EPA/600/7-90/021b
November 1990

RETROFIT COSTS FOR SO_2 AND NO_X CONTROL OPTIONS AT 200 COAL-FIRED PLANTS

VOLUME II - SITE SPECIFIC STUDIES FOR
Alabama, Delaware, Florida, Georgia, Illinois

by
T. Emmel and M. Maibodi
Radian Corporation
Post Office Box 13000
Research Triangle Park, NC 27709

EPA Contract No. 68-02-4286
Work Assignment 116

Project Officer

Norman Kaplan
U. S. Environmental Protection Agency
Air and Energy Engineering Research Laboratory
Research Triangle Park, North Carolina 27711

AIR AND ENERGY ENGINEERING RESEARCH LABORATORY
OFFICE OF RESEARCH AND DEVELOPMENT
U.S. ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before comple

1. REPORT NO. EPA/600/7-90/021b	2.	PB91-133330
4. TITLE AND SUBTITLE Retrofit Costs for SO_2 and NO_x Control Options at 200 Coal-fired Plants; Volume II - Site Specific Studies for AL, DE, FL, GA, IL		5. REPORT DATE November 1990
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) Thomas E. Emmel and Mehdi Maibodi		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Radian Corporation, P.O. Box 13000, Research Triangle Park, North Carolina 27709		10. PROGRAM ELEMENT NO.
		11. CONTRACT/GRANT NO. 68-02-4286, Task 116
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development, Air and Energy Engineering Research Laboratory, Research Triangle Park, North Carolina 27711		13. TYPE OF REPORT AND PERIOD COVERED Task Final; 1985-1990
		14. SPONSORING AGENCY CODE EPA/600/13

15. SUPPLEMENTARY NOTES AEERL project officer is Norman Kaplan, Mail Drop 62, 919/541-2556. This is one of five volumes and three diskettes comprising this report.

16. ABSTRACT The report gives results of a study, the objective of which was to significantly improve engineering cost estimates currently being used to evaluate the economic effects of applying SO2 and NOx controls at 200 large SO2-emitting coal-fired utility plants. To accomplish the objective, procedures were developed and used that account for site-specific retrofit factors. The site-specific information was obtained from aerial photographs, generally available data bases, and input from utility companies. Cost estimates are presented for six control technologies: lime/limestone flue gas desulfurization, lime spray drying, coal switching and cleaning, furnace and duct sorbent injection, low NOx combustion or natural gas reburn, and selective catalytic reduction. Although the cost estimates provide useful site-specific cost information on retrofitting acid gas controls, the costs are estimated for a specific time period and do not reflect future changes in boiler and coal characteristics (e.g., capacity factors and fuel proces) or significant changes in control technology and performance.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Pollution	Electric Power Plants	Pollution Control	13B 10B
Silfur Dioxide		Stationary Sources	07B
Nitrogen Oxides		Retrofits	
Cost Estimates			05A, 14A
Coal			21D
Combustion			21B

18. DISTRIBUTION STATEMENT Release to Public	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 446
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE

EPA Form 2220-1 (9-73)

ABSTRACT

This report documents the results of a study conducted under the National Acid Precipitation Assessment Program by the U.S. Environmental Protection Agency's Air and Energy Engineering Research Laboratory. The objective of this research program was to significantly improve engineering cost estimates currently being used to evaluate the economic effects of applying sulfur dioxide and nitrogen oxides controls at 200 large sulfur dioxide emitting coal-fired utility plants. To accomplish the objective, procedures were developed and used that account for site-specific retrofit factors. The site-specific information was obtained from aerial photographs, generally available data bases, and input from utility companies. Cost estimates are presented for the following control technologies: lime/limestone flue gas desulfurization, lime spray drying, coal switching and cleaning, furnace and duct sorbent injection, low NO_x combustion or natural gas reburn, and selective catalytic reduction. Although the cost estimates provide useful site-specific cost information on retrofitting acid gas controls, the costs are estimated for a specific time period and do not reflect future changes in boiler and coal characteristics (e.g., capacity factors and fuel prices) or significant changes in control technology cost and performance.

NOTICE

TABLE OF CONTENTS

VOLUME I - INTRODUCTION AND METHODOLOGY

VOLUME II - SITE SPECIFIC STUDIES FOR
Alabama, Delaware, Florida, Georgia, Illinois

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

VOLUME III - SITE SPECIFIC STUDIES FOR
Indiana, Kentucky, Massachusetts, Maryland, Michigan, Minnesota

VOLUME IV - SITE SPECIFIC STUDIES FOR
Missouri, Mississippi, North Carolina, New Hampshire,
New Jersey, New York, Ohio

VOLUME V - SITE SPECIFIC STUDIES FOR
Pennsylvania, South Carolina, Tennessee, Virginia,
Wisconsin, West Virginia

LIST OF FIGURES

LIST OF TABLES

LIST OF TABLES (Continued)

LIST OF TABLES (Continued)

LIST OF TABLES (Continued)

LIST OF TABLES (Continued)

LIST OF TABLES (Continued)

LIST OF TABLES (Continued)

TABLES | PAGE

LIST OF TABLES (Continued)

LIST OF TABLES (Continued)

LIST OF TABLES (Continued)

LIST OF TABLES (Continued)

ABBREVIATIONS AND SYMBOLS

ABBREVIATIONS

acfm	-- actual cubic feet per minute
AEERL	-- Air and Energy Engineering Research Laboratory
AEP	-- Associated Electric Cooperative
AFDC	-- allowance for funds during construction
AUSM	-- advanced utility simulation model
-C	-- constant dollars in cost tables
CG	-- coal gasfication
CG&E	-- Cincinnati Gas and Electric
CS	-- coal switching
CS/B	-- coal switching and blending
DOE	-- Department of Energy
DSD	-- duct spray drying
EIA-767	-- Energy Information Administration Form 767
EPA	-- Environmental Protection Agency
EPRI	-- Electric Power Research Institute
ESP	-- electrostatic precipitator
FBC	-- fluidized bed combustion
FF	-- fabric filter
FGD	-- flue gas desulfurization
FPD	-- fuel price differential
FSI	-- furnace sorbent injection
ft	-- feet
FWF	-- front, wall-fired
IAPCS	-- Integrated Air Pollution Control System

IRS	-- Internal Revenue Service
KU	-- Kentucky Utilities
kW	-- kilowatt
kWh	-- killowatt hour
LC	-- low cost
LIMB	-- limestone injection multistage burner
L/LS	-- lime/limestone
LNB	-- low-NO_x burner
LNC	-- low-NO_x combustion
LSD	-- lime spray drying
m	-- meter
MM	-- millions
MW	-- megawatt
NAPAP	-- National Acid Precipitation Assessment Program
NGR	-- natural gas reburning
NRDC	-- Natural Resources Defense Council
NSPS	-- new source performance standard
NTIS	-- National Technical Information Service
OEUI	-- Ohio Electric Utilities
OFA	-- overfire air
OWF	-- opposed, wall-fired
O&M	-- operating and maintenance
PCC	-- physical coal cleaning
PM	-- particulate matter
psia	-- pounds per square inch absolute

SCA	--	specific collection area (ft^2/1000 acfm)
SCR	--	selective catalytic reduction
SCR-CS	--	selective catalytic reduction - cold side
SCR-HS	--	selective catalytic reduction - hot side
sec	--	second
SI	--	sorbent injection
sq ft	--	square feet
TAG	--	Technical Assessment Guideline
TVA	--	Tennessee Valley Authority
UARG	--	Utility Air Regulatory Group
USGS	--	U.S. Geological Survey
$/kW	--	dollars per kilowatt

SYMBOLS

MgO	--	magnesium oxide
NH_3	--	ammonia
NO_x	--	nitrogen oxides
SO_2	--	sulfur dioxide
SO_3	--	sulfur trioxide

ACKNOWLEDGEMENT

We would like to thank the following people at Radian Corporation who helped in the preparation of this report: Robert Page, Susan Squire, JoAnn Gilbert, Linda Cooper, Sarah Godfrey, Kelly Martin, Karen Oliver, and Janet Mangum.

METRIC EQUIVALENTS

Readers more familiar with the metric system may use the following factors to convert to that system.

Non-metric	Times	Yields Metric
acfm	0.028317	acms
acre	4046.9	m^2
Btu/lb	0.5556	kg-calories/kg
°F	5/9 (°F-32)	°C
ft	0.3048	m
ft^2	0.0929	m^2
ft^3	0.028317	m^3
gal.	3.78533	L
lb/MMBtu	1.8	kg/kg-calorie
psia	0.0703	g/cm^2
ton	0.9072	ton

SECTION 3.0 ALABAMA

3.1 ALABAMA POWER COMPANY

3.1.1 Barry Steam Plant

The Barry steam plant is located within Mobile County, Alabama, as part of the Alabama Power Company system. The plant is located adjacent to the Mobile River and contains five coal-fired boilers with a total gross generating capacity of 1,525 MW.

Table 3.1.1-1 presents operational data for the existing equipment at the Barry plant. The boilers burn low sulfur coal. Coal shipments are received by barge and unloaded through a water channel to a coal storage and handling area west of the plant and close to the river.

PM emissions for the boilers are controlled with retrofit ESPs located behind old ESPs. Units 1-3 have hot side ESPs. The plant has a wet fly ash handling system and ash is disposed of in an ash pond southeast of the plant. Units 1-3 are ducted to a common retrofit chimney and units 4 and 5 have separate chimneys. Two old chimneys behind units 1-3 are left intact along with the old ESPs. The following evaluation is based on a 1980 aerial photograph of the plant. Any additions to the plant layout since that time should be taken into consideration.

Lime/Limestone and Lime Spray Drying FGD Costs--

The five boilers are located beside each other adjacent to the river. The absorbers for units 1-3 would be located close to unit 1 between the common chimney and the coal pile and adjacent to the employee parking area. The absorbers for units 4 and 5 would be located on the other side of the plant (to the east) and adjacent to the unit 5 chimney. The limestone preparation, storage, and handling area would be located behind the unit 1-3 absorbers. A plant road and part of the employee parking area would have to be relocated for unit 1-3 absorbers; therefore, a factor of 10 percent was assigned to general facilities. For unit 4-5 absorbers, some storage buildings and oil tanks would have to be demolished and relocated; as such,

TABLE 3.1.1-1. BARRY STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1, 2	3	4	5
GENERATING CAPACITY (MW,EACH)	125	225	350	700
CAPACITY FACTOR (PERCENT)	65,67	74	57	76
INSTALLATION DATE	1954	1959	1969	1971
FIRING TYPE		TANGENTIAL		
FURNACE VOLUME (1000 CU FT)	93	147	NA	334
LOW NOx COMBUSTION		NO		
COAL SULFUR CONTENT (PERCENT)		0.8		
COAL HEATING VALUE (BTU/LB)		12,000		
COAL ASH CONTENT (PERCENT)		13.0		
FLY ASH SYSTEM		WET SLUICE		
ASH DISPOSAL METHOD		PONDS/ON-SITE		
STACK NUMBER	1	1	2	3
COAL DELIVERY METHODS		BARGE		
PARTICULATE CONTROL				
TYPE		ESP		
INSTALLATION DATE		1976		
EMISSION (LB/MM BTU)	0.05	0.04	0.01	NA
REMOVAL EFFICIENCY	NA	99.9	99.9	99.9
DESIGN SPECIFICATION				
SULFUR SPECIFICATION (PERCENT)	0.7 to 5.0		0.5 to 3.0	
SURFACE AREA (1000 SQ FT)	183.6	316.6	451.2	635.0
GAS EXIT RATE (1000 ACFM)	714	1274	1367	2427
SCA (SQ FT/1000 ACFM)	257	249	330	262
OUTLET TEMPERATURE (°F)	655	721	269	266

a factor of 10 percent was assigned to general facilities for these absorbers. A low site access/congestion factor was assigned to all of the FGD absorber locations reflecting the easy accessibility to the absorber locations and the low congestion.

For units 1-3 and 5, short duct runs would be required for L/LS-FGD cases (about 100 to 300 feet) and a low site access/congestion factor was also assigned to the flue gas handling system because of no major obstacles/obstructions in the surrounding areas. Absorbers for unit 4 would be placed beside unit 5 ESPs resulting in a duct length of 500 feet and a new chimney for this unit. A high site access/congestion factor was assigned to the unit 4 flue gas handling system because the unit 4 chimney and unit 5 ESP makes access difficult. The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Tables 3.1.1-2 through 3.1.1-4.

LSD with reuse of the existing ESPs was not considered for units 1-4. Units 1, 2, and 3 have hot side ESPs and for unit 4 reuse of the existing ESPs would be very difficult. Therefore, LSD with a new baghouse was considered for units 1-4. LSD with reuse of the existing ESPs was considered for unit 5. The absorbers and new baghouses for all units would be located in similar locations as the absorbers in the L/LS-FGD case. For all units, moderate flue gas handling duct lengths were required. For all units, the locations of the baghouses would be close to the absorbers and, as such, a low site access/congestion factor was assigned to these locations.

FGD cost estimates for the Barry plant are not presented because it is unlikely that the current low sulfur coal would be used if scrubbing were required. FGD cost estimates based on the current coal would result in low estimates of capital/operating costs and high cost effectiveness values.

Coal Switching and Physical Coal Cleaning Costs--

Because the Barry plant is already using low sulfur coal, CS and PCC were not considered in this study.

TABLE 3.1.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR BARRY UNITS 1, 2, OR 3

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			NA
BAGHOUSE			100-300
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	1145,1940	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.16
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	10	0	10

TABLE 3.1.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR BARRY UNIT 4

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			
BAGHOUSE CASE			HIGH
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			NA
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	2882	NA	NA
NEW CHIMNEY	YES	NA	NO
ESTIMATED COST (1000$)	2450	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.48	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.36
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	10	0	10

TABLE 3.1.1-4. SUMMARY OF RETROFIT FACTOR DATA FOR BARRY UNIT 5

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	5365	NA	5365
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	NA	
ESP REUSE CASE			1.43
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	0	10

Low NO_x Combustion--

Units 1-5 are dry bottom, tangential-fired boilers. The combustion modification technique applied to all boilers was OFA. Table 3.1.1-5 shows the OFA NO_x reduction performance for each unit. Table 3.1.1-6 presents the NO_x cost results of retrofitting OFA at the Barry plant.

Selective Catalytic Reduction--

Hot side SCR reactors for units 1-3 would be located beside unit 1 in a low site access/congestion area. The cold side SCR reactor for unit 4 would be placed behind unit 5 ESPs adjacent to unit 4 ESPs/chimney. A high site access/congestion factor would be assigned to this location due to the limited space available behind unit 5. The cold side SCR reactor for unit 5 would be located adjacent to unit 5 in a low site access/congestion area. For flue gas handling, a duct length of 250 feet would be required for all units. Because units 1-3 have high temperature ESPs, flue gas preheat for the SCR unit is not required. The ammonia storage system was placed close to the sorbent storage preparation area west of the plant. A factor of 20 percent was assigned to general facilities for all units due to the need to relocate plant roads and storage buildings.

Table 3.1.1-5 presents the SCR process area retrofit factors and scope adder costs. Table 3.1.1-6 presents the estimated cost of retrofitting SCR at the Barry boilers.

Duct Spray Drying and Furnace Sorbent Injection--

DSD and FSI with ESP reuse were not evaluated for units 1-3 because these units have hot side ESPs. For unit 4, it appears that sufficient duct residence time is available between the boilers and the retrofit ESPs or the old ESPs could be used for sorbent injection or humidification. By contrast, for unit 5, there does not appear to be sufficient duct residence time between the boiler and the ESPs. However, sorbent injection was evaluated because the first ESP section could be modified for sorbent injection or humidification and additional plate area could be added downstream of the ESPs. A high site access/congestion factor was assigned for upgrading the ESPs for unit 4 because of the access difficulty to the existing ESPs. A

TABLE 3.1.1-5. SUMMARY OF NOx RETROFIT RESULTS FOR BARRY

	BOILER NUMBER			
COMBUSTION MODIFICATION RESULTS				
	1,2	3	4	5
FIRING TYPE	TANG	TANG	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA	OFA	OFA
FURNACE VOLUME (1000 CU FT)	93	147	NA	334
BOILER INSTALLATION DATE	1954	1959	1969	1971
SLAGGING PROBLEM	NO	NO	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	25	25	25	25
SCR RETROFIT RESULTS				
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	HIGH	LOW
SCOPE ADDER PARAMETERS--				
New Chimney (1000$)	0	0	0	0
Ductwork Demolition (1000$)	32	50	69	116
New Duct Length (Feet)	250	250	250	250
New Duct Costs (1000$)	1411	1991	2578	3867
New Heat Exchanger (1000$)	0	0	3952	5991
TOTAL SCOPE ADDER COSTS (1000$)	1443	2041	6599	9974
RETROFIT FACTOR FOR SCR	1.16	1.16	1.52	1.16
GENERAL FACILITIES (PERCENT)	20	20	20	20

Table 3.1.1-6. NOx Control Cost Results for the Barry Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	1	1.00	125	65	0.8	0.7	5.4	0.1	0.2	25.0	552	259.2
LNC-OFA	2	1.00	125	67	0.8	0.7	5.4	0.1	0.2	25.0	569	251.4
LNC-OFA	3	1.00	225	74	0.8	0.9	3.8	0.2	0.1	25.0	1131	160.1
LNC-OFA	4	1.00	350	57	0.8	1.0	2.9	0.2	0.1	25.0	1356	159.3
LNC-OFA	5	1.00	700	76	0.8	1.3	1.9	0.3	0.1	25.0	3615	78.8
LNC-OFA-C	1	1.00	125	65	0.8	0.7	5.4	0.1	0.1	25.0	552	154.0
LNC-OFA-C	2	1.00	125	67	0.8	0.7	5.4	0.1	0.1	25.0	569	149.4
LNC-OFA-C	3	1.00	225	74	0.8	0.9	3.8	0.1	0.1	25.0	1131	95.1
LNC-OFA-C	4	1.00	350	57	0.8	1.0	2.9	0.1	0.1	25.0	1356	94.6
LNC-OFA-C	5	1.00	700	76	0.8	1.3	1.9	0.2	0.0	25.0	3615	46.8
SCR-3	1	1.16	125	65	0.8	20.9	167.5	7.1	9.9	80.0	1767	4002.7
SCR-3	2	1.16	125	67	0.8	20.9	167.6	7.1	9.7	80.0	1821	3891.2
SCR-3	3	1.16	225	74	0.8	31.4	139.4	11.2	7.7	80.0	3621	3100.1
SCR-3	4	1.52	350	57	0.8	56.4	161.1	18.6	10.7	80.0	4338	4295.2
SCR-3	5	1.16	700	76	0.8	83.4	119.2	31.2	6.7	80.0	11568	2694.6
SCR-3-C	1	1.16	125	65	0.8	20.9	167.5	4.1	5.8	80.0	1767	2346.5
SCR-3-C	2	1.16	125	67	0.8	20.9	167.6	4.2	5.7	80.0	1821	2281.0
SCR-3-C	3	1.16	225	74	0.8	31.4	139.4	6.6	4.5	80.0	3621	1815.0
SCR-3-C	4	1.52	350	57	0.8	56.4	161.1	10.9	6.3	80.0	4338	2519.1
SCR-3-C	5	1.16	700	76	0.8	83.4	119.2	18.2	3.9	80.0	11568	1576.2
SCR-7	1	1.16	125	65	0.8	20.9	167.5	6.0	8.5	80.0	1767	3421.5
SCR-7	2	1.16	125	67	0.8	20.9	167.6	6.1	8.3	80.0	1821	3327.3
SCR-7	3	1.16	225	74	0.8	31.4	139.4	9.4	6.4	80.0	3621	2589.5
SCR-7	4	1.52	350	57	0.8	56.4	161.1	15.8	9.0	80.0	4338	3632.3
SCR-7	5	1.16	700	76	0.8	83.4	119.2	25.4	5.5	80.0	11568	2197.4
SCR-7-C	1	1.16	125	65	0.8	20.9	167.5	3.6	5.0	80.0	1767	2013.5
SCR-7-C	2	1.16	125	67	0.8	20.9	167.6	3.6	4.9	80.0	1821	1957.9
SCR-7-C	3	1.16	225	74	0.8	31.4	139.4	5.5	3.8	80.0	3621	1522.4
SCR-7-C	4	1.52	350	57	0.8	56.4	161.1	9.3	5.3	80.0	4338	2139.3
SCR-7-C	5	1.16	700	76	0.8	83.4	119.2	14.9	3.2	80.0	11568	1291.3

moderate access/congestion difficulty factor was assigned for upgrading the unit 5 ESP.

Tables 3.1.1-7 and 3.1.1-8 present a summary of the site access/congestion factors for FSI and DSD technologies at the Barry steam plant. Table 3.1.1-9 presents the costs estimated to retrofit sorbent injection technologies at the Barry boilers. Because the plant is burning low sulfur coal, the estimated unit costs are high.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Barry plant. Units 1-3 would be considered good candidates for repowering/retrofit because of their small boiler sizes. Units 4 and 5 would not be considered good candidates because they are more than 300 MW units. All units have high capacity factors making the cost of repowering less attractive due to downtime cost (replacement power).

TABLE 3.1.1-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR BARRY UNIT 4

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	2882
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	77

TOTAL COST (1000$)	
ESP UPGRADE CASE	2959
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

TABLE 3.1.1-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR BARRY UNIT 5

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	MEDIUM
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	5365
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	129
TOTAL COST (1000$)	
ESP UPGRADE CASE	5494
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.36
NEW BAGHOUSE	NA

Table 3.1.1-9. Summary of DSD/FSI Control Costs for the Barry Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	4	1.00	350	57	0.8	14.7	42.0	8.6	4.9	46.0	5234	1646.2
DSD+ESP	5	1.00	700	76	0.8	26.3	37.6	16.3	3.5	46.0	13764	1183.1
DSD+ESP-C	4	1.00	350	57	0.8	14.7	42.0	5.0	2.9	46.0	5234	955.7
DSD+ESP-C	5	1.00	700	76	0.8	26.3	37.6	9.4	2.0	46.0	13764	686.4
FSI+ESP-50	4	1.00	350	57	0.8	15.4	44.0	8.2	4.7	50.0	5640	1462.0
FSI+ESP-50	5	1.00	700	76	0.8	29.7	42.4	17.8	3.8	50.0	15039	1183.0
FSI+ESP-50-C	4	1.00	350	57	0.8	15.4	44.0	4.8	2.7	50.0	5640	849.8
FSI+ESP-50-C	5	1.00	700	76	0.8	29.7	42.4	10.3	2.2	50.0	15039	686.6
FSI+ESP-70	4	1.00	350	57	0.8	15.5	44.3	8.4	4.8	70.0	7895	1057.8
FSI+ESP-70	5	1.00	700	76	0.8	29.9	42.7	18.1	3.9	70.0	21054	857.6
FSI+ESP-70-C	4	1.00	350	57	0.8	15.5	44.3	4.9	2.8	70.0	7895	614.9
FSI+ESP-70-C	5	1.00	700	76	0.8	29.9	42.7	10.5	2.2	70.0	21054	497.7

3.1.2 Gadsden Steam Plant

The Gadsden Steam Plant is located in Etowah County, Alabama, as part of the Alabama Power Company system. The plant contains two coal-fired boilers with a total gross generating capacity of 120 MW. Tables 3.1.2-1 through 3.1.2-8 summarize the plant operational data and present the SO_2 and NO_x control cost and performance estimates.

TABLE 3.1.2-1. GADSDEN STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2
GENERATING CAPACITY (MW)	60
CAPACITY FACTOR (PERCENT)	48, 75
INSTALLATION DATE	1949
FIRING TYPE	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	NA
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	1.5
COAL HEATING VALUE (BTU/LB)	12500
COAL ASH CONTENT (PERCENT)	11.3
FLY ASH SYSTEM	WET DISPOSAL
ASH DISPOSAL METHOD	POND/ON-SITE
STACK NUMBER	1
COAL DELIVERY METHODS	TRUCK/RAILROAD
PARTICULATE CONTROL	
TYPE	ESP*
INSTALLATION DATE	1975
EMISSION (LB/MM BTU)	0.05, 0.02
REMOVAL EFFICIENCY	99.95
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	NA
SURFACE AREA (1000 SQ FT)	NA
EXIT GAS FLOW RATE (1000 ACFM)	300
SCA (SQ FT/1000 ACFM)	NA
OUTLET TEMPERATURE (°F)	315

* An SCA size of 300 was assumed for both units.

TABLE 3.1.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR GADSDEN UNITS 1 OR 2 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	HIGH
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			100-300
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	593	NA	593
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	NA	
ESP REUSE CASE			1.61
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.37
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	0	8

* L/S-FGD absorbers for units 1 and 2 would be located south of the common chimney for units 1 and 2. LSD-FGD absorbers would be located beside the unit ESPs.

Table 3.1.2-3. Summary of FGD Control Costs for the Gadsden Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.27	60	48	1.5	29.1	484.5	11.8	46.6	90.0	2622	4488.4
L/S FGD	2	1.27	60	75	1.5	29.1	484.8	12.8	32.4	90.0	4097	3117.5
L/S FGD	1-2	1.27	120	62	1.5	41.0	341.5	17.5	26.9	90.0	6773	2588.2
L/S FGD-C	1	1.27	60	48	1.5	29.1	484.5	6.9	27.2	90.0	2622	2621.3
L/S FGD-C	2	1.27	60	75	1.5	29.1	484.8	7.4	18.9	90.0	4097	1818.0
L/S FGD-C	1-2	1.27	120	62	1.5	41.0	341.5	10.2	15.7	90.0	6773	1510.0
LC FGD	1-2	1.27	120	62	1.5	28.6	238.1	13.8	21.1	90.0	6773	2032.6
LC FGD-C	1-2	1.27	120	62	1.5	28.6	238.1	8.0	12.3	90.0	6773	1183.5
LSD+ESP	1	1.61	60	48	1.5	13.6	225.9	6.4	25.5	76.0	2223	2897.7
LSD+ESP	2	1.61	60	75	1.5	13.6	225.9	6.8	17.3	76.0	3473	1967.1
LSD+ESP-C	1	1.61	60	48	1.5	13.6	225.9	3.8	14.9	76.0	2223	1687.5
LSD+ESP-C	2	1.61	60	75	1.5	13.6	225.9	4.0	10.1	76.0	3473	1144.5

Table 3.1.2-4. Summary of Coal Switching/Cleaning Costs for the Gadsden Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	60	48	1.5	2.8	46.5	4.2	16.5	37.0	1092	3812.1
CS/B+$15	2	1.00	60	75	1.5	2.8	46.5	6.1	15.6	37.0	1706	3594.7
CS/B+$15-C	1	1.00	60	48	1.5	2.8	46.5	2.4	9.5	37.0	1092	2195.5
CS/B+$15-C	2	1.00	60	75	1.5	2.8	46.5	3.5	8.9	37.0	1706	2066.9
CS/B+$5	1	1.00	60	48	1.5	2.2	36.1	2.0	7.8	37.0	1092	1803.2
CS/B+$5	2	1.00	60	75	1.5	2.2	36.1	2.8	7.0	37.0	1706	1621.9
CS/B+$5-C	1	1.00	60	48	1.5	2.2	36.1	1.1	4.5	37.0	1092	1042.0
CS/B+$5-C	2	1.00	60	75	1.5	2.2	36.1	1.6	4.0	37.0	1706	934.9

TABLE 3.1.2-5. SUMMARY OF NOx RETROFIT RESULTS FOR GADSDEN

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1, 2
FIRING TYPE	TANG
TYPE OF NOx CONTROL	OFA
FURNACE VOLUME (1000 CU FT)	NA
BOILER INSTALLATION DATE	1949
SLAGGING PROBLEM	NO
ESTIMATED NOx REDUCTION (PERCENT)	25
SCR RETROFIT RESULTS *	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	18
New Duct Length (Feet)	200
New Duct Costs (1000$)	735
New Heat Exchanger (1000$)	1372
TOTAL SCOPE ADDER COSTS (1000$)	
INDIVIDUAL CASE	2125
COMBINED CASE	3213
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	20

* Cold side SCR reactors for units 1 and 2 would be located south of the common chimney for units 1 and 2.

Table 3.1.2-6. NOx Control Cost Results for the Gadsden Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	1	1.00	60	48	1.5	0.5	8.4	0.1	0.4	25.0	187	571.4
LNC-OFA	2	1.00	60	75	1.5	0.5	8.4	0.1	0.3	25.0	292	365.7
LNC-OFA-C	1	1.00	60	48	1.5	0.5	8.4	0.1	0.3	25.0	187	339.5
LNC-OFA-C	2	1.00	60	75	1.5	0.5	8.4	0.1	0.2	25.0	292	217.3
SCR-3	1	1.16	60	48	1.5	14.0	232.6	4.3	17.0	80.0	598	7163.3
SCR-3	2	1.16	60	75	1.5	14.0	232.6	4.4	11.1	80.0	934	4681.6
SCR-3	1-2	1.16	120	62	1.5	21.3	177.2	6.9	10.6	80.0	1544	4488.4
SCR-3-C	1	1.16	60	48	1.5	14.0	232.6	2.5	10.0	80.0	598	4208.7
SCR-3-C	2	1.16	60	75	1.5	14.0	232.6	2.6	6.5	80.0	934	2749.3
SCR-3-C	1-2	1.16	120	62	1.5	21.3	177.2	4.1	6.2	80.0	1544	2633.3
SCR-7	1	1.16	60	48	1.5	14.0	232.6	3.8	15.0	80.0	598	6343.5
SCR-7	2	1.16	60	75	1.5	14.0	232.6	3.9	9.8	80.0	934	4156.9
SCR-7	1-2	1.16	120	62	1.5	21.3	177.2	6.0	9.2	80.0	1544	3879.8
SCR-7-C	1	1.16	60	48	1.5	14.0	232.6	2.2	8.9	80.0	598	3739.0
SCR-7-C	2	1.16	60	75	1.5	14.0	232.6	2.3	5.8	80.0	934	2448.7
SCR-7-C	1-2	1.16	120	62	1.5	21.3	177.2	3.5	5.4	80.0	1544	2284.6

TABLE 3.1.2-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR GADSDEN UNITS 1 OR 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	MEDIUM
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	593
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	20

TOTAL COST (1000$)	
ESP UPGRADE CASE	613
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.36
NEW BAGHOUSE	NA

Medium duct residence time exists between the boilers and their respective ESPs. A medium factor was assigned to ESP upgrade since there is some congestion among the ESPs.

Table 3.1.2-8. Summary of DSD/FSI Control Costs for the Gadsden Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	60	48	1.5	5.3	88.4	4.0	16.0	49.0	1417	2852.0
DSD+ESP	2	1.00	60	75	1.5	5.3	88.4	4.4	11.1	49.0	2215	1984.3
DSD+ESP-C	1	1.00	60	48	1.5	5.3	88.4	2.3	9.3	49.0	1417	1650.8
DSD+ESP-C	2	1.00	60	75	1.5	5.3	88.4	2.5	6.4	49.0	2215	1147.6
FSI+ESP-50	1	1.00	60	48	1.5	5.9	98.2	3.4	13.4	50.0	1457	2313.0
FSI+ESP-50	2	1.00	60	75	1.5	5.9	98.2	3.9	9.9	50.0	2276	1710.0
FSI+ESP-50-C	1	1.00	60	48	1.5	5.9	98.2	2.0	7.8	50.0	1457	1343.4
FSI+ESP-50-C	2	1.00	60	75	1.5	5.9	98.2	2.3	5.7	50.0	2276	991.4
FSI+ESP-70	1	1.00	60	48	1.5	5.9	99.0	3.4	13.5	70.0	2039	1667.8
FSI+ESP-70	2	1.00	60	75	1.5	5.9	99.0	3.9	10.0	70.0	3186	1235.2
FSI+ESP-70-C	1	1.00	60	48	1.5	5.9	99.0	2.0	7.8	70.0	2039	968.6
FSI+ESP-70-C	2	1.00	60	75	1.5	5.9	99.0	2.3	5.8	70.0	3186	716.1

3.1.3 Gaston Steam Plant

The Gaston steam plant is located within Shelby County, Alabama, as part of the Alabama Power Company system. The plant is located on the west bank of the Goosa River and contains five coal-fired boilers with a total gross generating capacity of 1,880 MW.

Table 3.1.3-1 presents operational data for the existing equipment at the Gaston plant. The boilers burn medium sulfur coal. Coal shipments are received by railroad and transferred to a coal storage and handling area south of the plant and adjacent to the river.

PM emissions for all boilers are controlled with retrofit ESPs located behind each unit and close to the river. The plant has a dry fly ash handling system. Fly ash is disposed of in a landfill adjacent to the coal pile. Part of the fly ash is sold. Units 1 through 4 are served by a common chimney located adjacent to unit 1 north of the plant. Unit 5 has its own chimney south of the plant. Four old chimneys, which were serving units 1-4, are left intact behind the units. A coal conveyor stretches from the coal pile to unit 1 runs behind the old chimneys and retrofit ESPs to each unit. The following evaluation is based on a 1981 aerial photograph, and any alterations made to the plant layout since this time should be taken into consideration.

Lime/Limestone and Lime Spray Drying FGD Costs--

The five boilers are located beside each other and parallel to the river. The absorbers for units 1-4 would be located beside the unit 1-4 common chimney to the north of the plant. The absorbers for unit 5 would be located adjacent to its chimney south of the plant. The limestone preparation, storage, and handling area would be located west of the plant and close to the cooling towers. For unit 1-4 absorber locations, part of the employee parking area has to be relocated and, as such, a base factor of 8 percent was assigned to general facilities. For the unit 5 absorber location, some of the oil storage tanks have to be relocated resulting in a 10 percent general facilities.

TABLE 3.1.3-1. GASTON STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2,3,4	5
GENERATING CAPACITY (MW)	250	880
CAPACITY FACTOR (PERCENT)	72,70,60,70	68
INSTALLATION DATE	1960,60,61,62	1974
FIRING TYPE	OPPOSED WALL	TANG
FURNACE VOLUME (1000 CU FT)	NA	400
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	1.4	1.4
COAL HEATING VALUE (BTU/LB)	12,300	12,300
COAL ASH CONTENT (PERCENT)	12.0	12.0
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	ON-SITE/SELL	
STACK NUMBER	1	2
COAL DELIVERY METHODS	RAILROAD	
<u>PARTICULATE CONTROL</u>		
TYPE	ESP	ESP
INSTALLATION DATE	1974-76	1974
EMISSION (LB/MM BTU)	0.05-0.07	0.12
REMOVAL EFFICIENCY	99.1-98.7	98.4
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	NA	NA
SURFACE AREA (1000 SQ FT)	342,363,342,342	1175
GAS EXIT RATE (1000 ACFM)	1250	4100
SCA (SQ FT/1000 ACFM)	274,290,274,274	287
OUTLET TEMPERATURE (°F)	650	630

A medium site access/congestion factor was assigned to all of the FGD absorber locations. For units 1-4 absorbers, this was due to being located close to the water channel and water intake structure (underground obstructions). The medium site access/congestion factor for unit 5 absorber location is due to the coal conveyor and oil storage tanks.

For flue gas handling, short duct runs would be required for the L/LS-FGD cases (about 200 feet) because the absorbers are placed immediately behind the chimneys. Low site access/congestion factors were also assigned to the flue gas handling system because of the easy accessibility to the existing chimneys.

LSD with reuse of the existing ESPs was not considered for this plant because the ESPs operate at temperatures greater than 600°F. This eliminates the benefits of gas cooling/humidification on ESP performance. Additionally, access to the ESPs is extremely difficult and might result in a long boiler downtime. Therefore, LSD with a new baghouse was considered for the Gaston plant. LSD absorbers would be located close to the chimneys and the baghouses would be located adjacent to the absorbers. A medium site access/congestion factor was also assigned to the absorber/baghouse locations.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Tables 3.1.3-2 and 3.1.3-3. Table 3.1.3-4 presents the capital and operating costs for commercial FGD technologies. The low cost FGD option reduces costs for units 1-4 due to the elimination of spare absorber modules and economy of scale that occurs when combining process areas and maximizing absorber size. For unit 5, the low cost option reduces cost due to the elimination of the spare absorbers and increased absorber size.

Coal Switching and Physical Coal Cleaning Costs--

Table 3.1.3-5 presents the IAPCS cost results for CS at the Gaston plant. These costs do not include boiler and pulverizer operating cost changes or any system modifications that may be necessary to blend coal. Coal switching for a fuel price differential of $15 per ton is higher than that of $5 per ton because of inventory capital and preproduction costs,

TABLE 3.1.3-2. SUMMARY OF RETROFIT FACTOR DATA FOR GASTON UNITS 1, 2, 3, OR 4

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	MEDIUM
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	MEDIUM
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.30	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.40
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.37
GENERAL FACILITIES (PERCENT)	8	0	8

TABLE 3.1.3-3. SUMMARY OF RETROFIT FACTOR DATA FOR GASTON UNIT 5

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	MEDIUM
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	MEDIUM
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.30	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.40
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.37
GENERAL FACILITIES (PERCENT)	10	0	10

Table 3.1.3-4. Summary of FGD Control Costs for the Gaston Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.30	250	72	1.4	65.8	263.3	28.8	18.3	90.0	15578	1851.0
L/S FGD	2	1.30	250	70	1.4	65.8	263.3	28.6	18.7	90.0	15145	1889.5
L/S FGD	3	1.30	250	60	1.4	65.8	263.2	27.5	20.9	90.0	12982	2120.4
L/S FGD	4	1.30	250	70	1.4	65.8	263.3	28.6	18.7	90.0	15145	1889.5
L/S FGD	5	1.30	880	68	1.4	150.3	170.8	69.5	13.2	90.0	51789	1341.1
L/S FGD-C	1	1.30	250	72	1.4	65.8	263.3	16.8	10.7	90.0	15578	1079.4
L/S FGD-C	2	1.30	250	70	1.4	65.8	263.3	16.7	10.9	90.0	15145	1102.0
L/S FGD-C	3	1.30	250	60	1.4	65.8	263.2	16.1	12.2	90.0	12982	1237.6
L/S FGD-C	4	1.30	250	70	1.4	65.8	263.3	16.7	10.9	90.0	15145	1102.0
L/S FGD-C	5	1.30	880	68	1.4	150.3	170.8	40.5	7.7	90.0	51789	781.4
LC FGD	1-4	1.30	1000	68	1.4	142.6	142.6	69.9	11.7	90.0	58851	1188.2
LC FGD	5	1.30	880	68	1.4	125.7	142.9	62.1	11.8	90.0	51789	1198.4
LC FGD-C	1-4	1.30	1000	68	1.4	142.6	142.6	40.7	6.8	90.0	58851	691.6
LC FGD-C	5	1.30	880	68	1.4	125.7	142.9	36.1	6.9	90.0	51789	697.5
LSD+FF	1	1.40	250	72	1.4	74.1	296.4	26.8	17.0	87.0	14974	1791.6
LSD+FF	2	1.40	250	70	1.4	74.1	296.4	26.7	17.4	87.0	14558	1831.0
LSD+FF	3	1.40	250	60	1.4	74.1	296.4	25.8	19.6	87.0	12479	2068.2
LSD+FF	4	1.40	250	70	1.4	74.1	296.4	26.7	17.4	87.0	14558	1831.0
LSD+FF	5	1.40	880	68	1.4	237.1	269.4	81.7	15.6	87.0	49782	1641.5
LSD+FF-C	1	1.40	250	72	1.4	74.1	296.4	15.7	10.0	87.0	14974	1048.7
LSD+FF-C	2	1.40	250	70	1.4	74.1	296.4	15.6	10.2	87.0	14558	1071.9
LSD+FF-C	3	1.40	250	60	1.4	74.1	296.4	15.1	11.5	87.0	12479	1211.5
LSD+FF-C	4	1.40	250	70	1.4	74.1	296.4	15.6	10.2	87.0	14558	1071.9
LSD+FF-C	5	1.40	880	68	1.4	237.1	269.4	47.9	9.1	87.0	49782	961.8

Table 3.1.3-5. Summary of Coal Switching/Cleaning Costs for the Gaston Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	250	72	1.4	8.4	33.7	22.4	14.2	34.0	5926	3772.1
CS/B+$15	2	1.00	250	70	1.4	8.4	33.7	21.8	14.2	34.0	5761	3781.1
CS/B+$15	3	1.00	250	60	1.4	8.4	33.7	18.9	14.4	34.0	4938	3834.9
CS/B+$15	4	1.00	250	70	1.4	8.4	33.7	21.8	14.2	34.0	5761	3781.1
CS/B+$15	5	1.00	880	68	1.4	26.2	29.7	72.7	13.9	34.0	19701	3691.1
CS/B+$15-C	1	1.00	250	72	1.4	8.4	33.7	12.8	8.1	34.0	5926	2167.6
CS/B+$15-C	2	1.00	250	70	1.4	8.4	33.7	12.5	8.2	34.0	5761	2172.9
CS/B+$15-C	3	1.00	250	60	1.4	8.4	33.7	10.9	8.3	34.0	4938	2204.8
CS/B+$15-C	4	1.00	250	70	1.4	8.4	33.7	12.5	8.2	34.0	5761	2172.9
CS/B+$15-C	5	1.00	880	68	1.4	26.2	29.7	41.8	8.0	34.0	19701	2120.7
CS/B+$5	1	1.00	250	72	1.4	5.8	23.3	8.9	5.6	34.0	5926	1497.8
CS/B+$5	2	1.00	250	70	1.4	5.8	23.3	8.7	5.7	34.0	5761	1504.6
CS/B+$5	3	1.00	250	60	1.4	5.8	23.3	7.6	5.8	34.0	4938	1545.2
CS/B+$5	4	1.00	250	70	1.4	5.8	23.3	8.7	5.7	34.0	5761	1504.6
CS/B+$5	5	1.00	880	68	1.4	17.1	19.4	27.8	5.3	34.0	19701	1412.2
CS/B+$5-C	1	1.00	250	72	1.4	5.8	23.3	5.1	3.2	34.0	5926	862.6
CS/B+$5-C	2	1.00	250	70	1.4	5.8	23.3	5.0	3.3	34.0	5761	866.6
CS/B+$5-C	3	1.00	250	60	1.4	5.8	23.3	4.4	3.3	34.0	4938	890.6
CS/B+$5-C	4	1.00	250	70	1.4	5.8	23.3	5.0	3.3	34.0	5761	866.6
CS/B+$5-C	5	1.00	880	68	1.4	17.1	19.4	16.0	3.1	34.0	19701	813.0

which are a function of variable costs (e.g. fuel costs). PCC was not evaluated because this is not a mine mouth plant.

Low NO_x Combustion--

Units 1-4 are dry bottom, opposed wall-fired boilers rated at 250 MW each and unit 5 is a dry bottom, tangential-fired boiler rated at 880 MW. The combustion modification technique applied to boilers 1-4 was LNB and for unit 5 was OFA. Tables 3.1.3-6 and 3.1.3-7 present the NO_x performance and cost results of retrofitting LNB and OFA at the Gaston plant. Although boiler volumetric data was not available for units 1-4, a moderate NO_x reduction was assumed to be typical for these boilers.

Selective Catalytic Reduction--

Hot side SCR reactors for all units would be located immediately behind the chimneys in low site access/congestion areas. This is due to the smaller space needed for the SCR reactors compared to the FGD absorbers. A duct length of 250 feet was estimated for the flue gas handling system. The ammonia storage system was placed close to the sorbent storage area adjacent to the air cooling towers. Some plant roads have to be relocated; therefore, a factor of 15 percent was assigned to general facilities.

Table 3.1.3-6 presents the SCR process area retrofit factors and scope adder costs. Table 3.1.3-7 presents the estimated cost of retrofitting SCR at the Gaston boilers.

Duct Spray Drying and Furnace Sorbent Injection--

The retrofit of FSI and DSD technologies at the Gaston steam plant is not feasible. This is due to the inadequate duct residence time between the boilers and the retrofit ESPs for either humidification (for FSI application) or sorbent droplet evaporation (for DSD application). Also, because the ESP temperatures are high (>600^{o}F), gas cooling/humidification would not significantly improve ESP performance and would hurt air heater heat recovery.

