	8.8	7.5	27.7	15.4	10.8	107.4
2005	13.0	21.0	2.2	5.7	9.5	8.4	31.1	17.1	13.2	121.2
2006	14.8	22.8	2.7	6.4	10.2	9.3	34.5	18.7	15.6	135.1
2007	16.6	24.7	3.1	7.0	10.9	10.2	37.9	20.4	18.1	149.0
2008	18.5	26.6	3.6	7.7	11.6	11.1	41.4	22.0	20.5	162.9
2009	20.3	28.5	4.1	8.3	12.4	11.9	44.8	23.7	22.9	176.8
2010	22.1	30.3	4.5	8.9	13.1	12.8	48.2	25.4	25.3	190.6
2011	24.0	32.2	5.0	9.6	13.8	13.7	51.6	27.0	27.7	204.5
2012	25.8	34.1	5.4	10.2	14.5	14.6	55.0	28.7	30.1	218.4
2013	27.7	35.9	5.9	10.8	15.2	15.5	58.5	30.3	32.5	232.3
2014	29.5	37.8	6.4	11.5	15.9	16.4	61.9	32.0	34.9	246.2
2015	31.3	39.7	6.8	12.1	16.6	17.3	65.3	33.6	37.3	260.0
2016	33.2	41.5	7.3	12.8	17.3	18.1	68.7	35.3	39.7	273.9
2017	35.0	43.4	7.8	13.4	18.0	19.0	72.1	37.0	42.1	287.8
2018	36.9	45.3	8.2	14.0	18.7	19.9	75.6	38.6	44.6	301.7
2019	38.7	47.1	8.7	14.7	19.4	20.8	79.0	40.3	47.0	315.6
2020	40.5	49.0	9.2	15.3	20.1	21.7	82.4	41.9	49.4	329.4
2021	42.4	50.9	9.6	15.9	20.8	22.6	85.8	43.6	51.8	343.3
2022	44.2	52.7	10.1	16.6	21.5	23.4	89.2	45.2	54.2	357.2
2023	46.0	54.6	10.5	17.2	22.2	24.3	92.6	46.9	56.6	371.1
2024	47.9	56.5	11.0	17.9	22.9	25.2	96.1	48.6	59.0	385.0
2025	49.7	58.3	11.5	18.5	23.6	26.1	99.5	50.2	61.4	398.9
2026	51.6	60.2	11.9	19.1	24.3	27.0	102.9	51.9	63.8	412.7
2027	53.4	62.1	12.4	19.8	25.0	27.9	106.3	53.5	66.2	426.6
2028	55.2	63.9	12.9	20.4	25.7	28.8	109.7	55.2	68.7	440.5
2029	57.1	65.8	13.3	21.0	26.4	29.6	113.2	56.8	71.1	454.4
2030	58.9	67.7	13.8	21.7	27.1	30.5	116.6	58.5	73.5	468.3

(continued)

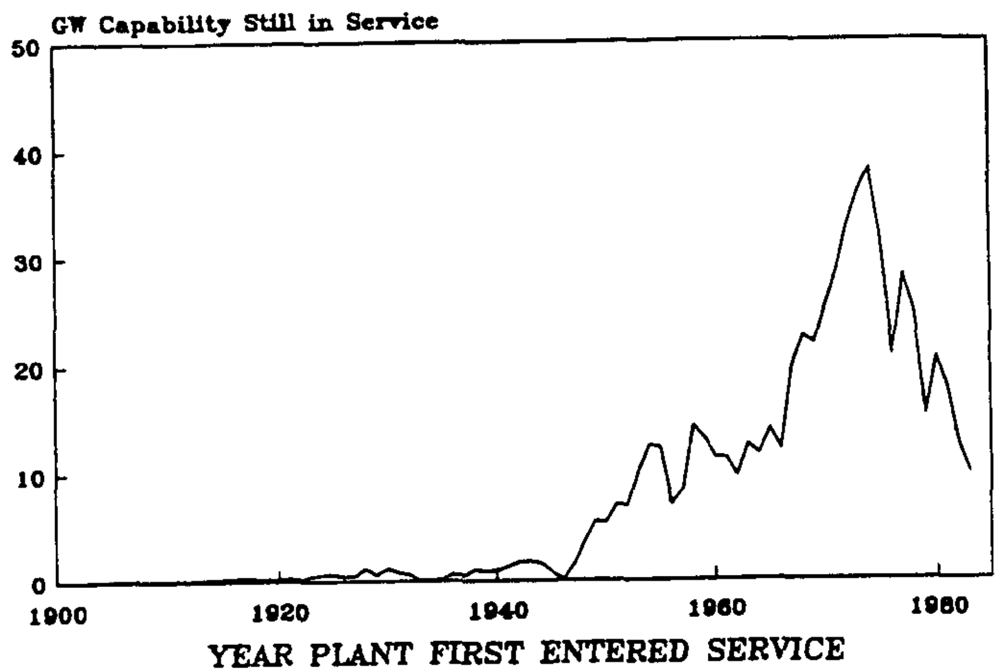
TABLE 1.4-15 (continued)

PRELIMINARY PROJECTION OF ANNUAL CAPACITY REQUIREMENTS TO YEAR 2030

Year	ECAR	ERCOT	MAAC	MAIN	U.S. Portion MAPP	U.S. Portion NPCC	SERC	SPP	U.S. Portion WSCC	U.S. TOTAL
1992	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.2
1993	0.0	0.2	0.0	0.0	0.6	0.0	0.0	0.0	0.0	0.8
1994	0.0	0.0	0.0	0.0	0.7	0.0	0.0	0.0	0.0	0.7
1995	0.0	0.3	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.6
1996	0.0	1.9	0.0	0.0	0.7	0.0	0.0	0.5	0.0	3.1
1997	0.0	1.9	0.0	0.0	0.7	0.4	0.3	1.7	0.0	5.0
1998	0.0	1.8	0.0	0.6	0.7	0.9	3.4	1.6	0.0	9.0
1999	0.1	1.9	0.0	0.7	0.7	0.9	3.5	1.7	0.0	9.5
2000	1.8	1.9	0.0	0.6	0.7	0.9	3.4	1.6	0.0	10.9
2001	1.9	1.8	0.0	0.7	0.7	0.9	3.4	1.7	1.2	12.3
2002	1.8	1.9	0.4	0.6	0.7	0.9	3.4	1.6	2.4	13.7
2003	1.8	1.9	0.4	0.6	0.7	0.8	3.4	1.7	2.4	13.7
2004	1.9	1.8	0.5	0.7	0.7	0.9	3.5	1.7	2.4	14.1
2005	1.8	1.9	0.4	0.6	0.7	0.9	3.4	1.6	2.4	13.7
2006	1.9	1.9	0.5	0.6	0.7	0.9	3.4	1.7	2.4	14.0
2007	1.8	1.8	0.5	0.7	0.7	0.9	3.4	1.6	2.4	13.8
2008	1.8	1.9	0.4	0.6	0.7	0.9	3.4	1.7	2.5	13.9
2009	1.9	1.9	0.5	0.7	0.7	0.9	3.5	1.6	2.4	14.1
2010	1.8	1.9	0.5	0.6	0.8	0.8	3.4	1.7	2.4	13.9
2011	1.8	1.8	0.4	0.6	0.7	0.9	3.4	1.7	2.4	13.7
2012	1.9	1.9	0.5	0.7	0.7	0.9	3.4	1.6	2.4	14.0
2013	1.8	1.9	0.4	0.6	0.7	0.9	3.4	1.7	2.4	13.8
2014	1.9	1.8	0.5	0.6	0.7	0.9	3.5	1.6	2.4	13.9
2015	1.8	1.9	0.5	0.7	0.7	0.9	3.4	1.7	2.4	14.0
2016	1.8	1.9	0.4	0.6	0.7	0.9	3.4	1.6	2.4	13.7
2017	1.9	1.8	0.5	0.7	0.7	0.8	3.4	1.7	2.4	13.9
2018	1.8	1.9	0.5	0.6	0.7	0.9	3.4	1.7	2.4	13.9
2019	1.9	1.9	0.4	0.6	0.7	0.9	3.5	1.6	2.5	14.0
2020	1.8	1.8	0.5	0.7	0.7	0.9	3.4	1.7	2.4	13.9
2021	1.8	1.9	0.5	0.6	0.7	0.9	3.4	1.6	2.4	13.8
2022	1.9	1.9	0.4	0.6	0.7	0.9	3.4	1.7	2.4	13.9
2023	1.8	1.8	0.5	0.7	0.7	0.8	3.4	1.6	2.4	13.7
2024	1.8	1.9	0.4	0.6	0.7	0.9	3.4	1.7	2.4	13.8
2025	1.9	1.9	0.5	0.7	0.7	0.9	3.5	1.7	2.4	14.2
2026	1.8	1.8	0.5	0.6	0.7	0.9	3.4	1.6	2.4	13.7
2027	1.9	1.9	0.4	0.6	0.7	0.9	3.4	1.7	2.4	13.9
2028	1.8	1.9	0.5	0.7	0.7	0.9	3.4	1.6	2.4	13.9
2029	1.8	1.8	0.5	0.6	0.7	0.9	3.4	1.7	2.5	13.9
2030	1.9	1.9	0.4	0.6	0.7	0.8	3.5	1.6	2.4	13.8

FIGURE 1.4-6

TOTAL GENERATION CAPABILITY OF U.S. FLEET BY AGE OF UNIT INCLUDES ALL UTILITY GENERATION (COAL, OIL, GAS AND NUCLEAR CAPACITY)



(source: DOE CURF Files)

It is impossible to predict what future course of plant retrofits, upgrades, and retirements will be chosen by utility companies for their existing plants. We can only infer that plant upgrades are both desirable and likely and establish a reasonable basis for a forecast of retirements that are based upon an assumption of a significant level of life extension activity.

Some of the existing plants would be retired during the period prior to the time frame that the acid rain legislation would take effect in year 2000. For this study, it has been assumed that the actual retrofits would begin in 1996. There would be a 35 year period of retrofit to the year 2030. Actual timing will be based on the final regulations written from the legislation. For this proposal, it has been assumed that plants retired from now through 2030 would not be subject to retrofit. This results in a conservative estimate of the plants or market potential for retrofit.

Thus, the following method has been chosen to evaluate capacity retirements:

a. Use DOE GURF data to show the current age of each generating plant. These data were in agreement with Edison Electric Institute data. For retirements, all plant type data in the GURF files, were evaluated for the relevant NERC regions.

b. Exclude from consideration a portion of the facilities. Some plants will not be retired in the time frame of the study; for example some power plants built between 1900 and 1920 are still generating electricity even though they are more than 65 years old; a similar longevity can be assumed for a portion of today's plants. In addition, some of the lost capacity will be offset by reduced demand from success in energy conservation efforts. It has been assumed, conservatively, that five percent never retired plus conservation offset could be excluded from retirement considerations, based on the total MWe contribution of very old plants currently evident in the GURF data.

c. Age the plants using a normal distribution curve for a fraction of the plants being considered as candidates for each year of age. It was assumed that most plants would have average economical life centered at about 45 years. An arbitrary distribution scheduling future upgrades or retirements could have been chosen; however, for technical reasons, it is much more convenient to use a distribution with probability density functions defined by a unique formula on the whole range of the possibilities.

d. Assume retirement of the units based on the total GW as aged by this normal curve. This assumption was made on a yearly forecast, those plants 45 years old (that is, those entering service in 1950) had the greatest proportion of retirements.

The result of these assumptions was a regional forecast of retirements for all type generating plants, TABLE 1.4-16.

Offsets Due To Independent Power Production Capacity

Another important aspect of projecting the market for power generation is the consideration of non-utility generation/industrial cogeneration from independent power producers (IPP). This is important in clean coal technology market projection for two reasons:

1. IPP generation tends to displace some electric utility power generation, potentially reducing the electric utility market size, but

2. IPP generation itself is a potential market for the S-H-U process, particularly that portion of cogenerators requiring larger (above 50 MW) capacity installations.

These factors offset each other to some extent, but not completely.

The amount of non-utility generation was forecast by using and extrapolating data from the DOE TOPS report, using appropriate portions of the state data to develop IPP expansion information for the NERC regions considered in utility industry regional forecasts.

TABLE 1.4-16

ESTIMATED MEGAWATTS OF U.S. GENERATOR CAPACITY RETIRED IN YEAR

Year	ECAR	ERCOT	MAAC	MAIN	U.S. Portion MAPP	U.S. Portion NPCC	SERC	SPP	U.S. Portion WSCC	U.S. TOTAL
1992	696	188	283	260	192	325	733	291	750	3,714
1993	829	231	330	309	222	382	875	348	875	4,397
1994	970	279	379	360	253	443	1,037	409	1,020	5,144
1995	1,115	329	425	414	282	501	1,207	468	1,168	5,901
1996	1,249	382	474	469	311	555	1,366	528	1,321	6,648
1997	1,373	433	521	522	339	608	1,525	585	1,485	7,384
1998	1,487	486	563	575	364	656	1,667	636	1,643	8,069
1999	1,566	534	610	624	388	697	1,775	689	1,789	8,662
2000	1,623	578	657	667	411	737	1,874	738	1,938	9,212
2001	1,664	623	698	712	433	773	1,958	787	2,081	9,716
2002	1,672	663	748	751	452	802	2,019	838	2,205	10,138
2003	1,668	704	801	788	472	838	2,091	891	2,339	10,579
2004	1,669	751	857	829	492	873	2,168	955	2,470	11,048
2005	1,666	802	927	873	509	914	2,261	1,024	2,580	11,539
2006	1,689	865	1,007	922	529	967	2,371	1,106	2,712	12,148
2007	1,762	942	1,111	986	555	1,032	2,507	1,206	2,843	12,923
2008	1,874	1,034	1,232	1,068	582	1,122	2,689	1,314	2,954	13,846
2009	2,043	1,137	1,369	1,151	616	1,226	2,889	1,442	3,085	14,933
2010	2,273	1,256	1,534	1,263	657	1,353	3,131	1,586	3,206	16,232
2011	2,547	1,382	1,700	1,381	707	1,498	3,424	1,736	3,319	17,662
2012	2,843	1,511	1,860	1,504	764	1,648	3,738	1,883	3,432	19,148
2013	3,160	1,641	2,014	1,629	833	1,792	4,085	2,037	3,543	20,685
2014	3,444	1,758	2,139	1,731	908	1,922	4,440	2,175	3,639	22,111
2015	3,682	1,856	2,215	1,819	988	2,023	4,758	2,285	3,725	23,300
2016	3,866	1,931	2,240	1,870	1,072	2,074	5,032	2,390	3,803	24,224
2017	3,966	1,980	2,236	1,880	1,155	2,075	5,235	2,472	3,855	24,794
2018	3,970	1,992	2,154	1,864	1,226	2,026	5,319	2,512	3,880	24,879
2019	3,901	1,960	2,023	1,787	1,292	1,910	5,268	2,543	3,866	24,482
2020	3,761	1,906	1,890	1,684	1,332	1,754	5,135	2,560	3,783	23,735
2021	3,532	1,807	1,697	1,560	1,351	1,565	4,875	2,526	3,657	22,500
2022	3,270	1,670	1,488	1,388	1,348	1,345	4,487	2,475	3,467	20,870
2023	2,968	1,526	1,310	1,219	1,304	1,131	4,092	2,406	3,199	19,090
2024	2,619	1,346	1,107	1,043	1,235	917	3,630	2,270	2,897	17,005
2025	2,274	1,160	915	860	1,141	722	3,112	2,106	2,557	14,793
2026	1,929	980	764	695	1,014	557	2,653	1,919	2,189	12,655
2027	1,578	796	615	544	878	415	2,196	1,674	1,822	10,480
2028	1,267	631	480	412	735	303	1,744	1,426	1,475	8,442
2029	980	485	378	302	588	218	1,370	1,178	1,163	6,637
2030	733	359	289	217	456	153	1,042	923	874	5,029
Total	87,589	41,471	45,061	39,870	29,092	41,994	114,535	58,290	101,672	558,330

The TOPS data is presented for various levels of projected return-on-investment (ROI) scenarios for industrial cogenerators. In today's financial environment, only the stronger return (ROI greater that 15 percent) cogenerators would be likely candidates. All estimates were based on these data, extrapolating the year 2000 data provided by TOPS to year 2030 as required for analysis. TABLE 1.4-17 shows the resulting regional forecast for IPP.

Projected Total Market and Timing - New Capacity Addition
In terms of meeting the projected growth in electric demand reserve requirements, new generation capability will consist of that installed by traditional utility sources, and to an increasingly significant degree, from independent power producers. Forecasted additions of each, developed earlier, are summarized in TABLE 1.4-18. While individual additions are indicated in five year time bands from 1991-2030, summations and subsequent development of the projected market by region is confined to periods after 1996. This is not to suggest that the S-H-U process will not make some inroads prior to that period; instead this is a conservative measure to justify the assumption of commercial maturity, since plants entering service in 1996 would be initiated prior to 1992.

Projected additions developed for the 35 year period total 570.1 GW or approximately 93 percent of the 615.4 GW corresponding to data in Appendix L of the PON. However, projections made on the basis of summer capability, and since 1984 total summer capability was approximately 91 percent of installed capacity, it would appear reasonable to adjust base projections to the Appendix L level in order to reflect nameplate ratings. This is accomplished as indicated in TABLE 1.4-19 at which point an estimated allowance is also made for Hawaii and Alaska, neither of which are represented in the NERC data upon which this projection was based.

TABLE 1.4-17

INDEPENDENT POWER PRODUCTION REGIONAL FORECAST

Year		TOPS Exhbt. 30 Cumltve Pot. MW Cogen.	TOPS Exhbt. 31 Cumltve Proj. MW Cogen.	Total Cumltve MW Cogen.	Cumltve Cogen. MW Added After 1985	ASCC 0.11%	ECAR 9.73%	ERCOT 8.95%	HICC 0.36%	MAAC 12.45%	MAIN 5.36%	MAPP 2.75%	NPCC 9.25%	SERC 13.72%	SPP 15.39%	WSCC 21.93%	All NERC 100.00%
						Estimated Cumulative MW Cogeneration Addition by NERC Region (percentages shown are those assumed for the total annual cogeneration addition in each region)											
1980	*	10600	100	10700													
1985	*	24000	9400	33400	9800	10	954	877	36	1220	525	269	907	1344	1508	2149	9799
1990	*	36600	20600	57200	33600	35	3269	3008	122	4183	1801	923	3109	4609	5171	7369	33599
1995	*	42824	33200	76024	52424	55	5101	4693	191	6526	2810	1439	4851	7191	8068	11498	52423
2000	*	42824	48470	91294	67694	71	6587	6061	247	8427	3628	1859	6264	9286	10418	14847	67695
2005		42824	63740	106564	82964	87	8073	7428	302	10328	4447	2278	7677	11381	12768	18196	82965
2010		42824	79010	121834	98234	103	9559	8795	358	12229	5265	2697	9090	13475	15117	21545	98233
2015		42824	94280	137104	113504	119	11045	10162	414	14130	6084	3116	10503	15570	17467	24894	113504
2020		42824	109550	152374	128774	135	12531	11529	469	16031	6902	3536	11916	17664	19817	28243	128773
2025		42824	124820	167644	144044	151	14016	12896	525	17931	7720	3955	13330	19759	22167	31592	144042
2030		42824	140090	182914	159314	167	15502	14263	581	19832	8539	4374	14743	21854	24517	34942	159314

Notes:
* Source Data Per DOE TOPS Report. DOE/CS/40362-1 May 1983; from Vol. I Exhibits 30 and 31

All others extrapolated or interpolated by G/C

TABLE 1.4-18

PROJECTION OF ESTIMATED GENERATING CAPACITY REQUIREMENTS

Year	ECAR	ERCOT	MAAC	MAIN	U.S. Portion MAPP	U.S. Portion NPCC	SERC	SPP	U.S. Portion WSCC	U.S. TOTAL*
ESTIMATED RELIABILITY (CAPABILITY) ADDITIONS - GW										
1991-1995	0	2.3	0	0	2.5	0	0	0.5	0	5.3
1996-2000	3.8	9.3	0	2.6	3.5	4	14	8.3	1.2	46.7
2001-2005	9.2	9.4	2.2	3.1	3.5	4.4	17.1	8.3	12	69.2
2006-2010	9.1	9.3	2.3	3.2	3.6	4.4	17.1	8.3	12.1	69.4
2011-2015	9.2	9.4	2.3	3.2	3.5	4.5	17.1	8.2	12	69.4
2016-2020	9.2	9.3	2.4	3.2	3.5	4.4	17.1	8.3	12.1	69.5
2021-2025	9.2	9.3	2.3	3.2	3.5	4.4	17.1	8.3	12	69.3
2026-2030	9.2	9.4	2.3	3.2	3.5	4.4	17.1	8.3	12.1	69.5
Total	58.9	67.7	13.8	21.7	27.1	30.5	116.6	58.5	73.5	468.3
ESTIMATED COGENERATION ADDITIONS - GW										
1991-1995	1.8	1.7	2.3	1	0.5	1.7	2.6	2.9	4.1	18.7
1996-2000	1.5	1.4	1.9	0.8	0.4	1.4	2.1	2.4	3.3	15.3
2001-2005	1.5	1.4	1.9	0.8	0.4	1.4	2.1	2.4	3.3	15.3
2006-2010	1.5	1.4	1.9	0.8	0.4	1.4	2.1	2.4	3.3	15.3
2011-2015	1.5	1.4	1.9	0.8	0.4	1.4	2.1	2.4	3.3	15.3
2016-2020	1.5	1.4	1.9	0.8	0.4	1.4	2.1	2.4	3.3	15.3
2021-2025	1.5	1.4	1.9	0.8	0.4	1.4	2.1	2.4	3.3	15.3
2026-2030	1.5	1.4	1.9	0.8	0.4	1.4	2.1	2.4	3.3	15.3
Total	12.3	11.5	15.6	6.6	3.3	11.5	17.3	19.7	27.2	125.8
TOTAL ESTIMATED ADDITIONS - GW										
1996-2000	5.3	10.7	1.9	3.4	3.9	5.4	16.1	10.7	4.5	62
2001-2005	10.7	10.8	4.1	3.9	3.9	5.8	19.2	10.7	15.3	84.5
2006-2010	10.6	10.7	4.2	4	4	5.8	19.2	10.7	15.4	84.7
2011-2015	10.7	10.8	4.2	4	3.9	5.9	19.2	10.6	15.3	84.7
2016-2020	10.7	10.7	4.3	4	3.9	5.8	19.2	10.7	15.4	84.8
2021-2025	10.7	10.7	4.2	4	3.9	5.8	19.2	10.7	15.3	84.6
2026-2030	10.7	10.8	4.2	4	3.9	5.8	19.2	10.7	15.4	84.8
Total	69.4	75.2	27.1	27.3	27.4	40.3	131.3	74.8	96.6	570.1
TOTAL CAPACITY ADJUSTMENT PER APPENDIX "L" - GW 2006-2030 0.93										
TOTAL ADJUSTED ESTIMATED ADDITIONS - GW										
1996-2000	5.7	11.6	2.1	3.7	4.2	5.8	17.4	11.6	4.9	66.9
2001-2005	11.6	11.7	4.4	4.2	4.2	6.3	20.7	11.6	16.5	91.2
2006-2010	11.4	11.6	4.5	4.3	4.3	6.3	20.7	11.6	16.6	91.4
2011-2015	11.6	11.7	4.5	4.3	4.2	6.4	20.7	11.4	16.5	91.4
2016-2020	11.6	11.6	4.6	4.3	4.2	6.3	20.7	11.6	16.6	91.6
2021-2025	11.6	11.6	4.5	4.3	4.2	6.3	20.7	11.6	16.5	91.3
2026-2030	11.6	11.7	4.5	4.3	4.2	6.3	20.7	11.6	16.6	91.6
Total	75.1	81.5	29.1	29.4	29.5	43.7	141.6	81	104.2	615.4

* Includes an adjustment for Alaska and Hawaii

(continued)

TABLE 1.4-18 (continued)

PROJECTION OF ESTIMATED GENERATING CAPACITY REQUIREMENTS

Year	ECAR	ERCOT	MAAC	MAIN	U.S. Portion MAPP	U.S. Portion NPCC	SERC	SPP	U.S. Portion WSCC	U.S. TOTAL*
NUCLEAR ADDITIONS - GW										
1996-2000	0.1	0	0.1	0.1	0	0.1	0.3	0.1	0.1	0.9
2001-2005	0	0	0	0	0	0	0	0	0	0
2006-2010	0	0	0	0	0	0	0	0	0	0
2011-2015	0	0	0	0	0	0	0	0	0	0
2016-2020	0	0	0	0	0	0	0	0	0	0
2021-2025	0	0	0	0	0	0	0	0	0	0
2026-2030	0	0	0	0	0	0	0	0	0	0
Total	0.1	0	0.1	0.1	0	0.1	0.3	0.1	0.1	0.9
HYDRO/RENEWABLES - GW										
1996-2000	0.2	0	0.1	0	0.1	0.4	0.8	0.1	2.2	4.1
2001-2005	0.7	0	0.4	0.1	0.4	1.5	2.8	0.4	7.4	13.7
2006-2010	0.4	0	0.2	0.1	0.2	0.8	1.5	0.2	4	7.4
2011-2015	0.7	0	0.4	0.1	0.4	1.5	2.8	0.4	7.6	14
2016-2020	1.1	0.1	0.6	0.2	0.7	2.5	4.8	0.8	12.9	23.8
2021-2025	1.3	0.1	0.7	0.3	0.8	2.9	5.5	0.9	14.6	27.1
2026-2030	1.3	0.1	0.7	0.3	0.8	2.9	5.5	0.9	14.5	26.9
Total	5.7	0.3	3.1	1.1	3.4	12.5	23.7	3.7	63.2	117
NET FOSSIL ADDITIONS - GW										
1996-2000	5.4	11.6	1.9	3.6	4.1	5.3	16.3	11.4	2.6	62.3
2001-2005	10.9	11.7	4.0	4.1	3.8	4.8	17.9	11.2	9.1	77.6
2006-2010	11.0	11.6	4.3	4.2	4.1	5.5	19.2	11.4	12.6	84.0
2011-2015	10.9	11.7	4.1	4.2	3.8	4.9	17.9	11.0	8.9	77.5
2016-2020	10.5	11.5	4.0	4.1	3.5	3.8	15.9	10.8	3.7	67.9
2021-2025	10.3	11.5	3.8	4.0	3.4	3.4	15.2	10.7	1.9	64.3
2026-2030	10.3	11.6	3.8	4.0	3.4	3.4	15.2	10.7	2.1	64.6
Total	69.3	81.2	25.9	28.2	26.1	31.1	117.6	77.2	40.9	498.2
ESTIMATED CAPACITY REPLACEMENTS - GW										
1996-2000	7.3	2.4	2.8	2.9	1.8	3.3	8.2	3.2	8.2	40.2
2001-2005	8.3	3.5	4	4	2.4	4.2	10.5	4.5	11.7	53.4
2006-2010	9.6	5.2	6.3	5.4	2.9	5.7	13.6	6.7	14.8	70.5
2011-2015	15.7	8.1	9.9	8.1	4.2	8.9	20.4	10.1	17.6	103.5
2016-2020	19.5	9.8	10.5	9.1	6.1	9.8	26	12.5	19.2	123.1
2021-2025	14.7	7.5	6.5	6.1	6.4	5.7	20.2	11.8	15.8	95.2
2026-2030	6.5	3.3	2.5	2.2	3.7	1.6	9	7.1	7.5	43.6
Total	81.6	39.8	42.5	37.8	27.5	39.2	107.9	55.9	94.8	529.5
ESTIMATED TOTAL CAPACITY REQUIREMENTS - GW										
1996-2000	13.2	14.9	4.9	6.8	6.2	9.1	25.9	15.5	11.2	107.9
2001-2005	20.1	16.1	8.4	8.4	6.5	9.5	30	16.6	22.1	138.1
2006-2010	21.5	17.2	11	9.9	7.3	11.7	34.4	19	28.7	161.6
2011-2015	27.5	20.7	14.4	12.6	8.3	14.3	39.9	22	27.8	188.1
2016-2020	30.9	22.2	14.9	13.5	9.9	14.1	43.5	24.2	24.2	198.1
2021-2025	25.9	19.9	10.7	10.4	10.1	9.6	37	23.4	19	166.6
2026-2030	17.7	15.8	6.7	6.5	7.4	5.5	25.8	18.7	10.9	115.4
Total	156.8	127.3	71.0	68.1	55.7	73.8	236.5	139.4	143.9	1875.8

It should also be indicated that though we have reconciled to Appendix L projections in total for the 35 year period, the pattern developed for individual five year intervals has been retained.

Retrofit Capacity

The 45 plus years of plant life used for the earlier forecasts cannot be reached without plant life extension and upgrade efforts. This life extension of existing plants is important in the market survey because a portion of these plant upgrades could utilize the S-H-U FGD process.

It was demonstrated earlier that the U.S. power generation fleet is aging and that the portion of the fleet that is fossil-fueled represents the potential market for S-H-U retrofit. A forecast of the amount of such fossil plant upgrades was made using a similar methodology to that previously described.

FIGURE 1.4-7 illustrates the dates when the fossil plants that are in current operation in the U.S. first entered service. These data are from the GURF files. It is assumed that 20 percent of these plants can be excluded from consideration for life extension upgrades; they will simply be too uneconomical for continued investment and will be operated to earlier retirement than those being upgraded. Retirement/upgrading will also be encouraged by recently passed acid rain legislation.

The remaining fossil plants are assumed updated at a plant age described by the normal distribution, as illustrated in FIGURE 1.4-8. This assumes that most upgrades will be concentrated on plants about 30 years old, with some upgraded as old as 40 years, and some as young as 20 years. This was done for each year of forecast, considering the age of each plant ink that forecast year.

FIGURE 1.4-7

DATES WHEN OPERATIONAL U.S. FOSSIL PLANTS FIRST ENTERED SERVICE

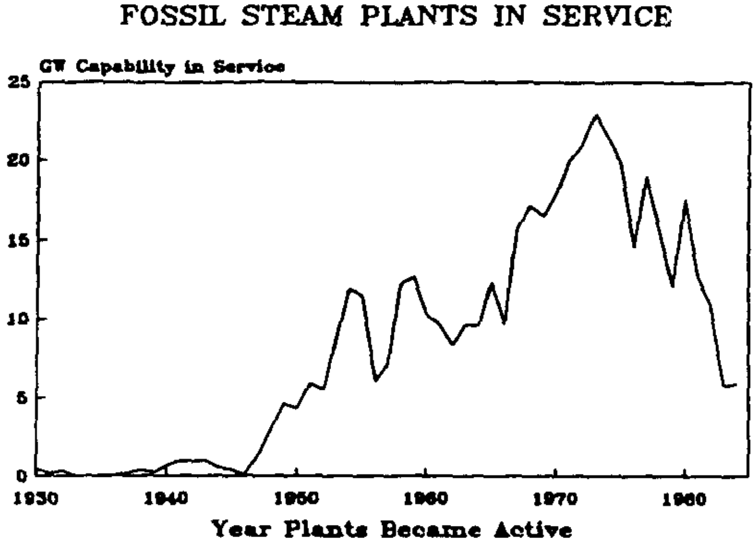


FIGURE 1.4-8

ASSUMED AGE AT WHICH PLANTS WILL BE UPGRADED

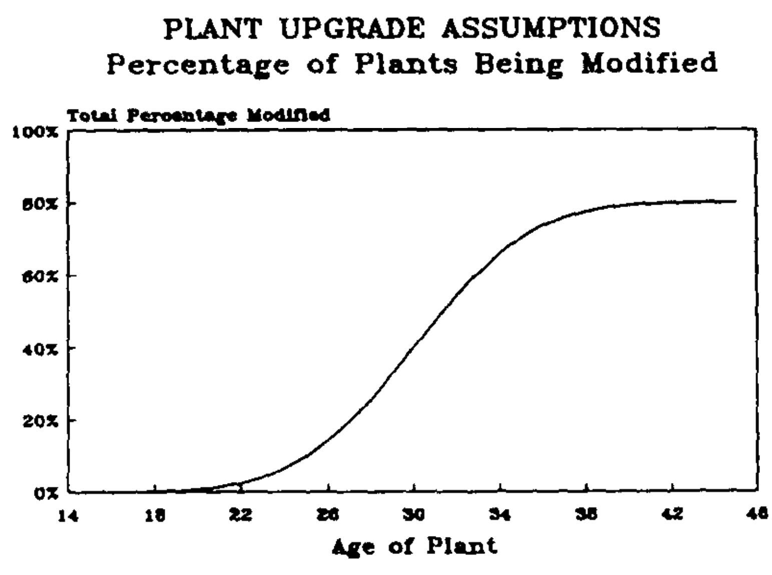


FIGURE 1.4-9 shows the amount of plant upgrade activity forecast in this manner and TABLE 1.4-19 provides a list of the data used to produce the figure. It is important to emphasize that this data represents the size of the plant upgrade market; most plants in this potential market will be candidates for life extension and not necessarily S-H-U retrofit.

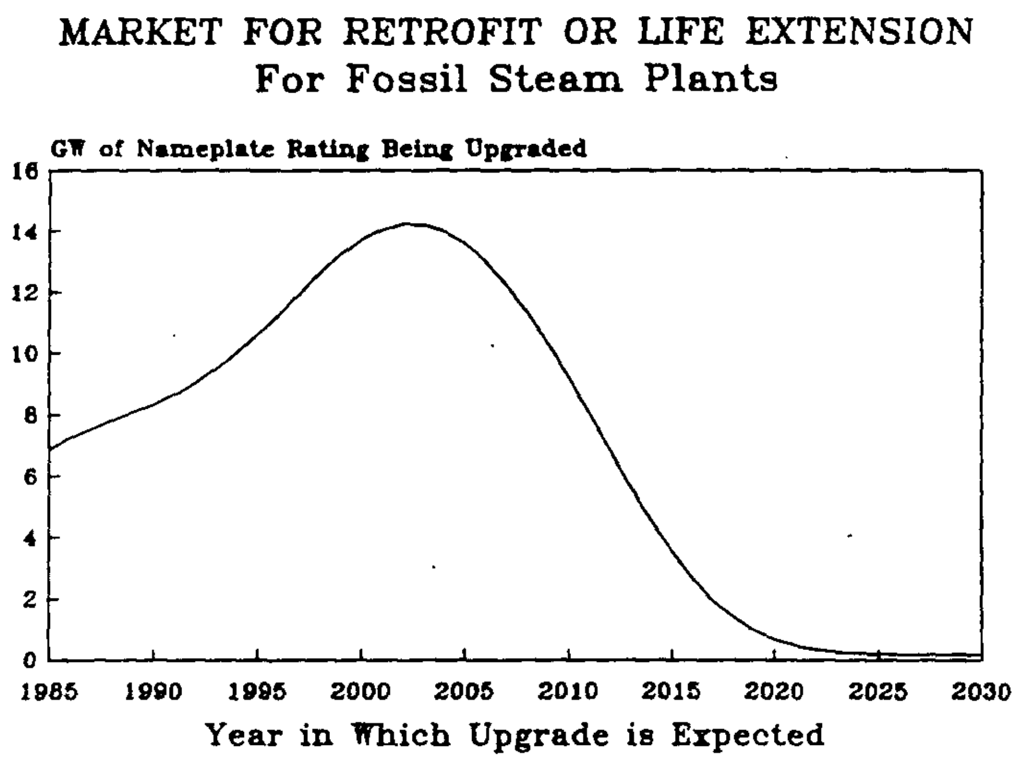
TABLE 1.4-19

BASIS FOR PLANT UPGRADE ESTIMATE

	ESTIMATED MW UPGRADED IN YEAR		ESTIMATED MW UPGRADED IN YEAR
1990	8,334	2011	8,036
1991	8,637	2012	6,836
1992	9,026	2013	5,653
1993	9,479	2014	4,560
1994	9,992	2015	3,568
1995	10,612	2016	2,694
1996	11,280	2017	1,979
1997	11,945	2018	1,424
1998	12,627	2019	990
1999	13,231	2020	688
2000	13,708	2021	480
2001	14,062	2022	345
2002	14,245	2023	263
2003	14,216	024	216
2004	13,986	2025	193
2005	13,607	2026	181
2006	13,001	2027	178
2007	12,267	2028	176
2008	11,356	2029	175
2009	10,320	2030	175
2010	9,185		

FIGURE 1.4-9

FORECAST AMOUNT OF PLANT UPGRADE ACTIVITY



The market to retrofit the integrated sulfur removal concept and flue gas desulfurization was developed using a combination of North American Reliability Council (NERC) data, GURF (DOE Generating Unit Reference File) data, and in-house analysis of plant retirements. NERC data was used to define the regional installed coal capacity which existed in 1980. The 1980 data presented should give a reasonably accurate accounting of the market potential since:

a. The number and capacity of planned plant additions in any year is small compared with the existing capacity.

b. Plant retirements tend to offset some of the plant additions from year to year.

The first line of TABLE 1.4-20 shows the installed coal capacity according to extrapolated NERC data for the year 1988. The second line of TABLE 1.4-20 was estimated from individual coal-fired plants existing or under construction by 1981.

TABLE 1.4-20

POTENTIAL U.S. RETROFIT MARKET FOR COAL POWER PLANTS (MW)

	Region Of The United States (*see FIGURE 1.4-4*)									
	ECAR	ERCOT	MAAC	MAIN	U.S. Portion MAPP	U.S. Portion NPCC	SERC	SPP	U.S. Portion WSCC	U.S. TOTAL
Existing and Planned Capacity, 1988	98,891	51,759	48,471	49,943	29,819	54,989	139,601	66,639	123,980	664,092
Capacity Retirements in 1988-2030	(86,611)	(41,257)	(44,647)	(39,480)	(28,801)	(41,527)	(113,330)	(57,923)	(100,262)	(553,838)
Total Potential Retrofit Market	12,280	10,502	3,824	10,463	1,018	13,462	26,271	8,716	23,718	110,254

S-H-U Market Penetration

In previous sections, a regional forecast of power generation capability expected to be supplied by coal fired technologies was established. The major task in this penetration analysis is to project the market shares for the S-H-U FGD process. Although this is a complex task, the examination of several basic characteristics shows why this technology will be more suitable than other available technology options available to utilities. For established technologies with known cost, economics will be the primary force in selection by utilities; however, with uncertain costs, the perception of economics as well as many other subjective and objective factors must be considered. To be a candidate for selection, the technology must first meet the regulatory and technical goals such as environmental compliance and reliability. However, once these goals qualify the technology as a legitimate candidate, it is economics which drives the selection of one technology over another. The method used here to project the market mix of new technologies and their capabilities to compete with existing technologies is based solely on this economic premise.

Specific economic factors used in this proposal are the investment cost needed to drive additional production of the technology (capital cost in \$/kW) and the cost of producing the technology's commodity, in this case the cost of removing sulfur, which must be expressed as \$/kW-yr.

Assumptions

Cost characteristic assumptions for the S-H-U FGD process, as applied to retrofit and new plant installations, were presented in previous sections. The potential retrofit and new markets for this sulfur reduction technique was developed. The new market was organized into five year segments. It is necessary to develop a similar schedule of replacement for the retrofit market so that a phased penetration of each sulfur reduction approach can be determined.

Retrofitting has been assumed to occur over a 15 year period beginning in 1995, with an initial buildup required, but favoring higher capacity retrofits early. The schedule is shown in TABLE 1.4-21.

TABLE 1.4-21

POTENTIAL RETROFIT CAPACITY, MW
SCHEDULE OF RETROFITS

Region Of The United States (*see FIGURE 1.4-4*)											
Period	Percent Of Capacity Retrofitted	ECAR	ERCOT	MAAC	MAIN	U.S. Portion MAPP	U.S. Portion NPCC	SERC	SPP	U.S. Portion WSCC	U.S. TOTAL
1996-2000	27.5	3,377	2,888	1,051	2,877	280	3,702	7,224	2,396	6,522	30,320
2001-2005	30.8	3,782	3,234	1,177	3,222	313	4,146	8,091	2,684	7,305	33,958
2006-2010	24.6	3,020	2,583	940	2,573	250	3,311	6,462	2,144	5,834	27,122
2011-2015	12.6	1,547	1,323	481	1,318	128	1,696	3,310	1,098	2,988	13,892
2016-2020	3.4	417	357	130	355	34	457	893	296	806	3,748
2021-2025	0.7	86	73	26	73	7	94	183	61	166	771
2026-2030	0.4	49	42	15	41	4	53	105	34	95	441
Total	100 %	12,280	10,502	3,824	10,462	1,018	13,462	26,271	8,716	23,718	110,253

Includes an adjustment for Alaska and Hawaii

The ground rules for this penetration study were established so that the market shares of new power generation technologies would be determined by economic parameters alone. Substitution of the S-H-U FGD process follow classical economic theory, i.e., that the new technology would be introduced gradually at the time of its commercialization, that the market would grow for a successful economical technology or "product", and that the shares of the technology would be based on relative costs.

The simplest substitution of one product for another would appear to depend on which product is more economical. However, historical examples show that seldom does a newer, more economical product immediately replace the sales of the existing product. In fact, the substitution of a new product is an evolutionary process with few sales at first, then an ever increasing market share until it, too, starts being replaced by another lower cost product.

There are at least two major reasons why a new, more economical product has an uphill battle to gain market share. First, there is a natural tendency by consumers or in this case, utilities, to continue buying the familiar product and wait for the new product to prove its worth. Second, the new product when established, has to live and grow on its own merits. Profit from sales are used to support increased production and marketing. The penetrations of new power plant sulfur reduction technologies should follow these general trends.

Peterka applied multivariate mathematics to develop a model where competing technologies can be evaluated. The Peterka model was selected for use in this study to forecast the market shares of the S-H-U FGD process. The Peterka model relates the differences in product costs, specific investments, and the total growth of the market. The basic equation of the model is:

$$a_i[p_i(t+\Delta t)-p_i(t)] = \int_t^{(t+\Delta t)} P_i(t)[p_i(t)-c_i]dt+Q_i(t,\Delta t)+\Delta_i(t+\Delta t)$$

Where $i=n$, the number of technologies (hence equations) being considered. The terms and parameters are defined as :

$a_i[p_i(t+\Delta t)-P_i(t)]$

the investment term, a_i is the capital (specific investment) needed to increase the production, P_i, by one unit in time, Δt.

$\int_t^{(t+\Delta t)} P_i(t)[p_i(t)-c_i]dt$

the capital accumulated by the producer during time period, t. c_i is the specific production costs (includes all expenses to produce and install, including taxes) and $p_i(t)$ is the market price.

a Δp_i terms could be added to p_i to represent the amount a consumer would be willing to pay for a perceived quality.

$Q_i(t,\Delta t)$

an external capital extended to the procedure from the outside, for example governmental support.

$\Delta_i(t+\Delta t)$

the change in capital experienced by the producer during the incremental production time.

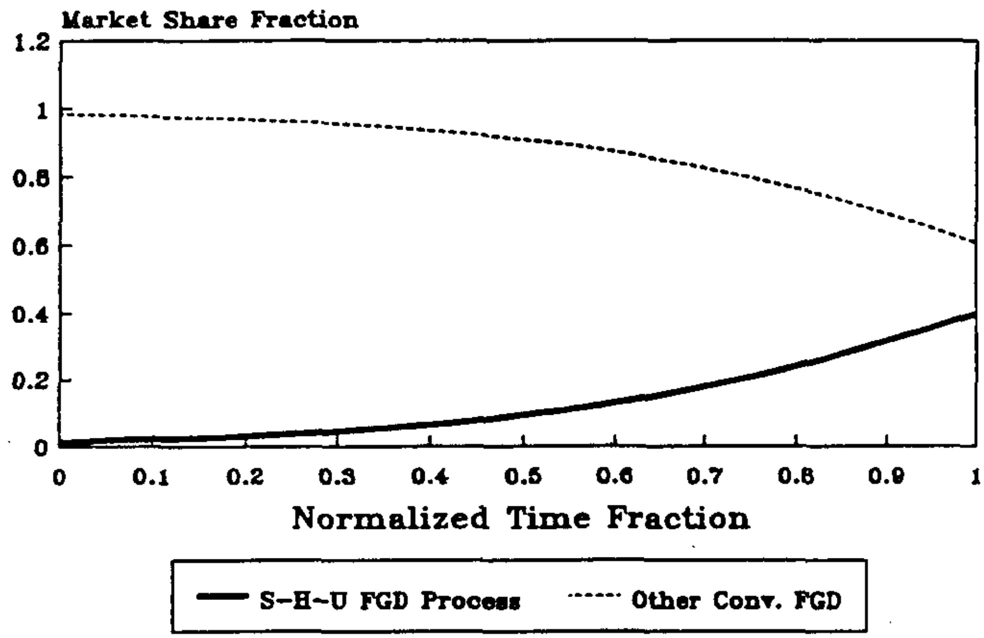
The solution of the Peterka model is intricate, resulting in an algorithm of numerous steps. The algorithm was reduced to a computer model for this proposal to assist in determining the market share of the S-H-U process against existing domestic FGD processes. The computer model was verified by using results presented in Peterka's book which showed the historic replacement of various fuels to satisfy energy needs.

TABLE 1.4-22 shows the resulting market share of the S-H-U FGD process compared with existing FGD for the retrofit power plant market. A five year average is also shown to format the shares according to the potential market, TABLE 1.4-22. FIGURE 1.4-10 depicts the retrofit market growth potential of the S-H-U FGD process.

TABLE 1.4-22
AMERICAN POWER INDUSTRY RETROFIT MARKET SHARE FOR THE S-H-U FGD PROCESS COMPARED TO OTHER TECHNOLOGIES

YEAR	YEARLY S-H-U SHARE	FIVE YEAR AVG. S-H-U SHARE	YEARLY OTHER FGD SHARE
1997	0.019		0.982
1998	0.021		0.980
1999	0.023		0.977
2000	0.026	0.020	0.974
2001	0.028		0.972
2002	0.032		0.968
2003	0.035		0.965
2004	0.039		0.961
2005	0.043	0.035	0.957
2006	0.048		0.952
2007	0.053		0.947
2008	0.059		0.941
2009	0.065		0.935
2010	0.072	0.059	0.928
2011	0.079		0.921
2012	0.088		0.912
2013	0.097		0.903
2014	0.106		0.894
2015	0.117	0.097	0.883
2016	0.129		0.871
2017	0.141		0.859
2018	0.155		0.845
2019	0.169		0.831
2020	0.185	0.156	0.815
2021	0.202		0.799
2022	0.219		0.781
2023	0.238		0.762
2024	0.258		0.742
2025	0.279	0.239	0.721
2026	0.301		0.699
2027	0.323		0.677
2028	0.347		0.653
2029	0.371		0.629
2030	0.396	0.348	0.604

FIGURE 1.4-10
S-H-U FGD RETROFIT MARKET PENETRATION
Fisher-Pry Model



Time Normalized Over 35 Years

Each year's fractional shares depends on the previous year's fractional shares. This means that an initial market share for the new S-H-U technology is required and must be assumed to stimulate a market. A 1.5 percent share was assumed. This is realistic in that it shows that an outside force, such as this proposed project or an initial investment, is needed before the product becomes accepted.

The absolute value of the retrofit market penetration for the S-H-U process can now be quantified by combining TABLE 1.4-21 and TABLE 1.4-22. TABLE 1.4-23 depicts the penetration for the retrofit market. Note that small quantities in some regions do not indicate actual plant sizes, but represent a statistical spread of a number of plants across several regions.

TABLE 1.4-23

U.S. RETROFIT MARKET FOR THE S-H-U FGD PROCESS (IN MW)

Region Of The United States (*see FIGURE 1.4-4*)

Period	*ECAR*	*ERCOT*	*MAAC*	*MAIN*	*U.S. Portion MAPP*	*U.S. Portion NPCC*	*SERC*	*SPP*	*U.S. Portion WSCC*	*U.S. TOTAL**
1996-2000	68	58	21	58	6	74	144	48	130	607
2001-2005	132	113	41	113	11	145	283	94	256	1,188
2006-2010	178	152	56	152	15	195	381	127	344	1,600
2011-2015	150	128	47	128	12	165	321	107	290	1,348
2016-2020	65	56	20	55	5	71	139	46	126	583
2021-2025	21	18	6	17	2	23	44	15	40	186
2026-2030	17	15	5	15	1	19	37	12	33	154
Total	631	540	196	538	52	692	1349	449	1,219	5,666

* Includes an adjustment for Alaska and Hawaii

The balance of the retrofit market would be captured by other available FGD technologies.

The penetration model was also used to generate the market share of the S-H-U process for the new power plant market. TABLE 1.4-24 depicts the market shares. The shares differ from those of the retrofit market due to several factors such as different relative capital costs and the growth of new power generation in the time frame of interest. A projection of 35 years, from 1995 to 2030, was analyzed. FIGURE 1.4-11 depicts the new market growth of the S-H-U FGD process. Note that the total market share for FGD systems diminishes as displaced by other advanced technologies.

TABLE 1.4-24

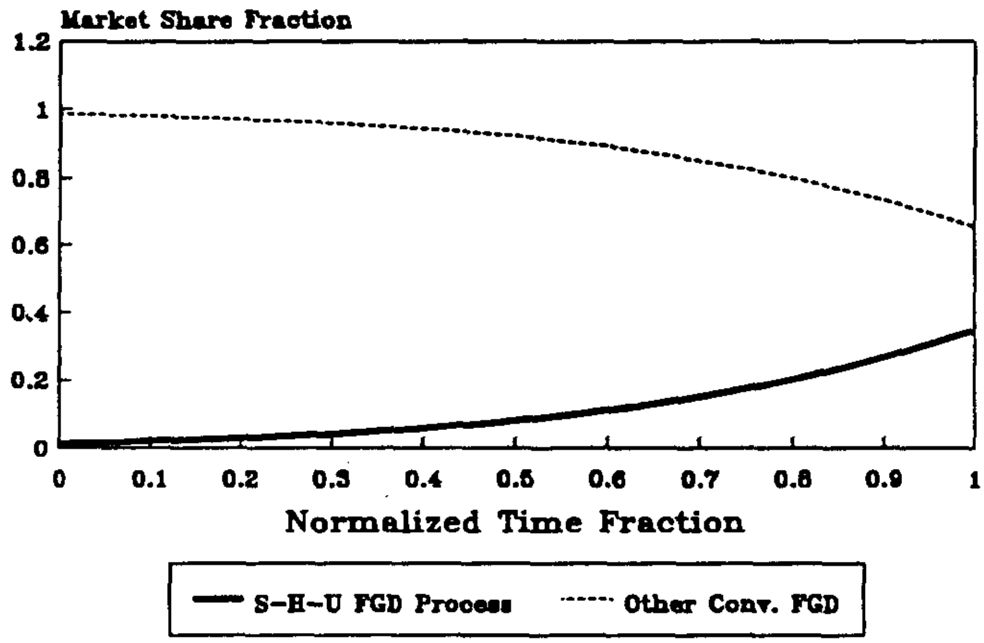
U.S. POWER INDUSTRY NEW POWER PLANT MARKET SHARE FOR THE S-H-U FGD PROCESS COMPARED TO OTHER TECHNOLOGIES

YEAR	YEARLY S-H-U SHARE	FIVE YEAR AVG. S-H-U SHARE	YEARLY OTHER FGD SHARE
1996	0.017		0.983
1997	0.018		0.982
1998	0.020		0.980
1999	0.022		0.978
2000	0.024	0.019	0.976
2001	0.027		0.973
2002	0.030		0.970
2003	0.033		0.967
2004	0.036		0.964
2005	0.040	0.033	0.961
2006	0.043		0.957
2007	0.048		0.952
2008	0.053		0.948
2009	0.058		0.942
2010	0.064	0.053	0.937
2011	0.070		0.931
2012	0.077		0.924
2013	0.084		0.916
2014	0.092		0.908
2015	0.101	0.085	0.899
2016	0.110		0.890
2017	0.121		0.879
2018	0.132		0.868
2019	0.144		0.856
2020	0.157	0.133	0.843
2021	0.171		0.829
2022	0.186		0.814
2023	0.202		0.798
2024	0.220		0.780
2025	0.238	0.203	0.762
2026	0.257		0.743
2027	0.277		0.722
2028	0.300		0.701
2029	0.322		0.678
2030	0.346	0.300	0.654

FIGURE 1.4-11

S-H-U PROCESS NEW MARKET PENETRATION

Fisher-Pry Model



Time Normalized Over 35 Years

The last grouping of TABLE 1.4-25 represents the estimated total capacity requirement for new coal-fired power plants. Thus, this capacity would be the estimated potential market for the S-H-U and other FGD processes.

TABLE 1.4-25

NEW MARKET FOR THE S-H-U FGD PROCESS (IN MW)

Region Of The United States (*see FIGURE 1.4-4*)										
Period	ECAR	ERCOT	MAAC	MAIN	U.S. Portion MAPP	U.S. Portion NPCC	SERC	SPP	U.S. Portion WSCC	U.S. TOTAL*
1996-2000	226	116	65	95	87	77	313	153	178	1,314
2001-2005	584	241	172	207	171	168	673	310	521	3,059
2006-2010	1,001	471	403	413	307	349	1,245	614	1,001	5,824
2011-2015	2,133	1,011	952	892	595	833	2,575	1,266	1,844	12,146
2016-2020	3,843	1,795	1,569	1,529	1,183	1,423	4,774	2,314	3,098	21,612
2021-2025	4,892	2,273	1,583	1,725	1,867	1,339	6,110	3,390	4,039	27,323
2026-2030	4,770	2,130	1,140	1,380	1,950	750	5,670	3,600	3,480	24,960
Total	17,451	8,039	5,883	6,243	6,162	4,942	21,363	11,649	14,165	96,241

* Includes adjustment for Alaska and Hawaii

The balance of the selected new power plant market would use other available sulfur reduction technologies.

1.4.2.3 Stebbins Tile Absorber Market Penetration

The market penetration for Stebbins tile was treated in a similar fashion to that of the S-H-U. The potential market was assumed to be the same. The Fisher-Pry penetration model predicted that by the year 2030 the Stebbins tile absorber had the potential of capturing approximately 24 percent of the market. Five year average market shares are given in TABLE 1.4-26. Total new and retrofit penetration by MW are given in TABLE 1.4-29.

TABLE 1.4-26

ESTIMATED STEBBINS TILE FGD ABSORBER MARKET SHARE

YEAR	FIVE YEAR AVG. SHARE
1996-2000	0.019
2001-2005	0.029
2006-2010	0.044
2011-2015	0.065
2016-2020	0.097
2021-2025	0.143
2026-2030	0.237

1.4.2.4 Heat Pipe Air Heater System Market Penetration

The market penetration of the heat pipe air heater system was treated in a similar fashion to that of the S-H-U. However, since the air heater is not limited to plants with needs for scrubbers, the potential market is much larger. Although the heat pipe air heater can be used in industrial boilers as well as electric utility applications, this study limited the market penetration analysis strictly to utility applications. Consideration of improved industrial acceptance due to this larger retrofit would serve to enhance the potential benefits to the U.S.

The Fisher-Pry penetration model predicted that by the year 2030 the heat pipe air heater had the potential of capturing approximately 25 percent of the market. Five year average market shares are given in TABLE 1.4-29. Total new and retrofit penetration by MW are given in TABLE 1.4-29.

TABLE 1.4-27

ESTIMATED MARKET PENETRATION FOR HEAT PIPE AIR HEATER SYSTEM

YEAR	FIVE YEAR AVG. SHARE
1996-2000	0.020
2001-2005	0.032
2006-2010	0.050
2011-2015	0.077
2016-2020	0.117
2021-2025	0.172
2026-2030	0.245

1.4.2.5 NO_xOUT^* Injection Market Penetration

The market penetration of NO_xOUT^* was treated in a similar fashion to that of the S-H-U. The Fisher-Pry penetration model predicted that by the year 2030 the Stebbins tile absorber had the potential of capturing approximately 24 percent of the market. Five year average market shares are given in TABLE 1.4-28. Total new and retrofit penetration by MW are given in TABLE 1.4-29.

TABLE 1.4-28

ESTIMATED NO_xOUT^* PROCESS MARKET SHARE

YEAR	FIVE YEAR AVG. SHARE
1996-2000	0.020
2001-2005	0.031
2006-2010	0.048
2011-2015	0.073
2016-2020	0.111
2021-2025	0.165
2026-2030	0.239

TABLE 1.4-29
RETROFIT AND NEW PLANT MARKETS FOR THE STEBBINS TILE ABSORBER, HEAT PIPE AIR HEATER, AND NO_xOUT^* TECHNOLOGIES
RETROFIT MARKET
FOR THE STEBBINS TILE AND ABSORBER, HEAT PIPE AIR HEATER, AND NO_xOUT^* INJECTION (IN MW)

Region Of The United States (see FIGURE 1.4-4)										
Estimate For Period 1996-2030										
Technology										
Stebbins Tile Absorber	472	405	147	402	38	516	1,009	335	911	4,235
Heat Pipe Air Heater System	535	458	167	457	45	587	1,144	380	1,032	4,805
NO_xOUT^* Injection	515	441	160	439	43	566	1,101	365	994	4,624

* Includes an adjustment for Alaska and Hawaii

NEW PLANT MARKET

FOR THE STEBBINS TILE ABSORBER, HEAT PIPE AIR HEATER, AND $NO_XOUT^{\circledR}$ INJECTION (IN MW)

Region Of The United States (*see FIGURE 1.4-4*)										
For Period 1996-2030					**U.S.**	**U.S.**			**U.S.**	
					Portion	**Portion**			**Portion**	
Technology	**ECAR**	**ERCOT**	**MAAC**	**MAIN**	**MAPP**	**NPCC**	**SERC**	**SPP**	**WSCC**	**TOTAL***
Stebbins Tile										
Absorber	12,906	5,978	4,601	4,909	4,275	4,112	15,904	8,160	10,923	72,004
Heat Pipe										
Air Heater System	15,971	12,966	7,232	6,936	5,673	7,517	24,089	14,199	14,657	109,578
NOxOUT® Injection	15,310	12,493	6,968	6,683	5,467	7,243	23,211	13,681	14,123	105,582

* Includes an adjustment for Alaska and Hawaii

1.4.3 Comparison with Competing Technologies

The following three subsections highlight the special features of the Saarberg-Hölter Umwelttechnik GmbH (S-H-U) wet flue gas desulfurization (FGD) process that provides advantages for the U.S. power industry. The first two subsections identify the sulfur reduction technologies that are in competition. The third subsection, Subsection 1.4.3.3, then highlights features of the S-H-U process that allow it to favorably compete with the others.

The remaining subsections discuss the features of the Stebbins tile absorber, heat pipe air heater system, and $NO_XOUT^{\circledR}$ injection system that provide advantages to the power industry. There are two subsections for each. The first identifies technologies that are in competition, and the second summarizes features of the technology that allow it to compete successfully with the alternatives.

1.4.3.1 Identification of Competing Sulfur Removal Technologies

The technologies most often considered to provide sulfur emission reductions in U.S. power plants include the following:

- Wet flue gas desulfurization (FGD), the class of technology in which the S-H-U process belongs
- Furnace sorbent injection
- Economizer sorbent injection
- Duct sorbent injection with either lime or sodium sorbent
- Tampella Process sulfur removal
- Lurgi circulating fluidized bed sulfur removal
- Fluidized bed combustion technologies
- Lime spray dryer sulfur removal
- Combined NOx/SOx Control Technologies, such as: NOXSO, Degussa, Haldor Topsoe, Electron Beam, and SNRB
- Pre-combustion sulfur control technologies, such as deep coal cleaning. Here, however, fuel cost becomes high, and only modest levels of sulfur removal are economically practical.

In addition to the technologies listed above, most of which are also amenable to retrofit, there are other technology choices that become strong competitors only when considering existing plant upgrade/retrofit for reduced sulfur emissions. For the retrofit market to existing coal-fired plants, options include:

- retire the unit, and either bulk purchase power or replace with clean new capacity;
- do nothing, controlling sulfur in other units, accepting low capacity factor and retirement prior to any requirement for mandated sulfur control;
- switch to a low sulfur coal or co-fire with natural gas or other clean fuel, accepting moderate sulfur emission levels, higher fuel cost, possible derate, and possible need for particulate control upgrade;

- switch to natural gas or other low sulfur fuel, accepting high fuel cost, and possible vulnerability to future fuel supply curtailment; or
- repower with a cleaner combustion technology (e.g. AFBC) or repower with a topping cycle (e.g. integrated gasification combined cycle) technology.

1.4.3.2 Identification of Competing FGD Processes and Systems

Wet processes are the class of FGD technology that have the largest installed experience base. Wet FGD, and some other competing technologies, have high (90 percent), or, in the case of S-H-U, very high (95+ percent) proven sulfur removal capability. Unfortunately, prior to S-H-U, other types of wet FGD had sensitive control requirements that made operations difficult and sensitive, particularly during load changes and plant transients; scaling deposits and plugging had been a persistent problem, and overall reliability of wet FGD equipped units had therefore suffered. The unique features of the S-H-U process, discussed in Subsection 1.4.3.3, either eliminate or mitigate these problems that are of concern in many other FGD processes. There are many wet FGD processes, some new and some commercially-established. These include:

- S-H-U wet flue-gas desulfurization.
- Conventional limestone wet flue-gas desulfurization.
- Conventional lime wet flue-gas desulfurization.
- Limestone forced-oxidation wet flue-gas desulfurization.
- Magnesium (Thiosorbic) lime wet flue-gas desulfurization.
- Magnesium oxide wet flue-gas desulfurization.
- Wet FGD with inhibited oxidation (Thiosulfate or elemental sulfur).
- Dual-Alkali wet flue-gas desulfurization.
- Bechtel CT-121 wet flue-gas desulfurization.
- Soda Ash wet flue-gas desulfurization.
- Dowa wet flue-gas desulfurization.
- Wellman-Lord (Sulfur) wet flue-gas desulfurization.

- Ispra (Sulfur) wet flue-gas desulfurization.
- SOXAL.
- Other regenerative systems.

1.4.3.3 **Competitive Advantages of the S-H-U Process**

The Electric Power Research Institute (EPRI) completed an evaluation of 24 competing FGD processes. The capital cost of SOXAL, Wellman-Lord, and other regenerable FGD processes is greater than the capital cost of wet limestone scrubbing. The levelized total annual revenue requirements and parasitic energy consumption of the regenerable processes (SOXAL, Wellman-Lord, et. al.) were greater than limestone wet scrubbing. The S-H-U process advantages, when compared to regenerable FGD processes include: lower energy consumption, lower capital and total annual operating costs, and minimal solid waste and scrubber blowdown production.

The throw-away sodium-based systems, such as the soda ash and dual-alkali, are based on expensive soda ash reagent and generate large quantities of sludge for disposal. Ever increasing landfill disposal costs and public resistance to new landfill siting will make expanded use of these processes less likely.

EPRI has recently revised the economic evaluation of commercially available limestone- and lime-based wet FGD systems. Based on this recent analysis, S-H-U has the potential to become the least-cost FGD process. The economic results of the proposed demonstration will be used to confirm the process economics. The project team will compare the Milliken results to these revised wet limestone economic evaluations prepared by EPRI.

The S-H-U process demonstration at Milliken Station will bring a number of attractive features to the U.S. power industry. These features all contribute to the market penetration of the S-H-U process compared to other sulfur removal technologies. The subsections below describe the most important of S-H-U's competitive advantages.

Greater Reduction in Emissions
The S-H-U process is very efficient at sulfur removal; 95 percent removal is guaranteed by S-H-U, and 98 percent sulfur removal can be achieved because of the co-current/counter-current operation and low pH absorption with formic acid buffering.

As a market develops for sulfur credit trading under the recent Clean Air Act Amendments, overscrubbing provides significant advantages to the owner of the ultra-clean unit; other units can remain in service with only modest expenditures, or if not needed for the system or load growth, sulfur credits can be traded.

Because of its ultra-high SO_2 removal, the S-H-U process possesses a very significant selling feature.

Proven High Reliability
In Germany, with 30 absorbers in service in units that are providing approximately 8,000 MW of capacity, the S-H-U process has proven high reliability. In spite of the first-of-a-kind innovations to be demonstrated at Milliken Station, the high reliability of the S-H-U process is still expected. The list below discusses the major innovations to be demonstrated for the first time at Milliken Station, and why these innovations should not affect the proven reliability of the S-H-U process:

a. **First U.S. Demonstration**. The proposed NYSEG team is prepared to bring this overseas technology to successful U.S. application. S-H-U is providing their process engineering, their experience, their considerable interest in U.S. commercialization, and their FGD system knowledge. NYSEG is a project sponsor with a reputation for excellence in operation of its facilities. As a successful operating utility company, it is experienced in selecting processes, A/E firms, equipment, and maintenance procedures that lead to high availability with U.S. operating methods and standards.

NYSEG success here is evident: Milliken Station reliability is exemplary, the station consistently exceeds 85 percent capacity factor; Kintigh Station, NYSEG's most recent addition, was brought in ahead of schedule and under budget. NYSEG will select an experienced U.S. A/E firm to work with S-H-U and NYSEG to develop a U.S. practice design, and effect the transfer of the S-H-U technology to U.S.

b. **First Below-Stack Demonstration of S-H-U Process**. Although Milliken Station is the first below-stack S-H-U design, S-H-U already has an operating plant inside a cross-flow cooling tower at the Völklingen power station in Germany. This plant has operated since 1982 with greater than 98 percent reliability.

c. **First S-H-U Split Module Absorber**. The split module absorber increases reliability, since the two parallel absorbers provide flexibility that increases reliability by providing the capability to operate with only a partial station outage.

Improved Energy Conservation

The S-H-U process is highly energy efficient; it requires less auxiliary power than most of its competitors. In relationship to its competitors, the S-H-U process has improved energy conservation because:

- Formic acid enhances SO_2 absorption efficiency, resulting in about 20 percent less recycle pump capacity for the S-H-U system, which reduces the pump size and power requirements proportionately.

- The S-H-U absorption product, bisulfite, oxidizes directly to gypsum, minimizing air requirements for oxidation; this saves on oxidation blower size and power requirements by about 30 percent.

- Since the use of formic acid is so effective in increasing reagent utilization, the S-H-U system can use a coarser limestone grind without compromising absorption efficiency. The coarser grind could reduce the required mill size and grinding power requirements by about 40 percent.

- The recycle slurry oxidizes completely in the absorber sump, eliminating the need for a separate oxidation step and the associated power loads for the equipment that would otherwise have to be operated.

- S-H-U produces no gypsum fines, which eliminates the power losses other processes consume operating equipment used to separate fines.

Reduced Water Use

The use of mechanical seals on rotating equipment along with operation at high equilibrium chloride levels allows for a reduction in make-up water requirements and improved process control for a tighter water balance. The balance between water required for process uses and for equipment can be better controlled; this assures a zero liquid discharge.

Reduced Waste Streams

By operating at an equilibrium chloride level of 40,000 ppm, the FGD blowdown stream volume is about half that of competing processes. Since the S-H-U process has a reduced volume of FGD blowdown, costs can be saved by installing a smaller treatment system.

The gypsum produced is of commercial grade, and 100 percent is in commercially useable form, thus, unlike most competing processes, there are no throwaway gypsum solids at any operating load level.

Easy Operation
The ease of operation afforded by the inherent stability of its low operating pH and formic acid buffering make the S-H-U process tolerant of disturbances, surges, and plant cycling. Since close control is not needed to assure stable operation, the S-H-U system is easier to control and operate without constant operator attention, compared to other FGD competitors.

Fuel Flexibility
Because of the low pH and formic acid buffering, the S-H-U process, unlike many other processes, is capable of processing a very wide range of coals in a given plant because of its tolerance to variations of sulfur and chloride content. Since fuel selection is not as significant a consideration for the successful operation of the S-H-U process as compared to others, the owner utility has flexibility in selecting the fuels best suited to their boiler and ESP. This also provides the utility with the flexibility to seek price competitive fuel supplies that provide the greatest system economy and boiler operational advantage.

Easy to Operate Over a Wide Load Range
S-H-U can operate a single absorber to very low loads, down to at least 20 percent of maximum; often this is well below the lower boundary that existing plant controls and firing systems allow (many boilers can turn down only to about 40 percent load). Since the utility will not be limited in turndown ability by the desulfurization process, greater economic dispatch flexibility is provided to the system dispatchers. The mist eliminator washing requirement is not as great as with many other FGD systems, so tighter control of the water balance is easier than other systems at low loads.

Produces Commercial Quality Gypsum at Low Load and Low Sulfur
Unlike most other processes, the S-H-U process retains high gypsum quality and desirable gypsum physical characteristics throughout its load range, and through wide variations in coal sulfur level.

Other forced oxidation processes may suffer product contamination and have difficultly producing commercial grade gypsum during load cycling or operation with coals lower in sulfur than specified in their original design. When this happens, the off-specification FGD solids may need to be sent to a landfill.

Easy to Operate During Rapid Load Ramping Power Plant Transients
Because of the ease of control and tolerance to upsets that is offered by the low pH and formic acid buffering, the S-H-U process is easy to operate during ramping conditions. During ramping, operator equipment manipulation requirements are more frequent. Ramping is a critical period of operation due to increased frequency of exposure to potential operator error.

During these transients, the S-H-U process has superior tolerance to system upsets compared to other processes, and unlike other wet FGDs, scaling has never caused a S-H-U shutdown. On the other hand, conventional wet FGDs operating through these load transients have an increased tendency for scale buildup in their absorbers.

If the boiler had low load or cycling capability prior to FGD upgrade, a S-H-U equipped unit can still be considered for that type of operation. A unit's inherent load cycling capability may be lost if certain other competing FGD processes were used instead.

Reduced Maintenance
The inherent chemical stability from the low pH of the S-H-U process results in less maintenance requirements for the system than for competing processes. There is no tendency to scale in the operating pH range. During transients, formic acid buffering aids in stabilizing the process chemistry. Maintenance is reduced to preventive measures. The preventive maintenance is predominantly confined to spared rotating equipment and minor repair of linings at scheduled boiler outages. Maintenance during outages will be less with the tile absorbers than it has been in past S-H-U absorbers which were made from lined carbon steel. This is because of the superior low-maintenance characteristics afforded by the structural and mechanical properties of the Stebbins tile compared to lined steel.

Fits at a Congested Site
The in-stack system being pioneered as part of the Milliken system requires little space compared to other processes. Since the absorber is constructed from relatively small tiles, access during construction is also less of a construction site burden. This system will be a practical candidate for retrofit at many sites where congestion is a problem that prevents other configurations from being considered.

Capital Savings
The formic acid buffering capacity of the S-H-U process, along with the cocurrent/countercurrent absorber results in capital savings due the need for smaller equipment, as summarized in TABLE 1.4-30.

TABLE 1.4-30

S-H-U PROCESS CAPITAL SAVINGS FROM REDUCED SIZE EQUIPMENT COMPARED TO COMPETING PROCESSES

Item	Approximate Size Ratio	Approximate Capital Savings
recycle pumps	25 % smaller volume	15 %
tower mills	up to 50 % smaller	25 % to 30 %
oxidation blowers	25 % smaller volume	15 %
induced draft or booster fans	15 % lower pressure drop	10 %

Improved Operating Economics
Compared to its competition, operating economics are expected to be excellent. This is due to:

- the operational flexibilities listed above increase limestone utilization and reduce auxiliary power requirements therefore leaving more power available for sale;
- the revenue from marketing the high quality gypsum byproduct;
- reduced water consumption and disposal waste
- improved system economy because of the greater dispatch and ramping flexibility; and finally,
- lower maintenance requirements.

1.4.3.4 Competitive Advantages of Stebbins Tile Absorbers

The use of Stebbins ceramic tile for absorbers in a split *cocurrent/countercurrent module will be pioneered at Milliken Station.* This will demonstrate its many competitive advantages as an alternative FGD absorber construction technique. The use of Stebbins tile should increase reliability; the tiles are expected to last the life of the plant, and only the integrity of the mortar need be of limited concern. The Stebbins tile and mortar system on reinforced concrete walls has only been used in one other utility scrubber, a Kellogg horizontal weir scrubber, however, this tile and mortar system is used with high success in the chemical process industry in chemical environments which are much more hostile than in an FGD. The mortar is expected to be very reliable, with only periodic inspection needed and repointing required every ten years. Even in the unlikely case of a leak in the mortar, leaks are easily discovered and repaired. Since repairs can be safely made while the unit is in operation, unscheduled shut-down for leaks should not be needed, so reliability of the tile and mortar system is expected to be superior to any other material for absorber construction.

Identification of Competing Absorber Liner Technologies
Conventional absorbers are usually made of carbon steel plate lined with a variety of different organic and inorganic materials, some of which are listed in TABLE 1.4-31. More recently, as a result of dissatisfaction with conventional lining systems, some utilities have begun to use an alloy wallpaper or cladding lining system whereby very thin gage sheets of high nickel alloy (eg Hastelloy C-276) are welded to the carbon steel substrate. The suitability of such construction in highly abrasive scrubber locations has not been fully demonstrated. More conservative designs use solid alloy construction. However, especially for applications with high chloride in concentrations, this construction requires a high capital cost premium and does not provide the corrosion protection comparable to Stebbins tile.

Competitive Advantages
Stebbins tile absorbers would have a number of competitive advantages. This tile system is amenable to a wide range of FGD systems, and not just limited to the S-H-U process.

Maintenance during outages will be less with the proposed Stebbins tile absorbers than other types of absorbers. This is because of the superior low-maintenance characteristics afforded by the structural and mechanical properties of the Stebbins tile. The tiles are also well suited to retrofit applications, where site space and construction access is usually at a premium. Since the absorber is constructed from relatively small tiles, access during construction is less of a construction site burden. Finally, Stebbins tile lining will be cost competitive with other available lining materials and technologies.

TABLE 1.4-31

COMPETING ABSORBER LINER TECHNOLOGIES

Organic Liners

Natural (gum) rubber
Neoprene
Glass flake-filled/Mica flake filled/Glass Cloth or Glass mat reinforced
- Polyester resin
- Chlorinated polyester resin
- Epoxy resin
- Vinyl ester resin

Fluorelastomer
Epoxy
Coal Tar Epoxy
Urethane
Urethane-asphalt
Chlorobutyl Rubber
Self-Vulcanizing Butyl Rubber

Inorganic Liners

Calcium Alumina Silicate
Potassium Silicate
Pre-krete

Metallic Liners

Numerous High Nickel Alloys

1.4.3.5 Competitive Advantages of the Heat Pipe Air Heater System

The use of heat pipe air heaters combined with corrosion monitoring at the Milliken Station will demonstrate, at a commercial scale, its competitive advantages.

Identification Of Competing Air Heater Technologies

There are two air heater technologies which will compete with the heat pipe air heater. These are the rotary regenerative air heater and the tubular recuperative air heater.

The rotary regenerative air heater consists of a large rotating wheel (rotor) of regenerative heat transfer surface which continuously turns through the gas and air streams. The main disadvantage of this type of air heater is the relatively high air leakage associated with this design and the even metal temperatures which must be maintained to minimize corrosion.

The tubular recuperative type air heater consists of a shell and tube multiple pass heat exchanger where the combustion air flows over the tubes and flue gas flows inside the tubes. The main disadvantage of this type of air heater is low metal temperatures in the cold end resulting in increased corrosion and fouling problems and the increased physical size required for the higher heat recovery sizes.

Competitive Advantages of the Heat Pipe Air Heater System

The advantages of the heat pipe air heater system include:

- **Improved Heat Rate Due to No Air Leakage.** There is no (0%) leakage between the combustion air and the flue gas. Rotary regenerative air heaters have radial and axial seals that are designed to reduce the leakage from the combustion air side of the preheater to the flue gas side. As the heat transfer elements (rotor) turn, air may leak into the gas in a Ljundstrom air heater in three ways: leakage into the gas chamber resulting from entrainment in the rotor passages, leakage at the periphery of the rotor through the clearance space between the rotor and the housing and then into the gas passage and leakage across the radial seals into the gas passage. The leakage reduces the flue gas temperature and causes corrosion and fouling of the air heater, in areas of flue gas condensation. The leakage increases forced and induced draft fans loads, reduces boiler thermal efficiency (since less heat is transferred to the combustion air) and increases maintenance on the air heater through the annual replacement of seals.

- **Improved Heat Rate and Reliability Due to Less Potential for Corrosion.** Conventional recuperative tube air heaters are designed with the flue gas flowing through the tubes, in a crossflow arrangement. The crossflow arrangement results in poor gas distribution and a high temperature differential between the flue gas and the combustion air at the air inlet and the gas outlet area. Because the distribution is poor, and the difference in temperature is high, the flue gas condenses and tube corrosion occurs. Conventional regenerative air heaters experience problems because of their rotating nature and the resulting high temperature differential between the metal elements and the flue gas. As the air heater elements rotate between hot flue gas and cold combustion air, the metal baskets are heated and cooled. The metal that is cooled in the combustion air is instantly subjected to hot fly ash and sulfur oxides on the flue gas side. This causes the sulfur oxides to condense and corrode the baskets and seals, while the fly ash agglomerates and fouls the air heater passages. Heat pipe air heaters, do not suffer from either high temperature differentials or poor gas distribution. The heat pipe is designed with the flue gas flow over the tubes, which enhances gas mixing and provides a more uniform temperature profile than either the tubular or regenerative air heaters. The heat pipe operates on counterflow principles and the heat pipes are isothermal. The result is that the air and gas stream temperatures along a row of heat pipes are virtually uniform, with a temperature differential of close to zero. A much smaller percentage of the total tube bundle and the center tube sheet is exposed to corrosive conditions. Therefore, flue gas condensation is reduced and corrosion and fly ash agglomeration (and fouling) are greatly reduced. The heat pipe air heater will use the CAPCIS corrosion detection system. The CAPCIS system is based on a combination of electrochemical impedance measurements (EIM), electrochemical potential noise (EPN) and electrochemical current noise (ECN). This combination of measurements is highly sensitive and reacts rapidly to changes in the rate of corrosion. The CAPCIS system will control the air heater gas bypass dampers and will allow the heat pipe air heater to be operated at the minimum flue gas outlet temperature consistent with acceptable corrosion rates as indicated by the CAPCIS system.

- **Flexible Design.** Tube pitch and tube pattern can be designed to reduce fouling and cleaning. The pitch and pattern set the gas velocity to establish a self-cleaning scouring action, and to assure that the soot blowing is thorough. The fin density design sets the expected wet fouling zone and fin biasing is used to increase the heat recovery and move the minimum metal temperature row by row. Fin thickness and tube wall thickness influence the effects of corrosion. Tube and fin material set the lower exit gas temperature. The modular construction and the provision for the replacement of individual pipes allows for heat pipe optimization and reconfiguration. Therefore, if corrosion occurs, or occurs at a greater rate than is acceptable, the characteristics of the heat pipe allow it to be modified easily. Conversely, if greater heat transfer were required from the heat pipe, additional tubes, or tubes with more or larger fins could be installed.

- **No Moving Parts.** There is no drive assembly and no rotating elements inside the heat exchanger. There are no shafts, bearings, seals, sector plates, drive motors, speed reducers/gear boxes, cooling fluids, lubricants or plate filled baskets to wear out or maintain, such as are found in the Ljundstorm regenerative air heaters. The heat pipe requires no energy to operate, other than the sootblowers. The heat pipe heat exchanger requires no maintenance, other than an annual inspection. If corroded tubes are found, they can be replaced, however a properly designed heat pipe, that utilizes the proper materials and fin and tube designs, will not suffer from corroded tubes.

- **Reduced wastewater.** Wastewater, from air heater washings is reduced. Conventional regenerative air heaters have to be washed periodically to prevent excessive fouling, high pressure drops, and reduced heat transfer. Because of the low temperature differentials and the reduction in flue gas condensate and fly ash deposition in the heat pipe air heaters, the heat pipe does not have to be washed annually. A heat pipe air heater installed on a 626 MW, high sulfur, coal fired boiler at the West Penn Power's Pleasant Station operated four to five years between washings. At Milliken Station, the regenerative air heaters must be washed twice a year. Each of the two air heaters per boiler produces 120,000 gallons of wastewater during each wash. A total of 480,000 gallons of wastewater must be treated each year for each boiler. During the three year demonstration, the installation of the heat pipe air heater will reduce the amount of wastewater that is treated by the plant by 1,500,000 gallons, for one 150 MW boiler.

Wide Market Appeal

This type of air heater has a wide potential market appeal. It is suited to any power generator, either utility or industrial, who needs reduction of leakage, heat rate improvement, and wide latitude in range of operating temperatures. Its use is suited to many applications beyond simply scrubber upgrades.

1.4.3.6 Competitive Advantages of NO_XOUT® Urea Injection

Combustion modifications, either over fired air ports or low NO_x burners, usually increase the amount of carbon in the fly ash, commonly referred to as loss on ignition (LOI), and can cause large changes in the slagging characteristics of the boiler. Utilities that are concerned about the quality of their fly ash and the performance and reliability of their boilers will be interested in the use the NO_XOUT® system. Fly ash with low LOI's, usually less than three percent of carbon on the ash, can be used as a pozzolonic material in the manufacture of cement. The use of the ash in this manner significantly reduces the amount solid waste that must be disposed, or landfilled. Milliken Station currently sells 90 percent of fly ash produced. The sole use of combustion modifications to reduce NO_x would double the carbon content of the ash and would halt all fly ash sales. Consequently, any utility that is interested in reducing solid waste could not hope to sell the fly ash using combustion modifications alone. In order to reduce LOI with combustion modifications, the utility would be forced to install new pulverizers to grind the coal finer. The coal would have to be reduced from 70 percent through a 200 mesh screen to 90 percent through the screen. The combination of over fired air ports, or low NO_x burners and the installation of new mills would involve a greater capital expenditure than the installation of the NO_XOUT® system.

The slagging problems that could be experienced by combustion modifications cannot be predicted accurately. Recent studies suggest that the furnace exit gas temperature could be changed as much as 100 to 200°F due to furnace heat absorption as a result of different levels of slagging in the furnace.

Another problem with combustion modifications would be the possibility of loosing the flame in staged combustion modifications. With overfired air ports, the burners will operate with very low excess air. Any problems in the burner control systems, or operator error, could produce a hazardous condition if the flame were lost. Excess air must be strictly controlled to prevent flame out, if excess air is low. If excess air is too high, NO_X could be increased.

Finally, combustion modifications will increase carbon monoxide (CO) in the flue gas. Carbon monoxide is a greenhouse gas and is an indicator of incomplete combustion and lost efficiency.

Therefore, in lieu of combustion modifications, utilities will have the incentive to consider use of NO_xOUT^* because it has the lowest capital cost per ton of NO_x removed, the least effect on boiler slagging, air heater fouling, cold end component corrosion, requires the least monitoring and control, is the safest NO_x removal technology, and has reduced chance of loosing the boiler flame or "puffing" the boiler.

Selective Catalytic Reduction (SCR) is the other NO_x removal technology that would be considered for large scale NO_x reduction. SCR installations have a very high capital cost. Typically, SCR installations are so large that they cannot be installed inside the boiler building. An SCR installation for the Milliken Station would require an area of 2400 square feet and would be sixty to seventy feet high. The installation would require significant structural steel and would weigh approximately 500 tons. Since the SCR would be external to the plant, new duct work would have to be installed between the economizer and the air heater, assuming hot side SCR were installed. If cold side SCR were installed, the flue gas would have to be reheated to 650°F, which would reduce plant thermal efficiency. SCR would increase the pressure drop across the system and could require significant induced draft fan upgrades. SCR catalysts have a predicted life of only five to six years and significantly increase the solid waste production of the plant when the catalyst is replaced. Also, the spent catalyst is a hazardous waste and cannot be landfilled in the same manner as fly ash, assuming that a non-regenerable catalyst is used. Finally, hot side SCR installations can promote the formation of ammonium bisulfate in the air heaters and can cause air heater fouling and increased particulate loading on the particulate air control device, which inevitably increases solid waste production.

The NO_xOUT^* system will considered for use by utilities that want to reduce NO_x emissions reliably, safely, and consistently, with the lowest capital and operating costs and the lowest production of solid wastes.

1.4.4 Developmental Risks

Based on successful operating data from applications involving combustion of low/medium-sulfur fuels in commercial plants and high-sulfur fuel in a pilot plant, the technical risk of failing to demonstrate 95% SO_2 removal efficiency and 95% reliability of the S-H-U FGD technology is small. Spare limestone slurry recycle pump capacity will be provided to mitigate this risk and to provide the ability to demonstrate very high SO_2 removal efficiencies of approximately 98% on a variety of coals.

The major risk associated with employing the Stebbins' tile/reinforced concrete design concerns potential corrosion of the concrete and rebar, due to leakage through cracks in the tiles or deteriorated mortar. To handle leaks, Stebbins has devised a repair method based on visual detection of a leak, drilling a hole from outside of the vessel, and pumping sealant through the hole to seal the leak. Since repairs to the external walls may be safely made while the unit is in operation, unscheduled shutdown for leaks should not be required. In addition, inspection and repointing, if necessary, of the mortar between the tiles will be performed during scheduled boiler outages.

Because of its resistance to chemical attack and its ease of repair, the reliability of the tile and mortar system is expected to be superior to any other material for absorber construction, and lifecycle costs are expected to be substantially lower than those of either a steel alloy absorber or a carbon steel absorber lined with chlorobutyl rubber or flake glass. In addition to increased reliability and decreased maintenance, the expected life of the tile lining is three to four times that expected for rubber liners. Thus, the probability of successful operation of the scrubber is high.

The integration of two FGD absorber modules in a single vessel has not been commercially demonstrated. The primary risk associated with a split module design, as compared with two independent modules, concerns the integrity of the central wall that divides the module into independent halves and problems that could result from a high temperature gradient across this wall. With the split module design, there will always be flue gas flowing on one or both sides of the central wall. Repairs to this wall, such as sealing leaks and repointing, will be performed while there is hot gas on the opposite side. The proposed project will demonstrate the success of the repair method and prove the reliability of the split module design and the ability of the central wall to act successfully as a barrier between a hot operating module and a cool shutdown module.

The concept of constructing an absorber module below the flues has not been demonstrated in the U.S., although this concept has been demonstrated in Austria. The proposed demonstration project differs from the Austrian unit in several significant areas. The MCCTD project will use multiple stack flues, a rectangular absorber base, a wet stack, and up to 4% sulfur coal and has a total capacity of 300 MWe. The Austrian unit has a single flue, a circular absorber base, flue gas reheat, burns low-sulfur coal, and has a total capacity of 220 MWe. However, none of these differences is expected to result in significant design or operational problems.

A potential problem is the accumulation on the inner surface of the stack flue of significant amounts of solids, which could break off and fall back into the absorber module and cause damage to its internals. The degree of buildup will be a function of process chemistry, process design, and mist eliminator performance. If solids buildup is a problem, it should appear during the demonstration run. However, with the advanced FGD process design provided by S-H-U, mist carryover should be low enough so that significant flue liner solids buildup will not occur.

Based on successful operating data from NO_xOUT^* applications and on 25 test demonstrations that include NO_x concentrations of up to 650 ppm, the technical risk of not achieving 30% NO_x removed in the flue gas, and manual testing of the fly ash will verify a maximum ammonia slip of 2 ppm to ensure that fly ash sales are not affected.

Failure of the high efficiency air heater system could result in plant shutdown or low load operation. Factors which may cause high efficiency air heater system unavailability include:

- Corrosion of tubes or plates due to SO_3 condensation.
- Inability to achieve design heat transfer rates due to unanticipated fouling and/or inability to clean the heat transfer surfaces.
- Inability to handle the required throughput of flue gas due to plugging with resultant high pressure drop across the unit.

These risk factors will be addressed in the design of the air heater by considering corrosion resistant tubes or plates, by using conservative fouling factors in the design, and by providing for adequate soot blowing. These risks are mitigated by installing the high efficiency air heater system on only one of Milliken's two units and by utilizing the CAPCIS corrosion monitoring system.

The approach of providing a feed/back control signal from corrosion monitoring sensors in the flue gas stream to adjust the high efficiency air heater bypass damper setting is feasible, based on previous work on behalf of EPRI in the U.S. and CEBG/PowerGen in Europe.

In summary, the technical risks associated with this project are small and acceptable.

This project comprises a unique combination of retrofit technologies and plant modifications designed to achieve Clean Air Act Amendment emission levels while maintaining plant efficiency. Although all the technologies have been used in similar situations, the particular combination proposed for this project while feeding high-sulfur coal has not been demonstrated.

There have been approximately 30 installations of the S-H-U FGD process in Europe and Asia, serving over 8,000 MWe of plant capacity. This project will be the first demonstration in the U.S. It will also be the first U.S. demonstration of the split-flow, Stebbins' tile-lined absorber installed below a flue.

The $NO_xOUT^®$ technology is installed, or in the planning stage, on approximately 30 boilers ranging in size up to 900 million Btu/hr. However, none of these installations is firing high-sulfur coal. Thus, this project will be the first commercial demonstration of the $NO_xOUT^®$ technology on a furnace firing U.S. high-sulfur bituminous coal.

Over 100 heat pipe air heaters have been installed on industrial and utility boilers. The most relevant utility installation is at West Penn Power's Pleasant Station at Willow Island, WV. The unit at Pleasant Station is about half the size of the unit proposed for this project. In addition, the unit that would be used in this project would incorporate features, such as corrosion feedback protection and replaceable tubes, included at EPRI's demonstration unit at Kintigh Station but not included at Pleasant Station. This project may be the first commercial-scale demonstration of some of these features. A heat plate air heater system has not been demonstrated in the U.S. If this option is selected, this project will be the first commercial demonstration of this technology in the U.S.

This project will be the first commercial-scale demonstration of this particular combination of air emissions reduction and energy improvement technologies and modifications.

1.4.5 Technical Feasibility

The S-H-U FGD process is fully commercial, with approximately 30 installations. The $NO_xOUT^®$ process is also fully commercial with approximately 30 installations on industrial and utility boilers, although not on high-sulfur coals. There are over 100 commercial installations of heat pipe air heaters. Heat plate air heaters have been used, but not to any extent on coal-fired utility boilers.

In summary, all the pieces of this project are technically feasible, and the probability of successfully integrating them to achieve anticipated CAAA emission levels, while maintaining station efficiency, is high.

The demonstration project will test all aspects of the technology at commercial scale on a commercial coal-fired unit. Data collection, analysis, and reporting will be performed during the operations phase and will include on-stream factors, material balances, equipment performance, efficiencies, and SO_2 and NO_x emission levels. The data that will be generated will be directly applicable to other applications and will provide valuable information to permit commercialization.

The 1990 CAAA requires existing coal-burning power plants to reduce SO_2 and NO_x emissions. Considering the technology options which are commercially available today, it appears that existing plants will have to rely heavily on wet FGD and NO_x mitigation upgrades to reach the levels of sulfur and NO_x removal expected in the legislation.

1.5 DOE'S ROLE IN PROJECT

Overview of Management Organization

The Milliken Clean Coal Technology Demonstration (MCCTD) Project is being managed by a NYSEG Project Manager. This individual is the principal contact with DOE for matters regarding the administration of the Cooperative Agreement between NYSEG and DOE. The DOE Contracting Officer is responsible for all contract matters, and the DOE Contracting Officer's Technical Project Officer (TPO) is responsible for technical liaison and monitoring of the project.

DOE shall be responsible for monitoring all aspects of the project and for granting or denying approvals required by the Cooperative Agreement. The DOE Contracting Officer is DOE's authorized representative for all matters related to the Cooperative Agreement.

The DOE Contracting Officer will appoint a Technical Project Officer (TPO) who will be the authorized representative for all technical matters and will have the authority to issue "Technical Advice" which may:

- Suggest redirection of the Cooperative Agreement effort, recommend a shifting of work emphasis between work areas or tasks, or suggest pursuit of certain lines of inquiry which assist in accomplishing the Statement of Work.
- Approve all technical reports, plans, and items of technical information required to be delivered by the Participant to the DOE under the Cooperative Agreement.

The DOE TPO does not have the authority to issue technical advice which:

- Constitutes an assignment of additional work outside the Statement of Work.
- In any manner causes an increase or decrease in the total estimated cost or the time required for performance of the Cooperative Agreement.
- Changes any of the terms, conditions, or specifications of the Cooperative Agreement.
- Interferes with the Participant's right to perform the terms and conditions of the Cooperative Agreement.

All technical advice shall be issued in writing by the DOE TPO.

NYSEG is primarily responsible for reporting to and interfacing with the DOE. NYSEG is responsible for all phases of the Project. NYSEG is the primary liaison between the DOE and all other participant organizations, as shown in FIGURE 1.5-1. The following organizations interact effectively to meet the intent of the PON and to assure a timely and cost-effective implementation of the MCCTD project through startup and operation.

- New York State Electric & Gas Corporation (NYSEG)
- Saarberg-Hölter-Umwelttechnik GmbH (S-H-U)
- Stebbins Engineering and Manufacturing Company (Stebbins)
- CONSOL, Inc.
- Nalco FuelTech
- ABB Air Preheater, Inc.
- DHR Technologies, Inc.

As shown in FIGURE 1.5-2, the total project encompasses 69 months.

Two budget periods have been established. Consistent with P.L. 101-512, DOE will obligate funds sufficient to cover its share of the cost for each budget period. Throughout the course of this project, reports dealing with the techncial, management, cost and environmental monitoring aspects of the project are prepared by NYSEG and provided to the DOE.

PARTICIPANT PROJECT ORGANIZATION FOR MILLIKEN CLEAN COAL TECHNOLOGY DEMONSTRATION PROJECT

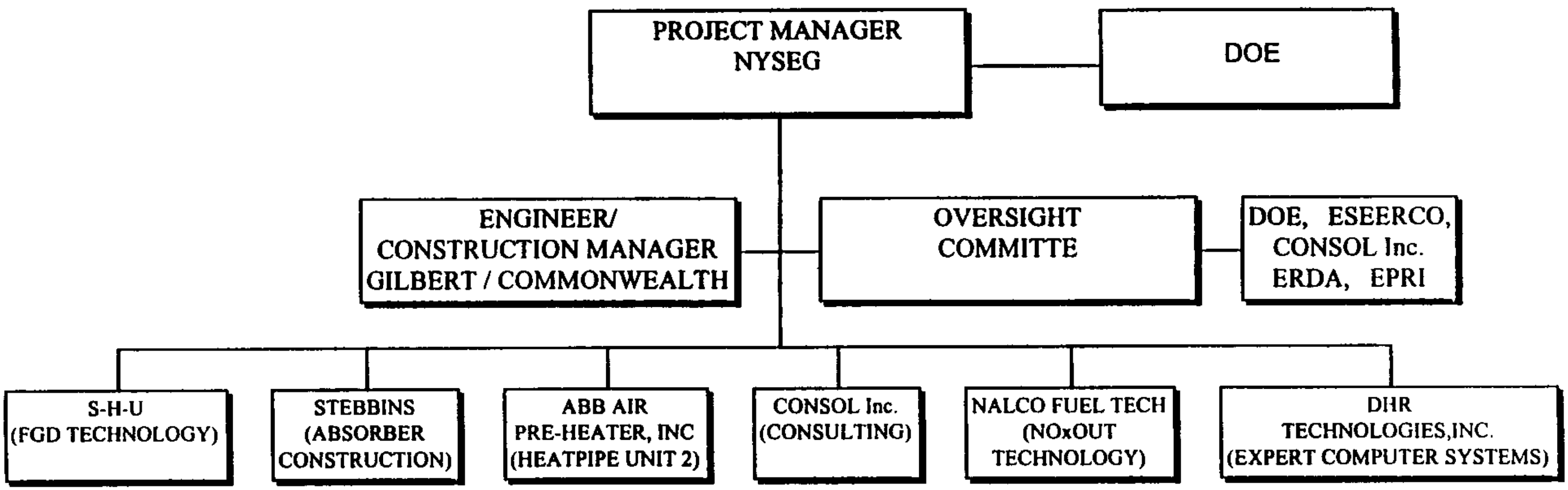
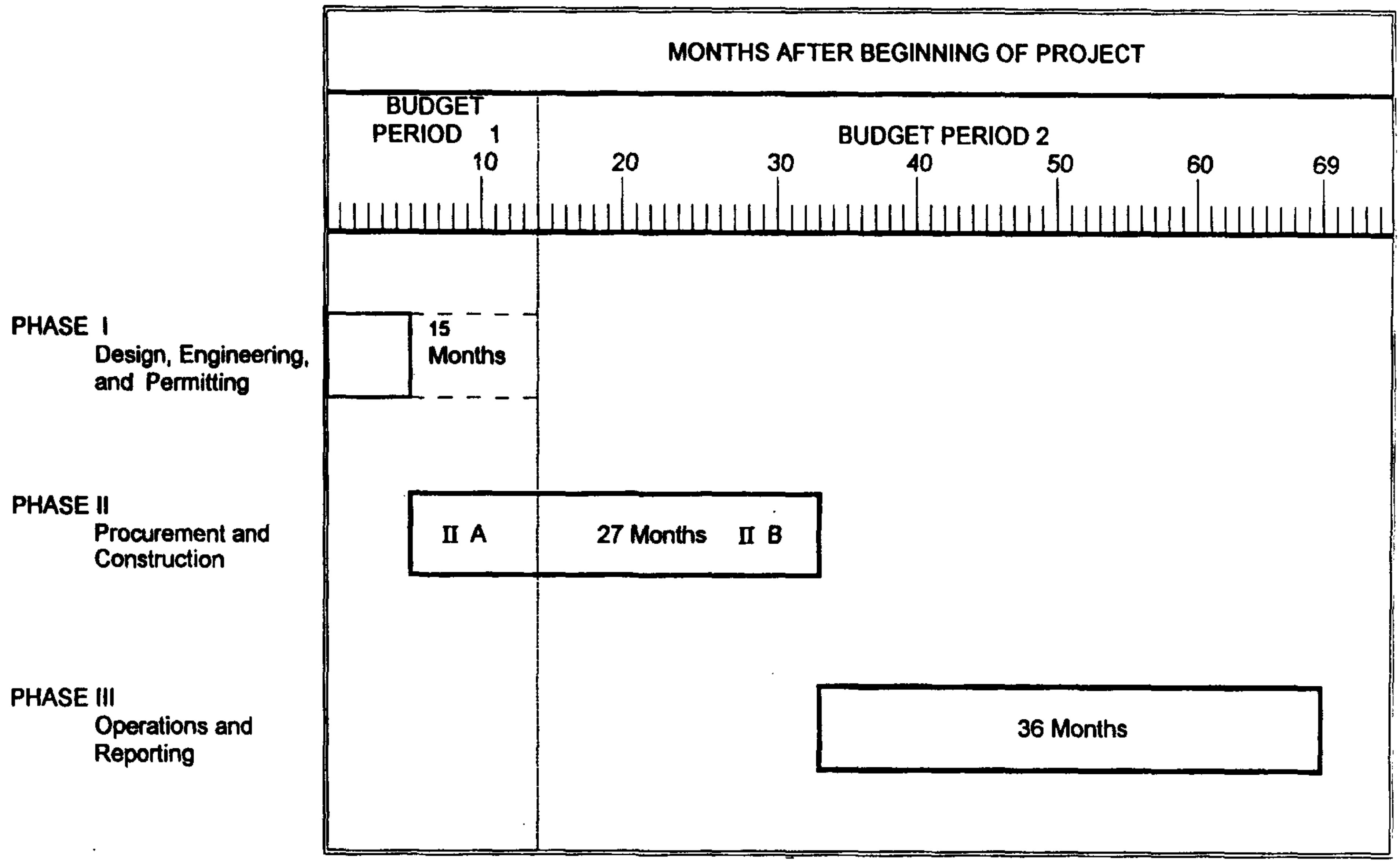


FIGURE 1.5-1

FIGURE 1.5-2

OVERALL SCHEDULE FOR MCCTD PROJECT



MILLIKEN CLEAN COAL TECHNOLOGY

DEMONSTRATION PROJECT

SECTION 2.0

TECHNOLOGY DESCRIPTION

DE-FC22-93PC92642

2.1 DESCRIPTION OF THE TECHNOLOGY BEING USED

The Milliken Clean Coal Technology Demonstration Project will provide significant reductions in emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X). The plant retrofits and upgrades for NYSEG's Milliken Station will demonstrate several innovative technologies that reduce emission of these gases and air toxics.

One particularly attractive feature of the Milliken Clean Coal Technology Demonstration Project is the energy efficiency of the plant upgrades. The integrated package of plant modifications provides excellent environmental characteristics while retaining the high energy efficiency of Milliken Station, historically one of the 20 most efficient generating stations in the United States. At other plants upgraded to reduce environmental emissions, energy efficiency was severely degraded (station heat rate Btu/kWh increased). This project seeks to minimize such heat rate penalties.

The overall project goals are:

- 98% SO_2 removal efficiency using limestone while burning high-sulfur coal.
- NO_X emission reduction by combustion modifications.
- Demonstration of NO_X reductions using selective non-catalytic reduction technology (SNCR) and NO_XOUT® in combination with combustion modifications.
- Production of marketable byproducts to minimize solid waste disposal
  - Commercial-grade gypsum
  - Calcium chloride
  - Fly ash
- Zero wastewater discharge.
- Maximum station efficiency using heat pipe air heater system and low power consuming scrubber system.
- Space-saving design.

The project uses two identical units. Technologies are demonstrated on either one or both of the units to maximize the comparison of innovative energy and environmental management features. All demonstration features of the Milliken Clean Coal Technology Project will be integrated in Milliken Station Unit 2. By incorporating this combination of innovative technologies into one unit, the project will demonstrate excellent pollution abatement with a high level of energy efficiency and conservation that is not possible with many competing technologies.

In addition, the sulfur control process chosen for Unit 2 will be shared with Unit 1, to demonstrate a unique below-stack split absorber flue gas desulfurization (FGD) design. By combining sulfur control in this way, a cost effective station approach results in ultra-high sulfur removal efficiency of the chosen FGD process to significantly reduce the sulfur emissions from both units.

Demonstration Technologies Proposed For Both Units 1 And 2

To accomplish the project goals, NYSEG has selected demonstration technologies which offer substantial improvements in environmental emissions. This project is designed to demonstrate in Milliken Station Units 1 and 2 each of the following:

- To demonstrate the superior energy conservation capabilities and ease of operations of the Saarberg-Hölter Umwelttechnik GmbH (S-H-U) formic acid enhanced wet limestone FGD system, a high reliability system currently in operation in Germany;
- To provide the first demonstration of the ultra-high sulfur removal efficiency (up to 98 percent) of the S-H-U process on a plant fired with high sulfur (greater than 3 percent) eastern sub-bituminous coal;
- To commercialize the S-H-U process in the US using American companies to bring the design to US utility industry standards and operating practice;
- To demonstrate the first S-H-U FGD directly below the flues;
- To demonstrate the first split module cocurrent-countercurrent absorber concept that utilizes Stebbins tile-lined FGD construction methods;
- To demonstrate a zero wastewater discharge FGD system which produces wallboard quality byproduct gypsum along with a marketable calcium chloride byproduct; and
- To demonstrate enhanced removal of hazardous air pollutants.

Complete Integrated Demonstration Technologies For Unit 2

In addition to these upgrades to both units, Unit 2 will be further modified to incorporate a unique combination of changes along with the S-H-U FGD retrofit. NYSEG has selected demonstration technologies which offer substantial improvements in energy conservation for Unit 2, providing one of the most completely integrated, and highly efficient clean air upgrade demonstrations in the world. In addition to the S-H-U/Stebbins retrofits summarized above, the project is designed to demonstrate the following:

- To demonstrate the improved energy efficiency and energy conservation aspects of a heat pipe air heater with temperature control employing a CAPCIS corrosion monitoring system;

- to demonstrate cost-effective compliance with the NO_X emission control provisions of the Clean Air Act Amendments through the use of combustion modifications in combination with improved boiler controls and the NO_XOUT® selective non-catalytic reduction system; and, finally,

- to demonstrate the potential of improved NO_X reduction using the Advanced Combustion Engineering Research Center PCGC-3D model to optimize the design of the NO_X combustion retrofit components.

Further definition of the project and processes are as follows:

Process Concept And How The MCCTD Process Technologies Operate

Three diagrams provide an overview of the proposed project. First, a summary profile of the project scope is shown in FIGURE 2.1-1. This figure illustrates all of the required project segments covered by the MCCTD. This diagram is followed by a process block diagram, FIGURE 2.1-2, which further describes the integration of the overall project. Later in this section, the operation of each of the major technologies that comprise the project is detailed. The third diagram, FIGURE 2.1-3, illustrates the location of the demonstration technologies on the site plan.

The process block diagram, shown as FIGURE 2.1-2, illustrates how Milliken Station Unit 2 will be used to demonstrate the full complement of project features. By incorporating these technologies into one integrated unit demonstration, a cost effective strategy is planned that will meet the goal of overall pollution abatement with increased energy efficiency and conservation. Both Unit 1 and Unit 2 will be used to demonstrate the commercialization aspects of the split module absorber, providing the first commercial

FIGURE 2.1-1
PROJECT PROFILE

SEGMENT OF PLANT	MCCTD PROJECT SCOPE
Raw Coal ↓ ↓ ↓ ↓	•change to high sulfur Eastern coal
PreCombustion ↓ ↓ ↓ ↓ ↓	•change mills to handle new coal
Combustion ↓ ↓ Flue Gas ↓ ↓ ↓	▸NO_X combustion modeling •combustion modifications for primary NO_X emissions
Post Combustion ↓ ↓ ↓ ↓ ↓ Clean Flue Gas	▸first US S-H-U demonstration ▸first US below-stack S-H-U absorber ▸first split S-H-U absorber ▸first utility Stebbins tile cocurrent/countercurrent absorber ▸first NO_XOUT® in high sulfur coal-fired utility furnace for NO_X emission control ▸first coal-fired heat pipe air heater with CAPCIS corrosion monitoring •ID fans •precipitator upgrade •ductwork
Balance of Plant Needs	•blowdown treatment •*power feeds to new equipment* •Unit 1 air heater upgrade •control system upgrade •electrical system upgrade

Legend:

▸novel technology in need of commercial demonstration
•commercial technology required in plant to support the demonstration of the novel technology

FIGURE 2.1-2

PROCESS BLOCK DIAGRAM FOR THE MCCTD PROJECT

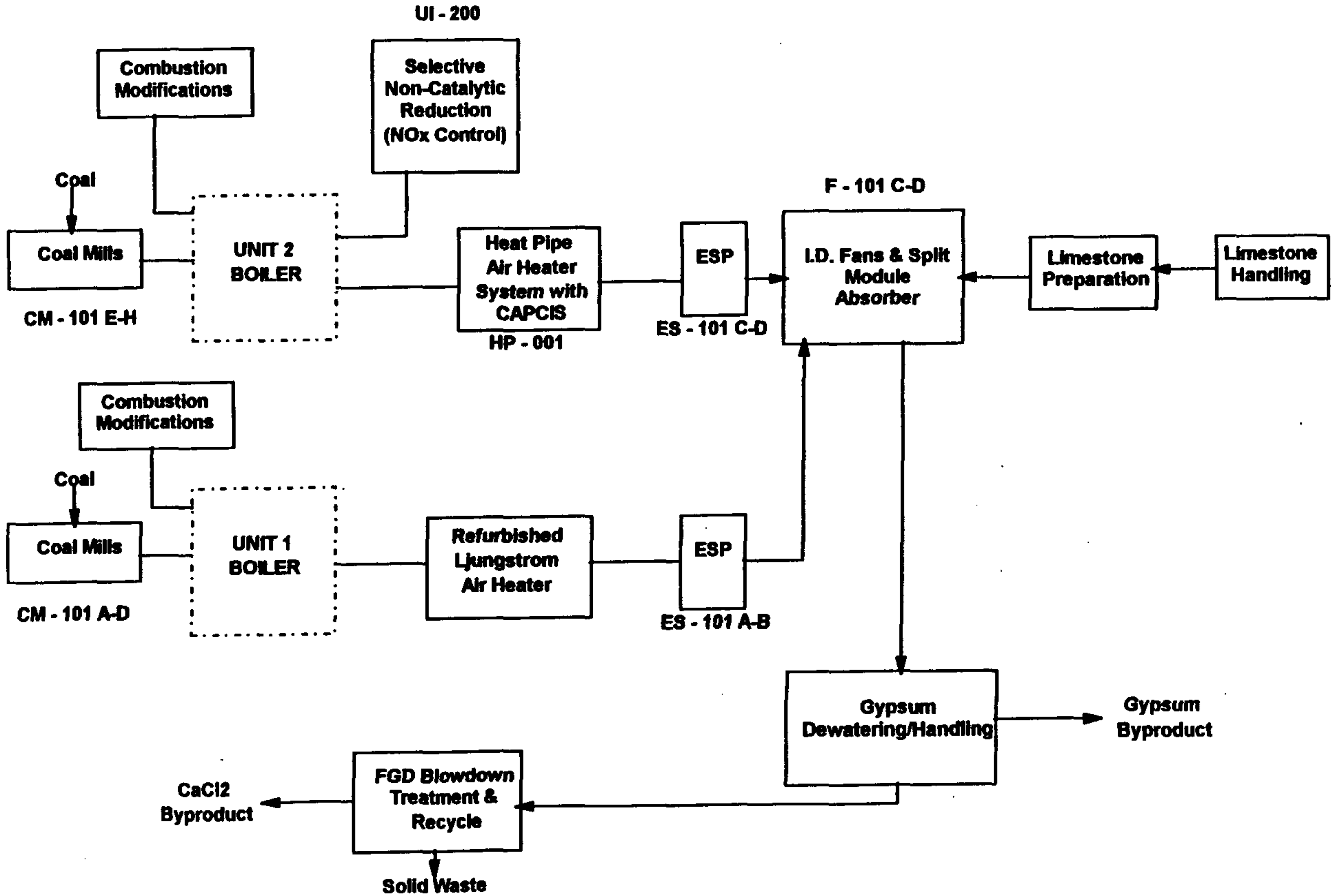
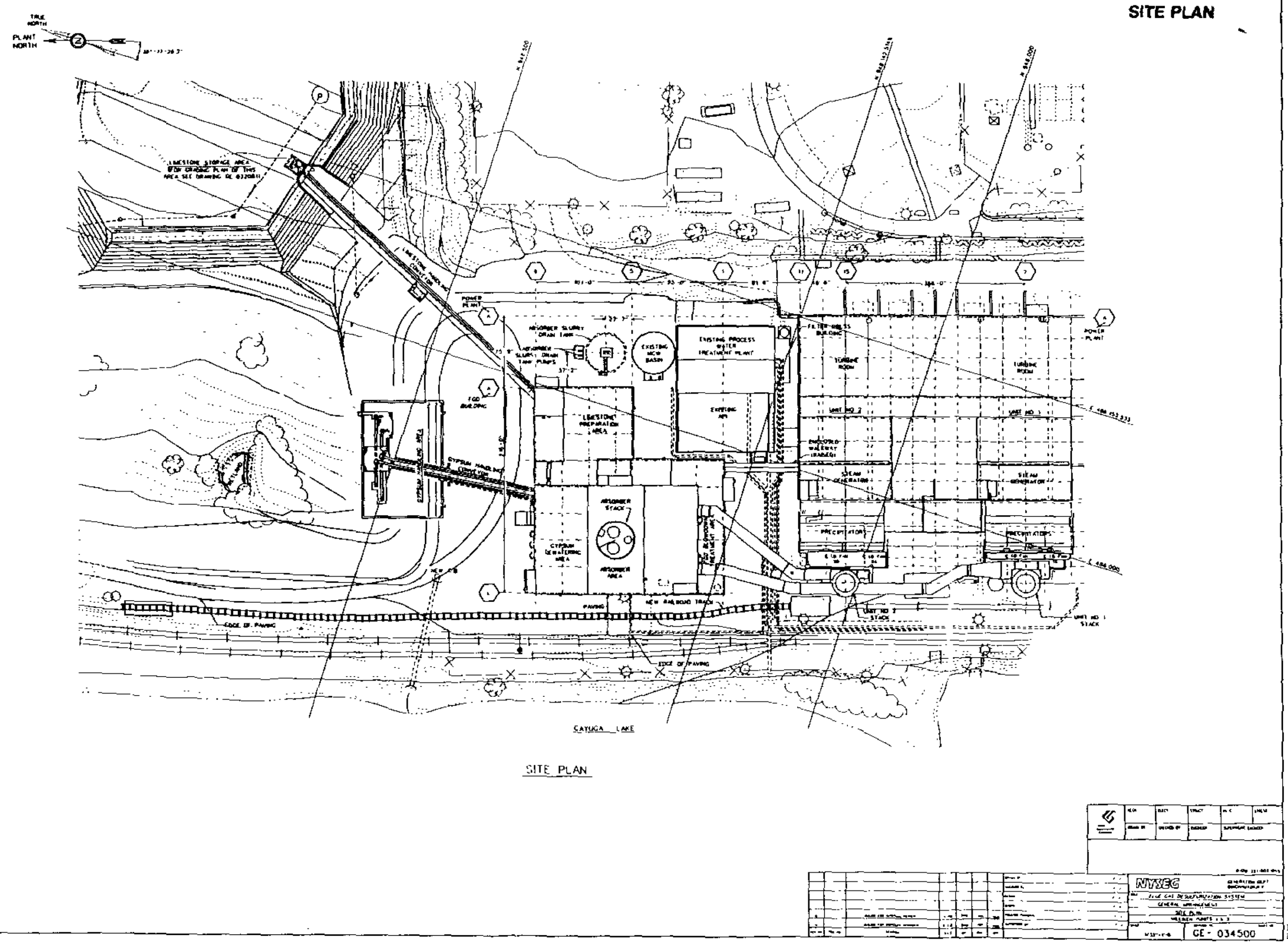


FIGURE 2.1-3

SITE PLAN



demonstration of a split cocurrent/countercurrent S-H-U absorber.

As noted, a main feature of this project is the demonstration of retrofit of both SO_2 and NO_X control systems to a plant with minimum impact to the overall plant heat rate. To accomplish this, energy efficient technologies were selected for integration into the project. An overall project energy balance is provided as TABLE 2.1-1.

TABLE 2.1-1

PROJECT ENERGY BALANCE ESTIMATE

TECHNOLOGY SAVINGS	POWER SAVINGS	HEAT RATE
S-H-U FGD and all Auxiliaries Btu/kWh	-4.04 MW	-120
Thermal Performance Advisor (0.75% Heat Rate) Advisor		70 Btu/kWh
Heat Pipe		47 Btu/kWh
Min 20°F decrease in Exit Gas Temperature (0.5% Heat Rate Improvement)		
16% Reduction in Air Flow Due to Leakage (Fan Power savings of 452 BHP)	337 KW	10 Btu/kWh
NO_X System		~0
NET HEAT RATE SAVINGS =		7 Btu/kWh

Current Heat Rate = **9,422 Btu/kWh**
Modified Heat Rate = **9,415 Btu/kWh**

S-H-U ADVANCED FGD SYSTEM

The S-H-U process is the only developed wet limestone FGD process which is specifically designed to employ the benefits of low pH operation, formic acid enhancement, single loop, cocurrent/countercurrent absorption, and in-situ forced oxidation. These features are inherent to the S-H-U design.

S-H-U Process Concept

The project will demonstrate that S-H-U has succeeded in creating a process with the following features:

- ultra-high SO_2 removal efficiency (up to 98 percent) with limestone,
- low limestone reagent consumption,
- excellent stability and easy operation during load changes and transients,
- low production of scrubber blowdown,
- freedom from scaling and plugging problems,
- high availability,
- low maintenance requirements,
- wallboard grade gypsum byproduct, and
- increased energy efficiency and conservation compared to competing FGD technologies.

For Milliken Units 1 and 2, a single-train FGD absorber has been proposed for each of the two boilers with common auxiliary equipment. A unique single cocurrent/countercurrent split absorber design is provided. This design is unique in that, unlike competitors' cocurrent towers or countercurrent towers, the S-H-U absorber uses no packing or grid work. Packing and grid work found in competitors' absorbers are susceptible to plugging that can lead to excessive pressure drop and power consumption, as well as increased maintenance.

The unique split module cocurrent/countercurrent concept provides greater operating flexibility and reliability to the plant. The absorber is a concrete vessel with tile lining that has a common center dividing wall to provide each unit with its own absorber. Each side of the vessel operates independently of the other. The split module allows the flue gas from each boiler to be independently treated at a lower capital cost than would be required for the construction of two separate vessels.

Below-Stack Absorber

The Milliken Clean Coal Technology Project will provide the first demonstration of the S-H-U process installed directly beneath a plant exhaust stack. This design approach saves considerable site space and is of considerable benefit for existing plants where space for retrofitting an FGD is at a premium. While the below-stack application of S-H-U technology is new, a related application, at the 230 MW Völklingen power plant in West Germany, houses the S-H-U absorber and auxiliary equipment inside a cooling tower. The Völklingen installation has been operating reliably since 1982.

STEBBINS TILE-LINED SPLIT MODULE ABSORBER

An additional feature to be demonstrated for the FGD market is the use of a tile-lined, split module absorber. This will be provided by the Stebbins Engineering and Manufacturing Company located in Watertown, New York. This innovation features an absorber vessel that is divided into two sections to provide separate absorber modules for Units 1 and 2. The design allows for increased flexibility in power plant operations while saving space and money over two totally separate absorbers. The tile lining has superior abrasion and corrosion resistance when compared to rubber and alloy linings, and is expected to last the life of the plant. In addition, the tile is easily installed at existing sites where space for construction is at a premium, making it ideal for retrofit projects.

Dewatering Will Be Located Adjacent to The Absorber

The dewatering area will be located adjacent to the absorber area. It contains the centrifuge feed tank, primary and secondary hydrocyclone system, clarified water tank and pumps, filtrate tank and filtrate pumps. The centrifuge system consists of four centrifuges for both absorbers including one common spare. Refer to FIGURE 2.1-4.

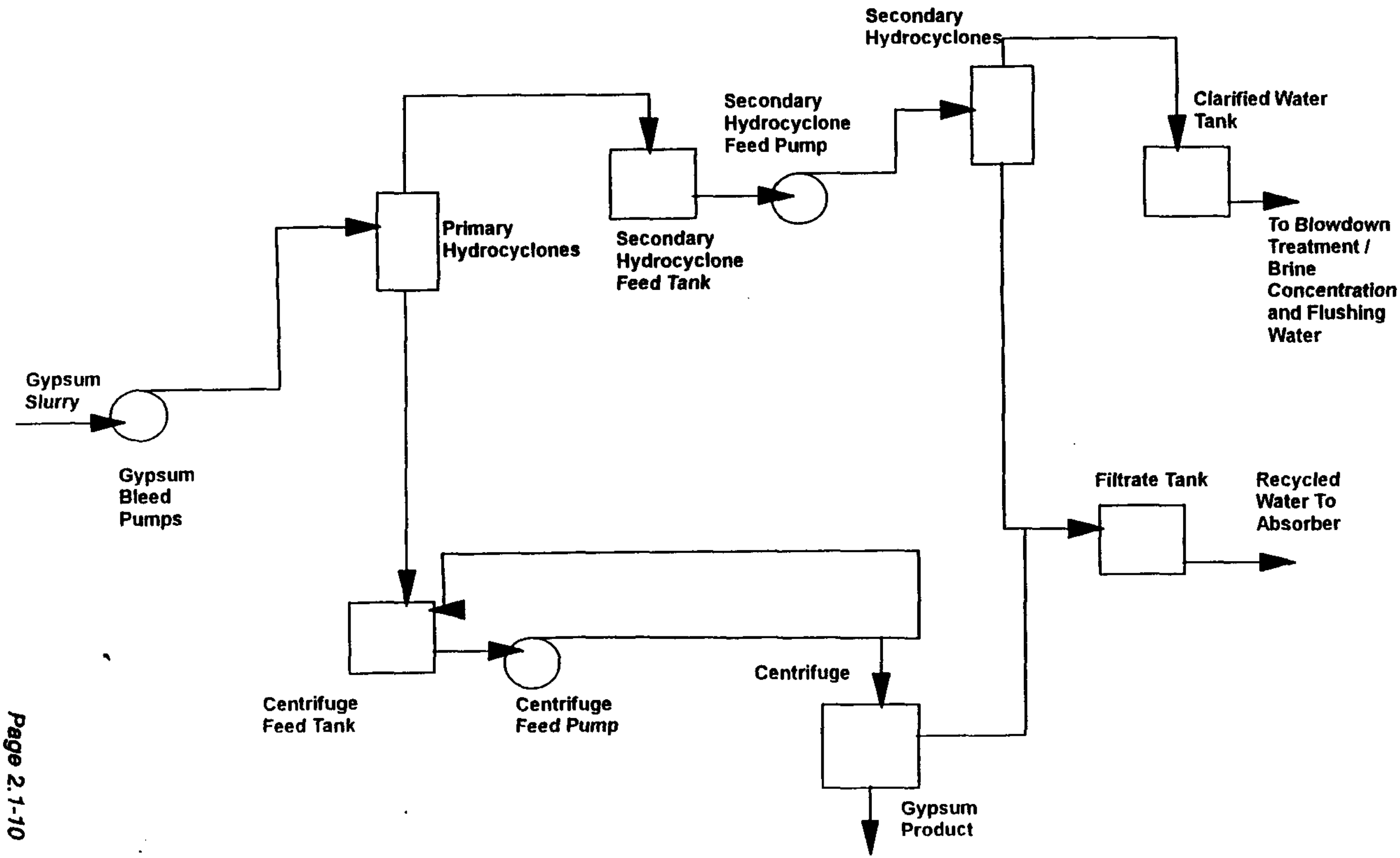
Zero Wastewater Discharge With Wallboard Grade Gypsum And Commercial $CaCl_2$ Production

This project will demonstrate that the S-H-U FGD system will not generate additional plant wastewater. Wallboard grade gypsum and calcium chloride will be produced as marketable byproducts.

Unlike many competing processes that produce gypsum, the S-H-U byproduct gypsum will be of excellent and consistent quality, regardless of the plant load level or flue gas sulfur concentration. The gypsum will be sold as a 6 percent moist gypsum powder for transportation to the purchaser.

FIGURE 2.1-4

BYPRODUCT DEWATERING



The brine concentration system will allow the S-H-U blowdown stream to be purified and recycled to the plant as FGD make-up water. The calcium chloride produced from the brine concentration system will be a commercially marketable product. Calcium chloride will be sold as a solution, or spray dried and sold as a powder, depending on the needs of the purchaser.

Limestone Delivery And Preparation

Common facilities are provided for limestone unloading, storage, and reclaiming. Limestone grinding, fresh slurry storage, and fresh slurry transfer are located in the limestone preparation area of the FGD building.

New Induced Draft Fans Included

Flue gas from the boilers will be discharged through new ID fans which are required to overcome the combined pressure loss of the absorber, ductwork, and new wet chimney. The new ID fans were chosen to minimize heat rate impact, control problems and cost, compared to the use of auxiliary fans.

Bypass Flue Provided

To maintain boiler reliability, the scrubber can be bypassed through a bypass flue in the new chimney. Inlet dampers are provided to isolate the absorbers during bypass operation. Since all the flues are completely separate, outlet isolation dampers are not required.

S-H-U Process Features An Ultra-High Efficiency Absorber

From the ID fans, the flue gas flows to the absorber. The flue gas from each boiler is treated for a minimum of 95 percent SO_2 removal, with a demonstration goal of 98 percent SO_2 removal. Virtually 100 percent chloride removal is accomplished in the combination cocurrent/countercurrent absorber.

Flue Gas Flow In The S-H-U Process

Flue gas enters at the top of the cocurrent section and is contacted with recycle slurry to absorb SO_2. The recycle slurry is introduced by spray nozzles at four separate levels in the cocurrent section of the absorber (three plus a spare). At the bottom of the absorber, the washing fluid disengages from the flue gas and collects in the absorber sump. The flue gas passes to the countercurrent section where it is contacted with recycle slurry from spray nozzles at three separate levels for residual SO_2 absorption (two plus a spare). The flue gas then passes through the two stage mist eliminators to remove entrained water droplets before discharge to the new wet chimney.

SO_2 Absorption

Recycle slurry from the absorber sump containing formic acid is continuously pumped to the absorber spray nozzles by the recycle pumps to provide the medium for SO_2 absorption. Each spray level (four cocurrent and three countercurrent) has one dedicated pump. The system is designed to meet the 95 percent SO_2 removal efficiency when firing 3.2 percent sulfur coal at design flue gas rates, with only five of the seven pumps in operation. The pumps operate at constant flow. For turndown operations, pumps can be taken off line to meet the reduced slurry requirement. Six or seven recycle pumps in service and formic acid are required to achieve 98 percent SO_2 removal. Without formic acid, all seven spray levels and finer limestone grinding (90 percent minus 325 mesh) are required to achieve 95 percent removal efficiency.

Reduction of Air Toxics Emissions

Based on the results of EPRI's "Power Plant Integrated System: Chemical

Emissions Studies" (PISCES) FGD systems have been shown to reduce air toxics emissions. Lower flue gas temperatures experienced in a wet FGD system cause volatile compounds to condense and be captured in the scrubber. PISCES results indicated that an FGD system is a significant contributor in removing chloride and mercury. Through operation at a pH lower then competing FGD processes, metal removal rates (including mercury) will be increased. This occurs because, in general, the solubility of metals increases as pH decreases.