TABLE 3.1.3-6. SUMMARY OF NOx RETROFIT RESULTS FOR GASTON

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1,2,3,4	5
FIRING TYPE	OWF	TANG
TYPE OF NOx CONTROL	LNB	OFA
FURNACE VOLUME (1000 CU FT)	NA	400
BOILER INSTALLATION DATE	1960	1974
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	40	35
SCR RETROFIT RESULTS (EACH UNIT)		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	54	138
New Duct Length (Feet)	250	250
New Duct Costs (1000$)	2117	4421
New Heat Exchanger (1000$)	0	0
TOTAL SCOPE ADDER COSTS (1000$)	2171	4559
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	15	15

Table 3.1.3-7. NOx Control Cost Results for the Gaston Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	1	1.00	250	72	1.4	3.7	14.7	0.8	0.5	40.0	2663	292.2
LNC-LNB	2	1.00	250	70	1.4	3.7	14.7	0.8	0.5	40.0	2589	300.6
LNC-LNB	3	1.00	250	60	1.4	3.7	14.7	0.8	0.6	40.0	2219	350.7
LNC-LNB	4	1.00	250	70	1.4	3.7	14.7	0.8	0.5	40.0	2589	300.6
LNC-LNB-C	1	1.00	250	72	1.4	3.7	14.7	0.5	0.3	40.0	2663	173.6
LNC-LNB-C	2	1.00	250	70	1.4	3.7	14.7	0.5	0.3	40.0	2589	178.6
LNC-LNB-C	3	1.00	250	60	1.4	3.7	14.7	0.5	0.4	40.0	2219	208.3
LNC-LNB-C	4	1.00	250	70	1.4	3.7	14.7	0.5	0.3	40.0	2589	178.6
LNC-OFA	5	1.00	880	68	1.4	1.5	1.7	0.3	0.1	35.0	5534	56.4
LNC-OFA-C	5	1.00	880	68	1.4	1.5	1.7	0.2	0.0	35.0	5534	33.5
SCR-3	1	1.16	250	72	1.4	33.3	133.1	12.2	7.7	80.0	5327	2289.6
SCR-3	2	1.16	250	70	1.4	33.3	133.1	12.2	7.9	80.0	5179	2348.5
SCR-3	3	1.16	250	60	1.4	33.3	133.1	12.0	9.1	80.0	4439	2703.0
SCR-3	4	1.16	250	70	1.4	33.3	133.1	12.2	7.9	80.0	5179	2348.5
SCR-3	5	1.16	880	68	1.4	99.1	112.6	37.7	7.2	80.0	12649	2977.0
SCR-3-C	1	1.16	250	72	1.4	33.3	133.1	7.1	4.5	80.0	5327	1339.8
SCR-3-C	2	1.16	250	70	1.4	33.3	133.1	7.1	4.6	80.0	5179	1374.3
SCR-3-C	3	1.16	250	60	1.4	33.3	133.1	7.0	5.3	80.0	4439	1582.2
SCR-3-C	4	1.16	250	70	1.4	33.3	133.1	7.1	4.6	80.0	5179	1374.3
SCR-3-C	5	1.16	880	68	1.4	99.1	112.6	22.0	4.2	80.0	12649	1740.7
SCR-7	1	1.16	250	72	1.4	33.3	133.1	10.1	6.4	80.0	5327	1905.3
SCR-7	2	1.16	250	70	1.4	33.3	133.1	10.1	6.6	80.0	5179	1953.2
SCR-7	3	1.16	250	60	1.4	33.3	133.1	10.0	7.6	80.0	4439	2241.9
SCR-7	4	1.16	250	70	1.4	33.3	133.1	10.1	6.6	80.0	5179	1953.2
SCR-7	5	1.16	880	68	1.4	99.1	112.6	30.5	5.8	80.0	12649	2407.4
SCR-7-C	1	1.16	250	72	1.4	33.3	133.1	6.0	3.8	80.0	5327	1119.6
SCR-7-C	2	1.16	250	70	1.4	33.3	133.1	5.9	3.9	80.0	5179	1147.9
SCR-7-C	3	1.16	250	60	1.4	33.3	133.1	5.9	4.5	80.0	4439	1318.1
SCR-7-C	4	1.16	250	70	1.4	33.3	133.1	5.9	3.9	80.0	5179	1147.9
SCR-7-C	5	1.16	880	68	1.4	99.1	112.6	17.9	3.4	80.0	12649	1414.4

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Gaston plant. Units 1-4 would be considered good candidates for repowering or retrofit because of their small boiler sizes. However, the long remaining boiler life and high capacity factors reduce the applicability of these technologies. Unit 5 is even less likely a candidate for repowering/retrofit because of the large boiler size, long remaining life, and high capacity factor.

3.1.4 Gorgas Steam Plant

Sorbent injection technologies (FSI and DSD) were not considered for the boilers at the Gorgas plant due to the short duct residence time between the boilers and the ESPs and the lack of ESP information.

TABLE 3.1.4-1. GORGAS STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	5	6,7	8,9	10
GENERATING CAPACITY (MW)	60	100	156,165	700
CAPACITY FACTOR (PERCENT)	41	42,48	63,55	79
INSTALLATION DATE	1944	1951,52	1956,58	1972
FIRING TYPE	TANG	FRONT WALL	TANGENTIAL	
FURNACE VOLUME (1000 CU FT)	NA	NA,58.9	NA	334
LOW NOx COMBUSTION	NO			
COAL SULFUR CONTENT (PERCENT)	1.5			
COAL HEATING VALUE (BTU/LB)	12500			
COAL ASH CONTENT (PERCENT)	11			
FLY ASH SYSTEM	WET DISPOSAL			
ASH DISPOSAL METHOD	POND/ON-SITE			
STACK NUMBER	1	1	2	2
COAL DELIVERY METHODS	RAILROAD/TRUCK			

PARTICULATE CONTROL

TYPE	ESP	ESP	ESP	ESP
INSTALLATION DATE	NA	NA	NA	1972
EMISSION (LB/MM BTU)	NA	NA	NA	0.06
REMOVAL EFFICIENCY	NA	NA	NA	99.4
DESIGN SPECIFICATION				
SULFUR SPECIFICATION (PERCENT)	NA	NA	NA	NA
SURFACE AREA (1000 SQ FT)	NA	NA	NA	NA
EXIT GAS FLOW RATE (1000 ACFM)	NA	NA	NA	320
SCA (SQ FT/1000 ACFM)	NA	NA	NA	NA
OUTLET TEMPERATURE (°F)	NA	NA	NA	NA

TABLE 3.1.4-2. SUMMARY OF RETROFIT FACTOR DATA FOR GORGAS UNITS 5, 6 AND 7 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	593,938	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.38	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.27
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	10	0	10

* L/S-FGD absorbers, LSD-FGD absorbers and new FFs for units 5, 6 and 7 would be located east of their common chimney.

TABLE 3.1.4-3. SUMMARY OF RETROFIT FACTOR DATA FOR GORGAS UNITS 8, 9 AND 10 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	NA	HIGH
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			HIGH
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			NA
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	HIGH
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	1397-5365	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.68	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.62
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.58
GENERAL FACILITIES (PERCENT)	15	0	15

* L/S-FGD absorbers, LSD-FGD absorbers and new FFs for units 8, 9 and 10 would be located north of their common chimney.

Table 3.1.4-4. Summary of FGD Control Costs for the Gorgas Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	5	1.38	60	41	1.5	31.8	529.3	12.3	57.3	90.0	2240	5510.4
L/S FGD	6	1.38	100	42	1.5	40.6	405.7	15.8	42.9	90.0	3824	4132.1
L/S FGD	7	1.38	100	48	1.5	40.6	405.7	16.1	38.4	90.0	4370	3694.1
L/S FGD	8	1.68	156	63	1.5	62.5	400.6	25.2	29.3	90.0	8947	2818.9
L/S FGD	9	1.68	165	55	1.5	64.7	392.3	25.5	32.0	90.0	8262	3081.0
L/S FGD	10	1.68	700	79	1.5	155.2	221.7	72.2	14.9	90.0	50345	1434.3
L/S FGD	5-7	1.38	260	44	1.5	68.9	265.0	27.4	27.4	90.0	10415	2632.4
L/S FGD	8-10	1.68	1021	66	1.5	221.2	216.7	96.8	16.4	90.0	61348	1578.4
L/S FGD-C	5	1.38	60	41	1.5	31.8	529.3	7.2	33.5	90.0	2240	3220.7
L/S FGD-C	6	1.38	100	42	1.5	40.6	405.7	9.2	25.1	90.0	3824	2415.0
L/S FGD-C	7	1.38	100	48	1.5	40.6	405.7	9.4	22.4	90.0	4370	2158.1
L/S FGD-C	8	1.68	156	63	1.5	62.5	400.6	14.7	17.1	90.0	8947	1646.4
L/S FGD-C	9	1.68	165	55	1.5	64.7	392.3	14.9	18.7	90.0	8262	1800.3
L/S FGD-C	10	1.68	700	79	1.5	155.2	221.7	42.1	8.7	90.0	50345	835.6
L/S FGD-C	5-7	1.38	260	44	1.5	68.9	265.0	16.0	16.0	90.0	10415	1537.9
L/S FGD-C	8-10	1.68	1021	66	1.5	221.2	216.7	56.5	9.6	90.0	61348	920.5
LC FGD	5-7	1.38	260	44	1.5	45.8	176.1	20.4	20.4	90.0	10415	1960.5
LC FGD	8-10	1.68	1021	66	1.5	172.6	169.1	82.1	13.9	90.0	61348	1337.4
LC FGD-C	5-7	1.38	260	44	1.5	45.8	176.1	11.9	11.9	90.0	10415	1143.0
LC FGD-C	8-10	1.68	1021	66	1.5	172.6	169.1	47.8	8.1	90.0	61348	778.9
LSD+FF	5	1.27	60	41	1.5	16.6	277.3	7.1	33.1	87.0	2153	3318.8
LSD+FF	6	1.27	100	42	1.5	23.8	237.8	9.5	25.8	87.0	3675	2579.9
LSD+FF	7	1.27	100	48	1.5	23.8	237.8	9.7	23.0	87.0	4200	2298.6
LSD+FF	8	1.62	156	63	1.5	43.4	278.3	16.2	18.9	87.0	8599	1887.4
LSD+FF	9	1.62	165	55	1.5	45.3	274.2	16.5	20.7	87.0	7941	2074.8
LSD+FF	10	1.62	700	79	1.5	153.6	219.4	58.3	12.0	87.0	48387	1204.6
LSD+FF-C	5	1.27	60	41	1.5	16.6	277.3	4.2	19.3	87.0	2153	1936.1
LSD+FF-C	6	1.27	100	42	1.5	23.8	237.8	5.5	15.1	87.0	3675	1507.1
LSD+FF-C	7	1.27	100	48	1.5	23.8	237.8	5.6	13.4	87.0	4200	1342.3
LSD+FF-C	8	1.62	156	63	1.5	43.4	278.3	9.5	11.0	87.0	8599	1104.0
LSD+FF-C	9	1.62	165	55	1.5	45.3	274.2	9.6	12.1	87.0	7941	1214.3
LSD+FF-C	10	1.62	700	79	1.5	153.6	219.4	34.1	7.0	87.0	48387	704.4

Table 3.1.4-5. Summary of Coal Switching/Cleaning Costs for the Gorgas Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	5	1.00	60	41	1.5	2.8	46.8	3.7	17.0	37.0	932	3923.2
CS/B+$15	6	1.00	100	42	1.5	4.1	40.7	5.9	16.0	37.0	1592	3696.3
CS/B+$15	7	1.00	100	48	1.5	4.1	40.7	6.6	15.7	37.0	1819	3623.4
CS/B+$15	8	1.00	156	63	1.5	5.8	37.0	12.7	14.7	37.0	3725	3403.2
CS/B+$15	9	1.00	165	55	1.5	6.0	36.6	11.8	14.9	37.0	3440	3442.7
CS/B+$15	10	1.00	700	79	1.5	21.4	30.6	67.0	13.8	37.0	20960	3198.3
CS/B+$15-C	5	1.00	60	41	1.5	2.8	46.8	2.1	9.8	37.0	932	2261.3
CS/B+$15-C	6	1.00	100	42	1.5	4.1	40.7	3.4	9.2	37.0	1592	2129.2
CS/B+$15-C	7	1.00	100	48	1.5	4.1	40.7	3.8	9.0	37.0	1819	2086.0
CS/B+$15-C	8	1.00	156	63	1.5	5.8	37.0	7.3	8.5	37.0	3725	1956.8
CS/B+$15-C	9	1.00	165	55	1.5	6.0	36.6	6.8	8.6	37.0	3440	1980.3
CS/B+$15-C	10	1.00	700	79	1.5	21.4	30.6	38.5	7.9	37.0	20960	1837.0
CS/B+$5	5	1.00	60	41	1.5	2.2	36.4	1.8	8.2	37.0	932	1897.5
CS/B+$5	6	1.00	100	42	1.5	3.0	30.3	2.7	7.2	37.0	1592	1673.3
CS/B+$5	7	1.00	100	48	1.5	3.0	30.3	2.9	7.0	37.0	1819	1614.6
CS/B+$5	8	1.00	156	63	1.5	4.2	26.6	5.3	6.1	37.0	3725	1418.2
CS/B+$5	9	1.00	165	55	1.5	4.3	26.3	5.0	6.3	37.0	3440	1446.6
CS/B+$5	10	1.00	700	79	1.5	14.1	20.2	25.8	5.3	37.0	20960	1228.7
CS/B+$5-C	5	1.00	60	41	1.5	2.2	36.4	1.0	4.7	37.0	932	1097.6
CS/B+$5-C	6	1.00	100	42	1.5	3.0	30.3	1.5	4.2	37.0	1592	967.2
CS/B+$5-C	7	1.00	100	48	1.5	3.0	30.3	1.7	4.0	37.0	1819	932.6
CS/B+$5-C	8	1.00	156	63	1.5	4.2	26.6	3.0	3.5	37.0	3725	817.6
CS/B+$5-C	9	1.00	165	55	1.5	4.3	26.3	2.9	3.6	37.0	3440	834.5
CS/B+$5-C	10	1.00	700	79	1.5	14.1	20.2	14.8	3.1	37.0	20960	707.0

TABLE 3.1.4-6. SUMMARY OF NOx RETROFIT RESULTS FOR GORGAS UNITS 5-7

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	5	6, 7	5-7
FIRING TYPE	TANG	FWF	NA
TYPE OF NOx CONTROL	OFA	LNB	NA
FURNACE VOLUME (1000 CU FT)	NA	NA, 58.9	NA
BOILER INSTALLATION DATE	1944	1951, 52	NA
SLAGGING PROBLEM	NO	NO	NA
ESTIMATED NOx REDUCTION (PERCENT)	25	40	NA
SCR RETROFIT RESULTS *			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	18	27	55
New Duct Length (Feet)	200	200	200
New Duct Costs (1000$)	735	991	1733
New Heat Exchanger (1000$)	1372	1864	3307
TOTAL SCOPE ADDER COSTS (1000$)	2125	2882	5095
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	20	20	20

* Cold side SCR reactors for units 5, 6 and 7 would be located east of their common chimney.

TABLE 3.1.4-7. SUMMARY OF NOx RETROFIT RESULTS FOR GORGAS UNITS 8-10

	BOILER NUMBER			
COMBUSTION MODIFICATION RESULTS				
	8	9	10	8-10
FIRING TYPE	TANG	TANG	TANG	NA
TYPE OF NOx CONTROL	OFA	OFA	OFA	NA
FURNACE VOLUME (1000 CU FT)	NA	NA	334	NA
BOILER INSTALLATION DATE	1956	1958	1972	NA
SLAGGING PROBLEM	NO	NO	NO	NA
ESTIMATED NOx REDUCTION (PERCENT)	25	25	25	NA
SCR RETROFIT RESULTS *				
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH	HIGH	HIGH
SCOPE ADDER PARAMETERS--				
Building Demolition (1000$)	0	0	0	0
Ductwork Demolition (1000$)	38	39	116	154
New Duct Length (Feet)	300	300	300	300
New Duct Costs (1000$)	1928	1992	4640	5787
New Heat Exchanger (1000$)	2434	2517	5991	7513
TOTAL SCOPE ADDER COSTS (1000$)	4400	4549	10747	13454
RETROFIT FACTOR FOR SCR	1.52	1.52	1.52	1.52
GENERAL FACILITIES (PERCENT)	38	38	38	38

* Cold side SCR reactors for units 8, 9 and 10 would be located north of their common chimney.

Table 3.1.4-8. NOx Control Cost Results for the Gorgas Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	6	1.00	100	42	1.5	2.6	25.5	0.5	1.5	40.0	610	884.4
LNC-LNB	7	1.00	100	48	1.5	2.6	25.5	0.5	1.3	40.0	697	773.8
LNC-LNB-C	6	1.00	100	42	1.5	2.6	25.5	0.3	0.9	40.0	610	525.4
LNC-LNB-C	7	1.00	100	48	1.5	2.6	25.5	0.3	0.8	40.0	697	459.7
LNC-OFA	5	1.00	60	41	1.5	0.5	8.4	0.1	0.5	25.0	160	668.9
LNC-OFA	8	1.00	156	63	1.5	0.7	4.7	0.2	0.2	25.0	637	245.1
LNC-OFA	9	1.00	165	55	1.5	0.8	4.6	0.2	0.2	25.0	588	271.6
LNC-OFA	10	1.00	700	79	1.5	1.3	1.9	0.3	0.1	25.0	3586	79.5
LNC-OFA-C	5	1.00	60	41	1.5	0.5	8.4	0.1	0.3	25.0	160	397.5
LNC-OFA-C	8	1.00	156	63	1.5	0.7	4.7	0.1	0.1	25.0	637	145.6
LNC-OFA-C	9	1.00	165	55	1.5	0.8	4.6	0.1	0.1	25.0	588	161.4
LNC-OFA-C	10	1.00	700	79	1.5	1.3	1.9	0.2	0.0	25.0	3586	47.2
SCR-3	5	1.16	60	41	1.5	13.9	232.1	4.3	19.7	80.0	510	8331.2
SCR-3	6	1.16	100	42	1.5	18.8	187.8	6.0	16.3	80.0	1220	4905.0
SCR-3	7	1.16	100	48	1.5	18.8	187.9	6.0	14.3	80.0	1394	4317.7
SCR-3	8	1.52	156	63	1.5	32.3	207.0	10.1	11.7	80.0	2039	4939.5
SCR-3	9	1.52	165	55	1.5	33.6	203.5	10.4	13.1	80.0	1883	5545.3
SCR-3	10	1.52	700	79	1.5	104.7	149.6	36.3	7.5	80.0	11475	3160.9
SCR-3	5-7	1.16	260	44	1.5	37.6	144.6	12.7	12.7	80.0	3323	3833.6
SCR-3	8-10	1.52	1021	66	1.5	146.6	143.6	50.8	8.6	80.0	13982	3634.3
SCR-3-C	5	1.16	60	41	1.5	13.9	232.1	2.5	11.6	80.0	510	4895.6
SCR-3-C	6	1.16	100	42	1.5	18.8	187.8	3.5	9.5	80.0	1220	2879.3
SCR-3-C	7	1.16	100	48	1.5	18.8	187.9	3.5	8.4	80.0	1394	2534.2
SCR-3-C	8	1.52	156	63	1.5	32.3	207.0	5.9	6.9	80.0	2039	2901.0
SCR-3-C	9	1.52	165	55	1.5	33.6	203.5	6.1	7.7	80.0	1883	3257.0
SCR-3-C	10	1.52	700	79	1.5	104.7	149.6	21.2	4.4	80.0	11475	1851.9
SCR-3-C	5-7	1.16	260	44	1.5	37.6	144.6	7.5	7.5	80.0	3323	2247.1
SCR-3-C	8-10	1.52	1021	66	1.5	146.6	143.6	29.8	5.0	80.0	13982	2129.2
SCR-7	5	1.16	60	41	1.5	13.9	232.1	3.8	17.5	80.0	510	7371.3
SCR-7	6	1.16	100	42	1.5	18.8	187.8	5.2	14.0	80.0	1220	4235.5
SCR-7	7	1.16	100	48	1.5	18.8	187.9	5.2	12.4	80.0	1394	3731.9
SCR-7	8	1.52	156	63	1.5	32.3	207.0	8.8	10.2	80.0	2039	4314.7
SCR-7	9	1.52	165	55	1.5	33.6	203.5	9.1	11.4	80.0	1883	4829.6
SCR-7	10	1.52	700	79	1.5	104.7	149.6	30.6	6.3	80.0	11475	2662.6
SCR-7	5-7	1.16	260	44	1.5	37.6	144.6	10.6	10.6	80.0	3323	3194.6
SCR-7	8-10	1.52	1021	66	1.5	146.6	143.6	42.5	7.2	80.0	13982	3037.9
SCR-7-C	5	1.16	60	41	1.5	13.9	232.1	2.2	10.3	80.0	510	4345.7
SCR-7-C	6	1.16	100	42	1.5	18.8	187.8	3.0	8.3	80.0	1220	2495.7
SCR-7-C	7	1.16	100	48	1.5	18.8	187.9	3.1	7.3	80.0	1394	2198.5
SCR-7-C	8	1.52	156	63	1.5	32.3	207.0	5.2	6.0	80.0	2039	2543.0
SCR-7-C	9	1.52	165	55	1.5	33.6	203.5	5.4	6.7	80.0	1883	2847.0
SCR-7-C	10	1.52	700	79	1.5	104.7	149.6	18.0	3.7	80.0	11475	1566.4
SCR-7-C	5-7	1.16	260	44	1.5	37.6	144.6	6.3	6.2	80.0	3323	1881.0
SCR-7-C	8-10	1.52	1021	66	1.5	146.6	143.6	25.0	4.2	80.0	13982	1787.5

3.1.5 Greene County Steam Plant

The Greene County steam plant is located within Greene County, Alabama, and is part of the Alabama Power Company. The plant houses two coal-fired boilers with a gross generating capacity of 506 MW. The plant is adjacent to the Black Warrier River with a water channel extending from the south loop of the river to the east side of the coal pile.

Table 3.1.5-1 presents the operational data for the Greene County plant. Both boilers burn moderate sulfur coal. Coal shipments are received by barge or railroad and conveyed to a coal storage and handling area south of the plant. The coal is crushed and then conveyed to the boilers.

PM emissions for both boilers are controlled with retrofit hot side ESPs. The ESPs are located behind each boiler. The units are ducted to a common retrofit chimney built southwest of unit 2. The two original chimneys are left intact and are located directly behind the retrofit ESPs. Ash from the units is wet sluiced to ponds located to the south of the coal pile. The following evaluation is based on a 1981 aerial photograph, and any alterations made to the plant since that time should be taken into consideration.

Lime/Limestone and Lime Spray Drying FGD Costs--

For L/LS-FGD system, the absorbers would be placed in a low site access/congestion area south of and close to the common chimney. A short duct run (100-300 feet) having a low access/congestion retrofit difficulty would be required. The lime/limestone preparation and waste handling area would be located close to the absorbers and north of the coal pile. A storage building would have to be relocated for the placement of the absorbers. Therefore, a factor of 8 percent was assigned to general facilities.

LSD with reuse of the existing ESPs was not considered for this plant because the ESPs are hot side and access to them is difficult. LSD with a new baghouse was considered with the baghouses being located adjacent to their respective absorbers which would be placed in a similar fashion as the L/LS-FGD absorbers.

TABLE 3.1.5-1. GREENE COUNTY STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2
GENERATING CAPACITY (MW)	250	256
CAPACITY FACTOR (PERCENT)	70	59
INSTALLATION DATE	1965	1966
FIRING TYPE	OPPOSED WALL	
FURNACE VOLUME (1000 CU FT)	124	124
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	1.4	1.4
COAL HEATING VALUE (BTU/LB)	12,500	12,500
COAL ASH CONTENT (PERCENT)	11.0	11.0
FLY ASH SYSTEM	WET DISPOSAL	
ASH DISPOSAL METHOD	PONDS/ON-SITE	
STACK NUMBER	1	1
COAL DELIVERY METHODS	BARGE/RAILROAD	
<u>PARTICULATE CONTROL</u>		
TYPE	ESP	ESP
INSTALLATION DATE	1975	1975
EMISSION (LB/MM BTU)	0.06	0.06
REMOVAL EFFICIENCY	99.7	99.7
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	0.7 to 5.0	
SURFACE AREA (1000 SQ FT)	394.0	394.0
GAS EXIT RATE (1000 ACFM)	1400	1400
SCA (SQ FT/1000 ACFM)	281.4	281.4
OUTLET TEMPERATURE (°F)	715	715

A moderate duct run (300-600 feet) would be required for the application of LSD technology. A low ductwork site access/congestion factor was assigned to both LSD and installation of ducting to the baghouse.

The major scope adjustment costs and estimated retrofit factors for the FGD technologies are presented in Table 3.1.5-2. Table 3.1.5-3 presents the process retrofit factors and capital and operating costs for commercial FGD technologies. The low cost FGD case shows the impact of eliminating spare absorbers and maximizing absorber size.

Coal Switching and Physical Coal Cleaning Costs--

Table 3.1.5-4 presents the IAPCS results for CS at the Greene County plant. These costs do not include changes in boiler and pulverizer operating costs. Coal switching for a fuel price differential of $15 per ton is higher than that of $5 per ton because of inventory capital and preproduction costs, which are a function of variable costs (e.g. fuel costs). PCC was not evaluated because the coal sulfur level is relatively low and this is not a mine mouth plant.

Low NO_x Combustion--

Units 1 and 2 are opposed wall-fired boilers rated at 250 and 256 MW, respectively. The combustion modification technique applied to unit 2 was LNB. LNBs were not considered for unit 1 since unit 1 has all burners, and LNBs are not yet satisfactorily demonstrated nor commercially available for all burner units. As Table 3.1.5-5 shows, the LNB NO_x reduction performance for unit 2 was assessed based on volumetric heat release rate (MW per furnace volume). Table 3.1.5-6 presents the cost of retrofitting LNB at the Greene County plant.

Selective Catalytic Reduction--

Two SCR configurations are possible at the Greene County plant. Because the units have hot ESPs, the SCR reactors could be located adjacent to the old chimneys and would have a high access/congestion factor. Cold side SCR reactors for units 1 and 2 would be located south of the common chimney and would have a low access/congestion factor and the need for flue gas reheat. Both cases were evaluated. The ammonia storage is placed south of the

TABLE 3.1.5-2. SUMMARY OF RETROFIT FACTOR DATA FOR GREENE COUNTY UNIT 1 OR 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	2132	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.27
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	8	0	8

Table 3.1.5-3. Summary of FGD Control Costs for the Greene County Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.27	250	76	1.4	64.6	258.3	28.8	17.3	90.0	16142	1781.5
L/S FGD	2	1.27	256	59	1.4	65.5	255.9	27.3	20.7	90.0	12832	2130.2
L/S FGD	1-2	1.27	506	65	1.4	99.9	197.4	44.2	15.3	90.0	27942	1581.7
L/S FGD-C	1	1.27	250	76	1.4	64.6	258.3	16.8	10.1	90.0	16142	1038.6
L/S FGD-C	2	1.27	256	59	1.4	65.5	255.9	16.0	12.1	90.0	12832	1243.4
L/S FGD-C	1-2	1.27	506	65	1.4	99.9	197.4	25.8	8.9	90.0	27942	922.2
LC FGD	1-2	1.27	506	65	1.4	80.2	158.5	38.3	13.3	90.0	27942	1369.1
LC FGD-C	1-2	1.27	506	65	1.4	80.2	158.5	22.3	7.7	90.0	27942	797.3
LSD+FF	1-2	1.27	506	65	1.4	132.3	261.4	46.2	16.0	87.0	26860	1721.4
LSD+FF-C	1-2	1.27	506	65	1.4	132.3	261.4	27.1	9.4	87.0	26860	1008.3

Table 3.1.5-4. Summary of Coal Switching/Cleaning Costs for the Greene County Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	250	70	1.4	8.6	34.2	21.9	14.3	33.0	5453	4024.3
CS/B+$15	2	1.00	256	59	1.4	8.7	34.1	19.2	14.5	33.0	4706	4085.6
CS/B+$15-C	1	1.00	250	70	1.4	8.6	34.2	12.6	8.2	33.0	5453	2312.7
CS/B+$15-C	2	1.00	256	59	1.4	8.7	34.1	11.1	8.4	33.0	4706	2349.1
CS/B+$5	1	1.00	250	70	1.4	6.0	23.8	8.8	5.8	33.0	5453	1618.9
CS/B+$5	2	1.00	256	59	1.4	6.1	23.7	7.8	5.9	33.0	4706	1664.7
CS/B+$5-C	1	1.00	250	70	1.4	6.0	23.8	5.1	3.3	33.0	5453	932.5
CS/B+$5-C	2	1.00	256	59	1.4	6.1	23.7	4.5	3.4	33.0	4706	959.6

TABLE 3.1.5-5. SUMMARY OF NOx RETROFIT RESULTS FOR GREENE COUNTY

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1	2
FIRING TYPE	NA	OWF
TYPE OF NOx CONTROL	NA	LNB
FURNACE VOLUME (1000 CU FT)	NA	124
BOILER INSTALLATION DATE	NA	1965
SLAGGING PROBLEM	NA	NO
ESTIMATED NOx REDUCTION (PERCENT)	NA	34
SCR RETROFIT RESULTS	COLD SIDE	HOT SIDE
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	HIGH
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	54	200
New Duct Length (Feet)	200	200
New Duct Costs (1000$)	2541	1694
New Heat Exchanger (1000$)	4895	0
TOTAL SCOPE ADDER COSTS (1000$)	7527	1894
RETROFIT FACTOR FOR SCR	1.16	1.52
GENERAL FACILITIES (PERCENT)	13	13

Table 3.1.5-6. NOx Control Cost Results for the Greene County Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	2	1.00	256	59	1.4	3.7	14.5	0.8	0.6	34.0	1865	421.3
LNC-LNB-C	2	1.00	256	59	1.4	3.7	14.5	0.5	0.4	34.0	1865	250.3
SCR-3 (CS)	1	1.16	250	70	1.4	38.7	154.7	13.1	8.5	80.0	5084	2574.0
SCR-3 (CS)	2	1.16	256	59	1.4	39.3	153.6	13.2	9.9	80.0	4388	2998.6
SCR-3 (HS)	1	1.52	250	70	1.4	39.1	156.2	13.5	8.8	80.0	5084	2664.9
SCR-3 (HS)	2	1.52	256	65	1.4	39.8	155.5	13.7	9.4	80.0	4834	2843.1
SCR-3-C (CS)	1	1.16	250	70	1.4	38.7	154.7	7.7	5.0	80.0	5084	1508.9
SCR-3-C (CS)	2	1.16	256	59	1.4	39.3	153.6	7.7	5.8	80.0	4388	1758.2
SCR-3-C (HS)	1	1.52	250	70	1.4	39.1	156.2	7.9	5.2	80.0	5084	1561.3
SCR-3-C (HS)	2	1.52	256	65	1.4	39.8	155.5	8.1	5.5	80.0	4834	1665.8
SCR-7 (CS)	1	1.16	250	70	1.4	38.7	154.7	11.0	7.2	80.0	5084	2172.4
SCR-7 (CS)	2	1.16	256	59	1.4	39.3	153.6	11.1	8.4	80.0	4388	2522.1
SCR-7 (HS)	1	1.52	250	65	1.4	39.1	156.2	11.4	8.0	80.0	4721	2419.9
SCR-7 (HS)	2	1.52	256	65	1.4	39.8	155.5	11.7	8.0	80.0	4834	2410.5
SCR-7-C (CS)	1	1.16	250	70	1.4	38.7	154.7	6.5	4.2	80.0	5084	1278.7
SCR-7-C (CS)	2	1.16	256	59	1.4	39.3	153.6	6.5	4.9	80.0	4388	1485.2
SCR-7-C (HS)	1	1.52	250	65	1.4	39.1	156.2	6.7	4.7	80.0	4721	1423.5
SCR-7-C (HS)	2	1.52	256	65	1.4	39.8	155.5	6.9	4.7	80.0	4834	1418.0

reactors and is assigned a low access/congestion factor. For both cases, 200 feet of duct is required to span the distance between the reactors and the existing duct work; no major demolition/relocation is required and the base value of 13 percent was assigned to general facilities.

Table 3.1.5-5 presents the SCR process area retrofit factors and scope adder costs. Table 3.1.5-6 presents the estimated cost of retrofitting SCR at the Greene County plant.

Furnace Sorbent Injection and Duct Spray Drying--

Because of the short duct residence time between the boilers and the ESPs, the marginal size of the ESPs, the congestion around the ESPs area, and the hot side ESPs (715^{o}F), FSI and DSD were not considered here.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Greene County plant. Both units would be considered candidates for repowering or retrofit because they are less than 300 MW. However, the high capacity factors could result in high costs associated with downtime (replacement power costs) and the moderate unit age makes these units unlikely repowering candidates in the near future. Space availability adjacent to both units enhances the potential for equipment reuse and reduces construction costs and downtime.

3.1.6 Miller Steam Plant

Both units at the Miller plant are currently burning a low sulfur coal; therefore, FGD costs were not presented since the low sulfur coal would yield high unit costs and CS was not considered for the plant. The only technology considered for control of NO_x emissions was SCR since both units are equipped with LNBs. Sorbent injection technologies (FSI and DSD) were not evaluated for this plant because the boilers are equipped with hot side ESPs which can not be reused.

TABLE 3.1.6-1. MILLER STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3,4
GENERATING CAPACITY (MW)	660	660
CAPACITY FACTOR (PERCENT)	38,39	
INSTALLATION DATE	1978,85	1989,91
FIRING TYPE	OPPOSED WALL	PLANNED
FURNACE VOLUME (1000 CU FT)	526	FOR
LOW NOx COMBUSTION	YES	CONSTRUCTION
COAL SULFUR CONTENT (PERCENT)	0.6	
COAL HEATING VALUE (BTU/LB)	12500	
COAL ASH CONTENT (PERCENT)	11.2	
FLY ASH SYSTEM	WET DISPOSAL	
ASH DISPOSAL METHOD	POND/ON-SITE	
STACK NUMBER	1	
COAL DELIVERY METHODS	RAILROAD/TRUCK	
PARTICULATE CONTROL		
TYPE	ESP	
INSTALLATION DATE	1978,85	
EMISSION (LB/MM BTU)	0.02,0.03	
REMOVAL EFFICIENCY	99.1	
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	0.5	
SURFACE AREA (1000 SQ FT)	1037	
EXIT GAS FLOW RATE (1000 ACFM)	3888	
SCA (SQ FT/1000 ACFM)	267	
OUTLET TEMPERATURE (°F)	679	

TABLE 3.1.6-2. SUMMARY OF RETROFIT FACTOR DATA FOR MILLER UNIT 1 OR 2 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	5090,9475	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.27
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	10	0	10

* Absorbers and new FFs for units 1 and 2 would be located behind the common chimney for units 1 and 2.

TABLE 3.1.6-3. SUMMARY OF NOx RETROFIT RESULTS FOR MILLER

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1,2
FIRING TYPE	OWF
TYPE OF NOx CONTROL	EQUIPPED WITH LNBs
FURNACE VOLUME (1000 CU FT)	526,NA
BOILER INSTALLATION DATE	1978,85
SLAGGING PROBLEM	NA
ESTIMATED NOx REDUCTION (PERCENT)	NA
SCR RETROFIT RESULTS *	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	111
New Duct Length (Feet)	250
New Duct Costs (1000$)	3736
New Heat Exchanger (1000$)	0
TOTAL SCOPE ADDER COSTS (1000$)	
INDIVIDUAL CASE	3847
COMBINED CASE	5792
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	20

* Hot side SCR reactors for units 1 and 2 would be located behind the common chimney for units 1 and 2.

Table 3.1.6-4. NOx Control Cost Results for the Miller Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
SCR-3	1	1.16	660	38	0.6	77.9	118.0	28.3	12.9	80.0	7286	3886.5
SCR-3	2	1.16	660	39	0.6	77.9	118.0	28.4	12.6	80.0	7477	3791.9
SCR-3	1-2	1.16	1320	39	0.6	147.9	112.0	54.7	12.1	80.0	14955	3660.9
SCR-3-C	1	1.16	660	38	0.6	77.9	118.0	16.6	7.5	80.0	7286	2274.6
SCR-3-C	2	1.16	660	39	0.6	77.9	118.0	16.6	7.4	80.0	7477	2219.2
SCR-3-C	1-2	1.16	1320	39	0.6	147.9	112.0	32.0	7.1	80.0	14955	2141.8
SCR-7	1	1.16	660	38	0.6	77.9	118.0	22.9	10.4	80.0	7286	3146.6
SCR-7	2	1.16	660	39	0.6	77.9	118.0	23.0	10.2	80.0	7477	3071.0
SCR-7	1-2	1.16	1320	39	0.6	147.9	112.0	44.0	9.7	80.0	14955	2940.0
SCR-7-C	1	1.16	660	38	0.6	77.9	118.0	13.5	6.1	80.0	7286	1850.7
SCR-7-C	2	1.16	660	39	0.6	77.9	118.0	13.5	6.0	80.0	7477	1806.2
SCR-7-C	1-2	1.16	1320	39	0.6	147.9	112.0	25.9	5.7	80.0	14955	1728.7

3.2 TENNESSEE VALLEY AUTHORITY

3.2.1 Colbert Steam Plant

Information for Colbert steam plant appears in U.S. EPA report number EPA-600/7-88/014 entitled "Ohio/Kentucky/TVA Coal-Fired Utility SO_2 and NO_x Retrofit Study" (NTIS PB88-244447/AS).

3.2.2 Widows Creek Steam Plant

The Widows Creek steam plant is located within Jackson County, Alabama, as part of the TVA system. The plant contains eight boilers with a total gross generating capacity of 1,965 MW. Figure 3.2.2-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 3.2.2-1 presents operational data for the existing equipment at the Widows Creek steam plant. Boilers 1 to 6 burn low sulfur coal (0.8 percent sulfur). Half of the coal shipments are received by freight barge and the other half is received by rail and conveyed to a coal storage and handling area located west of the plant.

Particulate matter emissions for boilers 1-6 are controlled with retrofit ESPs located behind the old ESP boxes. Ash from all units is wet sluiced to ponds on the far side of the coal storage area northwest of the plant. On-site waste disposal is limited and TVA is considering two options: the purchase of more land adjacent to the plant or dry disposing the waste off-site.

Boilers 7 and 8 burn high sulfur coal (3.5 percent) and have limestone flue gas scrubbing units. As such, cost estimates for SO_2 controls for units 7 and 8 are not presented.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 3.2.2-1 shows the general layout and location of the FGD control system. Absorbers for L/LS-FGD and LSD-FGD for units 1 to 6 would be located in a relatively small area southeast of unit 1. They were not located in the space available west of unit 6 due to the location of the preparation area for units 1 to 6. The preparation area is located to the

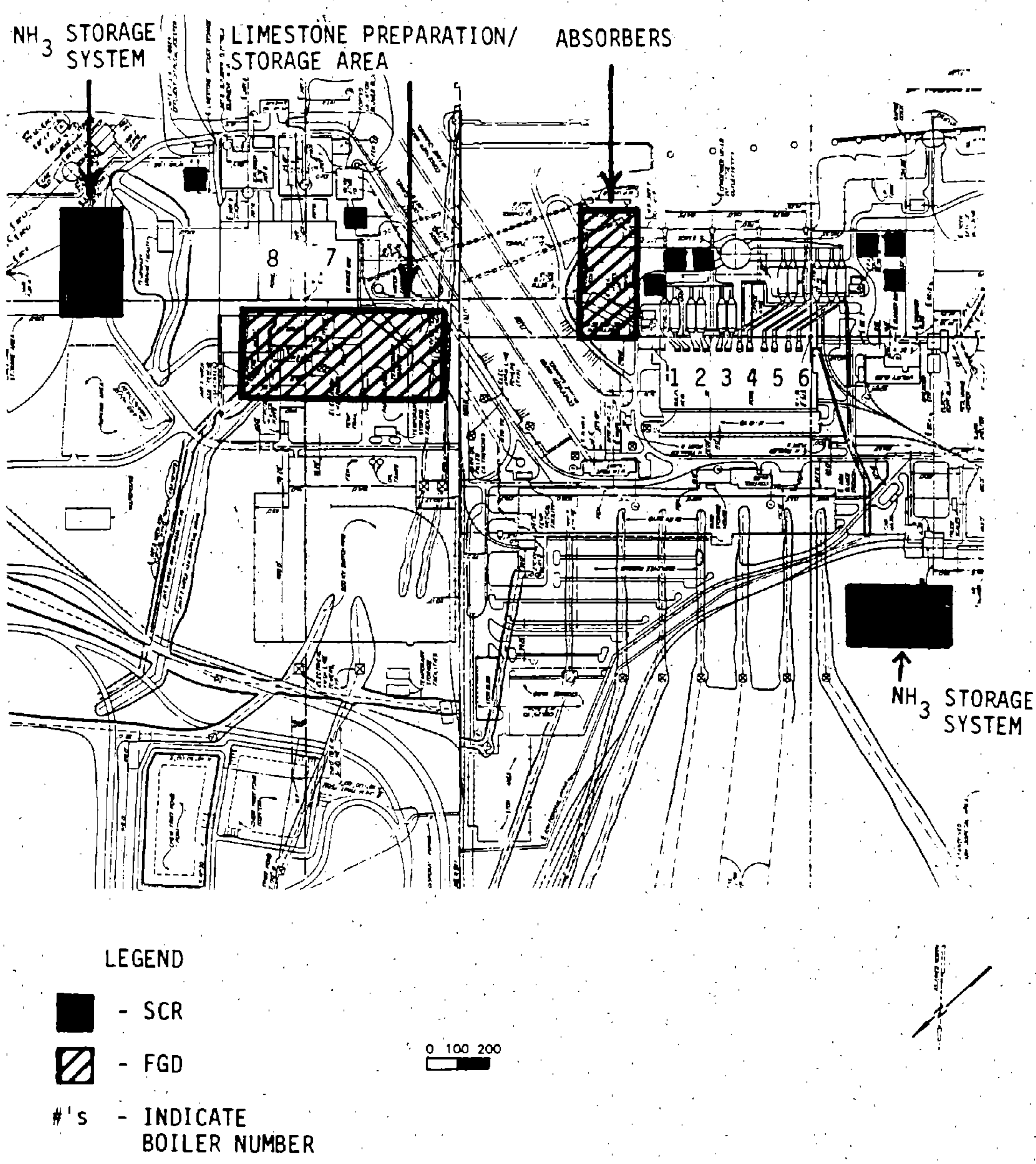

Figure 3.2.2-1. Widows Creek plant plot plan

TABLE 3.2.2-1. WIDOWS CREEK STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1-6	7	8
GENERATING CAPACITY (MW-each)	140	575	550
CAPACITY FACTOR (PERCENT)	29,26,37,35,29,35	24	38
INSTALLATION DATE	1952-54	1961	1965
FIRING TYPE	FWF	TANG	TANG
COAL SULFUR CONTENT (PERCENT)	0.8-1.1	3.4	3.6
COAL HEATING VALUE (BTU/LB)	12000	12000	12000
COAL ASH CONTENT (PERCENT)	10	11	11
FLY ASH SYSTEM		WET SLUICE	
ASH DISPOSAL METHOD		POND/ON-SITE	
STACK NUMBER	1	2	3
COAL DELIVERY METHODS		BARGE/RAIL	
FGD (TYPE)	NA	LIMESTONE	
PARTICULATE CONTROL			
TYPE	ESP	ESP	ESP
INSTALLATION DATE	1977	1981	1978
EMISION (LB/MM BTU)	0.05	0.06	0.07
REMOVAL EFFICIENCY	99.2	99.2	99.2
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	0.7	4.0	4.5
SURFACE AREA (1000 SQ FT)	322.6	217.7	217.7
GAS EXIT RATE (1000 ACFM)	575	1624	1473
SCA (SQ FT/1000 ACFM)	561	134	134
OUTLET TEMPERATURE (°F)	310	175	175

east of unit 1 on the other side of the water channel, which would make it difficult to reach the other side of unit 6 if the absorbers were located to the west. In addition, flue gas from units 4-6 are converged into a common duct. An easier approach, which would require a shorter breaching duct, would be the diversion of this flue gas to the southeast of unit 1 for the L/LS-FGD absorbers. The coal conveyor running to units 7 and 8 would be relocated to make more space available for the FGD equipment; therefore, a factor of 10 percent was assigned to general facilities for units 1-6. The limestone preparation/storage area for units 1 to 6 was placed by the corner (southwest) of the powerhouse and the waste handling area was placed adjacent to the limestone preparation and storage area for units 7 and 8 east of the plant.

Retrofit Difficulty and Scope Adder Costs--

Units 1-6 already have switched to low sulfur coal. It is unlikely that scrubbing would be needed. If this becomes needed, however, it is more cost effective to switch to a high sulfur coal taking into account the fuel cost differential for estimation of cost effectiveness. Costs presented in this section, it must be noted, are dependent upon acid rain legislation and the type of coal chosen for use.

The FGD scrubbing equipment for units 1 to 6 was assumed to be located in a high access/congestion area east of unit 1. This area is bounded by the cooling water intake channel to the east, the Tennessee River to the south, the coal conveyor to the north, and a powerhouse to the west. A high underground obstruction factor was assumed due to the underground discharge tunnels.

Boilers 1 to 3 and 4 to 6 presently converge into two separate duct runs before going to a common chimney. As a result, a modest duct run would be required for boilers 1 to 6.

For L/LS-FGD, a low ductwork access/congestion factor was assigned to units 1 to 3 because sufficient layout space was available. A medium ductwork access/congestion factor was assigned to units 4 to 6 because it would be necessary to route the ductwork around the existing chimney.

The major scope adjustment costs and estimated retrofit factors for the FGD control technologies are presented in Tables 3.2.2-2 and 3.2.2-3. The

TABLE 3.2.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR WIDOWS CREEK UNITS 1-3

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	HIGH	HIGH
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			600-1000
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	1268	NA	1268
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.59	1.56	
ESP REUSE CASE			1.73
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	10	10

TABLE 3.2.2-3. SUMMARY OF RETROFIT FACTOR DATA FOR WIDOWS CREEK UNITS 4-6

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	HIGH	HIGH
FLUE GAS HANDLING	MEDIUM	MEDIUM	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			1000 +
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	1268	NA	1268
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.64	1.60	
ESP REUSE CASE			2.03
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	10	10

largest scope adder for Widows Creek would be the conversion of units 1 to 6 fly ash conveying/disposal system from wet to dry for conventional L/LS-FGD and LSD-FGD cases. It was assumed that dry fly ash would be necessary to stabilize L/LS-FGD scrubber sludge waste and to prevent plugging of sluice lines in LSD-FGD cases. However, this conversion would not be necessary for the forced oxidation case. The overall retrofit factors determined for the L/LS-FGD cases were moderate to high for units 1 to 6 (1.56 to 1.64).

The LSD with reused ESP was evaluated for units 1-6. For LSD-FGD, a medium ductwork access/congestion factor was assigned to units 1 to 3, while a high factor was assigned to units 4 to 6. The ESPs at units 1 to 6 have large SCAs (>500) and, as such, it is likely that little or no ESP plate area addition would be required for spray drying at these units. The process area retrofit difficulty factors ranged from moderate to extreme for units 1 to 6 (1.73 to 2.03). A separate retrofit factor (1.58) was developed for the upgrade of the ESPs for units 1 to 6 and was used in the IAPCS model to estimate the particulate control costs if additional plate area was required.

Table 3.2.2-4 presents the costs estimated for L/LS-FGD and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs and ash handling systems for boilers 1-6.

The low cost control case reduces capital and annual operating costs. The significant reduction in costs is primarily due to the benefits of economies-of-scale when combining process areas, elimination of spare scrubber module, and optimization of scrubber size.

Coal Switching Costs--

Because units 1-6 have already switched to low sulfur coal and units 7-8 have limestone FGD units, coal switching was not evaluated.

NO_x Control Technology Costs--

This section presents the performance and various related costs estimated for NO_x controls at the Widows Creek steam plant. These controls include LNC modifications and SCR. The application of NO_x control technologies is determined by several site-specific factors which are

Table 3.2.2-4. Summary of FGD Control Costs for the Widows Creek Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1-3	1.59	421	31	0.8	102.6	243.7	37.5	32.8	90.0	6641	5644.9
L/S FGD	4-6	1.64	421	33	1.1	106.6	253.2	39.4	32.4	90.0	9720	4054.7
L/S FGD-C	1-3	1.59	421	31	0.8	102.6	243.7	21.9	19.2	90.0	6641	3303.4
L/S FGD-C	4-6	1.64	421	33	1.1	106.6	253.2	23.1	18.9	90.0	9720	2372.2
LC FGD	1-3	1.59	421	31	0.8	76.8	182.5	29.7	26.0	90.0	6641	4468.9
LC FGD	4-6	1.64	421	33	1.1	79.7	189.2	31.2	25.6	90.0	9637	3237.5
LC FGD-C	1-3	1.59	421	31	0.8	76.8	182.5	17.3	15.2	90.0	6641	2612.3
LC FGD-C	4-6	1.64	421	33	1.1	79.7	189.2	18.2	15.0	90.0	9637	1892.0
LSD+ESP	1	1.73	140	29	0.8	24.1	172.5	9.3	26.2	76.0	1751	5317.0
LSD+ESP	2	1.73	140	26	0.8	24.2	172.6	9.2	29.0	76.0	1570	5890.7
LSD+ESP	3	1.73	140	37	0.8	24.2	172.7	9.5	21.0	76.0	2235	4254.4
LSD+ESP	4	2.03	140	35	0.8	27.7	198.1	10.4	24.3	76.0	2114	4938.5
LSD+ESP	5	2.03	140	29	0.9	28.1	200.7	10.5	29.4	76.0	1970	5306.2
LSD+ESP	6	2.03	140	35	1.1	28.7	205.0	10.9	25.4	76.0	2906	3743.9
LSD+ESP-C	1	1.73	140	29	0.8	24.1	172.5	5.4	15.3	76.0	1751	3108.1
LSD+ESP-C	2	1.73	140	26	0.8	24.2	172.6	5.4	17.0	76.0	1570	3444.0
LSD+ESP-C	3	1.73	140	37	0.8	24.2	172.7	5.6	12.2	76.0	2235	2486.0
LSD+ESP-C	4	2.03	140	35	0.8	27.7	198.1	6.1	14.2	76.0	2114	2888.3
LSD+ESP-C	5	2.03	140	29	0.9	28.1	200.7	6.1	17.2	76.0	1970	3104.1
LSD+ESP-C	6	2.03	140	35	1.1	28.7	205.0	6.4	14.8	76.0	2906	2189.3

discussed in Section 2. The NO_x technologies evaluated at the steam plant were: LNB - units 1 to 6, OFA - units 7 to 8, and SCR for all units.

Low NO_x Combustion--

Units 1 to 6 are dry bottom, front wall-fired boilers rated at 140 MW each. Units 7 to 8 are dry bottom, tangential-fired boilers rated at 575 MW and 550 MW, respectively. Thus, the NO_x combustion control considered for units 1 to 6 was LNB and the NO_x combustion control considered for units 7 and 8 was OFA. Tables 3.2.2-5 through 3.2.2-7 present the NO_x reduction performance results for units 1 to 8. The NO_x reduction performance estimated for units 1 to 6 (equipped with LNBs) would be 30 percent while the NO_x reduction performance results for units 7 and 8 (equipped with OFA) would be 25 and 20 percent, respectively. The NO_x reduction performances were determined by examining the effects of heat release rates and furnace residence time on NO_x reduction through the use of the simplified procedure. Table 3.2.2-8 presents the estimated cost of retrofitting LNB and OFA ports on the Widows Creek boilers.

Selective Catalytic Reduction--

Tables 3.2.2-5 through 3.2.2-7 present the SCR retrofit results for each unit. The results include process area retrofit difficulty factors and scope adder costs. For scope adders, costs were estimated for ductwork demolition, new flue gas heat exchanger, and new duct runs to divert the flue gas from the ESP to the reactor and from the reactor to the chimney.

The SCR reactor for unit 1 was located east of the unit's ESPs, the reactors for units 2 and 3 were located behind their respective ESPs, and the reactors for units 4 to 6 were located west of the unit 6 ESPs. The reactor for unit 7 is located at the southwest corner of the boiler house in a highly congested area adjacent to the ESP while the reactors for unit 8 were located northeast of the boiler in an uncongested area.

Medium access/congestion factors were assigned to the reactors for units 1 to 6. These reactors were located in the relatively low access/congestion areas but general access to these areas is poor. The reactor for unit 7 was given a high access/congestion factor because the reactor would be blocked by the service bay, the ESPs, and the electrical power yard. The

TABLE 3.2.2-5. SUMMARY OF NOx RETROFIT RESULTS FOR WIDOWS CREEK UNITS 1-3

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	3
FIRING TYPE	FWF	FWF	FWF
TYPE OF NOx CONTROL	LNB	LNB	LNB
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	21.5	21.5	21.5
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	64.2	64.2	64.2
FURNACE RESIDENCE TIME (SECONDS)	1.73	1.73	1.73
ESTIMATED NOx REDUCTION (PERCENT)	30	30	30
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	MEDIUM	MEDIUM
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	NA	NA
Ductwork Demolition (1000$)	35	35	35
New Duct Length (Feet)	350	283	217
New Duct Costs (1000$)	2120	1714	1315
New Heat Exchanger (1000$)	2291	2291	2291
TOTAL SCOPE ADDER COSTS (1000$)	4446	4040	3640
RETROFIT FACTOR FOR SCR	1.34	1.34	1.34
GENERAL FACILITIES (PERCENT)	13	13	13

TABLE 3.2.2-6. SUMMARY OF NOx RETROFIT RESULTS FOR WIDOWS CREEK UNITS 4-6

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	4	5	6
FIRING TYPE	FWF	FWF	FWF
TYPE OF NOx CONTROL	LNB	LNB	LNB
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	21.5	21.4	21.4
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	64.2	67.5	67.5
FURNACE RESIDENCE TIME (SECONDS)	1.73	1.66	1.66
ESTIMATED NOx REDUCTION (PERCENT)	30	30	30
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	MEDIUM	MEDIUM
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	NA	NA
Ductwork Demolition (1000$)	35	35	35
New Duct Length (Feet)	650	650	684
New Duct Costs (1000$)	3938	3938	4144
New Heat Exchanger (1000$)	2291	2291	2291
TOTAL SCOPE ADDER COSTS (1000$)	6263	6263	6469
RETROFIT FACTOR FOR SCR	1.34	1.34	1.34
GENERAL FACILITIES (PERCENT)	13	13	13

TABLE 3.2.2-7. SUMMARY OF NOx RETROFIT RESULTS FOR WIDOWS CREEK UNITS 7-8

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	7	8
FIRING TYPE	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	11.2	11.7
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	88.7	103.1
FURNACE RESIDENCE TIME (SECONDS)	3.84	2.83
ESTIMATED NOx REDUCTION (PERCENT)	25	20
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	NA
Ductwork Demolition (1000$)	100	97
New Duct Length (Feet)	367	333
New Duct Costs (1000$)	5060	4473
New Heat Exchanger (1000$)	5324	5184
TOTAL SCOPE ADDER COSTS (1000$)	10484	9754
RETROFIT FACTOR FOR SCR	1.52	1.16
GENERAL FACILITIES (PERCENT)	13	13

Table 3.2.2-8. NOx Control Cost Results for the Widows Creek Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	1	1.00	140	29	0.8	2.9	20.9	0.6	1.7	30.0	464	1331.4
LNC-LNB	2	1.00	140	26	0.8	2.9	20.9	0.6	1.9	30.0	416	1485.0
LNC-LNB	3	1.00	140	37	0.8	2.9	20.9	0.6	1.4	30.0	591	1043.5
LNC-LNB	4	1.00	140	35	0.8	2.9	20.9	0.6	1.4	30.0	559	1103.2
LNC-LNB	5	1.00	140	29	0.9	2.9	20.9	0.6	1.7	30.0	464	1331.4
LNC-LNB	6	1.00	140	35	1.1	2.9	20.9	0.6	1.4	30.0	559	1103.2
LNC-LNB-C	1	1.00	140	29	0.8	2.9	20.9	0.4	1.0	30.0	464	791.0
LNC-LNB-C	2	1.00	140	26	0.8	2.9	20.9	0.4	1.1	30.0	416	882.2
LNC-LNB-C	3	1.00	140	37	0.8	2.9	20.9	0.4	0.8	30.0	591	619.9
LNC-LNB-C	4	1.00	140	35	0.8	2.9	20.9	0.4	0.9	30.0	559	655.4
LNC-LNB-C	5	1.00	140	29	0.9	2.9	20.9	0.4	1.0	30.0	464	791.0
LNC-LNB-C	6	1.00	140	35	1.1	2.9	20.9	0.4	0.9	30.0	559	655.4
LNC-OFA	7	1.00	575	24	3.4	1.2	2.2	0.3	0.2	25.0	938	281.0
LNC-OFA	8	1.00	550	38	3.6	1.2	2.2	0.3	0.1	20.0	1136	227.7
LNC-OFA-C	7	1.00	575	24	3.4	1.2	2.2	0.2	0.1	25.0	938	167.0
LNC-OFA-C	8	1.00	550	38	3.6	1.2	2.2	0.2	0.1	20.0	1136	135.3
SCR-3	1	1.34	140	29	0.8	26.2	187.5	8.2	23.0	80.0	1236	6609.5
SCR-3	2	1.34	140	26	0.8	25.8	184.5	8.1	25.3	80.0	1108	7285.2
SCR-3	3	1.34	140	37	0.8	25.4	181.6	8.1	17.8	80.0	1577	5130.4
SCR-3	4	1.34	140	35	0.8	28.1	200.7	8.5	19.9	80.0	1492	5727.1
SCR-3	5	1.34	140	29	0.9	28.1	200.7	8.5	23.9	80.0	1236	6872.5
SCR-3	6	1.34	140	35	1.1	28.3	202.2	8.6	20.0	80.0	1492	5751.8
SCR-3	7	1.52	575	24	3.4	81.6	141.8	27.1	22.4	80.0	3001	9026.4
SCR-3	8	1.16	550	38	3.6	66.6	121.0	23.6	12.9	80.0	4545	5183.5
SCR-3-C	1	1.34	140	29	0.8	26.2	187.5	4.8	13.5	80.0	1236	3882.0
SCR-3-C	2	1.34	140	26	0.8	25.8	184.5	4.7	14.9	80.0	1108	4278.4
SCR-3-C	3	1.34	140	37	0.8	25.4	181.6	4.7	10.5	80.0	1577	3011.7
SCR-3-C	4	1.34	140	35	0.8	28.1	200.7	5.0	11.7	80.0	1492	3365.7

continued . . .

Table 3.2.2-8. NOx Control Cost Results for the Widows Creek Plant (June 1988 Dollars) continued . . .

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
SCR-3-C	5	1.34	140	29	0.9	28.1	200.7	5.0	14.0	80.0	1236	4039.4
SCR-3-C	6	1.34	140	35	1.1	28.3	202.2	5.0	11.7	80.0	1492	3380.5
SCR-3-C	7	1.52	575	24	3.4	81.6	141.8	15.9	13.1	80.0	3001	5293.4
SCR-3-C	8	1.16	550	38	3.6	66.6	121.0	13.8	7.5	80.0	4545	3035.5
SCR-7	1	1.34	140	29	0.8	26.2	187.5	7.0	19.7	80.0	1236	5678.8
SCR-7	2	1.34	140	26	0.8	25.8	184.5	6.9	21.7	80.0	1108	6246.9
SCR-7	3	1.34	140	37	0.8	25.4	181.6	6.9	15.3	80.0	1577	4401.0
SCR-7	4	1.34	140	35	0.8	28.1	200.7	7.4	17.2	80.0	1492	4955.9
SCR-7	5	1.34	140	29	0.9	28.1	200.7	8.5	23.9	80.0	1236	6872.5
SCR-7	6	1.34	140	35	1.1	28.3	202.2	7.4	17.3	80.0	1492	4980.7
SCR-7	7	1.52	575	24	3.4	81.6	141.8	22.4	18.5	80.0	3001	7451.8
SCR-7	8	1.16	550	38	3.6	66.6	121.1	19.0	10.4	80.0	4545	4190.7
SCR-7-C	1	1.34	140	29	0.8	26.2	187.5	4.1	11.6	80.0	1236	3348.8
SCR-7-C	2	1.34	140	26	0.8	25.8	184.5	4.1	12.8	80.0	1108	3683.6
SCR-7-C	3	1.34	140	37	0.8	25.4	181.6	4.1	9.0	80.0	1577	2593.7
SCR-7-C	4	1.34	140	35	0.8	28.1	200.7	4.4	10.2	80.0	1492	2923.9
SCR-7-C	5	1.34	140	29	0.9	28.1	200.7	5.0	14.0	80.0	1236	4039.4
SCR-7-C	6	1.34	140	35	1.1	28.3	202.2	4.4	10.2	80.0	1492	2938.7
SCR-7-C	7	1.52	575	24	3.4	81.6	141.8	13.2	10.9	80.0	3001	4391.2
SCR-7-C	8	1.16	550	38	3.6	66.6	121.1	11.2	6.1	80.0	4545	2466.7

reactor for unit 8 was assigned a low access/congestion factor due to its easy accessibility. All reactors were assumed to be in areas with high underground obstructions. Table 3.2.2-8 presents the estimated cost of retrofitting SCR at the Widows Creek boilers.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas for units 1 through 6 were located east of boiler 1. The retrofit of DSD and FSI technologies at the Widows Creek steam plant for units 1 to 6 would be relatively easy. This is due to the large ESPs (SCA >500) long flue gas duct runs and the subsequent long residence time between the boilers and the retrofit ESPs. If ESP upgrading was required, a high site access/congestion factor was assigned to the ESPs upgrade (1.55) because of the close proximity of the ESPs. The conversion of wet to dry fly ash handling system would also be required for reusing the ESPs. Table 3.2.2-9 presents a summary of site access/congestion factors, scope adders, and retrofit factors for DSD and FSI technologies at the Widows Creek steam plant. Table 3.2.2-10 presents the costs estimated for FSI and DSD retrofit at Widows Creek for boilers 1-6.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

Using the applicability criteria presented in Section 2 for AFBC retrofit and AFBC/CG/combined cycle repowering, boilers 1 to 6 at Widows Creek would be considered good candidates for AFBC retrofit and AFBC or CG/combined cycle repowering because of their small boiler sizes and low capacity factors. Boilers 7 and 8 would not be considered candidates for this retrofit technology because both boilers are equipped with retrofit FGD units.

TABLE 3.2.2-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR WIDOWS CREEK UNITS 1-6

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	1268
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	38
TOTAL COST (1000$)	
ESP UPGRADE CASE	1306
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE	1.55
NEW BAGHOUSE	NA

Table 3.2.2-10. Summary of DSD/FSI Control Costs for the Widows Creek Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	140	29	0.8	7.9	56.4	4.6	13.0	49.0	1117	4142.8
DSD+ESP	2	1.00	140	26	0.8	7.9	56.5	4.6	14.3	49.0	1001	4566.1
DSD+ESP	3	1.00	140	37	0.8	7.9	56.6	4.8	10.6	49.0	1425	3366.8
DSD+ESP	4	1.00	140	35	0.8	7.9	56.3	4.7	11.0	49.0	1348	3517.3
DSD+ESP	5	1.00	140	29	0.9	8.1	58.0	4.7	13.3	49.0	1256	3770.7
DSD+ESP	6	1.00	140	35	1.1	8.5	60.8	5.1	11.8	49.0	1853	2743.2
DSD+ESP-C	1	1.00	140	29	0.8	7.9	56.4	2.7	7.6	49.0	1117	2405.3
DSD+ESP-C	2	1.00	140	26	0.8	7.9	56.5	2.7	8.3	49.0	1001	2651.5
DSD+ESP-C	3	1.00	140	37	0.8	7.9	56.6	2.8	6.1	49.0	1425	1953.9
DSD+ESP-C	4	1.00	140	35	0.8	7.9	56.3	2.8	6.4	49.0	1348	2041.4
DSD+ESP-C	5	1.00	140	29	0.9	8.1	58.0	2.8	7.7	49.0	1256	2189.3
DSD+ESP-C	6	1.00	140	35	1.1	8.5	60.8	3.0	6.9	49.0	1853	1592.3
FSI+ESP-50	1	1.00	140	29	0.8	8.1	58.0	3.7	10.4	50.0	1148	3221.3
FSI+ESP-50	2	1.00	140	26	0.8	8.1	58.0	3.6	11.4	50.0	1029	3518.7
FSI+ESP-50	3	1.00	140	37	0.8	8.1	58.0	3.9	8.6	50.0	1464	2664.2
FSI+ESP-50	4	1.00	140	35	0.8	8.1	58.0	3.9	9.0	50.0	1385	2779.5
FSI+ESP-50	5	1.00	140	29	0.9	8.3	59.0	3.8	10.7	50.0	1291	2953.9
FSI+ESP-50	6	1.00	140	35	1.1	8.5	60.8	4.3	9.9	50.0	1905	2231.5
FSI+ESP-50-C	1	1.00	140	29	0.8	8.1	58.0	2.2	6.1	50.0	1148	1877.3
FSI+ESP-50-C	2	1.00	140	26	0.8	8.1	58.0	2.1	6.6	50.0	1029	2051.4
FSI+ESP-50-C	3	1.00	140	37	0.8	8.1	58.0	2.3	5.0	50.0	1464	1551.3
FSI+ESP-50-C	4	1.00	140	35	0.8	8.1	58.0	2.2	5.2	50.0	1385	1618.8
FSI+ESP-50-C	5	1.00	140	29	0.9	8.3	59.0	2.2	6.2	50.0	1291	1721.0
FSI+ESP-50-C	6	1.00	140	35	1.1	8.5	60.8	2.5	5.8	50.0	1905	1298.6
FSI+ESP-70	1	1.00	140	29	0.8	8.2	58.7	3.7	10.5	70.0	1607	2326.2
FSI+ESP-70	2	1.00	140	26	0.8	8.2	58.7	3.7	11.5	70.0	1441	2540.4
FSI+ESP-70	3	1.00	140	37	0.8	8.2	58.7	3.9	8.7	70.0	2050	1925.0
FSI+ESP-70	4	1.00	140	35	0.8	8.2	58.7	3.9	9.1	70.0	1939	2008.0
FSI+ESP-70	5	1.00	140	29	0.9	8.4	59.7	3.9	10.8	70.0	1808	2134.2
FSI+ESP-70	6	1.00	140	35	1.1	8.6	61.6	4.3	10.0	70.0	2666	1614.7
FSI+ESP-70-C	1	1.00	140	29	0.8	8.2	58.7	2.2	6.1	70.0	1607	1355.7
FSI+ESP-70-C	2	1.00	140	26	0.8	8.2	58.7	2.1	6.7	70.0	1441	1481.1
FSI+ESP-70-C	3	1.00	140	37	0.8	8.2	58.7	2.3	5.1	70.0	2050	1120.9
FSI+ESP-70-C	4	1.00	140	35	0.8	8.2	58.7	2.3	5.3	70.0	1939	1169.5
FSI+ESP-70-C	5	1.00	140	29	0.9	8.4	59.7	2.2	6.3	70.0	1808	1243.5
FSI+ESP-70-C	6	1.00	140	35	1.1	8.6	61.6	2.5	5.8	70.0	2666	939.6

SECTION 4.0 DELAWARE

4.1 DELMARVA POWER AND LIGHT COMPANY

4.1.1 Indian River Steam Plant

The Indian River steam plant is located within Sussex County, Delaware, as part of the Delmarva Power and Light Company system. Adjacent to the Indian River, the plant contains four coal-fired boilers and has a total gross generating capacity of 780 MW.

Table 4.1.1-1 presents operational data for the existing equipment at the Indian River plant. Boilers 1-3 burn 1.4 percent sulfur coal and unit 4 burns 0.75 percent sulfur coal (1971 NSPS unit). Coal shipments are received by railroad and transferred to a coal storage and handling area east of the plant and beside the Indian River.

PM emissions for the boilers are controlled with ESPs located behind each unit. The plant has a dry fly ash handling system. Fly ash is disposed of in an ash pond east of the coal pile. Units 1 through 4 are served by their own chimneys located behind the ESPs.

Lime/Limestone and Lime Spray Drying FGD Costs--

The four boilers are located beside each other with boiler 1 being close to the Indian River and boiler 4 being away from the river. The absorbers for units 1 through 4 would be located behind the unit 4 chimney and close to the coal pile. Unit 4 is currently burning low sulfur coal and, as such, scrubbing would not be required. Although retrofit factors were developed for this unit, capital and operating costs were not. The limestone preparation, storage, and handling area would be located south and east of the coal pile. Some of the plant roads, coal storage area, and a coal conveyor would have to be relocated to make space available for the FGD absorbers. Therefore, a factor of 15 percent was assigned to general facilities.

The Indian River plant is surrounded by water and very limited space is available for locating FGD absorbers. FGD absorbers for units 1-3 were not

TABLE 4.1.1-1. INDIAN RIVER STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3	4
GENERATING CAPACITY (MW-each)	81	176	442
CAPACITY FACTOR (PERCENT)	73	64	54
INSTALLATION DATE	1957,59	1970	1980
FIRING TYPE	FRONT WALL	FRONT WALL	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	47.6,36.5	91.4	NA
LOW NOX COMBUSTION	NO	NO	NO
COAL SULFUR CONTENT (PERCENT)	1.4	1.4	0 .75
COAL HEATING VALUE (BTU/LB)	12700	12700	13200
COAL ASH CONTENT (PERCENT)	10.5	10.5	7.5
FLY ASH SYSTEM		DRY HANDLING	
ASH DISPOSAL METHOD		ON-SITE	
STACK NUMBER	1,2	3	4
COAL DELIVERY METHODS		RAILROAD	
<u>PARTICULATE CONTROL</u>			
TYPE	ESP	ESP	ESP
INSTALLATION DATE	1977,78	1981	1980
EMISSION (LB/MM BTU)	0.18,0.11	0.07	0.04
REMOVAL EFFICIENCY	99.5	99.5	99.5
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	1.8	1.8	0.9
SURFACE AREA (1000 SQ FT)	99.4	207.4	1210
GAS EXIT RATE (1000 ACFM)	298	525	1956
SCA (SQ FT/1000 ACFM)	333	395	618
OUTLET TEMPERATURE (°F)	270	285	300

located behind their respective chimneys due to major demolition/relocation that would be necessary. Therefore, the site behind unit 4 was selected for all units. This location has a high site access/congestion factor due to the access/congestion difficulties created by the coal pile and coal conveyors.

For flue gas handling, long duct runs (over 1000 feet) would be required for units 1-3 if chimneys are reused. Therefore, a new chimney was assumed to reduce the need for long return duct runs. Short duct runs were assigned to the unit 4 flue gas handling system because its absorbers can be placed immediately behind the unit 4 chimney. A high site access/congestion factor was assigned to the flue gas handling systems due to the access/congestion difficulties of this location.

LSD with reuse of the existing ESPs was not considered for units 1-3. Even though the ESPs are large (SCA >300) and would probably handle the increased load from LSD application, access to the inlet of the ESPs is extremely difficult. This could result in long boiler downtimes for tie-in. LSD with a new baghouse was not considered for units 1-3 because of a limited space available to locate both the absorbers, baghouses, a new chimney, and the long duct run requirements. For unit 4, ESPs may be accessed from the north side and absorbers would be located behind the chimney. A high site access/congestion factor was assumed for the absorber locations and the flue gas handling system. No major ESP upgrade would be anticipated because the ESPs are large (SCA >600).

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Table 4.1.1-2 and 4.1.1-3. Table 4.1.1-4 presents the capital and operating costs for commercial FGD technologies. Costs for unit 4 are not presented because the unit is burning low sulfur coal. The low cost FGD system for units 1-3 reduces capital costs because of the economies of scale obtained by combining the FGD systems and using large absorber sizes and eliminating spare absorber modules.

Coal Switching and Physical Coal Cleaning Costs--

Table 4.1.1-5 presents the IAPCS cost results for CS at the Indian River boilers 1-3. These costs do not include boiler and pulverizer

TABLE 4.1.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR INDIAN RIVER UNITS 1-3 (EACH)

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	NA	NA
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	600-1000	NA	
ESP REUSE			NA
BAGHOUSE			NA
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NA
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	NA	NA
ESTIMATED COST (1000$)	567	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.76	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	0

TABLE 4.1.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR INDIAN RIVER UNIT 4

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	NA	HIGH
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			600-1000
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.53	NA	
ESP REUSE CASE			1.76
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	8

Table 4.1.1-4. Summary of FGD Control Costs for the Indian River Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
LC FGD	1-3	1.76	338	68	1.4	70.5	208.6	36.4	18.0	90.0	18753	1939.0
LC FGD-C	1-3	1.76	338	68	1.4	70.5	208.6	21.1	10.5	90.0	18753	1127.8
LFGD	1,2	1.76	81	73	1.4	44.3	546.8	20.1	38.7	90.0	4934	4066.1
LFGD	3	1.76	176	64	1.4	64.6	367.2	29.2	29.6	90.0	9398	3108.8
LFGD-C	1,2	1.76	81	73	1.4	44.3	546.8	11.7	22.6	90.0	4934	2369.8
LFGD-C	3	1.76	176	64	1.4	64.6	367.2	17.0	17.3	90.0	9398	1811.9

Table 4.1.1-5. Summary of Coal Switching/Cleaning Costs for the Indian River Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1, 2	1.00	81	73	1.4	3.5	43.5	7.9	15.3	32.0	1742	4556.3
CS/B+$15	3	1.00	176	64	1.4	6.4	36.6	14.5	14.7	32.0	3318	4382.7
CS/B+$15-C	1, 2	1.00	81	73	1.4	3.5	43.5	4.6	8.8	32.0	1742	2619.5
CS/B+$15-C	3	1.00	176	64	1.4	6.4	36.6	8.4	8.5	32.0	3318	2519.7
CS/B+$5	1, 2	1.00	81	73	1.4	2.7	33.1	3.5	6.8	32.0	1742	2015.5
CS/B+$5	3	1.00	176	64	1.4	4.6	26.2	6.1	6.2	32.0	3318	1829.9
CS/B+$5-C	1, 2	1.00	81	73	1.4	2.7	33.1	2.0	3.9	32.0	1742	1161.6
CS/B+$5-C	3	1.00	176	64	1.4	4.6	26.2	3.5	3.5	32.0	3318	1054.6

operating cost changes or any system modifications that may be necessary to blend coal. PCC was not evaluated because this is not a mine mouth plant.

Low NO_x Combustion

Units 1-3 are dry bottom, wall-fired boilers. The combustion modification technique applied to these boilers was LNB. Tables 4.1.1-6 and 4.1.1-7 present the performance and cost results of retrofitting LNB at the Indian River plant. Unit 4 was assumed to already have LNBs as an NSPS unit.

Selective Catalytic Reduction

Cold side SCR reactors for units 1-3 would be located in the small space available between the coal pile and units 1 and 2. The SCR reactor for unit 4 would be located immediately behind the unit 4 chimney. Reactors for units 1-3 are located in high site access/congestion areas. The space between units 1-2 and the coal pile is very congested because of the ash silos, coal conveyors, and ESPs. Two of the ash silos have to be relocated to open up more space for units 1-3 reactors; therefore, a factor of 35 percent was assigned to general facilities. Access to unit 4 reactor area is difficult because of the coal conveyor. However, sufficient space is available behind the chimney and a medium site access/congestion factor was assigned to the unit 4 reactor location. All reactors were assumed to be in areas with high underground obstructions. The ammonia storage system was placed close to the coal pile in a similar layout as the sorbent storage/ preparation area for the case of wet FGD. Duct lengths of 250 feet were estimated for the flue gas handling systems.

Table 4.1.1-6 presents the SCR process area retrofit factors and scope adder costs. Table 4.1.1-7 presents the estimated cost of retrofitting SCR at the Indian River boilers.

Duct Spray Drying and Furnace Sorbent Injection--

The retrofit of sorbent injection technologies at the Indian River steam plant for all units would be difficult because the short duct residence time between the boilers and the ESPs would not be sufficient for either humidification (FSI application) or sorbent evaporation (DSD

TABLE 4.1.1-6. SUMMARY OF NOx RETROFIT RESULTS FOR INDIAN RIVER

	BOILER NUMBER			
COMBUSTION MODIFICATION RESULTS				
	1,2	3	1-3	4
FIRING TYPE	FWF	FWF	NA	OWF
TYPE OF NOx CONTROL	LNB	LNB	NA	LNB
FURNACE VOLUME (1000 CU FT)	47.6	91.4	NA	NA
BOILER INSTALLATION DATE	1959	1970	NA	1980
SLAGGING PROBLEM	NO	NO	NA	NO
ESTIMATED NOx REDUCTION (PERCENT)	40	36	NA	NA
SCR RETROFIT RESULTS				
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH	HIGH	MEDIUM
SCOPE ADDER PARAMETERS--				
Building Demolition (1000$)	0	0	0	0
Ductwork Demolition (1000$)	23	41	67	82
New Duct Length (Feet)	250	250	250	250
New Duct Costs (1000$)	1095	1724	2526	2955
New Heat Exchanger (1000$)	1642	2616	3870	4546
TOTAL SCOPE ADDER COSTS (1000$)	2761	4382	6464	7584
RETROFIT FACTOR FOR SCR	1.52	1.52	1.52	1.34
GENERAL FACILITIES (PERCENT)	35	35	35	13

Table 4.1.1-7. NOx Control Cost Results for the Indian River Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	1, 2	1.00	81	73	1.4	2.3	29.0	0.5	1.0	40.0	843	610.4
LNC-LNB	3	1.00	176	64	1.4	3.2	18.2	0.7	0.7	36.0	1446	485.7
LNC-LNB-C	1, 2	1.00	81	73	1.4	2.3	29.0	0.3	0.6	40.0	843	362.2
LNC-LNB-C	3	1.00	176	64	1.4	3.2	18.2	0.4	0.4	36.0	1446	288.2
SCR-3	1, 2	1.52	81	73	1.4	20.8	256.4	6.6	12.8	80.0	1687	3924.7
SCR-3	3	1.52	176	64	1.4	34.5	196.1	11.4	11.6	80.0	3213	3555.5
SCR-3	4	1.34	442	54	0.8	59.9	135.6	21.5	10.3	80.0	6513	3295.6
SCR-3	1-3	1.52	338	68	1.4	57.3	169.5	19.7	9.8	80.0	6556	3000.8
SCR-3-C	1, 2	1.52	81	73	1.4	20.8	256.4	3.9	7.5	80.0	1687	2303.8
SCR-3-C	3	1.52	176	64	1.4	34.5	196.1	6.7	6.8	80.0	3213	2085.2
SCR-3-C	4	1.34	442	54	0.8	59.9	135.6	12.6	6.0	80.0	6513	1929.4
SCR-3-C	1-3	1.52	338	68	1.4	57.3	169.5	11.5	5.7	80.0	6556	1758.4
SCR-7	1, 2	1.52	81	73	1.4	20.8	256.4	6.0	11.5	80.0	1687	3533.3
SCR-7	3	1.52	176	64	1.4	34.5	196.1	10.0	10.1	80.0	3213	3109.1
SCR-7	4	1.34	442	54	0.8	59.9	135.6	17.9	8.6	80.0	6513	2745.7
SCR-7	1-3	1.52	338	68	1.4	57.3	169.5	16.9	8.4	80.0	6556	2580.7
SCR-7-C	1, 2	1.52	81	73	1.4	20.8	256.4	3.5	6.8	80.0	1687	2079.6
SCR-7-C	3	1.52	176	64	1.4	34.5	196.1	5.9	6.0	80.0	3213	1829.4
SCR-7-C	4	1.34	442	54	0.8	59.9	135.6	10.5	5.0	80.0	6513	1614.4
SCR-7-C	1-3	1.52	338	68	1.4	57.3	169.5	10.0	4.9	80.0	6556	1517.7

application). However, both technologies were considered for this plant because the ESPs are large enough to modify the first ESP sections for humidification and sorbent injection. The sorbent receiving/storage/ preparation areas were located behind the unit 4 chimney.

Tables 4.1.1-8 and 4.1.1-9 present a summary of the site access/ congestion factors for sorbent injection technologies at the Indian River steam plant. Table 4.1.1-10 presents the costs estimated to retrofit FSI and DSD at the Indian River boilers.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Indian River plant. Units 1-2 would be considered good candidates for repowering or retrofit because of their small boiler sizes. Units 3-4 would not be considered because of their age and/or size.

TABLE 4.1.1-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR INDIAN RIVER UNITS 1-3 (EACH)

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	26
TOTAL COST (1000$)	
ESP UPGRADE CASE	26
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

TABLE 4.1.1-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR INDIAN RIVER UNIT 4

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	91
TOTAL COST (1000$)	
ESP UPGRADE CASE	91
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Table 4.1.1-10. Summary of DSD/FSI Control Costs for the Indian River Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1, 2	1.00	81	73	1.4	5.5	68.3	5.3	10.2	49.0	2667	1972.7
DSD+ESP	3	1.00	176	64	1.4	8.4	47.7	7.1	7.2	49.0	5080	1401.0
DSD+ESP	4	1.00	442	54	0.8	11.4	25.7	8.6	4.1	49.0	5885	1460.2
DSD+ESP-C	1, 2	1.00	81	73	1.4	5.5	68.3	3.0	5.9	49.0	2667	1139.5
DSD+ESP-C	3	1.00	176	64	1.4	8.4	47.7	4.1	4.2	49.0	5080	810.1
DSD+ESP-C	4	1.00	442	54	0.8	11.4	25.7	5.0	2.4	49.0	5885	845.2
FSI+ESP-50	1, 2	1.00	81	73	1.4	5.9	73.3	4.6	8.8	50.0	2741	1661.4
FSI+ESP-50	3	1.00	176	64	1.4	8.5	48.4	6.8	6.8	50.0	5221	1292.8
FSI+ESP-50	4	1.00	442	54	0.8	12.9	29.2	8.6	4.1	50.0	6048	1420.1
FSI+ESP-50-C	1, 2	1.00	81	73	1.4	5.9	73.3	2.6	5.1	50.0	2741	961.6
FSI+ESP-50-C	3	1.00	176	64	1.4	8.5	48.4	3.9	4.0	50.0	5221	748.0
FSI+ESP-50-C	4	1.00	442	54	0.8	12.9	29.2	5.0	2.4	50.0	6048	823.2
FSI+ESP-70	1, 2	1.00	81	73	1.4	6.0	74.6	4.6	8.9	70.0	3837	1203.9
FSI+ESP-70	3	1.00	176	64	1.4	8.6	49.1	6.9	7.0	70.0	7310	938.8
FSI+ESP-70	4	1.00	442	54	0.8	13.1	29.5	8.7	4.2	70.0	8467	1029.7
FSI+ESP-70-C	1, 2	1.00	81	73	1.4	6.0	74.6	2.7	5.2	70.0	3837	696.8
FSI+ESP-70-C	3	1.00	176	64	1.4	8.6	49.1	4.0	4.0	70.0	7310	543.2
FSI+ESP-70-C	4	1.00	442	54	0.8	13.1	29.5	5.1	2.4	70.0	8467	596.9

SECTION 5.0 FLORIDA

5.1 FLORIDA POWER CORPORATION

5.1.1 Crystal River Steam Plant

The Crystal River steam plant is located within Citrus County, Florida, as part of the Florida Power Corporation system. The plant is located near Crystal River City and adjacent to Crystal River Bay on the Gulf of Mexico. The plant contains four coal-fired and one nuclear boiler with a total gross generating capacity of 3,116 MW.

Table 5.1.1-1 presents operational data for the existing equipment at the Crystal River plant. The boilers burn low sulfur coal (0.7 to 1.0 percent). Coal shipments are received by barge/railroad and are transferred to the units 1-2 coal storage and handling area. Part of the coal is then transferred by a coal conveyor to a second coal pile east of units 4-5. Units 4-5 comply with the 1971 NSPS emission limit of <1.2 lbs SO_2 per MM Btu.

PM emissions for the boilers are controlled with new or retrofit ESPs located behind each unit. The plant has a dry fly ash handling system. Almost half of the fly ash is sold while the rest of it is disposed of on-site. In addition, the plant has the capability to sluice the fly ash in case of an emergency. All units have separate chimneys located behind each unit.

Lime/Limestone and Lime Spray Drying FGD Costs--

Units 1-2 are located beside each other and between the water channel and the water intake channel. Unit 3 (nuclear) is located east of unit 1. The absorbers for units 1-2 for both conventional and LSD-FGD cases would be located west of unit 2 in an open space between the unit 2 retrofit ESPs and the oil tanks. Space is also available east of unit 1. However, unit 1 is located very close to the nuclear unit and might cause some interferences. Therefore, this location was not considered in this study.

TABLE 5.1.1-1. CRYSTAL RIVER STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2	4, 5	3
GENERATING CAPACITY (MW-each)	420	476	665	890
CAPACITY FACTOR (PERCENT)	63	63	80	31
INSTALLATION DATE	1966	1969	1982, 84	1977
FIRING TYPE	TANGENTIAL		FRONT WALL	NUCLEAR POWER
FURNACE VOLUME (1000 CU FT)	228.5	NA	734	
LOW NOx COMBUSTION	NO	NO	YES	
COAL SULFUR CONTENT (PERCENT)	1.0	1.0	0.7	
COAL HEATING VALUE (BTU/LB)	12300	12300	12500	
COAL ASH CONTENT (PERCENT)	NA	NA	NA	
FLY ASH SYSTEM	DRY HANDLING			
ASH DISPOSAL METHOD	ON-SITE/SOLD			
STACK NUMBER	1	2	3-4	
COAL DELIVERY METHODS	BARGE/RAILROAD			
PARTICULATE CONTROL				
TYPE	ESP	ESP	ESP	
INSTALLATION DATE	1979	1979	1982, 84	
EMISSION (LB/MM BTU)	0.05	0.02	0.02-0.01	
REMOVAL EFFICIENCY	99.5	99.5	99.8	
DESIGN SPECIFICATION				
SULFUR SPECIFICATION (PERCENT)	1.3	1.3	0.8	
SURFACE AREA (1000 SQ FT)	432	1351	1582	
GAS EXIT RATE (1000 ACFM)	1415	1930	2348	
SCA (SQ FT/1000 ACFM)	305	700	674	
OUTLET TEMPERATURE (°F)	292	300	282, 287	

The absorbers for units 4-5 would be located behind the chimneys on either side of the coal conveyor for conventional FGD cases and on the side of each unit for the LSD case. No major demolition or relocation would be necessary for any of the units except units 4-5 in the LSD case. Because the absorbers for units 4-5 in the LSD-FGD case are located on the side of each unit, some of the storage areas and one of the ash silos would have to be relocated. Therefore, general facilities factors of 5 and 10 percent were assigned to the FGD costs accordingly. Sorbent storage and handling areas would be located south of the coal pile serving units 4-5 and close to the railroad tracks so that the existing tracks can be used for sorbent transfer.

A medium site access/congestion factor was assigned to the FGD absorber locations serving units 1-2 due to some access difficulties to this area created by the water channel, oil tanks, and units 1-2. For units 4-5, a low site access/congestion factor was assigned for the conventional FGD absorber locations. For flue gas handling, a long duct length with a high site access/congestion factor would be required for unit 1 because the chimney serving unit 1 is located away from the absorbers and access to this chimney is difficult. Because over 1,000 feet of duct would be needed to reuse the existing chimney, a new chimney would be located adjacent to the absorbers for unit 1. For units 2 and 4-5, a low site access/congestion factor was assigned due to relatively short duct runs and because of the open space available around the existing chimneys.

LSD with a new baghouse was considered for unit 1 because plant personnel indicated that on occasion SO_3 conditioning is necessary to meet the emission levels. Because of this problem and the location of the ESPs (away from the absorber location), the ESPs for unit 1 were not reused for the LSD-FGD case. A new baghouse and chimney were located close to the LSD absorbers which were located in a similar layout to the conventional wet FGD. A medium site access/congestion factor was also assigned to the new baghouse location. Reuse of the existing ESPs was considered for the other three units. For unit 2, a low site access/congestion factor was assigned to the flue gas handling system with a short to moderate duct run being required. For units 4-5, LSD absorbers would be located on either side of the units. However, access to the existing ESPs would be difficult due to the limited space available between the ESPs and the boilers. A high site access/congestion factor was assigned to the flue gas handling system.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Tables 5.1.1-2 through 5.1.1-4. Because all boilers currently burn low sulfur coal, an FGD system would only be considered at the plant if SO_2 emission levels were very low (<1.2 lbs per MM Btu) or the price differential between low and high sulfur coal made scrubbing economical. As such, FGD cost estimates are not presented for the currently used coal.

Coal Switching and Physical Coal Cleaning Costs--

Because the Crystal River plant already burns a low sulfur coal, costs were not developed for CS or PCC.

Low NO_x Combustion--

Units 1-2 are dry bottom, tangential-fired boilers rated at 420 and 476 MW, respectively. The combustion modification technique applied to these boilers was OFA. As Table 5.1.1-5 shows, the OFA NO_x reduction performance level was based on the low volumetric heat release rate. Units 4-5 are already equipped with LNB and are not considered as LNC candidates. Table 5.1.1-6 presents the cost of retrofitting OFA at the Crystal River plant.

Selective Catalytic Reduction--

Cold side SCR reactors for all units would be located behind the chimney or to the side of the unit. A low site access/congestion factor was assigned to all reactor locations. Approximately 200 feet of duct would be required for all units. No major demolition/relocation would be required for placement of the SCR reactors; therefore, a base factor of 13 percent was assigned to general facilities. The ammonia storage system was placed near the railroad tracks and close to the coal pile serving units 4-5.

Table 5.1.1-5 presents the SCR retrofit factors and scope adder costs. The scope adders include costs estimated for ductwork demolition, flue gas heat exchangers, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimney. Table 5.1.1-6 presents the

TABLE 5.1.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR CRYSTAL RIVER UNIT 1

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	MEDIUM
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			HIGH
DUCT WORK DISTANCE (FEET)	600-1000	NA	
ESP REUSE			
BAGHOUSE			600-1000
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	MEDIUM
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	2940	0	2940
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.65	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.69
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.36
GENERAL FACILITIES (PERCENT)	5	0	5

TABLE 5.1.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR CRYSTAL RIVER UNIT 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	MEDIUM
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			LOW
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.41	NA	
ESP REUSE CASE			1.40
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	5

TABLE 5.1.1-4. SUMMARY OF RETROFIT FACTOR DATA FOR CRYSTAL RIVER UNIT 4 OR 5

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			
BAGHOUSE			300-600
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.20	NA	
ESP REUSE CASE			1.36
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	10

TABLE 5.1.1-5. SUMMARY OF NOx RETROFIT RESULTS FOR CRYSTAL RIVER

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	4,5
FIRING TYPE	TANG	TANG	FWF
TYPE OF NOx CONTROL	OFA	OFA	LNB
FURNACE VOLUME (1000 CU FT)	228.5	NA	734
BOILER INSTALLATION DATE	1966	1969	1982
SLAGGING PROBLEM	NO	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	25	25	NA
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	LOW
SCOPE ADDER PARAMETERS--			
New Chimney (1000$)	0	0	0
Ductwork Demolition (1000$)	79	87	112
New Duct Length (Feet)	200	200	200
New Duct Costs (1000$)	2294	2469	3002
New Heat Exchanger (1000$)	4409	4753	5809
TOTAL SCOPE ADDER COSTS (1000$)	6782	7309	8923
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13	13

Table 5.1.1-6. NOx Control Cost Results for the Crystal River Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	1	1.00	420	63	1.0	1.1	2.6	0.2	0.1	25.0	1748	133.2
LNC-OFA	2	1.00	476	63	1.0	1.2	2.4	0.2	0.1	25.0	1981	123.5
LNC-OFA-C	1	1.00	420	63	1.0	1.1	2.6	0.1	0.1	25.0	1748	79.1
LNC-OFA-C	2	1.00	476	63	1.0	1.2	2.4	0.1	0.1	25.0	1981	73.4
SCR-3	1	1.16	420	63	1.0	52.1	124.1	18.8	8.1	80.0	5593	3364.6
SCR-3	2	1.16	476	63	1.0	58.1	122.2	21.1	8.0	80.0	6339	3328.3
SCR-3	4,5	1.16	665	80	0.7	77.5	116.6	29.8	6.4	80.0	15454	1929.5
SCR-3-C	1	1.16	420	63	1.0	52.1	124.1	11.0	4.8	80.0	5593	1969.5
SCR-3-C	2	1.16	476	63	1.0	58.1	122.2	12.3	4.7	80.0	6339	1948.0
SCR-3-C	4,5	1.16	665	80	0.7	77.5	116.6	17.4	3.7	80.0	15454	1128.0
SCR-7	1	1.16	420	63	1.0	52.1	124.1	15.4	6.6	80.0	5593	2749.8
SCR-7	2	1.16	476	63	1.0	58.1	122.2	17.2	6.5	80.0	6339	2713.5
SCR-7	4,5	1.16	665	80	0.7	77.5	116.6	24.4	5.2	80.0	15454	1578.0
SCR-7-C	1	1.16	420	63	1.0	52.1	124.1	9.0	3.9	80.0	5593	1617.2
SCR-7-C	2	1.16	476	63	1.0	58.1	122.2	10.1	3.9	80.0	6339	1595.8
SCR-7-C	4,5	1.16	665	80	0.7	77.5	116.6	14.3	3.1	80.0	15454	926.6

estimated cost of retrofitting SCR at the Crystal River boilers. Retrofit of hot side SCR system would result in a unit downtime penalty. The replacement cost could be significant for these large baseload units.