Production Of Wallboard Grade Gypsum

The recycle slurry from both cocurrent and countercurrent sections of absorption collects in the absorber sump. The absorber sump acts as a back-mixed reactor to oxidize the product of absorption (bisulfite) to calcium sulfate (gypsum). Air is injected by oxidation air blowers. Side-mounted agitators are installed to provide complete mixing of air and slurry and to prevent gypsum particles from settling to the bottom.

Oxidation also occurs in the absorber from excess oxygen in the flue gas. Slurry in the absorber sump contains approximately 10 percent gypsum, which provides seed crystals for the formation of gypsum particles. This eliminates uncontrolled gypsum growth on absorber internals that may occur in competing scrubber systems.

A gypsum slurry (approximately 10 percent $CaSO_4 \bullet 2H_2O$) is pumped from the absorber sump by the bleed pumps to the primary hydrocyclones in the dewatering area.

Underflow slurry from the primary hydrocyclones at approximately 25 percent solids, collects in the underflow launder and flows by gravity to one of the centrifuge feed tanks. The centrifuges produce a gypsum cake, 94 percent solids by weight. The cake is conveyed from the centrifuges by the transfer and forwarding conveyors to a storage building. The gypsum is stored until it is loaded onto trucks for transportation to the purchaser.

Water Use

During centrifugation, water from the gypsum slurry is directed through filtration media by centrifugal force and collects in the centrifuge. The filtrate from the centrifuge flows by gravity to the filtrate tank. Fresh process water is used as cake wash before gypsum discharge.

Overflow slurry from the primary hydrocyclones collects in the overflow launder, and flows by gravity to the secondary hydrocyclone feed tank. The secondary hydrocyclone feed pump forwards the slurry to the secondary hydrocyclones. Underflow from the secondary hydrocyclones flows by gravity from the underflow launder to the filtrate tank. Clarified water (the overflow from the secondary hydrocyclones) flows by gravity to the clarified water tank. A small portion of the clarified water from the clarified water tank is pumped to the blowdown water treatment. The major portion is pumped to the limestone grinding system for reagent preparation.

Chloride Purge

To purge absorbed chloride from the slurry system, the blowdown pumps transfer clarified water from the blowdown tank to the blowdown treatment system. See the description on Zero Wastewater Discharge on page 2.1-9, which describes how a commercially marketable $CaCl_2$ product is produced.

Reagent Preparation

Two reagent preparation systems (one spare) are installed. Limestone from storage is conveyed to two 24 hour storage silos. The silos are designed to each store 24 hours capacity of required limestone when burning 3.2 percent sulfur coal at 110 percent of the plant maximum continuous rating (MCR). Limestone is discharged from the bottom of the silos onto individual weigh feeders which convey the limestone to the wet ball mill for size reduction. Clarified water from the clarified water tank is pumped to the mills by the clarified water pumps to be used as grinding and dilution water. The limestone slurry flows through the ball mill to the mill product tank. The mill product pump feeds the slurry to the cyclone classifier. Cyclone classifier underflow is returned to the ball mill. The limestone slurry product, as 90 percent passing 170 mesh at approximately 25 percent solids slurry, flows by gravity from the cyclone classifier overflow launder to the fresh slurry feed tank.

Slurry Transport

Limestone slurry is continuously pumped from the fresh slurry feed tank by the fresh slurry pumps to the absorber. Slurry not required by the absorber flows back to the fresh slurry feed tank in a complete loop. Limestone slurry addition to the absorber is regulated by a control valve in the take off line to the absorber. The fresh slurry feed pumps are sized for two times required flow at design conditions, and operate at constant flow.

Service Water

Service water is piped to the common process water tank in the reagent preparation area. The process water is used for absorber makeup water.

Service water is also piped for use as gypsum wash water, quench sprays, and cooling.

Water from the process water tank is pumped by process water pumps (two operating, one spare) to the absorber. At the absorber, process water is added as mist eliminator wash, wall wash at the wet/dry interface, prequench water to cool the gas prior to absorption and makeup water to the absorber sump, as required.

Protecting The Slurry Lines Against Fouling

For protection of the slurry lines against solid deposition when not in use, each slurry piping system is equipped with piping and motorized valves to automatically drain the slurry to the flushing sumps and flush the lines with clarified water. When recycle pumps are shut down, the main recirculation headers are drained to the flushing sump, then filled with clarified water. The drain valve is then reopened and the header drained to flush solids from the header and recycle pump.

Drain sumps are provided at the absorber to collect slurry flushed from the slurry lines. This slurry is returned to the process via sump pumps to the absorber sumps.

An absorber slurry drain tank is provided to collect and store the contents of an absorber sump during emergency shutdown or scheduled outage when absorber sump inspection is required. This slurry is pumped back to the absorber sump as slurry makeup before restart of the FGD unit. Housekeeping trenches, sumps and pumps are provided in the reagent preparation, and gypsum dewatering area to collect material from floor washing. This material is pumped to the absorber sumps.

FGD CONTROL PHILOSOPHY

An effective control system is proposed for the S-H-U system. Concept with proven reliability. The details of its operation are summarized below.

Controlling The Preparation of the Limestone Slurry

Limestone from the limestone silo discharges to a variable speed belt weigh feeder. The limestone is discharged from the weigh feeder to a wet ball mill. Grinding water is added to the ball mill and dilution water to the mill product tank, in proportion to the limestone feed rate. Clarified water from the gypsum dewatering system is used in the ball mill and as dilution water to the mill product tank.

Control Of Limestone Addition

Limestone addition to the absorber sump is controlled by a feed forward control system. An air flow rate signal from the boiler is multiplied by the SO_2 concentration to create a signal proportional to total flue gas SO_2 mass flow to the absorber. Limestone slurry from the fresh slurry tank is added to the absorber in direct proportion to this SO_2 mass flow, by regulating the limestone slurry control valve. A limestone slurry density signal is fed to the control valve as a trim control to compensate for any variation in the slurry density. The recycle slurry pH is monitored, but is not used as the primary limestone addition control. If the pH exceeds specific minimum/maximum values, the pH will be used to control the limestone addition rate.

The fresh slurry forwarding pumps operate continuously to circulate limestone slurry in a loop from the fresh slurry storage tank to the absorber area and back. A take-off line from the main loop is located adjacent to each absorber and contains the control valves.

Emergency Water System

To protect the absorber internals from temperature excursion in the event of loss of power, an emergency water deluge system is provided. During loss of power, the recirculation pumps will cease to operate, but hot flue gas continues to flow from the boilers due to fan inertia. The controls are interlocked to open the bypass damper (the isolation damper is interlocked so that it cannot close faster than the bypass damper can open), close the inlet isolation damper, and start the emergency water pump to spray water into the absorber through the emergency spray nozzles located at the absorber inlet.

Recycle Pumps Are Placed In Service Manually

The recycle pumps run continuously without control on throughput. The pumps can be taken out of service or placed on line manually to suit the load condition.

Control Of Other Pumps And Filters

The bleed pumps operate continuously to transfer the gypsum slurry from the absorber to the primary hydrocyclones. Underflow from the primary hydrocyclone feeds the centrifuge feed tanks. The feed to the centrifuges is controlled by slurry density in the bleed pump discharge line. (When below the specified density, the primary hydrocyclone overflows the centrifuge feed tank to the filtrate tank.)

Filtrate from the centrifuges combines with the secondary hydrocyclone underflow and collects in the filtrate tanks. Filtrate pumps return the filtrate to the absorber sumps.

STEBBINS TILE ABSORBER CONSTRUCTION

The use of Stebbins tile for absorbers in a split cocurrent/countercurrent module will be pioneered at Milliken Station. This will demonstrate the many competitive advantages of the tile system as an alternative FGD absorber construction technique. The use of Stebbins tile will increase reliability; the tiles are expected to last the life of the plant. Only the integrity of the mortar need be of limited concern for maintenance.

Reliability Is High, And Lifecycle Cost Low

The mortar is expected to be very reliable, with only periodic inspection needed, and repointing required perhaps every 10 years. However, even in the unlikely event of a leak in the mortar, leaks are easily discovered and repaired. Since repairs to the external walls can be safely made while the unit is in operation, unscheduled shutdown for leaks should not be needed. The reliability of the tile and mortar system is expected to be superior to any other material for absorber construction. Lifecycle costs associated with the use of the tile and mortar lining system are expected to be substantially lower than those of either a steel alloy absorber or a carbon steel absorber lined with chlorobutyl rubber or flake glass linings. In addition to increased reliability and decreased maintenance, the expected life of the tile lining is three to four times that expected for rubber liners.

Maintenance during outages will be less with the proposed Stebbins tile absorbers than other types of absorbers. This is because of the superior low-maintenance characteristics afforded by the structural and mechanical properties of the Stebbins tile.

Construction Method Needs Little Site Space

The tiles are also well suited to retrofit applications, where site space and construction access is usually at a premium. Since the absorber is constructed from relatively small tiles, access during construction is less of a site area burden.

Prior Success Of The Tile And Mortar System

The Stebbins tile and mortar system is used with high success in the chemical process industry in chemical environments which are much more hostile than in an FGD system.

The Stebbins tile and mortar system has only been used over reinforced concrete in one other utility scrubber, a Kellogg horizontal weir scrubber. However, the application used here is substantially different from that used in the Kellogg unit. The S-H-U process involves vertical cocurrent and countercurrent flow absorbers. The absorber will have an internal wall to create two separate modules which is termed the split module absorber. The S-H-U process operates at a lower pH and higher chloride level, making this a harsher test of the tile system.

ABB AIR-PREHEATER, INC. HEAT PIPE AIR HEATER SYSTEM

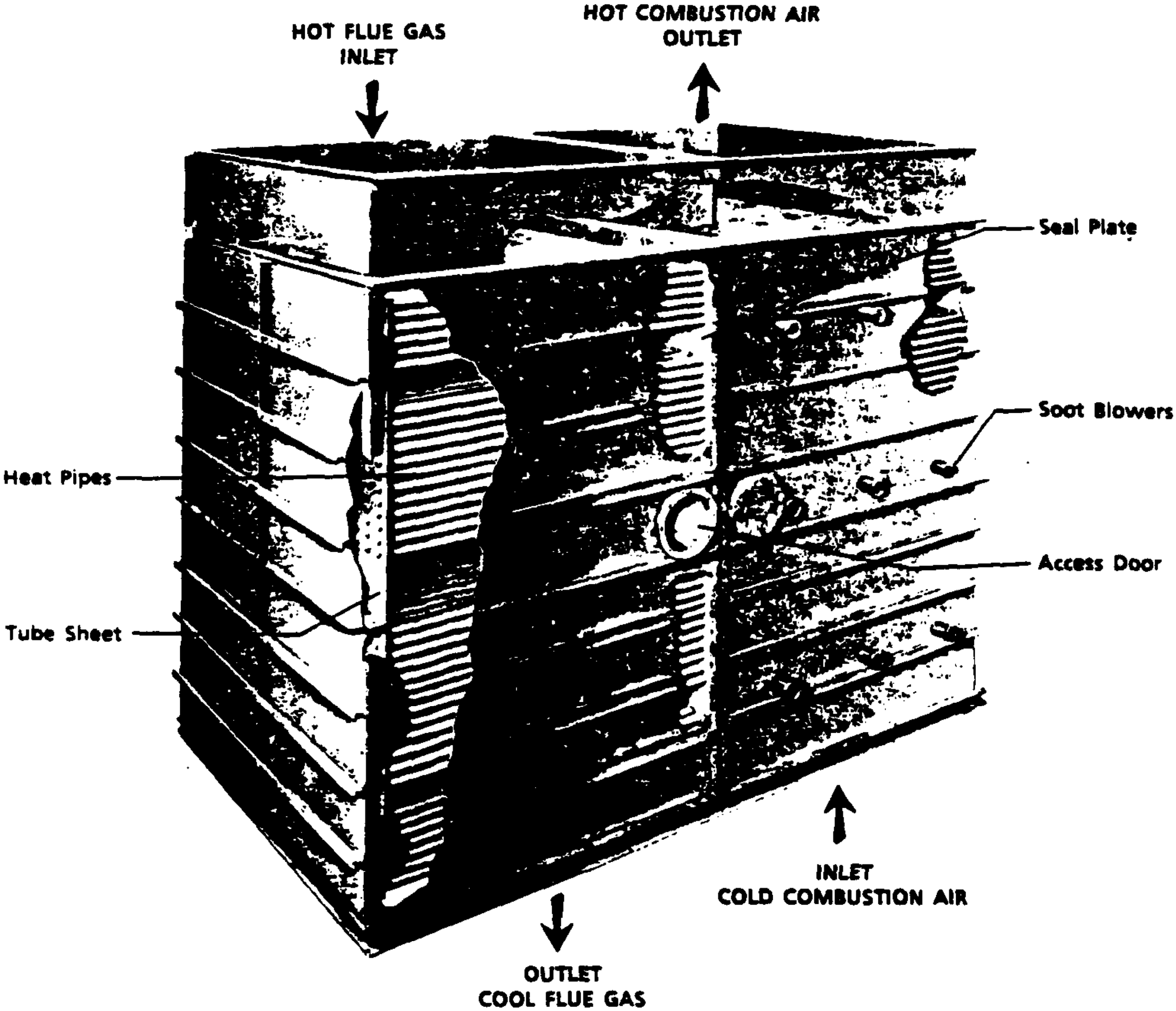
Demonstration of the energy savings provided by a heat pipe air heater installation on a utility boiler is another feature of this project. The heat pipe is an innovative replacement option for the Ljungstrom air heater. The replacement provides energy savings by eliminating air leakage across the air heater and by allowing lower average exit gas temperatures. It has been estimated that for every 35°F drop in flue gas temperature, plant efficiency increases by approximately one percent; thus the incentive is great to install a heat pipe air heater which allows flue gas temperature reduction by maintaining uniform temperatures. The heat pipe air heater will also utilize the CAPCIS corrosion monitoring system and air heater gas bypass system to control the air heater discharge temperature. This project will demonstrate the energy efficiency and conservation gains achievable by incorporating this total system. FIGURE 2.1-5 is an illustration of a typical heat pipe assembly.

Heat Pipe Air Heater Concept

The heat pipe air heater consists of a series of modules with finned, parallel tubes filled with heat transfer fluids, mounted perpendicular to the gas flow. The heat transfer mechanism in the intermediate fluid is based on the heat transfer fluid operating on its saturation-vapor curve. Fluid evaporation occurs on the flue gas side of each tube and fluid condensation occurs on the air side. Different intermediate heat transfer fluids are used for different temperature conditions. The quantity of fluid used in each tube is engineered to provide the correct internal tube pressure for the flue gas and air temperatures to be encountered.

FIGURE 2.1-5

TYPICAL HEAT PIPE ASSEMBLY
(EXCLUDES CAPCIS MONITORING)



Some of the different intermediate heat transfer fluids which may be used are:

- Toluene
- Naphthalene
- (1,1,3) Tri-chloro tri-fluoroethane
- Dowtherm A
- Dowtherm J

Multiple fluids may be used in one air heater application. But, only one fluid is used in any one tube (i.e., the fluids are not mixed together).

Multiple fluids may be used in a single air heater application. However, only one fluid is used in any one tube (i.e. the fluids are not mixed).

How The Heat Pipe Air Heaters Operate

The Milliken Station Unit 2 air heaters, which are Ljungstrom regenerative type air heaters, will be replaced with heat pipe air heaters.

Heat pipe air heaters transfer heat from the boiler flue gas to the boiler combustion air using an intermediate heat transfer fluid. The heat transfer fluid is sealed inside individual heat transfer tubes which are closed at each end. The tubes are installed with one portion of the tube in the flue gas stream and one portion in the air stream. Each tube provides an intermediate closed-loop evaporation/condensation cycle that is driven by the temperature difference between the hot flue gas and the cold combustion air.

On the hot flue gas side, heat is transferred from the flue gas through the tube wall to vaporize the heat transfer fluid (liquid). The vapor travels toward the cold (air side) of the tube, where heat is transferred from the vapor through the tube wall. This heats the combustion air. The vapor inside the tube condenses as it cools while delivering the heat. The condensed liquid in the tube then travels toward the flue gas end where it again vaporizes to repeat the heat transfer process.

A large quantity of heat can be transferred by a small amount of fluid. This fluid can transfer several thousand times as much heat as solid copper, even with only small temperature differences. The result is a very uniform temperature.

Active Anti-Corrosion Control

The thermal efficiency of the boiler is maximized while preventing corrosion by controlling the air heater outlet flue gas temperature. The flue gas exit temperature of the heat pipe air heater is controlled by bypassing the flue gas side of the heater through a control damper. When the corrosion rate gets too high, this on-line control bypass action reduces heat load and raises the flue gas exit temperature. A feed-back control signal is provided from corrosion rate sensors in the flue gas stream to adjust the air heater bypass control damper position. The system adjusts the flue gas exit temperature to the lowest temperature consistent with corrosion prevention.

CAPCIS Corrosion Monitoring System

The corrosion monitoring system includes a number of sensors which will be installed at strategic locations in the flue gas stream, the exit channels of the electrostatic precipitators, the air heater cold end section, and at the outlet of the induced draft fans. At each location, the following variables are sensed:

- Electrochemical Impedance
- Electrochemical Potential Noise
- Electrochemical Current Noise
- Temperature

The output from these sensors is processed in a programmable logic controller (PLC) and compared with pre-defined electrochemical parameters (set point) to control the position of the air heater bypass dampers.

The set point will be determined during this demonstration and will characterize the threshold for onset of material corrosion.

Testing will also be provided to monitor cold end corrosion in the air heater, so that preventative maintenance can be planned to replace corroded tubes at the most convenient time before tube wall thicknesses is reduced to unacceptable levels. This monitoring will minimize problems, eliminate forced outages, and reduce costly unplanned maintenance.

NALCO FUELTECH NOxOUT® SELECTIVE NON-CATALYTIC REDUCTION

The Project includes combustion modifications for primary NO_x emission control, and the NO_xOUT® selective non-catalytic reduction system (SNCR) to achieve a reduced NO_x emission rate that will retain flyash sales. The SNCR reduction system will only be demonstrated on Unit 2 of the Milliken Station. The NO_xOUT® system is a very energy efficient and low capital cost approach to controlling the emissions of nitrogen oxides produced in the combustion process. The proposed NO_xOUT® system used in this project on Unit 2 for the demonstration period will provide further reductions to that provided by combustion modifications made to both Unit 1 and Unit 2.

The NO_xOUT® process provides reduction in NO_x by its reaction of urea. This reaction occurs when urea is injected into the post-combustion zones of the boiler.

Analytical NO_x Computer Modelling

Before the NO_xOUT® system is installed, the process feasibility will be determined through computer modeling of the gas phase chemical kinetics, flue gas dynamics, heat transfer and particle momentum dynamics. Process performance will be analyzed using Nalco Fuel Tech's chemical kinetics computer model (CKM). Process conditions are evaluated using computational fluid dynamics (CFD) modeling techniques. The CFD modeling enables the simulation of injector design configurations to evaluate the effectiveness of urea dispersion in the flue gas, providing the necessary design information for location and number of injection points. Used together, the CKM and CFD models provide a sound basis for predicting expected performance.

Equipment Design Base

The process equipment designs incorporate experience from demonstration and commercial applications to oil and gas fired boilers. Control hardware and software are specified and designed to enable the NO_xOUT® process to compensate for load changes. The degree of NO_x removal can be customized for each application. Automatic feed control and monitoring software systems can also be provided.

NO_xOUT® As An Emission Control Demonstration

This project will demonstrate the overall effectiveness of the NO_xOUT® system in coordination with the other boiler upgrades that NYSEG will be installing. The upgrades to be included by NYSEG are combustion modifications, a coordinated plant control system, and a burner management system.

The incorporation of all these state-of-the-art features with the NO_xOUT® system will allow this project to demonstrate several criteria as follows:

- Minimum 30 percent additional NO_x reductions
- Improved cost effectiveness for NO_x reduction
- Evaluation of effects of simultaneous operation of the NO_x reduction technologies on air heater, ESP, scrubber operations and fly ash quality.

NO_x Removal By Combining Emission Control Technologies

By demonstrating the removal efficiency of the NO_xOUT® process in a boiler with these combined modifications, the NO_xOUT® system can be evaluated with respect to the applicability to either a retrofit application or a new installation.

At an equivalent NO_x emission rate, the Milliken project will demonstrate combining combustion modifications with the NO_xOUT® process to mitigate the adverse effects normally inherent with a single technology, including:

- ammonia slip with NO_xOUT®,
- carbon carry-over with combustion modifications, and
- waterwall slagging with combustion modifications.

The control of these effects are critical to a utility like NYSEG that is dedicated to maximizing the utilization and sale of byproducts, such as fly ash and gypsum. Excessive amounts of either ammonia slip or carbon carry-over would contaminate the fly ash collected in the electrostatic precipitators and prevent the continued sale of the fly ash. Fly ash sales are used by utility companies to reduce landfill requirements. Loss of these sales would greatly increase the landfill requirements for the fly ash, which would be detrimental to the overall environmental goals of the US.

Combustion Modifications

The burner and control system will be modified at NYSEG's expense to provide primary NO_x reduction. While not part of the proposed portion of the project submitted for DOE funding, combustion modifications are an integral portion of the project, since they reduce NO_x levels. The proposed downstream NO_xOUT® demonstration is designed to work with this primary combustion system on Unit 2 to demonstrate low levels of NO_X emissions.

PCGC-3 Combustion Model

The PCGC-3 Combustion model is a comprehensive computer model (3 dimensional) developed under funding from the National Science Foundation to Brigham Young University and the University of Utah through the establishment of an Advanced Combustion Engineering Research Center. The mission of ACERC is to develop advanced combustion technology through fundamental engineering research and educational programs aimed at the solution of critical national combustion problems. These programs are designed to enhance the international competitive position of the U.S. in the clean and efficient use of fossil fuels, particularly coal. The Center is joined and supported by 24 industrial firms, three U.S. government centers, the State of Utah, and three other universities.

The model developed by ACERC will be used to optimize the operation of the combustion equipment especially the design of the combustion modifications to the furnace.

Through the use of the model, the project will demonstrate on the Utility scale the validity of the model and quantify the NO_X reduction achieved through its use.

How The NO_XOUT® SNCR Process Operates

The Milliken project will include the demonstration of the NO_XOUT® selective non-catalytic reduction (SNCR) technology for control of NO_X emissions on Unit 2. The NO_XOUT® Process is offered by Nalco Fuel Tech. The NO_XOUT® process is a new urea-based chemical and mechanical system for cost-effective NO_X reduction from fossil-fueled and waste-fueled combustion sources. From 1976 to 1981, research sponsored by the Electric Power Research Institute (EPRI) established that urea was an effective agent to convert NO_X into harmless nitrogen, carbon dioxide, and water, via these reactions.

$$\mathbf{2NO + NH_2CONH_2 + 1/2\ O_2 \rightarrow 2N_2 + CO_2 + 2H_2O}$$
$$\mathbf{2NO_2 + 2NH_2CONH_2 + O_2 \rightarrow 3N_2 + 2CO_2 + 4H_2O}$$

These reactions take place only in a narrow temperature range, 1600°F to 2100°F, below which ammonia (NH_3) is formed, and above which NO_X emission levels actually increase.

The NO_XOUT® process uses patented chemical enhancers and mechanical modifications to widen the temperature range over which the process is effective and to control the formation of ammonia.

The NO_xOUT® process includes:

- Proprietary computer codes to ensure that the NO_xOUT® chemicals are optimally distributed in the boiler.

- Control hardware and software to enable the NO_xOUT® process to follow boiler load changes by altering the flow rate and injection point of the urea-based reagents.

- Chemical feed, storage, mixing, metering, and pumping systems.

FIGURE 2.1-6 contains a typical schematic diagram of the process.

<u>Zero Wastewater Discharge Description</u>

FIGURE 2.1-7 illustrates the FGD blowdown treatment and recycle system. FGD blowdown will be chemically treated to promote coagulation, flocculation, and sedimentation of suspended solids and metals. Reject (solids) will be dewatered via a plate and frame filter press.

Clarified water will be pumped to a brine concentrator/spray dryer system. Prior to processing in the brine concentrator, water is treated to adjust pH and remove dissolved gases. Ninety percent of the feed to the brine concentrator is recovered as condensate (distilled water) which will be returned to the FGD system as makeup water.

The remaining ten percent of the water will be a brine that is highly concentrated in calcium, magnesium, sodium, and chlorides. The brine is suitable for commercial marketing, but may be spray dried to produce a dry product if market conditions dictate.

The energy efficiency of the brine concentrator is enhanced through use of a vapor recovery system and heat exchangers. Steam is required only for brine concentrator cold startup. During operation, no steam input is required. This results in an energy efficient zero wastewater discharge system which enhances the environmental attractiveness of the Milliken project.

FIGURE 2.1-6

NO_xOUT PROCESS

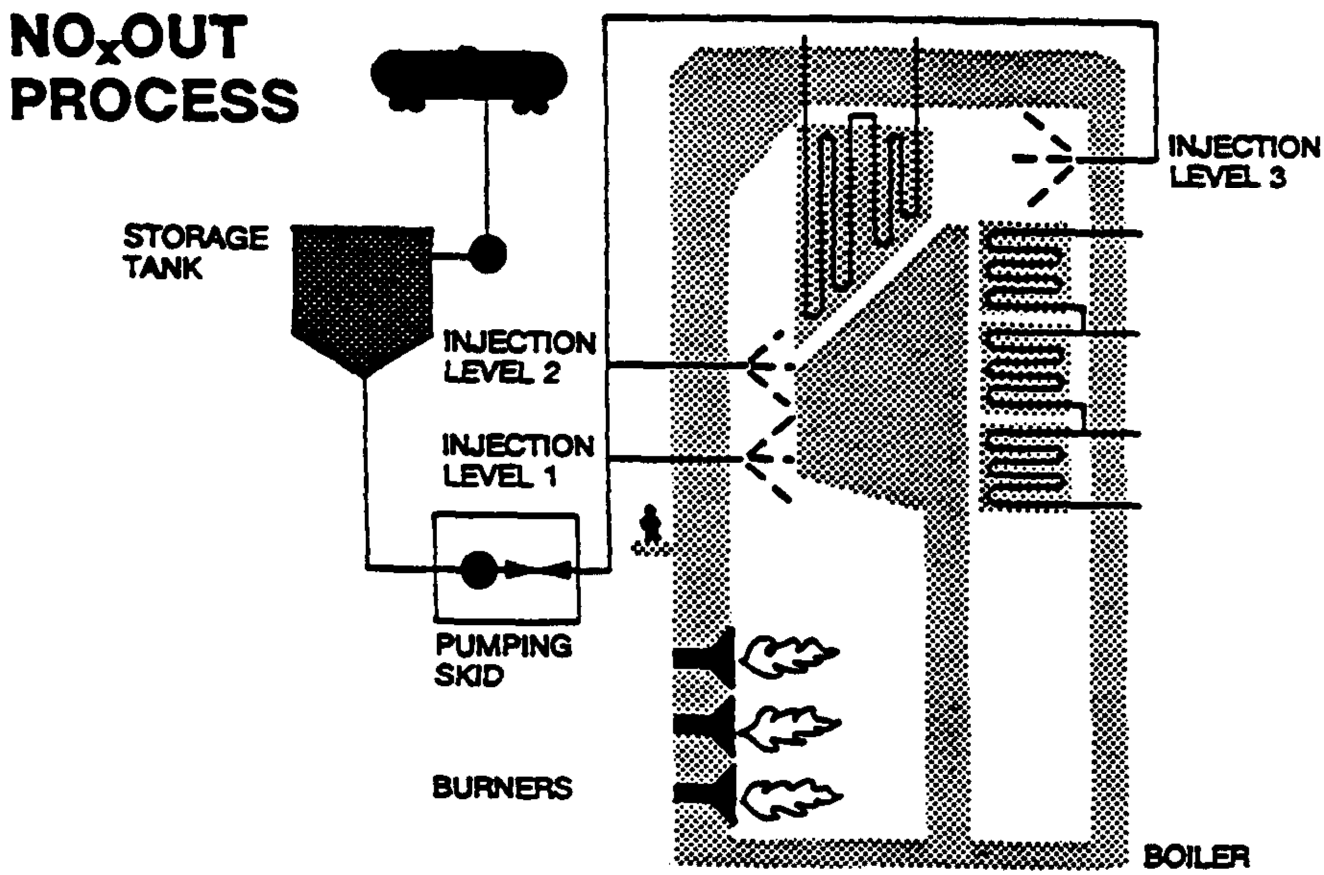
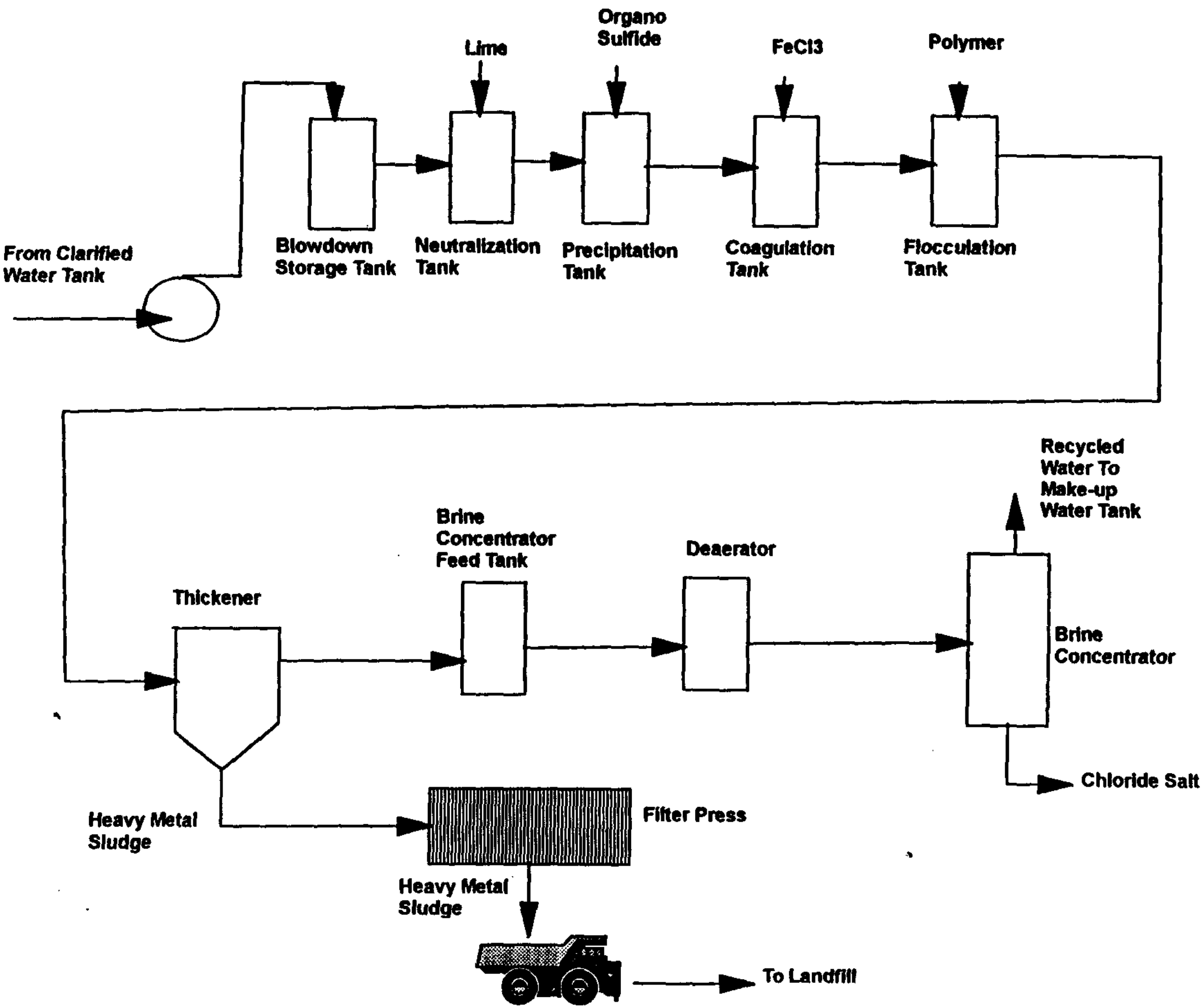


FIGURE 2.1-7
FGD BLOWDOWN TREATMENT & RECYCLE SYSTEM



BALANCE OF PLANT

Other major systems, which are necessary to demonstrate the features of the proposed technologies, are included in the balance of plant. These items are identified as such in FIGURE 2.1-2, found on page 2.1-5. Descriptions of the balance of the required plant systems are as follows:

- Coal mills are included for both Milliken Station Units 1 and 2 to allow testing, demonstration, and continued firing of a wide range of high sulfur eastern coals.

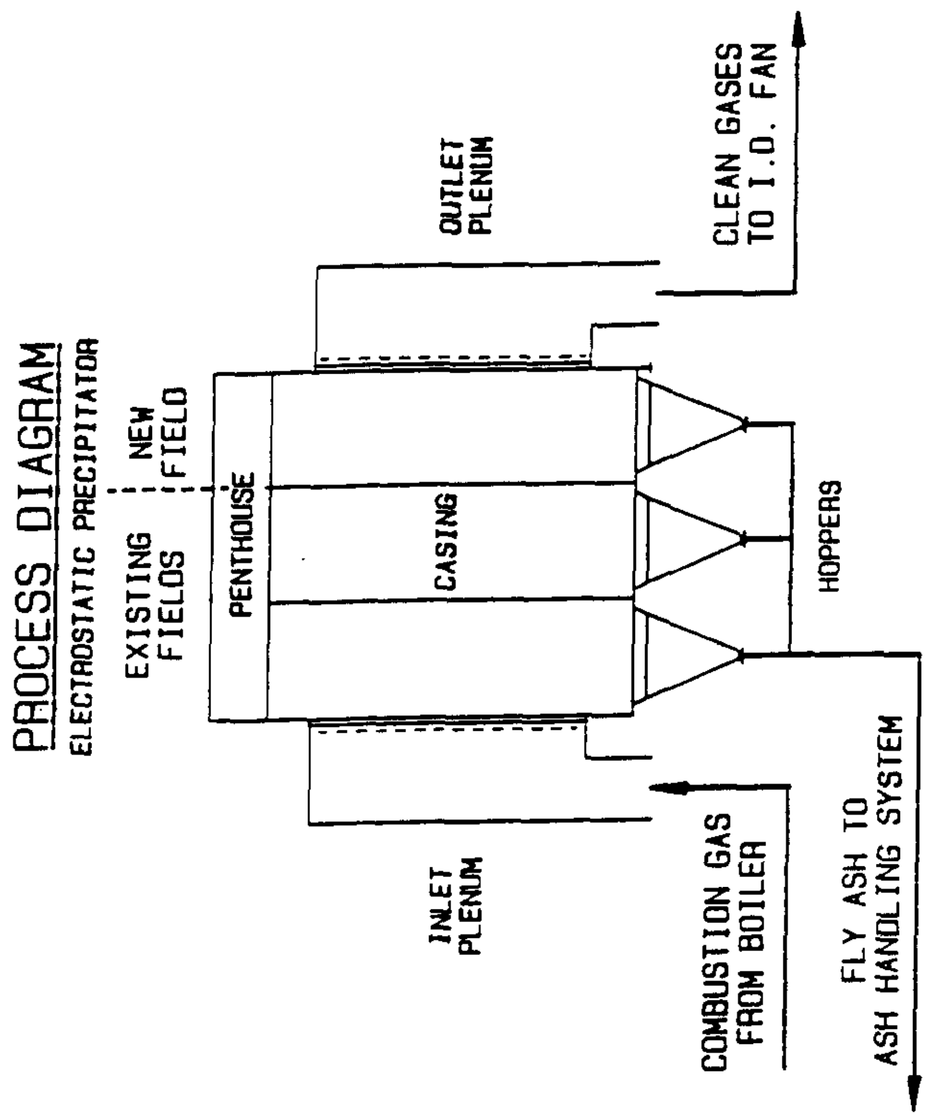
  The existing coal mills would not produce a sufficiently fine grind of the harder high sulfur coals to prevent an unacceptable increase of carbon carry over from the boiler. For a given grind, increased carbon in the fly ash is expected to occur with combustion modifications. Since increases in the carbon carry over would prevent the sale of the fly ash collected in the ESP, the inclusion of these mills is necessary to prevent a large increase in solid waste from the project.

  The coal mill upgrades are also required to demonstrate the suitability of the various processes to a wide range of harder-to-grind coals. To achieve full boiler load operation with the present mills, only soft grind (Hardgrove index of about 70) low sulfur seam coals could be fired, which would not demonstrate the full capability of the S-H-U scrubber.

- Upgrades to the electrostatic precipitators (ESP) are included in the project. With the S-H-U upgrade, the maximum particulate loading at the FGD inlet will be limited by commercial gypsum specifications and FGD operations. For this reason, the ESP's will be upgraded to meet a criteria of 0.017 grains/acf.

  The ESP's for Milliken Station will be completely upgraded. The precipitators will be modified to meet the required air pollution control standards as prescribed by the regulatory agency. The lower precipitator will be removed from operation; and the upper precipitator will be extensively modified. All existing internal components will be replaced. This will include all new collector plates and discharge electrodes as well as new high voltage support bushings, a new rapper system, and high voltage transformer rectifiers. A new third field will be added to the existing upper two field units. The addition of this field will substantially increase the capacity of the upper precipitators. FIGURE 2.1-7A is a process diagram which illustrates the additional field requirements for the ESP upgrade.

FIGURE 2.1-7A


PROCESS DIAGRAM
ELECTROSTATIC PRECIPITATOR
EXISTING FIELDS
NEW FIELD
PENTHOUSE
CASING
HOPPERS
OUTLET PLENUM
INLET PLENUM
CLEAN GASES TO I.D. FAN
COMBUSTION GAS FROM BOILER
FLY ASH TO ASH HANDLING SYSTEM

- The combustion modifications are designed to reduce NO_x emissions approximately 20 percent below present emission levels.

- Upgrades of the boiler control will be completed by NYSEG. These controls are being upgraded to provide reliable operations during the length of the demonstration by replacing original control equipment and instrumentation. Included in this upgrade to improve the plant operations are Boiler and Turbine Process Control, Burner Management System, Motor Start/Stop Control, Auxiliary System Controls, and CRT-based operator stations. This control upgrade will allow for increased reliability in the results of testing due to better data acquisition and less interference from disturbance in boiler operations.

DESCRIPTION OF THE PROCESS CHEMISTRY

The proposed project utilizes two different chemical processes in combination to reduce the emissions of sulfur dioxides and nitrogen oxides. The processes are the S-H-U formic acid enhanced wet limestone FGD process, and the NO_xOUT SNCR process. Simplified descriptions of the chemistry used in these technologies are provided in the subsections that follow.

S-H-U Process Chemistry

In the S-H-U process, SO_2 is absorbed from the flue gas by the recycle slurry and reacts to form bisulfite and hydrogen ions, according to the reaction:

$$SO_2 + H_2O \rightarrow HSO_3^- + H^+ \qquad (1)$$

Small amounts of formic acid, HCOOH, are added to the slurry. Formate ions in solution react with the H^+ to buffer the solution (as shown in reaction (2)), thereby maintaining the pH between 4.0 and 5.0 in the cocurrent zone and between 4.2 and 5.0 in the countercurrent spray zone.

$$H^+ + COOH^- \leftrightarrow HCOOH \qquad (2)$$

As a result of adding formic acid, SO_2 is efficiently absorbed throughout the entire spray zone. Maintaining the slurry in the pH range of 4.0 to 5.0 ensures the formation of calcium bisulfite, the water soluble form of calcium and sulfur.

Limestone added to the washing fluid is the source of calcium ions that precipitate sulfur-containing ions. Formic acid reacts with limestone to produce a washing fluid with calcium ion concentrations much higher than those found in conventional limestone FGD processes (see reaction (3)).

$$CaCO_3 + 2HCOOH \rightarrow Ca^{+2} + 2COOH^- + H_2O + CO_2 \qquad (3)$$

High natural oxidation readily occurs throughout the spray zone. Additional (forced) oxidation occurs in the absorber sump, without the need for an acidifying step. Dissolved oxygen in the washing fluid reacts to form sulfate ions according to reaction (4).

$$2HSO_3^- + O_2 \rightarrow 2H^+ + 2SO_4^{-2} \qquad (4)$$

The calcium ions present in solution combine with the sulfate ions to produce gypsum, according to reaction (5).

$$Ca^{+2}+SO_4^{=}+2H_2O \rightarrow CaSO_4 \cdot 2H_2O\downarrow \qquad (5)$$

For all load conditions, the S-H-U process with its buffered slurry operates within the pH range that precludes sulfite formation. This greatly reduces the operating and maintenance requirements compared to unbuffered processes. These processes usually require a large staff for operation and maintenance and suffer reduced availability due to forced outages to clean the absorbers.

The ability to operate in the non-scaling mode, even during transients, may be the single biggest advantage to low pH buffered absorption and is an extremely important consideration when operating the plant in a cycling mode or burning coals with wide variations in sulfur content.

The buffered operation of the cocurrent/countercurrent absorber permits the absorption/oxidation reaction to occur at a much lower pH than in unbuffered countercurrent absorbers. Low pH operation avoids scale formation and forms the easy-to-oxidize bisulfite ion. The large gypsum crystals that form in the scrubber sump are easy to dewater, and desired by wallboard manufacturers. Operation of the FGD absorption/oxidation reaction in the pH range of 5.5 to 6.0, the case for many competing processes, causes a risk of severe scale formation. In these competing processes, process control of pH is difficult, and the consequence of poor pH control is severe scaling. S-H-U developed the combination cocurrent/countercurrent absorber to operate in the pH range of 4.0 to 5.0. Scaling is thus avoided, and pH control is not critical.

The cocurrent/countercurrent absorber with its multi-level spray system maintains an optimum pH range for bisulfite formation throughout both stages as Figure 2.1-8 illustrates.

Typically, in the cocurrent section, the pH at the top of the spray zone is 5.0 and drops to 4.0 near the bottom of the spray zone. In the countercurrent section, where residual SO_2 is removed, the pH drops from 5.0 to approximately 4.4 to 4.2.

NO_xOUT® Process Chemistry

The NO_xOUT® process utilizes a mixture of urea and other reaction enhancing chemicals to reduce the levels of nitrogen oxides in the boiler. This process is based upon the chemical reaction between the nitrogen oxides and the urea according to reaction equations (6) and (7):

$$2NO + NH_2CONH_2 + 1/2\ O_2 \rightarrow 2N_2 + CO_2 + 2H_2O \quad (6)$$

$$2NO_2 + 2NH_2CONH_2 + O_2 \rightarrow 3N_2 + 2CO_2 + 4H_2O \quad (7)$$

The development of specialized chemical formulations for the NO_xOUT® process has increased the level of NO_x reduction as compared to urea injection. These formulations are carefully controlled to ensure the proper enhancer/urea (E/U) ratio and include proprietary additives to prevent problems such as injector fouling.

The E/U ratio is one of the most significant process variables in the NO_xOUT® process. As noted above, the E/U ratio can effect the amount of NO_x reduction achievable. The E/U ratio controls the formation of undesirable ammonia. Ammonia is formed as an undesirable side reaction which is accelerated as the flue gas temperature decreases or as the NO_x reduction level is increased. Ammonia production is generally undesirable because of the possibility of forming ammonium sulfate and ammonium bisulfate in the presence of sulfur trioxide. Ammonium bisulfate has been known to cause fouling in the air preheater.

Through the development of the enhancers and the E/U ratios, advances in the process chemistry have been realized. In addition, controlled multiple level staging of the injection points in the different temperature zones of the boiler is often possible. Multiple staging of injection points increases the NO_x reduction while maintaining low ammonia slip.

2.1.1 Proprietary Information

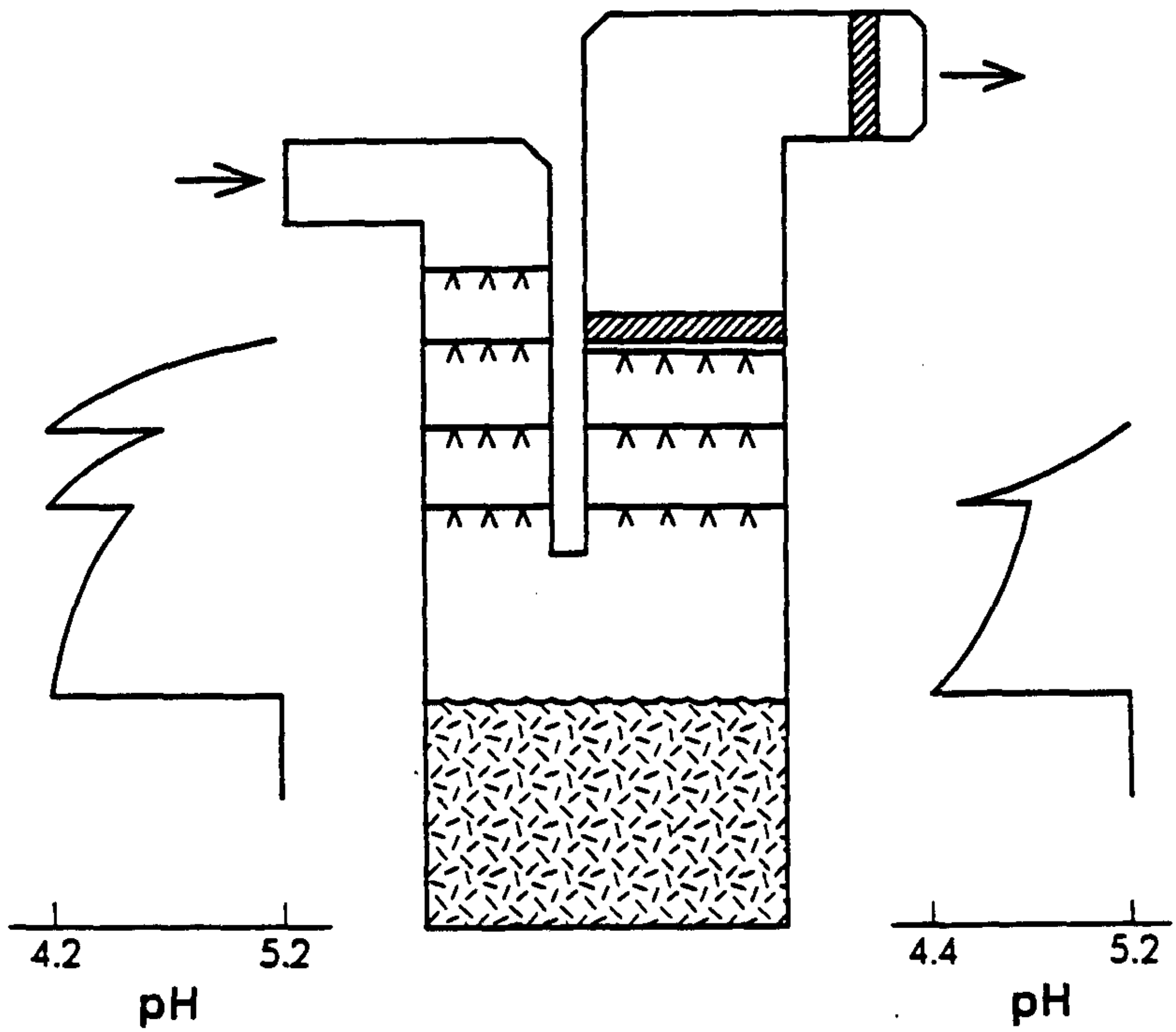
This section summarizes protected and proprietory information for Saarberg-Hölter Umwelttechnik, The Stebbins Engineering and Manufacturing Company, Nalco FuelTech, ABB Air Preheater and New York State Electric & Gas Corporation. In addition, other equipment vendors have identified their piping and instrumentation drawings (P&ID) and process flow diagrams (PFD) as proprietory. These vendors include; RCC and IDI (waste water treatment suppliers.)

Saarberg-Hölter Umwelttechnik has identified the following as proprietary:

- S-H-U/NYSEG contract
- Liquid to gas ratio specific to the Milliken design.
- Amount of recycle slurry ie. flow rate.
- Oxidation air ratio or oxidation air rate.
- Gas velocities and residence time within critical regions of the absorber. Critical regions are defined as the transition zone between cocurrent and countercurrent sections and the slurry contact zone between the cocurrent spray header and the countercurrent outlet header. The total residence time will be provided.
- Slurry distribution to each spray level or nozzle.
- Concentration of formic acid in recycle slurry.
- The method of using the quench to control formic acid consumption rate.
- The number and type of spray nozzles per level; however, the total number, type and material of construction for slurry nozzles will be provided.
- The process dewatering details ie. PFD with detailed mass balance.
- Detailed mass balances for internal scrubber process streams. This includes gypsum dewatering and absorber systems.

FIGURE 2.1-8

COCURRENT/COUNTERCURRENT ABSORBER PREVENTS HIGH pH ZONES THAT WOULD BE PRONE TO SCALING



- Detailed drawings of absorber internals.

Stebbins Engineering and Manufacturing Company has identified the following as proprietary:

- Stebbins/NYSEG contract.
- QA/QC Manual (includes installation techniques, maintenance techniques and mixing instructions.)
- Material formulas/compositions.
- Insert/nozzle placement details.
- Rebar placement details.
- Design of wall/cover details.
- Concrete mix composition/design.
- Specific cost of items.

Nalco FuelTech has identified the following as proprietary:

- Nalco FuelTech/NYSEG contract.
- The computer program and the results of Nalco FuelTech's fluid dynamic modeling of the Milliken Station boiler.
- The computer program and results of Nalco FuelTech's Kinetic modeling of the Milliken Station boiler.
- The formula or composition of chemical reagents supplied by Nalco FuelTech.
- The design and material of construction of the chemical injection equipment.

ABB Air Preheater, Inc. has identified the following as proprietary:

- Heat pipe fill fluid quantities/calculations.
- Performance calculations and computer programs.

- Shop fabrication procedures and detailed shop drawings.
- QA/QC manuals/records.
- Equipment pricing/costing data (audit reports).
- General arrangement drawings.
- Field installation drawings.
- Contract terms and conditions/warranties/guarantees.

New York State Electic & Gas Corporation identifies all of its contracts with participants and cofunders as proprietary information.

2.2 OVERALL BLOCK FLOW DIAGRAM

A block flow diagram for the entire MCCTD project is presented in FIGURE 2.2-1. Selected areas of the system are detailed further in additional flow diagrams as follows:

- NO_xOUT® Flow Diagram
  FIGURE 2.2-2

- Limestone Preparation Flow Diagram
  FIGURE 2.2-3

- S-H-U Flow Diagram
  FIGURE 2.2-4

- Byproduct Dewatering Flow Diagram (Gypsum)
  FIGURE 2.2-5

- Blowdown Treatment/Brine Concentration Flow Diagram
  FIGURE 2.2-6

More detailed information can be found in Section 4.0 - Detailed Process Design.

FIGURE 2.2-1

PROCESS BLOCK DIAGRAM FOR MCCTD PROJECT

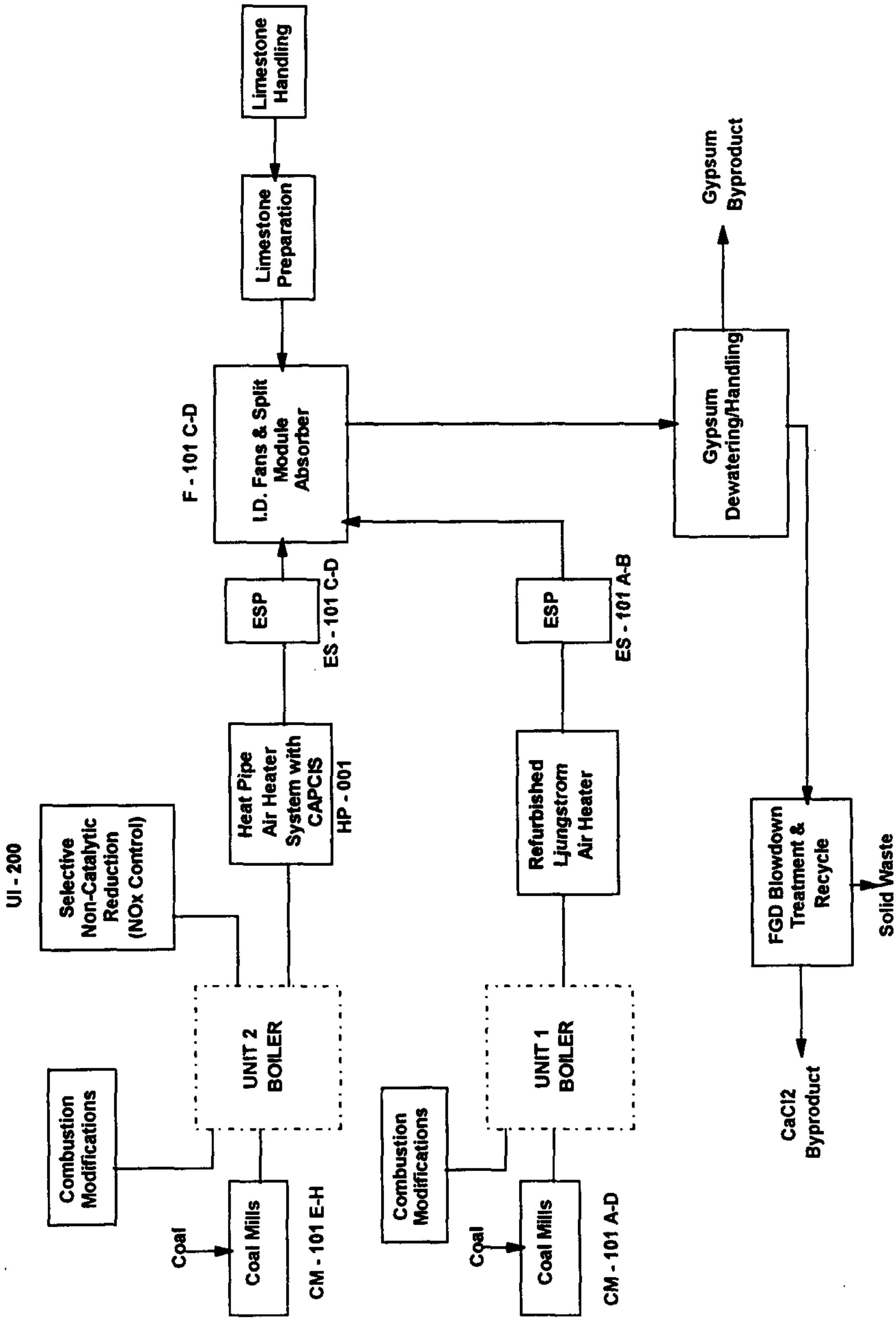


FIGURE 2.2.-2

NO_xOUT® FLOW DIAGRAM

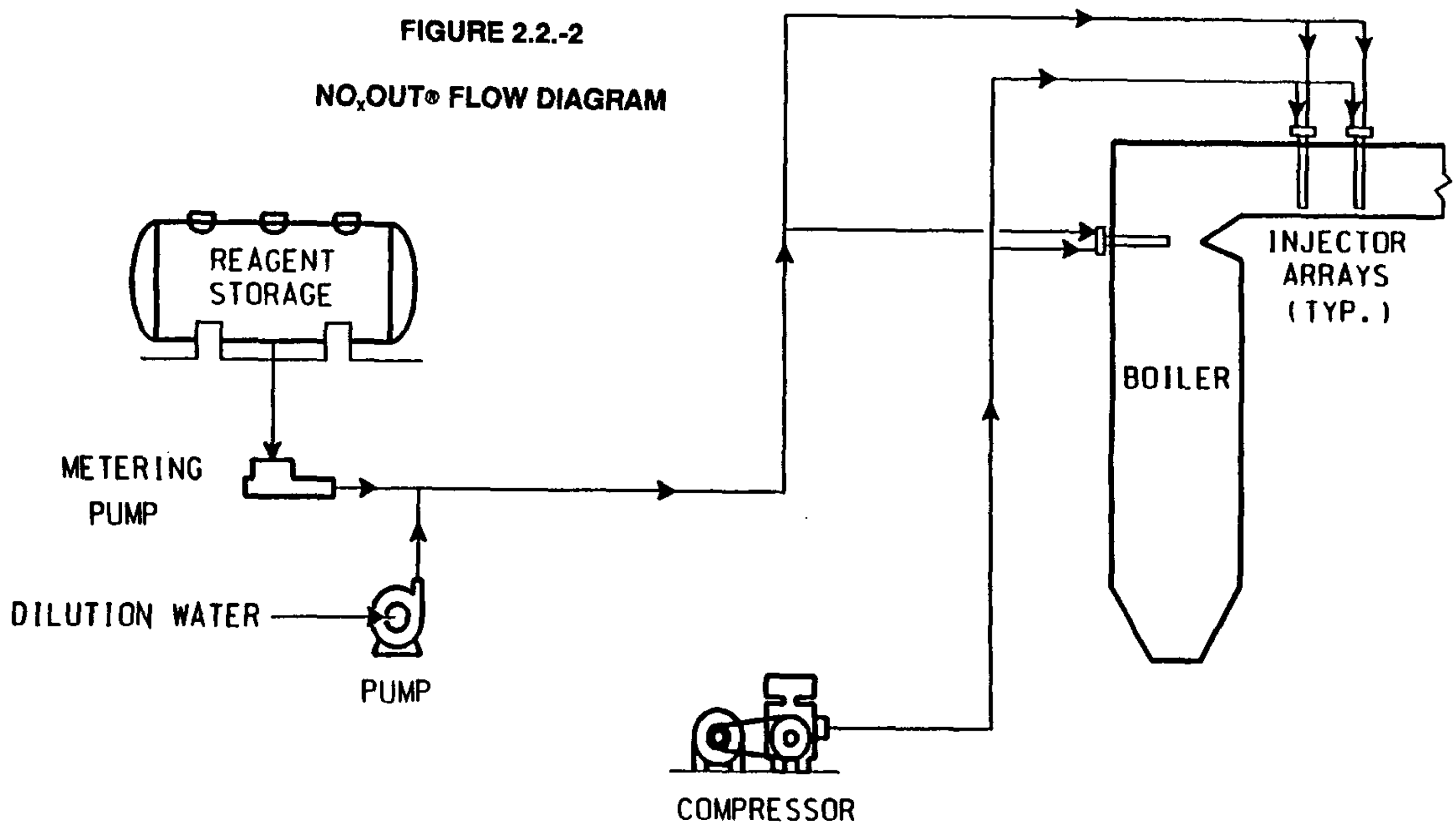


FIGURE 2.2.-3

LIMESTONE PREPARATION FLOW DIAGRAM

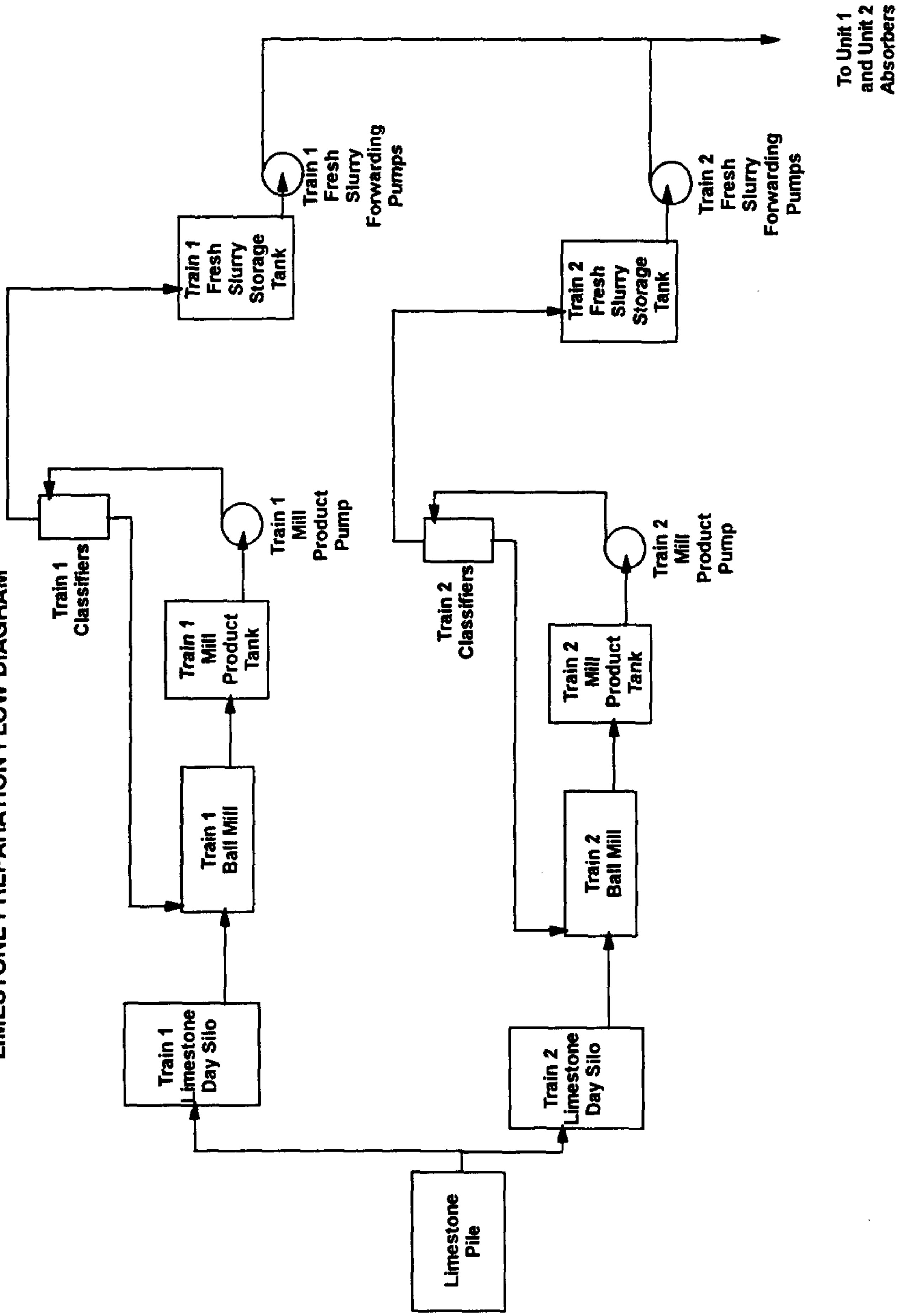


FIGURE 2.2-4

S-H-U FLOW DIAGRAM

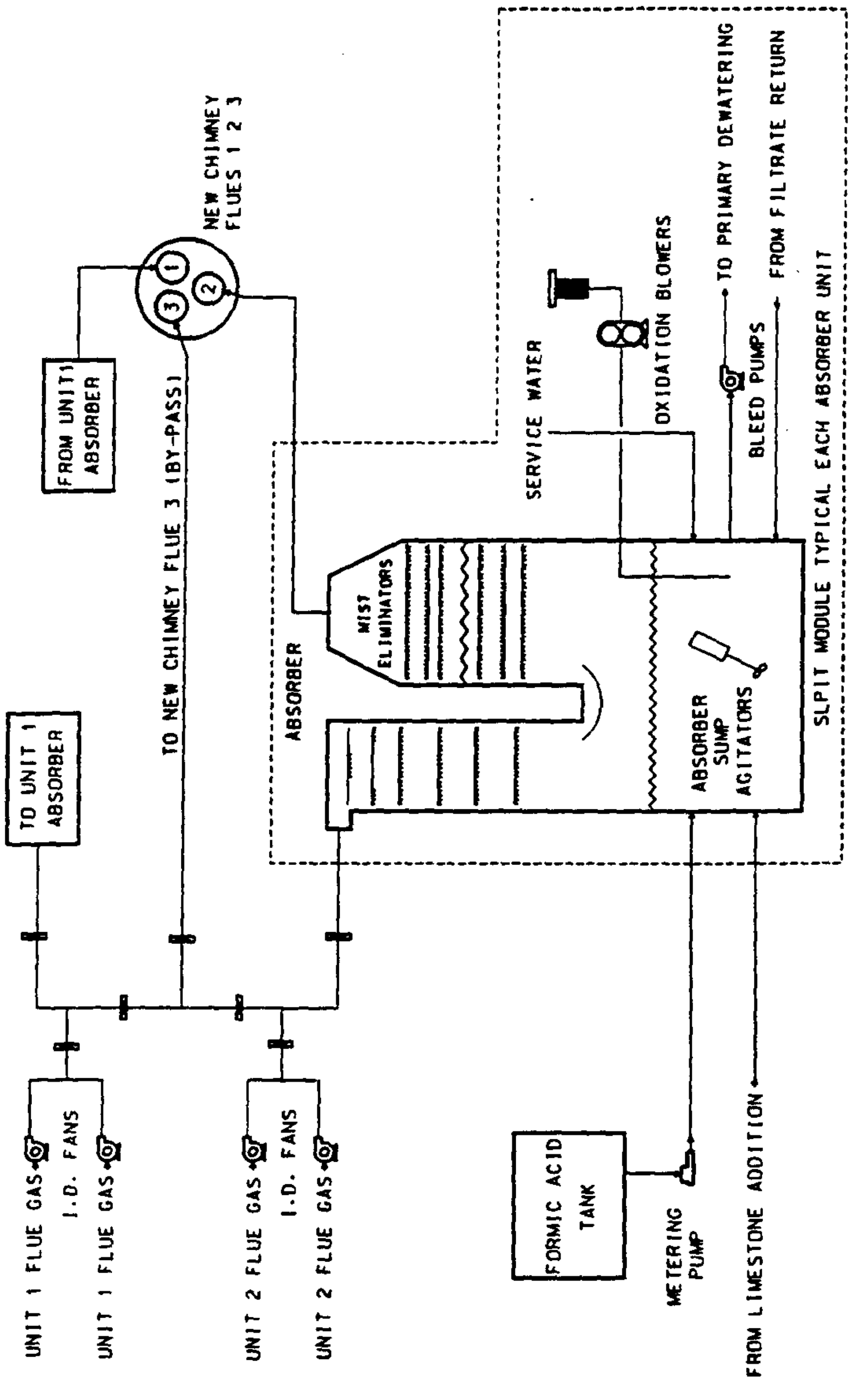
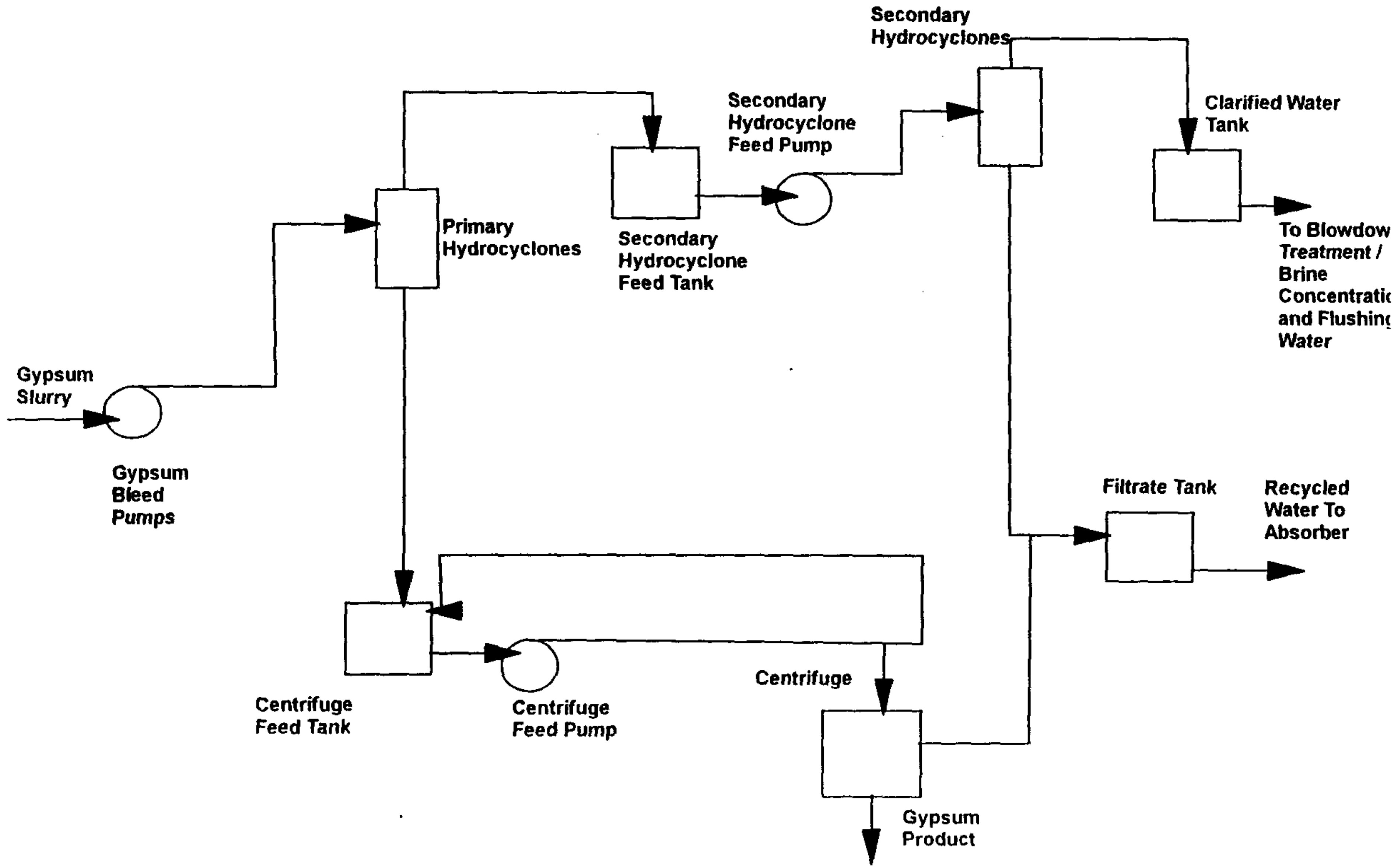


FIGURE 2.2-5

BYPRODUCT DEWATERING FLOW DIAGRAM



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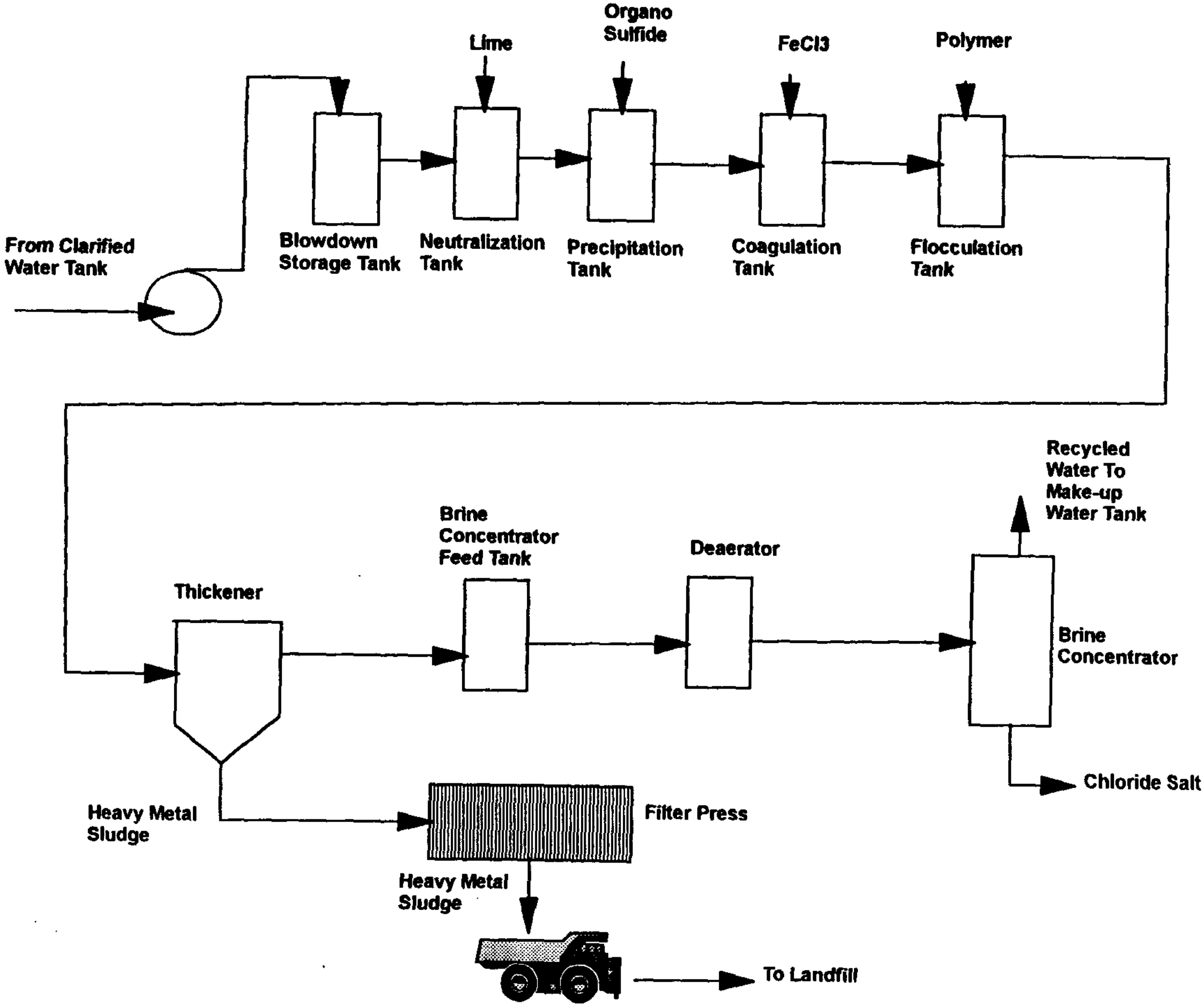
BLOWDOWN TREATMENT/BRINE CONCENTRATION FLOW DIAGRAM



MILLIKEN CLEAN COAL TECHNOLOGY

DEMONSTRATION PROJECT

SECTION 3.0

PROCESS DESIGN CRITERIA

DE-FC22-93PC92642

3.0 PROCESS DESIGN CRITERIA

Process design criteria and performance objectives developed for the MCCTD project can be found in the following tables:

- Test Coal Data
  TABLE 3.0-1

- Process Design Criteria (FGD System)
  TABLE 3.0-2

- Process Design Criteria (Boiler)
  TABLE 3.0-3

- Boiler Performance Parameters
  TABLE 3.0-4

- Site Design Criteria
  TABLE 3.0-5

TABLE 3.0-1

TEST COAL DATA

	Medium Sulfur	Base Coal	High Sulfur
Proximate Analyais, %			
Moisture	6.3	5.6	7.5
Ash	10.9	9.5	10.5
Volatile Matter	29.0	37.1	37.4
Fixed Carbon	53.8	47.8	44.6
High Heating Value, BTU/lb	12,600	12,800	12,165
Sulfur, %	1.6	2.9	4.3
Grindability, HGI	73	57	56
Ash Fusion Temperature, °F	2480	2200	2222
Ultimate Analysis, %			
Moisture	6.3	5.6	7.5
Ash	10.9	9.5	10.5
Carbon	73.5	74.3	66.4
Hydrogen	4.3	4.5	4.6
Nitrogen	1.3	1.5	1.2
Chlorine	0.1	0.2	0.1
Sulfur	1.6	2.9	4.3
Oxygen	2.0	1.5	5.4
TOTAL	100.0	100.0	100.0

TABLE 3.0-2
PROCESS DESIGN CRITERIA (FGD SYSTEM)

PROCESS AREA	DESIGN CRITERIA	INFORMATION
Flue Gas Handling	Flue Gas Inlet Flow	487,818 ACFM @ 270°F
	Pressure Drop	3.5 in. WG
	Particulate Removal	99.6 %
	Absorber Inlet	270°F
	Absorber Outlet	121°F
SO_2 Removal	SO_2 Removal	95%
	Scrubber Modules	1 Operating 0 Spare
	Reagent Feed Ratio	1.04 Ca/S Molar Ratio
	Pressure Loss	4.7 in. WC through absorber
Reagent Feed	Total Limestone Storage	6 months
	Limestone Day Bin	24 hours
	Limestone Slurry Tank	12 hours
Gypsum Handling	Primary Hydrocyclone Overflow	25% Solids
	Centrifuge Outlet	94% Solids
Balance Of Plant	Process Water Tank	90 Min. Retention
Water Treatment/ Brine Concentration	Design Flow (inlet)	30 GPM
	$CaCl_2$ Concentration in By-product	33-35%
	By-product Flow	4.5 GPM

TABLE 3.0-3

PROCESS DESIGN CRITERIA (BOILER)

PROCESS AREA	DESIGN CRITERIA	INFORMATION
Boiler Island	Generation	157.5 MW gross
	Steam Conditions	1.095 million lbs/hr @ 1005°F
	Coal Feed	105,379 lbs/hr
	Combustion Air	1.26 million lbs/hr
	Burners (number)	16 (corner)
	Heat Input	1420 MMBtu/hr
	Furnace Exit Gas	2000°F Approx.
Waste Handling	Ash Ratio (Fly/Bottom)	4:1
	Unburned Fuel (LOI)	3.5%
Flue Gas Handling	Air Preheater	1.585 million lbs/hr

TABLE 3.0-4

BOILER PERFORMANCE PARAMETERS

PARAMETER/REFERENCE	DATA
Excess Air (% O_2 Economizer Outlet)	3.3%
Excess Air (% O_2 Air Heater Outlet)	6.2%
Humidity	60% RH
Gas Pressure (Economizer Outlet)	-6.5 in. WG
Gas Pressure (Air Heater Outlet)	-11.5 in. WG
Gas Temperature (Economizer Outlet)	660°F
Gas Temperature (Air Heater Outlet)	270°F
NO_x Emissions	.65 lbs/MMBtu
Heat Rate (Steam Cycle)	7965 Btu/kwhr gross
Boiler Efficiency	89%
Boiler Heat Input	1400 million Btu/hr

TABLE 3.0-5

SITE DESIGN CRITERIA

PARAMETER	DATA
Elevation	394 Ft.
Barometric Pressure	14.57 psia
Temperature Range	-20 to 100°F
Seismic Zone	1
Rainfall	35.27 in/yr
Snow Load	35 lbs/Ft^2
Wind Speed	80 MPH
Ground Water Level	10 to 30 Ft
Soil Bearing Strength	19 Tons/Ft^2
Frost Penetration	4 Ft

MILLIKEN CLEAN COAL TECHNOLOGY DEMONSTRATION PROJECT

SECTION 4.0

DETAILED PROCESS DESIGN

DE-FC22-93PC92642

4.1 PLOT PLAN AND PLANT LAYOUT DRAWINGS

The following drawings are provided to indicate the site plan and general arrangement of process equipment:

- Site Plan
  FIGURE 4.1-1

- Site Preparation
  FIGURE 4.1-2

- General Arrangement Drawings

Elevation 394 ft	FIGURE 4.1-3
Elevation 412 ft	FIGURE 4.1-4
Elevation 424 ft	FIGURE 4.1-5
Elevation 442 ft	FIGURE 4.1-6
Elevation 459 ft	FIGURE 4.1-7
Elevation 472 ft	FIGURE 4.1-8
Elevation 475 ft	FIGURE 4.1-9
Elevation 492 ft	FIGURE 4.1-10
Elevation 564 ft	FIGURE 4.1-11
Elevation 498 ft	FIGURE 4.1-12
Elevation 524 ft	FIGURE 4.1-13
Elevation 437 ft	FIGURE 4.1-14

FIGURE 4.1-1

SITE PLAN

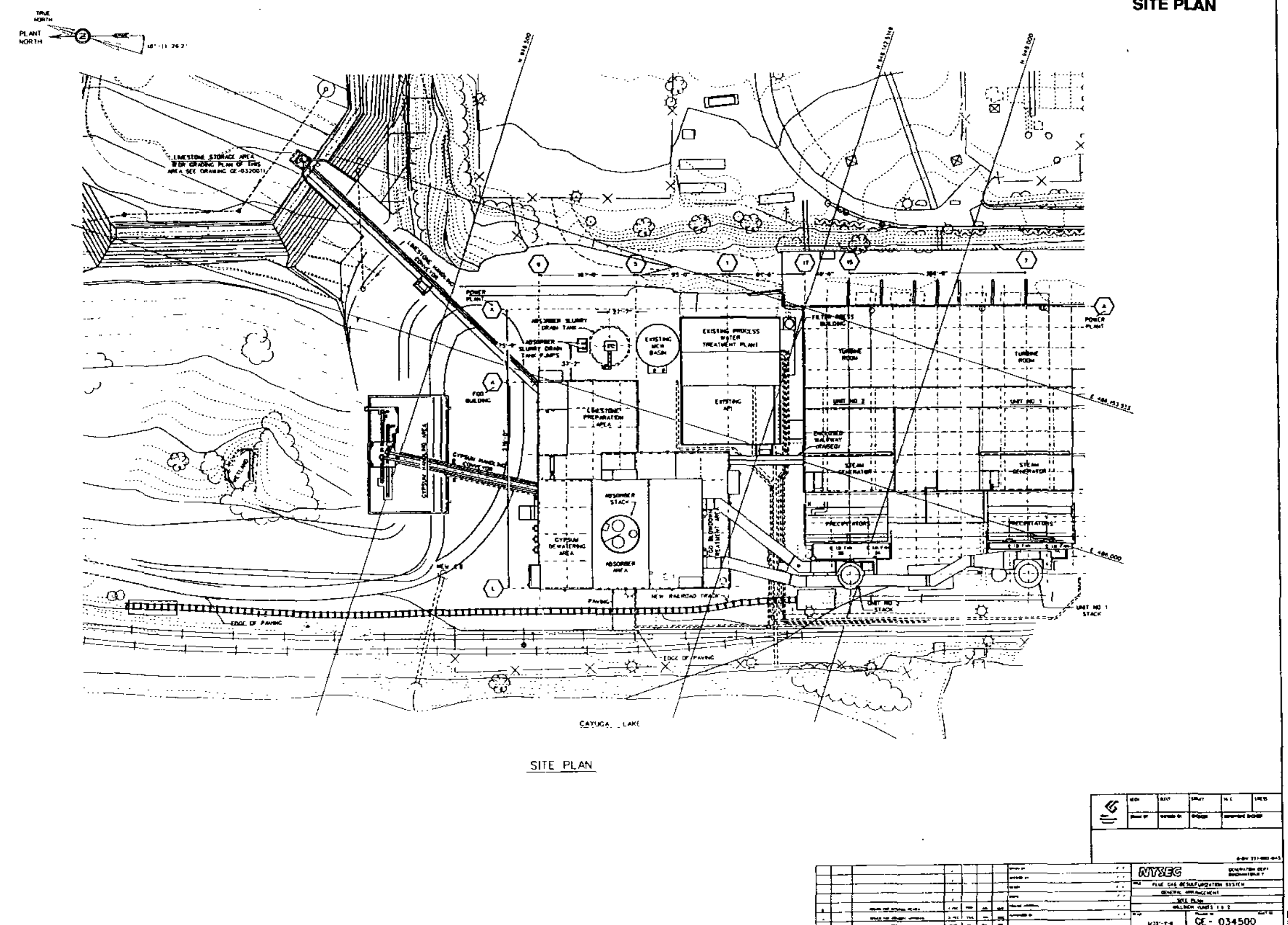


FIGURE 4.1-2

SITE PREPARATION

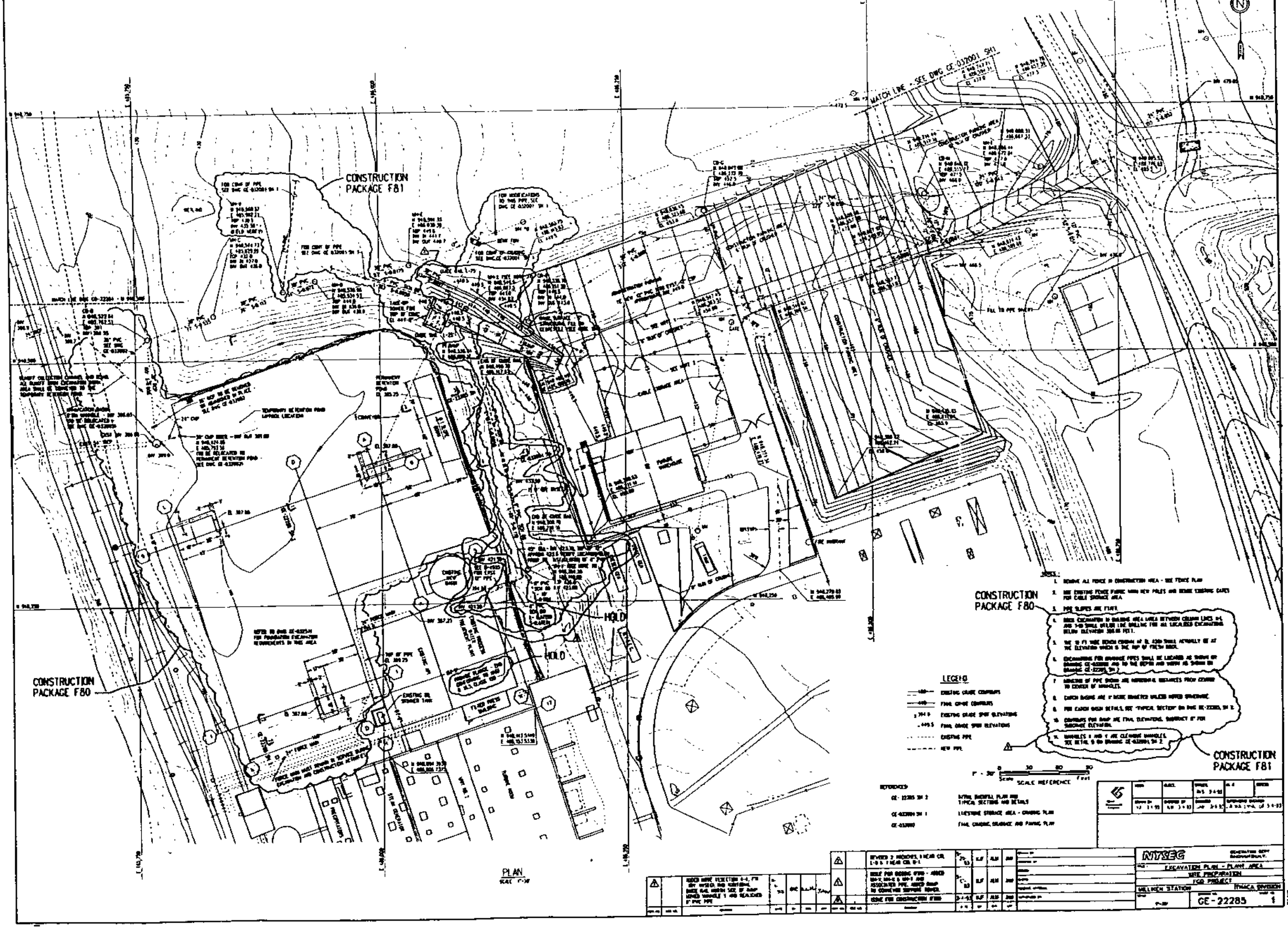


FIGURE 4.1-3
ELEVATION 394 FEET

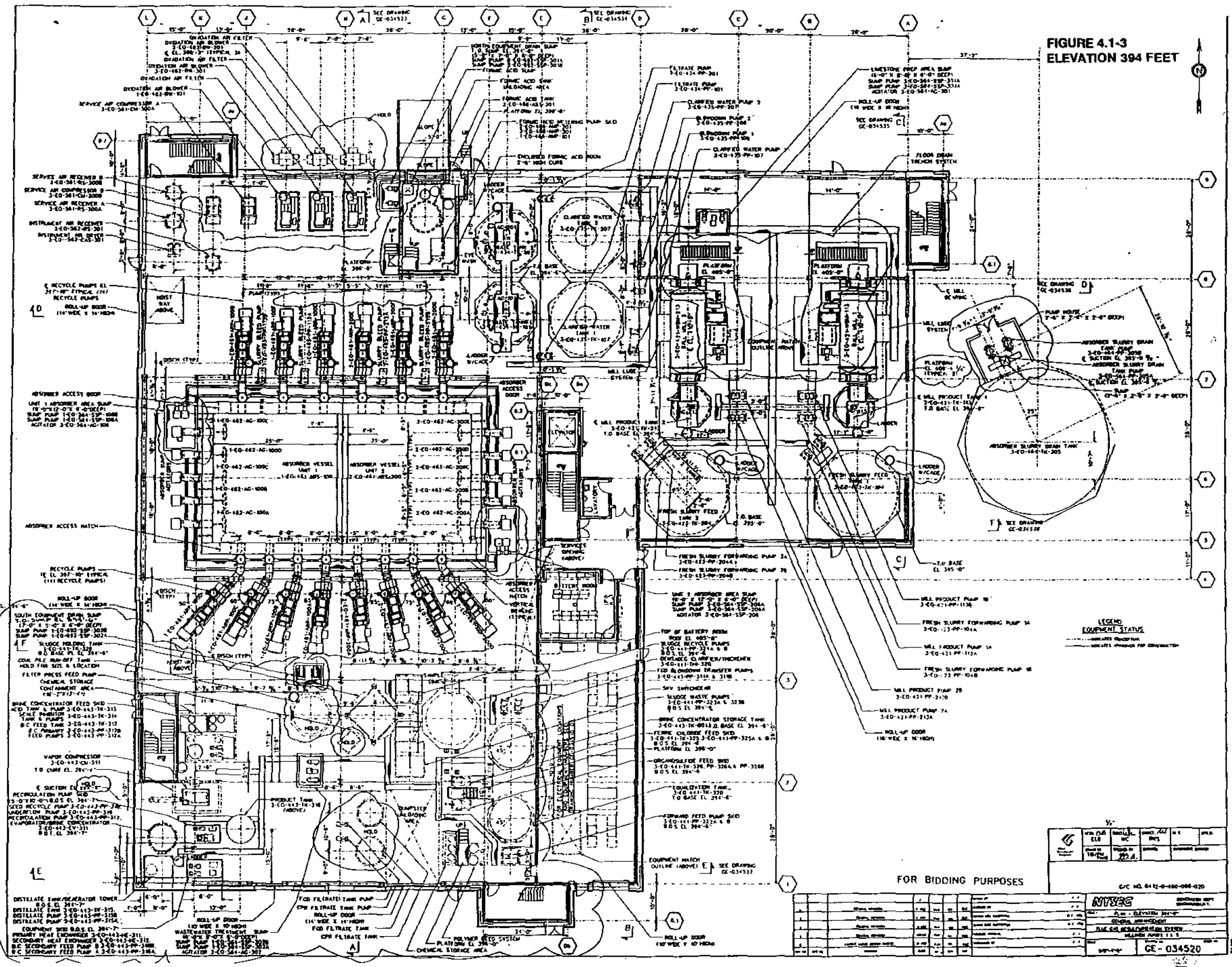


FIGURE 4.1-4
ELEVATION 412 FEET

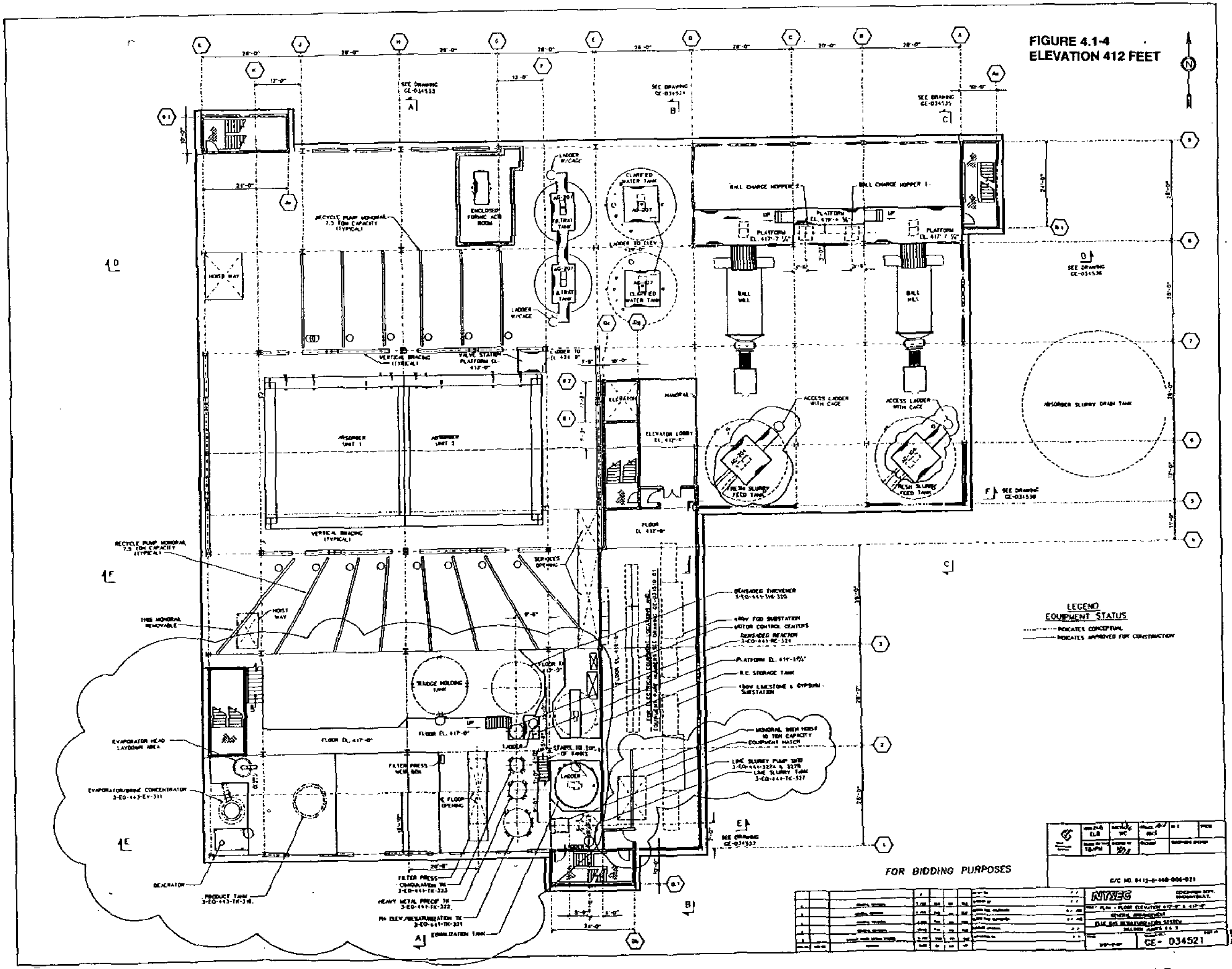


FIGURE 4.1-5
ELEVATION 424 FEET

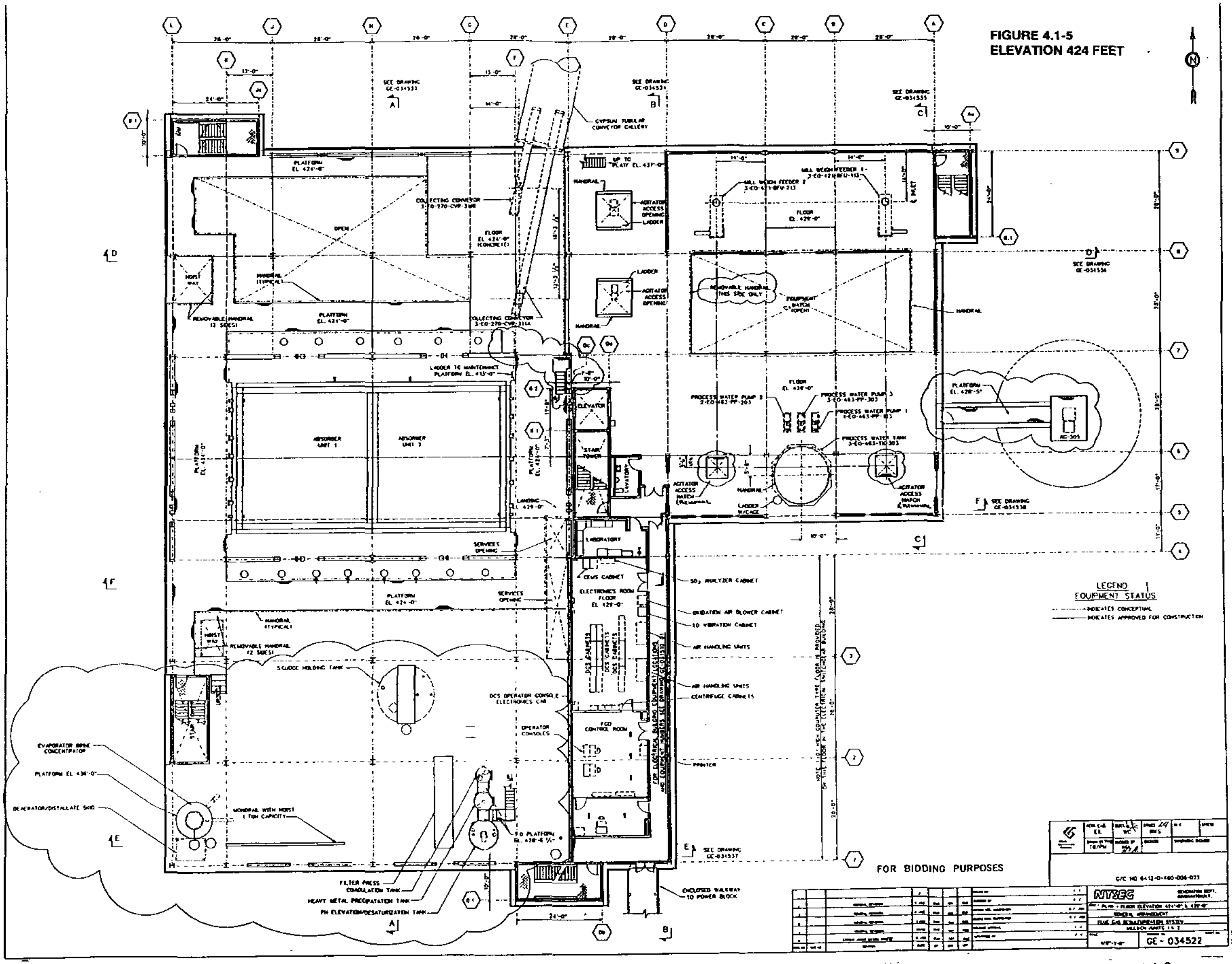
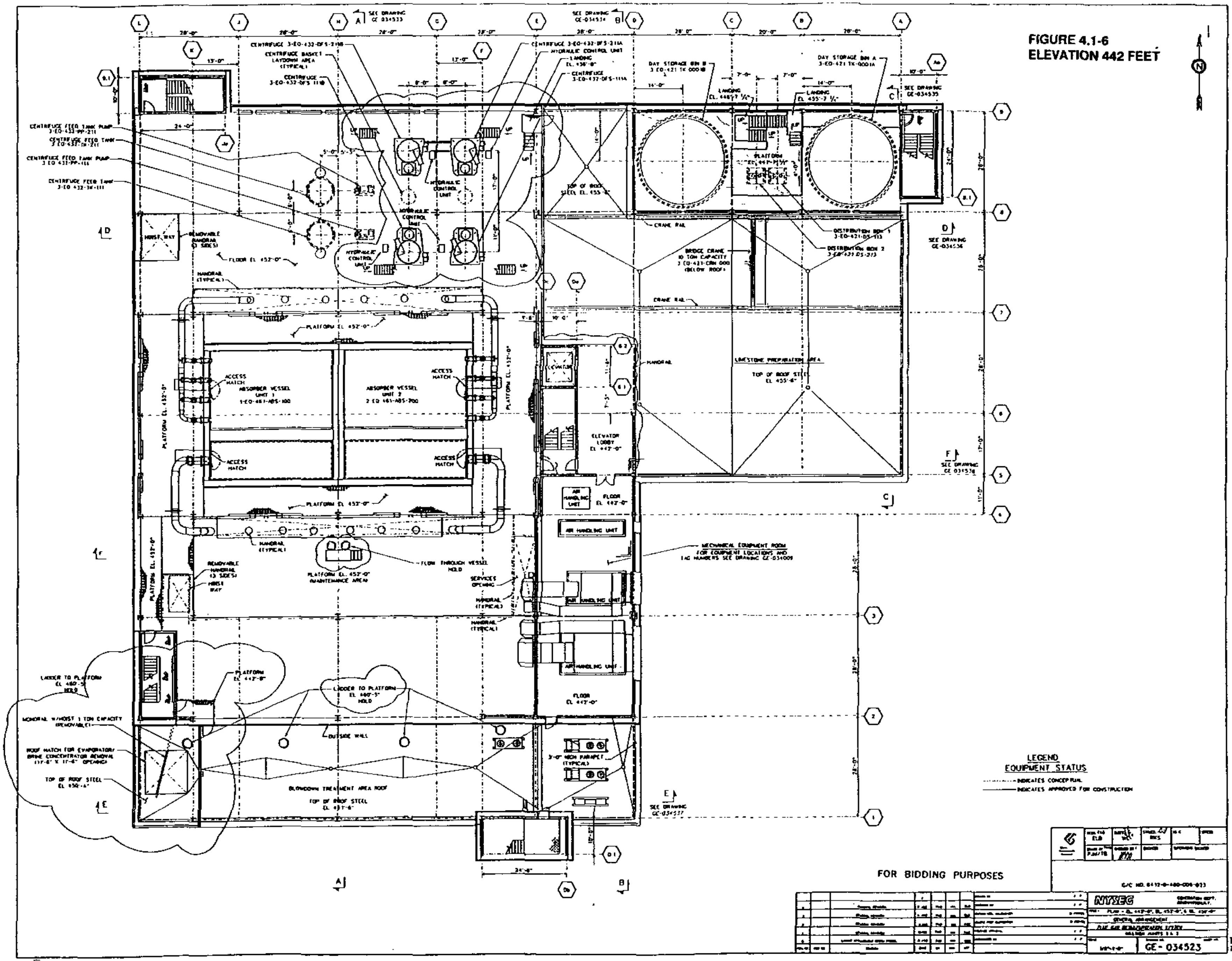


FIGURE 4.1-6
ELEVATION 442 FEET



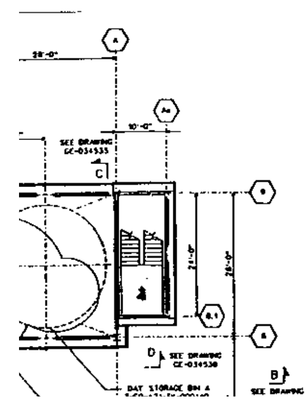


FIGURE 4.1-7
ELEVATION 459 FEET

FIGURE 4.1-8
ELEVATION 472 FEET

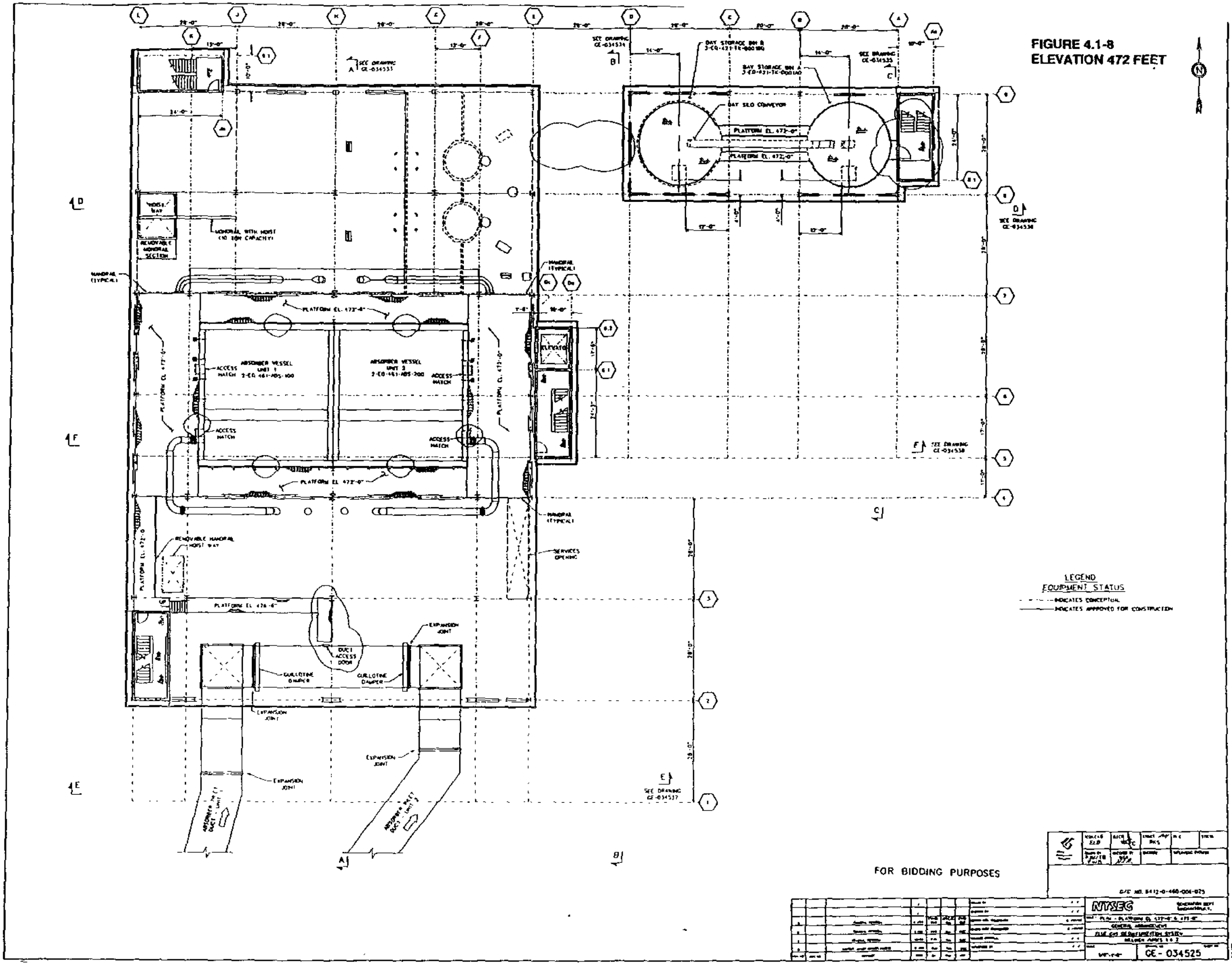


FIGURE 4.1-9
ELEVATION 475 FEET

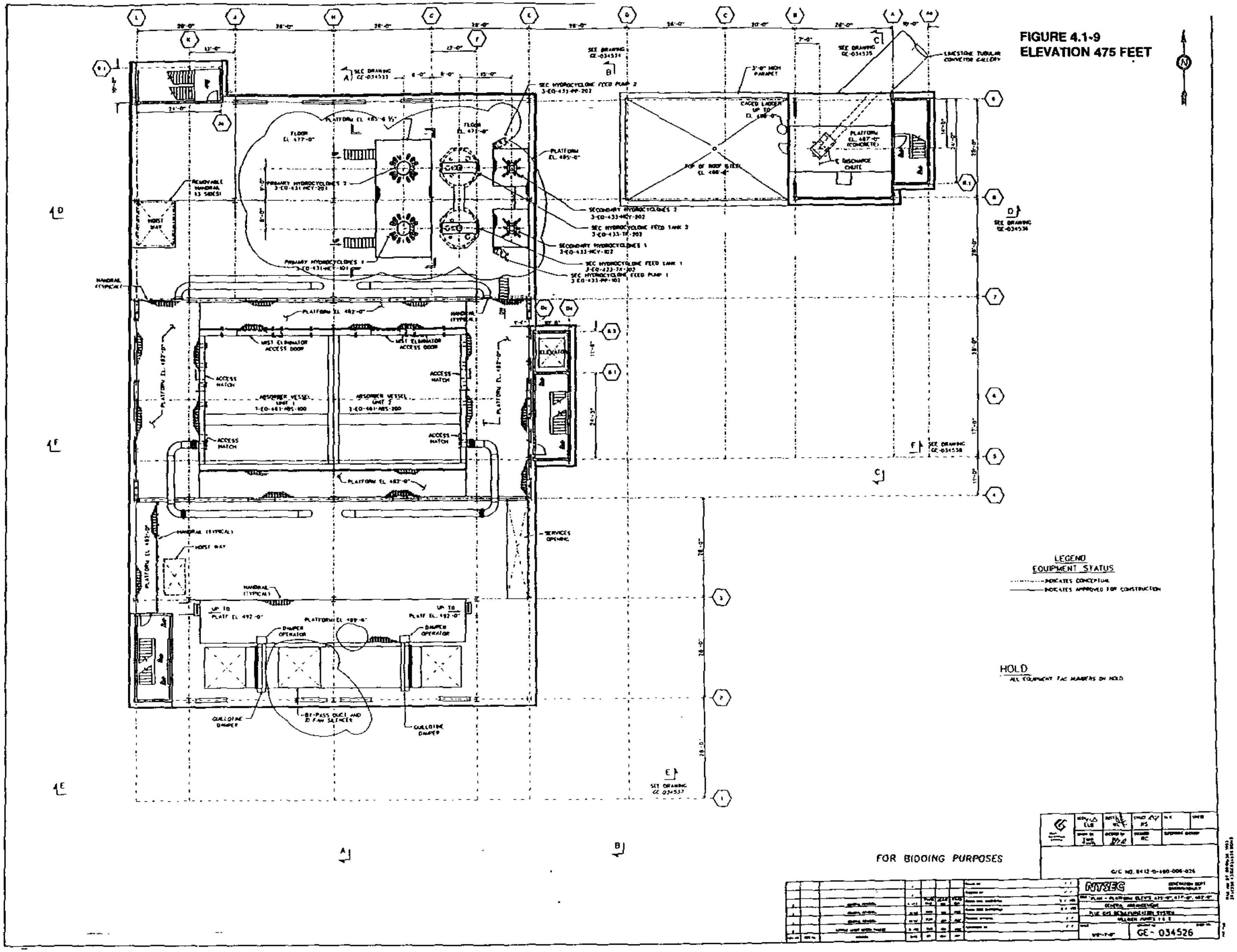
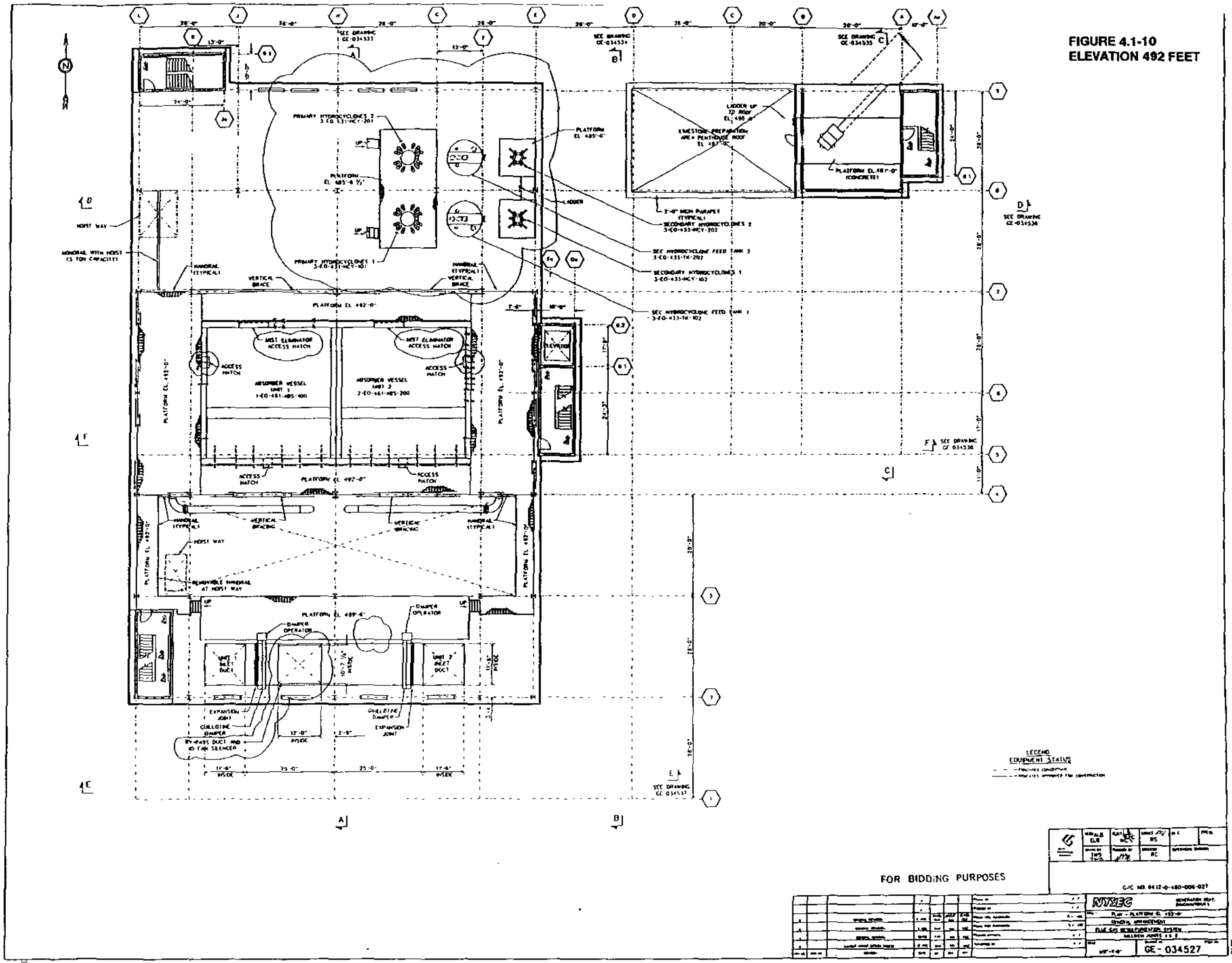


FIGURE 4.1-10
ELEVATION 492 FEET



FOR BIDDING PURPOSES

FIGURE 4.1-11
ELEVATION 564 FEET

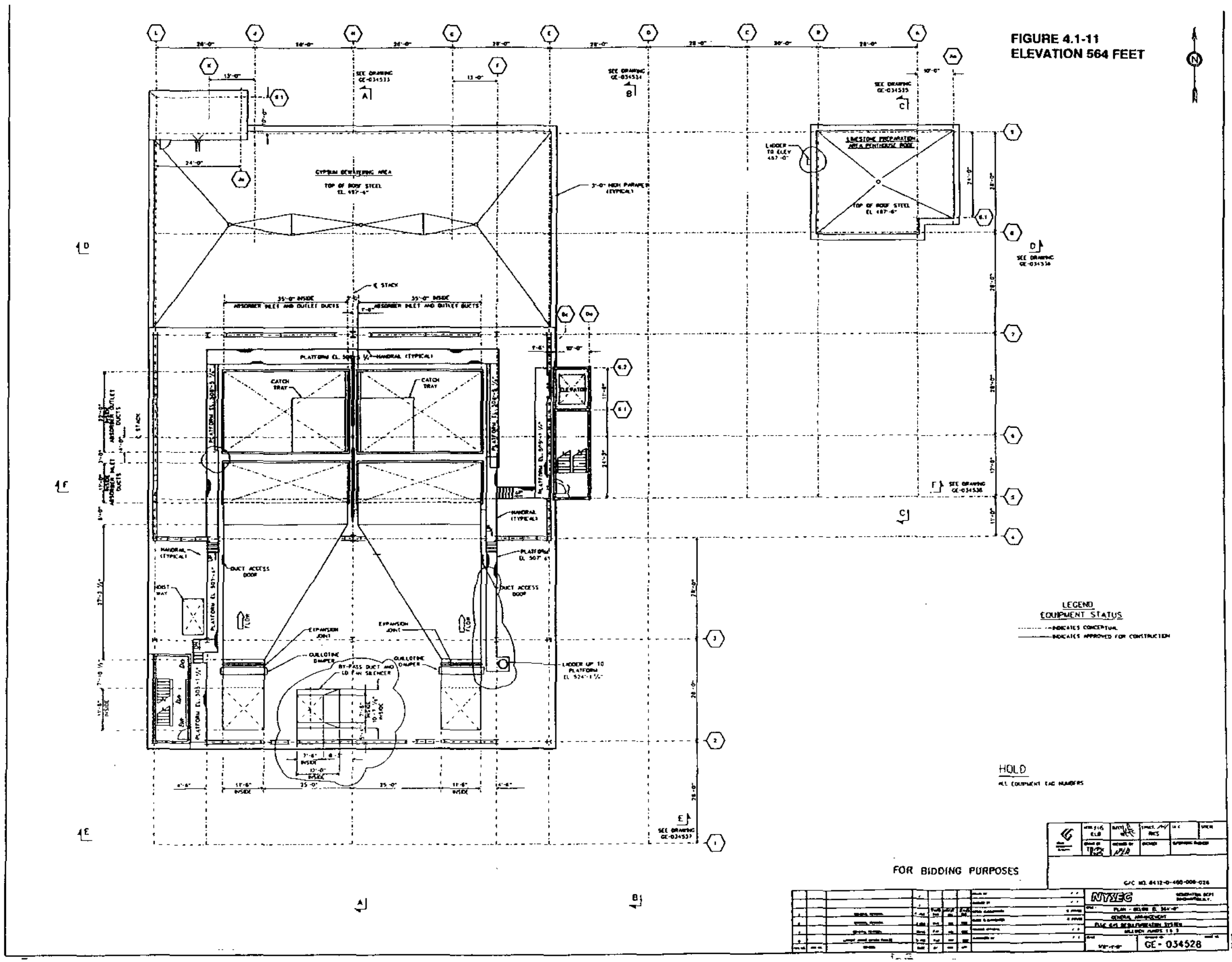


FIGURE 4.1-12
ELEVATION 498 FEET

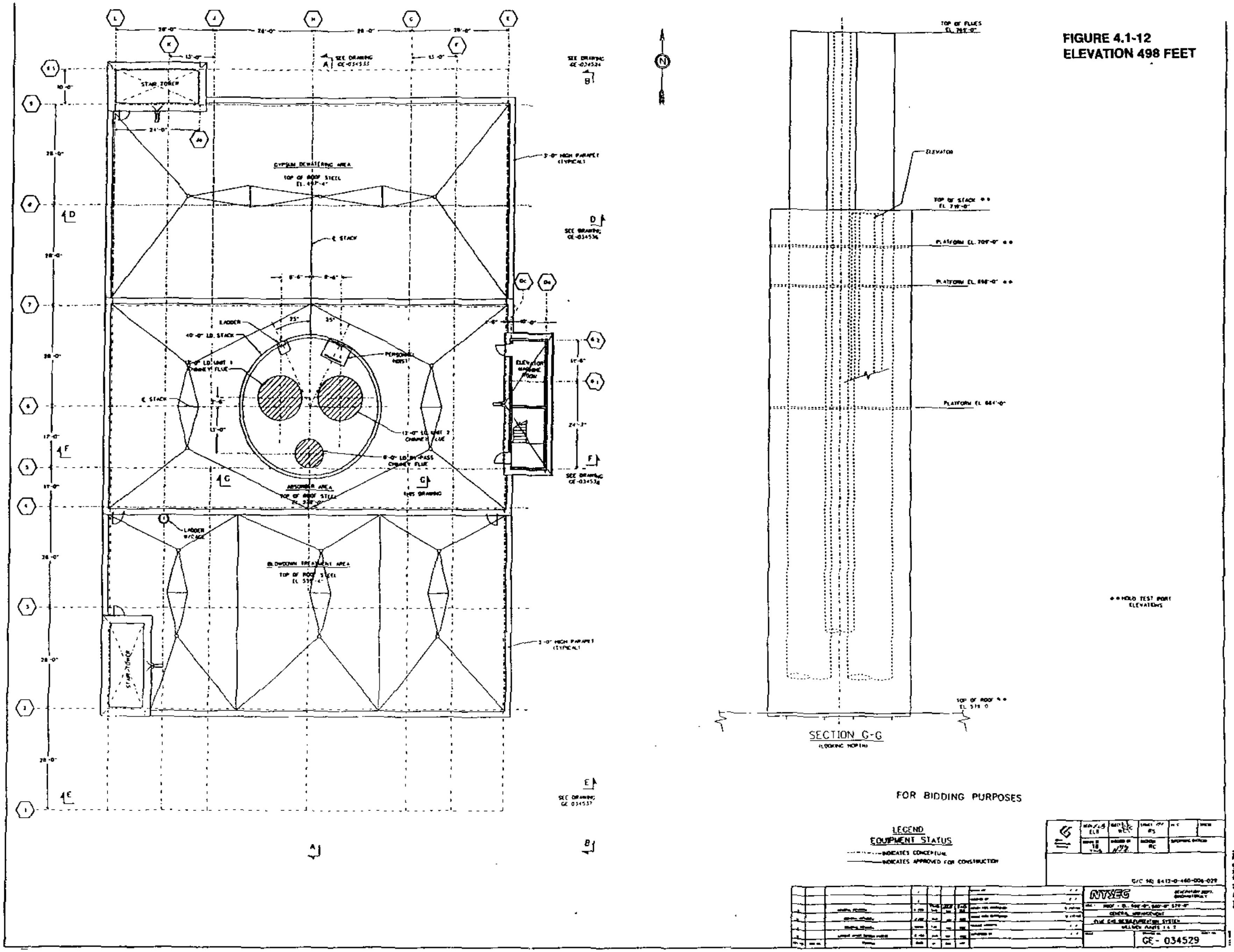


FIGURE 4.1-13
ELEVATION 524 FEET

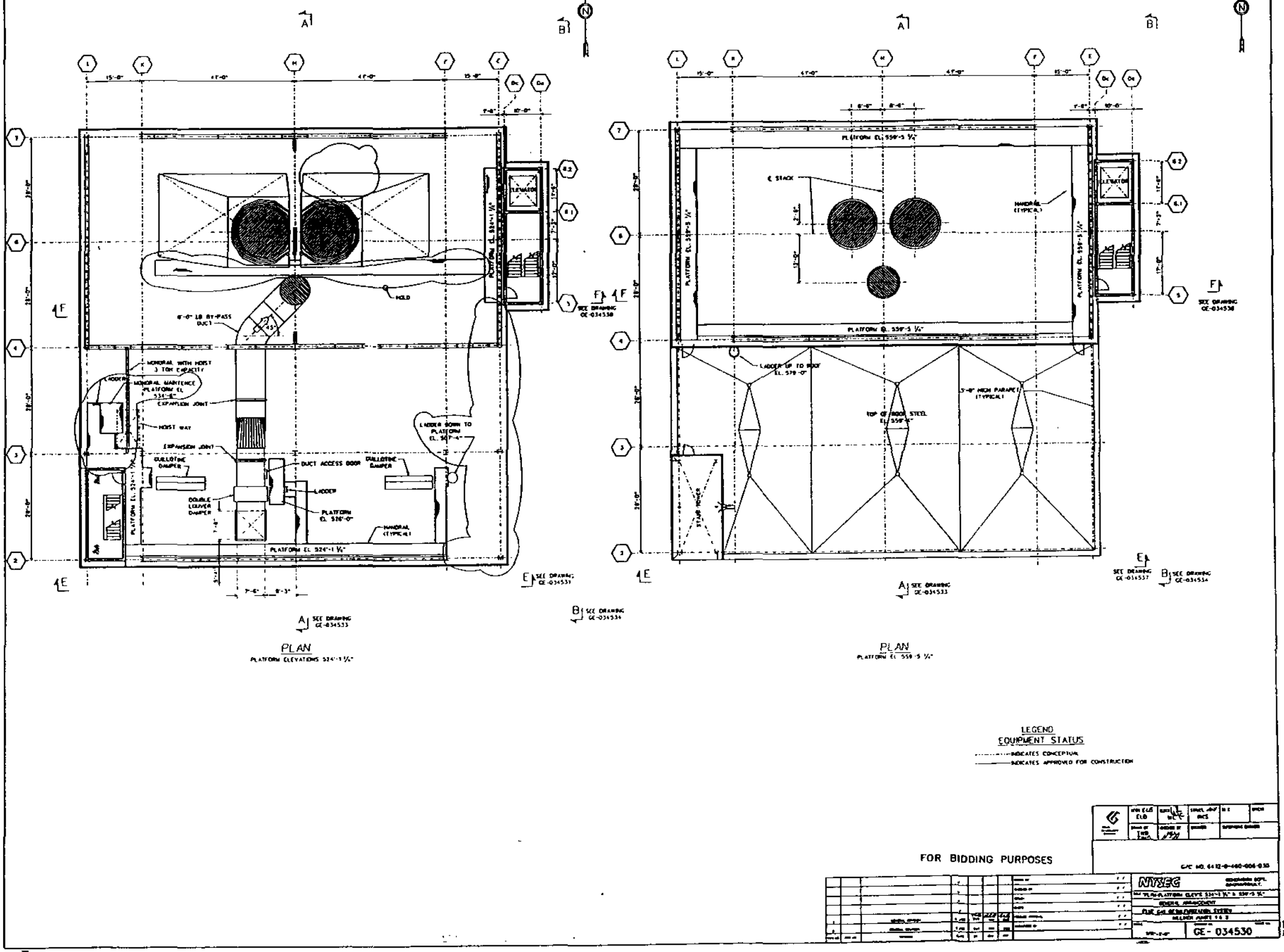
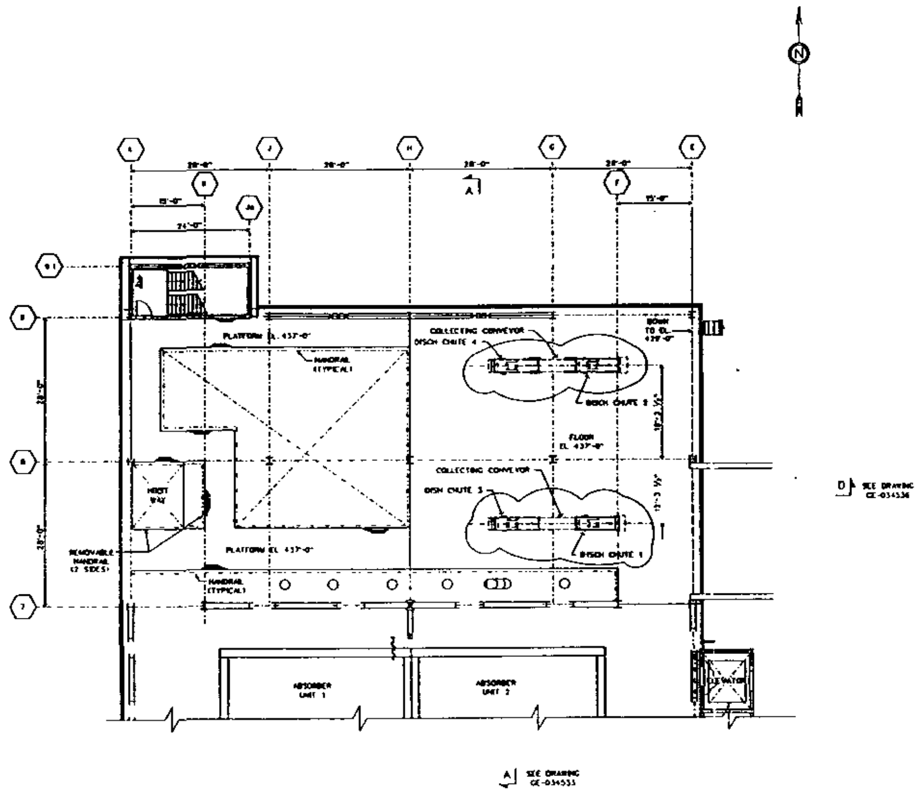


FIGURE 4.1-14
ELEVATION 437 FEET



PARTIAL PLAN
PLATFORM EL 437'-0"

LEGEND
EQUIPMENT STATUS
INDICATES CONCEPTUAL
INDICATES APPROVED FOR CONSTRUCTION

HOLD
ALL EQUIPMENT TAG NUMBERS ON HOLD

FOR BIDDING PURPOSES

NYSEG
PLATFORM EL 437'-0"
GENERAL ARRANGEMENT
GE- 034531

4.2 MAJOR PLANT PROCESS AREAS

The following sections provide data for the MCCTD project in the areas of process flow diagrams for each process, energy balances, and process and instrumentation (P&ID) diagrams.