Duct Spray Drying and Furnace Sorbent Injection--

The retrofit of FSI and DSD technologies at the Crystal River steam plant would be difficult for unit 1 for two major reasons: 1) the retrofit ESPs might not be able to handle the increased PM and would require major ESP upgrades and additional plate area; and 2) the short duct residence time between the boilers and ESPs would not be sufficient for either humidification (FSI application) or for sorbent evaporation (DSD application). By contrast, retrofit of FSI and DSD technologies on unit 2 would be easy. This is due to the long duct run between the boiler and retrofit ESP and to the fact that this ESP is oversized for its current load. For these reasons, unit 2 is a good candidate for DSD or FSI technologies. For units 4-5, the application of these two technologies would also be difficult for the latter reason. However, FSI and DSD technology was considered for these units because the ESPs could be modified for humidification and additional plate area could be added downstream of the ESPs.

A high site access/congestion factor was assigned for upgrading the unit 1 ESP because of access difficulty and some congestion that is created by the office building, ash silos, and chimney. For units 4-5, a low site access/congestion factor was assigned for the ESP upgrades because of the space availability behind the ESPs. The sorbent receiving/storage/ preparation areas would be located west of unit 2 for units 1-2 and east of unit 4 for units 4-5.

Tables 5.1.1-7 through 5.1.1-9 present a summary of the site access/ congestion factors for FSI and DSD technologies at the Crystal River steam plant. Table 5.1.1-10 presents the costs estimated to retrofit FSI and DSD at the Crystal River boilers. The high unit costs are a result of units burning low sulfur coal.

TABLE 5.1.1-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR CRYSTAL RIVER UNIT 1

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	88
TOTAL COST (1000$)	
ESP UPGRADE CASE	88
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

TABLE 5.1.1-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR CRYSTAL RIVER UNIT 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE	LOW
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	96
TOTAL COST (1000$)	
ESP UPGRADE CASE	96
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE	1.16
NEW BAGHOUSE	NA

TABLE 5.1.1-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR CRYSTAL RIVER UNITS 4 OR 5

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	LOW
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	124
TOTAL COST (1000$)	
ESP UPGRADE CASE	124
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.16
NEW BAGHOUSE	NA

Table 5.1.1-10. Summary of DSD/FSI Control Costs for the Crystal River Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	420	63	1.0	13.2	31.5	9.8	4.2	49.0	8843	1107.9
DSD+ESP	2	1.00	476	63	1.0	13.5	28.3	10.4	4.0	49.0	10022	1042.7
DSD+ESP	4,5	1.00	665	80	0.7	15.4	23.1	12.8	2.8	49.0	12218	1051.5
DSD+ESP-C	1	1.00	420	63	1.0	13.2	31.5	5.7	2.4	49.0	8843	641.5
DSD+ESP-C	2	1.00	476	63	1.0	13.5	28.3	6.0	2.3	49.0	10022	603.4
DSD+ESP-C	4,5	1.00	665	80	0.7	15.4	23.1	7.4	1.6	49.0	12218	608.1
FSI+ESP-50	1	1.00	420	63	1.0	15.7	37.3	10.7	4.6	50.0	9089	1180.5
FSI+ESP-50	2	1.00	476	63	1.0	13.7	28.8	11.0	4.2	50.0	10300	1063.9
FSI+ESP-50	4,5	1.00	665	80	0.7	16.0	24.1	13.2	2.8	50.0	12557	1050.3
FSI+ESP-50-C	1	1.00	420	63	1.0	15.7	37.3	6.2	2.7	50.0	9089	684.1
FSI+ESP-50-C	2	1.00	476	63	1.0	13.7	28.8	6.3	2.4	50.0	10300	615.5
FSI+ESP-50-C	4,5	1.00	665	80	0.7	16.0	24.1	7.6	1.6	50.0	12557	607.5
FSI+ESP-70	1	1.00	420	63	1.0	15.8	37.6	10.9	4.7	70.0	12724	856.0
FSI+ESP-70	2	1.00	476	63	1.0	13.9	29.1	11.1	4.2	70.0	14420	772.9
FSI+ESP-70	4,5	1.00	665	80	0.7	16.3	24.5	13.4	2.9	70.0	17579	764.4
FSI+ESP-70-C	1	1.00	420	63	1.0	15.8	37.6	6.3	2.7	70.0	12724	496.0
FSI+ESP-70-C	2	1.00	476	63	1.0	13.9	29.1	6.4	2.5	70.0	14420	447.1
FSI+ESP-70-C	4,5	1.00	665	80	0.7	16.3	24.5	7.8	1.7	70.0	17579	442.1

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Crystal River plant. None of the boilers would be considered good candidates for repowering and retrofit because of their large size, short service life, and high capacity factor.

5.2 GULF POWER COMPANY

5.2.1 Crist Electric Generating Plant

The Crist Electric Generating Plant is located near the mouth of the Escambia River in Escambia County near Pensacola, Florida, and is owned and operated by the Gulf Power Company. The Crist plant contains four coal-fired and three oil and gas-fired boilers with a total gross generating capacity of 1107 MW. The generating capacity of the four coal-fired boilers is 1022 MW.

Table 5.2.1-1 presents operational data for the existing equipment at the Crist plant. Shipments of coal are received by barge and transferred to a coal storage and handling area adjacent to the plant. PM emissions from two of the coal-fired boilers (6 and 7) are controlled by ESPs installed at the time of construction. PM emissions from the other two coal-fired boilers are controlled by retrofit ESPs in series with original ESPs. ESPs for all four units are located behind the boilers. Flue gases from boilers 1-5 are ducted to one chimney while the flue gas from boilers 6-7 is ducted to another chimney. Flyash from the coal-fired generating units is collected, dried, and pneumatically conveyed to storage tanks on the west side of the property. This ash is sold, when possible, otherwise it is transported by truck to a state permitted landfill on the west edge of the property.

Lime/Limestone and Lime Spray Drying FGD Costs--

Because the coal pile is located directly behind units 4-7, the absorbers for units 4-5 would be located east of unit 1 after relocating demineralizer/condensate storage tanks and No. 2 oil storage tanks adjacent to unit 1. These tanks would be relocated to a new location further south. For units 6-7, absorbers would be located west of unit 5 adjacent to the cooling towers, west of the office and general repair building. Additional ductwork would be required to go around the existing dry ash handling bridge.

A high site access/congestion factor would be assigned to the FGD absorber locations because of the space limitation created by the proximity

TABLE 5.2.1-1. CRIST POWER COMPANY OPERATIONAL DATA

BOILER NUMBER	1-3	4-5	6	7
GENERATING CAPACITY (MW-each)	28, 28, 38	88,89	327	519
CAPACITY FACTOR (PERCENT)	2,3	46	44	27
INSTALLATION DATE	1945,52	1958,61	1970	1973
FIRING TYPE	GAS FIRED	TANG	FRONT WALL	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)		42.4	158	282
LOW NOx COMBUSTION			NO	
COAL SULFUR CONTENT (PERCENT)			2.4	
COAL HEATING VALUE (BTU/LB)			12100	
COAL ASH CONTENT (PERCENT)			9.4	
FLY ASH SYSTEM			WET	
ASH DISPOSAL METHOD			ON-SITE/SOLD	
STACK NUMBER		1	2	2
COAL DELIVERY METHODS			BARGE	

<u>PARTICULATE CONTROL</u>

TYPE	ESP (COLD & HOT SIDE)	ESP	ESP
INSTALLATION DATE	NA	NA	NA
EMISSION (LB/MM BTU)	0.02	0.04	0.08
REMOVAL EFFICIENCY	99.0	98.5	98.5
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	0.5-3.5	0.6-3.5	0.6-3.5
SURFACE AREA (1000 SQ FT)	184	69.1	1582
GAS EXIT RATE (1000 ACFM)	515	505	2348
SCA (SQ FT/1000 ACFM)	357	137	158
OUTLET TEMPERATURE (°F)	650	283	285

of the river, the channels, and auxiliary equipment. In the L/LS-FGD case, medium to long duct runs would be required. A high site access/congestion factor was assigned to the flue gas handling system because of the difficulties accessing the downstream of the ESPs. For units 6-7, a new chimney would need to be installed close to the absorbers to reduce the duct length and congestion. Plant personnel indicated that construction of a new chimney may be difficult due to the close proximity of the Municipal airport.

LSD with reuse of the existing ESPs was not considered for units 4-5 because the units are equipped with an arrangement of cold and hot side ESPs which are not easy to reuse. For units 6-7, the access to the ESPs is difficult; therefore, reuse of the existing ESPs was not considered. LSD with a new baghouse was not considered for units 6-7 because the boilers are burning medium to high sulfur coal. (Gulf Power, under contract to EPRI, has been operating a high sulfur coal baghouse test facility at its Scholz steam plant.)

Tables 5.2.1-2 and 5.2.1-3 give a summary of retrofit data for commercial FGD technologies. Table 5.2.1-4 presents the FGD capital and operating cost results. The low cost FGD cases show the benefits of combining FGD systems to obtain economy of scale, eliminating spare absorber modules, and maximizing absorber size. Limited space is available on site for waste disposal. Plant personnel indicated that the wet sludge has to be transported by truck to a disposal site approximately ten miles away (this value was used in this study).

Coal Switching and Physical Coal Cleaning Costs--

Table 5.2.1-5 presents the IAPCS cost results for CS at the Crist plant. These costs do not include boiler and pulverizer operating cost changes or any system modifications that may be necessary to blend coal. PCC was not evaluated because this is not a mine mouth plant.

Low NO_x Combustion--

Boilers 4-7 at the Crist steam plant are rated at 88, 89, 327, and 519 MW, respectively. The combustion modification techniques applied to

TABLE 5.2.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR CRIST UNIT 4 OR 5

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	NA	NA
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			NA
BAGHOUSE			NA
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NA
ESTIMATED COST (1000$)	887	NA	NA
NEW CHIMNEY	NO	NA	NA
ESTIMATED COST (1000$)	0	0	0
OTHER	YES		NO
RETROFIT FACTORS			
FGD SYSTEM	1.88	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	0

TABLE 5.2.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR CRIST UNIT 6 OR 7

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	NA	NA
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	600-1000	NA	
ESP REUSE			NA
BAGHOUSE			NA
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NA
ESTIMATED COST (1000$)	4519	NA	NA
NEW CHIMNEY	YES	NA	NA
ESTIMATED COST (1000$)	4046	0	0
OTHER	YES		NO
RETROFIT FACTORS			
FGD SYSTEM	2.00	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	0

Table 5.2.1-4. Summary of FGD Control Costs for the Crist Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	4,5	1.88	88	46	2.4	66.9	760.4	24.3	68.5	90.0	6120	3967.4
L/S FGD	4-5	1.88	177	46	2.4	89.9	508.0	33.2	46.6	90.0	12309	2701.0
L/S FGD	6	2.00	327	44	2.4	127.9	391.0	48.4	38.4	90.0	21755	2222.7
L/S FGD	7	2.00	519	27	2.4	168.6	324.9	60.2	49.0	90.0	21188	2839.0
L/S FGD	6-7	2.00	846	34	2.4	237.4	280.6	88.6	35.2	90.0	43492	2037.7
L/S FGD-C	4,5	1.88	88	46	2.4	66.9	760.4	14.2	40.1	90.0	6120	2322.1
L/S FGD-C	4-5	1.88	177	46	2.4	89.9	508.0	19.5	27.3	90.0	12309	1580.2
L/S FGD-C	6	2.00	327	44	2.4	127.9	391.0	28.3	22.4	90.0	21755	1299.8
L/S FGD-C	7	2.00	519	27	2.4	168.6	324.9	35.2	28.7	90.0	21188	1662.2
L/S FGD-C	6-7	2.00	846	34	2.4	237.4	280.6	51.8	20.6	90.0	43492	1191.9
LC FGD	4-5	1.88	177	46	2.4	64.4	363.7	25.4	35.7	90.0	12309	2066.8
LC FGD	6-7	2.00	846	34	2.4	200.3	236.8	77.3	30.7	90.0	43492	1777.3
LC FGD-C	4-5	1.88	177	46	2.4	64.4	363.7	14.9	20.8	90.0	12309	1207.6
LC FGD-C	6-7	2.00	846	34	2.4	200.3	236.8	45.2	17.9	90.0	43492	1038.9

Table 5.2.1-5. Summary of Coal Switching/Cleaning Costs for the Crist Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	4, 5	1.00	88	46	2.4	3.8	42.9	5.7	16.1	62.0	4240	1349.5
CS/B+$15	6	1.00	327	44	2.4	13.0	39.8	19.4	15.4	62.0	15071	1288.9
CS/B+$15	7	1.00	519	27	2.4	18.9	36.3	20.1	16.4	62.0	14679	1369.5
CS/B+$15-C	4, 5	1.00	88	46	2.4	3.8	42.9	3.3	9.3	62.0	4240	777.2
CS/B+$15-C	6	1.00	327	44	2.4	13.0	39.8	11.2	8.9	62.0	15071	742.3
CS/B+$15-C	7	1.00	519	27	2.4	18.9	36.3	11.6	9.5	62.0	14679	790.4
CS/B+$5	4, 5	1.00	88	46	2.4	2.9	32.5	2.6	7.4	62.0	4240	621.0
CS/B+$5	6	1.00	327	44	2.4	9.6	29.4	8.4	6.7	62.0	15071	558.8
CS/B+$5	7	1.00	519	27	2.4	13.5	26.0	9.0	7.3	62.0	14679	614.6
CS/B+$5-C	4, 5	1.00	88	46	2.4	2.9	32.5	1.5	4.3	62.0	4240	358.8
CS/B+$5-C	6	1.00	327	44	2.4	9.6	29.4	4.9	3.9	62.0	15071	323.0
CS/B+$5-C	7	1.00	519	27	2.4	13.5	26.0	5.2	4.3	62.0	14679	356.2

TABLE 5.2.1-6. SUMMARY OF NOx RETROFIT RESULTS FOR CRIST

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	4, 5	6	7
FIRING TYPE	TANG	FWF	OWF
TYPE OF NOx CONTROL	OFA	LNB	LNB
FURNACE VOLUME (1000 CU FT)	42.4	158	282
BOILER INSTALLATION DATE	1959	1970	1973
SLAGGING PROBLEM	NO	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	25	29	34
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH	HIGH
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	26	72	101
New Duct Length (Feet)	500	250	250
New Duct Costs (1000$)	2389	2663	3457
New Heat Exchanger (1000$)	0	4086	5340
TOTAL SCOPE ADDER COSTS (1000$)			
INDIVIDUAL CASE	2415	6821	8898
COMBINED CASE	3628		11950
RETROFIT FACTOR FOR SCR	1.72	1.72	1.72
GENERAL FACILITIES (PERCENT)	38	38	38

Table 5.2.1-7. NOx Control Cost Results for the Crist Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	6	1.00	327	44	2.4	4.1	12.5	0.9	0.7	29.0	1573	552.0
LNC-LNB	7	1.00	519	27	2.4	4.9	9.5	1.0	0.9	34.0	1796	581.6
LNC-LNB-C	6	1.00	327	44	2.4	4.1	12.5	0.5	0.4	29.0	1573	328.0
LNC-LNB-C	7	1.00	519	27	2.4	4.9	9.5	0.6	0.5	34.0	1796	345.5
LNC-OFA	4, 5	1.00	88	46	2.4	0.6	6.7	0.1	0.4	25.0	273	457.7
LNC-OFA-C	4, 5	1.00	88	46	2.4	0.6	6.7	0.1	0.2	25.0	273	271.6
SCR-3	4, 5	1.72	88	46	2.4	24.2	275.4	7.2	20.2	80.0	872	8205.9
SCR-3	4-5	1.72	177	46	2.4	38.7	218.9	11.9	16.6	80.0	1754	6763.6
SCR-3	6	1.72	327	44	2.4	61.4	187.7	19.4	15.4	80.0	4339	4478.2
SCR-3	7	1.72	519	27	2.4	87.4	168.5	28.1	22.9	80.0	4226	6651.3
SCR-3	6-7	1.72	846	34	2.4	134.2	158.6	44.1	17.5	80.0	8674	5085.1
SCR-3-C	4, 5	1.72	88	46	2.4	24.2	275.4	4.2	11.9	80.0	872	4826.1
SCR-3-C	4-5	1.72	177	46	2.4	38[illegible]	218.9	7.0	9.8	80.0	1754	3974.2
SCR-3-C	6	1.72	327	44	2.4	61.4	187.7	11.4	9.1	80.0	4339	2629.2
SCR-3-C	7	1.72	519	27	2.4	87.4	168.5	16.5	13.4	80.0	4226	3903.5
SCR-3-C	6-7	1.72	846	34	2.4	134.2	158.6	25.9	10.3	80.0	8674	2982.8
SCR-7	4, 5	1.72	88	46	2.4	24.2	275.4	6.4	18.1	80.0	872	7377.6
SCR-7	4-5	1.72	177	46	2.4	38.7	218.9	10.4	14.6	80.0	1754	5935.1
SCR-7	6	1.72	327	44	2.4	61.4	187.7	16.7	13.3	80.0	4339	3859.7
SCR-7	7	1.72	519	27	2.4	87.4	168.5	23.8	19.4	80.0	4226	5643.2
SCR-7	6-7	1.72	846	34	2.4	134.2	158.6	37.2	14.7	80.0	8674	4284.6
SCR-7-C	4, 5	1.72	88	46	2.4	24.2	275.4	3.8	10.7	80.0	872	4351.5
SCR-7-C	4-5	1.72	177	46	2.4	38.7	218.9	6.1	8.6	80.0	1754	3499.4
SCR-7-C	6	1.72	327	44	2.4	61.4	187.7	9.9	7.8	80.0	4339	2274.8
SCR-7-C	7	1.72	519	27	2.4	87.4	168.5	14.1	11.4	80.0	4226	3326.0
SCR-7-C	6-7	1.72	846	34	2.4	134.2	158.6	21.9	8.7	80.0	8674	2524.2

these boilers are OFA for units 4-5 and LNB for units 6-7. Tables 5.2.1-6 and 5.2.1-7 give a summary of NO_x retrofit performance and cost results.

Selective Catalytic Reduction--

Hot side SCR reactors for units 4 and 5 would be located east of unit 1. Cold side SCR reactors for units 6 and 7 would be located beside the common chimney for units 6 and 7. High general facility factors were assigned to both locations. High site access/congestion factors were assigned to both locations due to the limited space available.
Tables 5.2.1-6 and 5.2.1-7 summarize the estimated retrofit factors and costs of retrofitting SCR at the Crist plant.

Furnace Sorbent Injection and Duct Spray Drying--

Sorbent injection technologies (FSI and DSD) were not evaluated for units 4-5 because the units are equipped with hot side ESPs which are not feasible to reuse. Units 6-7 have inadequate size ESPs and were not evaluated for the sorbent injection technologies.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Crist plant. Units 4-5 would be considered good candidates for repowering or retrofit because of their small boiler sizes and low capacity factors. Units 6-7 are large and have high capacity factors and would not be good candidates.

5.2.2 Lansing Smith Steam Plant

Both units are equipped with retrofit hot-side ESPs and were not considered for LSD or furnace sorbent injection technologies.

TABLE 5.2.2-1. LANSING SMITH STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2
GENERATING CAPACITY (MW)	150	190
CAPACITY FACTOR (PERCENT)	73	75
INSTALLATION DATE	1965	1967
FIRING TYPE	TANGENTIAL	
FURNACE VOLUME (1000 CU FT)	92	NA
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	2.4	
COAL HEATING VALUE (BTU/LB)	12100	
COAL ASH CONTENT (PERCENT)	9.4	
FLY ASH SYSTEM	WET DISPOSAL	
ASH DISPOSAL METHOD	POND/ON-SITE	
STACK NUMBER	1	1
COAL DELIVERY METHODS	BARGE	
PARTICULATE CONTROL*		
TYPE	ESP	ESP
INSTALLATION DATE	NA	NA
EMISSION (LB/MM BTU)	0.04	0.02
REMOVAL EFFICIENCY	99	99
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	0.5-3.5	0.6-3.5
SURFACE AREA (1000 SQ FT)	303.3	379
EXIT GAS FLOW RATE (1000 ACFM)	1313	1640
SCA (SQ FT/1000 ACFM)	231	231
OUTLET TEMPERATURE (°F)	260	260

* Both units are retrofitted with hot side ESPs.

TABLE 5.2.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR LANSING SMITH UNITS 1 OR 2*

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	NA
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			NA
BAGHOUSE			NA
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NA
ESTIMATED COST (1000$)	1348,1667	NA	NA
NEW CHIMNEY	YES	NA	NA
ESTIMATED COST (1000$)	1050,1330	0	NA
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.48	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	NA

* L/S-FGD and LSD-FGD absorbers for units 1 and 2 would be located east of the unit 2 retrofit ESPs.

Table 5.2.2-3. Summary of FGD Control Costs for the Lansing Smith Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.48	150	73	2.4	56.6	377.1	25.0	26.1	90.0	16557	1511.0
L/S FGD	2	1.48	190	75	2.4	63.9	336.2	28.9	23.2	90.0	21547	1342.1
L/S FGD	1-2	1.48	340	74	2.4	90.2	265.3	42.3	19.2	90.0	38043	1112.6
L/S FGD-C	1	1.48	150	73	2.4	56.6	377.1	14.6	15.2	90.0	16557	881.0
L/S FGD-C	2	1.48	190	75	2.4	63.9	336.2	16.9	13.5	90.0	21547	782.3
L/S FGD-C	1-2	1.48	340	74	2.4	90.2	265.3	24.7	11.2	90.0	38043	648.1
LC FGD	1-2	1.48	340	74	2.4	68.4	201.2	35.7	16.2	90.0	38043	937.9
LC FGD-C	1-2	1.48	340	74	2.4	68.4	201.2	20.7	9.4	90.0	38043	545.4

Table 5.2.2-4. Summary of Coal Switching/Cleaning Costs for the Lansing Smith Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	150	73	2.4	5.7	37.9	14.1	14.7	62.0	11470	1225.6
CS/B+$15	2	1.00	190	75	2.4	6.9	36.3	18.0	14.5	62.0	14927	1209.1
CS/B+$15-C	1	1.00	150	73	2.4	5.7	37.9	8.1	8.4	62.0	11470	704.4
CS/B+$15-C	2	1.00	190	75	2.4	6.9	36.3	10.4	8.3	62.0	14927	694.8
CS/B+$5	1	1.00	150	73	2.4	4.1	27.6	5.9	6.1	62.0	11470	511.1
CS/B+$5	2	1.00	190	75	2.4	4.9	25.9	7.4	5.9	62.0	14927	495.2
CS/B+$5-C	1	1.00	150	73	2.4	4.1	27.6	3.4	3.5	62.0	11470	294.5
CS/B+$5-C	2	1.00	190	75	2.4	4.9	25.9	4.3	3.4	62.0	14927	285.2

TABLE 5.2.2-5. SUMMARY OF NOx RETROFIT RESULTS FOR LANSING SMITH

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1	2
FIRING TYPE	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA
FURNACE VOLUME (1000 CU FT)	92	NA
BOILER INSTALLATION DATE	1965	1967
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	25	25
SCR RETROFIT RESULTS *		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	37	44
New Duct Length (Feet)	400	400
New Duct Costs (1000$)	2513	2885
New Heat Exchanger (1000$)	2377	2739
TOTAL SCOPE ADDER COSTS (1000$)	4926	5668
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	38	38

* Cold side SCR reactors for units 1 and 2 would be located east of the unit 2 retrofit ESPs.

Table 5.2.2-6. NOx Control Cost Results for the Lansing Smith Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	1	1.00	150	73	2.4	0.7	4.9	0.2	0.2	25.0	737	209.1
LNC-OFA	2	1.00	190	75	2.4	0.8	4.2	0.2	0.1	25.0	959	176.6
LNC-OFA-C	1	1.00	150	73	2.4	0.7	4.9	0.1	0.1	25.0	737	124.1
LNC-OFA-C	2	1.00	190	75	2.4	0.8	4.2	0.1	0.1	25.0	959	105.0
SCR-3	1	1.16	150	73	2.4	27.2	181.3	8.8	9.2	80.0	2359	3747.9
SCR-3	2	1.16	190	75	2.4	32.2	169.2	10.7	8.5	80.0	3069	3470.3
SCR-3-C	1	1.16	150	73	2.4	27.2	181.3	5.2	5.4	80.0	2359	2199.0
SCR-3-C	2	1.16	190	75	2.4	32.2	169.2	6.2	5.0	80.0	3069	2035.2
SCR-7	1	1.16	150	73	2.4	27.2	181.3	7.6	7.9	80.0	2359	3225.9
SCR-7	2	1.16	190	75	2.4	32.2	169.2	9.1	7.3	80.0	3069	2962.3
SCR-7-C	1	1.16	150	73	2.4	27.2	181.3	4.5	4.7	80.0	2359	1899.9
SCR-7-C	2	1.16	190	75	2.4	32.2	169.2	5.4	4.3	80.0	3069	1744.2

5.3 SEMINOLE ELECTRIC COOPERATIVE

5.3.1 Seminole Steam Plant

The Seminole steam plant is located within Putnam County, Florida, as part of the Seminole Electric Cooperative system. The plant is located west of the St. Johns River and contains two coal-fired boilers with a total gross generating capacity of 1,430 MW.

Table 5.3.1-1 presents the operational data for the existing equipment at the Seminole plant. The boilers burn 2.8 percent sulfur coal. Coal shipments are received by railroad and transferred to a coal storage and handling area west of the plant.

PM emissions for the boilers are controlled with ESPs located behind each unit. The plant has a dry fly ash handling system. Part of the fly ash and almost all the bottom ash are sold and the rest is disposed of on-site. Units 1 and 2 are served by separate flues within a common chimney.

Although both boilers are equipped with new FGD control systems, the Seminole plant is included in the Top 200 SO_2 emitting power plants; therefore, it was considered in this study. However, additional SO_2 controls were not considered. Because both units are equipped with LNB, only SCR was evaluated for this plant.

Selective Catalytic Reduction--

Cold side SCR reactors for both units would be located behind the common stack downstream of the existing FGD units. Both reactors would be located in a low site access/congestion area. For flue gas handling, duct lengths of 200 feet were estimated for units 1-2. The ammonia storage system would be placed beside the reactors. A storage building and a paved road would need to be relocated and a factor of 20 percent was assigned to general facilities. Table 5.3.1-2 presents the SCR retrofit results for all units. Table 5.3.1-3 presents the estimated cost of retrofitting SCR at the Seminole boilers.

TABLE 5.3.1-1. SEMINOLE STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1, 2
GENERATING CAPACITY (MW-each)	715
CAPACITY FACTOR (PERCENT)	60, 49
INSTALLATION DATE	1984-85
FIRING TYPE	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	513
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	2.8
COAL HEATING VALUE (BTU/LB)	12000
COAL ASH CONTENT (PERCENT)	8.7
FLY ASH SYSTEM	DRY HANDLING
ASH DISPOSAL METHOD	ON-SITE/SOLD
STACK NUMBER	1, 2 (INSIDE COMMON CHIMNEY)
COAL DELIVERY METHODS	RAILROAD
FGD SYSTEM	YES
FGD TYPE	SPRAY TOWER
FGD INSTALLATION DATE	1984, 85
<u>PARTICULATE CONTROL</u>	
TYPE	ESP
INSTALLATION DATE	1984, 85
EMISSION (LB/MM BTU)	0.02
REMOVAL EFFICIENCY	99.8
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	3.0
SURFACE AREA (1000 SQ FT)	462.0
GAS EXIT RATE (1000 ACFM)	2,132
SCA (SQ FT/1000 ACFM)	217
OUTLET TEMPERATURE (°F)	300

TABLE 5.3.1-2. SUMMARY OF NOx RETROFIT RESULTS FOR SEMINOLE

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1,2
FIRING TYPE	NA
TYPE OF NOx CONTROL	NA
FURNACE VOLUME (1000 CU FT)	NA
BOILER INSTALLATION DATE	NA
SLAGGING PROBLEM	NA
ESTIMATED NOx REDUCTION (PERCENT)	NA
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	118
New Duct Length (Feet)	200
New Duct Costs (1000$)	3132
New Heat Exchanger (1000$)	6067
TOTAL SCOPE ADDER COSTS (1000$)	9318
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	20

Table 5.3.1-3. NOx Control Cost Results for the Seminole Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
SCR-3	1	1.16	715	60	2.8	84.7	118.4	31.6	8.4	80.0	13060	2416.4
SCR-3	2	1.16	715	49	2.8	84.6	118.4	25.2	8.2	80.0	10666	2361.2
SCR-3-C	1	1.16	715	60	2.8	84.7	118.4	18.5	4.9	80.0	13060	1413.5
SCR-3-C	2	1.16	715	49	2.8	84.6	118.4	14.8	4.8	80.0	10666	1388.4
SCR-7	1	1.16	715	60	2.8	84.7	118.4	25.7	6.8	80.0	13060	1966.6
SCR-7	2	1.16	715	49	2.8	84.6	118.4	25.2	8.2	80.0	10666	2361.2
SCR-7-C	1	1.16	715	60	2.8	84.7	118.4	15.1	4.0	80.0	13060	1155.8
SCR-7-C	2	1.16	715	49	2.8	84.6	118.4	14.8	4.8	80.0	10666	1388.4

5.4 TAMPA ELECTRIC COMPANY

5.4.1 Big Bend Steam Plant

The Big Bend steam plant is located at the eastern entrance of Hillsborough Bay in Hillsborough County, Florida, and is part of the Tampa Electric Company. It is bounded on the north and south by water channels. The Big Bend plant contains four coal-fired boilers with a total gross name plate generating capacity of 1,821 MW.

Table 5.4.1-1 presents operational data for the existing equipment at the Big Bend plant. Shipments of medium sulfur coal are received by barge and conveyed to a coal storage and handling area west of the plant. PM emissions from the boilers are controlled by ESPs installed at the time of construction and one additional ESP added to unit 1. All ESPs are located behind the boilers. Flue gas from boilers 1 and 2 is ducted to a common chimney while the flue gas from boilers 3 and 4 is ducted to a separate chimney for each boiler. Dry fly ash from the plant is sold. Unit 4 was built with a forced oxidation limestone FGD system designed to remove 90 percent of the sulfur dioxide compounds from the flue gas. In addition, unit 4 has LNC controls.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS or LSD-FGD absorbers would be located behind the chimneys for units 1-3. Because units 1-2 share a chimney, a new chimney would be built to avoid a prolonged downtime for units 1-2. The silos located behind the chimneys would not be destroyed. The general facilities factor would be high (15 percent) due to the necessity for relocation of some storage buildings and roads. A high site access/congestion factor was assigned to the FGD absorber locations because of the proximity of the channel. In addition, there is considerable underground obstruction at the proposed FGD absorber location (two water discharge structures) and poor soil bearing capacity which affects the cost of earthwork, foundation design and construction. For the L/LS-FGD case, approximately 300 feet of ductwork would be required for units 1-2 and 500 feet for unit 3. A medium site

TABLE 5.4.1-1. BIG BEND STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3	4
GENERATING CAPACITY (MW-each)	445.5	445.5	486
CAPACITY FACTOR (PERCENT)	58,50	50	49
INSTALLATION DATE	1970,73	1976	1985
FIRING TYPE	TURBO-FURNACE		TANGENTIAL
FURNACE VOLUME (1000 CU FT)	222	243	383
LOW NOx COMBUSTION	NO	YES	YES
COAL SULFUR CONTENT (PERCENT)	2.8	2.0	2.8
COAL HEATING VALUE (BTU/LB)	11400	11850	10850
COAL ASH CONTENT (PERCENT)	9.4	8.8	9.6
FLY ASH SYSTEM	WET/DRY HANDLING		
ASH DISPOSAL METHOD	ON-SITE/SOLD		
STACK NUMBER	1	2	3
COAL DELIVERY METHODS		BARGE	
FGD SYSTEM	NO	NO	YES
FGD TYPE	--	--	LIMESTONE
FGD INSTALLATION DATE	--	--	1985
PARTICULATE CONTROL			
TYPE	ESP	ESP	ESP
INSTALLATION DATE	1970,73	1976	1985
EMISSION (LB/MM BTU)	0.06	0.02	0.01
REMOVAL EFFICIENCY	99.8	99.8	99.8
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	3.8	3.8	3.2
SURFACE AREA (1000 SQ FT)	498,467	458	440/550
GAS EXIT RATE (1000 ACFM)	1020,1408	1420	2200
SCA (SQ FT/1000 ACFM)	488,331	323	400/500*
OUTLET TEMPERATURE (°F)	298,301	351	340

*Given by plant personnel.

access/ congestion factor was assigned to flue gas handling because of the congestion around the boilers.

LSD with reuse of the existing ESPs was not considered although the ESPs are large. This is a result of the plant personnel stating that the ESPs would not be able to handle any increased load. Additionally, access to the ESPs is difficult, making reuse of the ESPs costly because of replacement power costs. All units are burning medium sulfur coal; therefore, LSD with a new baghouse was not considered as an option.

Tables 5.4.1-2 and 5.4.1-3 give a summary of retrofit data and costs for L/LS-FGD technologies. Because unit 4 is already equipped with an FGD absorber (meeting 1979 NSPS), SO_2 control technologies were not considered for this unit.

Coal Switching and Physical Coal Cleaning Costs--

Table 5.4.1-4 presents the IAPCS cost results for CS at units 1-3. These costs do not include boiler or pulverizer operating cost changes or system modifications that may be necessary to blend coal. Because of the distance from the plant's coal sources, transportation costs might be $20 per ton. Therefore, in addition to $5 and $15 per ton of fuel price differential, $20 per ton was also considered. PCC was not evaluated because this is not a mine mouth plant.

Low NOx Combustion--

Units 1-3 are Riley Stoker turbo-fired wet bottom boilers. Presently, there is no commercial technology available for reducing NO_x through LNC technologies, however, NGR was considered perhaps applicable for these boilers. A natural gas pipeline is not available in the surrounding area; therefore, NGR is not feasible. Unit 4 is already meeting 1979 NSPS and would not be considered.

Selective Catalytic Reduction--

Cold side SCR reactors would be located behind the chimneys for all units. As in the FGD case, storage buildings and roads would have to be relocated to provide room for the reactors and a medium general facilities value of 20 percent would be assigned to the location. After demolition,

TABLE 5.4.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR BIG BEND UNITS 1,2,3

	FGD TECHNOLOGY	
	L/LS FGD	LIME SPRAY DRYING
SITE ACCESS/CONGESTION		
SO2 REMOVAL	HIGH	NA
FLUE GAS HANDLING	MEDIUM	
ESP REUSE CASE		NA
BAGHOUSE CASE		NA
DUCT WORK DISTANCE (FEET)	300-600	
ESP REUSE		NA
BAGHOUSE		NA
ESP REUSE	NA	NA
NEW BAGHOUSE	NA	NA
SCOPE ADJUSTMENTS		
WET TO DRY	NO	NA
ESTIMATED COST (1000$)	NA	NA
NEW CHIMNEY (1-2,3)	YES, NO	NA
ESTIMATED COST (1000$)	6000, 0	0
OTHER	NO	
RETROFIT FACTORS		
FGD SYSTEM (1-2,3)	1.65, 1.60	
ESP REUSE CASE		NA
BAGHOUSE CASE		NA
ESP UPGRADE	NA	NA
NEW BAGHOUSE	NA	NA
GENERAL FACILITIES (PERCENT)	15	0

Table 5.4.1-3. Summary of FGD Control Costs for the Big Bend Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kWh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.65	445	58	2.8	126.1	283.3	55.5	24.5	90.0	48753	1138.3
L/S FGD	2	1.65	445	50	2.8	126.9	285.2	53.3	27.3	90.0	42028	1267.5
L/S FGD	3	1.60	445	50	2.0	120.6	270.9	49.6	25.5	90.0	30019	1653.1
L/S FGD	1-2	1.65	891	54	2.8	212.5	238.4	93.7	22.2	90.0	90880	1031.3
L/S FGD-C	1	1.65	445	58	2.8	126.1	283.3	32.4	14.3	90.0	48753	663.8
L/S FGD-C	2	1.65	445	50	2.8	126.9	285.2	31.1	16.0	90.0	42028	739.7
L/S FGD-C	3	1.60	445	50	2.0	120.6	270.9	29.0	14.9	90.0	30019	965.1
L/S FGD-C	1-2	1.65	891	54	2.8	212.5	238.4	54.6	13.0	90.0	90880	601.3
LC FGD	1-3	1.64	1336	53	2.5	250.8	187.7	116.3	18.7	90.0	119418	973.7
LC FGD-C	1-3	1.64	1336	53	2.5	250.8	187.7	67.7	10.9	90.0	119418	567.3

Table 5.4.1-4. Summary of Coal Switching/Cleaning Costs for the Big Bend Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	445	58	2.8	14.0	31.5	32.1	14.2	70.0	37843	848.9
CS/B+$15	2	1.00	445	50	2.8	14.0	31.5	28.1	14.4	70.0	32624	861.8
CS/B+$15	3	1.00	445	50	2.0	14.1	31.7	28.2	14.5	58.0	19282	1462.7
CS/B+$15-C	1	1.00	445	58	2.8	14.0	31.5	18.5	8.2	70.0	37843	488.1
CS/B+$15-C	2	1.00	445	50	2.8	14.0	31.5	16.2	8.3	70.0	32624	495.7
CS/B+$15-C	3	1.00	445	50	2.0	14.1	31.7	16.2	8.3	58.0	19282	841.3
CS/B+$20	1	1.00	445	58	2.8	16.3	36.7	41.9	18.5	70.0	37843	1106.4
CS/B+$20	2	1.00	445	50	2.8	16.3	36.7	36.6	18.8	70.0	32624	1120.9
CS/B+$20	3	1.00	445	50	2.0	16.4	36.9	36.7	18.8	58.0	19282	1901.1
CS/B+$20-C	1	1.00	445	58	2.8	16.3	36.7	24.1	10.6	70.0	37843	635.8
CS/B+$20-C	2	1.00	445	50	2.8	16.3	36.7	21.0	10.8	70.0	32624	644.5
CS/B+$20-C	3	1.00	445	50	2.0	16.4	36.9	21.1	10.8	58.0	19282	1093.0
CS/B+$5	1	1.00	445	58	2.8	9.4	21.2	12.6	5.6	70.0	37843	334.1
CS/B+$5	2	1.00	445	50	2.8	9.4	21.2	11.2	5.8	70.0	32624	343.6
CS/B+$5	3	1.00	445	50	2.0	9.5	21.3	11.3	5.8	58.0	19282	585.9
CS/B+$5-C	1	1.00	445	58	2.8	9.4	21.2	7.3	3.2	70.0	37843	192.5
CS/B+$5-C	2	1.00	445	50	2.8	9.4	21.2	6.5	3.3	70.0	32624	198.1
CS/B+$5-C	3	1.00	445	50	2.0	9.5	21.3	6.5	3.3	58.0	19282	337.9

the SCR reactors would be located in an area with significant underground obstructions and, as such, a medium site access/congestion factor was assigned to the SCR reactor locations. About 350 feet of ductwork would be required for units 1-2, 500 feet for unit 3, and 250 feet for unit 4. Tables 5.4.1-5 and 5.4.1-6 present the retrofit factor and cost estimates for retrofitting SCR at the Big Bend plant.

Furnace Sorbent Injection and Duct Spray Drying--

Sorbent injection technologies were not considered for the Big Bend plant because of the short duct residence time between the boilers and the ESPs.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

None of the boilers would be considered good candidates for repowering because of their large size and short service life.

5.4.2 F. J. Gannon Steam Plant

The F. J. Gannon steam plant is located on Hillsborough Bay in Hillsborough County, Florida, and is part of the Tampa Electric Company. The plant contains six coal-fired boilers with a total gross generating capacity of 1,271 MW.

Table 5.4.2-1 presents operational data for the existing equipment at the Gannon plant. Coal shipments are received by barge and rail and conveyed to a coal storage and handling area west of the plant. The south side of the Gannon plant abuts a county road alongside property belonging to a phosphate manufacturing plant. A railroad line runs on the property. PM emissions from the boilers are controlled by ESPs. Boilers 1-3 and 5-6 each have a separate stack. Boiler 4 has two chimneys. The ESPs were installed behind their respective stacks. The Gannon plant has a dry fly ash handling system.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS or LSD-FGD absorbers for units 1 and 2 would be located behind the unit 1 and 2 ESPs and the unit 3-6 absorbers would be located at the east

TABLE 5.4.1-5. SUMMARY OF NOx RETROFIT RESULTS FOR BIG BEND

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1,2	3	4
FIRING TYPE	TURBO-FURNACE		TANG
TYPE OF NOx CONTROL	NA	NA	NA
FURNACE VOLUME (1000 CU FT)	222	243	383
BOILER INSTALLATION DATE	1970,73	1976	1985
SLAGGING PROBLEM	YES	YES	NA
ESTIMATED NOx REDUCTION (PERCENT)	NA	NA	NA
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	MEDIUM	MEDIUM
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	83	83	88
New Duct Length (Feet)	350	500	250
New Duct Costs (1000$)	5250	7500	3124
New Heat Exchanger (1000$)	4571	4571	4813
TOTAL SCOPE ADDER COSTS (1000$)	9904	12154	8025
RETROFIT FACTOR FOR SCR	1.34	1.34	1.34
GENERAL FACILITIES (PERCENT)	20	20	20

Table 5.4.1-6. NOx Control Cost Results for the Big Bend Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
SCR-3	1	1.34	445	58	2.8	64.0	143.9	22.7	10.0	80.0	13493	1683.2
SCR-3	2	1.34	445	50	2.8	64.5	145.0	22.5	11.5	80.0	11632	1934.7
SCR-3	3	1.34	445	50	2.0	66.8	150.0	22.2	11.4	80.0	5132	4321.3
SCR-3	4	1.34	486	49	2.8	67.2	138.2	23.9	11.5	80.0	12449	1920.9
SCR-3-C	1	1.34	445	58	2.8	64.0	143.9	13.3	5.9	80.0	13493	985.7
SCR-3-C	2	1.34	445	50	2.8	64.5	145.0	13.2	6.8	80.0	11632	1133.3
SCR-3-C	3	1.34	445	50	2.0	66.8	150.0	13.0	6.7	80.0	5132	2534.1
SCR-3-C	4	1.34	486	49	2.8	67.2	138.2	14.0	6.7	80.0	12449	1124.7
SCR-7	1	1.34	445	58	2.8	64.0	143.9	19.0	8.4	80.0	13493	1410.2
SCR-7	2	1.34	445	50	2.8	64.5	145.0	18.8	9.7	80.0	11632	1618.0
SCR-7	3	1.34	445	50	2.0	66.8	150.0	18.5	9.5	80.0	5132	3603.3
SCR-7	4	1.34	486	49	2.8	67.2	138.2	19.9	9.5	80.0	12449	1597.7
SCR-7-C	1	1.34	445	58	2.8	64.0	143.9	11.2	4.9	80.0	13493	829.2
SCR-7-C	2	1.34	445	50	2.8	64.5	145.0	11.1	5.7	80.0	11632	951.9
SCR-7-C	3	1.34	445	50	2.0	66.8	150.0	10.9	5.6	80.0	5132	2122.7
SCR-7-C	4	1.34	486	49	2.8	67.2	138.2	11.7	5.6	80.0	12449	939.5

TABLE 5.4.2-1. F. J. GANNON STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3	4	5	6
GENERATING CAPACITY (MW-each)	125	180	188	239	414
CAPACITY FACTOR (PERCENT)	37,35	44	44	59	46
INSTALLATION DATE	1957	1960	1963	1965	1967
FIRING TYPE	CYCLONE BOILER			TURBO-FURNACE	
FURNACE VOLUME (1000 CU FT)	NA	66.6	NA	129.1	219.4
LOW NOx COMBUSTION	NO	NO	NO	NO	NO
COAL SULFUR CONTENT (PERCENT)	1.1	1.1	1.1	1.1	1.1
COAL HEATING VALUE (BTU/LB)	12500	12500	12500	12500	12500
COAL ASH CONTENT (PERCENT)	7.3	7.3	7.3	7.3	7.3
FLY ASH SYSTEM		DRY HANDLING			
ASH DISPOSAL METHOD		ON-SITE/SOLD			
STACK NUMBER	1,2	3	4	5	6
COAL DELIVERY METHODS			BARGE/RAIL		
<u>PARTICULATE CONTROL</u>					
TYPE	ESP	ESP	ESP	ESP	ESP
INSTALLATION DATE	1985	1984	1983	1973	1973
EMISSION (LB/MM BTU)	0.04	0.02	0.01	0.05	0.03
REMOVAL EFFICIENCY	99.1	99.1	99.1	99.8	99.8
DESIGN SPECIFICATION					
SULFUR SPECIFICATION (PERCENT)	1.25	1.25	1.25	2.8	2.8
SURFACE AREA (1000 SQ FT)	603	600	596	440	327
GAS EXIT RATE (1000 ACFM)	440	574	631	820	1350
SCA (SQ FT/1000 ACFM)	265	345	376	361	442
OUTLET TEMPERATURE (°F)	300	300	300	290	290

end of unit 6. The general facilities factor is low (5 percent) for the unit 1 and 2 locations. However, the general facilities factor is very high (15 percent) for the units 3-6 absorber locations because of the necessity for relocating the water treatment facility. An additional 30 percent has been added to the retrofit factor for installation of FGD technologies to account for the extraordinary cost of relocating the water treatment facility. The site access/congestion factor is high for the units 1 and 2 FGD absorber locations because of the proximity of the railroad tracks, roadways, ash handling silos, wastewater facilities, and property line. The site access/congestion factor is high for the units 3-6 absorber locations because of the high congestion and underground obstructions beneath the water treatment facility site.