4.2.1 Process Flow Diagrams

The process flow diagrams for each process area are included as follows:

- S-H-U FGD Process PFD
  FIGURE 4.2.1-1

- S-H-U FGD Gypsum Dewatering PFD
  FIGURE 4.2.1-2

- Limestone Preparation PFD
  FIGURE 4.2.1-3

- Wastewater Treatment PFD
  PROPRIETARY

NOTE: Proprietary information from S-H-U, IDI, and RCC are not included.

4.2.2 Material Balances

PROPRIETARY

4.2.3 Energy Balances

See TABLE 4.2.3-1 - Project Energy Balance Estimate.

4.2.4 Process and Instrumentation Diagrams

The process and instrumentation diagrams (P&ID) for the FGD process are included as follows. (P&ID's for the wastewater treatment area are not included due to proprietary notices from IDI and RCC.)

- Limestone Handling
  FIGURE 4.2.4-1

- Limestone Preparation
  FIGURES 4.2.4-2 through 4.2.4-8

- S-H-U FGD Process
  FIGURES 4.2.4-9 through 4.2.4-30

- Gypsum Handling
  FIGURE 4.2.4-31

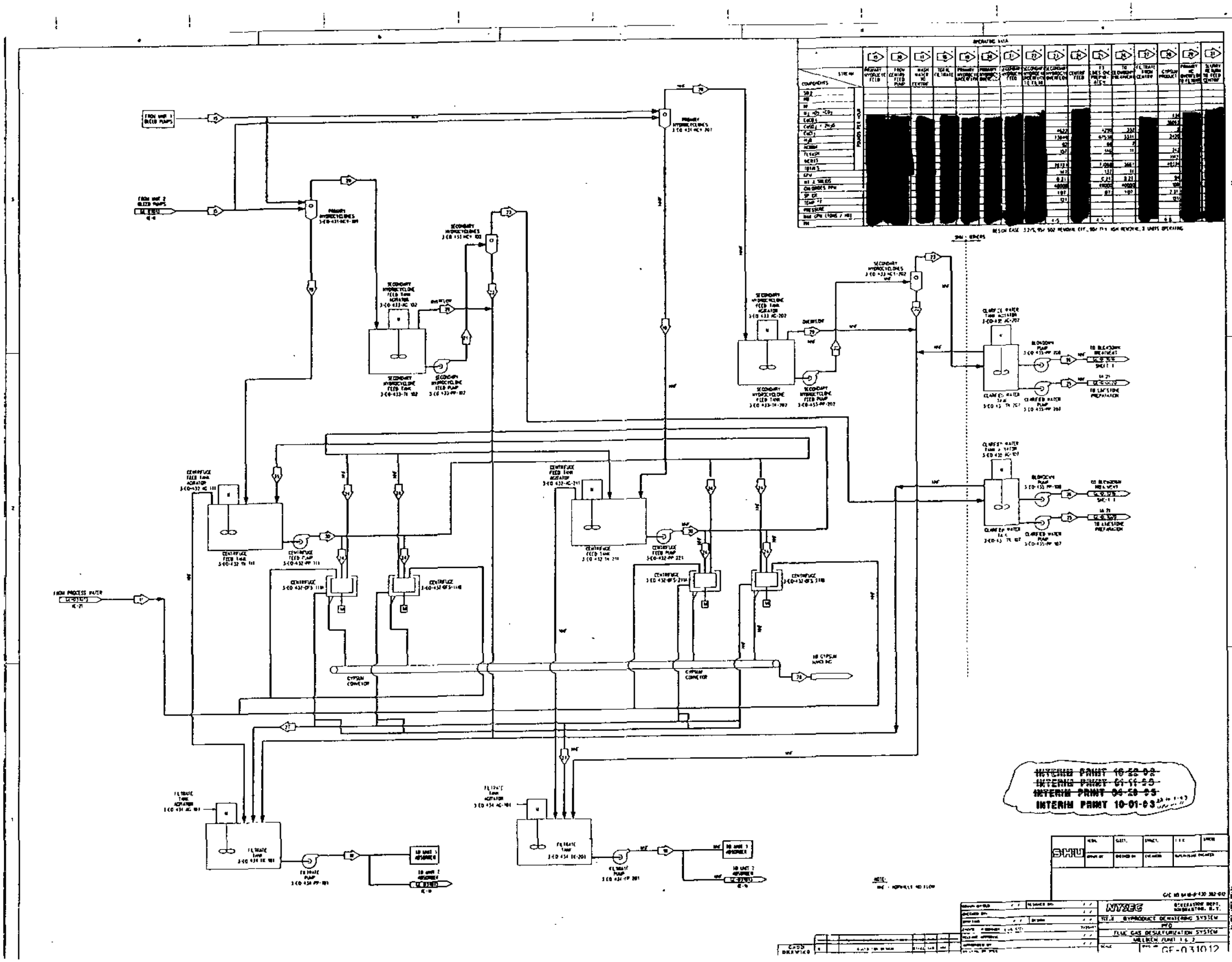
TABLE 4.2.3-1

PROJECT ENERGY BALANCE ESTIMATE

TECHNOLOGY	POWER SAVINGS	HEAT RATE SAVINGS
S-H-U FGD and all Auxiliaries	-4.04 MW	-120 Btu/kWh
Thermal Performance Advisor (0.75% Heat Rate) Advisor		70 Btu/kWh
Heat Pipe		47 Btu/kWh
Min 20°F decrease in Exit Gas Temperature (0.5% Heat Rate Improvement)		
16% Reduction in Air Flow Due to Leakage (Fan Power savings of 452 BHP)	337 KW	10 Btu/kWh
NO_X System		~0
	NET HEAT RATE SAVINGS =	7 Btu/kWh

Current Heat Rate = **9,422 Btu/kWh**
Modified Heat Rate = **9,415 Btu/kWh**

FIGURE 4.2.1-2
SHU FGD GYPSUM
DEWATERING PFD



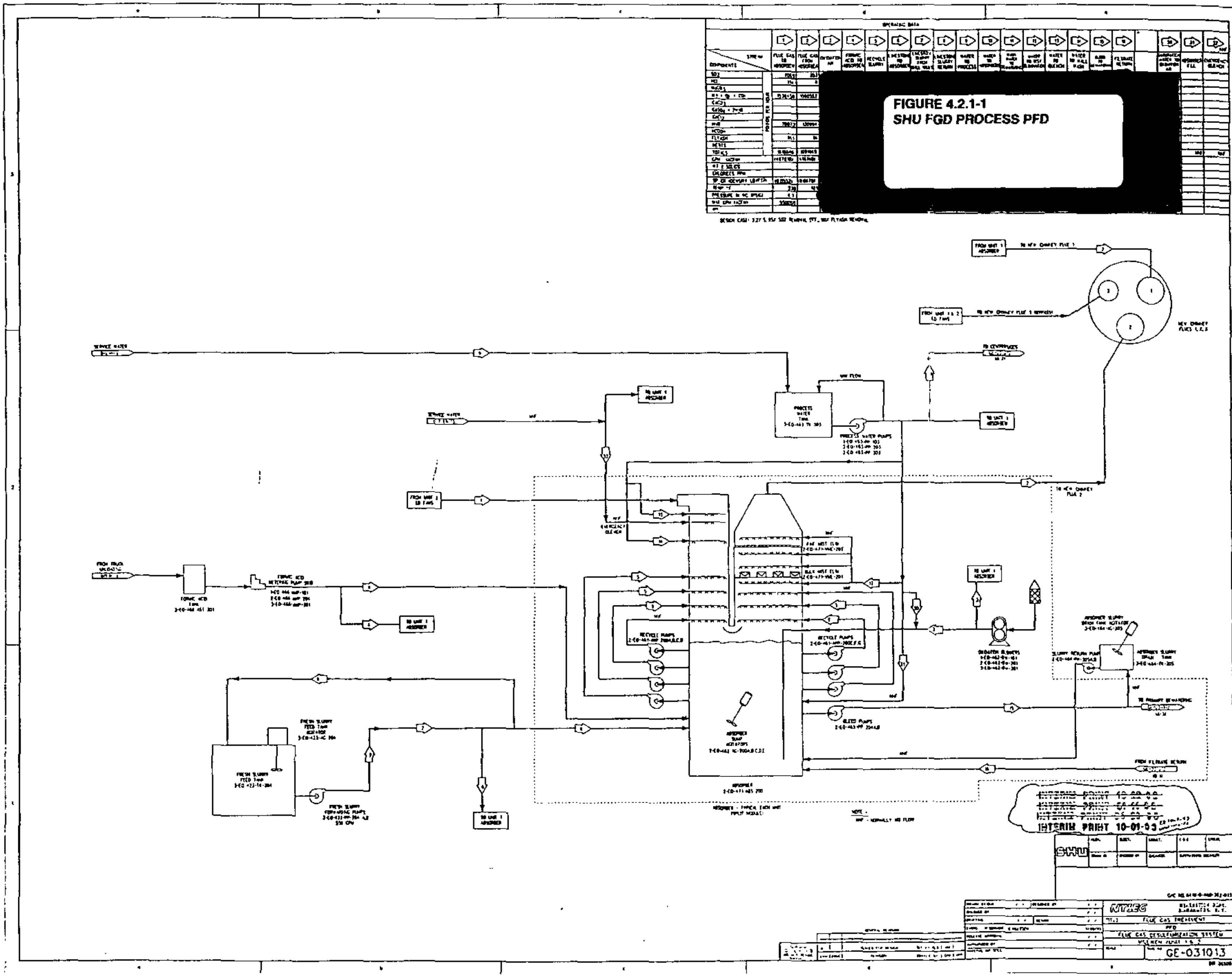
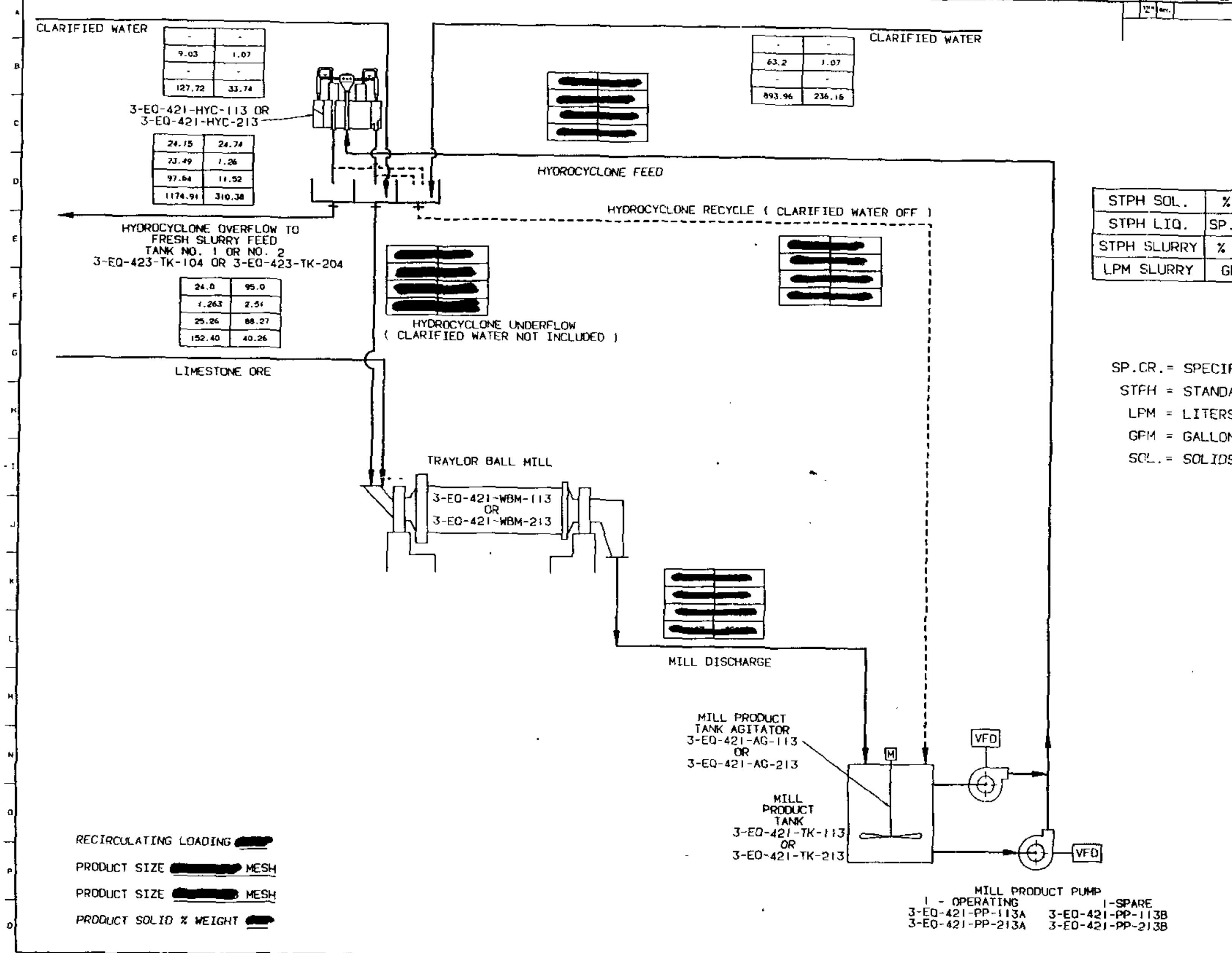


FIGURE 4.2.1-1
SHU FGD PROCESS PFD

FIGURE 4.2.1-3
LIMESTONE PREPARATION PFD



STPH SOL.	% SOL. WT.
STPH LIQ.	SP.GR. SLURRY
STPH SLURRY	% SOL. VOL.
LPM SLURRY	GPM SLURRY

SP.GR. = SPECIFIC GRAVITY
STPH = STANDARD TONS PER HOUR
LPM = LITERS PER MINUTE
GPM = GALLONS PER MINUTE
SOL. = SOLIDS

F10-421-GC 23098-1- 2

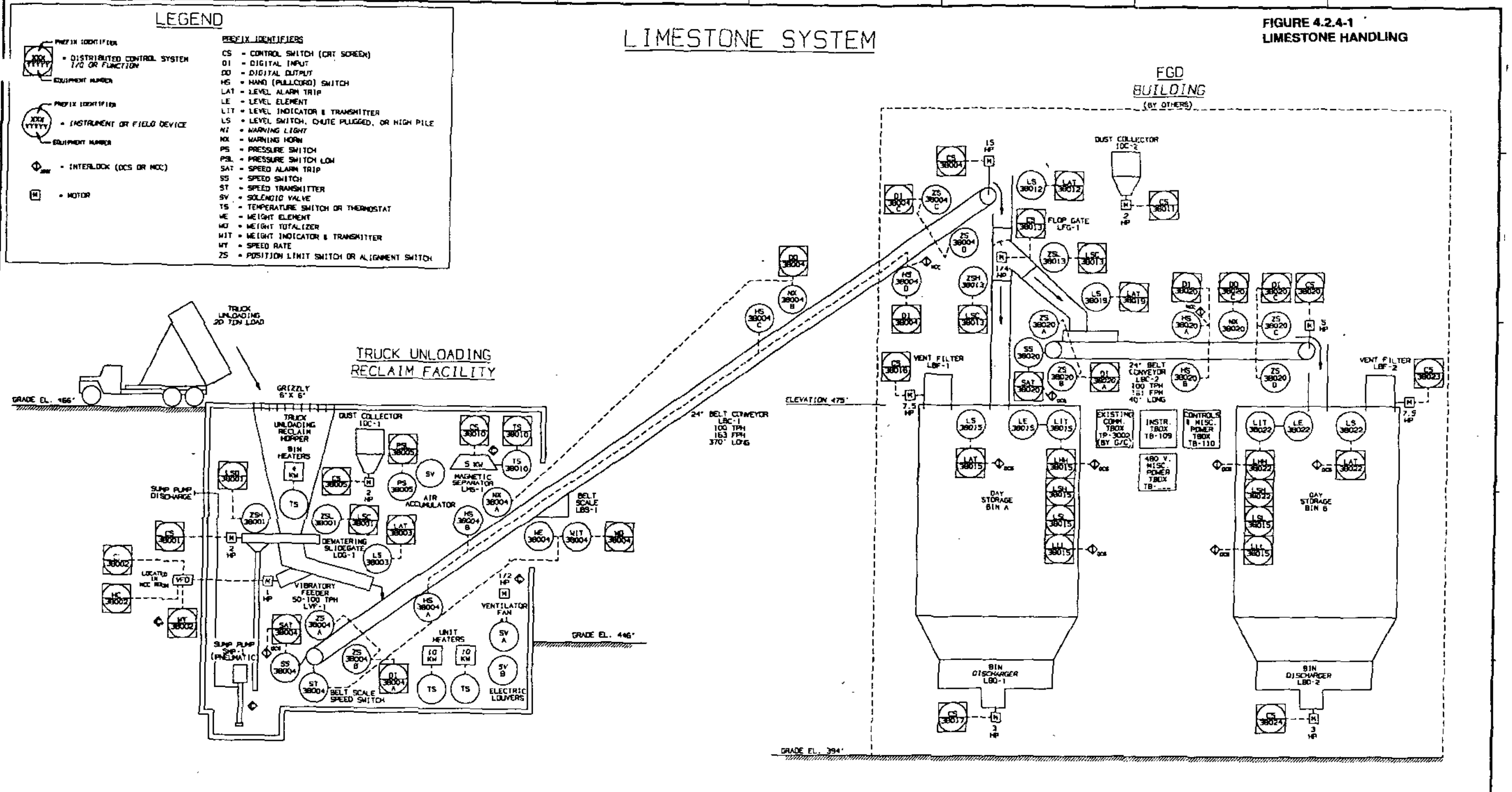
CERTIFIED FOR CONSTRUCTION
FULLER COMPANY BETHLEHEM PA.

GILBERT/COMMONWEALTH, INC

REV. NO.	BY	CHD.	APPD.	DATE	ZONE	MICRO	DESCRIPTION
2	RWS	AT	JX	26APR93			REVISED PER CUSTOMER COMMENTS
1	RWS	HB	HB	05MAR93			GENERAL REVISION

FULLER
FULLER COMPANY
DR. RWS
CHD. HB
APPR. HB
PROCESS FLOW SHEET
LIMESTONE GRINDING SYSTEM
NYSEG FGD RETROFIT PROJECT
MILLIKEN STATION
DRAWING NUMBER 135-92-4-3603 REV. 2
92-20278-135

FIGURE 4.2.4-1
LIMESTONE HANDLING



NOTES:

1. ALL MOTORS WILL BE WIRED DIRECTLY TO THE MCC.
2. ALL INSTRUMENT AND FIELD DEVICE DCS SIGNALS WILL BE WIRED TO THE JB-109 BOX LOCATED INSIDE THE FGD BUILDING.
3. PHONES AND OTHER COMMUNICATION EQUIPMENT WILL BE WIRED TO THE EXISTING TP-3002 BOX PROVIDED BY GILBERT/COMMONWEALTH LOCATED INSIDE THE FGD BUILDING.
4. CONTROLS AND MISC. POWER WILL BE WIRED TO THE TB-110 BOX LOCATED INSIDE THE FGD BUILDING.

REFERENCE DRAWINGS

JK6191-310 LOGIC DIAGRAMS-LIMESTONE SYSTEM
JK6191-311 LOGIC DIAGRAMS-LIMESTONE SYSTEM
JK6191-315 LOGIC DIAGRAMS-BIN DISCHARGERS
JK6191-316 LOGIC DIAGRAMS-DAY STORAGE BINS "A" & "B"
JK6191-317 LOGIC DIAGRAMS-CONVEYOR LBC-2
JK6191-318 LOGIC DIAGRAMS-CONVEYOR LBC-1
JK6191-319 LOGIC DIAGRAMS-VENT FILTERS LBF-1 & LBF-2
JK6191-320 LOGIC DIAGRAMS-DUST COLLECTORS IDC-1 & IDC-2
JK6191-321 LOGIC DIAGRAMS-DEWATERING SLIDE GATE LDG-1
JK6191-322 LOGIC DIAGRAMS-MAGNETIC SEPARATOR LMS-1
JK6191-323 LOGIC DIAGRAMS-VIBRATORY FEEDER LVF-1
JK6191-324 LOGIC DIAGRAMS-FLOP GATE LFG-1

REV	DATE	DRAWN	CHECKED	APPROVED	DESCRIPTION OF REVISION
3	09-02-93	[illegible]	KAM	[illegible]	REVISED PER G/C MARK-UPS 8-30-93
2	07-23-93	FARRELL	GCI	JLS	REVISED PER G/C MARK-UPS 7-19-93
1	08-25-93	FARRELL	JRB	JLS	REVISED PER G/C COMMENTS 8-10-93
0	05-03-93	FARRELL	SMF	JLS	ORIGINAL

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SCALE: NONE — DIMENSION TOLERANCES EXCEPT AS SPECIFIED: FRACTIONAL ±1/16" MACHINED FRACTIONAL ±1/32"

LIMESTONE SYSTEM P & I D
LIMESTONE & GYPSUM HANDLING SYS.
NYSEG-MILLIKEN STATION

NEW YORK STATE ELECTRIC & GAS CORP.
MILLIKEN STATION
GILBERT/COMMONWEALTH INC.
CONTRACT NO. MSH-F09

GRAPHICS NO. J.G.6191.EE.0003.C

DIV EE

FMC Corporation
MATERIAL HANDLING SYSTEMS DIV.