More than 300 feet of ductwork would be required for the installation of wet FGD absorbers for units 1 and 2. Approximately 300 feet of ductwork would be required for unit 6, 700 feet for unit 5, and greater than 1,000 feet for units 3 and 4. To reduce the duct lengths, a new chimney would be constructed behind the absorbers for units 3 and 4 and, as such, about 600 to 800 feet of duct length would be required. The flue gas handling site access/congestion factor is high for all of the units because of the close proximity of the ESPs and boilers to the chimneys and property line. It might not be possible to retrofit all the units with FGD systems because of this space limitation.

Because of the adequate sizes of the ESPs, LSD with reuse of the existing ESPs was considered for all of the units. The LSD absorbers would be located similarly to the wet FGD absorbers and were assigned the same general facilities percentages and site access/congestion factors. The ductwork for units 3,4,5, and 6 would be long in the LSD-FGD case.

Tables 5.4.2-2 through 5.4.2-5 give a summary of retrofit data for the FGD technologies. Table 5.4.2-6 presents the FGD costs.

Coal Switching and Physical Coal Cleaning Costs--

CS was not considered for units 1-4 because they are cyclone boilers requiring low sulfur bituminous coals having low ash fusion temperatures which are not readily available in the east. Plant personnel indicated that some degree of fuel switching is possible on these units with fluxing to

TABLE 5.4.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR F. J. GANNON UNITS 1 OR 2

	FGD TECHNOLOGY	
	L/LS FGD	LIME SPRAY DRYING
SITE ACCESS/CONGESTION		
SO2 REMOVAL	HIGH	HIGH
FLUE GAS HANDLING	HIGH	
ESP REUSE CASE		HIGH
BAGHOUSE CASE		NA
DUCT WORK DISTANCE (FEET)	300-600	
ESP REUSE		300-600
BAGHOUSE		NA
ESP REUSE	NA	HIGH
NEW BAGHOUSE	NA	NA
SCOPE ADJUSTMENTS		
WET TO DRY	NO	NO
ESTIMATED COST (1000$)	NA	NA
NEW CHIMNEY	YES	NO
ESTIMATED COST (1000$)	6000	0
OTHER	YES	YES
RETROFIT FACTORS		
FGD SYSTEM	1.80	
ESP REUSE CASE		1.72
BAGHOUSE CASE		NA
ESP UPGRADE	NA	1.58
NEW BAGHOUSE	NA	NA
GENERAL FACILITIES (PERCENT)	5	5

TABLE 5.4.2-3. SUMMARY OF RETROFIT FACTOR DATA FOR F. J. GANNON UNITS 3 OR 4

	FGD TECHNOLOGY	
	L/LS FGD	LIME SPRAY DRYING
SITE ACCESS/CONGESTION		
SO2 REMOVAL	HIGH	HIGH
FLUE GAS HANDLING	HIGH	
ESP REUSE CASE		HIGH
BAGHOUSE CASE		NA
DUCT WORK DISTANCE (FEET)	600-1000	
ESP REUSE		1000+
BAGHOUSE		NA
ESP REUSE	NA	HIGH
NEW BAGHOUSE	NA	NA
SCOPE ADJUSTMENTS		
WET TO DRY	NO	NO
ESTIMATED COST (1000$)	NA	NA
NEW CHIMNEY	YES	NO
ESTIMATED COST (1000$)	6000	0
OTHER	YES	YES
RETROFIT FACTORS		
FGD SYSTEM	1.91	
ESP REUSE CASE		2.26
BAGHOUSE CASE		NA
ESP UPGRADE	NA	1.58
NEW BAGHOUSE	NA	NA
GENERAL FACILITIES (PERCENT)	15	15

TABLE 5.4.2-4. SUMMARY OF RETROFIT FACTOR DATA FOR F. J. GANNON UNIT 5

	FGD TECHNOLOGY	
	L/LS FGD	LIME SPRAY DRYING
SITE ACCESS/CONGESTION		
SO2 REMOVAL	HIGH	HIGH
FLUE GAS HANDLING	HIGH	
ESP REUSE CASE		HIGH
BAGHOUSE CASE		NA
DUCT WORK DISTANCE (FEET)	600-1000	
ESP REUSE		1000+
BAGHOUSE		NA
ESP REUSE	NA	HIGH
NEW BAGHOUSE	NA	NA
SCOPE ADJUSTMENTS		
WET TO DRY	NO	NO
ESTIMATED COST (1000$)	NA	NA
NEW CHIMNEY	YES	NO
ESTIMATED COST (1000$)	6000	0
OTHER	YES	YES
RETROFIT FACTORS		
FGD SYSTEM	1.91	
ESP REUSE CASE		2.06
BAGHOUSE CASE		NA
ESP UPGRADE	NA	1.58
NEW BAGHOUSE	NA	NA
GENERAL FACILITIES (PERCENT)	15	15

TABLE 5.4.2-5. SUMMARY OF RETROFIT FACTOR DATA FOR F. J. GANNON UNIT 6

	FGD TECHNOLOGY	
	L/LS FGD	LIME SPRAY DRYING
SITE ACCESS/CONGESTION		
SO2 REMOVAL	HIGH	HIGH
FLUE GAS HANDLING	HIGH	
ESP REUSE CASE		HIGH
BAGHOUSE CASE		NA
DUCT WORK DISTANCE (FEET)	300-600	
ESP REUSE		600-1000
BAGHOUSE		NA
ESP REUSE	NA	HIGH
NEW BAGHOUSE	NA	NA
SCOPE ADJUSTMENTS		
WET TO DRY	NO	NO
ESTIMATED COST (1000$)	NA	NA
NEW CHIMNEY	YES	NO
ESTIMATED COST (1000$)	6000	0
OTHER	YES	YES
RETROFIT FACTORS		
FGD SYSTEM	1.80	
ESP REUSE CASE		1.86
BAGHOUSE CASE		NA
ESP UPGRADE	NA	1.58
NEW BAGHOUSE	NA	NA
GENERAL FACILITIES (PERCENT)	15	15

Table 5.4.2-6. Summary of FGD Control Costs for the Gannon Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1, 2	1.80	125	37	1.1	55.0	440.1	20.3	50.2	90.0	3088	6586.8
L/S FGD	3	1.91	180	44	1.1	76.4	424.5	28.4	40.9	90.0	5288	5364.9
L/S FGD	4	1.91	188	44	1.1	78.0	414.9	29.0	40.0	90.0	5523	5251.8
L/S FGD	5	1.91	239	59	1.1	88.9	371.8	34.9	28.3	90.0	9414	3707.0
L/S FGD	6	1.80	414	46	1.1	116.9	282.3	45.1	27.0	90.0	12714	3544.1
L/S FGD	1-2	1.80	250	36	1.1	83.8	335.2	30.9	39.1	90.0	6009	5134.3
L/S FGD	3-6	1.86	1021	48	1.1	240.0	235.1	94.1	21.9	90.0	32719	2877.4
L/S FGD-C	1, 2	1.80	125	37	1.1	55.0	440.1	11.9	29.4	90.0	3088	3853.7
L/S FGD-C	3	1.91	180	44	1.1	76.4	424.5	16.6	23.9	90.0	5288	3138.5
L/S FGD-C	4	1.91	188	44	1.1	78.0	414.9	17.0	23.4	90.0	5523	3072.3
L/S FGD-C	5	1.91	239	59	1.1	88.9	371.8	20.4	16.5	90.0	9414	2166.2
L/S FGD-C	6	1.80	414	46	1.1	116.9	282.3	26.3	15.8	90.0	12714	2071.7
L/S FGD-C	1-2	1.80	250	36	1.1	83.8	335.2	18.1	22.9	90.0	6009	3004.2
L/S FGD-C	3-6	1.86	1021	48	1.1	240.0	235.1	55.0	12.8	90.0	32719	1681.4
LC FGD	1-6	1.85	1271	46	1.1	225.0	177.0	92.9	18.1	90.0	39034	2379.1
LC FGD-C	1-6	1.85	1271	46	1.1	225.0	177.0	54.2	10.6	90.0	39034	1388.9
LSD+ESP	1, 2	1.72	125	37	1.1	21.1	168.4	8.5	20.9	76.0	2618	3235.5
LSD+ESP	3	2.26	180	44	1.1	35.4	196.6	12.9	18.5	76.0	4483	2870.0
LSD+ESP	4	2.26	188	44	1.1	36.4	193.6	13.2	18.2	76.0	4682	2817.4
LSD+ESP	5	2.06	239	59	1.1	44.5	186.1	16.6	13.4	76.0	7981	2073.8
LSD+ESP	6	1.86	414	46	1.1	62.4	150.8	22.3	13.4	76.0	10779	2067.9
LSD+ESP-C	1, 2	1.72	125	37	1.1	21.1	168.4	4.9	12.2	76.0	2618	1889.8
LSD+ESP-C	3	2.26	180	44	1.1	35.4	196.6	7.5	10.9	76.0	4483	1679.7
LSD+ESP-C	4	2.26	188	44	1.1	36.4	193.6	7.7	10.7	76.0	4682	1649.0
LSD+ESP-C	5	2.06	239	59	1.1	44.5	186.1	9.7	7.8	76.0	7981	1213.2
LSD+ESP-C	6	1.86	414	46	1.1	62.4	150.8	13.1	7.8	76.0	10779	1210.7

lower ash fusion temperatures. However, this was beyond the scope of this work and was not considered. Costs were developed for units 5 and 6 and are presented in Table 5.4.2-7. PCC was not evaluated because this is not a mine mouth plant.

Low NO_x Combustion--

The combustion modification technique applicable to the boilers at the Gannon plant would be NGR; however, a natural gas pipeline is not available in the surrounding area; therefore, NGR application would not be feasible.

Selective Catalytic Reduction--

For units 1-5, cold side SCR reactors would be located south of the unit ESPs and for unit 6 east of its ESPs. The general facilities factor is low for this location. However, the site access/congestion factor is high because of the proximity of the railroad track and property boundary. About 250 feet of ductwork would be required for units 1 and 2, 300 feet for unit 3, 500 feet for unit 4, 600 feet for unit 5, and 700 feet for unit 6. Tables 5.4.2-8 through 5.4.2-10 present retrofit factor and cost estimates for retrofitting SCR at the Gannon plant.

Furnace Sorbent Injection and Duct Spray Drying--

Sorbent injection technologies (FSI and DSD) were considered for the Gannon plant because of the large size ESPs. The front section of the existing ESPs could be modified for sorbent injection or humidification. Tables 5.4.2-11 and 5.4.2-12 give a summary of retrofit factors for FSI and DSD technologies at the Gannon plant. Table 5.4.2-13 presents the costs for FSI and DSD.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

Units 1-5 would be considered good candidates for repowering or retrofit because of the small boiler size and likely short remaining life. However, the high capacity factors could result in high replacement power costs for extended downtime. Unit 6 is large and would not be considered for repowering.

Table 5.4.2-7. Summary of Coal Switching/Cleaning Costs for the Gannon Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	5	1.00	239	59	1.1	8.4	35.1	18.1	14.7	15.0	1541	11749.9
CS/B+$15	6	1.00	414	46	1.1	13.5	32.6	24.7	14.8	15.0	2081	11854.3
CS/B+$15-C	5	1.00	239	59	1.1	8.4	35.1	10.4	8.4	15.0	1541	6756.4
CS/B+$15-C	6	1.00	414	46	1.1	13.5	32.6	14.2	8.5	15.0	2081	6820.9
CS/B+$5	5	1.00	239	59	1.1	5.9	24.7	7.5	6.0	15.0	1541	4846.9
CS/B+$5	6	1.00	414	46	1.1	9.2	22.2	10.1	6.1	15.0	2081	4871.7
CS/B+$5-C	5	1.00	239	59	1.1	5.9	24.7	4.3	3.5	15.0	1541	2794.2
CS/B+$5-C	6	1.00	414	46	1.1	9.2	22.2	5.8	3.5	15.0	2081	2811.1

TABLE 5.4.2-8. SUMMARY OF NOx RETROFIT RESULTS FOR F. J. GANNON UNITS 1-3

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	3
FIRING TYPE	CYC	CYC	CYC
TYPE OF NOx CONTROL	NA	NA	NA
FURNACE VOLUME (1000 CU FT)	NA	NA	66.6
BOILER INSTALLATION DATE	1957	1958	1960
SLAGGING PROBLEM	NA	NA	NA
ESTIMATED NOx REDUCTION (PERCENT)	NA	NA	NA
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH	HIGH
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	32	32	42
New Duct Length (Feet)	250	250	300
New Duct Costs (1000$)	3750	3750	4500
New Heat Exchanger (1000$)	2131	2131	2652
TOTAL SCOPE ADDER COSTS (1000$)	5913	5913	7194
RETROFIT FACTOR FOR SCR	1.52	1.52	1.52
GENERAL FACILITIES (PERCENT)	13	13	13

TABLE 5.4.2-9. SUMMARY OF NOx RETROFIT RESULTS FOR F. J. GANNON UNITS 4-6

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	4	5	6
FIRING TYPE	CYC	TURBO-FURNACE	
TYPE OF NOx CONTROL	NA	NA	NA
FURNACE VOLUME (1000 CU FT)	NA	129.1	219.4
BOILER INSTALLATION DATE	1963	1965	1967
SLAGGING PROBLEM	NA	YES	YES
ESTIMATED NOx REDUCTION (PERCENT)	NA	NA	NA
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH	HIGH
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	43	52	78
New Duct Length (Feet)	500	600	700
New Duct Costs (1000$)	7500	9000	10500
New Heat Exchanger (1000$)	2722	3144	4371
TOTAL SCOPE ADDER COSTS (1000$)	10266	12196	14950
RETROFIT FACTOR FOR SCR	1.52	1.52	1.52
GENERAL FACILITIES (PERCENT)	13	13	13

Table 5.4.2-10. NOx Control Cost Results for the Gannon Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
SCR-3	1, 2	1.52	125	37	1.1	27.9	223.3	8.4	20.8	80.0	2367	3561.1
SCR-3	3	1.52	180	44	1.1	35.8	198.8	11.2	16.1	80.0	4054	2759.8
SCR-3	4	1.52	188	44	1.1	40.0	212.7	12.1	16.7	80.0	4234	2862.1
SCR-3	5	1.52	239	59	1.1	48.0	200.7	15.0	12.1	80.0	6632	2255.9
SCR-3	6	1.52	414	46	1.1	69.2	167.2	22.4	13.5	80.0	8957	2506.4
SCR-3-C	1, 2	1.52	125	37	1.1	27.9	223.3	5.0	12.2	80.0	2367	2093.2
SCR-3-C	3	1.52	180	44	1.1	35.8	198.8	6.6	9.5	80.0	4054	1620.7
SCR-3-C	4	1.52	188	44	1.1	40.0	212.7	7.1	9.8	80.0	4234	1682.1
SCR-3-C	5	1.52	239	59	1.1	48.0	200.7	8.8	7.1	80.0	6632	1324.9
SCR-3-C	6	1.52	414	46	1.1	69.2	167.2	13.2	7.9	80.0	8957	1470.7
SCR-7	1, 2	1.52	125	37	1.1	27.9	223.3	7.4	18.3	80.0	2367	3129.9
SCR-7	3	1.52	180	44	1.1	35.8	198.8	9.7	14.0	80.0	4054	2397.1
SCR-7	4	1.52	188	44	1.1	40.0	212.7	10.6	14.6	80.0	4234	2499.4
SCR-7	5	1.52	239	59	1.1	48.0	200.7	13.0	10.5	80.0	6632	1961.6
SCR-7	6	1.52	414	46	1.1	69.2	167.2	19.1	11.4	80.0	8957	2128.9
SCR-7-C	1, 2	1.52	125	37	1.1	27.9	223.3	4.4	10.8	80.0	2367	1846.1
SCR-7-C	3	1.52	180	44	1.1	35.8	198.8	5.7	8.3	80.0	4054	1412.9
SCR-7-C	4	1.52	188	44	1.1	40.0	212.7	6.2	8.6	80.0	4234	1474.3
SCR-7-C	5	1.52	239	59	1.1	48.0	200.7	7.7	6.2	80.0	6632	1156.3
SCR-7-C	6	1.52	414	46	1.1	69.2	167.2	11.2	6.7	80.0	8957	1254.4

TABLE 5.4.2-11. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR F. J. GANNON UNITS 1 OR 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	35
TOTAL COST (1000$)	
ESP UPGRADE CASE	35
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

TABLE 5.4.2-12. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR F. J. GANNON UNITS 3,4,5,OR 6

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	46, 46, 57, 87
TOTAL COST (1000$)	
ESP UPGRADE CASE	46, 46, 57, 87
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Table 5.4.2-13. Summary of DSD/FSI Control Costs for the Gannon Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1, 2	1.00	125	37	1.1	5.5	44.2	4.2	10.3	49.0	1669	2490.3
DSD+ESP	3	1.00	180	44	1.1	6.3	35.1	4.8	6.9	49.0	2858	1674.5
DSD+ESP	4	1.00	188	44	1.1	6.5	34.3	4.9	6.7	49.0	2985	1630.2
DSD+ESP	5	1.00	239	59	1.1	8.6	36.0	6.5	5.2	49.0	5089	1267.6
DSD+ESP	6	1.00	414	46	1.1	11.9	28.7	8.0	4.8	49.0	6873	1171.1
DSD+ESP-C	1, 2	1.00	125	37	1.1	5.5	44.2	2.4	5.9	49.0	1669	1441.6
DSD+ESP-C	3	1.00	180	44	1.1	6.3	35.1	2.8	4.0	49.0	2858	969.3
DSD+ESP-C	4	1.00	188	44	1.1	6.5	34.3	2.8	3.9	49.0	2985	943.7
DSD+ESP-C	5	1.00	239	59	1.1	8.6	36.0	3.7	3.0	49.0	5089	733.8
DSD+ESP-C	6	1.00	414	46	1.1	11.9	28.7	4.7	2.8	49.0	6873	678.7
FSI+ESP-50	1, 2	1.00	125	37	1.1	8.3	66.3	4.2	10.4	50.0	1715	2452.6
FSI+ESP-50	3	1.00	180	44	1.1	8.7	48.1	5.0	7.3	50.0	2938	1718.1
FSI+ESP-50	4	1.00	188	44	1.1	8.7	46.2	5.1	7.1	50.0	3068	1673.2
FSI+ESP-50	5	1.00	239	59	1.1	9.8	40.8	6.8	5.5	50.0	5230	1291.1
FSI+ESP-50	6	1.00	414	46	1.1	13.4	32.3	8.8	5.3	50.0	7063	1244.8
FSI+ESP-50-C	1, 2	1.00	125	37	1.1	8.3	66.3	2.4	6.0	50.0	1715	1426.8
FSI+ESP-50-C	3	1.00	180	44	1.1	8.7	48.1	2.9	4.2	50.0	2938	997.6
FSI+ESP-50-C	4	1.00	188	44	1.1	8.7	46.2	3.0	4.1	50.0	3068	971.3
FSI+ESP-50-C	5	1.00	239	59	1.1	9.8	40.8	3.9	3.2	50.0	5230	748.1
FSI+ESP-50-C	6	1.00	414	46	1.1	13.4	32.3	5.1	3.1	50.0	7063	721.7
FSI+ESP-70	1, 2	1.00	125	37	1.1	8.4	67.2	4.3	10.5	70.0	2402	1772.8
FSI+ESP-70	3	1.00	180	44	1.1	8.8	48.8	5.1	7.4	70.0	4113	1244.9
FSI+ESP-70	4	1.00	188	44	1.1	8.8	47.0	5.2	7.2	70.0	4295	1214.0
FSI+ESP-70	5	1.00	239	59	1.1	9.9	41.5	6.9	5.6	70.0	7322	937.6
FSI+ESP-70	6	1.00	414	46	1.1	13.6	32.8	8.9	5.4	70.0	9889	904.3
FSI+ESP-70-C	1, 2	1.00	125	37	1.1	8.4	67.2	2.5	6.1	70.0	2402	1031.4
FSI+ESP-70-C	3	1.00	180	44	1.1	8.8	48.8	3.0	4.3	70.0	4113	722.8
FSI+ESP-70-C	4	1.00	188	44	1.1	8.8	47.0	3.0	4.2	70.0	4295	704.8
FSI+ESP-70-C	5	1.00	239	59	1.1	9.9	41.5	4.0	3.2	70.0	7322	543.3
FSI+ESP-70-C	6	1.00	414	46	1.1	13.6	32.8	5.2	3.1	70.0	9889	524.3

SECTION 6.0 GEORGIA

6.1 GEORGIA POWER COMPANY

6.1.1 P. S. Arkwright Steam Plant

The P. S. Arkwright steam plant is located within Bibb County, Georgia, as part of the Georgia Power Company system. The plant is located just north of the city of Macon along the Ocmulgee River and contains four coal-fired boilers with a total gross generating capacity of 160 MW.

Table 6.1.1-1 presents operational data for the existing equipment at the Arkwright plant. The boilers burn medium sulfur coal. Coal shipments are received by railroad and transferred to the coal storage and handling area which is north of the boilers between the river and the railroad tracks.

PM emissions for the boilers are controlled with retrofit ESPs located behind each unit. The fly ash is wet sluiced to an on-site ash pond located one-half mile west of the plant. Units 1-4 are served by a common chimney located behind the retrofit ESPs and situated between units 2 and 3.

Lime/Limestone and Lime Spray Drying FGD Costs--

The four boilers are located beside each other, parallel to the river, with the switchyard being located between the boilers and the river. The absorbers for units 1-4 would be located in an open area directly behind the chimney which is between the ESPs and the railroad tracks with the coal pile lying to the north. The limestone preparation, storage and handling area would be south of the coal pile, adjacent to the water treatment area, and next to the railroad tracks so that the limestone can be unloaded into the area. No major demolition or relocation of equipment or buildings would be necessary; hence, a base factor of 5 percent was assigned to general facilities.

A low site access/congestion factor was assigned to the FGD absorber locations. For flue gas handling, short duct runs of less than 300 feet would be required for the L/LS-FGD case because the absorbers would be

TABLE 6.1.1-1. P.S. ARKWRIGHT STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1, 2	3, 4
GENERATING CAPACITY (MW-each)	40	40
CAPACITY FACTOR (PERCENT)	53,70	67,62
INSTALLATION DATE	1941, 1942	1943, 1948
FIRING TYPE	TANGENTIAL	FRONT WALL
FURNACE VOLUME (1000 CU FT)	NA	
LOW NOx COMBUSTION	NO	
COAL SULFUR CONTENT (PERCENT)	1.9	
COAL HEATING VALUE (BTU/LB)	12,700	
COAL ASH CONTENT (PERCENT)	9.8	
FLY ASH SYSTEM	WET DISPOSAL	
ASH DISPOSAL METHOD	ON-SITE	
STACK NUMBER	1	
COAL DELIVERY METHODS	RAILROAD	
PARTICULATE CONTROL		
TYPE	ESP	
INSTALLATION DATE	1978	
EMISSION (LB/MM BTU)	0.02	
REMOVAL EFFICIENCY	85.0	
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	2.0	
SURFACE AREA (1000 SQ FT)	39.3	
GAS EXIT RATE (1000 ACFM)	180	
SCA (SQ FT/1000 ACFM)	222	
OUTLET TEMPERATURE (°F)	400	

placed immediately behind the chimney. The existing chimney can be accessed easily; therefore, a low site access/congestion factor was assigned to the flue gas handling system.

LSD with reuse of the existing ESPs was considered for all units at the Arkwright plant. The ESPs are small (SCA=222); however, sufficient room exists behind the units for upgrading with additional plate area. For the flue gas handling systems, a moderate duct length of 500 feet was required for these units. Although there is plenty of open area for the absorbers, access to the ESPs is difficult due to the close proximity of the ESPs to each other. For this reason, a medium site access/congestion factor was assigned to the flue gas handling system. A medium access/congestion factor was assigned for upgrades to the existing ESPs.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Table 6.1.1-2. Table 6.1.1-3 presents the capital and operating costs for commercial FGD technologies. The low cost option reduces costs due to economies of scale and elimination of a spare absorber modules.

Coal Switching and Physical Coal Cleaning Costs--

Table 6.1.1-4 presents the IAPCS results for CS at the Arkwright plant. These costs do not include boiler and pulverizer operating cost changes or any system modifications that may be necessary to blend coal. PCC was not evaluated because this is not a mine mouth plant.

Low NO_x Combustion--

Units 1-2 are tangential-fired boilers rated at 40 MW each, while units 3-4, also rated at 40 MW, are front wall-fired. The combustion modification technique applied to boilers 1 and 2 was OFA, and to units 3 and 4 was LNB.

Tables 6.1.1-5 and 6.1.1-6 present the NO_x performance and cost results of retrofitting OFA and LNB at the Arkwright plant. Although furnace volumes were not available for any of the boilers, values were estimated based on boiler size and age.

TABLE 6.1.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR P.S. ARKWRIGHT UNITS 1-4 (EACH)

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	412	NA	412
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	NA	
ESP REUSE CASE			1.38
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	5

Table 6.1.1-3. Summary of FGD Control Costs for the Arkwright Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.27	40	53	1.9	24.3	607.1	10.1	54.4	90.0	2401	4210.7
L/S FGD	2	1.27	40	70	1.9	24.3	607.4	10.6	43.2	90.0	3171	3344.1
L/S FGD	3	1.27	40	67	1.9	24.3	607.3	10.5	44.8	90.0	3035	3465.6
L/S FGD	4	1.27	40	62	1.9	24.3	607.2	10.4	47.7	90.0	2808	3693.7
L/S FGD	1-4	1.27	160	63	1.9	48.1	300.5	21.1	23.8	90.0	11414	1844.7
L/S FGD-C	1	1.27	40	53	1.9	24.3	607.1	5.9	31.8	90.0	2401	2457.8
L/S FGD-C	2	1.27	40	70	1.9	24.3	607.4	6.2	25.2	90.0	3171	1950.3
L/S FGD-C	3	1.27	40	67	1.9	24.3	607.3	6.1	26.1	90.0	3035	2021.5
L/S FGD-C	4	1.27	40	62	1.9	24.3	607.2	6.1	27.9	90.0	2808	2155.0
L/S FGD-C	1-4	1.27	160	63	1.9	48.1	300.5	12.3	13.9	90.0	11414	1075.8
LC FGD	1-4	1.27	160	63	1.9	33.2	207.3	16.5	18.7	90.0	11414	1447.5
LC FGD-C	1-4	1.27	160	63	1.9	33.2	207.3	9.6	10.9	90.0	11414	842.4
LSD+ESP	1	1.38	40	53	1.9	10.1	252.9	5.4	29.2	76.0	2035	2662.9
LSD+ESP	2	1.38	40	70	1.9	10.1	252.9	5.6	22.9	76.0	2688	2087.4
LSD+ESP	3	1.38	40	67	1.9	10.1	252.9	5.6	23.8	76.0	2573	2167.6
LSD+ESP	4	1.38	40	62	1.9	10.1	252.9	5.5	25.4	76.0	2381	2318.8
LSD+ESP-C	1	1.38	40	53	1.9	10.1	252.9	3.2	17.0	76.0	2035	1548.0
LSD+ESP-C	2	1.38	40	70	1.9	10.1	252.9	3.3	13.3	76.0	2688	1212.8
LSD+ESP-C	3	1.38	40	67	1.9	10.1	252.9	3.2	13.8	76.0	2573	1259.5
LSD+ESP-C	4	1.38	40	62	1.9	10.1	252.9	3.2	14.8	76.0	2381	1347.6

Table 6.1.1-4. Summary of Coal Switching/Cleaning Costs for the Arkwright Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	40	53	1.9	2.4	59.5	3.3	17.7	50.0	1326	2478.2
CS/B+$15	2	1.00	40	70	1.9	2.4	59.5	4.2	16.9	50.0	1752	2371.7
CS/B+$15	3	1.00	40	67	1.9	2.4	59.5	4.0	17.0	50.0	1677	2386.6
CS/B+$15	4	1.00	40	62	1.9	2.4	59.5	3.7	17.2	50.0	1552	2414.4
CS/B+$15-C	1	1.00	40	53	1.9	2.4	59.5	1.9	10.2	50.0	1326	1428.0
CS/B+$15-C	2	1.00	40	70	1.9	2.4	59.5	2.4	9.7	50.0	1752	1364.9
CS/B+$15-C	3	1.00	40	67	1.9	2.4	59.5	2.3	9.8	50.0	1677	1373.8
CS/B+$15-C	4	1.00	40	62	1.9	2.4	59.5	2.2	9.9	50.0	1552	1390.3
CS/B+$5	1	1.00	40	53	1.9	2.0	49.1	1.7	9.0	50.0	1326	1267.1
CS/B+$5	2	1.00	40	70	1.9	2.0	49.1	2.1	8.4	50.0	1752	1173.7
CS/B+$5	3	1.00	40	67	1.9	2.0	49.1	2.0	8.5	50.0	1677	1186.8
CS/B+$5	4	1.00	40	62	1.9	2.0	49.1	1.9	8.7	50.0	1552	1211.2
CS/B+$5-C	1	1.00	40	53	1.9	2.0	49.1	1.0	5.2	50.0	1326	732.6
CS/B+$5-C	2	1.00	40	70	1.9	2.0	49.1	1.2	4.8	50.0	1752	677.5
CS/B+$5-C	3	1.00	40	67	1.9	2.0	49.1	1.1	4.9	50.0	1677	685.3
CS/B+$5-C	4	1.00	40	62	1.9	2.0	49.1	1.1	5.0	50.0	1552	699.6

TABLE 6.1.1-5. SUMMARY OF NOx RETROFIT RESULTS FOR P.S. ARKWRIGHT

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1, 2	3, 4	1-4
FIRING TYPE	TANG	FWF	NA
TYPE OF NOx CONTROL	OFA	LNB	NA
FURNACE VOLUME (1000 CU FT)	NA	NA	NA
BOILER INSTALLATION DATE	1941,42	1943,48	NA
SLAGGING PROBLEM	NO	NO	NA
ESTIMATED NOx REDUCTION (PERCENT)	25	40	NA
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	14	14	38
New Duct Length (Feet)	200	200	200
New Duct Costs (1000$)	580	580	1305
New Heat Exchanger (1000$)	1076	1076	2471
TOTAL SCOPE ADDER COSTS (1000$)	1669	1669	3814
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13	13

Table 6.1.1-6. NOx Control Cost Results for the Arkwright Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	3	1.00	40	67	1.9	1.8	44.2	0.4	1.6	40.0	382	980.3
LNC-LNB	4	1.00	40	62	1.9	1.8	44.2	0.4	1.7	40.0	354	1059.3
LNC-LNB-C	3	1.00	40	67	1.9	1.8	44.2	0.2	0.9	40.0	382	582.4
LNC-LNB-C	4	1.00	40	62	1.9	1.8	44.2	0.2	1.0	40.0	354	629.3
LNC-OFA	1	1.00	40	53	1.9	0.4	10.7	0.1	0.5	25.0	135	674.1
LNC-OFA	2	1.00	40	70	1.9	0.4	10.7	0.1	0.4	25.0	178	510.4
LNC-OFA-C	1	1.00	40	53	1.9	0.4	10.7	0.1	0.3	25.0	135	400.0
LNC-OFA-C	2	1.00	40	70	1.9	0.4	10.7	0.1	0.2	25.0	178	302.9
SCR-3	1	1.16	40	53	1.9	11.1	277.9	3.4	18.1	80.0	432	7761.3
SCR-3	2	1.16	40	70	1.9	11.1	277.9	3.4	13.8	80.0	571	5942.8
SCR-3	3	1.16	40	67	1.9	11.1	278.1	3.4	14.5	80.0	765	4459.1
SCR-3	4	1.16	40	62	1.9	11.1	278.0	3.4	15.6	80.0	707	4800.2
SCR-3	1-4	1.16	40	67	1.9	13.3	332.8	3.8	16.2	80.0	765	4961.0
SCR-3-C	1	1.16	40	53	1.9	11.1	277.9	2.0	10.6	80.0	432	4562.1
SCR-3-C	2	1.16	40	70	1.9	11.1	277.9	2.0	8.1	80.0	571	3492.2
SCR-3-C	3	1.16	40	67	1.9	11.1	278.1	2.0	8.5	80.0	765	2620.1
SCR-3-C	4	1.16	40	62	1.9	11.1	278.0	2.0	9.2	80.0	707	2820.7
SCR-3-C	1-4	1.16	40	67	1.9	13.3	332.8	2.2	9.5	80.0	765	2920.4
SCR-7	1	1.16	40	53	1.9	11.1	277.9	3.0	16.3	80.0	432	7007.0
SCR-7	2	1.16	40	70	1.9	11.1	277.9	3.1	12.5	80.0	571	5371.7
SCR-7	3	1.16	40	67	1.9	11.1	278.1	3.1	13.1	80.0	765	4033.0
SCR-7	4	1.16	40	62	1.9	11.1	278.0	3.1	14.1	80.0	707	4339.5
SCR-7	1-4	1.16	40	67	1.9	12.0	299.8	3.2	13.8	80.0	765	4232.7
SCR-7-C	1	1.16	40	53	1.9	11.1	277.9	1.8	9.6	80.0	432	4129.8
SCR-7-C	2	1.16	40	70	1.9	11.1	277.9	1.8	7.4	80.0	571	3164.9
SCR-7-C	3	1.16	40	67	1.9	11.1	278.1	1.8	7.7	80.0	765	2375.9
SCR-7-C	4	1.16	40	62	1.9	11.1	278.0	1.8	8.3	80.0	707	2556.7
SCR-7-C	1-4	1.16	40	67	1.9	12.0	299.8	1.9	8.1	80.0	765	2495.4

Selective Catalytic Reduction--

Cold side SCR reactors for all units would be located immediately behind the chimneys as were the FGD absorbers. All four reactors would be located in a low site/congestion area with 200 feet of ducting required. The ammonia storage system was placed close to the reactors, west of the plant. No major demolition/relocation would be necessary and, as such, a base factor of 13 percent was assigned to general facilities.

Table 6.1.1-5 presents the SCR process area retrofit factors and scope adder costs. Table 6.1.1-6 presents the estimated cost of retrofitting SCR at the Arkwright boilers.

Duct Spray Drying and Furnace Sorbent Injection--

The retrofit of FSI and DSD technologies at the Arkwright steam plant was considered for all units. Although the ESPs have marginal SCAs (222), there appears to be room available behind the ESPs for additional plate area and sufficient duct residence time is available between the boilers and the ESPs. A medium site access/congestion factor was assigned for upgrading the ESPs because of the space limitation around the ESPs. The sorbent receiving/storage/preparation area was located in the same area as that described for L/LS-FGD.

Table 6.1.1-7 presents a summary of the site access/congestion factors for FSI and DSD technologies at the Arkwright steam plant. Table 6.1.1-8 presents the costs estimated to retrofit sorbent injection technologies at Arkwright.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

All units would be considered good candidates for repowering or retrofit because of the small boiler size and likely short remaining life. Although the capacity factors are high, the small unit sizes would minimize system impacts due to extended downtimes.

TABLE 6.1.1-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR P.S. ARKWRIGHT UNITS 1-4 (EACH)

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	MEDIUM
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	412
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	15
TOTAL COST (1000$)	
ESP UPGRADE CASE	427
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.36
NEW BAGHOUSE	NA

Table 6.1.1-8. Summary of DSD/FSI Control Costs for the Arkwright Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	40	53	1.9	4.8	120.3	3.9	20.8	49.0	1298	2979.9
DSD+ESP	2	1.00	40	70	1.9	4.8	120.3	4.0	16.5	49.0	1714	2358.4
DSD+ESP	3	1.00	40	67	1.9	4.8	120.3	4.0	17.1	49.0	1640	2445.2
DSD+ESP	4	1.00	40	62	1.9	4.8	120.3	4.0	18.2	49.0	1518	2608.4
DSD+ESP-C	1	1.00	40	53	1.9	4.8	120.3	2.2	12.0	49.0	1298	1724.0
DSD+ESP-C	2	1.00	40	70	1.9	4.8	120.3	2.3	9.5	49.0	1714	1363.8
DSD+ESP-C	3	1.00	40	67	1.9	4.8	120.3	2.3	9.9	49.0	1640	1414.1
DSD+ESP-C	4	1.00	40	62	1.9	4.8	120.3	2.3	10.5	49.0	1518	1508.7
FSI+ESP-50	1	1.00	40	53	1.9	5.3	131.7	3.2	17.1	50.0	1334	2375.1
FSI+ESP-50	2	1.00	40	70	1.9	5.3	131.7	3.4	14.0	50.0	1761	1954.2
FSI+ESP-50	3	1.00	40	67	1.9	5.3	131.7	3.4	14.5	50.0	1686	2012.9
FSI+ESP-50	4	1.00	40	62	1.9	5.3	131.7	3.3	15.3	50.0	1560	2123.6
FSI+ESP-50-C	1	1.00	40	53	1.9	5.3	131.7	1.8	9.9	50.0	1334	1378.5
FSI+ESP-50-C	2	1.00	40	70	1.9	5.3	131.7	2.0	8.1	50.0	1761	1133.1
FSI+ESP-50-C	3	1.00	40	67	1.9	5.3	131.7	2.0	8.4	50.0	1686	1167.3
FSI+ESP-50-C	4	1.00	40	62	1.9	5.3	131.7	1.9	8.8	50.0	1560	1231.8
FSI+ESP-70	1	1.00	40	53	1.9	5.3	133.5	3.2	17.3	70.0	1867	1716.7
FSI+ESP-70	2	1.00	40	70	1.9	5.3	133.5	3.5	14.2	70.0	2466	1413.8
FSI+ESP-70	3	1.00	40	67	1.9	5.3	133.5	3.4	14.6	70.0	2360	1455.9
FSI+ESP-70	4	1.00	40	62	1.9	5.3	133.5	3.4	15.4	70.0	2184	1535.6
FSI+ESP-70-C	1	1.00	40	53	1.9	5.3	133.5	1.9	10.0	70.0	1867	996.3
FSI+ESP-70-C	2	1.00	40	70	1.9	5.3	133.5	2.0	8.2	70.0	2466	819.7
FSI+ESP-70-C	3	1.00	40	67	1.9	5.3	133.5	2.0	8.5	70.0	2360	844.3
FSI+ESP-70-C	4	1.00	40	62	1.9	5.3	133.5	1.9	9.0	70.0	2184	890.8

6.1.2 Bowen Steam Plant

The ESPs for units 3 and 4 would be difficult to upgrade due to the configuration of the boilers and the ESPs; therefore, FSI and DSD were not evaluated for the Bowen Plant. In addition, the duct residence time between the boilers and the ESPs for these units is short.

TABLE 6.1.2-1. BOWEN STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3,4
GENERATING CAPACITY (MW-each)	700	880
CAPACITY FACTOR (PERCENT)	70,74	77,83
INSTALLATION DATE	1971,72	1974,75
FIRING TYPE	TANGENTIAL	
FURNACE VOLUME (1000 CU FT)	334	607
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	1.8	
COAL HEATING VALUE (BTU/LB)	12200	
COAL ASH CONTENT (PERCENT)	10.5	
FLY ASH SYSTEM	WET DISPOSAL	
ASH DISPOSAL METHOD	ON-SITE/SOLD	
STACK NUMBER	1	2
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1981	1981
EMISSION (LB/MM BTU)	0.02	0.02
REMOVAL EFFICIENCY	NA	NA
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	2.0	2.0
SURFACE AREA (1000 SQ FT)	476.6	622
GAS EXIT RATE (1000 ACFM)	2017.9	2930
SCA (SQ FT/1000 ACFM)	236	212
OUTLET TEMPERATURE (°F)	NA	NA

TABLE 6.1.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR BOWEN UNIT 1 OR 2 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	NA	HIGH
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	5365	NA	5365
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.68	NA	
ESP REUSE CASE			1.69
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	15

* L/LS-FGD and LSD-FGD absorbers for units 1 and 2 would be located behind the common chimney for units 1 and 2.

TABLE 6.1.2-3. SUMMARY OF RETROFIT FACTOR DATA FOR BOWEN UNIT 3 OR 4 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	NA	HIGH
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			NA
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	HIGH
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	6587	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.55	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.53
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.58
GENERAL FACILITIES (PERCENT)	15	0	15

* L/LS-FGD absorbers, LSD-FGD absorbers, and new FFs for units 3 and 4 would be located behind the common chimney for units 3 and 4.

Table 6.1.2-4. Summary of FGD Control Costs for the Bowen Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.68	700	70	1.8	160.2	228.9	73.0	17.0	90.0	55045	1326.7
L/S FGD	2	1.68	700	74	1.8	160.2	228.9	74.4	16.4	90.0	58190	1278.1
L/S FGD	3	1.55	880	77	1.8	181.1	205.8	87.9	14.8	90.0	76119	1154.6
L/S FGD	4	1.55	880	83	1.8	181.1	205.8	90.4	14.1	90.0	82050	1101.9
L/S FGD	1-2	1.68	1400	72	1.8	280.5	200.3	132.4	15.0	90.0	113235	1169.0
L/S FGD	3-4	1.55	1760	80	1.8	307.6	174.8	158.2	12.8	90.0	158170	1000.2
L/S FGD-C	1	1.68	700	70	1.8	160.2	228.9	42.6	9.9	90.0	55045	773.2
L/S FGD-C	2	1.68	700	74	1.8	160.2	228.9	43.3	9.5	90.0	58190	744.6
L/S FGD-C	3	1.55	880	77	1.8	181.1	205.8	51.2	8.6	90.0	76119	672.2
L/S FGD-C	4	1.55	880	83	1.8	181.1	205.8	52.6	8.2	90.0	82050	641.2
L/S FGD-C	1-2	1.68	1400	72	1.8	280.5	200.3	77.1	8.7	90.0	113235	680.9
L/S FGD-C	3-4	1.55	1760	80	1.8	307.6	174.8	92.0	7.5	90.0	158170	581.8
LC FGD	1-2	1.68	1400	72	1.8	241.1	172.2	120.4	13.6	90.0	113235	1063.0
LC FGD	3-4	1.55	1760	80	1.8	273.4	155.3	147.8	12.0	90.0	158170	934.4
LC FGD-C	1-2	1.68	1400	72	1.8	241.1	172.2	70.0	7.9	90.0	113235	618.6
LC FGD-C	3-4	1.55	1760	80	1.8	273.4	155.3	85.9	7.0	90.0	158170	543.1
LSD+ESP	1	1.69	700	70	1.8	104.7	149.6	43.8	10.2	76.0	46665	939.5
LSD+ESP	2	1.69	700	74	1.8	104.7	149.6	44.6	9.8	76.0	49332	904.3
LSD+ESP-C	1	1.69	700	70	1.8	104.7	149.6	25.6	6.0	76.0	46665	548.3
LSD+ESP-C	2	1.69	700	74	1.8	104.7	149.6	26.0	5.7	76.0	49332	527.6
LSD+FF	3	1.53	880	77	1.8	198.8	226.0	75.2	12.7	87.0	73158	1028.1
LSD+FF	4	1.53	880	83	1.8	198.9	226.0	77.0	12.0	87.0	78859	976.6
LSD+FF-C	3	1.53	880	77	1.8	198.8	226.0	44.0	7.4	87.0	73158	601.2
LSD+FF-C	4	1.53	880	83	1.8	198.9	226.0	45.0	7.0	87.0	78859	570.8

Table 6.1.2-5. Summary of Coal Switching/Cleaning Costs for the Bowen Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	700	70	1.8	21.4	30.6	60.0	14.0	49.0	30167	1988.4
CS/B+$15	2	1.00	700	74	1.8	21.4	30.6	63.2	13.9	49.0	31890	1980.4
CS/B+$15	3	1.00	880	77	1.8	26.6	30.2	82.2	13.8	49.0	41716	1969.8
CS/B+$15	4	1.00	880	83	1.8	26.6	30.2	88.1	13.8	49.0	44967	1960.2
CS/B+$15-C	1	1.00	700	70	1.8	21.4	30.6	34.5	8.0	49.0	30167	1142.4
CS/B+$15-C	2	1.00	700	74	1.8	21.4	30.6	36.3	8.0	49.0	31890	1137.6
CS/B+$15-C	3	1.00	880	77	1.8	26.6	30.2	47.2	8.0	49.0	41716	1131.4
CS/B+$15-C	4	1.00	880	83	1.8	26.6	30.2	50.6	7.9	49.0	44967	1125.7
CS/B+$5	1	1.00	700	70	1.8	14.2	20.3	23.3	5.4	49.0	30167	771.0
CS/B+$5	2	1.00	700	74	1.8	14.2	20.3	24.4	5.4	49.0	31890	765.2
CS/B+$5	3	1.00	880	77	1.8	17.5	19.8	31.5	5.3	49.0	41716	756.3
CS/B+$5	4	1.00	880	83	1.8	17.5	19.8	33.7	5.3	49.0	44967	749.5
CS/B+$5-C	1	1.00	700	70	1.8	14.2	20.3	13.4	3.1	49.0	30167	443.9
CS/B+$5-C	2	1.00	700	74	1.8	14.2	20.3	14.0	3.1	49.0	31890	440.4
CS/B+$5-C	3	1.00	880	77	1.8	17.5	19.8	18.2	3.1	49.0	41716	435.2
CS/B+$5-C	4	1.00	880	83	1.8	17.5	19.8	19.4	3.0	49.0	44967	431.1

TABLE 6.1.2-6. SUMMARY OF NOx RETROFIT RESULTS FOR BOWEN

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1, 2	3, 4
FIRING TYPE	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA
FURNACE VOLUME (1000 CU FT)	334	607
BOILER INSTALLATION DATE	1971, 1972	1974, 1975
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	25	25
SCR RETROFIT RESULTS *		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	116, 196	138, 232
New Duct Length (Feet)	500	300
New Duct Costs (1000$)	7734, 11601	5305, 7958
New Heat Exchanger (1000$)	5991, 9080	6872, 10416
TOTAL SCOPE ADDER COSTS (1000$)		
INDIVIDUAL CASE	13841	12315
COMBINED CASE	20877	18606
RETROFIT FACTOR FOR SCR	1.52	1.52
GENERAL FACILITIES (PERCENT)	38	38

* Cold side SCR reactors for units 1-2 and 3-4 would be located north of the unit 1-2 chimney and north of the unit 3-4 chimney, respectively.