JK6191-3

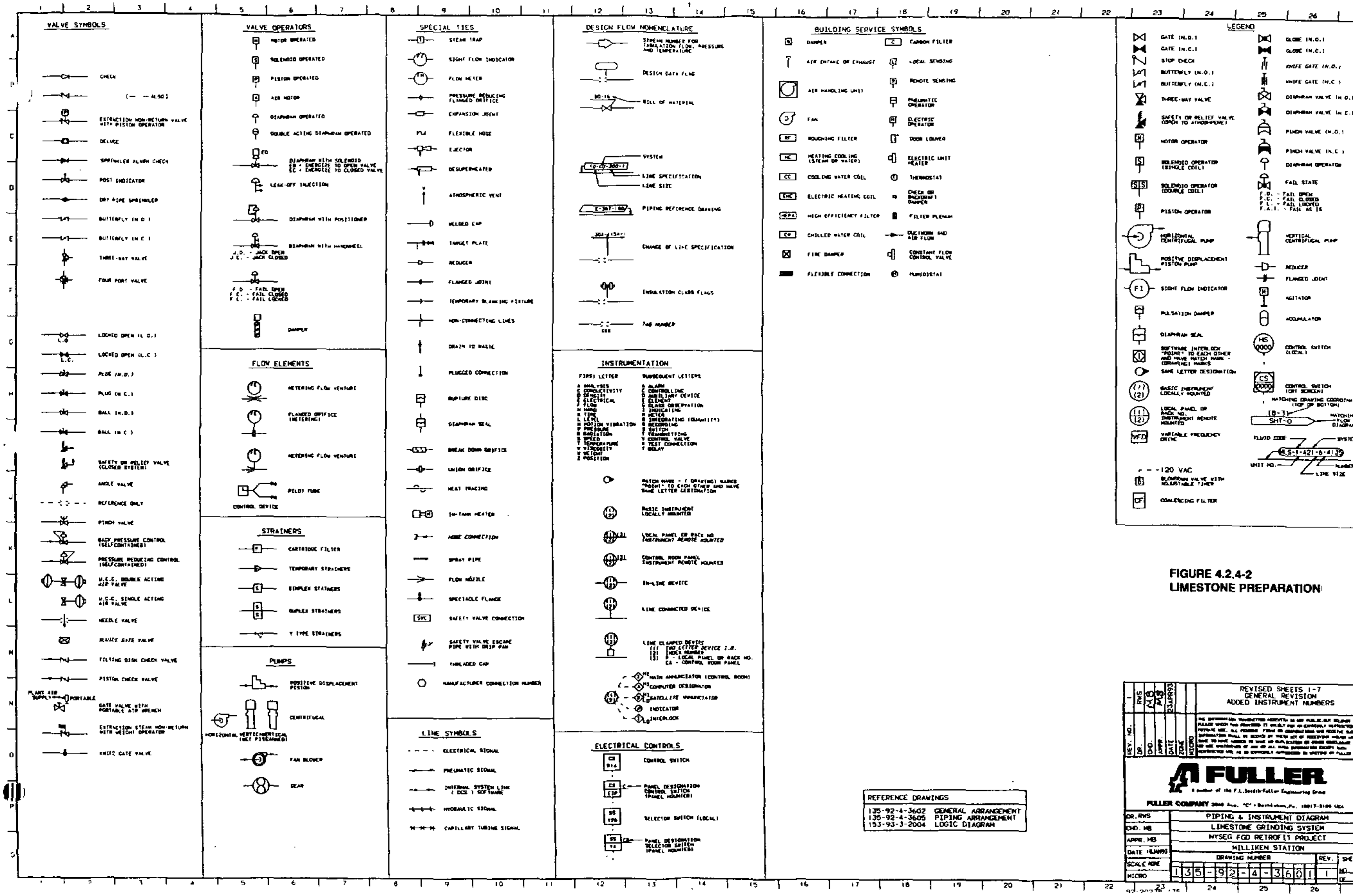


FIGURE 4.2.4-2
LIMESTONE PREPARATION

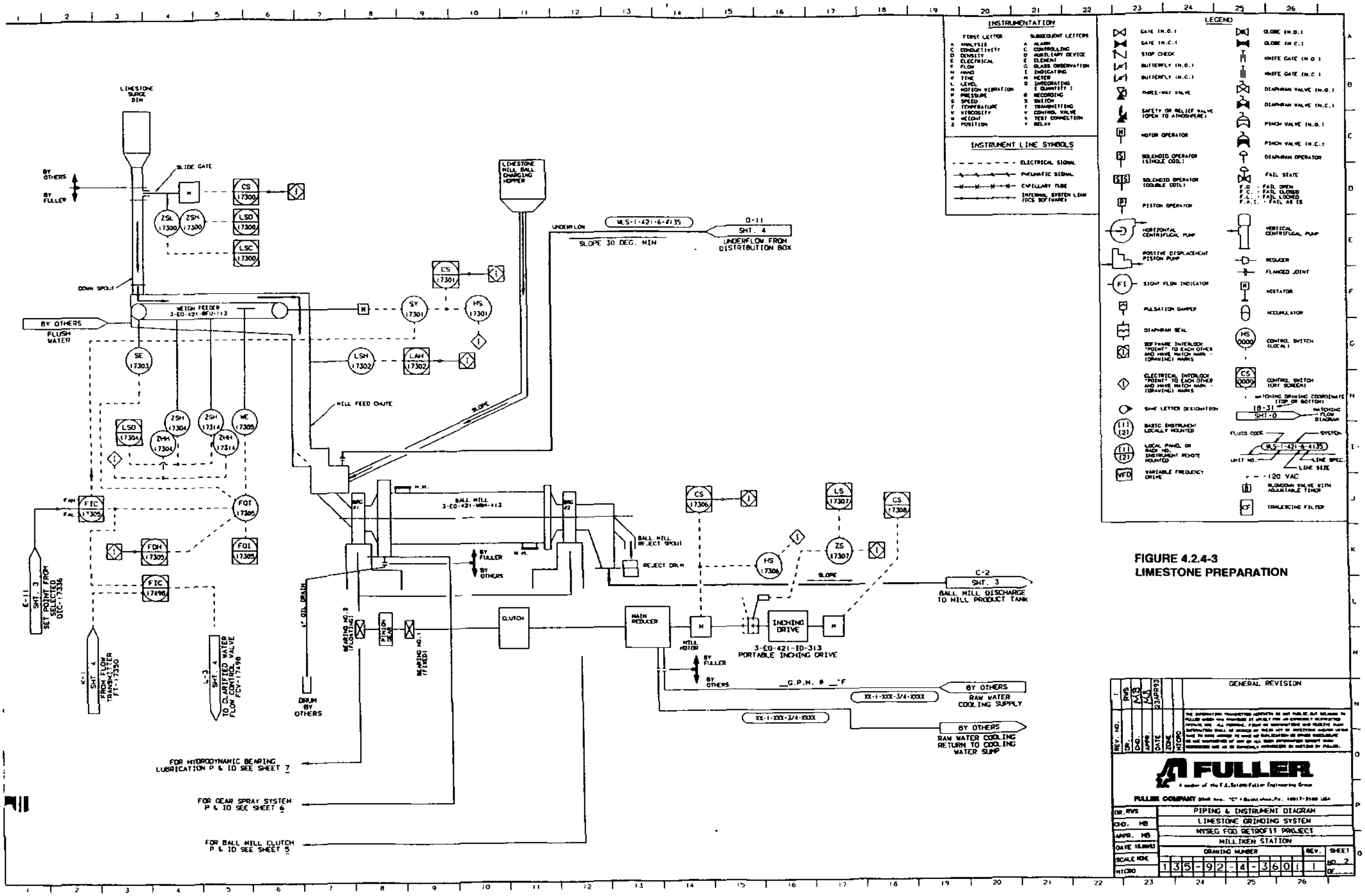


FIGURE 4.2.4-3
LIMESTONE PREPARATION

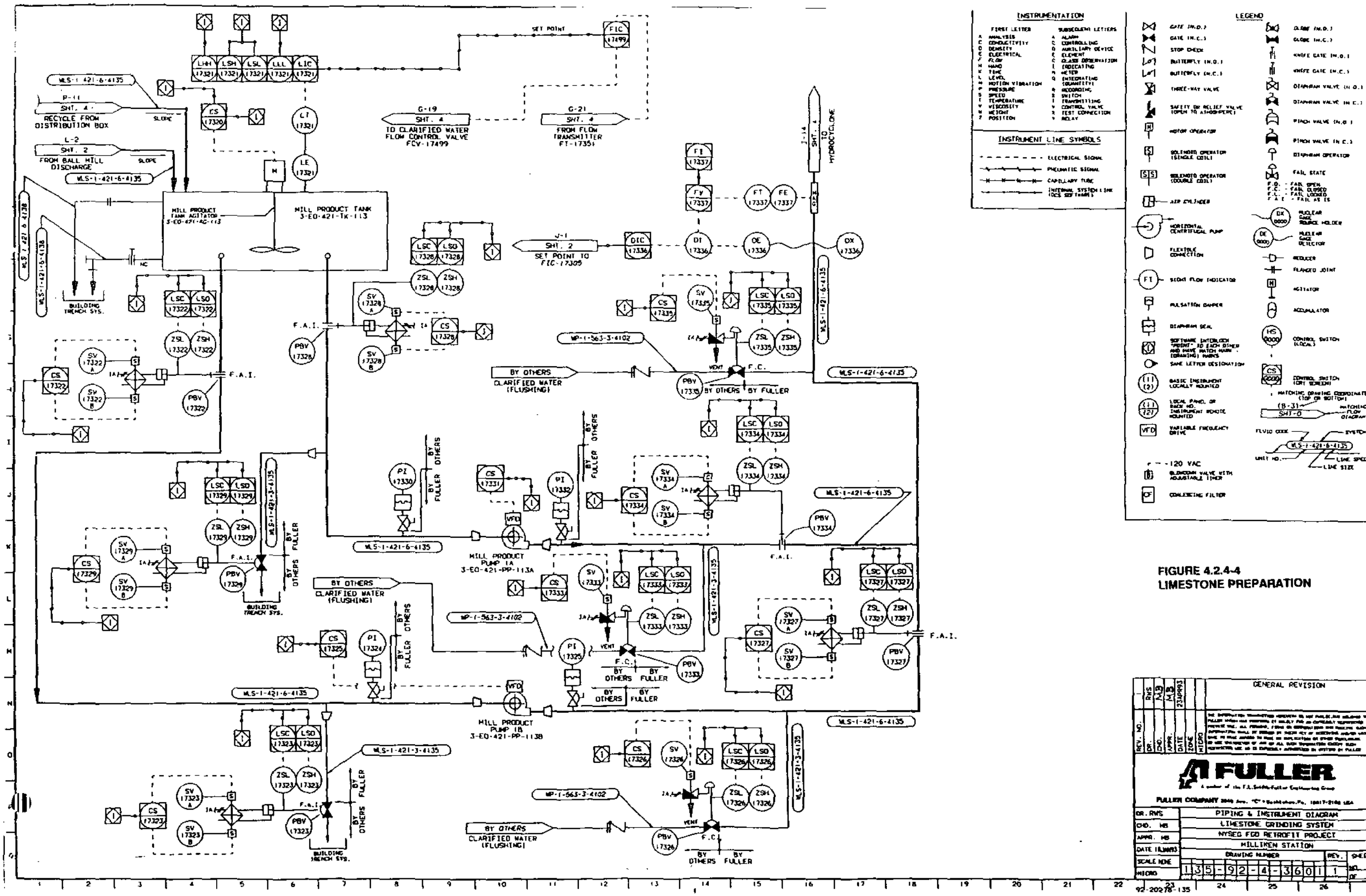


FIGURE 4.2.4-4
LIMESTONE PREPARATION

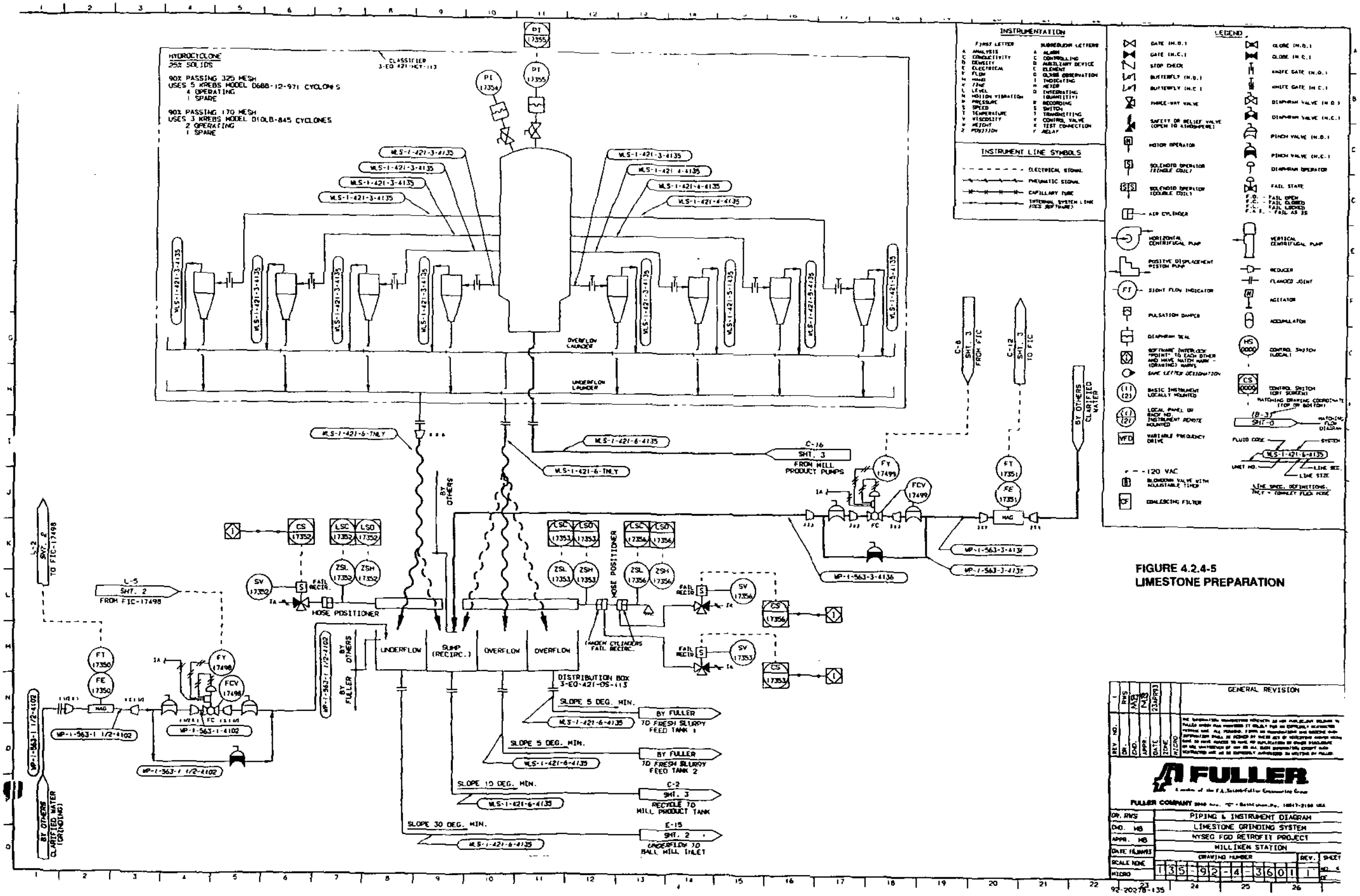


FIGURE 4.2.4-5
LIMESTONE PREPARATION

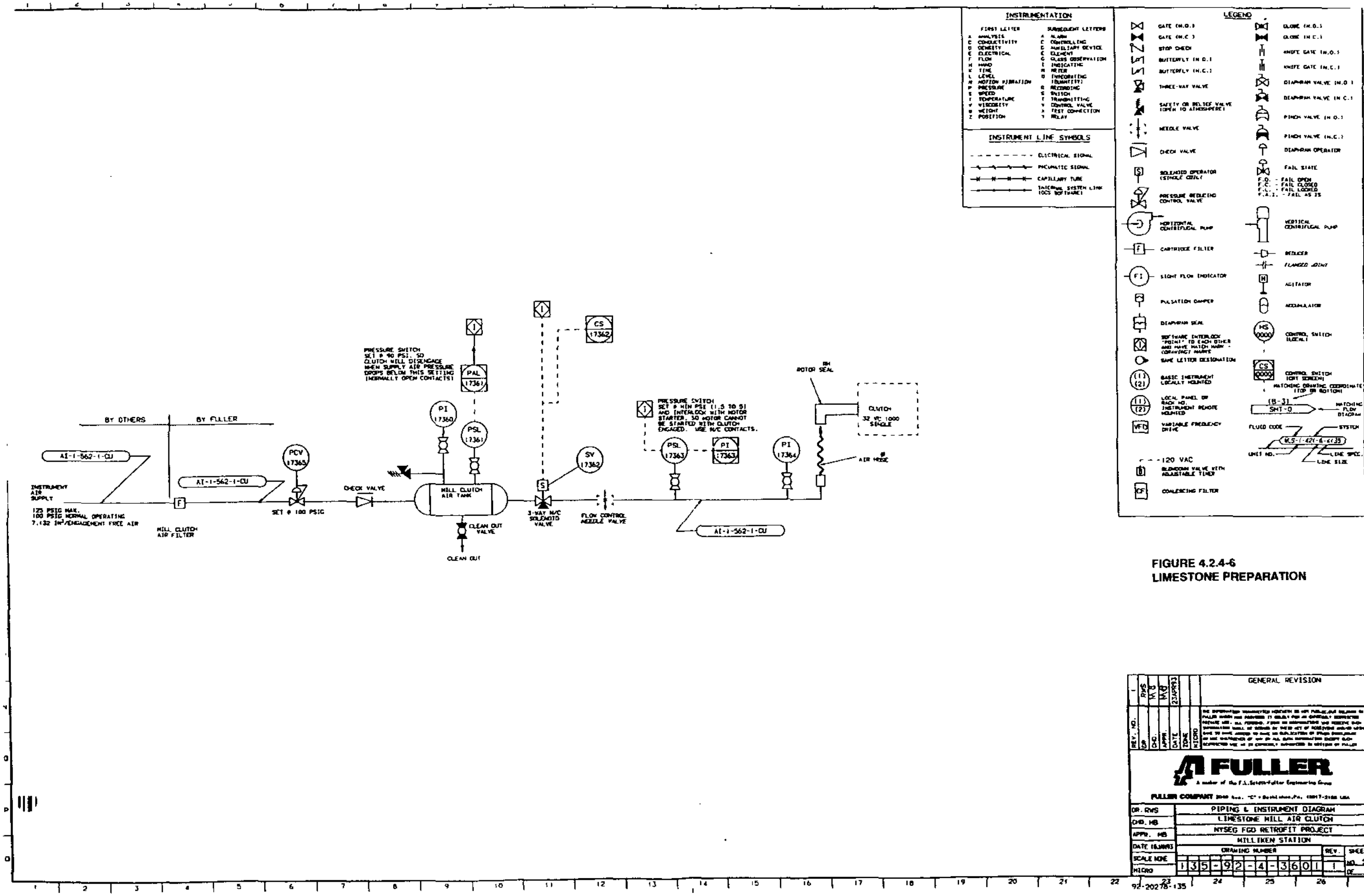


FIGURE 4.2.4-6
LIMESTONE PREPARATION

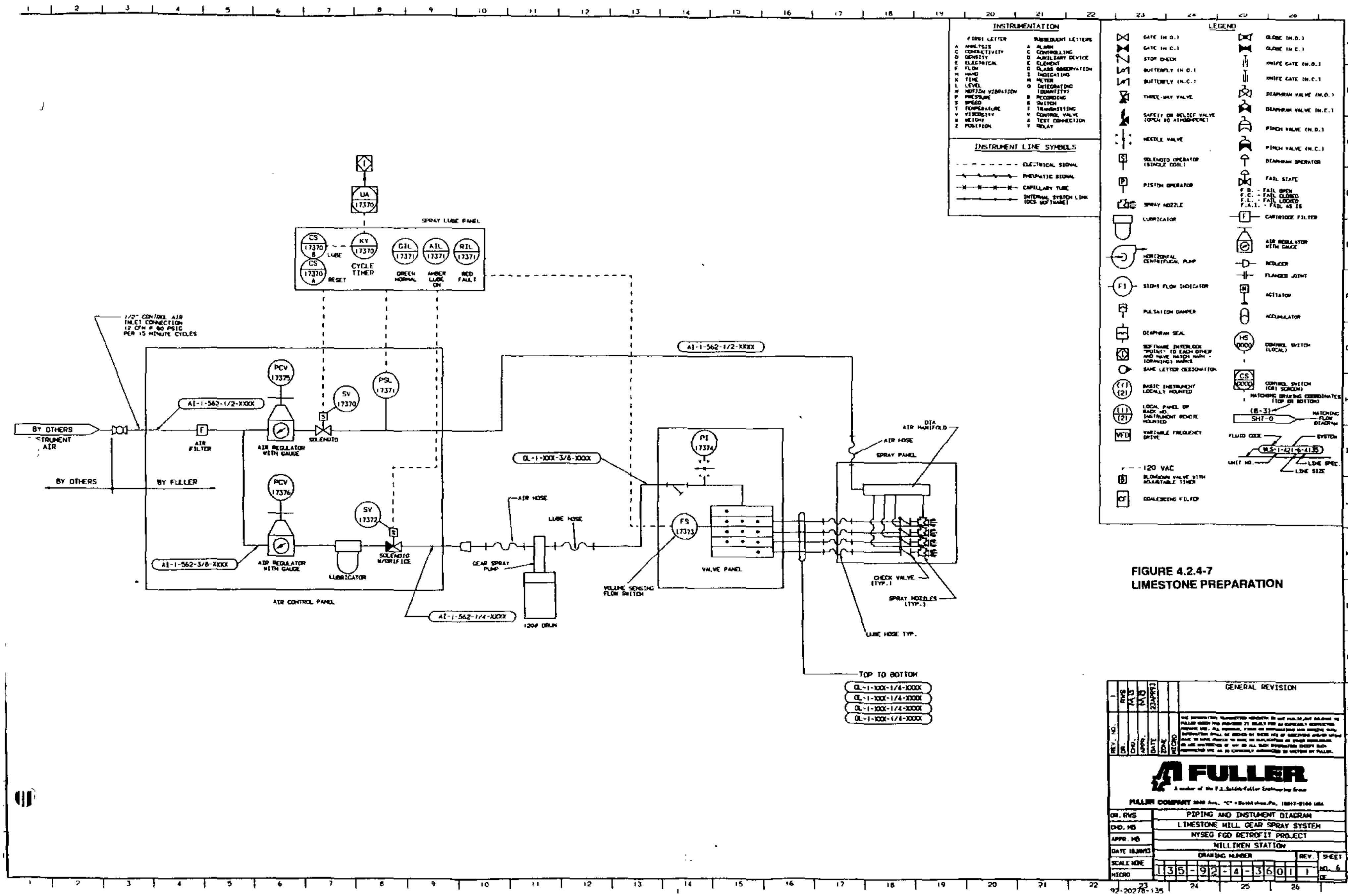


FIGURE 4.2.4-7
LIMESTONE PREPARATION

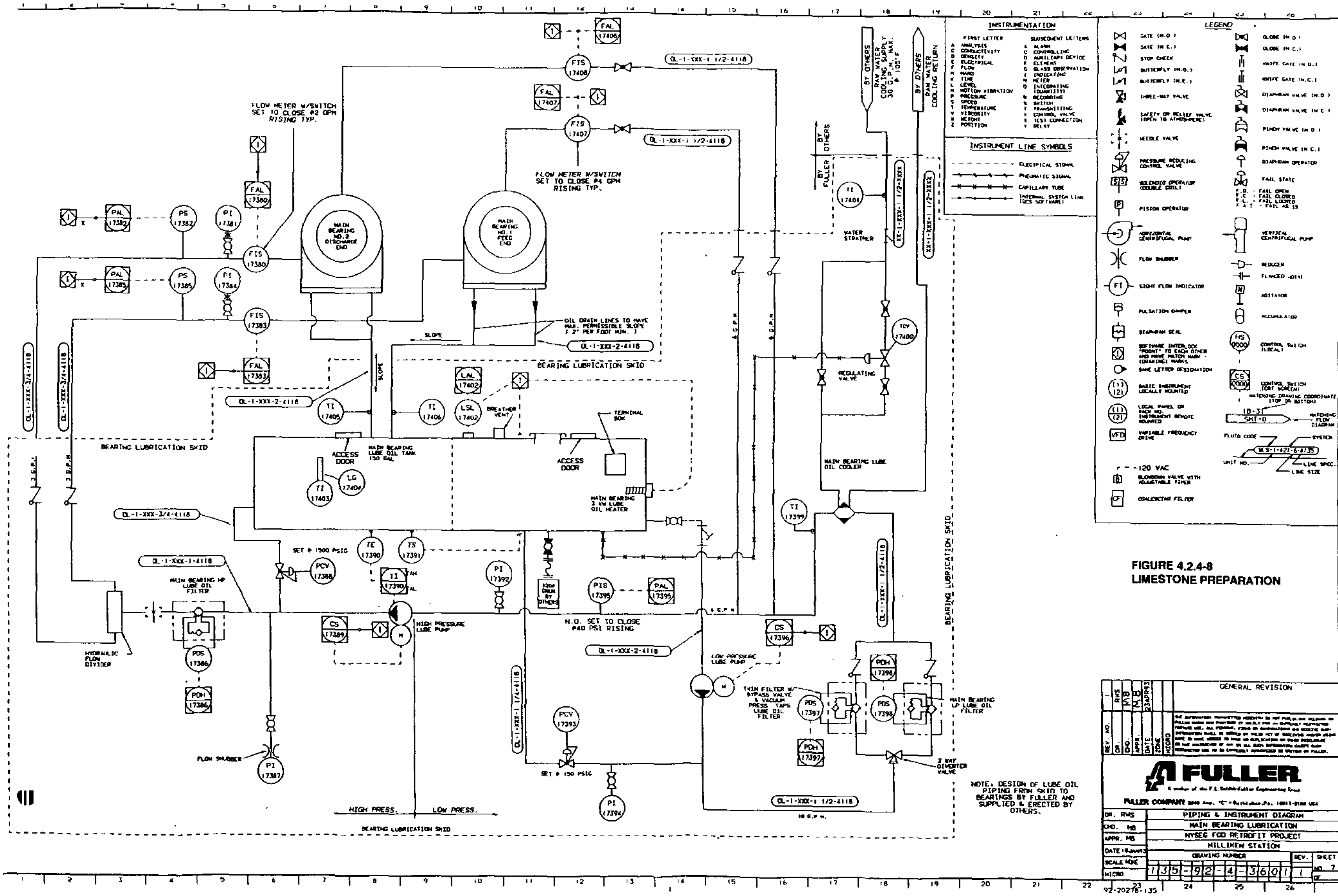


FIGURE 4.2.4-8
LIMESTONE PREPARATION

FIGURE 4.2.4-9
S-H-U FGD PROCES

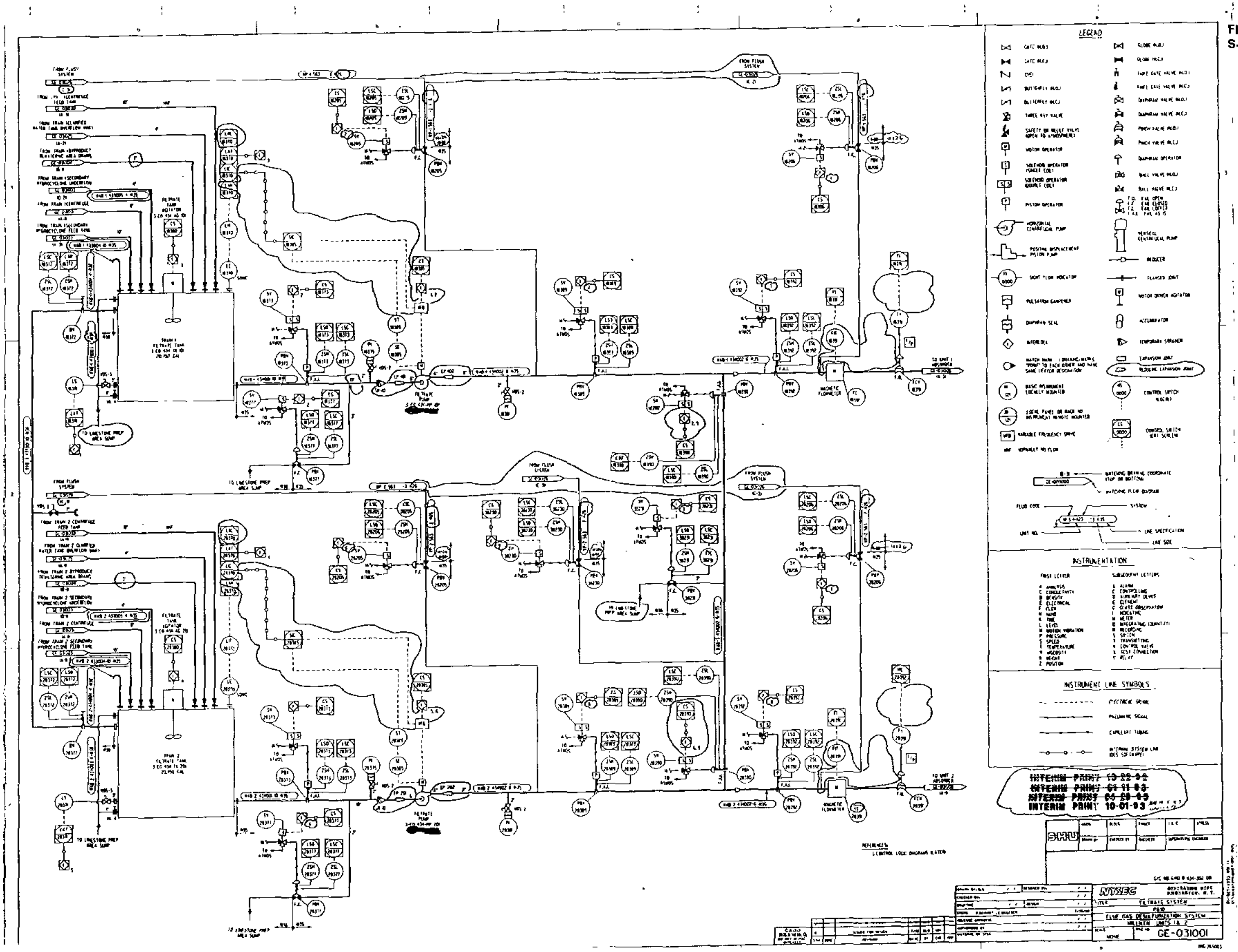


FIGURE 4.2.4-10
S-H-U FGD PROCESS

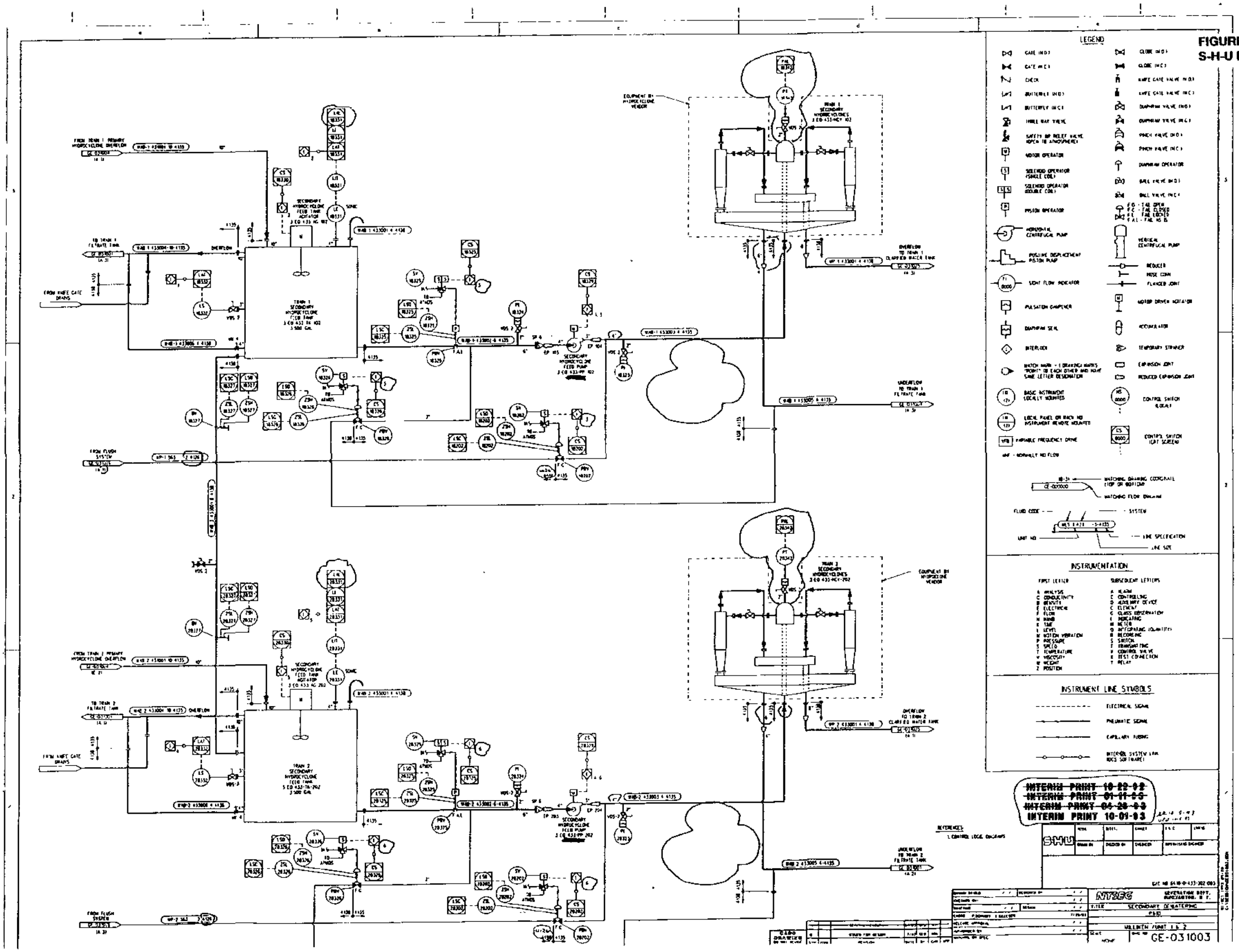


FIGURE 4.2.4-11
S-H-U FGD PROCESS

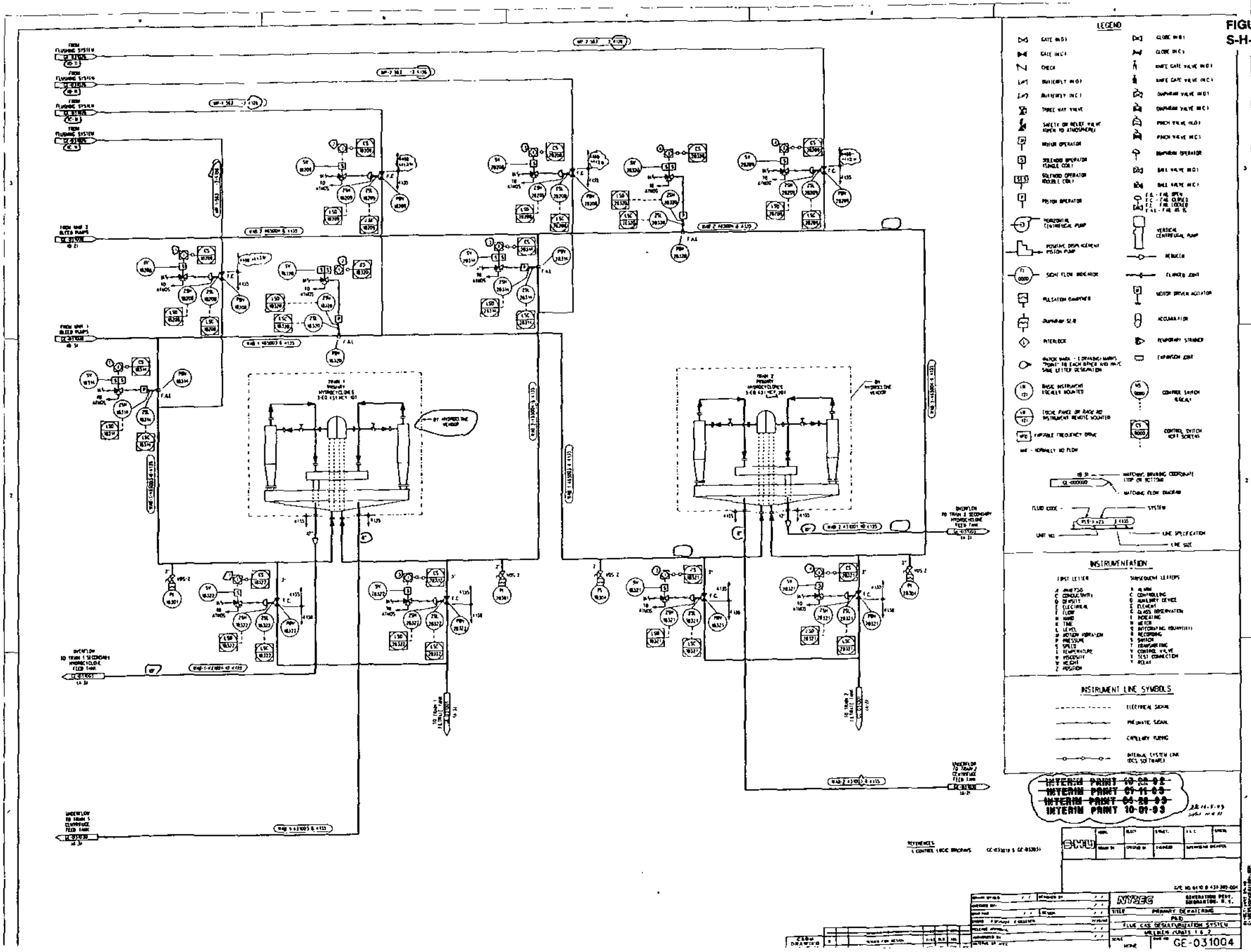


FIGURE 4.2.4-12
S-H-U FGD PROCESS

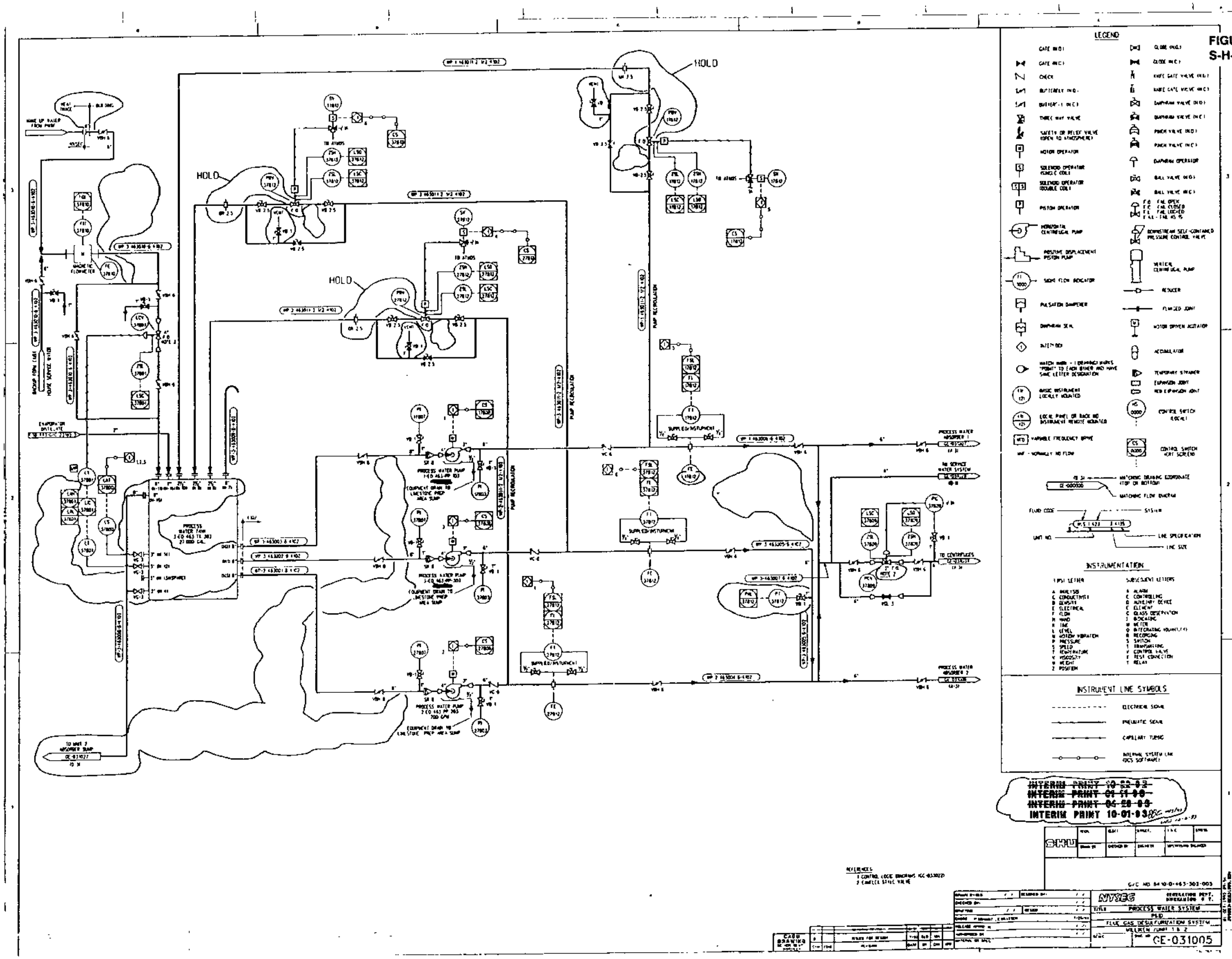


FIGURE 4.2.4-13
S-H-U FGD PROCESS

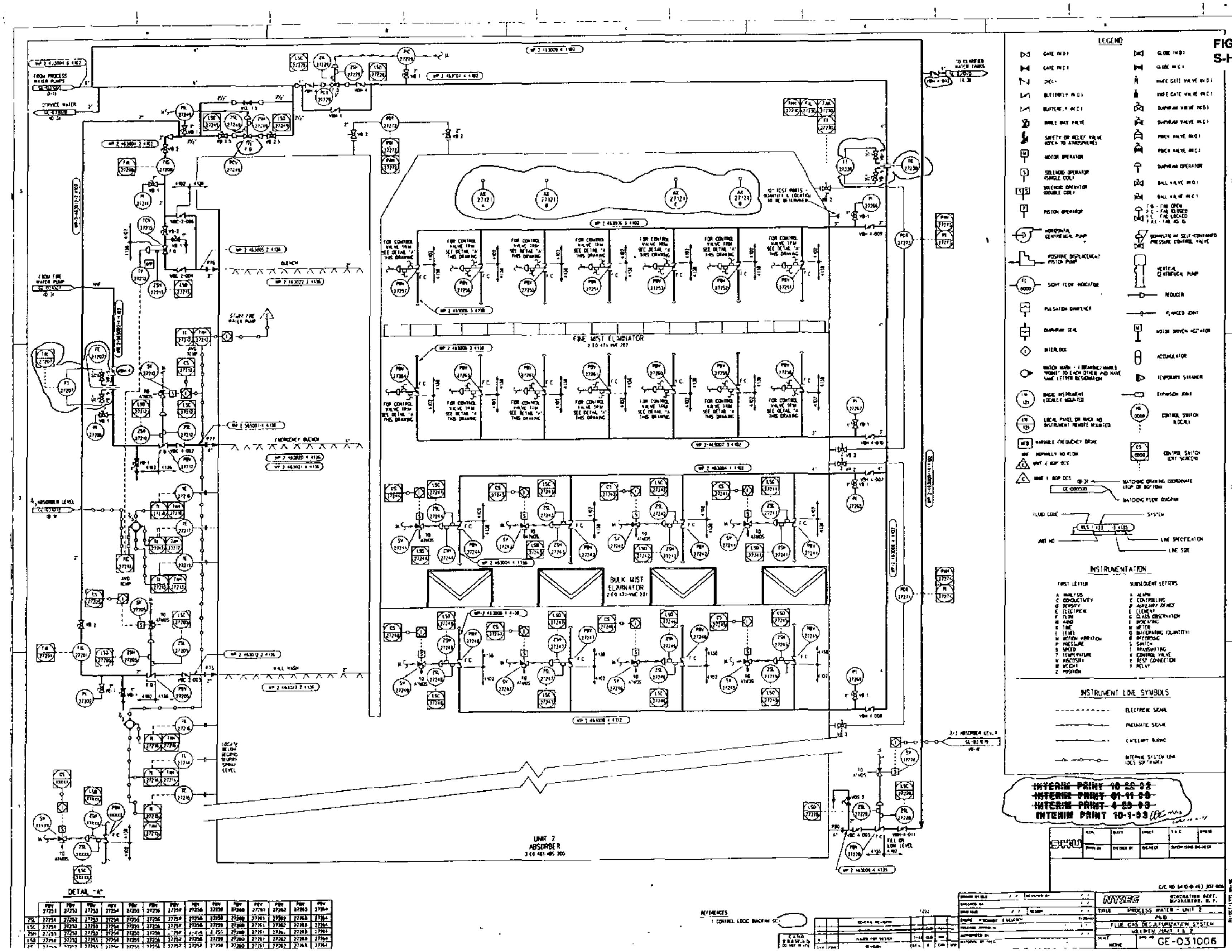


FIGURE 4.2.4-14
S-H-U FGD PROCESS

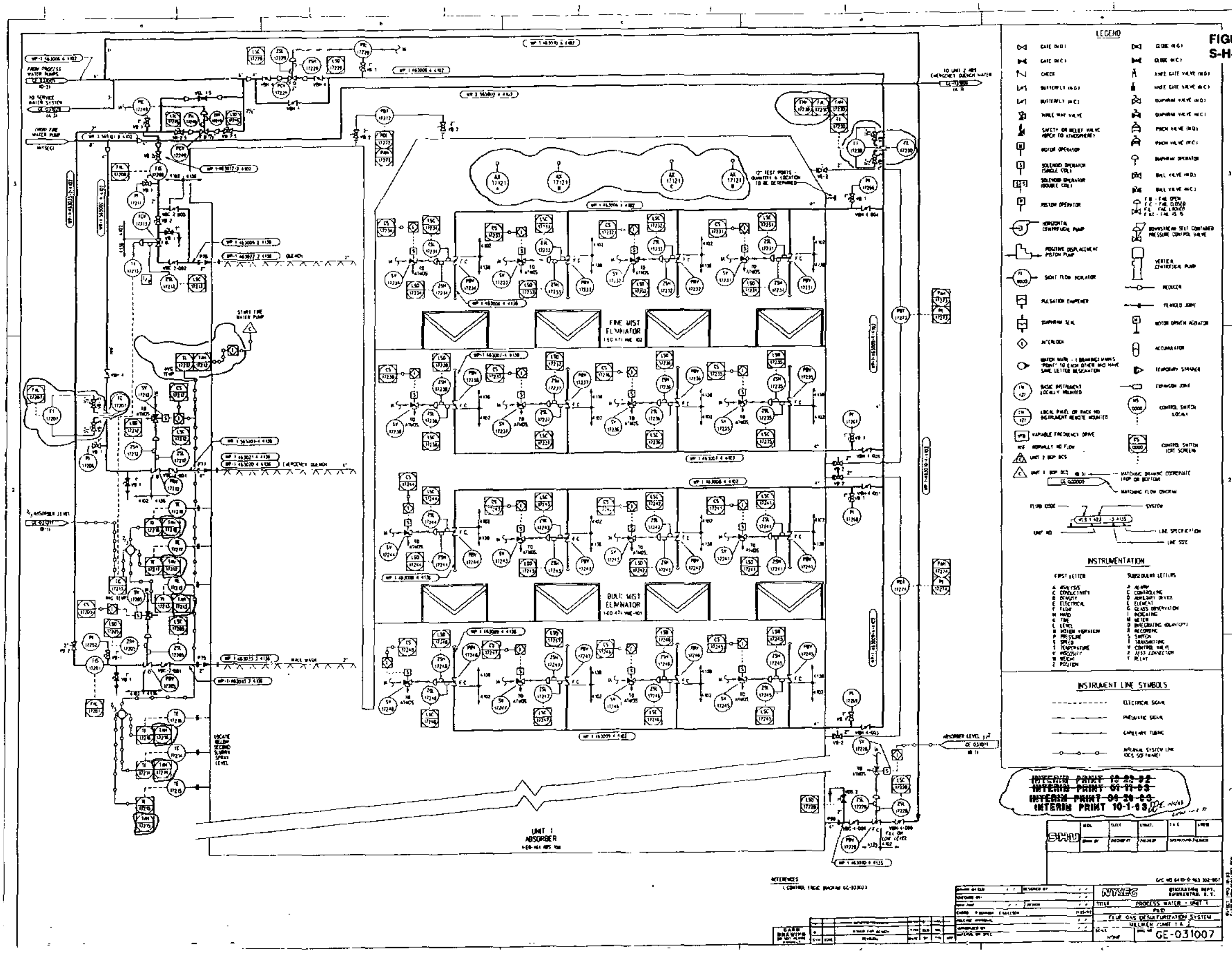


FIGURE 4.2.4-15
S-H-U FGD PROCESS

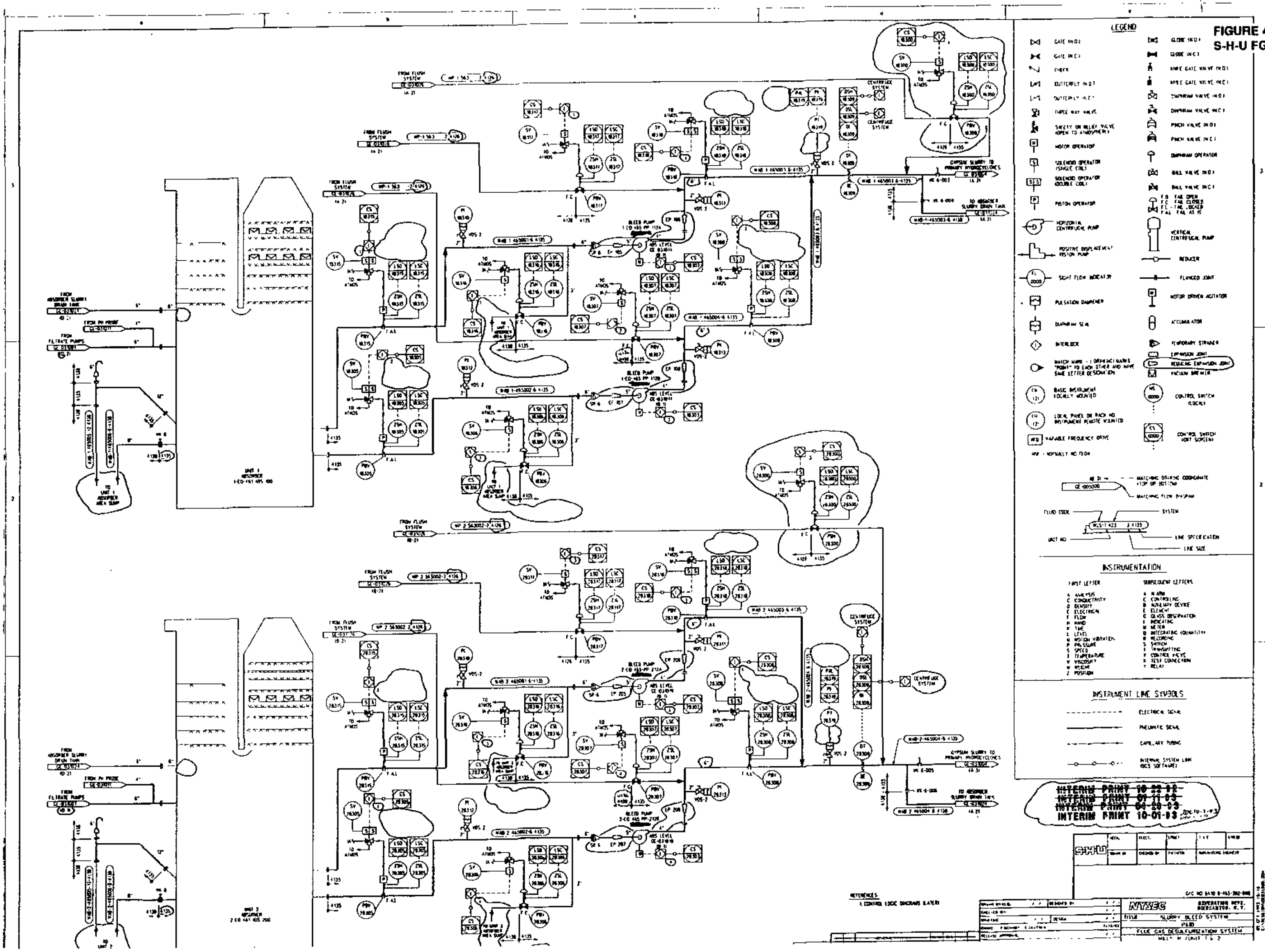


FIGURE 4.2.4-16
S-H-U FGD PROCESS

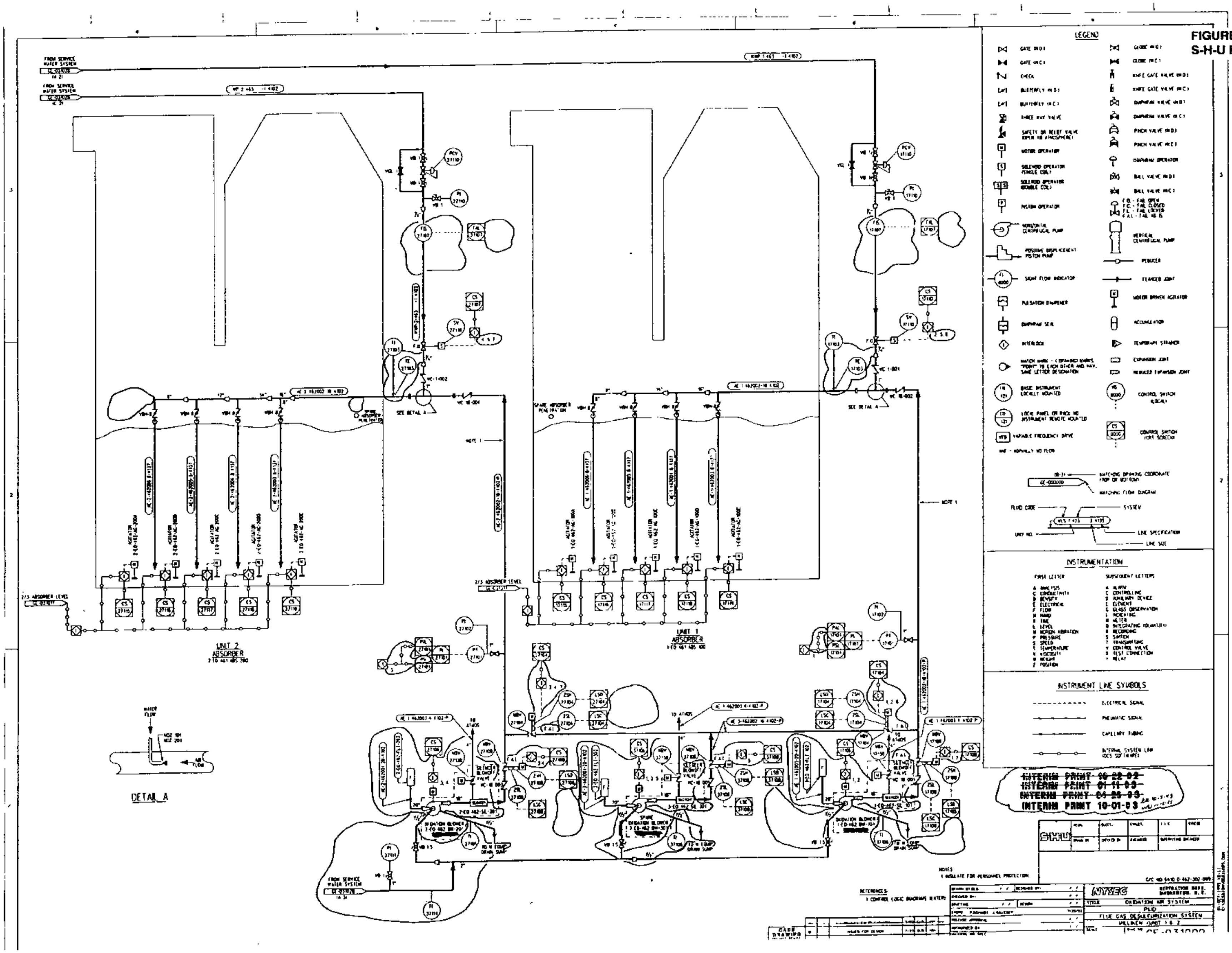


FIGURE 4.2.4-17
S-H-U FGD PROCESS

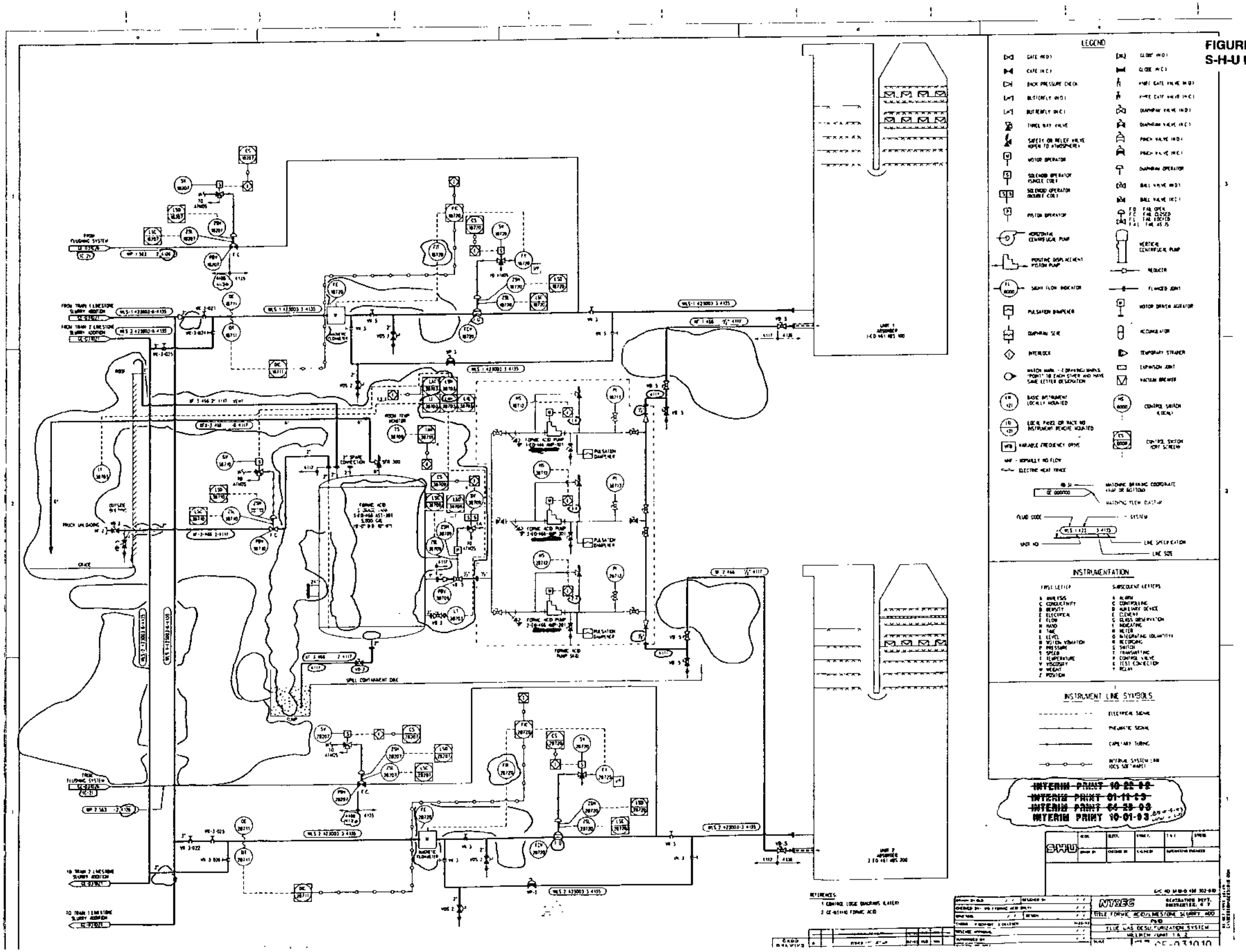


FIGURE 4.2.4-18
S-H-U FGD PROCESS

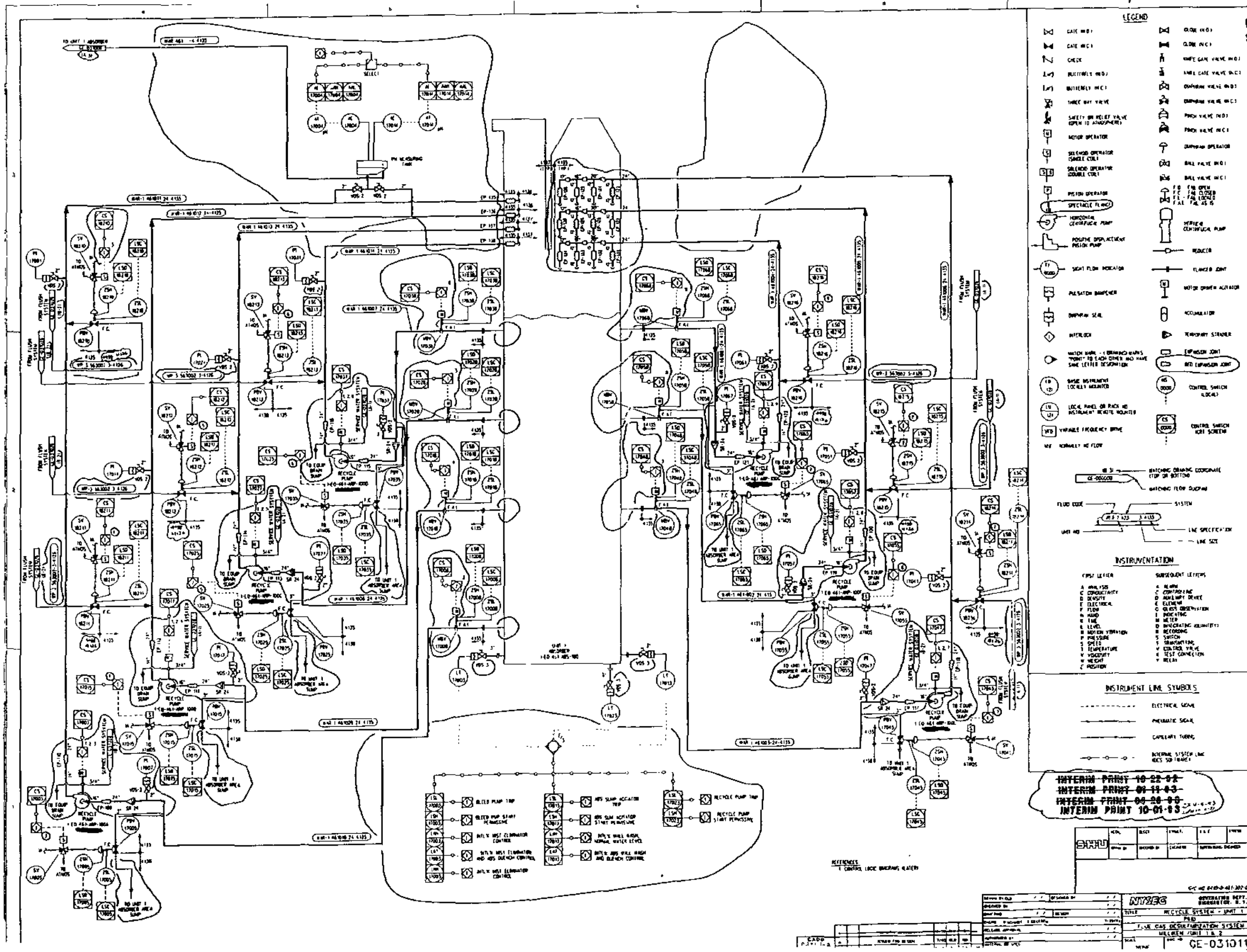
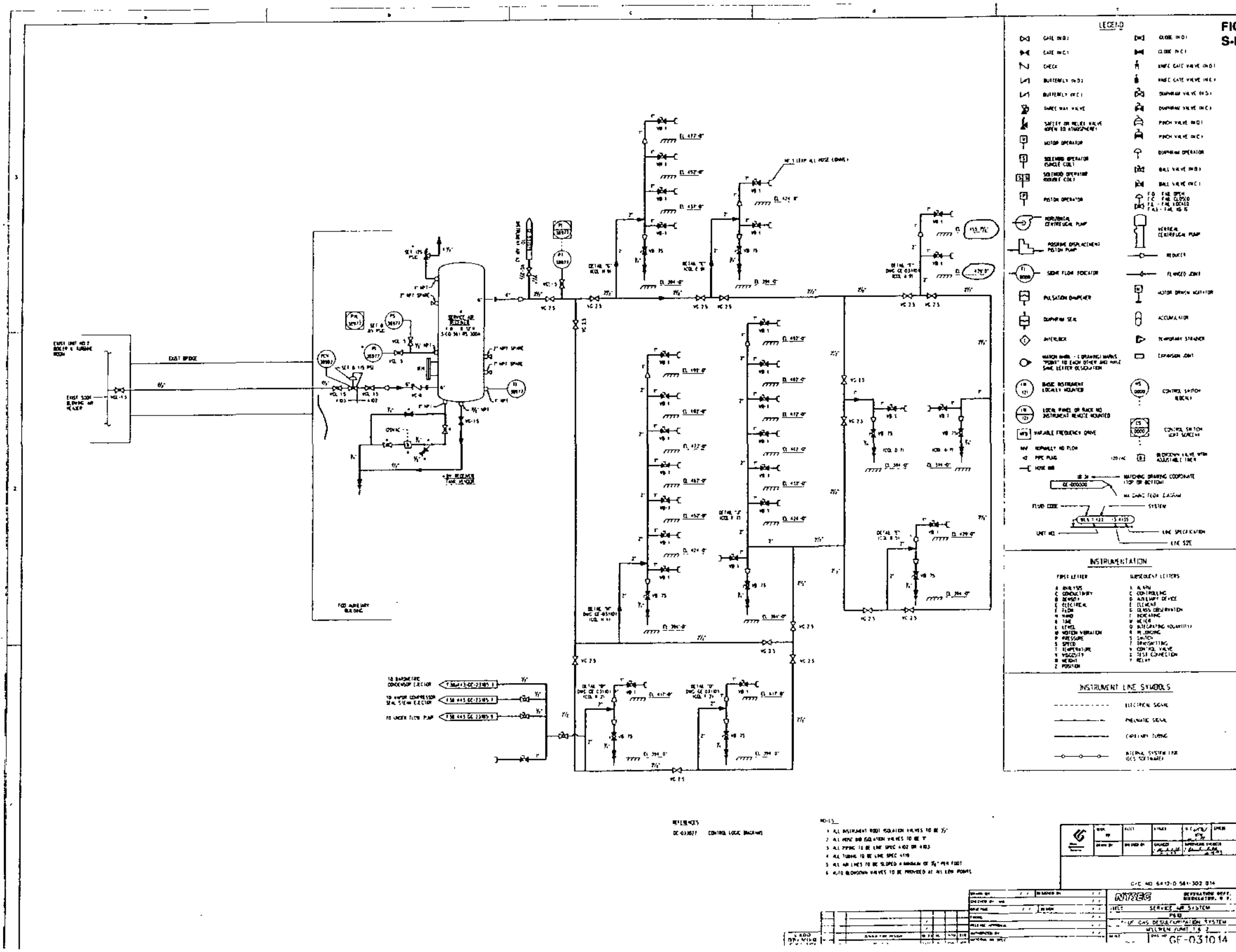


FIGURE 4.2.4-19
S-H-U FGD PROCESS



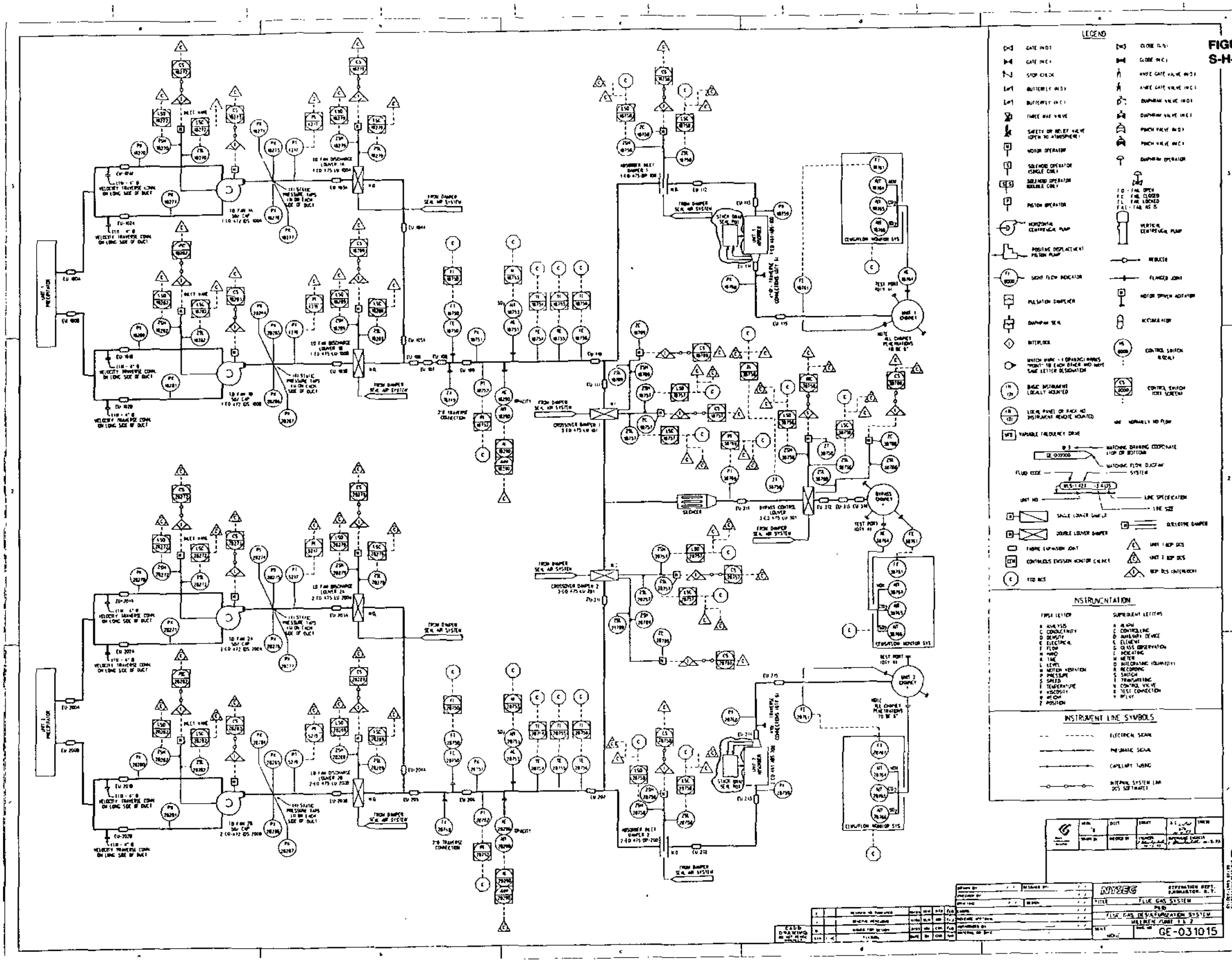


FIGURE 4.2.4-20
S-H-U FGD PROCESS

FIGURE 4.2.4-21
S-H-U FGD PROCESS

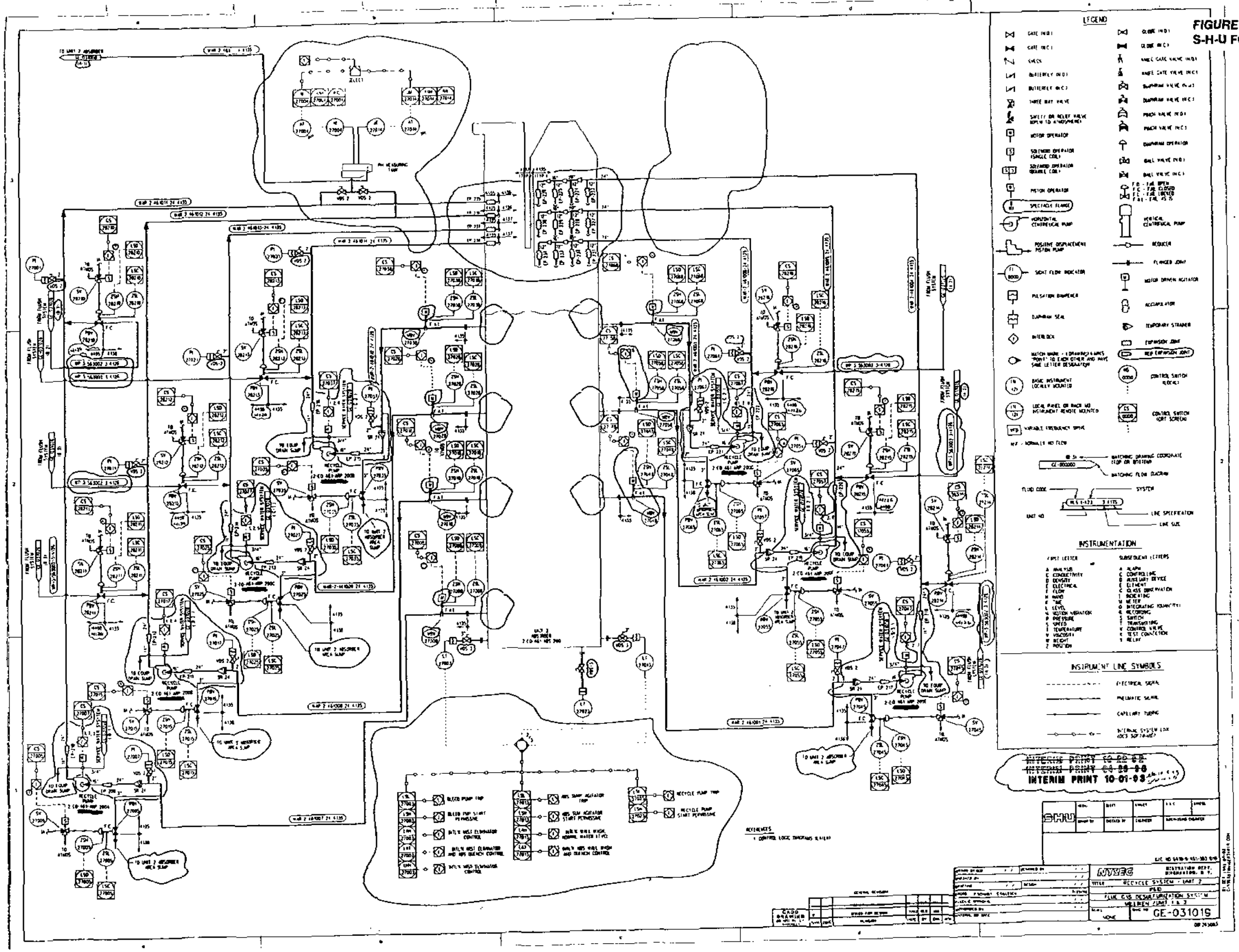


FIGURE 4.2.4-22
S-H-U FGD PROCESS

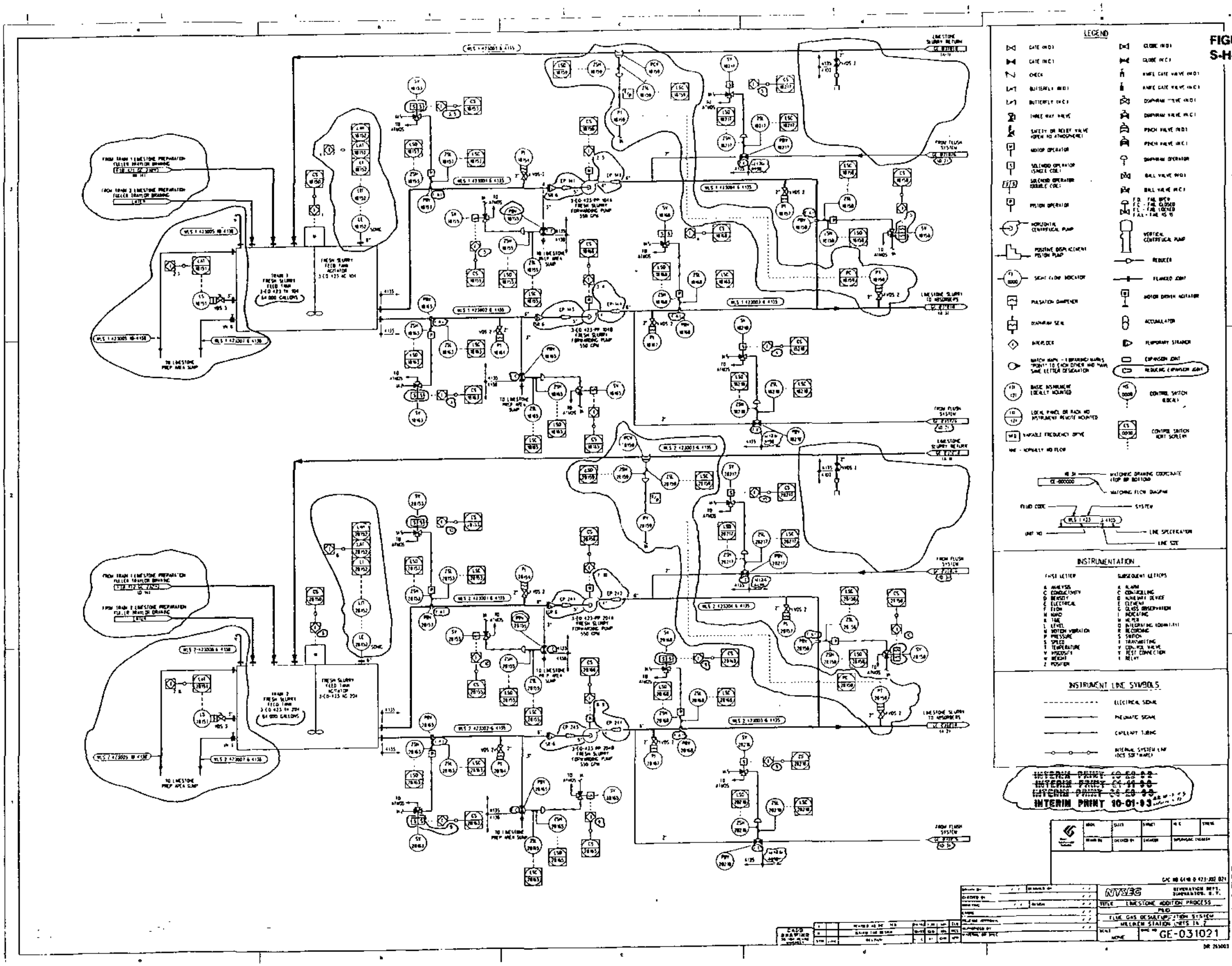


FIGURE 4.2.4-23
S-H-U FGD PROCESS

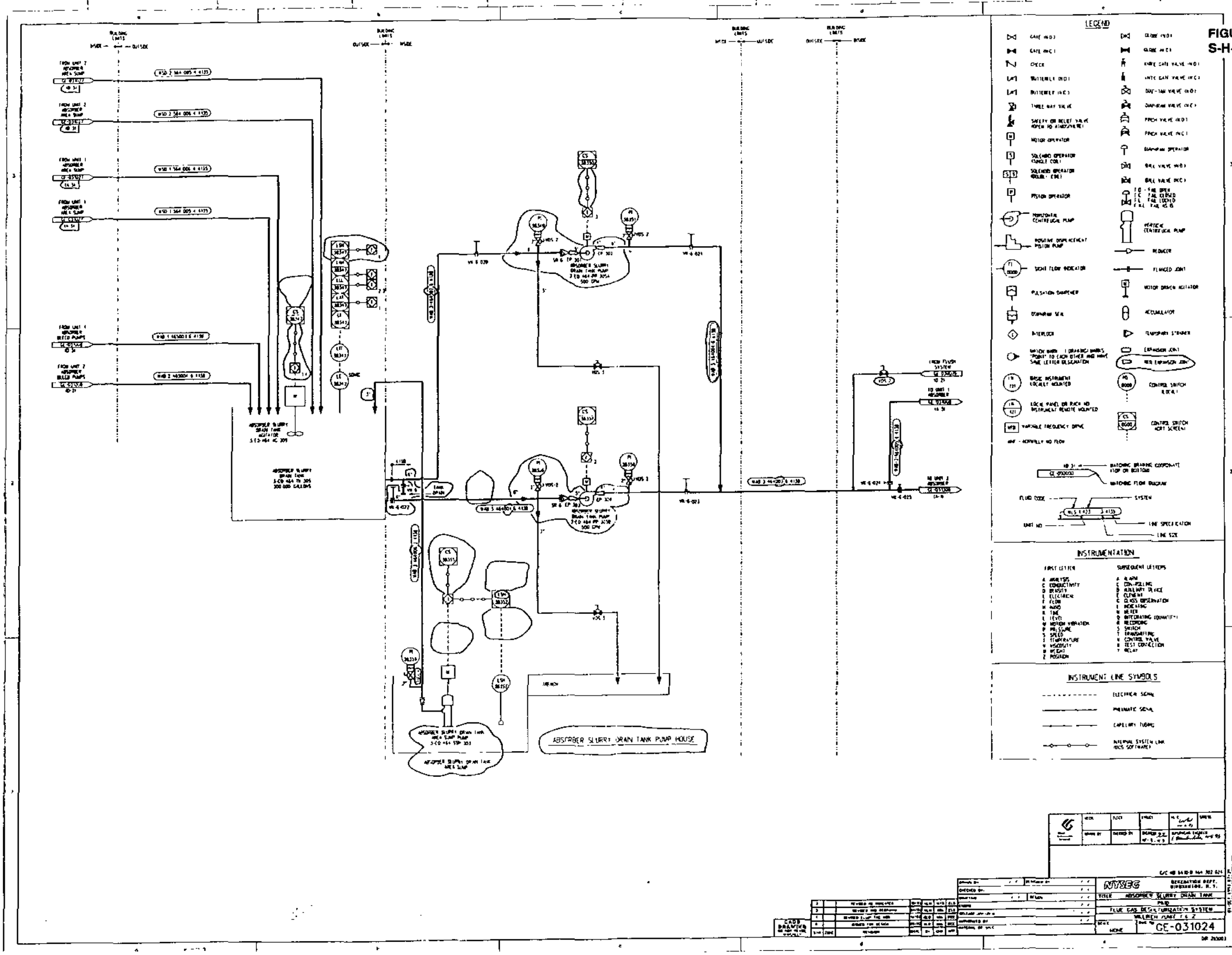
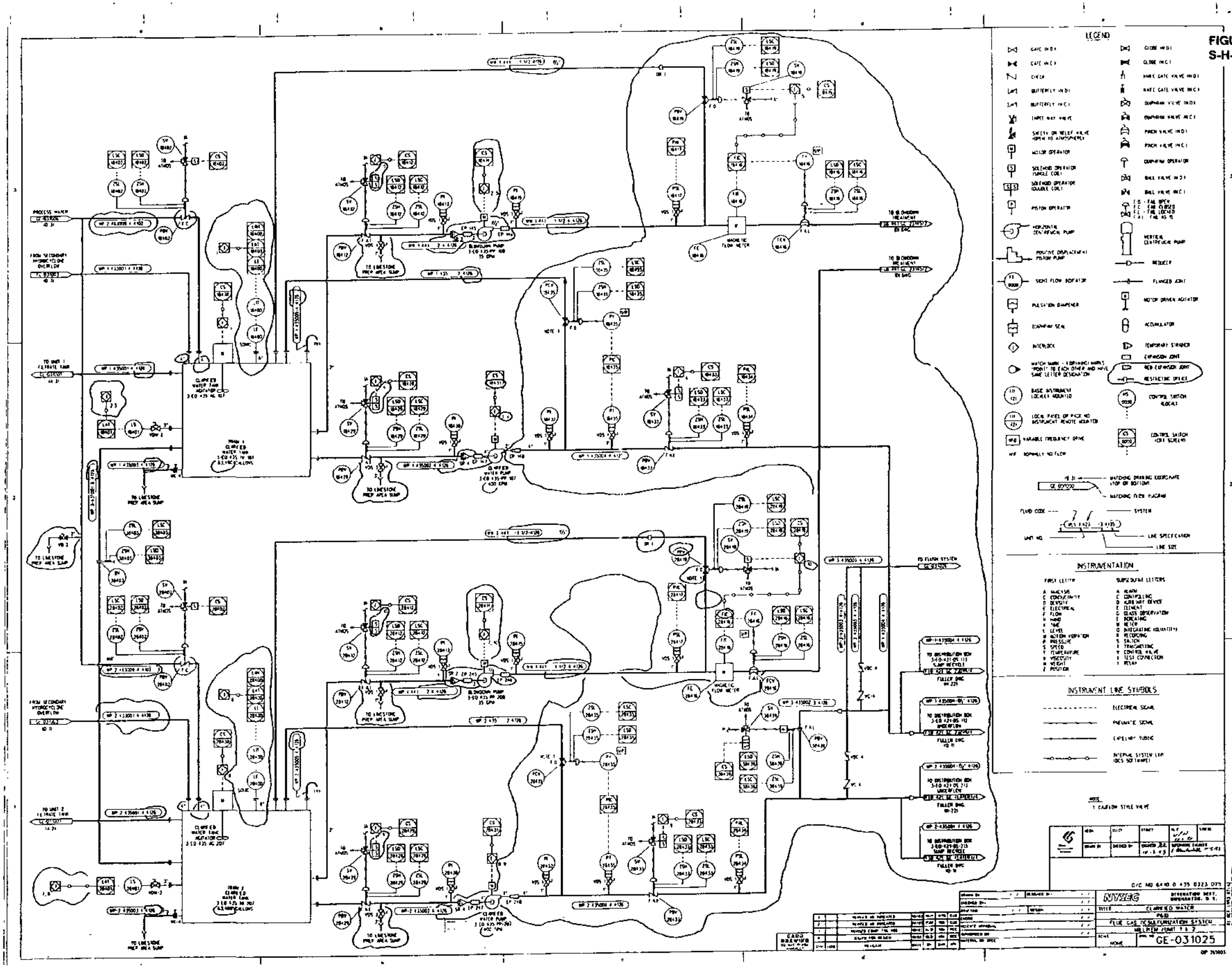


FIGURE 4.2.4-24
S-H-U FGD PROCESS



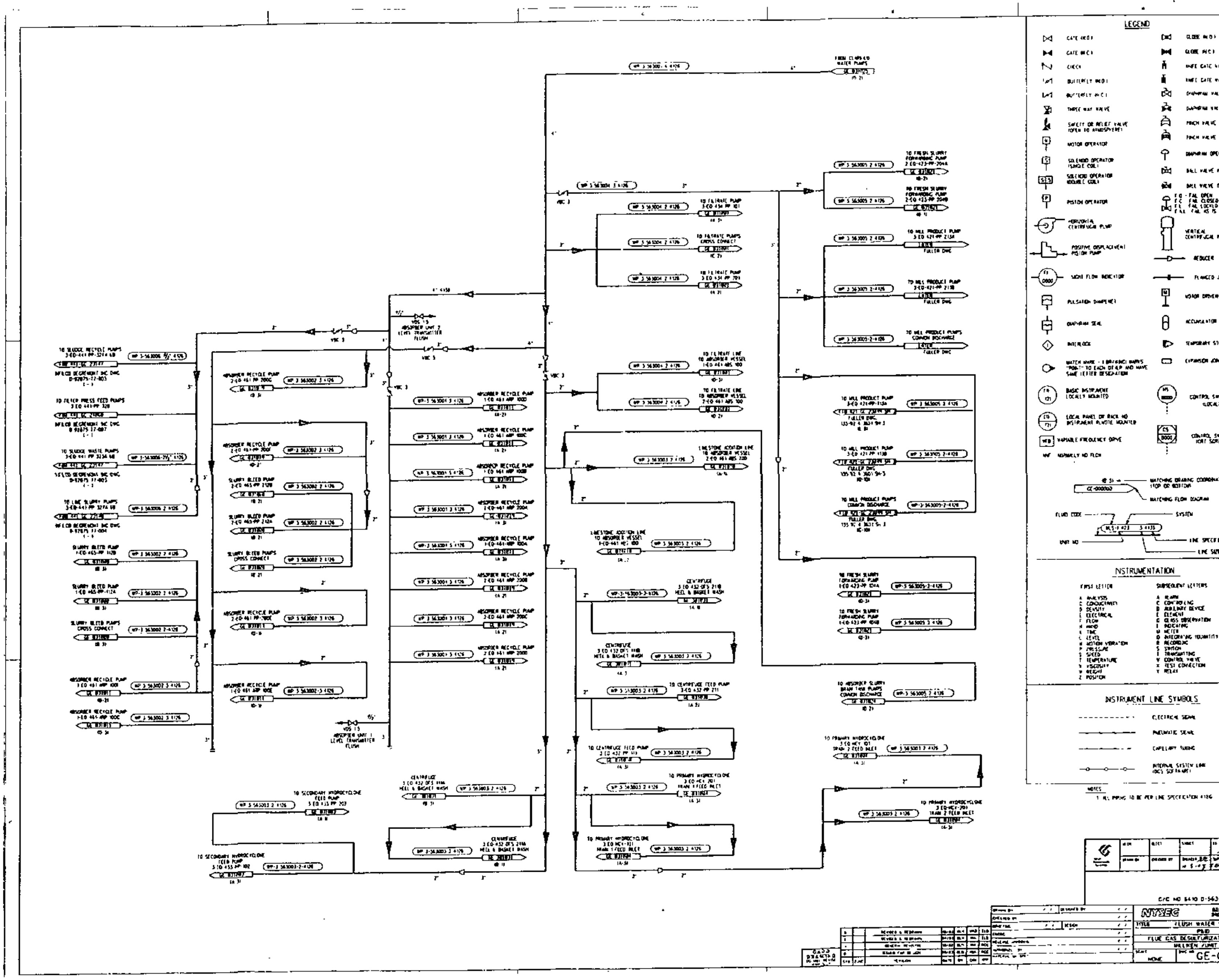


FIGURE 4.2.4-25
S-H-U FGD PROCESS

FIGURE 4.2.4-26
S-H-U FGD PROCESS

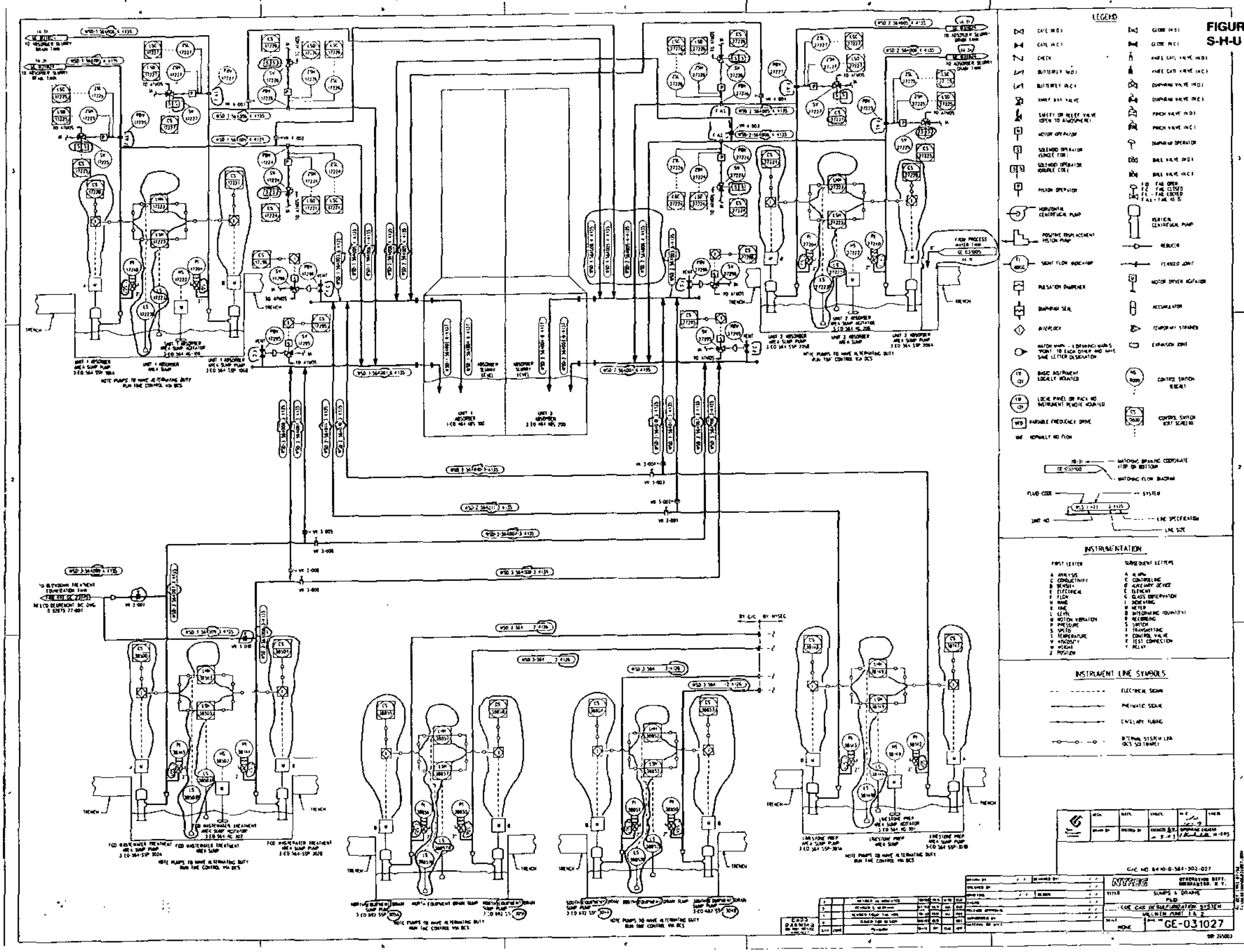


FIGURE 4.2.4-27
S-H-U FGD PROCESS

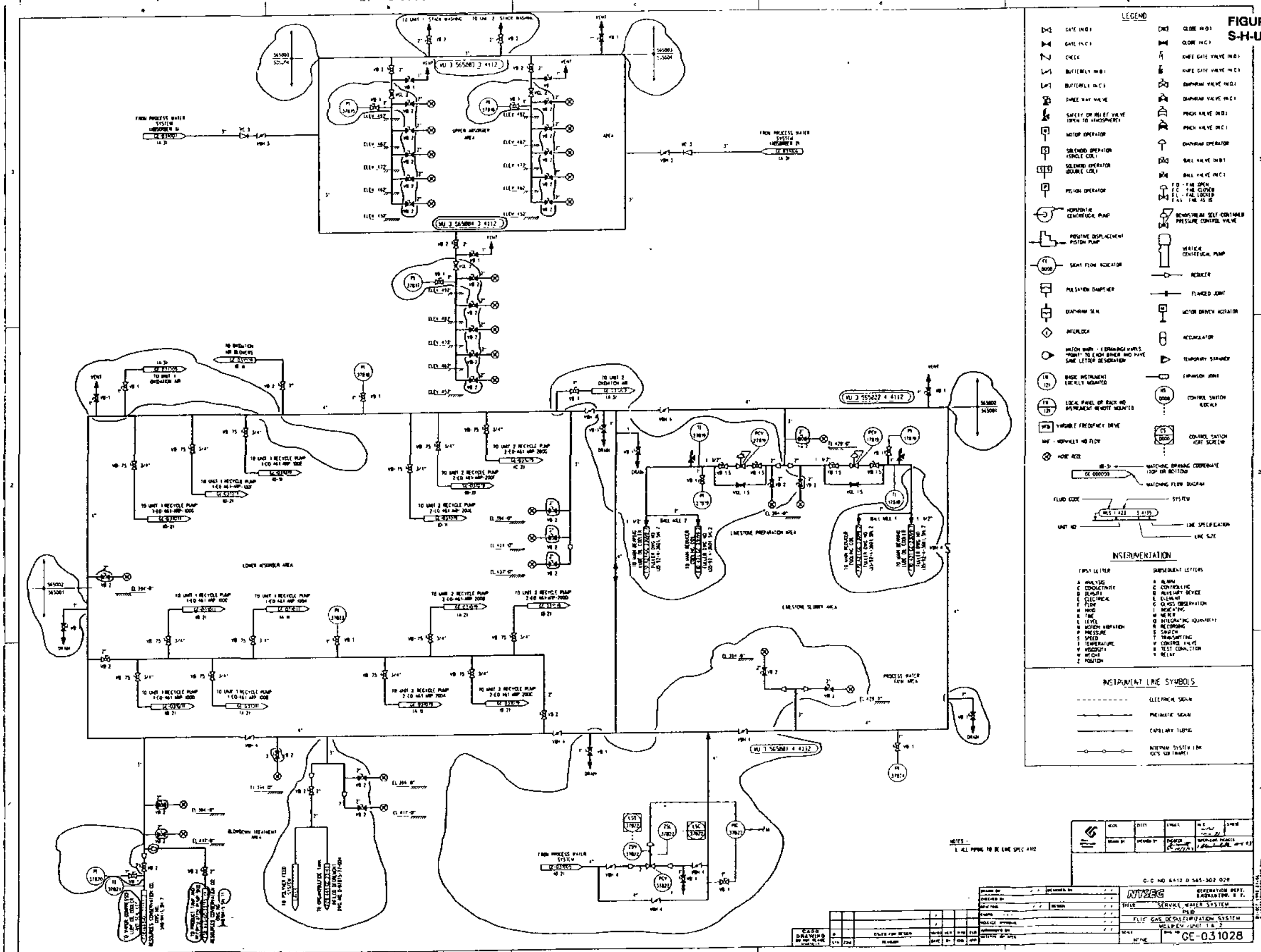


FIGURE 4.2.4-28
S-H-U FGD PROCESS

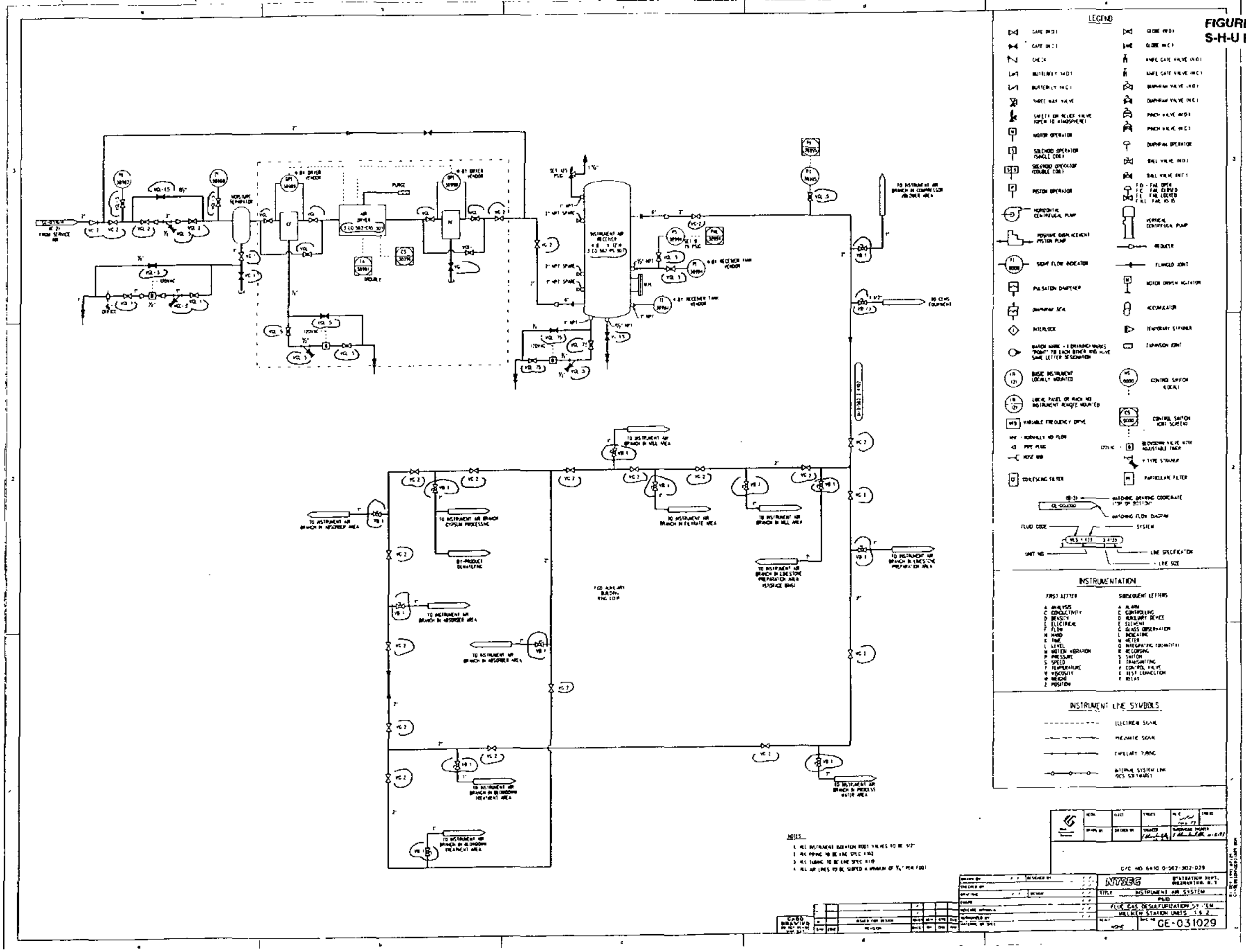


FIGURE 4.2.4-29
S-H-U FGD PROCESS

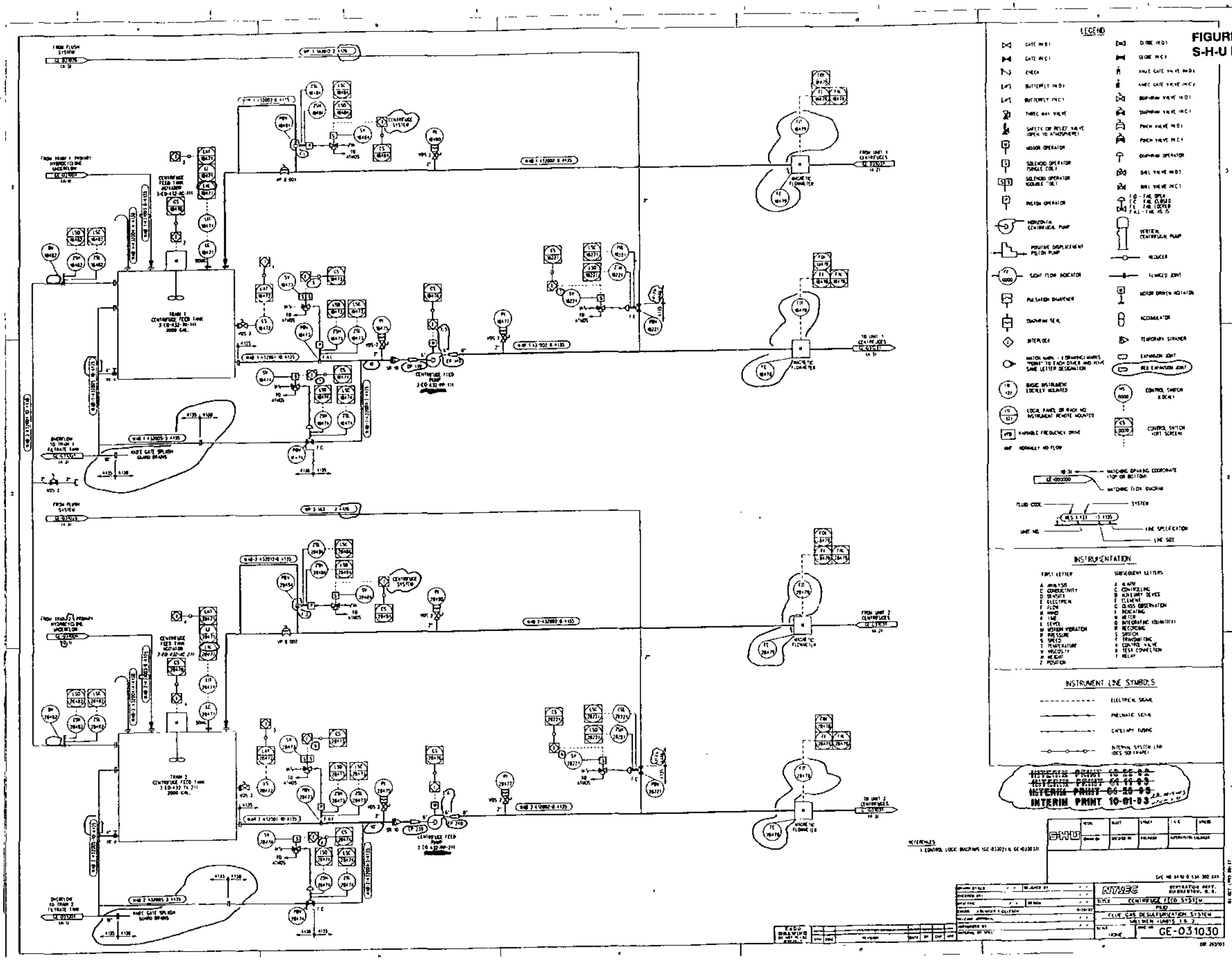


FIGURE 4.2.4-30
S-H-U FGD PROCESS

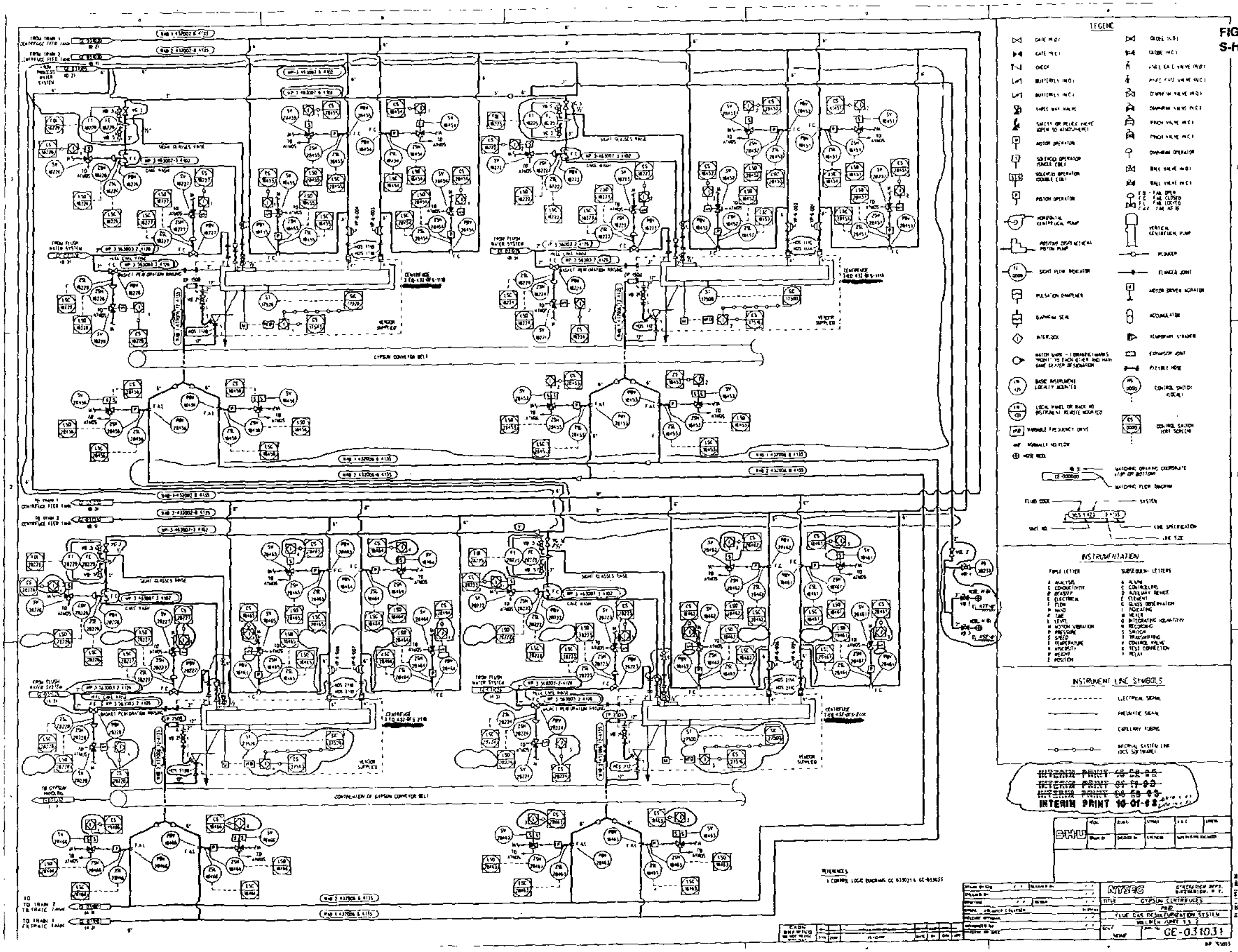


FIGURE 4.2.4-31
GYPSUM HANDLING

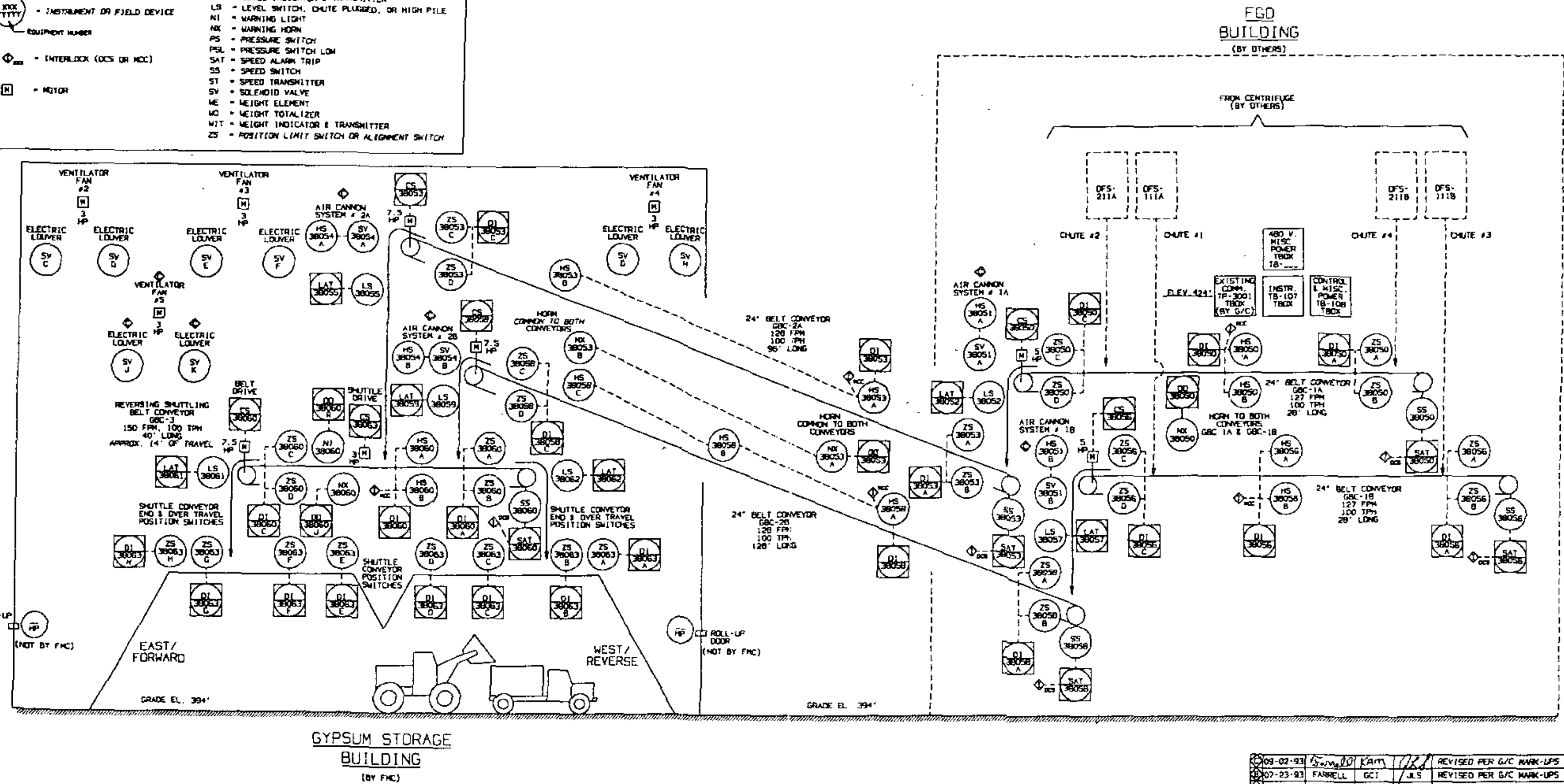
GYPSUM SYSTEM

LEGEND

XXX / YYYY (prefix identifier / equipment number, in square-circle)	DISTRIBUTED CONTROL SYSTEM I/O OR FUNCTION
XXX / YYYY (prefix identifier / equipment number, in circle)	INSTRUMENT OR FIELD DEVICE
◇	INTERLOCK (DCS OR MCC)
M	MOTOR

PREFIX IDENTIFIERS

- CS = CONTROL SWITCH (CRT SCREEN)
- DI = DIGITAL INPUT
- DO = DIGITAL OUTPUT
- HS = HAND (PULLCORD) SWITCH
- LAT = LEVEL ALARM TRIP
- LE = LEVEL ELEMENT
- LIT = LEVEL INDICATOR & TRANSMITTER
- LS = LEVEL SWITCH, CHUTE PLUGGED, OR HIGH PILE
- NI = WARNING LIGHT
- NX = WARNING HORN
- PS = PRESSURE SWITCH
- PSL = PRESSURE SWITCH LOW
- SAT = SPEED ALARM TRIP
- SS = SPEED SWITCH
- ST = SPEED TRANSMITTER
- SV = SOLENOID VALVE
- WE = WEIGHT ELEMENT
- WQ = WEIGHT TOTALIZER
- WIT = WEIGHT INDICATOR & TRANSMITTER
- ZS = POSITION LIMIT SWITCH OR ALIGNMENT SWITCH



NOTES:

1. ALL MOTORS WILL BE WIRED DIRECTLY TO THE MCC.
2. ALL INSTRUMENT AND FIELD DEVICE DCS SIGNALS WILL BE WIRED TO THE TB-107 BOX LOCATED INSIDE THE FGD BUILDING.
3. PHONES AND OTHER COMMUNICATION EQUIPMENT WILL BE WIRED TO AN EXISTING TP-3001 BOX PROVIDED BY GILBERT/COMMONWEALTH LOCATED INSIDE THE FGD BUILDING.
4. CONTROLS AND MISC. POWER WILL BE WIRED TO THE TB-108 BOX LOCATED INSIDE THE FGD BUILDING.

REFERENCE DRAWINGS

JK6191-328	LOGIC DIAGRAMS-GYPSUM SYSTEM
JK6191-329	LOGIC DIAGRAMS-GYPSUM SYSTEM
JK6191-331	LOGIC DIAGRAMS-CONVEYOR GBC-2B
JK6191-332	LOGIC DIAGRAMS-CONVEYOR GBC-2A
JK6191-333	LOGIC DIAGRAMS-CONVEYOR GBC-1B
JK6191-334	LOGIC DIAGRAMS-CONVEYOR GBC-1A
JK6191-335	LOGIC DIAGRAMS-AIR CANNON SYSTEMS
JK6191-336	LOGIC DIAGRAMS-CONVEYOR GBC-3
JK6191-337	LOGIC DIAGRAMS-CONVEYOR GBC-3
JK6191-338	LOGIC DIAGRAMS-CONVEYOR GBC-3 SHUTTLE

NEW YORK STATE ELECTRIC & GAS CORP.
MILLIKEN STATION
GILBERT/COMMONWEALTH INC.
CONTRACT NO. NSN-F09

GRAPHICS NO J_G_6191_EE_0004_C

DIV EE

REV	DATE	DRAWN	CHECKED	APPROVED	DESCRIPTION OF REVISION
C	09-02-93	Sem	Kam	JLS	REVISED PER G/C MARK-UPS 8-30-93
B	07-23-93	FARRELL	GCI	JLS	REVISED PER G/C MARK-UPS 7-19-93
A	06-25-93	FARRELL	JRB	JLS	REVISED PER G/C COMMENTS 6-10-93
0	05-03-93	FARRELL	SMF	JLS	ORIGINAL

SCALE NONE | DIMENSION TOLERANCES EXCEPT AS SPECIFIED FRACTIONAL ±1/16" MACHINED FRACTIONAL ±1/32"

GYPSUM SYSTEM P & I D
LIMESTONE & GYPSUM HANDLING SYS.
NYSEG-MILLIKEN STATION

FORM | REFERENCES

FMC Corporation
MATERIAL HANDLING SYSTEMS DIV

JK6191-4

4.3 WASTE STREAMS

The demonstration project will install state of the art emission controls, monitoring equipment and ancillary machinery to accomplish the following goals:

- High SO_2 removal; a flue gas desulfurization system which will remove 98% of the sulfur dioxide from the plants emissions.
- NO_X reduction by using low NO_X burners on Milliken's two boilers and by demonstrating the NO_XOUT® process on one boiler
- High energy efficiency; the project will seek to minimize the impact of the SO_2 and NO_X removal on the plant's heat rate by using innovative technologies.
- Marketable byproducts; production of commercial-grade gypsum, calcium chloride and other saleable materials.
- Zero waste water discharge
- Space saving design

All demonstration features, retrofits and upgrades will be integrated into Unit 2. The sulfur control process proposed for Unit 2 will be shared with Unit 1. Unit 2 also will be modified with additional control and monitoring technology. A site plan showing the proposed location of demonstration project components is presented in FIGURE 4.3-1. Project highlights are summarized in TABLE 4.3-1 and are described in further detail below.

A Saarberg-Hölter Umwelttechnik GmbH (S-H-U) formic acid-enhanced flue gas desulfurization (FGD) system is being constructed. In this desulfurization process, limestone slurry reacts with and removes SO_2 from the flue gas. FIGURE 4.3-2 shows major steps in the scrubbing process. FIGURE 4.3-3 depicts the overall project. It is anticipated that the S-H-U system will demonstrate SO_2 emission reduction of up to 98 percent.

The scrubber system will incorporate a Stebbins tile-lined split-module absorber. The split-FGD absorber will be a concrete vessel, lined with abrasion- and corrosion-resistant tile, and will have a common center dividing wall separating absorber modules for Units 1 and 2. Each side of the vessel will operate independently, allowing flue gas from each boiler to be separately treated and discharged. The absorber will not contain any packing or grid work, which will significantly reduce the potential for plugging. The system is

FIGURE 4.3-1

SITE PLAN

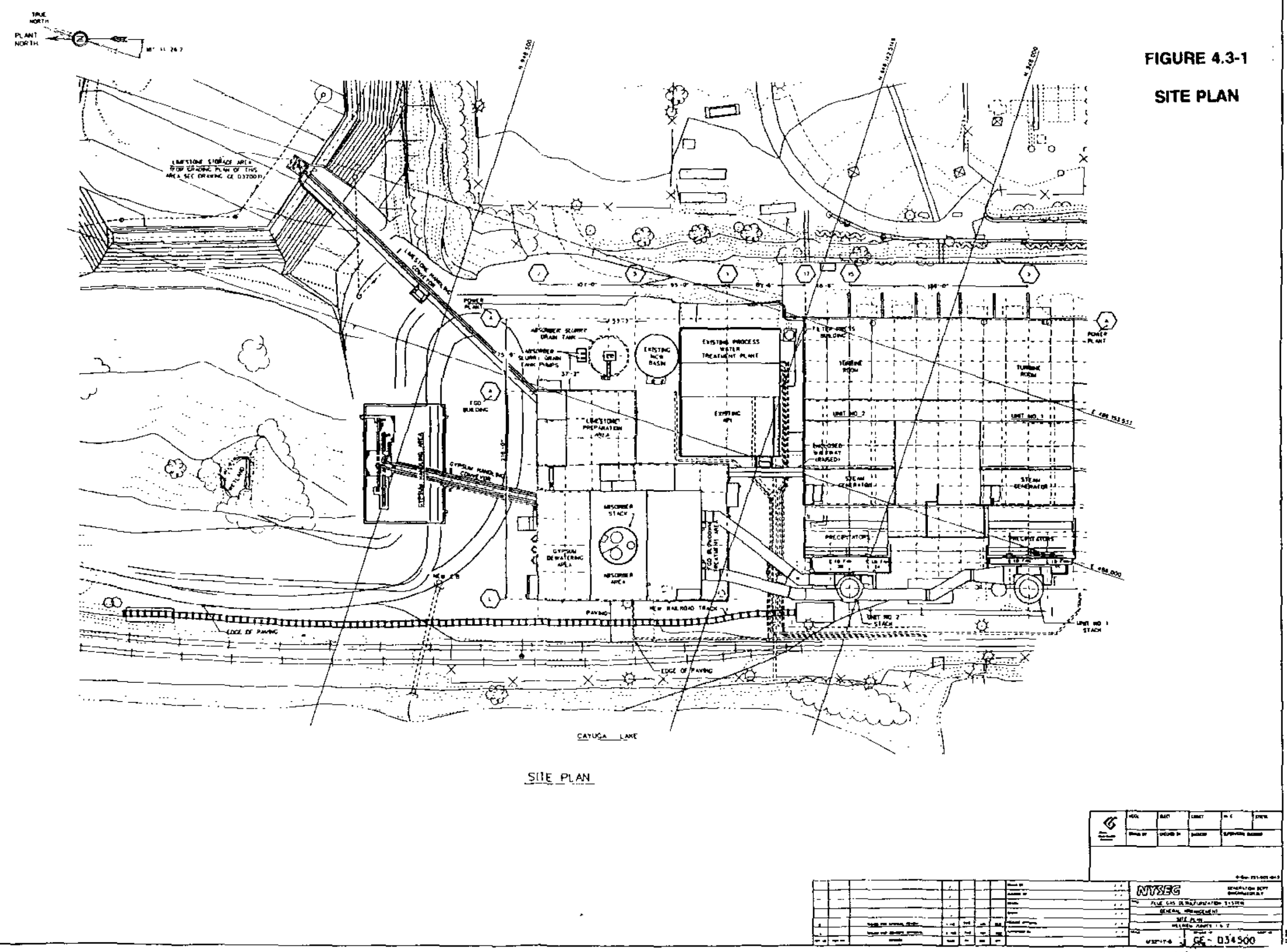


TABLE 4.3-1

MCCTD PROJECT COMPONENTS

SEGMENT OF PLANT	MCCTD PROJECT SCOPE
Raw Coal ↓ ↓ ↓ ↓	•change to high sulfur Eastern coal
PreCombustion ↓ ↓ ↓ ↓ ↓	•change mills to handle new coal
Combustion ↓ ↓ Flue Gas ↓ ↓ ↓	▸NO_X combustion modeling •combustion modifications for primary NO_X emissions
Post Combustion ↓ ↓ ↓ ↓ ↓ Clean Flue Gas	▸first US S-H-U demonstration ▸first US below-stack S-H-U absorber ▸first split S-H-U absorber ▸first utility Stebbins tile cocurrent/countercurrent absorber ▸first NO_XOUT® in high sulfur coal-fired utility furnace for NO_X emission control ▸first coal-fired heat pipe air heater with CAPCIS corrosion monitoring •ID fans •precipitator upgrade •ductwork
Balance of Plant Needs	•blowdown treatment •power feeds to new equipment •Unit 1 air heater upgrade •control system upgrade •electrical system upgrade

Legend:
▸novel technology in need of commercial demonstration
•commercial technology required in plant to support the demonstration of the novel

FIGURE 4.3-2

SIMPLIFIED S-H-U PROCESS FLOW DIAGRAM

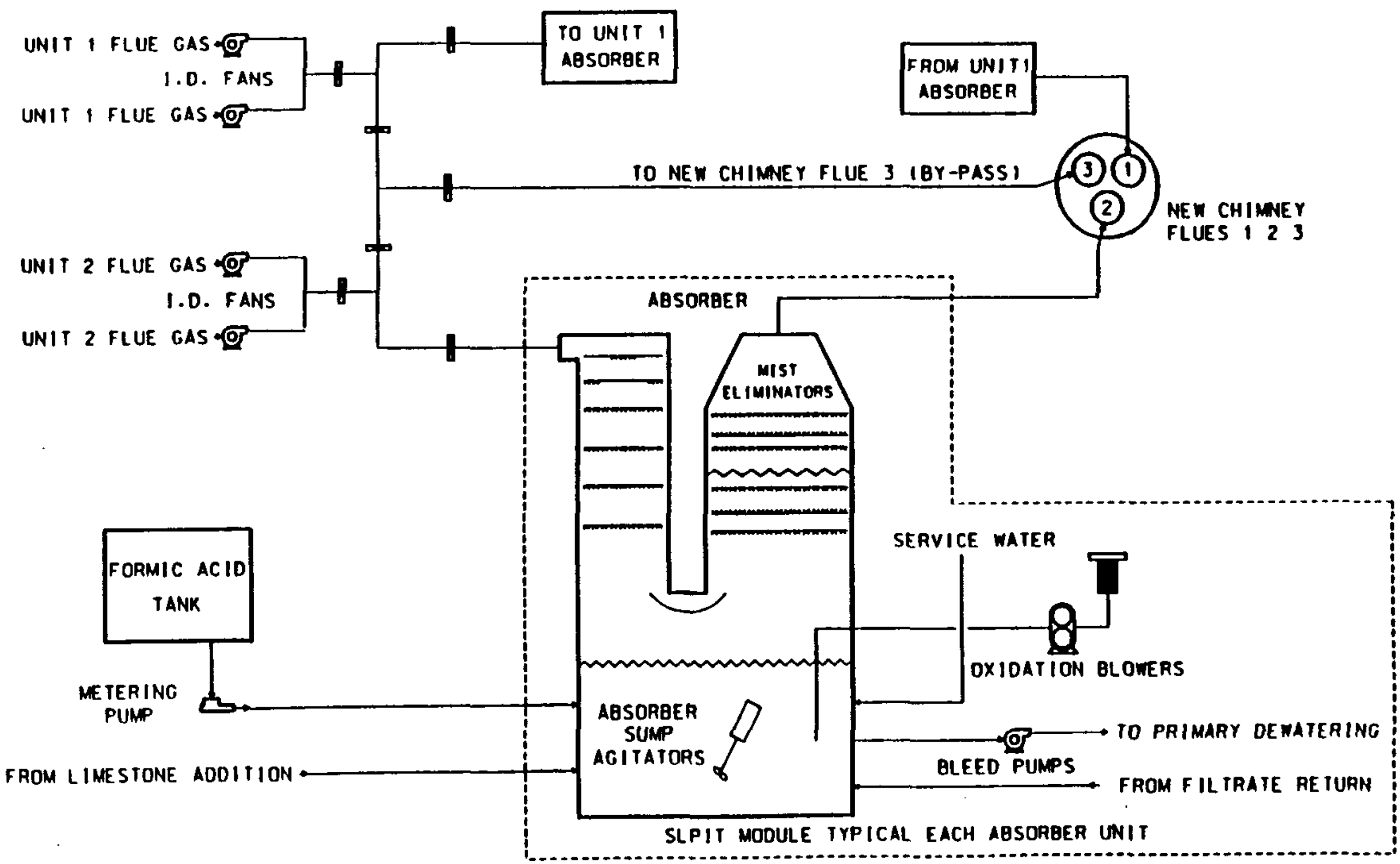
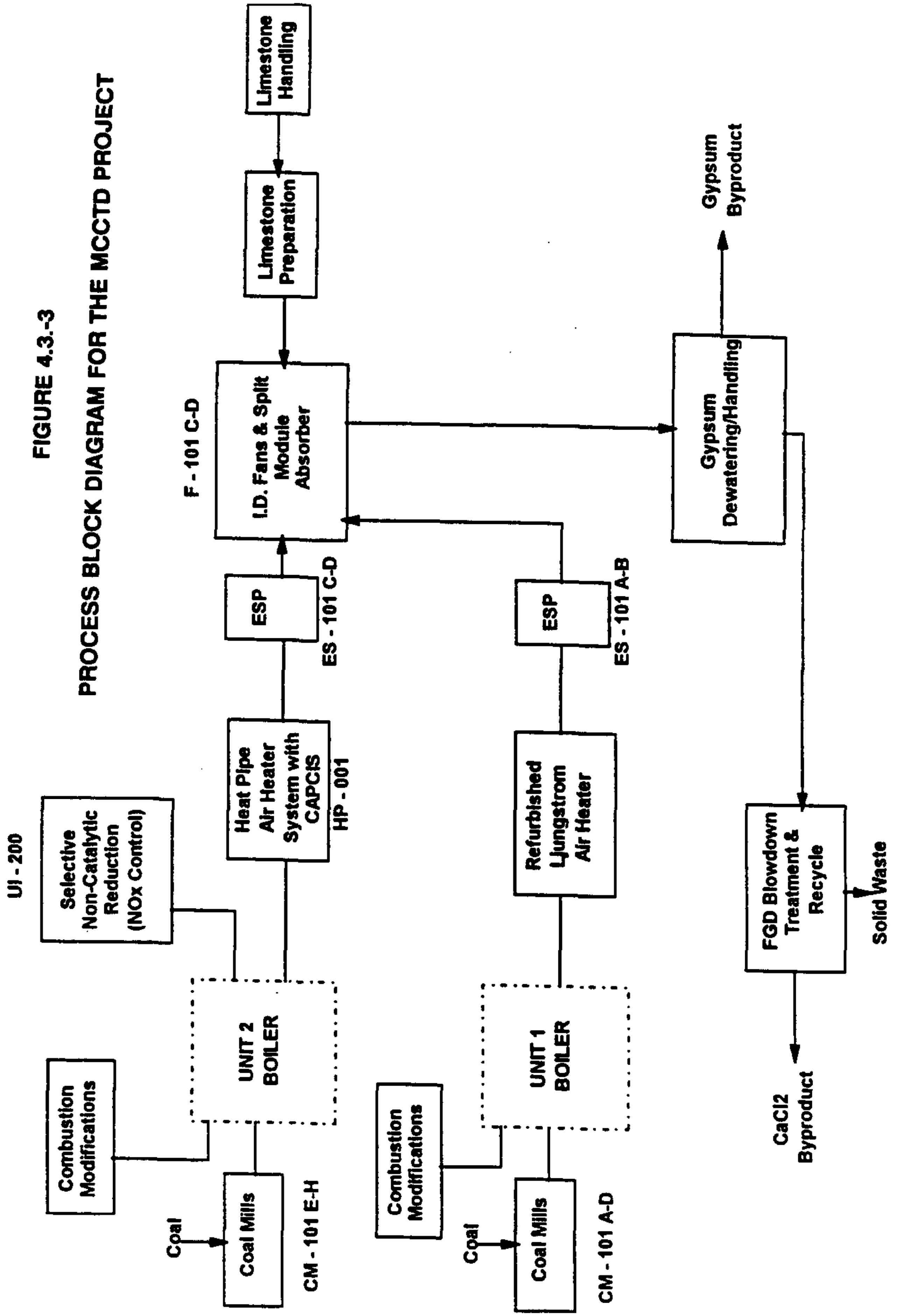


FIGURE 4.3-3

PROCESS BLOCK DIAGRAM FOR THE MCCTD PROJECT



flue gas SO_2 concentration.

During centrifugation, water from the slurry will be transported through filtration media by centrifugal force and collect in the centrifuge. The filtrate will flow to the filtrate tank. Fresh process water will be used as the cake wash before gypsum discharge.

Overflow slurry from the primary hydrocyclones will collect in the overflow launder and flow by gravity to the secondary hydrocyclone feed tank. The secondary hydrocyclone feed pump will send slurry to the secondary hydrocyclones. Underflow from the secondary hydrocyclones will flow by gravity from the under flow launder to the filtrate tank. Clarified water (overflow from the secondary hydrocyclones) will flow by gravity to a clarified water tank. A small portion of clarified water from the clarified water tank will be pumped to the blowdown water treatment system. A portion of clarified water will be recycled to the limestone mills and used for reagent preparation.

4.3.3 Intermediates and By-products Storage and Flows

The FGD system by-products, gypsum and calcium chloride, are expected to be of marketable quality and will be utilized accordingly. NYSEG expects to dispose of any off-specification or otherwise unmarketable material in the Milliken Ash Disposal Facility. Leachate and surface water runoff from Milliken landfill is expected to remain within present discharge limits. Permits have been modified to allow disposal of off spec material.

4.3.4 Other Plant Modifications

Combustion Modifications

New low-NO_X firing systems will be installed in each boiler. Each system includes new burners, wind boxes and over-fire air systems that will lower NO_X emissions by enhancing the staging of air flow during combustion. No additional waste streams will be generated by this system.

New Coal Mills

New coal mills have been installed on Unit 1 and will be installed on Unit 2 to test, demonstrate and operate with a wider range of eastern coals. Existing coal mills would be unable to process the harder, higher sulfur coals to a fineness necessary to prevent unacceptable increase of carbon carry-over from the boilers, thereby affecting efficiency and fly ash quality. New coal mills are also required to demonstrate the suitability of higher sulfur coals in conjunction with use of the S-H-U scrubber. New coal mills will be installed within the existing coal processing area. This system will generate pyrites similar to the previous mills. Pyrites generation is dependant on the type of coal burned, therefore no additional requirements will be needed for this waste stream. Pyrites are presently disposed on site in the ash disposal facility.

Electrostatic Precipitator Upgrades

Vendor specifications for the gypsum by-product and overall FGD operations will require that residual particulates in the absorber inlet flue gas not exceed specified levels. For this reason, the electrostatic precipitators will be upgraded to achieve the lower particulate levels required to maintain efficient FGD scrubbing and ensure a high-quality gypsum by-product. Nominal increases are expected for flyash as a result of these modifications. Flyash will continue to be sold as a marketable additive for concrete.

4.3.5 Modifications Proposed for Unit 2

High-Efficiency Heat Pipe Air Heater System

NYSEG will replace the existing Ljungstrom regenerative air heaters in Unit 2. Regenerative air heaters are used to increase boiler efficiency. ABB Air Preheater's high-efficiency heat pipe air heater system will be installed on Unit 2. The new system will optimize the thermal efficiency of the Unit 2 boiler. This is a passive heat exchange system which will not generate any additional wastes.

NO_xOUT® Selective Non-Catalytic Reduction System

NYSEG will demonstrate NO_xOUT® selective non-catalytic reduction (SNCR) system on Unit 2. The SNCR system is a chemical and mechanical system offered by Nalco Fuel Technologies. The objective of demonstrating this system is to achieve a reduced NO_x emission rate while maintaining marketable quality fly ash. The NO_xOUT® process provides NO_x reduction by injecting urea (NH_2CONH_2) into the boiler's post-combustion zones. Minimum NO_x reduction is anticipated to be 30 percent over reductions achieved by combustion modifications. As a result of this process the flyash will contain residual amounts of ammonia. However it is expected that minute levels of ammonia will not effect the marketability of the flyash.

designed to meet 95 percent SO_2 removal efficiency when firing 3.2 percent sulfur coal at design flow rates.

Flue gas from the boilers will be discharged through two new induced-draft (ID) fans, required to overcome the combined pressure loss of the ductwork, absorber and new wet stack flues. From the ID fans, gas will flow to the absorber, where it will be treated for a minimum of 95 percent SO_2 removal. Flue gas will enter at the top of the cocurrent section and come into contact with the recycled slurry. Slurry will be introduced by spray nozzles at four separate levels in the cocurrent section of the absorber. Each spray level will have one dedicated pump. Pumps will be taken off line when less slurry is needed to suit operating conditions. Recycle slurry will collect in the absorber sump at the bottom of the absorber. Flue gas will continue to pass to the countercurrent section where it will come into contact with slurry from spray nozzles at three separate levels for residual SO_2 absorption. The gas will then pass through two-stage mist eliminators which will remove entrained water droplets before the gas is discharged to the new stack flues.

Slurry from the absorber sump will contain formic acid and will be continuously pumped to the absorber spray nozzles. Using formic acid in conjunction with the S-H-U design allows control of pH drop in the recycle fluid, which permits low-pH absorption and eliminates scaling and plugging. This creates a stable system that can accommodate substantial changes in inlet SO_2 mass loading without affecting performance.

An absorber slurry drain tank will be provided to collect the contents of an absorber sump in the event of an emergency shutdown or scheduled outage. This slurry will be pumped back to the absorber sump as slurry makeup before restart of the FGD unit. This feature will allow utilization of the existing slurry and will reduce the generation of an additional waste stream. Housekeeping trenches, sumps and pumps will be provided to collect material from floor washing. This material will be pumped to the absorber modules to used as make up water.

The absorber sump will act as a back-mixed reactor to oxidize the product of absorption (bisulfite) to calcium sulfate (gypsum). Oxidation will also occur in the absorber due to excess oxygen in the flue gas. Slurry in the absorber sump will contain approximately 10 percent gypsum, which will provide seed crystals for the formation of gypsum particles, eliminating uncontrolled growth on absorber internals. Air will be injected into absorber sumps by oxidation air blowers. Side mounted agitators will be installed to provide complete mixing of air and slurry and to prevent gypsum particles from settling to the bottom.

Gypsum slurry will be pumped from the absorber sump to the gypsum dewatering and processing system, where it will be processed into wallboard-grade gypsum. At full station capacity, approximately 25 tons per hour of gypsum cake (94 percent solids by weight) will be produced. The hydrocyclone overflow will feed the clarified water tank where it will be used in the production of fresh slurry.

4.3.1 Raw Material Storage and Handling

Limestone will be brought in by truck and stored in an outside storage area. The storage area will have a storm water drainage system which will convey the surface runoff in an orderly manner to a sedimentation basin. The runoff from the limestone storage area will be pumped to the Process Water Reclamation Facility where it will receive additional treatment including sedimentation and filtration. The water will then be used in the scrubber for make up. During extreme rainfall events (greater than a 10 year - 24 hr. storm) excess runoff will be conveyed through an emergency overflow which discharges directly into the receiving water.

Limestone from the storage pile will be conveyed by individual constant-speed belt weigh feeders to the wet ball mill for size reduction. Clarified water, to be supplied from the gypsum dewatering system and stored in a clarified water tank, will be used for limestone grinding and dilution. Grinding water will be added to the ball mill, and dilution water to the mill slurry pump, in proportion to the limestone feed rate.

4.3.2 Product Storage and Handling

Gypsum slurry will be pumped from the absorber sump by bleed pumps to the primary hydrocyclones. Gypsum processing will include the primary and secondary hydrocyclone system, filtrate tank, filtrate pumps and centrifuge feed tank, centrifuge seed pumps and centrifuges. The dewatering system will consist of two trains operating either one train on both units or operating in parallel with each unit feeding a dedicated train.

Underflow slurry from the primary hydrocyclones, at about 25 percent solids, will collect in the underflow launder and will flow by gravity to the centrifuge seed tank. The centrifuge will produce a gypsum cake, 94 percent solids by weight. At full station capacity, approximately 25 tons per hour of gypsum cake will be produced. The cake will then be conveyed from the centrifuge by transfer and forward conveyors to gypsum storage building. The S-H-U by-product gypsum will be of wallboard grade and consistent quality, regardless of plant load level or

TABLE 4.3-2

COMPARISON OF EXISTING AND PROJECTED ANNUAL EMISSION RATES (Tons/Year)[1]

Pollutant	Existing	Estimated Future	Net Change
CO	260	260	0
NMHC	30	30	0
NO_x	6,900	4,700	-2,200
SO_2	31,000	2,565 to 5,130[2]	-28,435 to -25,870
TSP/PM_{10}	410	410	0[3]
Pb	0.3	0.1	-0.2
NH_3	0	11	11

(1) Based on average of 1988-1990 fuel use.
(2) Assumes 100 percent scrubber availability and a range of 90 to 95 percent removal efficiency.
(3) Some reductions anticipated due to ESP efficiency improvements.

TABLE 4.3-3

PROPOSED PROJECT CO_2 EMISSIONS COMPARED TO OTHER TECHNOLOGIES

	Proposed Project	Conventional Wet-Limestone Scrubber	Wet-Lime Scrubber
Technology's Power Consumption	4.04 MW (1.2%)	6.74 MW (2.0%)	3.37 MW (1.0%)
CO_2 Emissions from Additional Power Consumption @ (0.9 tons CO_2/hr/MW)	3.63 tons/hr	6.06 tons/hr	3.03 tons/hr
CO_2 Emissions from Scrubber Chemistry	6.0 tons/hr*	6.0 tons/hr	N/A
CO_2 Emissions at Calciner Limestone to Lime Fuel (0.73 tons CO_2/ton Lime)	N/A N/A	N/A N/A	6.0 tons/hr 4.75 tons/hr
CO_2 Reductions Due to Heat Rate/Plant Improvements			
Energy Efficiency Improvement Goals (0.75% Heat Rate Improvement) (70 Btu/kWhr)	(2.29) tons/hr	(2.29) tons/hr	(2.29) tons/hr
High Efficiency Air Heater System (0.5% Heat Rate Improvement) (47 Btu/kWhr)	(1.53) tons/hr	(1.53) tons/hr	(1.53) tons/hr
20% Reduction in Airflow Due to In-Leakage (0.5 MW @ 9 tons CO_2/hr/MW)	(0.5) tons/hr	(0.5) tons/hr	(0.5) tons/hr
Total CO_2 Emission Balance	5.8/tons/hr	8.19 tons/hr	9.46 tons/hr
Current Plant CO_2 Emissions @ 337 MW & 9,422 Btu/kWhr	305.5 tons/hr	305.5 tons/hr	305.5 tons/hr
New Total Plant CO_2 Emissions	311.31 tons/hr	313.69 tons/hr	314.96 tons/hr

* Decomposition of formic acid to CO_2 is negligible.

water treatment system and will be used as make-up in the FGD system. The solids will be periodically removed from the basin and utilized in making fresh slurry.

To purge absorbed chlorides from the slurry system, blowdown pumps will transfer clarified water from the blowdown tank to a blowdown treatment system. Blowdown from the scrubber will be discharged from the FGD system to maintain dissolved chloride in the system at an acceptable level. Blowdown will be pumped to a newly constructed basin where it will be collected and chemically and mechanically treated at a new wastewater treatment system to remove metals and suspended solids. FGD water treatment sludge will be dewatered via a plate and frame filter press and disposed of in the Milliken Ash Disposal Facility. Filtrate from dewatering will be returned to the FGD system.

The treated effluent will be pumped to a brine concentrator/spray dryer system. Prior to processing in the brine concentrator, water will be treated to adjust pH and remove dissolved gases. Approximately ninety percent of the feed to the brine concentrator will be recovered as condensate (distilled water) which will be returned to the FGD system as makeup water. The remaining ten percent of the feed will be a brine that will be highly concentrated in chlorides of calcium. The brine will be suitable for commercial marketing.

Operational Impacts

The anticipated increase in process water consumption by the modified facility will not degrade Cayuga Lake's existing quality. The anticipated increase represents less than 0.1 percent of the lake's annual throughput, and is an insignificant fraction of the lake's safe yield.

There will be no expected additional increase in process waste water discharge flows from Milliken due to the FGD/NO_xOUT systems. The wastewater treatment system will allow the scrubber blowdown stream to be treated and recycled to the plant as FGD make-up water. Surface runoff from the limestone storage area will be discharged to a sedimentation basin in the limestone storage area and then used as makeup to the FGD system. The proposed project will not result in any new point source discharges. In addition to the proposed changes due to the implementation of the FGD/NO_xOUT® systems, if determined feasible, discharge from the existing coal-pile run off and maintenance cleaning water treatment (about four million gallons annually) will also be recycled to the FGD system.

NYSEG presently operates a sedimentation pond associated with the Milliken ash landfill. The pond receives surface runoff and leachate from the landfill area. The discharge from this sedimentation pond is regulated under NYSEG's current SPDES permit for the landfill. Unmarketable by-products from the FGD system, including FGD water treatment sludge, may be disposed of in the landfill. The NYSDEC has modified the landfill SPDES permit and Solid Waste Management Facility (SWMF) permit to account for these changes.

4.3.8 Waste Discharges and Management Systems

The FGD system by-products, gypsum and calcium chloride, are expected to be of marketable quality. NYSEG expects to dispose of any off-specification or otherwise unmarketable material in the Milliken Ash Disposal Facility. Combined leachate and storm water runoff from Milliken landfill is expected to remain within present discharge limits. Fly ash and bottom ash are also expected to be usable and will be marketed. FGD blowdown treatment sludge will be disposed of in the Milliken Ash Disposal Facility.

4.3.9 Storm Water Flows

Management techniques are employed during operation with regard to storm water flows.
Volume of site storm water run off will increase due to creation of new impervious areas. The storm water management system is adapted to prevent flooding, erosion, and water quality degradation.

Storm water runoff from the site flows overland to existing storm water detention and sedimentation basins, as well as to on-site natural surface water bodies. Storm water runoff from the limestone handling area will be collected, filtered and recycled to the FGD system.

4.3.10 Waste Summary

TABLE 4.3-4 summarizes the waste streams associated with the MCCTD project. Waste streams are generally utilized or recycled to promote beneficial use and to minimize environmental impacts.

TABLE 4.3-4

WASTE STREAM SUMMARY

Waste Stream	Component	Quantity	Treatment	Removal Efficiency	End Product	Utilization Disposal	Monitor
Flue Gas	Nitrous Oxides	6,900 ton/yr	Low NO_x Combustion Firing Selective Non Catalytic Reduction	30%	None None	N/A *N/A	Continuous Emission Monitors
	Sulfur Dioxide	31,000 ton/yr	Formic Acid Enhanced Wet Limestone Scrubber	98%	Gypsum	Marketable Gypsum for Cement & Wallboard Mfg.	Continuous Emission Monitoring
Limestone Storage Runoff	Solids	15,000 cu/ft	Sedimentation Filtration	90%	Limestone Fines	Reagent Slurry	Periodic Measurements
	Water	550,000 gallons			Make Up Water		
FGD Blowdown	Metals Suspended Solids	11 cu/yd/day	Precipitation Coagulation Floculation Sedimentation	>95%	Metral Hydroxide Sludge	Disposed in Permitted Landfill	Composite Samples
	Calcium Chloride (33%)	4.5 gpm	Concentration	8.25 concentration factor	Chloride Brine	Marketed Road Deicer Dust Suppressant	Continuous Chloride
	Water	25 gpm	Distillation Condensation	83% Recovery	Make Up Water	Mist Eliminator Wash	None
Gypsum Slurry Bleed	Gypsum Hydroclone Underflow	20.2 Tons/hr	Centrifugation (Dewatering)	94%	Gypsum	Marketable Cement & Wallboard Mfg.	Grab Samples (Moisture)
	Water Hydroclone Overflow	137 gpm	Classification		Make Up Water	Limestone Grinding	None

4.4 EQUIPMENT LIST

The following TABLE 4.4-1 is an equipment listing of all major items of process equipment. Equipment is sorted by process area (WBS) and includes item number, name of item, number of units required for operation, size/capacity of unit, design characteristics, materials of construction and vendor.

TABLE 4.4-1
MAJOR EQUIPMENT LIST

Item No.	Item Name	Number In Use	Number Spare	Unit Capacity	Design Conditions	Material of Construction	Vendor
1.2A.04 350	FGD Chimney & Flues	1	0	416,140 ACFM Per Flue	(2) 12' Diameter Flues; (1) 8' Diameter Bypass	Steel Shell (2) FRP Flues (1) Carbon Steel Bypass	Inter-national Chimney
1.2A.04 461	Absorber Modules ABS-100, 200	2	0	35'W, 36'L, 108'H		Stebbins Tile	Stebbins
1.2B.02 263	Limestone Day Storage Bins BI340- A-B	2	0	320 Tons Each	Vertical Cylindrical	Lined Carbon Steel	FMC
1.2B.02 421	Ball Mill WBM-113 & 213	2	0	24 TPH	Wet Horizontal	Carbon Steel	Fuller
1.2B.02 421	Weigh Feeder BFU-113 & 213	1	1	24 Tons Per Hour	Gravimetric	Carbon Steel Housing, Rubber Belts	Stock
1.2B.02 421	Mill Hydroclone Set - HCY-113 & 213	1	1	865 GPM	90%-325 Mesh & 90%-170 Mesh	Rubber Lined Carbon Steel	Krebs
1.2B.02 421	Mill Slurry Tank TK-113 & 213	1	1	5,000 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	Fuller
1.2B.02 421	Mill Slurry Tank Agitator AG-113 & 213	1	1	7.5 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.02 421	Mill Slurry Pumps PP-113A & B, PP-213A & B	1	3	865 GPM 100' TDH, 50 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.02 423	Fresh Slurry Feed Tank, TK-104 & 204	2	0	64,000 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	Fisher

Item No.	Item Name	Number In Use	Number Spare	Unit Capacity	Design Conditions	Material of Construction	Vendor
1.2B.02 423	Fresh Slurry Feed Tank Agitator, AG-104 & 204	1	1	5 HP	*Top Mounted*	Rubber Lined Carbon Steel	Lightnin
1.2B.02 423	Fresh Slurry Forwarding Pump PP-104A&B, 204A&B	1	3	550 GPM 83' TDH, 25 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.02 432	Centrifuge Feed Tanks, TK-111,211	1	1	3,500 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	Sterling Boiler
1.2B.02 432	Centrifuge Feed Tank Agitators AG-111,211	1	1	1 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.02 432	Centrifuges DFS-111A & B, 211A & B	3	1	27 Tons Per Hour	Vertical Basket Centrifuges	Rubber Lined Carbon Steel	Krauss
1.2B.02 432	Centrifuge Feed Pumps, PP-111,211	1	1	1,000 GPM 60' TDH, 30 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.02 433	Primary Hydroclones, HCY-101, 201	1	1	1,050 GPM	6 Cyclones Per Half; 5 Operating At Once	Rubber Lined Carbon Steel	Warman
1.2B.02 433	Secondary Hydroclones, HCY-102, 202	1	1	300 GPM	6 Cyclones; 5 operating at once	Rubber Lined Carbon Steel	Warman
1.2B.02 433	Secondary Hydroclone Feed Tank Agitators, AG-102,202	1	1	1 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.02 433	Secondary Hydroclone Feed Pumps, PP-102,202	1	1	300 GPM 81' TDH, 15 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.02 433	Secondary Hydroclone Feed Tanks, TK-102,202	1	1	3,500 GALS	Vertical Cylindrical	Vinyl Ester Lined Carbon Steel	Sterling Boiler

Item No.	Item Name	Number In Use	Number Spare	Unit Capacity	Design Conditions	Material of Construction	Vendor
1.2B.02 434	Filtrate Return Pumps, PP-101, 201	1	1	1000 GPM 69' TDH, 40 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.02 434	Filtrate Tank Agitator, AG-101, 201	1	1	1.5 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.02 434	Filtrate Tanks, TK-101 & 201	1	1	20,750 GALS	Vertical Cylindrical	Vinyl Ester Lined Carbon Steel	Fisher
1.2B.02 435	Clarified Water Tanks, TK-107 & 207	1	1	63,400 GALS	Vertical Cylindrical	Vinyl Ester Lined Carbon Steel	Fisher
1.2B.02 435	Clarified Water Tank Agitators, AG-107, AG-207	1	1	3 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.02 435	Blowdown Pumps, PP-108, 208	1	1	35 GPM 48' TDH, 5 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.02 435	Clarified Water Pumps, PP-107, 207	1	1	400 GPM 120' TDH, 25 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.02 461	Slurry Recycle Pumps, ARP 100A-G, 200A-G	10	4	10,500 GPM 80/90/100/110' TDH 350/400/450/ 500HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	GIW
1.2B.02 462	Oxidation Blowers, BW-101,201,301	2	1	5,000 ACFM 500 HP	Centrifugal; Includes Sound Enclosure	Carbon Steel	Turblex
1.2B.02 462	Absorber Agitator, AG-100A-E, 200A-E	8	2	25 HP	Side Mounted	Alloy Shafts & Impellers	Ekato

Item No.	Item Name	Number		Unit Capacity	Design Conditions	Material of Construction	Vendor
		In Use	Spare				
1.2B.02 463	Process Water Tank	1	0	27,000 GALS	Vertical Cylindrical	Coated Carbon Steel	Fisher
1.2B.02 463	Process Water Pump, PP-103, 203, 303	2	1	700 GPM 273' TDH, 75 HP	Horizontal Centrifugal Flow	Carbon Steel	Goulds
1.2B.02 464	Absorber Slurry Drain Tank, TK-305	1	0	300,000 GALS	Vertical Cylindrical	Mastic Lined Concrete	San-Con
1.2B.02 464	Absorber Slurry Drain Tank Agitator, AG-305	1	0	20 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.02 464	Absorber Slurry Drain Pumps, PP-305A & PP-305B	1	1	500 GPM 73' TDH, 20 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.02 465	Bleed Pumps, PP-112A&B, 212A&B	2	2	500 GPM 133' TDH, 40 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.02 466	Formic Acid Tank, AST-301	1	0	5,000 Gal.	Vertical Cylindrical	316L SS	Sterling Boiler
1.2B.02 466	Formic Acid Metering Pumps, AMP-101,201,301	2	1	6.2 GPM 60 PSI, .5 HP	Metering Pumps Diaphram Type	316 SS	Milton Roy
1.2B.02 467	Mist Eliminator Wash Spray Nozzles, WWN-025	56	0	10 GPM	Full Cone	Polypropylene	Bete
1.2B.02 467	Quench Water Spray Nozzles, EQN-0375,QNS-025	80	0	2 GPM	Pig Tail	Hastelloy	Lechler
1.2B.02 467	Recirc Spray Cocurrent Section Spray Nozzles	106	0	875 GPM	Pig Tail	Silica Carbon	Lechler

Item No.	Item Name	Number In Use	Number Spare	Unit Capacity	Design Conditions	Material of Construction	Vendor
1.2B.02 467	Recirc Spray Counter Current Spray Nozzles	159	0	438 GPM	Pig Tail	Silica Carbon	Lechler
1.2B.02 471	Mist Eliminators, VME-101,102,201 & 202	4	0	416,000 ACFM	Chevron Vertical Flow 1st & 2nd Stage Mist Eliminators	FRP Polypropylene	Munters
1.2B.03 260	Limestone Handling Equipment, Including Belt Conveyors, CON340A, B; Scale, Separator, Gates, Chutes,etc.	2	0	100 Ton/Hour Each	200 Ton/HourTotal Capacity	Carbon Steel	FMC
1.2B.03 260	Vibrating Bin Discharger	1	1	100 Ton/Hour 3 HP	12' Diameter Inlet 2' Diameter Outlet 60^0 Conical Slope	Steel Neoprene	Kinergy
1.2B.03 260	Dust Collection System 1DC-2, 1BVF-1, 1BVF-2, 1DC-1	4	0	161 Sq. Ft. 484 Sq. Ft. 150 Sq. Ft.	Insertable Venting Filters	Steel Polyester	DCE
1.2B.05 441	Equalization Tank, TK-320	1	0	16,000 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	FMC
1.2B.05 441	Desaturation Tank, TK-321	1	0	3,225 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	IDI
1.2B.05 441	Heavy Metal Tank, TK-322	1	0	800 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	IDI
1.2B.05 441	Coagulation Tank, TK-323	1	0	420 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	IDI
1.2B.05 441	Ferric Chloride Tank, TK-325	1	0	185 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	IDI
1.2B.05 441	Organo Sulfide Tank, TK-326	1	0	132 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	IDI

Item No.	Item Name	Number		Unit Capacity	Design Conditions	Material of Construction	Vendor
		In Use	Spare				
1.2B.05 441	Lime Slurry Tank , TK-327	1	0	575 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	IDI
1.2B.05 441	Sludge Holding Tank , TK-328	1	0	24,000 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	IDI
1.2B.05 441	CPR Sludge Holding Tank , TK-329	1	0	24,000 GALS	Vertical Cylindrical	Carbon Steel	IDI
1.2B.05 441	FGD Filtrate Tank , TK-330	1	0	3,500 GPM	Vertical Cylindrical	Carbon Steel	IDI
1.2B.05 441	CPR Filtrate Tank , TK-331	1	0	3,500 GPM	Vertical Cylindrical	Carbon Steel	IDI
1.2B.05 441	Equalization Tank Agitator, AG-320	1	0	3 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.05 441	pH Elevation/Saturation Tank Agitator, AG-321	1	0	2 HP	Top Mounted	Rubber Lined Carbon Steel	IDI
1.2B.05 441	Heavy Metal Precip. Tank Agitator, AG-322	1	0	0.5 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.05 441	Coagulation Tank Agitator, AG-323	1	0	0.5 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.05 441	Densadeg Reactor Agitator, AG-324	1	0	2 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.05 441	Lime Slurry Tank Agitator, AG-327	1	0	1 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.05 441	Sludge Holding Tank Agitator, AG-328	1	0	10 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.05 441	Filter Press, FLP-328	1	0	5 HP		Carbon Steel	IDI

Item No.	Item Name	Number In Use	Number Spare	Unit Capacity	Design Conditions	Material of Construction	Vendor
1.2B.05 441	Ferric Chloride Feed Pumps, PP-325A,B	1	1	1.4 HP, 1.4 Amp	Metering Pump	Polypropylene	Promi-nont
1.2B.05 441	Organosulfide Feed Pumps, PP-326A,B	1	1	0.6 LPH, 1.4 Amp	Metering Pump	Polypropylene	Promi-nont
1.2B.05 441	Forward Feed Pumps, PP-322A, B	1	1	30 GPM 30' TDH, 2 HP	Horizontal Centrifugal Flow	Rubberized Cast Iron	IDI
1.2B.05 441	Sludge Waste Pumps, PP-323A, B	1	1	50 GPM 70' TDH, 5 HP	Positive Displacement	Rubber Lined Carbon Steel	IDI
1.2B.05 441	Sludge Recycle Pumps, PP324A, B	1	1	20 GPM 70' TDH, 2 HP	Positive Displacement	Rubber Lined Carbon Steel	IDI
1.2B.05 441	Filter Press Feed Pump, PP-328	1	0	90 GPM 225 PSI, 20 HP	Positive Displacement	Rubber Lined Carbon Steel	IDI
1.2B.05 441	Lime Slurry Pump Skid, PP-327	1	0	70 GPM 50' TDH, 3 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.05 441	FGD Filtrate Pump, PP-330	1	0	70 GPM 35' TDH, 5 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.05 441	CPR Filtrate Pump, PP-331	1	0	250 GPM 67' TDH, 7.5 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.05 441	Densadeg Reactor, RE-324	1	0	700 GAL		Rubber Lined Carbon Steel	IDI
1.2B.05 441	Densadeg Thickener, THI-320	1	0	30,000 GAL		Rubber Lined Carbon Steel	IDI
1.2B.05 441	Densadeg Scraper, SCR-320	1	0	1 HP	Top Mounted	Rubber Lined Carbon Steel	IDI

Item No.	Item Name	Number In Use	Number Spare	Unit Capacity	Design Conditions	Material of Construction	Vendor
1.2B.05 443	Evaporator/Brine Concentrator, EV-311	1	0	30 GPM 4,000 GAL	Falling Film Evaporator	Titanium	RCC
1.2B.05 443	Brine Concentrator Storage Tank Agitator, AG-311	1	0	2 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.05 443	Brine Concentrator Storage Tank, TK-311	1	0	19,000 GALS	Vertical Cylindrical	Vinyl Ester Lined Carbon Steel	RCC
1.2B.05 443	Product Tank, TK-316	1	0	4,700 GALS	Vertical Cylindrical	FRP	ERSHIGS
1.2B.05 443	Brine Concentrator Feed Tank Agitator, AG-312	1	0	0.25 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.05 443	Product Tank Agitator, AG-316	1	0	1 HP	Top Mounted	Hastelloy	Lightnin
1.2B.05 443	Vapor Compressor W/ Sound Enclosure, CM-311	1	0	4,139 ACFM 450 HP	Centrifugal	Titanium/ 316 SS	Ingersoll-Rand
1.2B.05 443	FGD Blowdown Transfer Pumps, PP-311A, B	1	1	30 GPM 3 HP	Horizontal Centrifugal Flow	Monel	Goulds
1.2B.05 443	Brine Concentrator Primary Feed Pumps, PP-312A, B	1	1	40 GPM 7.5 HP	Horizontal Centrifugal Flow	Monel	Goulds
1.2B.05 443	Acid Tank, TK-313	1	0	55 GAL	Vertical Cylindrical	PVDF	RCC
1.2B.05 443	Scale Inhibitor Feed Tank, TK-314	1	0	55 GAL	Vertical Cylindrical	Polyethylene	RCC
1.2B.05 443	Brine Concentrate Feed Tank, TK-312	1	0	300 GAL	Vertical Cylindrical	FRP	Chemical Proof Corp.