Table 6.1.2-7. NOx Control Cost Results for the Bowen Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost (\$MM)	Capital Cost (\$/kW)	Annual Cost (\$MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. (\$/ton)
LNC-OFA	1	1.00	700	70	1.8	1.3	1.9	0.3	0.1	25.0	3267	87.3
LNC-OFA	2	1.00	700	74	1.8	1.3	1.9	0.3	0.1	25.0	3454	82.6
LNC-OFA	3	1.00	880	77	1.8	1.5	1.7	0.3	0.1	25.0	4518	69.3
LNC-OFA	4	1.00	880	83	1.8	1.5	1.7	0.3	0.0	25.0	4870	64.3
LNC-OFA-C	1	1.00	700	70	1.8	1.3	1.9	0.2	0.0	25.0	3267	51.9
LNC-OFA-C	2	1.00	700	74	1.8	1.3	1.9	0.2	0.0	25.0	3454	49.1
LNC-OFA-C	3	1.00	880	77	1.8	1.5	1.7	0.2	0.0	25.0	4518	41.1
LNC-OFA-C	4	1.00	880	83	1.8	1.5	1.7	0.2	0.0	25.0	4870	38.2
SCR-3	1	1.52	700	70	1.8	107.9	154.2	36.6	8.5	80.0	10455	3500.6
SCR-3	2	1.52	700	74	1.8	107.9	154.2	36.8	8.1	80.0	11052	3326.0
SCR-3	3	1.52	880	77	1.8	128.4	145.9	44.9	7.6	80.0	14457	3103.0
SCR-3	4	1.52	880	83	1.8	128.4	145.9	45.2	7.1	80.0	15584	2899.0
SCR-3	1-2	1.52	1400	72	1.8	200.7	143.4	70.0	7.9	80.0	21507	3253.8
SCR-3	3-4	1.52	1760	80	1.8	242.5	137.8	86.8	7.0	80.0	30041	2889.9
SCR-3-C	1	1.52	700	70	1.8	107.9	154.2	21.5	5.0	80.0	10455	2051.9
SCR-3-C	2	1.52	700	74	1.8	107.9	154.2	21.5	4.7	80.0	11052	1949.4
SCR-3-C	3	1.52	880	77	1.8	128.4	145.9	26.3	4.4	80.0	14457	1817.6
SCR-3-C	4	1.52	880	83	1.8	128.4	145.9	26.5	4.1	80.0	15584	1697.9
SCR-3-C	1-2	1.52	1400	72	1.8	200.7	143.4	41.0	4.6	80.0	21507	1906.0
SCR-3-C	3-4	1.52	1760	80	1.8	242.5	137.8	50.8	4.1	80.0	30041	1691.9
SCR-7	1	1.52	700	70	1.8	107.9	154.2	30.9	7.2	80.0	10455	2951.7
SCR-7	2	1.52	700	74	1.8	107.9	154.2	31.0	6.8	80.0	11052	2806.9
SCR-7	3	1.52	880	77	1.8	128.4	145.9	37.6	6.3	80.0	14457	2604.0
SCR-7	4	1.52	880	83	1.8	128.4	145.9	38.0	5.9	80.0	15584	2436.2
SCR-7	1-2	1.52	1400	72	1.8	200.7	143.4	58.5	6.6	80.0	21507	2720.2
SCR-7	3-4	1.52	1760	80	1.8	242.5	137.8	72.4	5.9	80.0	30041	2409.7
SCR-7-C	1	1.52	700	70	1.8	107.9	154.2	18.2	4.2	80.0	10455	1737.4
SCR-7-C	2	1.52	700	74	1.8	107.9	154.2	18.3	4.0	80.0	11052	1651.9
SCR-7-C	3	1.52	880	77	1.8	128.4	145.9	22.1	3.7	80.0	14457	1531.7
SCR-7-C	4	1.52	880	83	1.8	128.4	145.9	22.3	3.5	80.0	15584	1432.7
SCR-7-C	1-2	1.52	1400	72	1.8	200.7	143.4	34.4	3.9	80.0	21507	1600.3
SCR-7-C	3-4	1.52	1760	80	1.8	242.5	137.8	42.6	3.5	80.0	30041	1416.8

TABLE 6.1.2-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR BOWEN UNIT 1 OR 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	5365
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	129

TOTAL COST (1000$)	
ESP UPGRADE CASE	5494
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

The duct residence time between units 1 and 2 and their respective ESPs is sufficient for FSI and DSD. A high factor was assigned to ESP upgrade.

Table 6.1.2-9. Summary of DSD/FSI Control Costs for the Bowen Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	700	70	1.8	35.9	51.3	23.2	5.4	49.0	29754	781.0
DSD+ESP	2	1.00	700	74	1.8	35.9	51.3	23.9	5.3	49.0	31455	761.1
DSD+ESP-C	1	1.00	700	70	1.8	35.9	51.3	13.5	3.1	49.0	29754	452.9
DSD+ESP-C	2	1.00	700	74	1.8	35.9	51.3	13.9	3.1	49.0	31455	441.2
FSI+ESP-50	1	1.00	700	70	1.8	38.7	55.2	29.2	6.8	50.0	30580	955.9
FSI+ESP-50	2	1.00	700	74	1.8	38.7	55.2	30.3	6.7	50.0	32328	938.2
FSI+ESP-50-C	1	1.00	700	70	1.8	38.7	55.2	16.9	3.9	50.0	30580	553.3
FSI+ESP-50-C	2	1.00	700	74	1.8	38.7	55.2	17.6	3.9	50.0	32328	542.9
FSI+ESP-70	1	1.00	700	70	1.8	38.9	55.6	29.7	6.9	70.0	42812	694.8
FSI+ESP-70	2	1.00	700	74	1.8	38.9	55.6	30.9	6.8	70.0	45259	682.1
FSI+ESP-70-C	1	1.00	700	70	1.8	38.9	55.6	17.2	4.0	70.0	42812	402.1
FSI+ESP-70-C	2	1.00	700	74	1.8	38.9	55.6	17.9	3.9	70.0	45259	394.6

6.1.3 Branch Steam Plant

The Branch Steam Plant is located in Putnam County, Georgia, as part of the Georgia Power Company system. The plant contains four coal-fired boilers with a total gross generating capacity of 1,540 MW. Tables 6.1.3-1 through 6.1.3-11 summarize the plant operational data and present the SO_2 and NO_x control cost and performance estimates.

TABLE 6.1.3-1. BRANCH STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2	3	4
GENERATING CAPACITY (MW-each)	250	319	481	490
CAPACITY FACTOR (PERCENT)	89	77	69	65
INSTALLATION DATE	1965	1967	1968	1969
FIRING TYPE		OPPOSED WALL		
FURNACE VOLUME (1000 CU FT)	NA	162.2	NA	NA
LOW NOx COMBUSTION	NO	NO	NO	NO
COAL SULFUR CONTENT (PERCENT)		1.3		
COAL HEATING VALUE (BTU/LB)		12400		
COAL ASH CONTENT (PERCENT)		10.6		
FLY ASH SYSTEM		WET DISPOSAL		
ASH DISPOSAL METHOD		PONDS/ON-SITE		
STACK NUMBER	5	5	5	5
COAL DELIVERY METHOD		RAILROAD		
PARTICULATE CONTROL				
TYPE	ESP	ESP	ESP	ESP
INSTALLATION DATE	1978	1978	1981	1982
EMISSION (LB/MM BTU)	0.08	NA	0.02	0.02
REMOVAL EFFICIENCY	98.0	98.0	98.0	98.0
DESIGN SPECIFICATION				
SULFUR SPECIFICATION (PERCENT)	1.0	1.0	0.6	1.0
SURFACE AREA (1000 SQ FT)	335.2	417.4	999.0	453.1
GAS EXIT RATE (1000 ACFM)	1386	1679	1963.8	1963.8
SCA (SQ FT/1000 ACFM)	242	249	509	231
OUTLET TEMPERATURE (°F)	300	240	300	300

TABLE 6.1.3-2. SUMMARY OF RETROFIT FACTOR DATA FOR BRANCH UNITS 1 AND 2 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			NA
BAGHOUSE			100-300
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	2132,2652	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.16
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	10	0	10

* L/S-FGD absorbers, LSD-FGD absorbers and new FFs for units 1 and 2 would be located southwest of the common chimney.

TABLE 6.1.3-3. SUMMARY OF RETROFIT FACTOR DATA FOR BRANCH UNITS 3 AND 4 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			NA
BAGHOUSE			100-300
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	3833,3897	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.16
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	10	0	10

* L/S-FGD and LSD-FGD absorbers for units 3 and 4 would be located southwest of the common chimney. ESP reuse was not considered due to the access/congestion problems near the ESPs.

Table 6.1.3-4. Summary of FGD Control Costs for the Branch Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
LC FGD	1-4	1.27	1540	73	1.3	190.5	123.7	104.2	10.6	90.0	89522	1163.9
LC FGD-C	1-4	1.27	1540	73	1.3	190.5	123.7	60.5	6.1	90.0	89522	676.4
LFGD	1	1.27	250	89	1.3	63.0	252.0	30.6	15.7	90.0	17718	1729.8
LFGD	2	1.27	319	77	1.3	71.2	223.1	34.1	15.9	90.0	19561	1745.2
LFGD	3	1.27	481	69	1.3	91.0	189.1	43.1	14.8	90.0	26429	1630.5
LFGD	4	1.27	490	65	1.3	91.9	187.6	42.8	15.3	90.0	25363	1686.4
LFGD	1-4	1.27	1540	73	1.3	222.0	144.2	113.7	11.5	90.0	89522	1270.5
LFGD-C	1	1.27	250	89	1.3	63.0	252.0	17.8	9.2	90.0	17718	1007.0
LFGD-C	2	1.27	319	77	1.3	71.2	223.1	19.9	9.2	90.0	19561	1016.2
LFGD-C	3	1.27	481	69	1.3	91.0	189.1	25.1	8.6	90.0	26429	949.6
LFGD-C	4	1.27	490	65	1.3	91.9	187.6	24.9	8.9	90.0	25363	982.5
LFGD-C	1-4	1.27	1540	73	1.3	222.0	144.2	66.2	6.7	90.0	89522	739.0
LSD+FF	1	1.16	250	89	1.3	49.9	199.8	20.8	10.7	87.0	17029	1222.9
LSD+FF	2	1.16	319	77	1.3	55.8	175.0	21.9	10.2	79.0	17200	1275.9
LSD+FF	3	1.16	481	69	1.3	82.7	172.0	32.1	11.0	87.0	25401	1263.7
LSD+FF	4	1.16	490	65	1.3	83.9	171.2	32.0	11.5	87.0	24376	1313.6
LSD+FF	1-4	1.16	1540	73	1.3	246.6	160.1	94.9	9.6	87.0	86040	1103.5
LSD+FF-C	1	1.16	250	89	1.3	49.9	199.8	12.2	6.2	87.0	17029	713.8
LSD+FF-C	2	1.16	319	77	1.3	55.8	175.0	12.8	6.0	79.0	17200	745.5
LSD+FF-C	3	1.16	481	69	1.3	82.7	172.0	18.8	6.5	87.0	25401	738.6
LSD+FF-C	4	1.16	490	65	1.3	83.9	171.2	18.7	6.7	87.0	24376	768.1
LSD+FF-C	1-4	1.16	1540	73	1.3	246.6	160.1	55.5	5.6	87.0	86040	645.1

Table 6.1.3-5. Summary of Coal Switching/Cleaning Costs for the Branch Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	250	89	1.3	8.6	34.3	27.4	14.1	29.0	5613	4880.6
CS/B+$15	2	1.00	319	77	1.3	10.6	33.2	30.3	14.1	29.0	6196	4895.0
CS/B+$15	3	1.00	481	69	1.3	15.2	31.7	40.9	14.1	29.0	8372	4890.6
CS/B+$15	4	1.00	490	65	1.3	15.5	31.6	39.5	14.1	29.0	8035	4912.5
CS/B+$15-C	1	1.00	250	89	1.3	8.6	34.3	15.7	8.1	29.0	5613	2803.1
CS/B+$15-C	2	1.00	319	77	1.3	10.6	33.2	17.4	8.1	29.0	6196	2812.2
CS/B+$15-C	3	1.00	481	69	1.3	15.2	31.7	23.5	8.1	29.0	8372	2810.2
CS/B+$15-C	4	1.00	490	65	1.3	15.5	31.6	22.7	8.1	29.0	8035	2823.2
CS/B+$5	1	1.00	250	89	1.3	6.0	24.0	10.8	5.6	29.0	5613	1931.6
CS/B+$5	2	1.00	319	77	1.3	7.3	22.8	12.0	5.6	29.0	6196	1933.4
CS/B+$5	3	1.00	481	69	1.3	10.3	21.3	16.1	5.5	29.0	8372	1918.2
CS/B+$5	4	1.00	490	65	1.3	10.4	21.3	15.5	5.6	29.0	8035	1933.7
CS/B+$5-C	1	1.00	250	89	1.3	6.0	24.0	6.2	3.2	29.0	5613	1111.5
CS/B+$5-C	2	1.00	319	77	1.3	7.3	22.8	6.9	3.2	29.0	6196	1113.0
CS/B+$5-C	3	1.00	481	69	1.3	10.3	21.3	9.2	3.2	29.0	8372	1104.5
CS/B+$5-C	4	1.00	490	65	1.3	10.4	21.3	8.9	3.2	29.0	8035	1113.7

TABLE 6.1.3-6. SUMMARY OF NOx RETROFIT RESULTS FOR BRANCH +

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	3
FIRING TYPE	OWF	OWF	OWF
TYPE OF NOx CONTROL	NA	LNB	NA
FURNACE VOLUME (1000 CU FT)	NA	162.2	NA
BOILER INSTALLATION DATE	1965	1967	1968
SLAGGING PROBLEM	NO	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	NA	35	NA
SCR RETROFIT RESULTS *			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	54	65	88
New Duct Length (Feet)	200	200	200
New Duct Costs (1000$)	1694	1953	2484
New Heat Exchanger (1000$)	3230	3738	4783
TOTAL SCOPE ADDER COSTS (1000$)	4977	5756	7355
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	20	20	20

\+ Units 1 and 3 have cell burners, therefore LNBs were not evaluated for these units.
* Cold side SCR reactors for all units would be located southwest of the common chimney.

TABLE 6.1.3-7. SUMMARY OF NOx RETROFIT RESULTS FOR BRANCH +

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	4	1-4
FIRING TYPE	OWF	NA
TYPE OF NOx CONTROL	NA	NA
FURNACE VOLUME (1000 CU FT)	NA	NA
BOILER INSTALLATION DATE	1969	NA
SLAGGING PROBLEM	NO	NA
ESTIMATED NOx REDUCTION (PERCENT)	NA	NA
SCR RETROFIT RESULTS *		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	89	210
New Duct Length (Feet)	200	200
New Duct Costs (1000$)	2511	4907
New Heat Exchanger (1000$)	4836	9614
TOTAL SCOPE ADDER COSTS (1000$)	7436	14731
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	20	20

+ Unit 4 has cell burners and was not evaluated for LNBs.
* Cold side SCR reactors for all units would be located southwest of the common chimney.

Table 6.1.3-8. NOx Control Cost Results for the Branch Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	2	1.00	319	77	1.3	4.1	12.7	0.9	0.4	35.0	3151	272.9
LNC-LNB-C	2	1.00	319	77	1.3	4.1	12.7	0.5	0.2	35.0	3151	162.1
SCR-3	1	1.16	250	89	1.3	36.4	145.5	13.1	6.7	80.0	6523	2002.5
SCR-3	2	1.16	319	77	1.3	43.8	137.4	15.8	7.3	80.0	7202	2190.7
SCR-3	3	1.16	481	69	1.3	59.8	124.4	22.0	7.6	80.0	9731	2264.6
SCR-3	4	1.16	490	65	1.3	60.9	124.3	22.3	8.0	80.0	9338	2389.4
SCR-3	1-4	1.16	1540	73	1.3	169.9	110.4	66.2	6.7	80.0	32960	2008.0
SCR-3-C	1	1.16	250	89	1.3	36.4	145.5	7.6	3.9	80.0	6523	1172.3
SCR-3-C	2	1.16	319	77	1.3	43.8	137.4	9.2	4.3	80.0	7202	1282.4
SCR-3-C	3	1.16	481	69	1.3	59.8	124.4	12.9	4.4	80.0	9731	1325.0
SCR-3-C	4	1.16	490	65	1.3	60.9	124.3	13.1	4.7	80.0	9338	1398.2
SCR-3-C	1-4	1.16	1540	73	1.3	169.9	110.4	38.7	3.9	80.0	32960	1173.5
SCR-7	1	1.16	250	89	1.3	36.4	145.5	11.0	5.7	80.0	6523	1689.1
SCR-7	2	1.16	319	77	1.3	43.8	137.4	13.2	6.1	80.0	7202	1828.4
SCR-7	3	1.16	481	69	1.3	59.8	124.4	18.1	6.2	80.0	9731	1860.4
SCR-7	4	1.16	490	65	1.3	60.9	124.3	18.3	6.6	80.0	9338	1960.3
SCR-7	1-4	1.16	1540	73	1.3	169.9	110.4	53.6	5.4	80.0	32960	1625.9
SCR-7-C	1	1.16	250	89	1.3	36.4	145.5	6.5	3.3	80.0	6523	992.8
SCR-7-C	2	1.16	319	77	1.3	43.8	137.4	7.7	3.6	80.0	7202	1074.8
SCR-7-C	3	1.16	481	69	1.3	59.8	124.4	10.6	3.7	80.0	9731	1093.4
SCR-7-C	4	1.16	490	65	1.3	60.9	124.3	10.8	3.9	80.0	9338	1152.4
SCR-7-C	1-4	1.16	1540	73	1.3	169.9	110.4	31.5	3.2	80.0	32960	954.6

TABLE 6.1.3-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR BRANCH UNITS 1 AND 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	2132, 2652
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	59, 71

TOTAL COST (1000$)	
ESP UPGRADE CASE	2191, 2723
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Units 1 and 2 have a long duct residence time. A high factor was assigned to ESP upgrade because of the congestion around the ESPs for these units.

TABLE 6.1.3-10. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR BRANCH UNITS 3 AND 4

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	LOW
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	3833,3897
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	97,97

TOTAL COST (1000$)	
ESP UPGRADE CASE	3930,3995
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.16
NEW BAGHOUSE	NA

Units 3 and 4 have a long duct residence time. Room is available for ESP upgrade, hence a low factor was assigned.

Table 6.1.3-11. Summary of DSD/FSI Control Costs for the Branch Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	250	89	1.3	14.2	56.7	9.9	5.1	49.0	9578	1035.7
DSD+ESP	2	1.00	319	77	1.3	15.4	48.2	9.8	4.5	42.0	9170	1066.8
DSD+ESP	3	1.00	481	69	1.3	19.6	40.6	13.3	4.6	49.0	14286	930.2
DSD+ESP	4	1.00	490	65	1.3	22.6	46.0	13.9	5.0	49.0	13710	1010.8
DSD+ESP-C	1	1.00	250	89	1.3	14.2	56.7	5.7	2.9	49.0	9578	600.0
DSD+ESP-C	2	1.00	319	77	1.3	15.4	48.2	5.7	2.6	42.0	9170	618.7
DSD+ESP-C	3	1.00	481	69	1.3	19.6	40.6	7.7	2.6	49.0	14286	539.1
DSD+ESP-C	4	1.00	490	65	1.3	22.6	46.0	8.0	2.9	49.0	13710	586.5
FSI+ESP-50	1	1.00	250	89	1.3	16.1	64.2	11.1	5.7	50.0	9843	1131.1
FSI+ESP-50	2	1.00	319	77	1.3	18.6	58.4	12.3	5.7	50.0	10867	1131.9
FSI+ESP-50	3	1.00	481	69	1.3	18.6	38.6	14.5	5.0	50.0	14683	987.6
FSI+ESP-50	4	1.00	490	65	1.3	24.2	49.4	15.7	5.6	50.0	14090	1113.9
FSI+ESP-50-C	1	1.00	250	89	1.3	16.1	64.2	6.5	3.3	50.0	9843	655.4
FSI+ESP-50-C	2	1.00	319	77	1.3	18.6	58.4	7.1	3.3	50.0	10867	656.2
FSI+ESP-50-C	3	1.00	481	69	1.3	18.6	38.6	8.4	2.9	50.0	14683	571.5
FSI+ESP-50-C	4	1.00	490	65	1.3	24.2	49.4	9.1	3.3	50.0	14090	645.9
FSI+ESP-70	1	1.00	250	89	1.3	16.2	64.9	11.3	5.8	70.0	13781	821.3
FSI+ESP-70	2	1.00	319	77	1.3	18.8	58.8	12.5	5.8	70.0	15213	821.2
FSI+ESP-70	3	1.00	481	69	1.3	18.7	39.0	14.8	5.1	70.0	20556	718.1
FSI+ESP-70	4	1.00	490	65	1.3	24.4	49.7	15.9	5.7	70.0	19726	808.4
FSI+ESP-70-C	1	1.00	250	89	1.3	16.2	64.9	6.6	3.4	70.0	13781	475.8
FSI+ESP-70-C	2	1.00	319	77	1.3	18.8	58.8	7.2	3.4	70.0	15213	476.0
FSI+ESP-70-C	3	1.00	481	69	1.3	18.7	39.0	8.5	2.9	70.0	20556	415.5
FSI+ESP-70-C	4	1.00	490	65	1.3	24.4	49.7	9.2	3.3	70.0	19726	468.7

6.1.4 Hammond Steam Plant

The Hammond steam plant is located on the Coosa River in Floyd County, Georgia, and is part of the Georgia Power Company. The plant contains four coal-fired boilers with a total gross generating capacity of 800 MW.

Table 6.1.4-1 presents operational data for the existing equipment at the Hammond plant. Coal shipments are received by railroad and conveyed to a coal storage and handling area west of the plant and adjacent to the river. PM emissions from boilers 1-3 are controlled by retrofit ESPs. Emissions from boiler 4 are controlled by an ESP installed at the time of construction. All four ESPs are located behind the boilers and flue gas is directed to two flues inside a common chimney. Three old chimneys are retired and left intact behind the units. Ash from the units is disposed of in ash ponds to the east and west of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS or LSD-FGD absorbers would be located behind the common chimney. The general facilities factor would be high (15 percent) because of the need to relocate storage buildings and roads. A low site access/congestion factor can then be assigned to the FGD absorber locations. Land across the road can be acquired for the storage and preparation areas. In the L/LS-FGD case, approximately 250 feet of ductwork would be required. For the LSD case, approximately 350 feet of ductwork would be required. In both FGD cases, a low site access/congestion factor would be assigned to flue gas handling because of the easy access to the common stack.

Because of the small size of the existing ESPs, LSD was only considered in conjunction with the use of new FFs. FFs would be located adjacent to the absorbers and similar site access/congestion factors would be assigned to their locations.

Tables 6.1.4-2 and 6.1.4-3 give a summary of retrofit data for commercial FGD technologies. Table 6.1.4-4 presents the process area retrofit factors and capital/operating costs for commercial FGD technologies. The low cost option reduces capital/operating costs due to economy of scale and elimination of a spare absorber module.

TABLE 6.1.4-1. HAMMOND STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1, 2, 3	4
GENERATING CAPACITY (MW-each)	100	500
CAPACITY FACTOR (PERCENT)	64,84,70	70
INSTALLATION DATE	1954,54,55	1970
FIRING TYPE	FRONT WALL	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	47.5	276.6
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	1.7	1.7
COAL HEATING VALUE (BTU/LB)	12500	12500
COAL ASH CONTENT (PERCENT)	9.7	9.7
FLY ASH SYSTEM	WET DISPOSAL	
ASH DISPOSAL METHOD	PONDS/ON-SITE	
STACK NUMBER	1	2
COAL DELIVERY METHODS	RAILROAD	
PARTICULATE CONTROL		
TYPE	ESP	
INSTALLATION DATE	1971,69,69	1970
EMISSION (LB/MM BTU)	NA	NA
REMOVAL EFFICIENCY	98	98.4
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	0.7	0.7
SURFACE AREA (1000 SQ FT)	69.1	129.6
GAS EXIT RATE (1000 ACFM)	420	803
SCA (SQ FT/1000 ACFM)	165	161
OUTLET TEMPERATURE (°F)	320	320

TABLE 6.1.4-2. SUMMARY OF RETROFIT FACTOR DATA FOR HAMMOND UNITS 1-3 (EACH)

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	938	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.27
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	15	0	15

TABLE 6.1.4-3. SUMMARY OF RETROFIT FACTOR DATA FOR HAMMOND UNIT 4

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	3968	NA	0
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.27
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	15	0	15

Table 6.1.4-4. Summary of FGD Control Costs for the Hammond Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.27	100	64	1.7	39.2	392.3	16.8	30.0	90.0	6603	2544.0
L/S FGD	2	1.27	100	84	1.7	39.2	392.5	17.9	24.4	90.0	8667	2069.1
L/S FGD	3	1.27	100	70	1.7	39.2	392.4	17.1	28.0	90.0	7222	2373.3
L/S FGD	4	1.27	500	70	1.7	100.2	200.5	47.8	15.6	90.0	36112	1322.3
L/S FGD	1-3	1.27	300	73	1.7	72.4	241.2	33.7	17.6	90.0	22596	1492.7
L/S FGD-C	1	1.27	100	64	1.7	39.2	392.3	9.8	17.5	90.0	6603	1484.2
L/S FGD-C	2	1.27	100	84	1.7	39.2	392.5	10.5	14.2	90.0	8667	1205.8
L/S FGD-C	3	1.27	100	70	1.7	39.2	392.4	10.0	16.3	90.0	7222	1384.1
L/S FGD-C	4	1.27	500	70	1.7	100.2	200.5	27.8	9.1	90.0	36112	770.0
L/S FGD-C	1-3	1.27	300	73	1.7	72.4	241.2	19.6	10.2	90.0	22596	869.6
LC FGD	1-4	1.27	800	71	1.7	108.7	135.9	59.5	12.0	90.0	58605	1015.6
LC FGD-C	1-4	1.27	800	71	1.7	108.7	135.9	34.6	7.0	90.0	58605	590.2
LSD+FF	1	1.27	100	64	1.7	26.1	260.7	10.7	19.1	87.0	6347	1690.8
LSD+FF	2	1.27	100	84	1.7	26.1	260.8	11.4	15.4	87.0	8330	1364.3
LSD+FF	3	1.27	100	70	1.7	26.1	260.7	10.9	17.8	87.0	6942	1572.9
LSD+FF	4	1.27	500	70	1.7	93.7	187.5	36.7	12.0	87.0	34708	1058.6
LSD+FF	1-3	1.27	300	73	1.7	63.4	211.4	24.9	13.0	87.0	21717	1148.4
LSD+FF-C	1	1.27	100	64	1.7	26.1	260.7	6.3	11.2	87.0	6347	987.1
LSD+FF-C	2	1.27	100	84	1.7	26.1	260.8	6.6	9.0	87.0	8330	795.7
LSD+FF-C	3	1.27	100	70	1.7	26.1	260.7	6.4	10.4	87.0	6942	918.0
LSD+FF-C	4	1.27	500	70	1.7	93.7	187.5	21.5	7.0	87.0	34708	618.6
LSD+FF-C	1-3	1.27	300	73	1.7	63.4	211.4	14.6	7.6	87.0	21717	671.0

Coal Switching and Physical Coal Cleaning Costs--

Table 6.1.4-5 presents the IAPCS cost results for CS at the Hammond plant. These costs do not include boiler and pulverizer operation cost changes or any system modifications that may be necessary to blend coal. PCC was not evaluated because this is not a mine mouth plant.

Low NO_x Combustion--

The four boilers at the Hammond steam plant are wall-fired boilers rated at 100, 100, 100, and 500 MW, respectively. The combustion modification technique applied to all four boilers was LNB. Tables 6.1.4-6 and 6.1.4-7 present the NO_x performance and cost results of retrofitting LNB at the Hammond plant.

Selective Catalytic Reduction--

Cold side SCR reactors would be located similarly behind the ESPs and chimneys. As in the FGD case, storage buildings and roads would have to be relocated to provide room for the reactors and a high general facilities value of 30 percent would be assigned to the location. However, after demolition, the SCR reactors would be located in an area with a low site access/congestion factor. About 250 feet of ductwork would be required. Tables 6.1.4-6 and 6.1.4-7 summarize the retrofit factors scope adders and estimated costs for retrofitting SCR at the Hammond plant.

Duct Spray Drying and Furnace Sorbent Injection--

The retrofit of FSI and DSD technologies at the Hammond plant was not considered for any of the units. All the units have small SCAs (<170) and would not be able to handle additional particulate loading.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

Units 1-3 would be considered good candidates for repowering or retrofit because of the small boiler size and likely short remaining life. However, the capacity factors are high which might result in high replacement power cost for an extended downtime. Unit 4 is not a good candidate for repowering because of its large boiler size, high capacity factor, and longer remaining life.

Table 6.1.4-5. Summary of Coal Switching/Cleaning Costs for the Hammond Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	100	64	1.7	4.7	46.7	8.7	15.5	45.0	3289	2644.7
CS/B+$15	2	1.00	100	84	1.7	4.7	46.7	11.1	15.1	45.0	4317	2566.5
CS/B+$15	3	1.00	100	70	1.7	4.7	46.7	9.4	15.3	45.0	3597	2616.5
CS/B+$15	4	1.00	500	70	1.7	18.7	37.4	44.1	14.4	45.0	17986	2454.1
CS/B+$15-C	1	1.00	100	64	1.7	4.7	46.7	5.0	8.9	45.0	3289	1521.6
CS/B+$15-C	2	1.00	100	84	1.7	4.7	46.7	6.4	8.7	45.0	4317	1475.3
CS/B+$15-C	3	1.00	100	70	1.7	4.7	46.7	5.4	8.8	45.0	3597	1504.9
CS/B+$15-C	4	1.00	500	70	1.7	18.7	37.4	25.4	8.3	45.0	17986	1410.7
CS/B+$5	1	1.00	100	64	1.7	3.6	36.4	3.9	6.9	45.0	3289	1181.5
CS/B+$5	2	1.00	100	84	1.7	3.6	36.4	4.8	6.5	45.0	4317	1116.5
CS/B+$5	3	1.00	100	70	1.7	3.6	36.4	4.2	6.8	45.0	3597	1158.1
CS/B+$5	4	1.00	500	70	1.7	13.5	27.0	17.9	5.8	45.0	17986	995.7
CS/B+$5-C	1	1.00	100	64	1.7	3.6	36.4	2.2	4.0	45.0	3289	681.9
CS/B+$5-C	2	1.00	100	84	1.7	3.6	36.4	2.8	3.8	45.0	4317	643.4
CS/B+$5-C	3	1.00	100	70	1.7	3.6	36.4	2.4	3.9	45.0	3597	668.0
CS/B+$5-C	4	1.00	500	70	1.7	13.5	27.0	10.3	3.4	45.0	17986	573.8

TABLE 6.1.4-6. SUMMARY OF NOx RETROFIT RESULTS FOR HAMMOND

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1,2,3	4	1-3
FIRING TYPE	FWF	FWF	NA
TYPE OF NOx CONTROL	LNB	LNB	NA
FURNACE VOLUME (1000 CU FT)	47.5	276.6	NA
BOILER INSTALLATION DATE	1954	1970	NA
SLAGGING PROBLEM	NO	NO	NA
ESTIMATED NOx REDUCTION (PERCENT)	33	38	NA
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	27	90	62
New Duct Length (Feet)	250	250	250
New Duct Costs (1000$)	1239	3176	2356
New Heat Exchanger (1000$)	1864	4895	3603
TOTAL SCOPE ADDER COSTS (1000$)	3130	8161	6021
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	30	30	30

Table 6.1.4-7. NOx Control Cost Results for the Hammond Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	1	1.00	100	64	1.7	2.6	25.5	0.5	1.0	33.0	767	704.9
LNC-LNB	2	1.00	100	84	1.7	2.6	25.5	0.5	0.7	33.0	1007	537.1
LNC-LNB	3	1.00	100	70	1.7	2.6	25.5	0.5	0.9	33.0	839	644.5
LNC-LNB	4	1.00	500	70	1.7	4.9	9.7	1.0	0.3	38.0	4830	213.0
LNC-LNB-C	1	1.00	100	64	1.7	2.6	25.5	0.3	0.6	33.0	767	418.7
LNC-LNB-C	2	1.00	100	84	1.7	2.6	25.5	0.3	0.4	33.0	1007	319.0
LNC-LNB-C	3	1.00	100	70	1.7	2.6	25.5	0.3	0.5	33.0	839	382.8
LNC-LNB-C	4	1.00	500	70	1.7	4.9	9.7	0.6	0.2	38.0	4830	126.6
SCR-3	1	1.16	100	64	1.7	19.7	197.4	6.3	11.3	80.0	1859	3413.2
SCR-3	2	1.16	100	84	1.7	19.7	197.4	6.5	8.8	80.0	2440	2656.2
SCR-3	3	1.16	100	70	1.7	19.7	197.4	6.4	10.4	80.0	2034	3140.1
SCR-3	4	1.16	500	70	1.7	64.3	128.7	23.5	7.7	80.0	10167	2315.1
SCR-3	1-3	1.16	300	73	1.7	43.9	146.4	15.4	8.0	80.0	6362	2415.1
SCR-3-C	1	1.16	100	64	1.7	19.7	197.4	3.7	6.6	80.0	1859	2003.2
SCR-3-C	2	1.16	100	84	1.7	19.7	197.4	3.8	5.2	80.0	2440	1558.1
SCR-3-C	3	1.16	100	70	1.7	19.7	197.4	3.7	6.1	80.0	2034	1842.6
SCR-3-C	4	1.16	500	70	1.7	64.3	128.7	13.8	4.5	80.0	10167	1354.8
SCR-3-C	1-3	1.16	300	73	1.7	43.9	146.4	9.0	4.7	80.0	6362	1414.6
SCR-7	1	1.16	100	64	1.7	19.7	197.4	5.5	9.9	80.0	1859	2973.9
SCR-7	2	1.16	100	84	1.7	19.7	197.4	5.7	7.7	80.0	2440	2321.5
SCR-7	3	1.16	100	70	1.7	19.7	197.4	5.6	9.1	80.0	2034	2738.4
SCR-7	4	1.16	500	70	1.7	64.3	128.7	19.5	6.3	80.0	10167	1913.5
SCR-7	1-3	1.16	300	73	1.7	43.9	146.4	12.9	6.7	80.0	6362	2029.9
SCR-7-C	1	1.16	100	64	1.7	19.7	197.4	3.3	5.8	80.0	1859	1751.4
SCR-7-C	2	1.16	100	84	1.7	19.7	197.4	3.3	4.5	80.0	2440	1366.3
SCR-7-C	3	1.16	100	70	1.7	19.7	197.4	3.3	5.3	80.0	2034	1612.4
SCR-7-C	4	1.16	500	70	1.7	64.3	128.7	11.4	3.7	80.0	10167	1124.7
SCR-7-C	1-3	1.16	300	73	1.7	43.9	146.4	7.6	4.0	80.0	6362	1194.0

6.1.5 Jack McDonough Steam Plant

The Jack McDonough plant is located within Cobb County, Georgia, as part of the Georgia Power Company system. The plant, located directly south of the oil burning Atkinson power plant and west of the Chattahoochee River, contains two coal-fired boilers and has a total gross generating capacity of 490 MW.

Table 6.1.5-1 presents operational data for the existing equipment at the Jack McDonough plant. Both boilers burn medium sulfur coal which is received by railroad and transferred to a coal storage and handling area northeast of the plant away from the river.

PM emissions for the boilers are controlled with retrofit ESPs located behind each unit and stacked on top of each other. The plant has a wet fly ash handling system. Part of the fly ash is temporarily disposed of in an ash pond beside the coal pile while the rest is sold. Both units are served by a common chimney located behind the ESPs.

Lime/Limestone and Lime Spray Drying FGD Costs--

Absorbers for both units would be located east of the chimney beside the river. The limestone preparation, storage, and handling area would be located south of the coal pile and close to the railroad tracks. This would most likely enable the plant to receive the sorbent via existing railroad tracks. Some of the roads and a major part of the storage building beside the chimney would be relocated; therefore, a factor of 15 percent was assigned to general facilities. The temporary waste handling area would be located close to the ash pond site. However, because of the limited space available, waste generated by the FGD absorbers would have to be deposited off-site in the same manner as the fly ash.

The site beside the common chimney is surrounded by the river to the east, chimney to the west, storage building to the north, and office building and ESPs to the south. As such, a high site access/congestion factor was assigned to the FGD absorber locations. In addition to general facilities, 10 percent was added to the retrofit factor due to major demolitions and relocations which would be necessary. Short duct runs of

TABLE 6.1.5-1. JACK McDONOUGH STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1, 2
GENERATING CAPACITY (MW-each)	245
CAPACITY FACTOR (PERCENT)	71,77
INSTALLATION DATE	1963,64
FIRING TYPE	TANG
FURNACE VOLUME (1000 CU FT)	154.5
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	2.5
COAL HEATING VALUE (BTU/LB)	11800
COAL ASH CONTENT (PERCENT)	9.6
FLY ASH SYSTEM	WET DISPOSAL
ASH DISPOSAL METHOD	ON-SITE PONDS/SELL
STACK NUMBER	1
COAL DELIVERY METHODS	RAILROAD
<u>PARTICULATE CONTROL</u>	
TYPE	ESP
INSTALLATION DATE	1972
EMISSION (LB/MM BTU)	0.04
REMOVAL EFFICIENCY	99.0
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	2.0
SURFACE AREA (1000 SQ FT)	209.3
GAS EXIT RATE (1000 ACFM)	1000
SCA (SQ FT/1000 ACFM)	209
OUTLET TEMPERATURE (°F)	300

150 feet would be required for L/LS-FGD cases because absorbers were placed immediately behind the chimneys.

LSD with reuse of the existing ESPs was not considered for this plant because the ESPs are small and are located in a very high site/access congestion area. The ESPs would probably require major upgrades and plate area additions to handle the increased PMs generated from the LSD application. LSD with a new baghouse was not considered because the boilers are not burning low sulfur coal.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Table 6.1.5-2. Table 6.1.5-3 presents the capital and operating cost estimates for commercial FGD technologies. The low cost FGD case shows the effect of a combined system (economy of scale), no spare absorber modules and large absorber modules.

Coal Switching and Physical Coal Cleaning Costs--

Table 6.1.5-4 presents the IAPCS cost results for CS at the Jack McDonough plant. These costs do not include boiler and pulverizer operating cost change or any system modifications that may be necessary to blend coal. PCC was not evaluated because this is not a mine mouth plant.

Low NO_x Combustion--

Units 1 through 2 are dry bottom, tangential-fired boilers rated at 245 MW each. The combustion modification technique applied to both boilers was OFA. Tables 6.1.5-5 and 6.1.5-6 present the NO_x performance and cost results of retrofitting OFA at the Jack McDonough plant. A high NO_x reduction performance was estimated based on the relatively low volumetric heat release rate.

Selective Catalytic Reduction--

Cold side SCR reactors would be located immediately beside the common chimney in an area having high site congestion and high underground obstruction factors. The SCR reactors were located close to the chimney and, as such, a short duct run of 200 feet was required. Some of the plant roads and storage buildings would be relocated; therefore, a factor of 30 percent was assigned to general facilities.

TABLE 6.1.5-2. SUMMARY OF RETROFIT FACTOR DATA FOR JACK McDONOUGH UNIT 1 OR 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	NA	NA
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			NA
BAGHOUSE			NA
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NA
ESTIMATED COST (1000$)	2093	NA	NA
NEW CHIMNEY	NO	NA	NA
ESTIMATED COST (1000$)	0	0	0
OTHER	YES		
RETROFIT FACTORS			
FGD SYSTEM	1.70	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	0

Table 6.1.5-3. Summary of FGD Control Costs for the Jack McDonough Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1,2	1.70	245	74	2.5	86.5	353.2	38.4	24.2	90.0	29390	1306.0
L/S FGD	1-2	1.70	490	74	2.5	133.5	272.4	62.2	19.6	90.0	58780	1058.0
L/S FGD-C	1,2	1.70	245	74	2.5	86.5	353.2	22.4	14.1	90.0	29390	761.5
L/S FGD-C	1-2	1.70	490	74	2.5	133.5	272.4	36.2	11.4	90.0	58780	616.4
LC FGD	1-2	1.70	490	74	2.5	101.6	207.3	52.5	16.5	90.0	58780	892.4
LC FGD-C	1-2	1.70	490	74	2.5	101.6	207.3	30.5	9.6	90.0	58780	519.0

Table 6.1.5-4. Summary of Coal Switching/Cleaning Costs for the Jack McDonough Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	245	71	2.5	8.6	35.0	21.9	14.4	65.0	20329	1076.4
CS/B+$15	2	1.00	245	77	2.5	8.6	35.0	23.6	14.3	65.0	22047	1069.2
CS/B+$15-C	1	1.00	245	71	2.5	8.6	35.0	12.6	8.3	65.0	20329	618.6
CS/B+$15-C	2	1.00	245	77	2.5	8.6	35.0	13.5	8.2	65.0	22047	614.4
CS/B+$5	1	1.00	245	71	2.5	6.0	24.6	8.9	5.8	65.0	20329	435.4
CS/B+$5	2	1.00	245	77	2.5	6.0	24.6	9.5	5.7	65.0	22047	429.9
CS/B+$5-C	1	1.00	245	71	2.5	6.0	24.6	5.1	3.3	65.0	20329	250.8
CS/B+$5-C	2	1.00	245	77	2.5	6.0	24.6	5.5	3.3	65.0	22047	247.6

TABLE 6.1.5-5. SUMMARY OF NOx RETROFIT RESULTS FOR JACK McDONOUGH

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1, 2
FIRING TYPE	TANG
TYPE OF NOx CONTROL	OFA
FURNACE VOLUME (1000 CU FT)	154.5
BOILER INSTALLATION DATE	1963
SLAGGING PROBLEM	NO
ESTIMATED NOx REDUCTION (PERCENT)	25
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	89
New Duct Length (Feet)	200
New Duct Costs (1000$)	2511
New Heat Exchanger (1000$)	4836
TOTAL SCOPE ADDER COSTS (1000$)	
COMBINED	7436
INDIVIDUAL	4918
RETROFIT FACTOR FOR SCR	1.52
GENERAL FACILITIES (PERCENT)	30

Table 6.1.5-6. NOx Control Cost Results for the Jack McDonough Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	1	1.00	245	71	2.5	0.9	3.6	0.2	0.1	25.0	1205	155.7
LNC-OFA	2	1.00	245	77	2.5	0.9	3.6	0.2	0.1	25.0	1307	143.5
LNC-OFA-C	1	1.00	245	71	2.5	0.9	3.6	0.1	0.1	25.0	1205	92.5
LNC-OFA-C	2	1.00	245	77	2.5	0.9	3.6	0.1	0.1	25.0	1307	85.3
SCR-3	1,2	1.52	245	74	2.5	43.4	177.1	14.3	9.0	80.0	4019	3559.4
SCR-3	1-2	1.52	490	74	2.5	74.0	151.0	25.5	8.0	80.0	8038	3176.4
SCR-3-C	1,2	1.52	245	74	2.5	43.4	177.1	8.4	5.3	80.0	4019	2087.7
SCR-3-C	1-2	1.52	490	74	2.5	74.0	151.0	15.0	4.7	80.0	8038	1861.1
SCR-7	1,2	1.52	245	74	2.5	43.4	177.1	12.3	7.7	80.0	4019	3057.2
SCR-7	1-2	1.52	490	74	2.5	74.0	151.0	21.5	6.8	80.0	8038	2674.2
SCR-7-C	1,2	1.52	245	74	2.5	43.4	177.1	7.2	4.6	80.0	4019	1800.0
SCR-7-C	1-2	1.52	490	74	2.5	74.0	151.0	12.6	4.0	80.0	8038	1573.4

Table 6.1.5-5 presents the SCR retrofit results which include process area retrofit factors and scope adder costs. Table 6.1.5-6 presents the estimated cost of retrofitting SCR at the Jack McDonough boilers.

Duct Spray Drying and Furnace Sorbent Injection--

The retrofit of FSI and DSD technologies at the Jack McDonough steam plant for both units would be difficult because ESPs have small SCAs (<210) and probably would not be able to handle the increased PM without a major ESP upgrade and/or plate area addition. However, long duct residence time between the boilers and ESPs would be sufficient for humidification (FSI application) or sorbent evaporation (DSD application). As a result, FSI and DSD technologies were considered for this plant. A high site access/congestion factor was assigned for upgrading the ESPs and adding plate area due to space limitation around the ESPs.

Table 6.1.5-7 presents a summary of the site access/congestion factors for FSI and DSD technologies at the Jack McDonough steam plant. Table 6.1.5-8 presents the costs estimated to retrofit sorbent injection technologies at the Jack McDonough plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Jack McDonough plant. Both units would be considered good candidates for repowering or retrofit because of their small boiler sizes. However, the high unit capacity factors could result in significant replacement power costs.