Item No.	Item Name	Number		Unit Capacity	Design Conditions	Material of Construction	Vendor
		In Use	Spare				
1.2B.05 443	Distillate Tank, TK-315	1	0	200 GAL	Vertical Cylindrical	316 SS	Chemi-thon
1.2B.05 443	Primary Heat Exchanger, HE-311	1	0	30 GPM, Feed 88°F ΔT, Feed 106°F ΔT, Distillate	Plate Type SR-250	Titanium GR1	APV Crepaco
1.2B.05 443	Secondary Heat Exchanger, HE-312	1	0	30 GPM, Feed 61°F ΔT, Feed 74°F ΔT Distillate	Plate Type SR-250	Titanium GR1	APV Crepaco
1.2B.05 443	Deaerator Tower, DA-311	1	0	30 GPM	Vertical Cylindrical	FRP Polypropylene	Chemical Proof Corp.
1.2B.05 443	Seed Hydroclone	1	0	20 GPM	PC2-1597	Kynar/Ceramic	Krebs
1.2B.05 443	Scale Inhibitor Pumps, PP-314A,B	1	1	0.036 GPH 120 V Solonoid	Metering Pump	Polypropylene	Promi-nont
1.2B.05 443	Acid Pumps, PP-313A,B	1	1	0.084 GPH 120 V Solonoid	Metering Pump	Teflon	Promi-nont
1.2B.05 443	Seed Recyle Pump, PP-318	1	0	20 GPM 3 HP, 75 PSI	Horizontal Centrifugal Flow	Ferralium 255	Goulds
1.2B.05 443	Underflow Pump, PP-319	1	0	30 GPM	Air Operated	Hastelloy C	Wilden Pumps
1.2B.05 443	Recirculation Pump, PP-317	1	0	1820 GPM 30 HP, 28 PSI	Horizontal Centrifugal Flow	Ferallium 255	Goulds

Item No.	Item Name	Number		Unit Capacity	Design Conditions	Material of Construction	Vendor
		In Use	Spare				
1.2B.05	B.C. Secondary Feed Pumps, PP-316A,B	1	0	30 GPM 7.5 HP, 54 PSI	Horizontal Centrifugal Flow	Monel	Goulds
1.2B.05	Distillate Pumps, PP-315A,B	1	0	30 GPM 15 HP, 85 PSI	Horizontal Centrifugal Flow	316 SS	Goulds
1.2B.06 270	Gypsum Handling Equipment, Including Belt Conveyors, & CON-341A, B, C, D, E	3	2	100 Ton/Hour Each	200 Ton Total Capacity	Carbon Steel	FMC
1.2B.15 472	Unit 1 & Unit 2 ID Fans	4	0	295,000 ACFM 2,000 HP	Single Speed W/Backward Curve Blades; Induced Air Cooled Bearings	Carbon Steel	Buffalo Forge
1.2B.15 475	Absorber Inlet Isolation Dampers	2	0	1,616,646 Lb/Hr 550,000 ACFM (Each)	Guillotine	Carbon Steel	Effox
1.2B.15 475	Absorber Crossover Isolation Dampers	2	0	1,616,646 Lb/Hr 550,000 ACFM (Each)	Double Louver	Carbon Steel	Effox
1.2B.15 475	ID Fan Outlet Isolation Dampers	4	0	808,300 Lb/Hr 253,000 ACFM (Each)	Double Louver	Carbon Steel	Effox
1.2B.15 475	Bypass Control Damper	1	0	1,550,000 Lb/Hr 483,500 ACFM	Modulating Double Louver	Carbon Steel	Effox

Item No.	Item Name	Number In Use	Number Spare	Unit Capacity	Design *Conditions*	Material of Construction	Vendor
BALANCE OF PLANT							
1.2A&B 09&10 CM-101 A - H	Coal Mills & Balance of Job	8	0	36,800 lb/hr	Pressurized mill with Dynamic Classifier	Alloy hardened and ceramic lined wear parts	Reilly-Stoker
1.2B.12 HP-001	Heat Pipe	2	0	250° F Gas *Outlet*		Carbon Steel with Alloy Tubes	ABB Air Pre-heater
1.2B.11 *UI-200*	SNCR	1	0			Leased Equipment	NALCO
1.2A&B.07&08 ES-101 A - D	ESP Modifications	2	0	99.6%	Rigid Electrode	Carbon Steel	BELCO

MILLIKEN CLEAN COAL TECHNOLOGY DEMONSTRATION PROJECT

SECTION 5.0

PROCESS CAPITAL COST

DE-FC22-93PC92642

5.0 PROCESS CAPITAL COST

As of the end of fiscal year 1993, 54.4 million dollars have been spent on the Milliken Clean Coal Technology Demonstration Project (MCCTD). Of this amount, the Department of Energy has reimbursed NYSEG for 11.2 million dollars to date. The current status of "Installed Equipment Costs" is presented in TABLE 5.0-1. Additional information regarding quantities, capacities, design characteristics, vendor and associated process areas are shown on TABLE 4.4-1 in Section 4.4 of this PDR. The Major Equipment Costs, TABLE 5.0-1, includes material and installation costs for the various pieces of equipment.

NYSEG has taken the approach to prefabricate as much of the equipment as possible at the vendors' facilities. The extent of prefabrication depends upon cost savings, transportation restrictions, and installation restrictions such as weight, access and clearance requirements necessary to install the various pieces of equipment. Wherever possible, equipment will be preassembled on-site before it is installed. The remaining equipment will be assembled as it is set in place.

TABLE 5.0-1
MAJOR EQUIPMENT COSTS

Item No.	Item Name	Cost/Unit							No. of Units	Total Cost/ Year
		F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field	Total		
1.2A.04 350	FGD Chimney & Flues	$892,440	Exempt	Included	$707,690	$1,035,300	W/Field Labor	$2,635,430	1	$2,635,430 1994
1.2A.04 461	Absorber Modules ABS-100, 200	$3,656,599	Exempt	Included	With Equipment	With Equipment	With Equipment	$3,656,599	2	$3,656,599 1994
1.2B.02 263	Limestone Day Storage Bins BI340 - A-B	$75,380	Exempt	Included	$0	$57,082	W/Field Labor	$132,462	2	$264,923 1994
1.2B.02 421	Ball Mill WBM-113 & 213	$1,213,513[1]	Exempt	Included	$0	$166,210	W/Field Labor	$1,379,723	2	$2,759,445 1994
1.2B.02 421	Weigh Feeder BFU-113 & 213	W/Ball Mill	Exempt	Included	$0	$5,000	W/Field Labor	$5,000	2	$10,000 1994
1.2B.02 421	Mill Hydroclone Set - HCY-113 & 213	W/Ball Mill	Exempt	Included	$0	$8,000	W/Field Labor	$8,000	2	$16,000 1994
1.2B.02 421	Mill Slurry Tank TK-113 & 213	W/Ball Mill	Exempt	Included	$0	$6,000	W/Field Labor	$6,000	2	$12,000 1994
1.2B.02 421	Mill Slurry Tank Agitator AG-113 & 213	$12,547	Exempt	Included	$0	$3,000	W/Field Labor	$15,547	2	$31,093 1994
1.2B.02 421	Mill Slurry Pumps, PP-113A & B, PP-213A & B	$27,198	Exempt	Included	$0	$6,000	W/Field Labor	$33,198	4	$132,791 1994

[1] All major equipment costs include motor and ancillaries.

Item No.	Item Name	Cost/Unit							No. of Units	Total Cost/ Year
		F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field	Total		
1.2B.02 423	Fresh Slurry Feed Tank, TK-104 & 204 (Incl. Tank Lining)	$0	Exempt	Included	$78,325	$88,181	W/Field Labor	$166,506	2	$333,011 1993
1.2B.02 423	Fresh Slurry Feed Tank Agitator, AG-104 & 204	$17,294	Exempt	Included	$0	$3,000	W/Field Labor	$20,294	2	$40,587 1994
1.2B.02 423	Fresh Slurry Forwarding Pump PP-104A&B, 204A&B	$12,310	Exempt	Included	$0	$4,000	W/Field Labor	$16,310	4	$65,241 1994
1.2B.02 432	Centrifuge Feed Tanks, TK-111,211	$14,571	Exempt	Included	$0	$5,400	W/Field Labor	$19,971	2	$39,941 1994
1.2B.02 432	Centrifuge Feed Tank Agitators AG-111,211	$6,047	Exempt	Included	$0	$2,000	W/Field Labor	$8,047	2	$16,094 1994
1.2B.02 432	Centrifuges DFS-111A & B, 211A & B	$412,756	Exempt	Included	$0	$18,294	W/Field Labor	$431,049	4	$1,724,197 1993
1.2B.02 432	Centrifuge Feed Pumps PP-111,211	$17,603	Exempt	Included	$0	$6,000	W/Field Labor	$23,603	2	$47,206 1994
1.2B.02 433	Primary Hydroclones HCY-101, 201	$59,988	Exempt	Included	$0	$6,000	W/Field Labor	$65,988	2	$131,976 1994
1.2B.02 433	Secondary Hydroclones HCY-102, 202	$18,975	Exempt	Included	$0	$6,000	W/Field Labor	$24,975	2	$49,949 1994
1.2B.02 433	Sec Hydroclone Feed Tank Agitators AG-102,202	$8,256	Exempt	Included	$0	$1,000	W/Field Labor	$9,256	2	$18,511 1994

Item No.	Item Name	Cost/Unit							No. of Units	Total Cost/ Year
		F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field	Total		
1.2B.02 433	Secondary Hydroclone Feed Pumps PP-102,202	$10,363	Exempt	Included	$0	$3,000	W/Field Labor	$13,363	2	$26,725 1994
1.2B.02 433	Secondary Hydroclone Feed Tanks TK-102,202	$0	Exempt	Included	$14,392	$7,400	W/Field Labor	$21,792	2	$43,584 1994
1.2B.02 434	Filtrate Return Pumps PP-101, 201	$26,310	Exempt	Included	$0	$5,000	W/Field Labor	$31,310	2	$62,620 1994
1.2B.02 434	Filtrate Tank Agitator AG-101, 201	$11,339	Exempt	Included	$0	$2,000	W/Field Labor	$13,339	2	$26,678 1994
1.2B.02 434	Filtrate Tanks, TK-101 & 201	$0	Exempt	Included	$20,565	$23,000	W/Field Labor	$43,565	2	$87,130 1993
1.2B.02 435	Clarified Water Tanks, TK-107 & 207	$0	Exempt	Included	$29,280	$31,950	W/Field Labor	$61,230	2	$122,460 1993
1.2B.0 2435	Clarified Water Tank Agitator AG-107, 207	$0	Exempt	Included	$20,358	$2,000	W/Field Labor	$22,358	2	$44,715 1994
1.2B.02 435	Blowdown Pump PP-108, 208	$7,467	Exempt	Included	$0	$1,000	W/Field Labor	$8,467	2	$16,933 1994
1.2B.02 435	Clarified Water Pumps PP-107, 207	$10,533	Exempt	Included	$0	$2,500	W/Field Labor	$13,033	2	$26,066 1994
1.2B.02 461	Slurry Recycle Pumps, ARP 100A-G, 200A-G	$111,541	Exempt	Included	$0	$15,714	W/Field Labor	$127,255	14	$1,781,574 1994
1.2B.02 462	Oxidation Blowers BW-101,201,301	$215,311	Exempt	Included	$0	$10,000	W/Field Labor	$225,311	3	$675,934 1994
1.2B.02 462	Absorber Agitator AG-100A-E, 200A-E	$47,301	Exempt	Included	$0	$5,000	W/Field Labor	$52,301	10	$523,010 1994

Item No.	Item Name	Cost/Unit							No. of Units	Total Cost/ Year
		F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field	Total		
1.2B.02 463	Process Water Tank	0	Exempt	Included	$19,150	$21,800	W/Field Labor	$40,950	1	$40,950 1994
1.2B.02 463	Process Water Pump PP-103, 203, 303	$12,346	Exempt	Included	$0	$8,000	W/Field Labor	$20,346	3	$61,037 1994
1.2B.02 464	Absorber Slurry Drain Tank	$0	Exempt	Included	$276,883	Included W/Material	W/Field Labor	$276,883	1	$276,883 1994
1.2B.02 464	Absorber Slurry Drain Tank Agitator AG-305	$36,835	Exempt	Included	$0	$8,000	W/Field Labor	$44,835	1	$44,835 1994
1.2B.02 464	Absorber Slurry Drain Pumps PP-305A & B	$12,362	Exempt	Included	$0	$5,000	W/Field Labor	$17,362	2	$34,723 1994
1.2B.02 465	Bleed Pumps PP-112A&B, 212A&B	$13,593	Exempt	Included	$0	$5,000	W/Field Labor	$18,593	4	$74,371 1994
1.2B.02 466	Formic Acid Tank, TK-301	$26,103	Exempt	Included	$0	$5,000	W/Field Labor	$31,103	1	$31,103 1994
1.2B.02 466	Formic Acid Metering Pumps, AMP-101,201,301	$6,948	Exempt	Included	$0	$333	W/Field Labor	$7,281	3	$21,843 1994
1.2B.02 467	Mist Eliminator Wash Spray Nozzles WWN-025	$37	Exempt	Included	$0	$36	W/Field Labor	$73	56	$4,099 1994
1.2B.02 467	Quench Water Spray Nozzles EQN-0375,QNS-025	$90	Exempt	Included	$0	$50	W/Field Labor	$140	80	$11,201 1994
1.2B.02 467	Recirc Spray Cocurrent Section Spray Nozzles	$502	Exempt	Included	$0	$189	W/Field Labor	$690	106	$73,183 1994

Item No.	Item Name	Cost/Unit F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field	Total	No. of Units	Total Cost/ Year
1.2B.02 467	Recirc Spray Counter Current Spray Nozzles	$639	Exempt	Included	$0	$157	W/Field Labor	$797	159	$126,676 1994
1.2B.02 471	Mist Eliminators, VME-101,102,201 & 202	$150,400	Exempt	Included	$0	$10,000	W/Field Labor	$160,400	4	$641,600 1994
1.2B.02	Balance of Job - Civil	$0	Included	Included	$1,439,854	$684,403	W/Field Labor	$2,124,257	1	$2,124,257 1994
1.2B.02	Balance of Job - Structural/ Architectural	$0	Included	Included	$9,750,880	$3,981,820	W/Field Labor	$13,732,700	1	$13,732,700 1994
1.2B.02	Balance of Job - Mechanical	$0	Exempt	Included	$6,942,047	$3,761,050	W/Field Labor	$10,703,097	1	$10,703,097 1994
1.2B.02	Balance of Job- Electrical & I&C	$0	Exempt	Included	$3,570,491	$689,681	W/Field Labor	$4,260,172	1	$4,260,172 1994
1.2B.03 260	Limestone Handling Equipment: Incl. Belt Conveyors, CON340A, B; Scales, Separator, Gates, Chutes	$278,609	Exempt	Included	$0	$159,408	W/Field Labor	$438,017	2	$876,034 1994
1.2B.03 260	Vibrating Bin Discharger	$14,636	Exempt	Included	$0	$17,539	W/Field Labor	$32,175	2	$64,350 1994
1.2B.03 260	Dust Collection System	$13,432	Exempt	Included	$0	$1,368	W/Field Labor	$14,800	4	$59,199 1994

Item No.	Item Name	Cost/Unit F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field	Total	No. of Units	Total Cost/ Year
1.2B.03	Balance of Job - Civil/Limestone Storage- Pond & Discharge Structure	$0	Exempt	Included	$353,557	$287,600	W/Field Labor	$641,157	1	$641,157 1994
1.2B.05 441	FGD Blowdown Equipment (Complete)	$1,596,131	Exempt	Included	$0	$0	W/Field Labor	$1,596,131	1	$1,596,131 1994
1.2B.05 441	Equalization Tank TK-320 (Incl. Insulation)	W/ FGD Equipment	Exempt	Included	$0	$24,000	W/Field Labor	$24,000	1	$24,000 1994
1.2B.05 441	Desaturation Tank TK-321	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	Heavy Metal Tank TK-322	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	Coagulation Tank TK-323	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	Ferric Chloride Tank TK-325	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	Organo Sulfide Tank TK-326	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	Lime Slurry Tank , TK-327	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	Sludge Holding Tank, TK-328	W/ FGD Equipment	Exempt	Included	$0	$47,500	W/Field Labor	$47,500	1	$47,500 1994
1.2B.05 441	CPR Sludge Holding Tank, TK-329	W/ FGD Equipment	Exempt	Included	$0	$67,500	W/Field Labor	$67,500	1	$67,500 1994

Item No.	Item Name	Cost/Unit							No. of Units	Total Cost/ Year
		F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field	Total		
1.2B.05 441	FGD Filtrate Tank, TK-330	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	CPR Filtrate Tank, TK-331	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	Equalization Tank Agitator, AG-320	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	pH Elevation/Saturation Tank Agitator, AG-321	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	Heavy Metal Precip. Tank Agitator, AG-322	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	Coagulation Tank Agitator, AG-323	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	Densadeg Reactor Agitator, AG-324	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	Lime Slurry Tank Agitator AG-327	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	Sludge Holding Tank Agitator, AG-328	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	Filter Press, FLP-328	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	Ferric Chloride Feed Pumps, PP-325A,B	W/ FGD Equipment	Exempt	Included	$0	W/ Skid	W/Field Labor	$0	2	$0
1.2B.05 441	Organosulfide Feed Pumps, PP-326A,B	W/ FGD Equipment	Exempt	Included	$0	W/ Skid	W/Field Labor	$0	2	$0

Item No.	Item Name	Cost/Unit							No. of Units	Total Cost/ Year
		F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field	Total		
1.2B.05 441	Forward Feed Pumps, PP-322A, B	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	2	$4,000 1994
1.2B.05 441	Sludge Waste Pumps, PP-323A, B	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	2	$4,000 1994
1.2B.05 441	Sludge Recycle Pumps, PP324A, B	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	2	$4,000 1994
1.2B.05 441	Filter Press Feed Pump, PP-328	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	Lime Slurry Pump Skid, PP-32x	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	FGD Filtrate Pump, PP-330	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	CPR Filtrate Pump, PP-331	W/ FGD Equipment	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1994
1.2B.05 441	Densadeg Reactor, RE-324 (Including Insulation)	W/ FGD Equipment	Exempt	Included	$0	$7,000	W/Field Labor	$7,000	1	$7,000 1994
1.2B.05 441	Densadeg Thickener, THI-320 (Including Insulation)	W/FGD Equipment	Exempt	Included	$0	$50,000	W/Field Labor	$50,000	1	$50,000 1994
1.2B.05 441	Densadeg Scraper, SCR-320	W/ FGD Equipment	Exempt	Included	$0	$4,000	W/Field Labor	$4,000	1	$4,000 1994
1.2B.05 443	Evaporator/Brine Concentrator, EV-311 Including Insulation)	$1,864,486	Exempt	Included	$0	$45,000	W/Field Labor	$1,909,486	1	$1,909,486 1993

Item No.	Item Name	Cost/Unit							No. of Units	Total Cost/ Year
		F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field	Total		
1.2B.05 443	Brine Concentrator Storage Tank Agitator, AG-311	$20,286	Exempt	Included	$0	$2,000	W/Field Labor	$22,286	1	$22,286 1993
1.2B.05 443	Brine Concentrator Tank - TK-311 (Including Insulation)	$21,316	Exempt	Included	$0	$11,400	W/Field Labor	$32,716	1	$32,716 1993
1.2B.05 443	Product Tank TK-316	W/Brine Concentrator	Exempt	Included	$0		W/Field Labor	$0	1	$0 1993
1.2B.05 443	Brine Concentrator Feed Tank Agitator, AG-312	W/Brine Concentrator	Exempt	Included	$0	$1,000	W/Field Labor	$1,000	1	$1,000 1993
1.2B.05 443	Product Tank Agitator, AG-316	W/Brine Concentrator	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	1	$2,000 1993
1.2B.05 443	Vapor Compressor W/Sound Enclosure, CM-311	W/Brine Concentrator	Exempt	Included	$0	$20,000	W/Field Labor	$20,000	1	$20,000 1993
1.2B.05 443	FGD Blowdown Transfer Pumps, PP-311A, B	W/Brine Concentrator	Exempt	Included	$0	$4,000	W/Field Labor	$4,000	2	$8,000 1993
1.2B.05 443	Brine Concentrator Primary Feed Pumps, P-312A, B	W/Brine Concentrator	Exempt	Included	$0	$2,000	W/Field Labor	$2,000	2	$4,000 1993
1.2B.05 443	Acid Tank, TK-313	W/Brine Concentrator	Exempt	Included	$0	W/Skid	W/Field Labor	$0	1	$0 1993
1.2B.05 443	Scale Inhibitor Feed Tank, TK-314	W/Brine Concentrator	Exempt	Included	$0	W/Skid	W/Field Labor	$0	1	$0 1993

Item No.	Item Name	Cost/Unit							No. of Units	Total Cost/ Year
		F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field	Total		
1.2B.05 443	Brine Concentrate Feed Tank, TK-312	W/Brine Concentrator	Exempt	Included	$0	W/Skid	W/Field Labor	$0	1	$0 1993
1.2B.05 443	Distillate Tank, TK-315	W/Brine Concentrator	Exempt	Included	$0	W/Skid	W/Field Labor	$0	1	$0 1993
1.2B.05 443	Primary Heat Exchanger, HE-311	W/Brine Concentrator	Exempt	Included	$0	W/Skid	W/Field Labor	$0	1	$0 1993
1.2B.05 443	Secondary Heat Exchanger, HE-312	W/Brine Concentrator	Exempt	Included	$0	W/Skid	W/Field Labor	$0	1	$0 1993
1.2B.05 443	Deaerator Tower, DA-311	W/Brine Concentrator	Exempt	Included	$0	W/Skid	W/Field Labor	$0	1	$0 1993
1.2B.05 443	Seed Hydroclone	W/Brine Concentrator	Exempt	Included	$0	W/Skid	W/Field Labor	$0	1	$0 1993
1.2B.05 443	Scale Inhibitor Pumps, PP-314A,B	W/Brine Concentrator	Exempt	Included	$0	W/Skid	W/Field Labor	$0	2	$0 1993
1.2B.05 443	Acid Pumps, PP-313A,B	W/Brine Concentrator	Exempt	Included	$0	W/Skid	W/Field Labor	$0	2	$0 1993
1.2B.05 443	Seed Recycle Pump, PP-318	W/Brine Concentrator	Exempt	Included	$0	W/Skid	W/Field Labor	$0	1	$0 1993
1.2B.05 443	Underflow Pump, PP-319	W/Brine Concentrator	Exempt	Included	$0	W/Skid	W/Field Labor	$0	1	$0 1993
1.2B.05 443	Recirculation Pump, PP-317	W/Brine Concentrator	Exempt	Included	$0	W/Skid	W/Field Labor	$0	1	$0 1993
1.2B.05 443	B.C. Secondary Feed Pumps, PP-316A,B	W/Brine Concentrator	Exempt	Included	$0	W/Skid	W/Field Labor	$0	2	$0 1993

Item No.	Item Name	Cost/Unit							No. of Units	Total Cost/ Year
		F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field	Total		
1.2B.05 443	Distillate Pumps PP-315A,b	W/Brine Concentrator	Exempt	Included	$0	W/Skid	W/Field Labor	$0	2	$0 1993
1.2B.05	Balance of Job - Civil/Concrete	$0	Exempt	Included	$10,000	$10,400	W/Field Labor	$20,400	1	$20,400 1993
1.2B.05	Balance of Job - Mechanical/Piping	$0	Exempt	Included	$70,805	$377,280	W/Field Labor	$448,085	1	$448,085 1993
1.2B.06 270	Gypsum Handling Equipment, Including Belt Conveyors, & CON-341A, B, C, D, E	$150,454	Exempt	Included	$0	$103,476	W/Field Labor	$253,930	5	$1,269,651 1994
1.2B.06	Balance of Job - Mechanical	$0	Exempt	Included	$37,324	Included	W/Field Labor	$37,324	1	$37,324 1994
1.2B.06	Balance of Job - Gypsum Storage Bldg	$0	Included	Included	$250,440	$89,660	W/Field Labor	$340,100	1	$340,100 1994
1.2B.15 472	Unit 1 & Unit 2 ID Fans	$323,383	Exempt	Included	$0	Included W/Ductwork	W/Field Labor	$323,383	4	$1,293,531 1994
1.2B.15 475	FGD Dampers	$72,125	Exempt	Included	$0	Included W/Ductwork	$10,000	$82,125	9	$739,120 1993
1.2B.15 307	Ductwork & Insulation	$0	Exempt	Included	$3,860,493	$1,857,741	W/Field Labor	$5,718,234	86,330 SF	$5,718,234 1994
1.2B.15	Balance of Job - Mechanical/Piping	$0	Exempt	Included	$17,600	$156,900	W/Field Labor	$174,500	1	$174,500 1994
1.2B.15	Balance of Job - Civil/Concrete	$0	Exempt	Included	$15,325	$7,102	W/Field Labor	$22,427	1	$22,427 1994

Item No.	Item Name	Cost/Unit							No. of Units	Total Cost/ Year
		F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field	Total		
BALANCE OF PLANT										
1.2A&B.09&10 CM-101 A - H	Coal Mills & Balance of Job	$1,958,680	Exempt	Included	$0	$720,900	W/Field Labor	$2,679,580	8	$21,436,640
1.2B.12 HP-001	Heat Pipe	$2,091,000	Exempt	Included	$0	$1,000,000	W/Field Labor	$3,091,000	2	$6,182,000
1.2B.11 UI-200	SNCR								1	LEASE
1.2A&B.07&08 ES-101 A - D	ESP Modifications	$2,301,529	Exempt	Included	$0	$1,914,481	W/Field Labor	$4,216,010	2	$8,432,020

MILLIKEN CLEAN COAL TECHNOLOGY

DEMONSTRATION PROJECT

SECTION 6.0

ESTIMATED OPERATING COST

DE-FC22-93PC92642

6.1 FIXED OPERATING AND MAINTENANCE COSTS

Estimates have been made on new positions required for operating an FGD system at Milliken Station. The breakdown for the personnel who will be 100% dedicated to the FGD system consists of thirteen new operators, five new maintenance personnel, and seven new administrative and support personnel. An estimate was made of the percent of time existing operators, maintenance, and administrative and support personnel will allocate to the FGD system.

Total operating labor costs were calculated using a composite rate applied to the additional operators. An estimate of the percentage of existing operator's total hours was also included.

Total maintenance labor costs were calculated from the listing of required maintenance personnel at various wage levels and existing maintenance personnel with a percent of the total hours dedicated to the FGD system.

Total maintenance material costs were estimated from a review of NYSEG's Kintigh Station FGD system maintenance records for the year 1990. The Kintigh Station FGD system is similar in the types, number and size of operating equipment proposed at Milliken Station.

Total administrative and support labor costs were calculated from the listing of required new support personnel at various wage levels and existing support personnel with a percent of total hours dedicated to the FGD system.

Reference TABLE 6.1-1 - Summary of Estimated Annual Operating Costs.

TABLE 6.1-1

SUMMARY OF ESTIMATED ANNUAL OPERATING COSTS

BASE YEAR 1991

ANNUAL FIXED OPERATING COST		
OPERATING LABOR COSTS:		
	Number of operators per shift: 5 Total Operating Hours: 8,760 Operating Labor Pay Rate per Hour: $17.13	
		COST $/YEAR
1.	Total Annual Operating Labor Costs	$ 750,294
2.	Total Annual Maintenance Labor Costs	$ 663,352
3.	Total Annual Maintenance Material Costs	$ 376,535
4.	Total Administrative and Support Labor Costs	$ 695,608
5.	Total Fixed O&M Costs	$2,485,789

6.2 VARIABLE OPERATING COSTS

Variable operating costs were calculated from vendor consumption rates and mass balances. Unit prices for the consumables were acquired from suppliers or materials. Total hours were calculated assuming a 95% availability on the FGD system.

TABLE 6.2-1

VARIABLE OPERATING COSTS

BASE YEAR 1991

COMMODITIES	$/UNIT	QUANTITY/ HR	COST $/HOUR	TOTAL HOURS	TOTAL COST
Formic Acid	$4.10/Gallon	*	*	8,322	117,340
Limestone	18.500	13.5	249.75	8,322	2,078,419
Electric Power	0.036	4,100.0	147.60	8,322	1,228,327
Urea	0.970	115.0	111.55	7,463	832,462
TOTAL VARIABLE OPERATING COSTS					4,256,548

*Proprietary

Startup costs were estimated for commodities utilized during a 6 month continuous operation, new operators and maintenance personnel for a 10 month period, a trainer specialist for one man-year, and travel expenses.

Total startup costs include the costs for the following items:

- Wages for a Training Specialist for one man-year to include two months of training preparation, four months of operator and maintenance training, and six months of continuous operation startup support requirements.
- Wages for hourly operator and maintenance personnel for 20 personnel for a 10 month period to include four months of training and six months of continuous operation startup.
- Costs for commodities utilized during the six month continuous operation were also included.

TABLE 6.2-2

SUMMARY OF ESTIMATED STARTUP COSTS

Base Year 1991

STARTUP	COST, $
Operating Labor Cost	445,489
Maintenance and Materials Cost	290,169
Administrative and Support Cost	280,347
Commodity Cost*	
Formic Acid	29,328
Limestone	259,750
Electric Power	307,008
Urea	232,024
TOTAL	**$1,844,115**

*Includes process fuels, sorbents, chemicals, water, auxiliary power and waste disposal.

LENGTH OF STARTUP PERIOD, MONTHS	6

MILLIKEN CLEAN COAL TECHNOLOGY DEMONSTRATION PROJECT

SECTION 7.0

COMMERCIAL APPLICATIONS

DE-FC22-93PC92642

7.1 COMMERCIALIZATION

This project comprises a unique combination of retrofit technologies and plant modifications designed to achieve Clean Air Act Amendment (CAA) emission levels while maintaining plant efficiency. Although all the technologies have been used in similar situations, the particular combination for this project while feeding high-sulfur coal has not been demonstrated.

There have been approximately 30 installations of the S-H-U FGD process in Europe and Asia, serving over 8,000 MWe of plant capacity. This project will be the first demonstration in the US. It will also be the first US demonstration of the split-flow, Stebbins' tile-lined absorber, installed below a flue.

The NO_XOUT® technology is installed, or in the planning stage, on approximately 30 boilers ranging in size up to 900 million Btu/hr. However, none of these installations is firing high-sulfur coal. Thus, this project will be the first commercial demonstration of the NO_XOUT® technology on a furnace firing US high sulfur bituminous coal.

Over 100 heat pipe air heaters have been installed on industrial and utility boilers. The most relevant utility installation is at West Penn Power's Pleasant Station at Willow Island, WV. The unit at Pleasant Station is about half the size of the unit for this project. In addition, the unit that would be used in this project would incorporate features, such as corrosion feedback protection and replaceable tubes, included at EPRI's demonstration unit at Kintigh Station but not included at Pleasant Station. This project may be the first commercial-scale demonstration of some of these features.

This project will be the first commercial-scale demonstration of this particular combination of air emissions reduction and energy improvement technologies and modifications.

7.1.1 Technical Feasibility

The S-H-U FGD process is fully commercial, with approximately 30 installations. The NO_XOUT® process is also fully commercial with approximately 30 installations on industrial and utility boilers, although not on high-sulfur coals. There are over 100 commercial installations of heat pipe air heaters.

In summary, all the pieces of this project are technically feasible, and the probability of successfully integrating them to achieve anticipated CAAA emission levels, while maintaining station efficiency, is high.

7.1.2 Relationships Between Project Size And Projected Scale Of Commercial Facility

As already discussed, the test boilers are 150 MWe pulverized-coal-fired utility units which will fire high-sulfur coal during the demonstration. These units are typical of a significant portion of the nation's electric utility operating base. Thus, there is the potential for wide application of the demonstrated technology after successful completion of this project.

7.1.3 Role Of The Project In Achieving Commercial Feasibility Of The Technology

This project will demonstrate, at commercial scale, novel technologies for meeting CAAA limits for SO_2 and NO_X levels on existing coal-fired units. The technology can use virtually any coal and can be retrofitted to many types of coal-fired furnaces. Success of the demonstration project will provide a great impetus to commercialization.

7.1.4 Applicability Of The Data To Be Generated

The demonstration project will test all aspects of the technology at commercial scale on a commercial coal-fired unit. Data collection, analysis, and reporting will be performed during the operations phase and will include on-stream factors, material balances, equipment performance, efficiencies, and SO_2 and NO_X emission levels. The data that will be generated will be directly applicable to other applications and will provide valuable information to permit commercialization.

7.1.5 Comparative Merits Of The Project And Projection Of Future Commercial Economics And Market Acceptability

The MCCTD project will demonstrate a combination of technologies, including the S-H-U process for SO_2 reduction, NO_XOUT® technology for NO_X reduction, and ABB Air Preheater's heat pipe air heater system for efficiency improvement. These technologies are suitable for either retrofit on existing boilers or incorporation into new construction. They are also suitable for a wide variety of boiler types, ages, sizes, fuel types, and fuel sulfur levels.

This technology should permit furnaces to meet CAAA air emission levels at competitive costs; and features, such as little or no loss in efficiency, production of marketable by-products, and no waste water discharge, should make the technology attractive to the commercial market from an environmental and economic point of view.

Emissions of nitrogen oxides from coal-fired boilers have typically been controlled through combustion modification technology. This technology will not ensure that the mandated reductions are achieved. This is evident in the regulatory exception provided in the CAA for those units in which combustion technology fails to meet the emission limits. While the first phase of the CAAA will allow continuation of this practice, stricter guidelines set forth in 1997 will require emission reductions to be based on the best available technology, taking into account the costs, energy, and environmental impacts. Therefore, control technologies which can demonstrate compliance with emission goals on a cost effective basis will be commercially sought after.

7.1.6 Commercialized Technologies

The commercialization of several technologies will be supported with the Milliken Station demonstration. FIGURE 7.1-1 presents a summary profile of the structure of the demonstration project.

FIGURE 7.1-2 provides a process block diagram that shows how the demonstration technologies will be implemented. Those needing commercial demonstration are:

- Saarberg-Hölter Umwelttechnik GmbH (S-H-U) Wet Flue Gas Desulfurization (FGD) Technology,
- Stebbins Tile-Lined Split Module Absorber,
- ABB Air Preheater Heat Pipe Air Heater System
- Nalco FuelTech NO_XOUT® Injection For NO_X Emission Control.

S-H-U Technology

S-H-U has researched, demonstrated and successfully commercialized their wet limestone FGD technology in Europe and Asia. At this time, S-H-U is marketing this process in the US. However, US utilities are reluctant to invest in a technology which remains unproven within the US, where fuels and operating conditions generally differ. Further, some US companies are reluctant to purchase equipment from international suppliers; a successful demonstration at Milliken Station in conjunction with S-H-U's experience in Europe will thus enable S-H-U to effectively market this technology (through its US design and manufacturing partners) in the US.

FIGURE 7.1-1
PROJECT PROFILE

SEGMENT OF PLANT	MCCTD PROJECT SCOPE
Raw *Coal* ↓ ↓ ↓ ↓	•change to high sulfur Eastern coal
PreCombustion ↓ ↓ ↓ ↓ ↓	•change mills to handle new coal
Combustion ↓ ↓ Flue Gas ↓ ↓ ↓	▸NO_X combustion modeling •combustion modifications for primary NO_X emissions
Post Combustion ↓ ↓ ↓ ↓ ↓ Clean Flue Gas	▸first US S-H-U demonstration ▸first US below-stack S-H-U absorber ▸first split S-H-U absorber ▸first utility Stebbins tile cocurrent/countercurrent absorber ▸first NO_XOUT® in high sulfur coal-fired utility furnace for NO_X emission control ▸first coal-fired heat pipe air heater with CAPCIS corrosion monitoring •ID fans •precipitator upgrade •ductwork
Balance of Plant Needs	•blowdown treatment •power feeds to new equipment •Unit 1 air heater upgrade •control system upgrade •electrical system upgrade

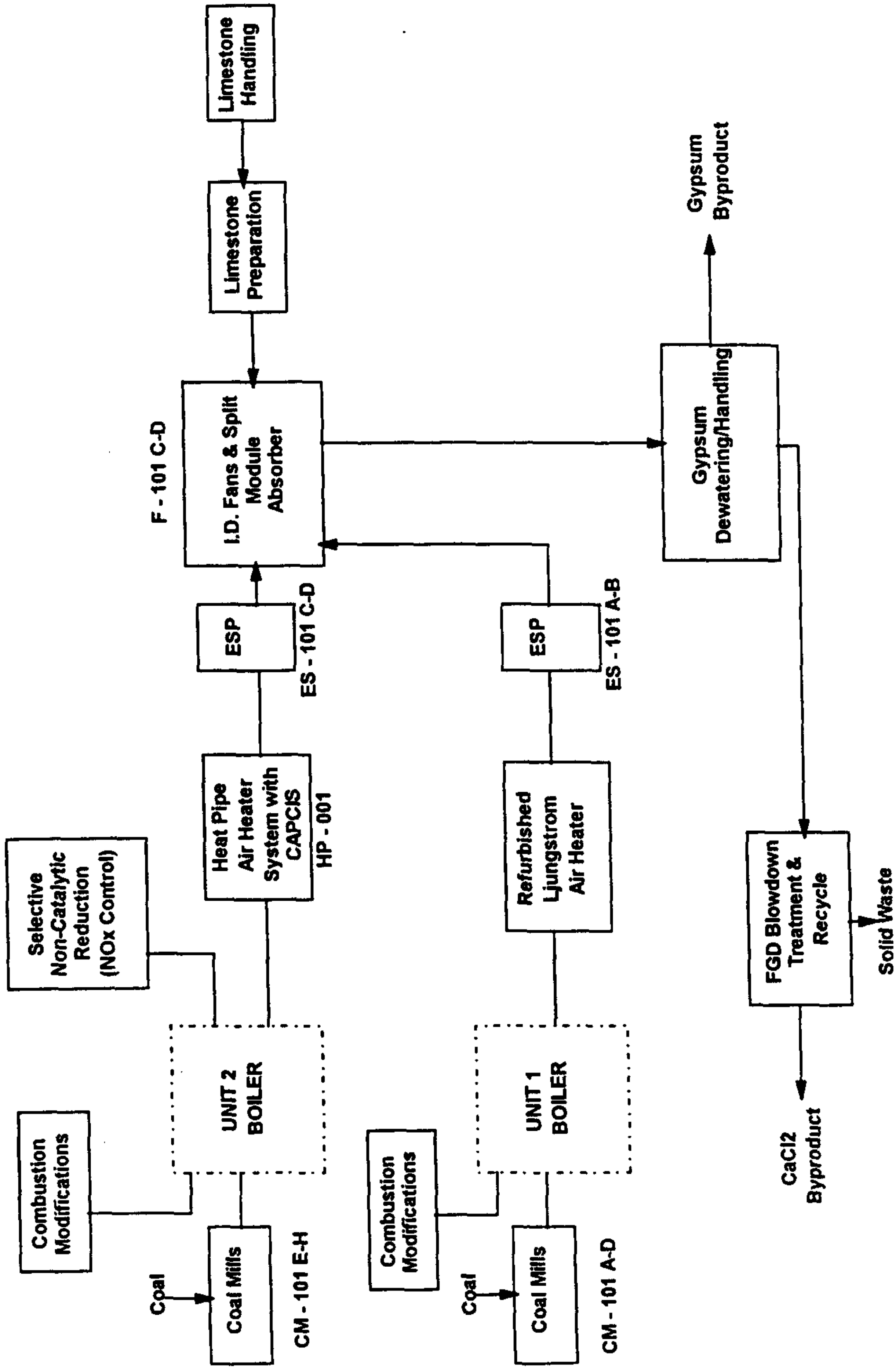
Legend:

▸novel technology in need of commercial demonstration

•*commercial technology required in plant to support the demonstration of the novel technology*

FIGURE 7.1-2

PROCESS BLOCK DIAGRAM FOR MCCTD PROJECT



Data from the Milliken demonstration will be collected to demonstrate reliable ultra-high SO_2 removal on a wide range of US coals. The validation of data will attest to the applicability of the S-H-U process to US coals.

In addition, several unique features are included that will be the first demonstrations anywhere in the world: ultra-high SO_2 removal efficiency on a high sulfur coal with limestone reagent, using a split module absorber, and using Stebbins tile in a vertical tower for the absorber liner for a cocurrent/countercurrent absorber with the S-H-U process. Success here will make both S-H-U technology and Stebbins tile absorbers attractive to a larger range of potential applications.

Stebbins Tile-Lined Split Module Absorber

Although Stebbins, one of America's largest tile companies, has effectively commercialized the use of its tile for the industrial market (chemical and pulp/paper industry), the use of Stebbins tile and mortar system as a lining for an FGD absorber has not been demonstrated sufficiently to prove its viability and acceptability to the satisfaction of electric utility companies. Stebbins tile has been applied as a liner to a horizontal Kellogg Weir absorber. The MCCTD application is substantially different from that used in the Kellogg unit. The S-H-U system will provide a harsher environment in which to demonstrate the durability of Stebbins tile. The S-H-U absorber has vertical cocurrent and countercurrent gas flow whereas the Weir scrubber is a horizontal gas flow absorber. In addition to having an increased velocity, the S-H-U recycle slurry is more acidic, has a higher chloride concentration, and includes an organic acid buffered chemistry. A successful demonstration at the Milliken station would enable Stebbins to effectively market this product as an absorber liner to US utilities and FGD vendors. NYSEG, with Stebbins, developed the split module concept.

ABB Air Preheater Heat Pipe Air Heater System

The use of a heat pipe heat exchanger in conjunction with the CAPCIS corrosion monitoring system, has not been commercially demonstrated prior to this proposed application. Both the heat pipe and the CAPCIS probe have been used on high sulfur burning boilers; however, this is the first demonstration of both technologies, used together, to minimize the heat rate impact caused by the addition of a wet scrubber. The heat pipe will reduce the flue gas outlet temperature and maintain that temperature based on the corrosion indicated by the CAPCIS corrosion monitor. Usually flue gas temperatures are required to stay above an average cold end temperature (ACET), so that minimum temperatures remain above the acid dew point of the gas to prevent duct work corrosion; however, this is an approximation and may not represent the onset of corrosion. The CAPCIS probe will monitor actual corrosion rates and control the gas bypass dampers. The dampers will be adjusted to keep corrosion to a minimum while keeping the flue gas temperatures as low as possible, hence the best possible thermal efficiency is retained.

Nalco FuelTech NO_xOUT® Injection

The NO_xOUT® process has been commercially demonstrated on industrial and utility boilers; however, this is the first application where NO_xOUT® has been demonstrated on a tangentially fired boiler firing high sulfur coal in conjunction with combustion modifications. Combustion modifications will be used as the primary reduction technology for NO_x removal and the NO_xOUT® Selective Non-Catalytic Reduction (SNCR) will be used to demonstrate its NO_x removal capabilities. The NO_xOUT® demonstration will show that NO_x can be removed, with a high degree of repeatability, while keeping levels of ammonia in the fly ash below 2 ppm. This demonstration will show that fly ash used as pozzolonic material in concrete, in lieu of land filling, will not be affected by the application of SNCR.

Milliken Station is an Excellent Demonstration Site to Launch the Commercialization of These Technologies

The proposed changes to Milliken Station will allow the demonstrated use of high sulfur coal up to 4.6 percent sulfur. Research organizations participating in the project will provide efficient and extensive technical transfer. Compared to competing processes, the combination of technologies have the potential to maintain the Station heat rate at the current level. The project is providing high energy efficiency at low cost while providing superior environmental emissions reduction.

7.1.7 Key Features And Interfaces Of The Anticipated Commercial Version Of Proposed Technology

Milliken Station retrofits and upgrades represent the first commercial application of one embodiment of the proposed technologies. Replicates using many of the same features would be possible after the proposed demonstration brings them into commercial service.

S-H-U Technology

The key features of the S-H-U technology which make it marketable are its consistent ultra-high SO_2 removal using limestone as a reagent (above 95 percent; 98 percent is expected to be demonstrated) over wide load ranges; its ease of operation during plant transients; its consistently high quality gypsum byproduct; its low energy needs; and, the excellent FGD reliability which results in low maintenance cost. The formic acid buffering permits operation within a pH range that precludes the formation of sulfite scale, often a problem in competing wet FGD systems. The buffering also has another significant advantage: the ultra-high SO_2 removal is possible at lower liquid to gas (L/G) ratios.

S-H-U absorbers may be used effectively on a wide range of boiler sizes. Experience in Europe and Asia has included installation of units on plants with generating capacities ranging as low as 20 MW to units of over 800 MW.

The most important interfaces between the S-H-U absorber and other equipment are the heat pipe air heater and the brine concentrator. The primary concerns for these interfaces include:

- Heat Pipe Air Heater: lowers both the temperature and oxygen concentration of the incoming flue gas, making the oxidation air and water balance more critical.

- Brine concentrator: must operate reliably in order to purge chlorides from the process.

Stebbins Tile

The demonstration of Stebbins ceramic tile offers several advantages to the utility marketplace. These advantages include on-line repair, a reduction in maintenance cost and increased reliability. The split module absorber can not be constructed with rubber lined, flake glass lined, or alloy clad vessels. The ability to provide individual modules at a relatively low cost is a very marketable concept. The most marketable aspect of the tile itself will most likely be its expected lower life cycle costs compared to other material of construction. Life cycle cost associated with the use of tile and mortar lining system proposed here are expected to be substantially lower than those of either the steel alloy or rubber lining. In addition to increased reliability and decreased maintenance, the expected life of the tile lining is three to four times that expected for rubber liners.

Since the demonstration is expected to last three years, the total potential lifespan for the Stebbins tile will not be assessed. However, the split module concept will be fully demonstrated. The combination of the durability and reliability already demonstrated within the non-FGD industrial market and the Milliken Station demonstration will enable Stebbins to effectively market this product to FGD vendors and utilities.

ABB Air Preheater Heat Pipe Air Heater System

The key features of the heat pipe air heater system which make it marketable are:

- Improvement in boiler thermal efficiency over a regenerative air heater with the same flue gas exit temperature. Further improvement with lower gas exit temperatures.

- Zero leakage from air side to flue gas side.

- Similar heat recovery capabilities as a regenerative air heater for the same space requirements.

- Potential for increased heat transfer, reduced exit gas temperature, and increased boiler efficiency due to CAPCIS corrosion monitoring system.

- Easily replaceable tubes or modules.

The demonstration of these features will encourage the widespread commercialization of heat pipe air heaters.

Nalco FuelTech NO_xOUT® Injection

The key features of the NO_xOUT® technology which make it marketable are the consistent rate of NO_x removal with a very low ammonia slip. Low ammonia slip eliminates air heater pluggage. The low ammonia slip will not affect the sale and use of the fly ash as a pozzolonic material in the formation of concrete. Also, the addition of proprietary chemicals have increased the temperature range in which the chemical reaction is active. The increased temperature range allows NO_xOUT® to be injected at various elevations of the boiler, reducing the number of new injection penetrations that have to be installed. Injecting NO_xOUT® at different elevations allows the NO_x to be removed in stages, with a portion of the required NO_x being removed at each level. This staged approach allows high NO_x removal efficiencies with very low ammonia slip.

The proposed demonstration size of 150 MW (1527 million Btu/hr) will consume an estimated 115 gallons of NO_xOUT® per hour. However, NO_xOUT® can be used very effectively on a wide range of boiler sizes and configurations. Experience in Europe has included installations ranging from a low as 130,000 pounds of steam per hour to over 900 million Btu per hour.

7.1.8 <u>Process Description</u>

S-H-U Technology

The S-H-U technology is a wet limestone FGD process and encompasses an integrated system based on formic acid enhanced limestone-SO_2 chemistry. The S-H-U process equipment has been optimized to take advantage of the favorable process chemistry and to minimize capital cost. The process is designed to desulfurize flue gases to environmentally acceptable levels and to form, in an integrated process step, a high grade gypsum byproduct for sale to the wallboard or cement industries. Process features in dude formic acid buffering, low pH (4.0 - 5.0) SO_2 absorption, cocurrent/countercurrent absorber, in-situ forced oxidation, ultra-high SO_2 removal, high limestone utilization, and low energy consumption.

Formic Acid Buffering

The S-H-U process uses formic acid in the recycle slurry to enhance SO_2 absorption efficiency, to buffer and control the pH drop in the recycle slurry spray during the SO_x absorption step, and to influence the reaction products formed. Formic acid buffering allows operational flexibility. During sudden load changes from 20 percent to 100 percent of maximum continuous load, even with simultaneous increases in SO_2 concentration up to 100 percent, SO_2 emissions are maintained. Another advantage of formic acid buffering is that process chemistry minimally impacted by chlorides, often a problem with competing processes. SO_2 absorption is essentially unaffected at chloride levels up to 50,000 ppm, eliminating the need for a prescrubber or high volume scrubber blow down stream. This reduces the amount of waste water to be purged.

Low pH Absorption

Perhaps the most advantageous aspect of the S-H-U process is that SO_2 absorption occurs in the 4.0-5.0 pH range. In this range, virtually all sulfur containing ions are bisulfite. Sulfite ions are not formed, thereby precluding the formation of calcium sulfite and eliminating susceptibility to sulfite scale formation.

Operation within this pH range with formic acid buffering has the additional benefit of producing desirable barrel-shaped gypsum crystals. In competing limestone-based processes operating at higher levels of pH, crystals are sometimes needle or slab-shaped. In these competing processes, gypsum fines must be removed from the process and disposed in a landfill. The fines are a continuing waste disposal problem in these other systems. By contrast, the consistent high quality commercial gypsum from the S-H-U process is produced simply by washing the gypsum for chloride removal and residual formic acid removal during the dewatering step.

Cocurrent/Countercurrent Absorption

A combination two-stage cocurrent/countercurrent absorber was developed to take advantage of the process chemistry and to optimize residence time and liquid-to-gas ratio. Flue gas enters the top of the absorber and flows cocurrently downward. The recycle limestone slurry is introduced through spray nozzles. The recycle limestone slurry containing the absorbed SO_2 collects in the sump. The flue gas continues to the second stage of the absorber, a countercurrent section, where most of the residual SO_2 is absorbed. The treated gas is then discharged to the stack.

In-Situ Oxidation

Water soluble calcium bisulfite, the product of absorption in the S-H-U process, is easily oxidized to gypsum. Forced oxidation ensures bisulfite oxidation levels greater than 99 percent, and is achieved by injecting air into the absorber sump at a theoretical rate of about 1.0-1.5 mole O2/mole SO_2 absorbed.

Stebbins Tile Split Module Absorber

The great majority of FGD absorbers installed in the US have been constructed of stainless steel or carbon steel with a variety of different lining systems. The Stebbins Engineering and Manufacturing Company (Stebbins) offers an alternative construction material that possesses the following significant advantages over conventional FGD absorber designs:

- superior corrosion and abrasion resistance,
- high reliability and availability,
- suitability to construction in a congested area,
- on-line repairs, and
- ability to withstand higher temperatures and temperature excursions.

The absorber design offered by Stebbins follows: exterior walls constructed of various thickness of carbon steel reinforced concrete walls with block exterior and a mechanically anchored ceramic tile interior. The center dividing wall required by the FGD process design is also constructed of carbon steel reinforced concrete with ceramic tiles on both sides. The absorber floors are constructed of carbon steel reinforced concrete fill sloped to drain, with 2-inch grouted ceramic tile lining over the fill. Carbon steel reinforced concrete corbels, lined with ceramic tiles, are provided to support internal piping, mist eliminators or packing as required by the FGD process design. All interior joints are grouted with chemically resistant mortar cement. Piping penetrations are constructed of flanged carbon steeL lined with FRP inserts set solidly in the mortar or, at the users option, of suitable alloy. Embedded alloy bolting and plates are provided as required for the attachment of expansion joints, agitators, platforming, piping supports, ladders or other structures. The inherent strength of reinforced concrete construction permits the support of significant loads from the absorber walls.

The Stebbins ceramic tile lined reinforced concrete construction is a cost effective alternative to conventional lined carbon steel or alloy absorbers. This construction has superior resistance to corrosion and abrasion to deliver improved reliability and availability. The tile should be unaffected for the life of the plant, leading to low maintenance cost.

The ceramic tile is resistant to attack from a high chloride environment making it preferable to alloy liners. The ceramic tile is abrasion resistant, even to direct impingement of slurry sprays, making it superior to rubber lining.

Because the individual building components are small an absorber can be constructed of reinforced concrete/Stebbins tile in a more congested area, compared to the area needed for conventional scrubber construction.

The ceramic tile/mortar system is designed to expand after start-up, ensuring that the tile is in compression and the mortar joints are very tight. This nearly eliminates tile cracking. It also reduces lining permeability, insuring the reinforced concrete core will be well protected.

Should leakage occur, it can easily be detected and repaired external to the module while the absorber is in operation. The repair method consists of drilling small holes in the area of the leaks to a depth of approximately 2", installing a 1/4" PVC nipple and pumping a catalyzed epoxy resin or a colloid into the affected area. This mixture solidifies along the path of the leak forming an effective and permanent plug.

The reinforced concrete/tile construction is inherently immune to damage from high temperature due to excellent thermal shock resistance. Thermal excursions due to power outages and/or air heater failures have often caused catastrophic failure of conventional lining systems.

The split module absorber concept was developed to provide the operational advantages of two separate absorber modules but at considerable savings of capital cost and plot space. The absorber has a central vertical wall dividing it into two independent module halves. Each half is dedicated to one of two boilers with a separate inlet duct and outlet flue. Each half of the split module is functionally equivalent to an independent absorber module with its own set of scrubber recycle pumps, agitators, absorber sprays, limestone and formic acid feed pipes, oxidation air feed pipes, etc.

Having a split module absorber, with one-half dedicated to each boiler, *permits internal inspection and maintenance of the modules during* regularly scheduled individual boiler outages. The split module absorber design provides the same opportunities for inspection and maintenance as the two module design and the ability to achieve 100 percent availability. However, because the central dividing wall is common to both module halves, the total cost of the split module is less than the cost of two separate modules (the thickness of the central dividing wall is the same as the side walls). In addition, because no space is required between the module halves, the split module design has a footprint that is about 15 percent smaller than that of the two module design. For the below-stack design this space savings translates to cost savings due to the proximity of the absorber outlets at the base of the stack.

ABB Air Preheater Heat Pipe Air Heater System Using CAPCIS Corrosion Monitoring

Demonstration of the energy savings provided by a heat pipe air heater installation on a utility boiler is another feature of this project. The heat pipe is an innovative replacement option for the Ljungstrom air heater on Unit 2. The replacement provides energy savings by significantly reducing air leakage across the air heater and by allowing lower average exit gas temperatures. The heat pipe air heater will also utilize the CAPCIS corrosion monitoring system and damper bypass system to control the air heater discharge temperature. This project will demonstrate the energy efficiency and conservation gains achievable by incorporating this total system.

The heat pipe heat exchanger system is composed of a heat pipe exchanger and a continuous corrosion monitor to control the air heater bypass. The heat pipe exchanger is composed of rows of finned tubes, arranged in parallel rows, set perpendicularly to the flue gas and combustion air flows. The gas and air flow counter currently over the tubes. The tubes are filled with a heat transfer fluid. The heat from the flue gas is transferred through the tube to the fluid, which evaporates. The vapor flows up the tube where it is condensed after transferring its heat to the combustion air. The fluid then returns to the evaporator end and repeats the cycle. This arrangement eliminates air leakage to the flue gas and greatly reduces the potential for corrosion. The CAPCIS probe measures the voltage and current generated by corrosion. By monitoring the electrical signals, the probe can detect corrosion and determine the rate of corrosion. The CAPCIS probe, and the associated computer, will control the heat pipe air heater gas bypass dampers, based on an acceptable rate of corrosion. The combination of the two technologies will allow the boiler to run at higher thermal efficiencies, while maintaining the integrity of the equipment downstream of the air heater. This demonstration will also show a significant reduction in plant waste water because of the reduced frequency of air heater washing. It is anticipated that over one and a half million gallons less waste water will be produced during the three-year demonstration period.

Nalco FuelTech NO_xOUT® SNCR Process

The Milliken project will include demonstration of the NO_xOUT® urea injection, selective non-catalytic reduction (SNCR) technology for control of NO_x emissions on Unit 2. The NO_xOUT® process is offered by Nalco FuelTech. The NO_xOUT® process is a new chemical and mechanical system for cost-effective NO_x reduction from fossil-fueled and waste-fueled combustion sources. From 1976 to 1981, research sponsored by the Electric Power Research Institute (EPRI) established that urea was an effective agent to convert NO_x into harmless nitrogen, carbon dioxide, and water, via equations (1) and (2).

(1) $NO + NH_2CONH_2 + 1/2\ 0_2 \rightarrow 2N_2 + CO_2 + 2H_2O$

(2) $2NO + 2NH_2CONH_2 + O2 \rightarrow 3N_2 + 2CO_2 + 4H_2O$

The reaction listed in equation (1) takes place only in a narrow temperature range, 1600°F to 2100°F, below which ammonia (NH_3) is formed, and above which NO_x emission levels actually increase.

The NO_xOUT® process uses patented chemical enhancers and mechanical modifications to widen the temperature range over which the process is effective and to control the formation of ammonia.

The NO_xOUT® process includes:

- the proprietary computer codes to ensure that the NO_xOUT® chemicals are optimally distributed in the boiler;

- the control hardware and software to enable the NO_xOUT® process to follow boiler load changes by altering the flow rate and chemical composition of the urea-based reagent; and,

- the chemical feed, storage, mixing, metering, and pumping systems.

The Nalco FuelTech NO_xOUT® module system is a versatile group of pre-engineered modularized component assemblies which are combined to produce a complete NO_xOUT® treatment facility. The modules are:

- Supply Module: This chemical supply component may be either Porta-Feed returnable, stainless steel vessels or a permanent storage tank fitted with heat tracing and insulation for outdoor installations.

- Circulation Module: This component is used both to supply NO_xOUT® chemical to the Metering/Mixing Module(s) and to provide continuous recirculation of the stored chemical. The circulation Module may be equipped with an additional heater.

- Metering/Mixing Module: This component contains all pumps, piping and controls needed to accurately meter and mix NO_xOUT® chemical and water. Additional units may be grouped together for specific installations to provide spare units, additional capacity or dedicated multi-level systems. All feature the ability to be operated locally or automatically and to proportion the injection rate in response to external signals. They include safety features such as automatic alarms and flush systems.

- Distribution Module: The Distribution Module provides air and fluid flow control for each injection lance. Modules can be arranged as an individual component for each lance or be assembled into a central station.

- Injection Module: These components are specially designed for high temperature applications and provide control of droplet size, exit velocity, and spray shape to meet the parameters established by Nalco FuelTech NO_xOUT® Process Models.

7.2 EXPECTED MARKET APPLICATIONS

The Milliken Clean Coal Demonstration Project will provide widespread application to several US markets.

7.2.1 S-H-U Technology

The S-H-U technology has wide-spread application within the utility and industrial market. With slight modification, this process has been used in Europe to successfully reduce SO_2 emissions generated from boilers fired with lignite, oil and gas; industrial boilers; and also in municipal waste incinerators. This process also has the potential for use in reducing SO_2 emissions associated with coal gasification and shale oil retorting.

7.2.2 Stebbins Tile

Stebbins reinforced concrete/ceramic tile absorber module construction is applicable to the retrofit and grass roots wet lime and wet limestone utility and industrial FGD markets. Its life-cycle costs compare favorably with lined carbon steel and alloy construction, with which it would compete. The construction method is suitable for single or split absorber modules from less than 100 to greater than 500 MW equivalent, making it applicable to most, it not all, utility wet FGD retrofit and grass roots installations.

7.2.3 ABB Air Preheater Heat Pipe Air Heater System

The expected market application of the heat pipe air heater technology can be applied to replacement of existing regenerative and tubular air heaters in sizes equivalent to Milliken's as well as smaller sizes and sizes up to twice Milliken's where leakage improvement and efficiency improvement are desired.

A primary target will be in retrofit applications where reduced air flow will allow downsizing of new downstream emission control equipment.

The size of the heat pipe air heater demonstrated can be used on much larger stations if the air preheat arrangement is sub-divided. A split back-pass 400 MW boiler could be retrofit with two heat pipe air heater modules of the size demonstrated.

It is also expected that the market application will include the heat pipe air heater both with and without corrosion monitoring features. The heat pipe air heater also has an expected market application in new facilities. The advantages are the same as in retrofit applications, and the benefit may be greater where the plant is designed with the heat pipe air heater.

7.2.4 Nalco FuelTech NO_xOUT® SNCR System

Market applications resulting from this project would include any tangentially fired boiler that fires medium to high sulfur coal. Additional demonstration of the technology would be expected to expand the market to all types of boilers including cyclones and stokers. The size of the application is not limited by the size of the NO_xOUT® system since the system is modular and can be made as large, or small, as required. The NO_xOUT® system could be used in conjunction with, or in lieu of, combustion modifications, selective catalytic reduction (SCR) units (to reduce the size of the SCR system) or low NO_x burners.

As a stand-alone removal technology, the NO_xOUT® process could have the lowest cost per ton of NO_x removed when the consequences of other technologies are considered.

Combustion modifications used alone, either over-fired air ports or low NO_x burners, usually increase the amount of carbon in fly ash, commonly referred to as loss on ignition (LOI), and can cause severe changes in the slagging characteristics of the boiler. Utilities that are concerned about the quality of their fly ash and the performance and reliability of their boilers may use the NO_xOUT® trim control system. Fly ash with low LOI's, usually less than three percent of carbon in the ash, can be used as a pozzolonic material in the manufacture of concrete. The sole use of combustion modifications to reduce NO_x could double the carbon content of the ash, causing the fly ash to be unmarketable, requiring land filling of the ash. Consequently, any utility that is interested in reducing solid waste may choose to limit NO_x reductions achieved by combustion modification to a level consistent with fly ash sales and use the NO_xOUT® process to trim the NO_x to the desired level.

The slagging problems that could be experienced by combustion modifications can not be predicted accurately. Increased slagging in the furnace would increase the furnace exit gas temperature (FEGT). The higher steam temperatures prior to the finishing superheat/reheat may require attemperation, which reduces cycle efficiency, to maintain steam conditions at the turbine inlet. The higher FEGT will cause increases in back-pass temperatures. The flue gas exit temperature will increase which reduces boiler efficiency. The use of the NO_xOUT® process in combination with combustion modifications may reduce excessive slagging in the furnace while achieving design NO_x emission reduction.

Another problem with combustion modifications would be the distinct possibility of losing the flame in staged combustion modifications. With overfired air ports, the burners will operate with no excess air. Any problems in the burner control systems, or operator error, could produce a hazardous condition if the flame were lost. The combination of NO_xOUT® with combustion technologies will allow higher combustion oxygen levels and hence better boiler performance while maintaining NO_x levels similar to those achieved by operating at low oxygen levels.

Finally, combustion modifications can increase carbon monoxide (CO) in the flue gas if the operators do not closely monitor boiler performance. Carbon monoxide is an atmospheric pollutant and is an indicator of incomplete combustion.

Rather than relying solely on combustion modifications, we believe that utilities will use NO_xOUT® in combination with combustion modifications because this combination has the lowest capital cost per ton of NO_x removed, the least effect on boiler slagging, maintains boiler and cycle efficiency, and requires the least monitoring and control.

Selective Catalytic Reduction (SCR) is the other NO_x removal technology that would be considered for large scale NO_x reduction. SCR installations have a very high capital cost. Typically, SCR installations are too large to be installed inside the boiler building. The installation would also require significant structural steel. Since the SCR would be external to the plant, new duct work would have to be installed between the economizer and the air heater, assuming hot-side SCR were installed. If cold-side SCR were installed, the flue gas would have to be reheated to 650°F, which would reduce plant thermal efficiency. SCR would increase the pressure drop across the system and could require significant induced draft fan upgrades. SCR catalysts have a predicted life of two to five years in coal-fired applications and significantly increase the solid waste production of the plant when the catalyst is replaced. Also, the spent catalyst is a hazardous waste and cannot be landfilled in the same manner as fly ash, assuming that a non-regenerable catalyst is used. Finally, hot-side SCR installations can promote the formation of ammonium bisulfate in the air heaters and can cause air heater fouling and increased particulate loading on the particulate air control device, which inevitably increases solid waste production.

MILLIKEN CLEAN COAL TECHNOLOGY DEMONSTRATION PROJECT

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