TABLE 6.1.5-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR JACK McDONOUGH UNIT 1 OR 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	2093
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	59
TOTAL COST (1000$)	
ESP UPGRADE CASE	2152
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Table 6.1.5-8. Summary of DSD/FSI Control Costs for the Jack McDonough Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	245	71	2.5	18.7	76.4	12.6	8.3	49.0	15243	825.1
DSD+ESP	2	1.00	245	77	2.5	18.7	76.4	13.1	7.9	49.0	16531	790.4
DSD+ESP-C	1	1.00	245	71	2.5	18.7	76.4	7.3	4.8	49.0	15243	478.2
DSD+ESP-C	2	1.00	245	77	2.5	18.7	76.4	7.6	4.6	49.0	16531	458.0
FSI+ESP-50	1	1.00	245	71	2.5	19.3	78.7	15.3	10.0	50.0	15666	974.3
FSI+ESP-50	2	1.00	245	77	2.5	19.3	78.7	16.1	9.7	50.0	16990	946.7
FSI+ESP-50-C	1	1.00	245	71	2.5	19.3	78.7	8.8	5.8	50.0	15666	563.7
FSI+ESP-50-C	2	1.00	245	77	2.5	19.3	78.7	9.3	5.6	50.0	16990	547.5
FSI+ESP-70	1	1.00	245	71	2.5	19.5	79.5	15.5	10.2	70.0	21932	708.7
FSI+ESP-70	2	1.00	245	77	2.5	19.5	79.5	16.4	9.9	70.0	23785	688.8
FSI+ESP-70-C	1	1.00	245	71	2.5	19.5	79.5	9.0	5.9	70.0	21932	410.0
FSI+ESP-70-C	2	1.00	245	77	2.5	19.5	79.5	9.5	5.7	70.0	23785	398.3

6.1.6 Mitchell Steam Plant

The Mitchell Steam Plant is located in Dougherty County, Georgia, as part of the Georgia Power Company system. The plant contains three coal-fired boilers with a total gross generating capacity of 202 MW. Tables 6.1.6-1 through 6.1.6-8 summarize the plant operational data and present the SO_2 and NO_x control cost and performance estimates.

TABLE 6.1.6-1. MITCHELL STEAM PLANT OPERATIONAL DATA *

BOILER NUMBER	1,2	3
GENERATING CAPACITY (MW-each)	23	156
CAPACITY FACTOR (PERCENT)	20	68
INSTALLATION DATE	1948,49	1964
FIRING TYPE	FRONT WALL	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	NA	91.8
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	1.3	
COAL HEATING VALUE (BTU/LB)	12300	
COAL ASH CONTENT (PERCENT)	9.5	
FLY ASH SYSTEM	WET DISPOSAL	
ASH DISPOSAL METHOD	POND/ON-SITE	
STACK NUMBER	1	
COAL DELIVERY METHODS	RAILROAD	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1975	1964
EMISSION (LB/MM BTU)	0.01	0.01
REMOVAL EFFICIENCY	99.5	99.5
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	1.0	1.0
SURFACE AREA (1000 SQ FT)	28.5	103.7
GAS EXIT RATE (1000 ACFM)	128.4	NA
SCA (SQ FT/1000 ACFM)	222	NA
OUTLET TEMPERATURE (°F)	299	299

* Some information was obtained from plant personnel.

TABLE 6.1.6-2. SUMMARY OF RETROFIT FACTOR DATA FOR MITCHELL UNITS 1-3 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			NA
BAGHOUSE			100-300
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	1761	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.16
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	8	0	8

* Absorbers and new FFs for units 1-3 combined would be located east of the common chimney.

Table 6.1.6-3. Summary of FGD Control Costs for the Mitchell Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1-3	1.27	202	57	1.3	54.5	269.8	23.3	23.1	90.0	9254	2521.4
L/S FGD-C	1-3	1.27	202	57	1.3	54.5	269.8	13.6	13.5	90.0	9254	1471.0
LC FGD	1-3	1.27	202	57	1.3	37.3	184.4	18.1	17.9	90.0	9254	1954.4
LC FGD-C	1-3	1.27	202	57	1.3	37.3	184.4	10.5	10.4	90.0	9254	1137.8
LSD+FF	1-3	1.16	202	57	1.3	41.8	207.1	15.7	15.6	87.0	8894	1770.2
LSD+FF-C	1-3	1.16	202	57	1.3	41.8	207.1	9.2	9.1	87.0	8894	1035.3

Table 6.1.6-4. Summary of Coal Switching/Cleaning Costs for the Mitchell Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1,2	1.00	23	20	1.3	1.6	68.8	1.0	25.7	29.0	120	8633.9
CS/B+$15	3	1.00	156	68	1.3	6.1	38.8	13.7	14.8	29.0	2764	4971.3
CS/B+$15-C	1,2	1.00	23	20	1.3	1.6	68.8	0.6	14.9	29.0	120	5005.8
CS/B+$15-C	3	1.00	156	68	1.3	6.1	38.8	7.9	8.5	29.0	2764	2858.0
CS/B+$5	1,2	1.00	23	20	1.3	1.3	58.4	0.7	16.4	29.0	120	5508.1
CS/B+$5	3	1.00	156	68	1.3	4.4	28.4	5.8	6.2	29.0	2764	2091.6
CS/B+$5-C	1,2	1.00	23	20	1.3	1.3	58.4	0.4	9.5	29.0	120	3205.9
CS/B+$5-C	3	1.00	156	68	1.3	4.4	28.4	3.3	3.6	29.0	2764	1205.5

TABLE 6.1.6-5. SUMMARY OF NOx RETROFIT RESULTS FOR MITCHELL[a]

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	3	1-3
FIRING TYPE	TANG	NA
TYPE OF NOx CONTROL	OFA	NA
FURNACE VOLUME (1000 CU FT)	91.8	NA
BOILER INSTALLATION DATE	1964	NA
SLAGGING PROBLEM	NO	NA
ESTIMATED NOx REDUCTION (PERCENT)	25	NA
SCR RETROFIT RESULTS *		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	NA	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	NA	0
Ductwork Demolition (1000$)	NA	46
New Duct Length (Feet)	NA	200
New Duct Costs (1000$)	NA	1495
New Heat Exchanger (1000$)	NA	2842
TOTAL SCOPE ADDER COSTS (1000$)	NA	4383
RETROFIT FACTOR FOR SCR	NA	1.16
GENERAL FACILITIES (PERCENT)	NA	20

a Units 1 and 2 were considered to be too small for LNBs.
* Cold side SCR reactors for units 1-3 combined would be located east of the common chimney.

Table 6.1.6-6. NOx Control Cost Results for the Mitchell Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	3	1.00	156	68	1.3	0.7	4.7	0.2	0.2	25.0	701	223.5
LNC-OFA-C	3	1.00	156	68	1.3	0.7	4.7	0.1	0.1	25.0	701	132.7
SCR-3	1-3	1.16	202	61	1.3	30.8	152.6	10.5	9.8	80.0	3646	2891.4
SCR-3-C	1-3	1.16	202	61	1.3	30.8	152.6	6.2	5.7	80.0	3646	1694.5
SCR-7	1-3	1.16	202	61	1.3	30.8	152.6	8.9	8.2	80.0	3646	2437.8
SCR-7-C	1-3	1.16	202	61	1.3	30.8	152.6	5.2	4.8	80.0	3646	1434.6

TABLE 6.1.6-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR MITCHELL UNIT 1 OR 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	251
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	10

TOTAL COST (1000$)	
ESP UPGRADE CASE	261
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Long duct residence time exists between boilers 1 and 2 and their retrofit ESPs. A high factor was assigned to ESP upgrade. Unit 3 was not a candidate for FSI or DSD because of the inadequate size of the unit 3 ESPs.

Table 6.1.6-8. Summary of DSD/FSI Control Costs for the Mitchell Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1,2	1.00	23	20	1.3	3.6	155.9	3.1	77.0	49.0	200	15521.7
DSD+ESP-C	1,2	1.00	23	20	1.3	3.6	155.9	1.8	44.5	49.0	200	8973.5
FSI+ESP-50	1,2	1.00	23	20	1.3	4.4	192.9	2.3	56.2	50.0	205	11026.2
FSI+ESP-50-C	1,2	1.00	23	20	1.3	4.4	192.9	1.3	32.7	50.0	205	6414.3
FSI+ESP-70	1,2	1.00	23	20	1.3	4.5	195.4	2.3	56.6	70.0	288	7935.3
FSI+ESP-70-C	1,2	1.00	23	20	1.3	4.5	195.4	1.3	32.9	70.0	288	4616.4

6.1.7 Robert W. Scherer Steam Plant

The Robert W. Scherer steam plant is located on Lake Juliette in Monroe County, Georgia, and is operated by the Georgia Power Company. The Scherer plant has four coal-fired boilers with a gross generating capacity of 3,564 MW. Unit 3 is operating under test conditions and unit 4 is planned for start-up in 1989. A 1982 aerial photograph was used in evaluating this plant and units 3 and 4 were absent. However, in this report units 3 and 4 will be included under the assumption that the units are situated north of unit 2 in a similar layout as units 1 and 2.

Table 6.1.7-1 presents the operational data for the existing equipment at the Scherer plant. Coal shipments are received by railroad and transferred to a coal storage and handling area east of the plant. PM emissions from the boilers are controlled by ESPs installed at the time the boilers were constructed. Units 1 and 2 have hot side ESPs, while units 3 and 4 have cold side ESPs. The ESPs are located behind the boilers. Flue gases from units 1 and 2 are directed to separate stacks within a common chimney, located behind the ESPs for those units. Units 3 and 4 have their own chimney located behind their respective ESPs. Since units 3 and 4 are 1979 NSPS boilers, it was assumed that both boilers are equipped with FGD systems and are not considered for further SO_2 scrubbing.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for units 1 and 2 would be located behind their common chimney. The site access/congestion factor for both locations would be low. No major relocations/demolitions would be required for installation of the absorbers; therefore, all locations were assigned a low 5 percent to general facilities. Ductwork of 100 to 300 feet would be required for both units. The site access/congestion factor assigned to flue gas handling was low.

Since units 1 and 2 have hot side ESPs, LSD with reuse of the existing ESPs was not possible. Therefore, LSD with a new baghouse was considered for units 1 and 2. The LSD absorbers would have a similar location as the wet FGD absorbers, behind the common chimney, with a low site access/ congestion factor and a low general facility value of 5 percent. The new

TABLE 6.1.7-1. SCHERER STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2,3,4
GENERATING CAPACITY (MW-each)	891
CAPACITY FACTOR (PERCENT)	24,35,65,65 *
INSTALLATION DATE	1982,84,87,89
FIRING TYPE	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	NA
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	0.6
COAL HEATING VALUE (BTU/LB)	12700
COAL ASH CONTENT (PERCENT)	8.9
FLY ASH SYSTEM	WET DISPOSAL
ASH DISPOSAL METHOD	PONDS/ON-SITE
STACK NUMBER	1,2,3,4 (1,2 WITHIN ONE CHIMNEY)
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1982,84,87,89
EMISSION (LB/MM BTU)	0.03,0.02,0.01,NA
REMOVAL EFFICIENCY	99.6,99.6,99.9,NA
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	0.6
SURFACE AREA (1000 SQ FT)	1804,1804,1361,1361
GAS EXIT RATE (1000 ACFM)	5924,5924,3253,3253
SCA (SQ FT/1000 ACFM)	305,305,418,418
OUTLET TEMPERATURE (°F)	824,824,247,247

* Capacity factors for units 3 and 4 are assumed as 65 percent

FFs would be located adjacent to the LSD absorbers. A duct length of 100 to 300 feet would be required. A low site access/congestion factor was assigned to flue gas handling.

Tables 6.1.7-2 presents the retrofit factor input to the IAPCS model. However, the costs are not presented since the Scherer plant is burning a low sulfur compliance coal.

Coal Switching and Physical Coal Cleaning Costs--

The boilers at the Scherer plant are currently burning a low sulfur coal; therefore, CS and PCC were not considered for this plant.

NO_x Control Technologies--

The boilers at the Scherer plant are already meeting 1979 NSPS NO_x emissions and were not considered.

Selective Catalytic Reduction-

Hot side SCR reactors would be located behind the common chimney for units 1 and 2 and cold side reactors would be located behind the respective chimney for units 3 and 4. As in the FGD case, low site access/congestion factors and low general facility values (13 percent) were assigned to the reactor locations. For each unit, approximately 250 feet of duct would be required to span the distance between the SCR reactors and the chimney. The site access/congestion factor for flue gas handling was low for all units. Tables 6.1.7-3 and 6.1.7-4 present the NO_x performance and cost estimates for installation of SCR at the Scherer plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) were not considered for unit 1 and 2 since they are equipped with hot side ESPs.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

All boilers at the Scherer plant are too large and have a long remaining useful life; therefore, should not be considered for AFBC/CG technologies.

TABLE 6.1.7-2. SUMMARY OF RETROFIT FACTOR DATA FOR SCHERER UNIT 1 OR 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			
BAGHOUSE			100-300
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	6661	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.16
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	5	0	5

TABLE 6.1.7-3. SUMMARY OF NOx RETROFIT RESULTS FOR SCHERER

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1,2	3,4
FIRING TYPE	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA
FURNACE VOLUME (1000 CU FT)	NA	NA
BOILER INSTALLATION DATE	1982,84	1987,89
SLAGGING PROBLEM	NA	NA
ESTIMATED NOx REDUCTION (PERCENT)	NA	NA
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	139	139
New Duct Length (Feet)	250	250
New Duct Costs (1000$)	4453	4453
New Heat Exchanger (1000$)	0	6924
TOTAL SCOPE ADDER COSTS (1000$)		
INDIVIDUAL CASE	4592	11516
COMBINED CASE	6915	17409
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13

Table 6.1.7-4. NOx Control Cost Results for the Scherer Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
SCR-3	1	1.16	891	24	0.6	102.2	114.7	36.6	19.5	80.0	4357	8389.7
SCR-3	2	1.16	891	35	0.6	102.3	114.8	37.0	13.5	80.0	6354	5822.8
SCR-3	3	1.16	891	65	0.6	100.8	113.1	37.7	7.4	80.0	11800	3191.3
SCR-3	4	1.16	891	65	0.6	100.8	113.1	37.7	7.4	80.0	11800	3191.3
SCR-3	1-2	1.16	1782	30	0.6	196.6	110.3	71.6	15.3	80.0	10893	6577.7
SCR-3	3-4	1.16	1782	65	0.6	190.1	106.7	72.8	7.2	80.0	23601	3082.6
SCR-3-C	1	1.16	891	24	0.6	102.2	114.7	21.4	11.4	80.0	4357	4911.9
SCR-3-C	2	1.16	891	35	0.6	102.3	114.8	21.7	7.9	80.0	6354	3408.3
SCR-3-C	3	1.16	891	65	0.6	100.8	113.1	22.0	4.3	80.0	11800	1866.7
SCR-3-C	4	1.16	891	65	0.6	100.8	113.1	22.0	4.3	80.0	11800	1866.7
SCR-3-C	1-2	1.16	1782	30	0.6	196.6	110.3	41.9	9.0	80.0	10893	3849.5
SCR-3-C	3-4	1.16	1782	65	0.6	190.1	106.7	42.5	4.2	80.0	23601	1802.3
SCR-7	1	1.16	891	24	0.6	102.2	114.7	29.3	15.6	80.0	4357	6723.2
SCR-7	2	1.16	891	35	0.6	102.3	114.8	29.7	10.9	80.0	6354	4680.2
SCR-7	3	1.16	891	65	0.6	100.8	113.1	30.4	6.0	80.0	11800	2576.0
SCR-7	4	1.16	891	65	0.6	100.8	113.1	30.4	6.0	80.0	11800	2576.0
SCR-7	1-2	1.16	1782	30	0.6	196.6	110.3	57.1	12.2	80.0	10893	5244.6
SCR-7	3-4	1.16	1782	65	0.6	190.1	106.7	58.2	5.7	80.0	23601	2467.4
SCR-7-C	1	1.16	891	24	0.6	102.2	114.7	17.2	9.2	80.0	4357	3957.2
SCR-7-C	2	1.16	891	35	0.6	102.3	114.8	17.5	6.4	80.0	6354	2753.6
SCR-7-C	3	1.16	891	65	0.6	100.8	113.1	17.9	3.5	80.0	11800	1514.2
SCR-7-C	4	1.16	891	65	0.6	100.8	113.1	17.9	3.5	80.0	11800	1514.2
SCR-7-C	1-2	1.16	1782	30	0.6	196.6	110.3	33.6	7.2	80.0	10893	3085.7
SCR-7-C	3-4	1.16	1782	65	0.6	190.1	106.7	34.2	3.4	80.0	23601	1449.8

6.1.8 Wansley Steam Plant

The Wansley steam plant is located within Heard County, Georgia, and is a part of the Georgia Power Company system. Situated in the western central part of the state, approximately 40 miles to the southeast of Atlanta, the plant site is located alongside the Chattahoochie River. To the northwest of the plant site is a man-made lake. The plant contains two coal-fired boilers with a total gross generating capacity of 1,730 MW.

Table 6.1.8-1 presents the operational data for the existing equipment at the Wansley plant. The boilers burn a medium sulfur coal. Coal shipments are received by railroad and transferred to a coal storage and handling area located to the northwest of the plant site between the powerhouse and the man-made lake.

PM emissions for the boilers are controlled with ESPs located behind each unit. The plant has a wet fly ash handling system. Approximately one-third of the fly ash is removed from the plant site through paid disposal. The remaining fly ash is conveyed through sluice lines to a disposal site located beside the man-made lake to the northwest. Units 1 and 2 are served by separate flues within a common chimney. The following evaluation is based on a 1981 aerial photograph, and any alterations made to the plant layout since this time should be taken into consideration.

Lime/Limestone and Lime Spray Drying FGD Costs--

The two boilers are located beside each other with the chimney located midway between the units and behind the ESPs. Limited space exists between the two coal conveyors for placement of the FGD absorbers. The area to the east of the plant contains oil tanks, storage structures, and office buildings which also would not be a suitable location for the retrofit control equipment. The FGD system was assumed to be located on the southwestern side of the plant where ample open space exists for control equipment and absorber placement. Although this area would no longer be available for future units, locating the FGD absorber behind the units between the two coal conveyors would result in a high site access/ congestion factor. The L/LS preparation area would be located adjacent to the absorbers. No major

TABLE 6.1.8-1. WANSLEY STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1, 2
GENERATING CAPACITY (MW-each)	865
CAPACITY FACTOR (PERCENT)	79,68
INSTALLATION DATE	1976, 1978
FIRING TYPE	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	603
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	2.5
COAL HEATING VALUE (BTU/LB)	11,400
COAL ASH CONTENT (PERCENT)	8.6
FLY ASH SYSTEM	WET SLUICE
ASH DISPOSAL METHOD	ON-SITE POND/PAID DISPOSAL
STACK NUMBER	1 - ENCLOSING 2 CHIMNEYS
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1976, 1978
EMISSION (LB/MM BTU)	0.06
REMOVAL EFFICIENCY	98.6
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	2.5
SURFACE AREA (1000 SQ FT)	656.6
GAS EXIT RATE (1000 ACFM)	3,070
SCA (SQ FT/1000 ACFM)	214
OUTLET TEMPERATURE (°F)	268

demolition would be necessary and, for this reason, a factor of 5 percent was assigned to general facilities for absorber placement.

For the flue gas handling system, a duct run of approximately 700 feet per unit would be needed. Because ductwork passes beneath the existing coal conveyor, a medium site access/congestion factor was assigned to the flue gas handling system.

LSD with reuse of existing ESPs was not considered for this plant because the ESPs are small (SCA=214) and are located in a high site access/ congestion area with coal conveyors on either side and with the common chimney placed midway between the ESPs. The LSD with a new baghouse option was also not considered since the Wansley plant is burning a medium-to-high sulfur coal.

The major scope adjustment items and retrofit factor estimates for the FGD technologies are presented in Table 6.1.8-2. Table 6.1.8-3 presents the capital and operating cost estimates for commercial FGD technologies. The low cost FGD cases show the effect of no absorber sparing and large absorber sizes.

Coal Switching and Physical Coal Cleaning Costs--

Table 6.1.8-4 presents the IAPCS cost results for CS at the Wansley plant. These costs do not include boiler and pulverizer operating cost changes or any system modifications that may be necessary to blend coal. Coal switching for a fuel price differential of $15 per ton is higher than that of $5 per ton because of inventory capital and preproduction costs, which are a function of variable costs (e.g. fuel costs). PCC was not evaluated because this is not a mine mouth plant.

Low NO_x Combustion--

Both Wansley units are dry bottom, tangential-fired boilers rated at 865 MW each. The combustion modification technique applied to both boilers is OFA. Tables 6.1.8-5 and 6.1.8-6 present the performance and cost results of retrofitting OFA at the Wansley plant.

TABLE 6.1.8-2. SUMMARY OF RETROFIT FACTOR DATA FOR WANSLEY UNITS 1 OR 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	NA
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	600-1000	NA	
ESP REUSE			NA
BAGHOUSE			NA
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NA
ESTIMATED COST (1000$)	6055	NA	NA
NEW CHIMNEY	NO	NA	NA
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		
RETROFIT FACTORS			
FGD SYSTEM	1.49	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	0

Table 6.1.8-3. Summary of FGD Control Costs for the Wansley Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.49	865	79	2.5	177.4	205.1	94.5	15.8	90.0	115250	819.9
L/S FGD	2	1.49	865	68	2.5	177.4	205.1	88.9	17.2	90.0	99202	895.8
L/S FGD-C	1	1.49	865	79	2.5	177.4	205.1	54.9	9.2	90.0	115250	476.7
L/S FGD-C	2	1.49	865	68	2.5	177.4	205.1	51.7	10.0	90.0	99202	521.2
LC FGD	1	1.49	865	79	2.5	149.6	172.9	86.1	14.4	90.0	115250	746.7
LC FGD	2	1.49	865	68	2.5	149.6	172.9	80.4	15.6	90.0	99202	810.7
LC FGD-C	1	1.49	865	79	2.5	149.6	172.9	50.0	8.3	90.0	115250	433.6
LC FGD-C	2	1.49	865	68	2.5	149.6	172.9	46.8	9.1	90.0	99202	471.3

Table 6.1.8-4. Summary of Coal Switching/Cleaning Costs for the Wansley Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	865	79	2.5	26.3	30.5	83.3	13.9	66.0	84829	981.6
CS/B+$15	2	1.00	865	68	2.5	26.3	30.5	72.4	14.1	66.0	73017	992.0
CS/B+$15-C	1	1.00	865	79	2.5	26.3	30.5	47.8	8.0	66.0	84829	563.8
CS/B+$15-C	2	1.00	865	68	2.5	26.3	30.5	41.6	8.1	66.0	73017	570.0
CS/B+$5	1	1.00	865	79	2.5	17.4	20.1	32.3	5.4	66.0	84829	380.2
CS/B+$5	2	1.00	865	68	2.5	17.4	20.1	28.3	5.5	66.0	73017	387.7
CS/B+$5-C	1	1.00	865	79	2.5	17.4	20.1	18.6	3.1	66.0	84829	218.8
CS/B+$5-C	2	1.00	865	68	2.5	17.4	20.1	16.3	3.2	66.0	73017	223.2

TABLE 6.1.8-5. SUMMARY OF NOx RETROFIT RESULTS FOR WANSLEY

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1	2
FIRING TYPE	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA
FURNACE VOLUME (1000 CU FT)	603	603
BOILER INSTALLATION DATE	1976	1978
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	35	35
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	MEDIUM
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	136	136
New Duct Length (Feet)	200	200
New Duct Costs (1000$)	3501	3501
New Heat Exchanger (1000$)	6802	6802
TOTAL SCOPE ADDER COSTS (1000$)	10439	10439
RETROFIT FACTOR FOR SCR	1.34	1.34
GENERAL FACILITIES (PERCENT)	13	13

Table 6.1.8-6. NOx Control Cost Results for the Wansley Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	1	1.00	865	79	2.5	1.5	1.7	0.3	0.1	35.0	6895	45.1
LNC-OFA	2	1.00	865	68	2.5	1.5	1.7	0.3	0.1	35.0	5935	52.4
LNC-OFA-C	1	1.00	865	79	2.5	1.5	1.7	0.2	0.0	35.0	6895	26.8
LNC-OFA-C	2	1.00	865	68	2.5	1.5	1.7	0.2	0.0	35.0	5935	31.1
SCR-3	1	1.34	865	79	2.5	106.9	123.5	39.9	6.7	80.0	15760	2529.3
SCR-3	2	1.34	865	68	2.5	106.8	123.5	39.3	7.6	80.0	13566	2895.9
SCR-3-C	1	1.34	865	79	2.5	106.9	123.5	23.3	3.9	80.0	15760	1479.5
SCR-3-C	2	1.34	865	68	2.5	106.8	123.5	23.0	4.5	80.0	13566	1694.5
SCR-7	1	1.34	865	79	2.5	106.9	123.5	32.7	5.5	80.0	15760	2074.9
SCR-7	2	1.34	865	68	2.5	106.8	123.5	32.1	6.2	80.0	13566	2368.0
SCR-7-C	1	1.34	865	79	2.5	106.9	123.5	19.2	3.2	80.0	15760	1219.1
SCR-7-C	2	1.34	865	68	2.5	106.8	123.5	18.9	3.7	80.0	13566	1392.0

Selective Catalytic Reduction--

Cold side SCR reactors can be located on the northern side of the plant in an open area adjacent to the chimney and ESPs between the two coal conveyors. Due to the congestion created by the coal conveyors and ESPs, a medium site access/congestion factor was assigned to the SCR reactor locations. Since the SCR reactors are located beside the chimney, a short duct length of less than 200 feet would be required. No major demolition/relocation would be required and, as such, a low factor of 13 percent was assigned to general facilities.

Evaluation of SCR controls was done separately from FGD. Both technologies need to be considered if the SCR reactors could be located downstream from the FGD absorbers. For this scenario, site access/congestion factors would be similar to those for the FGD absorber placement location which are low.

Table 6.1.8-5 presents the SCR retrofit results for both units. Table 6.1.8-6 presents the estimated cost of retrofitting SCR at the Wansley plant.

Duct Spray Drying and Furnace Sorbent Injection--

DSD and FSI were not considered at the Wansley Plant for the following reasons.

- o Short duct residence time between the boilers and the ESPs is not sufficient for humidification (FSI) and sorbent injection (DSD) applications.

- o ESPs are small and the addition of plate area would be difficult because of the coal conveyors on either side of the ESPs and the chimney behind the ESPs.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The repowering applicability criteria presented in Section 2 was used to determine the applicability of these technologies at the Wansley plant. Neither of these units would be considered good candidates for repowering or retrofit because of their large boiler sizes, high capacity factors, and long remaining life.

6.1.9 Yates Steam Plant

The Yates steam plant is located within Coweta County, Georgia, as part of the Georgia Power Company system. The plant is located adjacent to the Chattahoochie River and contains seven coal-fired boilers with a total gross generating capacity of 1,465 MW.

Table 6.1.9-1 presents operational data for the existing equipment at the Yates plant. The boilers burn medium sulfur coal. Coal shipments are received by railroad and transferred to the coal storage and handling area north of units 1-5, east of units 6-7, and close to the Chattahoochie River.

PM emissions for boilers 1-5 are controlled with retrofit ESPs, while boilers 6-7 have original ESPs, which in each case are located behind the respective unit. The plant has a dry fly ash handling system. Part of the waste ash is disposed of in a landfill southwest of the plant while some is sold or paid disposed of off-site. Units 1-5 are served by a common chimney and units 6-7 are served also by a separate common chimney. Each chimney contains multiple flues. The following evaluation is based on a 1981 aerial photograph, and any alterations made to the plant layout since that time should be taken into consideration.

Lime/Limestone and Lime Spray Drying FGD Costs--

Units 1-5 are located beside each other in an area that is adjacent to the river and close to the coal pile. Unit 1 is closest to the river and units 6-7 are situated a few thousand feet east of the coal pile. The absorbers for units 1-5 would be located east of the boilers and south of the coal pile. The absorbers for units 5-6 would be located directly behind the chimney in an open area. The limestone preparation and storage/handling area would be located in an open area between the absorbers for units 6-7 and units 1-5. No major demolition or relocation would be necessary for any of the 7 absorber areas. Consequently, a base factor of 5 percent was assigned to general facilities.

A low site access/congestion factor was assigned to all of the FGD absorber locations. For units 1-5, a flue gas handling duct length of 400-500 feet would be required since the absorbers are located to the side of boiler 5. Units 6-7 would require less than 300 feet of ducting because

TABLE 6.1.9-1. YATES STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1, 2, 3	4, 5	6, 7
GENERATING CAPACITY (MW-each)	115	156	404
CAPACITY FACTOR (PERCENT)	42,48,45	47,48	51,54
INSTALLATION DATE	1950,50,52	1957,58	1974
FIRING TYPE		TANGENTIAL	
FURNACE VOLUME (1000 CU FT)	74	94	222
LOW NOx COMBUSTION	NO	NO	NO
COAL SULFUR CONTENT (PERCENT)		2.4	
COAL HEATING VALUE (BTU/LB)		11,600	
COAL ASH CONTENT (PERCENT)		10.4	
FLY ASH SYSTEM		DRY	
ASH DISPOSAL METHOD		LANDFILL/SELL	
STACK NUMBER	1	1	2
COAL DELIVERY METHODS		RAILROAD	
PARTICULATE CONTROL			
TYPE	ESP	ESP	ESP
INSTALLATION DATE	1971,68,69	1970,68	1974
EMISSION (LB/MM BTU)	0.09	0.09	0.05,0.06
REMOVAL EFFICIENCY	98.4,98.1,98.0	98.5	99.9
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)		0.7	
SURFACE AREA (1000 SQ FT)	103.3,75.6,75.6	103.3	NA
GAS EXIT RATE (1000 ACFM)	490,420,420	685,550	NA
SCA (SQ FT/1000 ACFM)	211,180,180	151,188	324
OUTLET TEMPERATURE (°F)	300	310	320

the absorbers are located directly behind the chimney. A low site access/congestion factor was also assigned to the flue gas handling systems because the chimneys are relatively easy to access in all cases.

LSD with reuse of the existing ESPs was considered for units 6-7 but not for units 1-5. ESPs for units 6 and 7 have large SCAs (~630) and would be able to accommodate the extra particulate load from LSD. On the other hand, the SCAs for units 1-5 are inadequate, ranging from 151 to 211, and would not be able to handle the excess load. Installation of baghouses for these units was not considered because the boilers are not burning low sulfur coal. The absorbers for units 6-7 would be located in the same locations as in the L/LS-FGD case. Moderate duct lengths of less than 600 feet would be required for these units. A high site access/congestion factor was assigned to the flue gas handling system because it is difficult to access the flue gas ducting between the ESPs and boilers. A medium site access/congestion factor was assigned for ESP upgrades which would not likely be required.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Tables 6.1.9-2 and 6.1.9-3. Table 6.1.9-4 presents the capital and operating costs for commercial FGD technologies. The low cost FGD cases show the effect of combined FGD systems, no spare scrubber modules, and large absorber sizes.

Coal Switching and Physical Coal Cleaning Costs--
Table 6.1.9-5 presents the IAPCS results for CS at the Yates plant. These costs do not include boiler and pulverizer operating cost changes or system modifications that may be necessary to blend coal. Coal switching for a fuel price differential of $15 per ton is higher than that of $5 per ton because of the inventory capital and preproduction costs, which are a function of variable costs (e.g. fuel costs). PCC was not evaluated because this is not a mine mouth plant.

TABLE 6.1.9-2. SUMMARY OF RETROFIT FACTOR DATA FOR YATES UNITS 1-5 (EACH)

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	NA
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			NA
BAGHOUSE			NA
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NA
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NA
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		
RETROFIT FACTORS			
FGD SYSTEM	1.31	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	0

TABLE 6.1.9-3. SUMMARY OF RETROFIT FACTOR DATA FOR YATES UNIT 6-7 (EACH)

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.20	NA	
ESP REUSE CASE			1.36
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	5

Table 6.1.9-4. Summary of FGD Control Costs for the Yates Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1,2,3	1.31	115	45	2.4	43.8	381.1	17.9	39.5	90.0	8213	2178.6
L/S FGD	4,5	1.31	156	48	2.4	51.3	328.7	21.4	32.7	90.0	11884	1803.2
L/S FGD	1-3	1.31	345	45	2.4	81.1	235.0	34.6	25.4	90.0	24639	1403.7
L/S FGD	4-5	1.31	312	48	2.4	76.8	246.1	33.0	25.2	90.0	23768	1390.2
L/S FGD	6	1.20	404	51	2.4	82.9	205.2	37.8	20.9	90.0	32700	1154.9
L/S FGD	7	1.20	404	54	2.4	82.9	205.3	38.5	20.1	90.0	34623	1110.8
L/S FGD-C	1,2,3	1.31	115	45	2.4	43.8	381.1	10.4	23.0	90.0	8213	1272.1
L/S FGD-C	4,5	1.31	156	48	2.4	51.3	328.7	12.5	19.1	90.0	11884	1052.4
L/S FGD-C	1-3	1.31	345	45	2.4	81.1	235.0	20.2	14.8	90.0	24639	819.0
L/S FGD-C	4-5	1.31	312	48	2.4	76.8	246.1	19.3	14.7	90.0	23768	811.0
L/S FGD-C	6	1.20	404	51	2.4	82.9	205.2	22.0	12.2	90.0	32700	673.0
L/S FGD-C	7	1.20	404	54	2.4	82.9	205.3	22.4	11.7	90.0	34623	647.2
LC FGD	1-5	1.31	657	46	2.4	103.3	157.3	49.1	18.4	90.0	48381	1014.3
LC FGD	6-7	1.20	808	53	2.4	116.6	144.3	59.2	15.9	90.0	67322	879.4
LC FGD-C	1-5	1.31	657	46	2.4	103.3	157.3	28.6	10.7	90.0	48381	590.7
LC FGD-C	6-7	1.20	808	53	2.4	116.6	144.3	34.4	9.3	90.0	67322	511.6
LSD+ESP	6	1.36	404	51	2.4	54.0	133.7	24.0	13.3	76.0	27722	867.3
LSD+ESP	7	1.36	404	54	2.4	54.0	133.7	24.5	12.8	76.0	29353	833.7
LSD+ESP-C	6	1.36	404	51	2.4	54.0	133.7	14.0	7.8	76.0	27722	505.6
LSD+ESP-C	7	1.36	404	54	2.4	54.0	133.7	14.3	7.5	76.0	29353	485.9

Table 6.1.9-5. Summary of Coal Switching/Cleaning Costs for the Yates Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	115	42	2.4	4.5	39.4	6.7	15.8	64.0	5462	1223.3
CS/B+$15	2	1.00	115	48	2.4	4.8	42.0	7.6	15.7	64.0	6242	1213.3
CS/B+$15	3	1.00	115	45	2.4	4.8	42.0	7.2	15.8	64.0	5852	1225.0
CS/B+$15	4	1.00	156	47	2.4	6.6	42.2	10.0	15.6	64.0	8291	1206.0
CS/B+$15	5	1.00	156	48	2.4	6.1	39.0	10.0	15.3	64.0	8468	1185.8
CS/B+$15	6	1.00	404	51	2.4	13.0	32.1	26.1	14.5	64.0	23300	1122.3
CS/B+$15	7	1.00	404	54	2.4	13.0	32.1	27.5	14.4	64.0	24671	1115.7
CS/B+$15-C	1	1.00	115	42	2.4	4.5	39.4	3.8	9.1	64.0	5462	704.6
CS/B+$15-C	2	1.00	115	48	2.4	4.8	42.0	4.4	9.0	64.0	6242	698.6
CS/B+$15-C	3	1.00	115	45	2.4	4.8	42.0	4.1	9.1	64.0	5852	705.6
CS/B+$15-C	4	1.00	156	47	2.4	6.6	42.2	5.8	9.0	64.0	8291	694.5
CS/B+$15-C	5	1.00	156	48	2.4	6.1	39.0	5.8	8.8	64.0	8468	682.6
CS/B+$15-C	6	1.00	404	51	2.4	13.0	32.1	15.0	8.3	64.0	23300	645.5
CS/B+$15-C	7	1.00	404	54	2.4	13.0	32.1	15.8	8.3	64.0	24671	641.6
CS/B+$5	1	1.00	115	42	2.4	3.3	29.0	3.0	7.0	64.0	5462	545.2
CS/B+$5	2	1.00	115	48	2.4	3.6	31.7	3.4	7.0	64.0	6242	540.0
CS/B+$5	3	1.00	115	45	2.4	3.6	31.7	3.2	7.1	64.0	5852	549.5
CS/B+$5	4	1.00	156	47	2.4	5.0	31.9	4.4	6.9	64.0	8291	532.0
CS/B+$5	5	1.00	156	48	2.4	4.5	28.6	4.3	6.6	64.0	8468	512.6
CS/B+$5	6	1.00	404	51	2.4	8.8	21.7	10.5	5.8	64.0	23300	451.0
CS/B+$5	7	1.00	404	54	2.4	8.8	21.7	11.0	5.8	64.0	24671	446.2
CS/B+$5-C	1	1.00	115	42	2.4	3.3	29.0	1.7	4.1	64.0	5462	315.1
CS/B+$5-C	2	1.00	115	48	2.4	3.6	31.7	1.9	4.0	64.0	6242	312.0
CS/B+$5-C	3	1.00	115	45	2.4	3.6	31.7	1.9	4.1	64.0	5852	317.6
CS/B+$5-C	4	1.00	156	47	2.4	5.0	31.9	2.5	4.0	64.0	8291	307.5
CS/B+$5-C	5	1.00	156	48	2.4	4.5	28.6	2.5	3.8	64.0	8468	296.0
CS/B+$5-C	6	1.00	404	51	2.4	8.8	21.7	6.1	3.4	64.0	23300	260.1
CS/B+$5-C	7	1.00	404	54	2.4	8.8	21.7	6.3	3.3	64.0	24671	257.2

Low NO_x Combustion--

Units 1-7 are dry bottom, tangential-fired boilers. The combustion modification technique applied to all boilers was OFA. Tables 6.1.9-6 and 6.1.9-7 present the NO_x performance and cost results of retrofitting OFA at the Yates plant.

Selective Catalytic Reduction--

Cold side SCR reactors for units 1-3 would be located west of unit 1, close to the coal conveyor. For units 4-5, reactors would be located east of the common chimney. For units 6-7, reactors would be placed behind their common chimney. All seven reactors would be located in low site/congestion areas. The ammonia storage system was placed in an open area between the absorbers for units 1-5 and units 6-7. An additional 350-450 feet of ducting would be required for units 1-3 and 4-5, respectively, with 200 feet needed for units 6-7. More ducting would be needed for units 1-5 since the absorbers are placed at the side of the boilerhouse; whereas, unit 6-7 absorbers would be placed directly behind the chimneys.

Table 6.1.9-6 presents the SCR retrofit factors and scope adder costs. Table 6.1.9-7 presents the estimated cost of retrofitting SCR at the Yates boilers.

Duct Spray Drying and Furnace Sorbent Injection--

For units 6-7, it appears that sufficient duct residence time could be made available between the boilers and the ESPs by modifying the first ESP section for sorbent injection or humidification. For units 6-7, a medium site access/congestion factor would be assigned for upgrading or modifying the ESPs. By contrast, units 1-5 do not have sufficient duct residence time between the boiler and ESPs and the ESPs are too small to use the first part for sorbent injection or humidification. As such, the sorbent injection technologies were not evaluated for units 1-5. The sorbent receiving/ storage/preparation areas would be located between the two boilerhouse sites.

TABLE 6.1.9-6. SUMMARY OF NOx RETROFIT RESULTS FOR YATES

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1, 2, 3	4, 5	6, 7
FIRING TYPE	TANG	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA	OFA
FURNACE VOLUME (1000 CU FT)	74	94	222
BOILER INSTALLATION DATE	1950-52	1957-58	1974
SLAGGING PROBLEM	NO	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	25	25	35
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	68	63	77
New Duct Length (Feet)	350	300	200
New Duct Costs (1000$)	3579	2892	2243
New Heat Exchanger (1000$)	3918	3689	4308
TOTAL SCOPE ADDER COSTS (1000$)			
COMBINED	7566	6645	NA
INDIVIDUAL	3939	3670	6628
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13	13

Table 6.1.9-7. NOx Control Cost Results for the Yates Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost (\$MM)	Capital Cost (\$/kW)	Annual Cost (\$MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. (\$/ton)
LNC-OFA	1	1.00	115	42	2.4	0.7	5.7	0.1	0.3	25.0	341	406.5
LNC-OFA	2	1.00	115	48	2.4	0.7	5.7	0.1	0.3	25.0	390	355.7
LNC-OFA	3	1.00	115	45	2.4	0.7	5.7	0.1	0.3	25.0	366	379.4
LNC-OFA	4	1.00	156	47	2.4	0.7	4.7	0.2	0.2	25.0	518	302.3
LNC-OFA	5	1.00	156	48	2.4	0.7	4.7	0.2	0.2	25.0	529	296.0
LNC-OFA	6	1.00	404	51	2.4	1.1	2.7	0.2	0.1	35.0	2038	112.4
LNC-OFA	7	1.00	404	54	2.4	1.1	2.7	0.2	0.1	35.0	2158	106.2
LNC-OFA-C	1	1.00	115	42	2.4	0.7	5.7	0.1	0.2	25.0	341	241.5
LNC-OFA-C	2	1.00	115	48	2.4	0.7	5.7	0.1	0.2	25.0	390	211.3
LNC-OFA-C	3	1.00	115	45	2.4	0.7	5.7	0.1	0.2	25.0	366	225.4
LNC-OFA-C	4	1.00	156	47	2.4	0.7	4.7	0.1	0.1	25.0	518	179.5
LNC-OFA-C	5	1.00	156	48	2.4	0.7	4.7	0.1	0.1	25.0	529	175.8
LNC-OFA-C	6	1.00	404	51	2.4	1.1	2.7	0.1	0.1	35.0	2038	66.8
LNC-OFA-C	7	1.00	404	54	2.4	1.1	2.7	0.1	0.1	35.0	2158	63.1
SCR-3	1,2,3	1.16	115	45	2.4	21.0	183.0	6.7	14.8	80.0	1170	5716.0
SCR-3	4,5	1.16	156	48	2.4	24.9	159.4	8.3	12.6	80.0	1693	4875.5
SCR-3	1-3	1.16	345	45	2.4	46.2	134.0	15.9	11.7	80.0	3510	4533.3
SCR-3	4-5	1.16	312	48	2.4	43.8	140.5	14.9	11.4	80.0	3386	4411.2
SCR-3	6	1.16	404	51	2.4	51.0	126.3	18.1	10.0	80.0	4658	3890.8
SCR-3	7	1.16	404	54	2.4	51.0	126.3	18.2	9.5	80.0	4932	3687.9
SCR-3-C	1,2,3	1.16	115	45	2.4	21.0	183.0	3.9	8.7	80.0	1170	3355.6
SCR-3-C	4,5	1.16	156	48	2.4	24.9	159.4	4.8	7.4	80.0	1693	2859.3
SCR-3-C	1-3	1.16	345	45	2.4	46.2	134.0	9.3	6.9	80.0	3510	2656.3
SCR-3-C	4-5	1.16	312	48	2.4	43.8	140.5	8.8	6.7	80.0	3386	2585.3
SCR-3-C	6	1.16	404	51	2.4	51.0	126.3	10.6	5.9	80.0	4658	2278.2
SCR-3-C	7	1.16	404	54	2.4	51.0	126.3	10.6	5.6	80.0	4932	2159.3
SCR-7	1,2,3	1.16	115	45	2.4	21.0	183.0	5.7	12.7	80.0	1170	4904.3
SCR-7	4,5	1.16	156	48	2.4	24.9	159.4	7.0	10.6	80.0	1693	4114.5
SCR-7	1-3	1.16	345	45	2.4	46.2	134.0	13.1	9.6	80.0	3510	3721.6
SCR-7	4-5	1.16	312	48	2.4	43.8	140.5	12.4	9.4	80.0	3386	3650.1
SCR-7	6	1.16	404	51	2.4	51.0	126.3	14.8	8.2	80.0	4658	3174.5
SCR-7	7	1.16	404	54	2.4	51.0	126.3	14.9	7.8	80.0	4932	3011.5
SCR-7-C	1,2,3	1.16	115	45	2.4	21.0	183.0	3.4	7.5	80.0	1170	2890.5
SCR-7-C	4,5	1.16	156	48	2.4	24.9	159.4	4.1	6.3	80.0	1693	2423.2
SCR-7-C	1-3	1.16	345	45	2.4	46.2	134.0	7.7	5.7	80.0	3510	2191.3
SCR-7-C	4-5	1.16	312	48	2.4	43.8	140.5	7.3	5.5	80.0	3386	2149.3
SCR-7-C	6	1.16	404	51	2.4	51.0	126.3	8.7	4.8	80.0	4658	1867.9
SCR-7-C	7	1.16	404	54	2.4	51.0	126.3	8.7	4.6	80.0	4932	1771.7

Table 6.1.9-8 presents a summary of the site access/congestion factor for FSI and DSD technologies at the Yates steam plant. Table 6.1.9-9 presents the costs estimated to retrofit FSI and DSD at Yates.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 was used to determine the applicability of these technologies at the Yates plant. Units 1-5 would be considered good candidates for repowering and retrofit because of their small boiler sizes. However, units 6-7 would not be considered because they are more than 300 MW. All units have moderate to high capacity factors which could result in high replacement power cost for extensive downtimes. Units 2-4 would be difficult to access for rebuilds or reuse of the furnace, pulverizers, and heat recovery sections.

TABLE 6.1.9-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR YATES UNIT 6-7 (EACH)

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	MEDIUM
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	85

TOTAL COST (1000$)	
ESP UPGRADE CASE	85
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.36
NEW BAGHOUSE	NA

Table 6.1.9-9. Summary of DSD/FSI Control Costs for the Yates Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	6	1.00	404	51	2.4	19.7	48.8	14.1	7.8	49.0	17676	798.2
DSD+ESP	7	1.00	404	54	2.4	19.7	48.8	14.5	7.6	49.0	18716	775.1
DSD+ESP-C	6	1.00	404	51	2.4	19.7	48.8	8.2	4.5	49.0	17676	462.3
DSD+ESP-C	7	1.00	404	54	2.4	19.7	48.8	8.4	4.4	49.0	18716	448.8
FSI+ESP-50	6	1.00	404	51	2.4	17.6	43.5	16.4	9.1	50.0	18166	902.4
FSI+ESP-50	7	1.00	404	54	2.4	17.6	43.5	17.0	8.9	50.0	19235	886.3
FSI+ESP-50-C	6	1.00	404	51	2.4	17.6	43.5	9.5	5.2	50.0	18166	521.3
FSI+ESP-50-C	7	1.00	404	54	2.4	17.6	43.5	9.8	5.2	50.0	19235	511.9
FSI+ESP-70	6	1.00	404	51	2.4	17.4	43.1	16.6	9.2	70.0	25433	653.4
FSI+ESP-70	7	1.00	404	54	2.4	17.4	43.1	17.3	9.0	70.0	26929	642.0
FSI+ESP-70-C	6	1.00	404	51	2.4	17.4	43.1	9.6	5.3	70.0	25433	377.4
FSI+ESP-70-C	7	1.00	404	54	2.4	17.4	43.1	10.0	5.2	70.0	26929	370.7

Page Intentionally Left Blank

SECTION 7.0 ILLINOIS

7.1 CENTRAL ILLINOIS LIGHT COMPANY

7.1.1 E. D. Edwards Steam Plant

L/S-FGD and LSD-FGD retrofit factors were developed for the boilers at the Edwards plant; however, costs are not presented since the low sulfur coal being used by the plant would yield low capital/operating costs and high cost per ton of SO_2 removed. The boilers currently fire a low sulfur coal hence CS was not considered. Since 1984 CILCO has been implementing a coal blending program to comply with the 1.8 mmBTU standard. Sorbent injection technologies were not evaluated because of the inadequate size of the ESPs.

TABLE 7.1.1-1. E. D. EDWARDS STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2	3
GENERATING CAPACITY (MW-each)	125	272	376
CAPACITY FACTOR (PERCENT)	34	39	63
INSTALLATION DATE	1960	1968	1972
FIRING TYPE		FRONT WALL	
FURNACE VOLUME (1000 CU FT)	73.5	155.6	187.5
LOW NOx COMBUSTION	NO	NO	NO
COAL SULFUR CONTENT (PERCENT)		0.9	
COAL HEATING VALUE (BTU/LB)		13000	
COAL ASH CONTENT (PERCENT)		6.0	
FLY ASH SYSTEM		WET DISPOSAL	
ASH DISPOSAL METHOD		POND/ON-SITE	
STACK NUMBER	1	1	2
COAL DELIVERY METHODS		RAILROAD/BARGE/TRUCK	
PARTICULATE CONTROL			
TYPE	ESP	ESP	ESP
INSTALLATION DATE	1960	1968	1972
EMISSION (LB/MM BTU)	0.20	0.15	0.10
REMOVAL EFFICIENCY	96.3	98.6	98.9
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	NA	NA	NA
SURFACE AREA (1000 SQ FT)	63.4	138.2	215
GAS EXIT RATE (1000 ACFM)	462	815	1210
SCA (SQ FT/1000 ACFM)	137	170	178
OUTLET TEMPERATURE (°F)	300	300	300

TABLE 7.1.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR EDWARDS UNIT 1 OR 2 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	NA	HIGH
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			MEDIUM
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	MEDIUM
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	1145,2299	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.64	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.58
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.36
GENERAL FACILITIES (PERCENT)	15	0	15

* L/LS-FGD absorbers, LSD-FGD absorbers, and new FFs for units 1 and 2 would be located south of the common chimney for units 1 and 2.

TABLE 7.1.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR EDWARDS UNIT 3 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	3073	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.38	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.27
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	8	0	8

* L/S-FGD absorbers, LSD-FGD absorbers, and new FFs for unit 3 would be located north of the unit 3 chimney.

TABLE 7.1.1-4. SUMMARY OF NOx RETROFIT RESULTS FOR EDWARDS

	BOILER NUMBER			
COMBUSTION MODIFICATION RESULTS				
	1	2	1-2	3
FIRING TYPE	FWF	FWF	NA	FWF
TYPE OF NOx CONTROL	LNB	LNB	NA	LNB
FURNACE VOLUME (1000 CU FT)	73.5	155.6	NA	187.5
BOILER INSTALLATION DATE	1960	1968	NA	1972
SLAGGING PROBLEM	NO	NO	NA	NO
ESTIMATED NOx REDUCTION (PERCENT)	40	39	NA	34
SCR RETROFIT RESULTS *				
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH	HIGH	LOW
SCOPE ADDER PARAMETERS--				
Building Demolition (1000$)	0	0	0	0
Ductwork Demolition (1000$)	32	57	76	73
New Duct Length (Feet)	400	400	400	400
New Duct Costs (1000$)	2258	3559	4440	4301
New Heat Exchanger (1000$)	2131	3397	4263	4126
TOTAL SCOPE ADDER COSTS (1000$)	4421	7014	8779	8500
RETROFIT FACTOR FOR SCR	1.52	1.52	1.52	1.16
GENERAL FACILITIES (PERCENT)	38	38	38	20

* Cold side SCR reactors for units 1 and 2 would be located south of the common chimney for units 1 and 2. Cold side SCR reactors for unit 3 would be located north of the unit 3 chimney.

Table 7.1.1-5. NOx Control Cost Results for the Edwards Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	1	1.00	125	34	0.9	2.8	22.3	0.6	1.6	40.0	590	1034.2
LNC-LNB	2	1.00	272	39	0.9	3.8	14.0	0.8	0.9	39.0	1436	580.1
LNC-LNB	3	1.00	376	63	0.9	4.3	11.5	0.9	0.5	34.0	2796	339.1
LNC-LNB-C	1	1.00	125	34	0.9	2.8	22.3	0.4	1.0	40.0	590	613.8
LNC-LNB-C	2	1.00	272	39	0.9	3.8	14.0	0.5	0.5	39.0	1436	344.2
LNC-LNB-C	3	1.00	376	63	0.9	4.3	11.5	0.6	0.3	34.0	2796	201.2
SCR-3	1	1.52	125	34	0.9	28.3	226.7	8.8	23.6	80.0	1180	7447.4
SCR-3	2	1.52	272	39	0.9	49.9	183.5	16.2	17.4	80.0	2946	5482.6
SCR-3	3	1.16	376	63	0.9	50.7	134.9	18.3	8.8	80.0	6578	2774.9
SCR-3	1-2	1.52	397	37	0.9	65.5	165.0	21.7	16.9	80.0	4079	5323.9
SCR-3-C	1	1.52	125	34	0.9	28.3	226.7	5.2	13.9	80.0	1180	4374.6
SCR-3-C	2	1.52	272	39	0.9	49.9	183.5	9.5	10.2	80.0	2946	3217.1
SCR-3-C	3	1.16	376	63	0.9	50.7	134.9	10.7	5.1	80.0	6578	1624.4
SCR-3-C	1-2	1.52	397	37	0.9	65.5	165.0	12.7	9.9	80.0	4079	3122.2
SCR-7	1	1.52	125	34	0.9	28.3	226.7	7.8	20.9	80.0	1180	6587.5
SCR-7	2	1.52	272	39	0.9	49.9	183.5	13.9	15.0	80.0	2946	4732.8
SCR-7	3	1.16	376	63	0.9	50.7	134.9	15.2	7.3	80.0	6578	2310.8
SCR-7	1-2	1.52	397	37	0.9	65.5	165.0	18.5	14.4	80.0	4079	4533.6
SCR-7-C	1	1.52	125	34	0.9	28.3	226.7	4.6	12.3	80.0	1180	3881.9
SCR-7-C	2	1.52	272	39	0.9	49.9	183.5	8.2	8.8	80.0	2946	2787.5
SCR-7-C	3	1.16	376	63	0.9	50.7	134.9	8.9	4.3	80.0	6578	1358.5
SCR-7-C	1-2	1.52	397	37	0.9	65.5	165.0	10.9	8.5	80.0	4079	2669.4

7.2 CENTRAL ILLINOIS PUBLIC SERVICE

7.2.1 Coffeen Steam Plant

The Coffeen steam plant is located within Montgomery County, Illinois, and is part of the Central Illinois Public Service Company system. The plant contains two coal-fired boilers with a total gross generating capacity of 1,006 MW. Figure 7.2.1-1 presents the plant plot plan showing the location of the boilers and major associated auxiliary equipment.

Table 7.2.1-1 presents operational data for the existing equipment at the Coffeen steam plant. Both boilers burn high sulfur coal (3.7 percent sulfur). The plant is located next to the Hillsboro coal mine and the coal is conveyed from the mine to a coal storage area located south of the plant.

Particulate matter emissions for both boilers are controlled with retrofit ESPs located behind each unit. Fly ash from all units is sold to the County Road Commission for their use. On-site landfills are available northeast of the plant for bottom ash from the boilers.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 7.2.1-1 shows the general layout and location of the FGD control system. The absorbers for both units and all FGD technologies were located south of the boilers in a relatively small area. A storage area building and part of the plant road would be relocated to make more space available for the FGD absorbers. Therefore, a factor of 7 percent was assigned to general facilities. The limestone preparation/storage area was placed directly east of the absorbers with the waste handling area being located east of the preparation/storage area in the ash pond #1 site.

Retrofit Difficulty and Scope Adder Costs--

The Coffeen plant is equipped with two boilers, one chimney, and two retrofit ESPs. The boilers sit east to west, side by side. The ESPs are located directly behind (south) the units with the chimney centered behind. The FGD absorbers were placed south of the chimney where they would be bounded on three sides. The absorbers would be bounded to the west by the coal conveyor, to the north by the chimney, and to the south by the coal

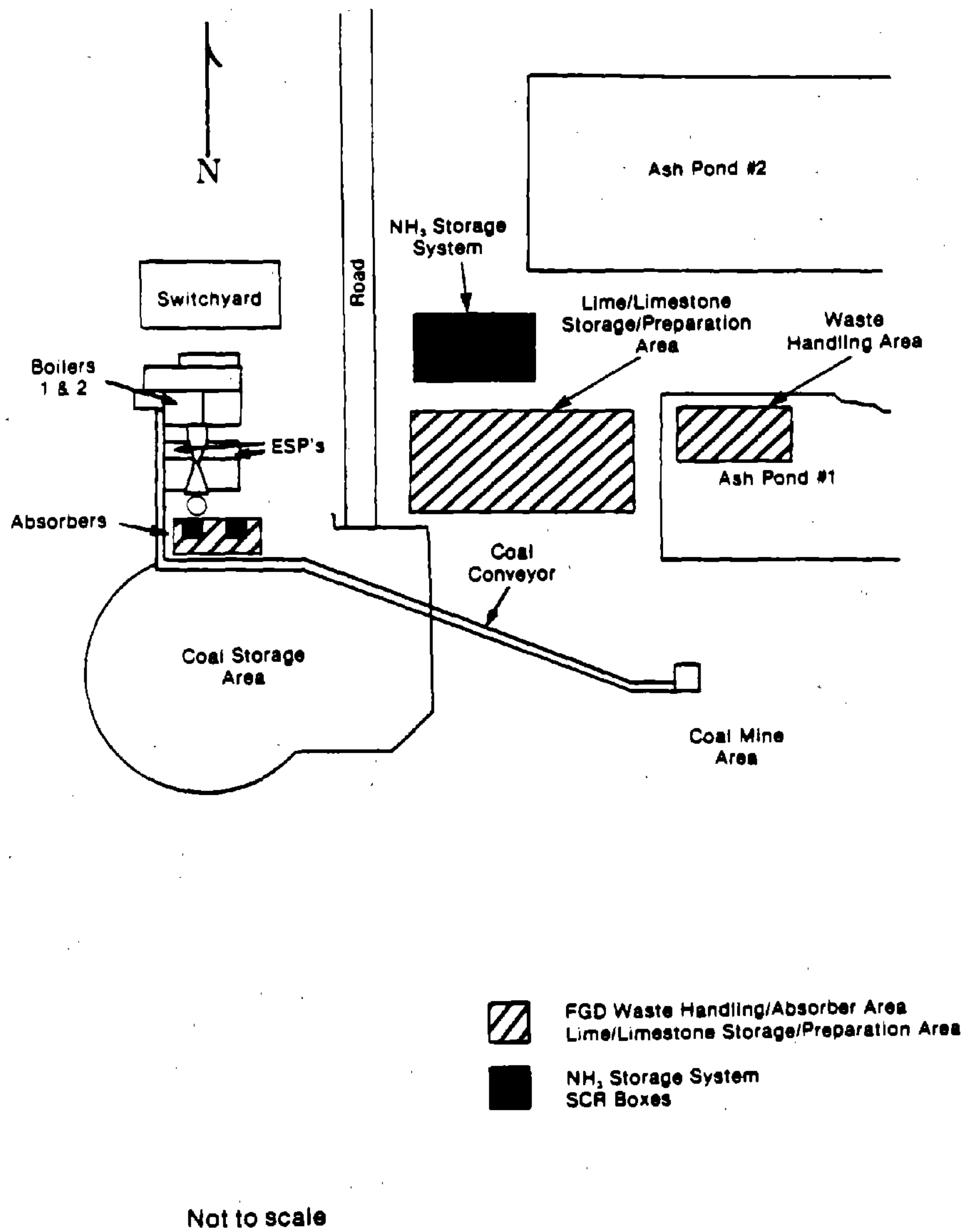

Figure 7.2.1-1. Coffeen plant plot plan

TABLE 7.2.1-1. COFFEEN STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2
GENERATING CAPACITY (MW)	389	617
CAPACITY FACTOR (PERCENT)	29	52
INSTALLATION DATE	1965	1972
FIRING TYPE	CYC	CYC
COAL SULFUR CONTENT (PERCENT)	3.7	3.7
COAL HEATING VALUE (BTU/LB)	10400	10400
COAL ASH CONTENT (PERCENT)	10.0	10.0
FLY ASH SYSTEM	DRY	
ASH DISPOSAL METHOD	OFF-SITE	
STACK NUMBER	1	
COAL DELIVERY METHODS	CONVEYOR COAL MINE NEXT TO THE PLANT	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1973	1982
EMMISION (LB/MM BTU)	0.05	0.05
REMOVAL EFFICIENCY	98.5	97.4
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	4.5	4.5
SURFACE AREA (1000 SQ FT)	308.9	397.4
GAS FLOW (1000 ACFM)	1422.7	2217
SCA (SQ FT/1000 ACFM)	217	179
OUTLET TEMPERATURE (°F)	310	310

storage/handling area. A high site access/congestion factor was assigned to the absorbers to reflect this congestion. No obstructions exist in the area where the tie-in ductwork would be located and short to medium duct runs for all units would be required since the absorbers are close to the chimney. As a result, a low site access/congestion factor was assigned to flue gas handling for all units and all FGD technologies.

The major scope adjustment costs and estimated retrofit factors for the FGD control technologies are presented in Table 7.2.1-2. There are no significant scope adders for the retrofit of FGD control technologies at the Coffeen steam plant. The overall retrofit factors estimated for the L/LS-FGD cases were moderate (1.44 to 1.48).

The only LSD-FGD case considered was LSD with a new baghouse. The existing ESPs are located in a high site access/congestion area and the SCAs are small (179-220). Also, it is likely that a considerable plate area increase would be required to upgrade the existing ESPs. The retrofit factor determined for the LSD technology was moderate (1.45) and did not include particulate control costs. A separate factor of 1.58 was estimated for new particulate controls. This high factor is a result of the high site access/congestion associated with the intended location of the absorbers and baghouses.

Table 7.2.1-3 presents the cost estimates for L/LS and LSD-FGD cases. The LSD-FGD costs include installing new baghouses to handle the additional particulate loading for boilers 1 and 2.

The low cost control case reduces capital and annual operating costs. The significant reduction in costs is primarily due to the benefits of economies-of-scale when combining process areas, elimination of spare scrubber, and optimization of scrubber size.

Coal Switching and Physical Coal Cleaning Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined. This is particularly true for cyclone boilers; therefore, coal switching was not evaluated for the Coffeen plant.

TABLE 7.2.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR COFFEEN UNITS 1-2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	HIGH	HIGH
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	100-300	
ESP REUSE			NA
BAGHOUSE			100-300
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	HIGH
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NO	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.44	1.48	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.45
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.58
GENERAL FACILITIES (PERCENT)	7	7	7

Table 7.2.1-3. Summary of FGD Control Costs for the Coffeen Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.44	389	29	3.7	111.3	286.1	46.3	46.9	90.0	31287	1480.3
L/S FGD	2	1.44	617	52	3.7	152.0	246.3	75.1	26.7	90.0	88983	843.8
L/S FGD-C	1	1.44	389	29	3.7	111.3	286.1	27.0	27.4	90.0	31287	864.0
L/S FGD-C	2	1.44	617	52	3.7	152.0	246.3	43.7	15.5	90.0	88983	491.1
LC FGD	1-2	1.44	1006	41	3.7	192.4	191.3	94.1	26.0	90.0	114393	822.6
LC FGD-C	1-2	1.44	1006	41	3.7	192.4	191.3	54.8	15.2	90.0	114393	478.9
LSD+FF	1	1.45	389	29	3.7	103.4	265.9	37.0	37.5	84.0	29063	1274.2
LSD+FF	2	1.45	617	52	3.7	156.2	253.1	63.0	22.4	84.0	82657	761.6
LSD+FF-C	1	1.45	389	29	3.7	103.4	265.9	21.7	21.9	84.0	29063	746.0
LSD+FF-C	2	1.45	617	52	3.7	156.2	253.1	36.8	13.1	84.0	82657	444.8

Table 7.2.1-4 presents the IAPCS results for physical coal cleaning at the Coffeen plant. These costs do not include reduced pulverizer operating costs or system modifications that may be necessary to handle deep cleaned coal.

NO_x Control Technology Costs--

This section presents the performance and various related costs estimated for NO_x controls at Coffeen. These controls include LNC and SCR. The application of NO_x control technologies is affected by several site-specific factors which are discussed in Section 2. The NO_x control technologies evaluated at Coffeen were: NGR and SCR.

Low NO_x Combustion--

Units 1 and 2 are wet bottom, cyclone-fired boilers rated at 389 and 617 MW, respectively. The combustion modification technique applied was NGR. The NO_x reduction performance estimated for both units was 60 percent. Table 7.2.1-5 presents the results for all boilers evaluated for NO_x control applicability at the Coffeen plant. Table 7.2.1-6 presents the cost of retrofitting NGR at the Coffeen plant.

Selective Catalytic Reduction--

Table 7.2.1-5 presents the SCR retrofit factors for each unit. The table includes process area retrofit difficulty factors and scope adder costs. The scope adders include costs estimated for ductwork demolition, new heat exchanger, and new duct runs to divert the flue gas from the ESP to the reactor and from the reactor to the chimney.

The reactors for units 1 and 2 were located south of the powerhouse, behind the ESPs, and north of the crusher house. The reactor for unit 1 would be bounded on three sides by the coal conveyor belt, the chimney, and the crusher house. Meanwhile, the reactor for unit 2 would be bounded on two sides by the chimney and the coal conveyor.

The reactors for units 1 and 2 were assigned medium site access/ congestion factors. The ammonia storage system, which would supply ammonia to both reactors, would be located in an open area. The reactors were placed in an area with high underground obstructions and the ammonia system was

Table 7.2.1-4. Summary of Coal Switching/Cleaning Costs for the Coffeen Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
PCC	1	1.00	389	29	3.7	5.3	13.8	3.6	3.6	31.0	10766	334.2
PCC	2	1.00	617	52	3.7	10.3	16.7	8.9	3.2	31.0	30621	289.6
PCC-C	1	1.00	389	29	3.7	5.3	13.8	2.1	2.1	31.0	10766	193.7
PCC-C	2	1.00	617	52	3.7	10.3	16.7	5.1	1.8	31.0	30621	167.4

TABLE 7.2.1-5. SUMMARY OF NOx RETROFIT RESULTS FOR COFFEEN

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1	2
FIRING TYPE	CY	CY
TYPE OF NOx CONTROL	NGR	NGR
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	NA	NA
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	NA	NA
FURNACE RESIDENCE TIME (SECONDS)	NA	NA
ESTIMATED NOx REDUCTION (PERCENT)	60	60
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	MEDIUM
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	75	106
New Duct Length (Feet)	150	150
New Duct Costs (1000$)	1,503	1,968
New Heat Exchanger (1000$)	4,198	5,554
TOTAL SCOPE ADDER COSTS (1000$)	5,776	7,628
RETROFIT FACTOR FOR SCR	1.34	1.34
GENERAL FACILITIES (PERCENT)	13	13

Table 7.2.1-6. NOx Control Cost Results for the Coffeen Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
NGR	1	1.00	389	29	3.7	6.1	15.7	5.9	6.0	60.0	4915	1203.7
NGR	2	1.00	617	52	3.7	8.7	14.1	15.6	5.5	60.0	13977	1114.1
NGR-C	1	1.00	389	29	3.7	6.1	15.7	3.4	3.5	60.0	4915	695.2
NGR-C	2	1.00	617	52	3.7	8.7	14.1	9.0	3.2	60.0	13977	641.1
SCR-3	1	1.34	389	29	3.7	53.3	137.1	19.1	19.3	80.0	6553	2913.7
SCR-3	2	1.34	617	52	3.7	79.4	128.6	30.4	10.8	80.0	18637	1630.6
SCR-3-C	1	1.34	389	29	3.7	53.3	137.1	11.2	11.3	80.0	6553	1705.9
SCR-3-C	2	1.34	617	52	3.7	79.4	128.6	17.8	6.3	80.0	18637	953.3
SCR-7	1	1.34	389	29	3.7	53.3	137.1	15.8	16.0	80.0	6553	2415.5
SCR-7	2	1.34	617	52	3.7	79.4	128.6	25.2	9.0	80.0	18637	1352.8
SCR-7-C	1	1.34	389	29	3.7	53.3	137.1	9.3	9.4	80.0	6553	1420.4
SCR-7-C	2	1.34	617	52	3.7	79.4	128.6	14.8	5.3	80.0	18637	794.1

placed in an area with no significant underground obstructions. Table 7.2.1-6 presents the estimated cost of retrofitting SCR at the Coffeen boilers.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas for both units would be located south of the plant in a relatively small area. The retrofit of DSD and FSI technologies at the Coffeen steam plant would be difficult because of the small SCA (<220), although there is more than 2 seconds of flue gas ducting residence time between the boilers and the ESPs. Significant particulate control upgrading would likely be needed to handle the increased solids loading resulting from the DSD and FSI retrofit. As a result, DSD followed by new fabric filters installed behind the chimney was evaluated. Tables 7.2.1-7 and 7.2.1-8 present a summary of site access/congestion factors, scope adders, and retrofit factors for DSD and FSI technologies at the Coffeen steam plant. Table 7.2.1-9 presents the costs estimated to retrofit DSD at the Coffeen plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Coffeen plant. The boilers at Coffeen would not be considered good candidates for AFBC retrofit and AFBC or CG/combined cycle repowering because of their large boiler sizes (>300 MW). However, the capacity factor on boiler 1 is low and NO_x/SO_2 emissions are high suggesting that this boiler may be a good candidate if size is not a technology limiting constraint.

TABLE 7.2.1-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR COFFEEN UNIT 1

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE	NA
NEW BAGHOUSE	HIGH
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	300
ESTIMATED COST (1000$)	3,051
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	83

TOTAL COST (1000$)	
ESP UPGRADE CASE	NA
A NEW BAGHOUSE CASE	3,134
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE	NA
NEW BAGHOUSE	1.55

TABLE 7.2.1-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR COFFEEN UNIT 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	HIGH
ESP UPGRADE	NA
NEW BAGHOUSE	HIGH
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	300
ESTIMATED COST (1000$)	3,996
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	117
TOTAL COST (1000$)	
ESP UPGRADE CASE	NA
A NEW BAGHOUSE CASE	4,113
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE	NA
NEW BAGHOUSE	1.55

Table 7.2.1-9. Summary of DSD/FSI Control Costs for the Coffeen Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+FF	1	1.00	389	29	3.7	66.6	171.2	25.7	26.0	69.0	24091	1066.8
DSD+FF	2	1.00	617	52	3.7	100.5	162.9	45.5	16.2	69.0	68518	664.1
DSD+FF-C	1	1.00	389	29	3.7	66.6	171.2	15.0	15.2	69.0	24091	623.6
DSD+FF-C	2	1.00	617	52	3.7	100.5	162.9	26.5	9.4	69.0	68518	387.1

7.2.2 Grand Tower Steam Plant

The Grand Tower steam plant is located in Jackson County, Illinois, as part of the Central Illinois Public Service Company system. The plant contains three coal-fired boilers with a gross generating capacity of 286 MW. Figure 7.2.2-1 presents the plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 7.2.2-1 presents operational data for the existing equipment for the boilers at Grand Tower. The boilers burn medium sulfur coal (2.7 percent sulfur). Coal is received by truck and taken to the coal storage/handling area located next to boilers/powerhouse (north).

Particulate emissions are controlled with retrofit ESPs located behind the units. The ash from all units is wet sluiced to the ash ponds which are located on the far side of the powerhouse (south).

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 7.2.2-1 shows the general layout and location of the FGD control system. The FGD absorbers for all FGD technologies were located in an open area south of the chimney in an uncongested area. The only demolition and relocation required for this placement of the FGD absorbers would be a plant road; therefore, a factor of 5 percent was assigned to general facilities. The lime and limestone preparation/storage area and waste handling area were located south of the absorbers in close proximity to the ash ponds in a low access/congestion area.

Retrofit Difficulty and Scope Adder Costs--

The Grand Tower plant has 3 units, numbered 7, 8, and 9. No information was available for units 1 to 6 in the EIA-767 forms or other data reviewed and, as a result, it was assumed that these units have been retired and are no longer in service. The plant is bounded on the west side by the Mississippi River and on the remaining sides by rolling hills. All boilers sit side by side, parallel to the river. The coal storage/handling area is located to the north of the powerhouse while the ash ponds are located to the south of the powerhouse. The L/LS and LSD-FGD absorbers were located between the powerhouse and the ash ponds. A low site access/congestion factor was

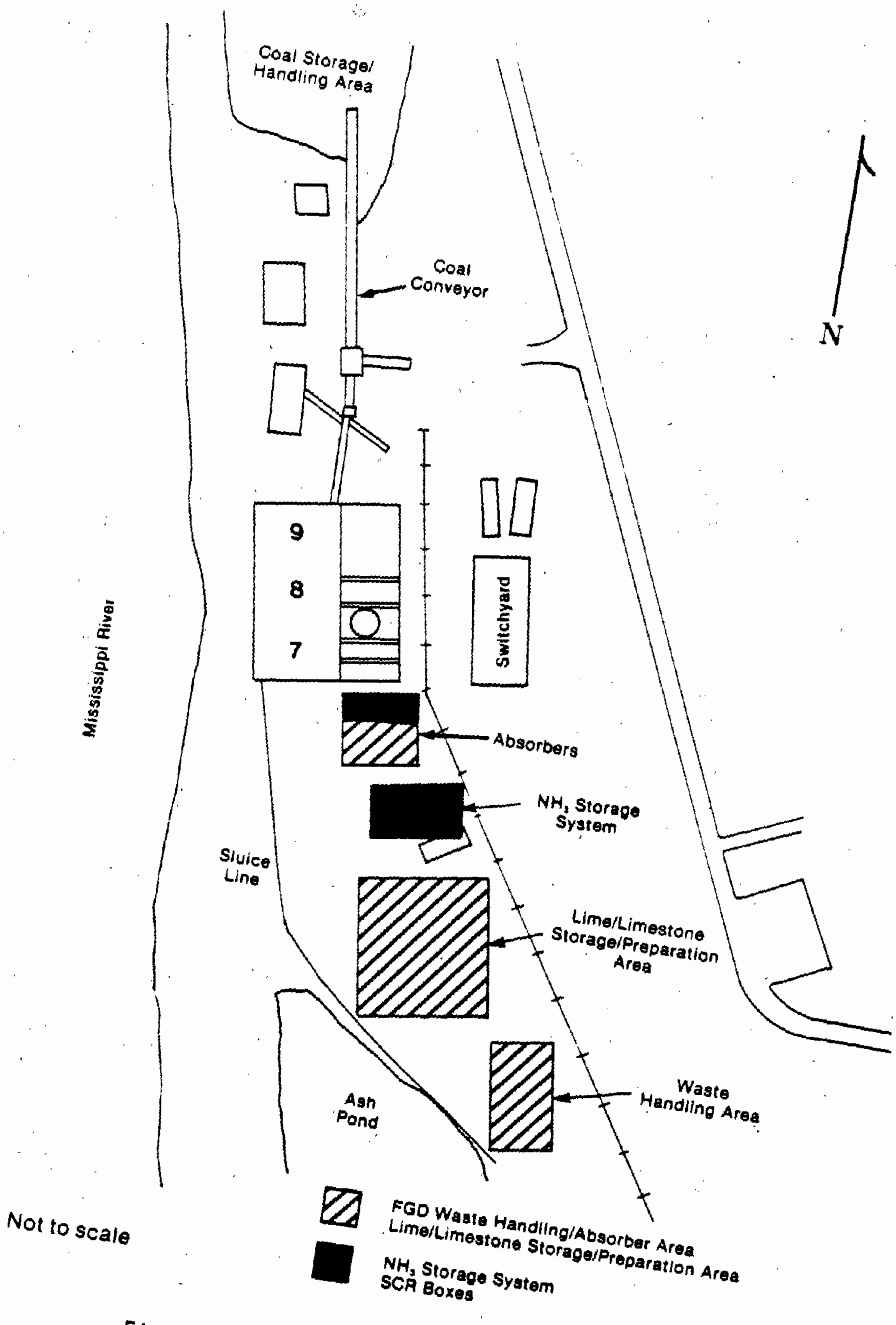

Figure 7.2.2-1. Grand Tower plant plot plan

TABLE 7.2.2-1. GRAND TOWER STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	7,8	9
GENERATING CAPACITY (MW-each)	85, 81	114
CAPACITY FACTOR (PERCENT)	10	40
INSTALLATION DATE	1951	1958
FIRING TYPE	FWF	FWF
COAL SULFUR CONTENT (PERCENT)	2.7	2.7
COAL HEATING VALUE (BTU/LB)	11500	11500
COAL ASH CONTENT (PERCENT)	10.3	10.7
FLY ASH SYSTEM	WET SLUICE	
ASH DISPOSAL METHOD	POND/ON-SITE	
STACK NUMBER	1	
COAL DELIVERY METHODS	TRUCK	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1969	1970
EMISSION (LB/MM BTU)	0.13	0.16
REMOVAL EFFICIENCY	98.4	97.9
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	2.1	2.1
SURFACE AREA (1000 SQ FT)	19.9	54
EXIT GAS FLOW RATE (1000 ACFM)	149.5	377
SCA (SQ FT/1000 ACFM)	133	143
OUTLET TEMPERATURE (°F)	310	310

assigned to the location of the absorbers because there is no plant facility surrounding this location. The access/congestion factor assigned to the flue gas handling was medium as a result of the ductwork congestion created by the closeness of the chimneys to the boilers and the railroad track. Also, a long duct run would be required for all FGD retrofit cases at the Grand Tower plant.

The major scope adjustment costs and estimated retrofit factors for the FGD technologies are presented in Table 7.2.2-2. The largest scope adders for the Grand Tower plant would be construction of a new chimney and the conversion from wet to dry ash handling/disposal system for the L/LS-FGD cases evaluated. It was assumed that the dry fly ash would be necessary to stabilize the scrubber sludge waste for these cases. This conversion is not required for the application of forced oxidation FGD. Reuse of the existing chimney was difficult due to the location of the chimney between the existing ESPs. The cost of a new chimney was added to the scope adders. The overall retrofit factors determined for the L/LS-FGD cases were moderate (1.44 to 1.49).

The LSD-FGD case evaluated at Grand Tower was LSD with a new baghouse. This case was evaluated for the primary reason that the SCAs at these units are small (<145). The overall retrofit factor estimated for the LSD technology was moderate (1.45). A separate factor was developed for the new particulate controls and used by the IAPCS model to determine any additional cost which might be required. This factor was low (1.16) and is a result of the location chosen for the new particulate control on the side of the boiler between the powerhouse and the ash ponds.

Table 7.2.2-3 presents the process area retrofit factors and cost estimates for L/LS and LSD-FGD cases. The LSD-FGD costs include installing new baghouses to handle the additional particulate loading for boilers 7-9.

Two combined FGD cases for units 7-9 were considered. The first case uses conventional forced oxidation technology for an NSPS type system and demonstrates the economies of scale. The second case represents the low cost control case. The additional reduction in costs is primarily due to the elimination of spare scrubber module, the optimization of scrubber module size, and the use of adipic acid.

TABLE 7.2.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR GRAND TOWER UNITS 7-9

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	MEDIUM	MEDIUM	
ESP REUSE CASE			NA
BAGHOUSE CASE			MEDIUM
DUCT WORK DISTANCE (FEET)	600-1000	600-1000	
ESP REUSE			NA
BAGHOUSE			600-1000
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	NO
ESTIMATED COST (1000$)	819	NA	NA
NEW CHIMNEY	YES	YES	YES
ESTIMATED COST (1000$)	2,075	2,075	2,075
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.49	1.44	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.45
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	5	5	5

Table 7.2.2-3. Summary of FGD Control Costs for the Grand Tower Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	7	1.49	85	10	2.7	43.6	513.3	16.2	217.1	90.0	1533	10544.0
L/S FGD	8	1.49	81	10	2.7	42.7	526.7	15.8	223.0	90.0	1461	10833.7
L/S FGD	9	1.49	114	40	2.7	49.8	436.6	21.0	52.6	90.0	8223	2554.0
L/S FGD-C	7	1.49	85	10	2.7	43.6	513.3	9.5	127.0	90.0	1533	6168.7
L/S FGD-C	8	1.49	81	10	2.7	42.7	526.7	9.3	130.5	90.0	1461	6338.0
L/S FGD-C	9	1.49	114	40	2.7	49.8	436.6	12.3	30.7	90.0	8223	1490.4
LC FGD	7-9	1.49	280	22	2.7	62.5	223.0	25.5	47.3	90.0	11108	2298.9
LC FGD-C	7-9	1.49	280	22	2.7	62.5	223.0	14.9	27.6	90.0	11108	1342.3
LSD+FF	7	1.45	85	10	2.7	25.8	303.6	10.0	134.0	87.0	1473	6773.3
LSD+FF	8	1.45	81	10	2.7	24.7	305.2	9.7	136.2	87.0	1404	6882.4
LSD+FF	9	1.45	114	40	2.7	31.7	278.4	13.2	33.1	86.0	7869	1678.2
LSD+FF-C	7	1.45	85	10	2.7	25.8	303.6	5.8	78.3	87.0	1473	3959.2
LSD+FF-C	8	1.45	81	10	2.7	24.7	305.2	5.6	79.6	87.0	1404	4022.1
LSD+FF-C	9	1.45	114	40	2.7	31.7	278.4	7.7	19.3	86.0	7869	979.6

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined.

The ESP performance impacts were evaluated using the IAPCS model to estimate the needed plate area. This plate area was compared to the existing area to determine whether SO_3 conditioning or additional plate area was needed. SO_3 conditioning was assumed to reduce the needed plate area up to 25 percent.

Costs were generated to show the impact of two different coal fuel cost differentials. The costs associated with each boiler for the range of fuel cost differential are shown in Table 7.2.2-4.

NO_x Control Technology Costs

This section presents the performance and costs estimated for NO_x controls at the Grand Tower steam plant. These controls include LNC modification and SCR. The application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2. The NO_x technologies evaluated at the steam plant were: LNB and SCR.

Low NO_x Combustion--

Units 7 to 9 are dry bottom, front wall-fired boilers rated at 85, 81, and 114 MW, respectively. The combustion modification technique applied for these boilers was LNB. As Table 7.2.2-5 shows, the LNB NO_x reduction performances for units 7 and 8 could not be estimated using the simplified procedures. No boiler information could be found for units 7 and 8 in POWER to assess their NO_x reduction performances. Since these boilers are relatively old, it is estimated that a NO_x reduction of 20 to 30 percent can be achieved by these boilers retrofitted with LNB. For unit 9, the LNB NO_x reduction performance was estimated at 50 percent using the simplified procedures. Table 7.2.2-6 presents the cost of retrofitting LNB at the Grand Tower boilers, assuming a NO_x reduction performance of 25 percent for units 7 and 8.

Table 7.2.2-4. Summary of Coal Switching/Cleaning Costs for the Grand Tower Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	7	1.00	85	10	2.7	4.2	49.2	2.0	27.3	68.0	1165	1746.3
CS/B+$15	8	1.00	81	10	2.7	4.0	49.7	2.0	27.6	68.0	1111	1761.1
CS/B+$15	9	1.00	114	40	2.7	5.1	45.1	6.6	16.5	68.0	6252	1052.2
CS/B+$15-C	7	1.00	85	10	2.7	4.2	49.2	1.2	15.9	68.0	1165	1016.6
CS/B+$15-C	8	1.00	81	10	2.7	4.0	49.7	1.1	16.0	68.0	1111	1025.2
CS/B+$15-C	9	1.00	114	40	2.7	5.1	45.1	3.8	9.5	68.0	6252	606.5
CS/B+$5	7	1.00	85	10	2.7	3.3	38.8	1.3	17.0	68.0	1165	1086.1
CS/B+$5	8	1.00	81	10	2.7	3.2	39.3	1.2	17.2	68.0	1111	1100.7
CS/B+$5	9	1.00	114	40	2.7	4.0	34.8	3.1	7.7	68.0	6252	491.4
CS/B+$5-C	7	1.00	85	10	2.7	3.3	38.8	0.7	9.9	68.0	1165	635.0
CS/B+$5-C	8	1.00	81	10	2.7	3.2	39.3	0.7	10.1	68.0	1111	643.5
CS/B+$5-C	9	1.00	114	40	2.7	4.0	34.8	1.8	4.5	68.0	6252	284.4

TABLE 7.2.2-5 SUMMARY OF NOx RETROFIT RESULTS FOR GRAND TOWER

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	7	8	9
FIRING TYPE	FWF	FWF	FWF
TYPE OF NOx CONTROL	LNB	LNB	LNB
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	NA	NA	17.9
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	NA	NA	53.7
FURNACE RESIDENCE TIME (SECONDS)	NA	NA	2.39
ESTIMATED NOx REDUCTION (PERCENT)	25	25	50
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	LOW
SCOPE ADDER PARAMETERS--			
New Chimney (1000$)	2,075	2,075	2,075
Ductwork Demolition (1000$)	24	24	30
New Duct Length (Feet)	600	600	700
New Duct Costs (1000$)	2,722	2,722	3,745
New Heat Exchanger (1000$)	1,703	1,703	2,016
TOTAL SCOPE ADDER COSTS (1000$)	6,524	6,524	7,866
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13	13

Table 7.2.2-6. NOx Control Cost Results for the Grand Tower Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	7	1.00	85	10	2.7	2.4	28.2	0.5	7.0	25.0	85	6160.6
LNC-LNB	8	1.00	81	10	2.7	2.3	29.0	0.5	7.2	25.0	81	6340.0
LNC-LNB	9	1.00	114	40	2.7	2.7	23.6	0.6	1.5	50.0	911	645.5
LNC-LNB-C	7	1.00	85	10	2.7	2.4	28.2	0.3	4.2	25.0	85	3656.8
LNC-LNB-C	8	1.00	81	10	2.7	2.3	29.0	0.3	4.3	25.0	81	3762.0
LNC-LNB-C	9	1.00	114	40	2.7	2.7	23.6	0.3	0.9	50.0	911	383.1
SCR-3	7	1.16	85	10	2.7	20.7	243.1	6.0	81.0	80.0	272	22186.8
SCR-3	8	1.16	81	10	2.7	20.2	249.1	5.9	82.5	80.0	259	22617.4
SCR-3	9	1.16	114	40	2.7	25.0	219.3	7.6	19.0	80.0	1458	5205.2
SCR-3-C	7	1.16	85	10	2.7	20.7	243.1	3.5	47.6	80.0	272	13052.6
SCR-3-C	8	1.16	81	10	2.7	20.2	249.1	3.4	48.6	80.0	259	13307.5
SCR-3-C	9	1.16	114	40	2.7	25.0	219.3	4.5	11.2	80.0	1458	3059.1
SCR-7	7	1.16	85	10	2.7	20.7	243.1	5.3	71.5	80.0	272	19599.6
SCR-7	8	1.16	81	10	2.7	20.2	249.1	5.2	73.1	80.0	259	20029.8
SCR-7	9	1.16	114	40	2.7	25.0	219.3	6.6	16.6	80.0	1458	4558.6
SCR-7-C	7	1.16	85	10	2.7	20.7	243.1	3.1	42.2	80.0	272	11570.2
SCR-7-C	8	1.16	81	10	2.7	20.2	249.1	3.1	43.2	80.0	259	11825.3
SCR-7-C	9	1.16	114	40	2.7	25.0	219.3	3.9	9.8	80.0	1458	2688.7

Selective Catalytic Reduction--

Table 7.2.2-5 presents the SCR retrofit results for each unit. The results include process area retrofit factors and scope adder costs. The scope adders include costs estimated for ductwork demolition, new flue gas heat exchanger, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimney.

The SCR reactors for units 7 to 9 would be located side-by-side in a relatively open area close to the powerhouse between it and the ash ponds. Since the reactors were located in an open area having easy access with no major obstacles, the reactors for units 7 to 9 were assigned low access/congestion factors. All reactors were assumed to be in areas with high underground obstructions. The ammonia storage system was placed in a remote area having a low access/congestion factor.

As discussed in Section 2, all NO_x control techniques were evaluated independently from those techniques evaluated for SO_2 control. Using this scheme, both the SCR reactors and the FGD absorbers were located in the same area. If both SO_2 and NO_x emissions were reduced at this plant, the SCR reactors would have to be located downstream of the FGD absorbers in a relatively open area further south from the SCR reactors' original locations. In this case, low access and congestion factors would be assigned to all SCR reactors. Table 7.2.2-6 presents the estimated cost of retrofitting SCR at the Grand Tower boilers.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas for all units were placed in a layout similar to that for LSD-FGD. The retrofit of DSD and FSI would be difficult and costly because the SCAs are small (<150) and, for DSD retrofit, there is insufficient duct residence time (1 second). Therefore, a new particulate control (new baghouse) would be needed to handle the increased particulate load resulting from DSD or FSI application. For DSD with a new fabric filter, the baghouse would be located south of the plant between the powerhouse and ash ponds and the retrofit factors for the new controls would be low (1.13). It was assumed that the ESPs could not be upgraded for FSI due to a high access/congestion factor for modifying the existing ESPs. Additionally, the conversion of the wet to dry ash handling system would be required when reusing the ESPs for FSI. Tables 7.2.2-7 and 7.2.2-8 present a summary of the site access/congestion factors for DSD and FSI technologies at the Grand Tower plant. Table 7.2.2-9 presents the estimated cost to retrofit DSD with fabric filter at the Grand Tower plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC or CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Grand Tower plant. The boilers at the Grand Tower are small, they were built prior to 1960 and have low capacity factors. As such, they would be considered good candidates for retrofit/repowering using AFBC or CG. Additionally, application of coal switching and sorbent injection would be costly due to the need to add new particulate control devices.

7.2.3 Hutsonville Steam Plant

The Hutsonville steam plant is located within Crawford County, Illinois, as part of the Central Illinois Public Service Company system. The plant is located beside the Wabash River which separates Illinois and Indiana. The plant contains four retired oil burning boilers and two operating coal-fired boilers. Both coal burning boilers have a combined total gross generating capacity of 150 MW.

Table 7.2.3-1 presents operational data for the existing equipment at the Hutsonville plant. The boilers burn medium sulfur coal. Coal shipments are received by trucks and transferred to a coal storage and handling area south of the plant.

PM emissions for both boilers are controlled with retrofit ESPs located behind each unit. The plant has a wet fly ash handling system. Fly ash is

TABLE 7.2.2-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR GRAND TOWER UNITS 7-8

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE (FSI)	HIGH
NEW BAGHOUSE (DSD)	LOW
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	819
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	600
ESTIMATED COST (1000$)	2523
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	27

TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	846
A NEW BAGHOUSE CASE (DSD)	2550
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE (FSI)	1.55
NEW BAGHOUSE (DSD)	1.13

TABLE 7.2.2-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR GRAND TOWER UNIT 9

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE (FSI)	HIGH
NEW BAGHOUSE (DSD)	LOW
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	1054
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	600
ESTIMATED COST (1000$)	2976
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	33

TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	1087
A NEW BAGHOUSE CASE (DSD)	3009
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE (FSI)	1.55
NEW BAGHOUSE (DSD)	1.13

Table 7.2.2-9. Summary of DSD/FSI Control Costs for the Grand Tower Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+FF	7	1.00	85	10	2.7	17.7	207.8	7.3	97.9	71.0	1205	6052.6
DSD+FF	8	1.00	81	10	2.7	17.1	211.4	7.1	100.4	71.0	1148	6205.0
DSD+FF	9	1.00	114	40	2.7	21.7	190.2	9.8	24.6	71.0	6447	1521.8
DSD+FF-C	7	1.00	85	10	2.7	17.7	207.8	4.3	57.2	71.0	1205	3533.5
DSD+FF-C	8	1.00	81	10	2.7	17.1	211.4	4.2	58.6	71.0	1148	3621.9
DSD+FF-C	9	1.00	114	40	2.7	21.7	190.2	5.7	14.3	71.0	6447	887.0

TABLE 7.2.3-1. HUTSONVILLE STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	5, 6
GENERATING CAPACITY (MW-each)	75
CAPACITY FACTOR (PERCENT)	78
INSTALLATION DATE	1953-54
FIRING TYPE	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	49.2
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	2.4
COAL HEATING VALUE (BTU/LB)	11000
COAL ASH CONTENT (PERCENT)	9.5
FLY ASH SYSTEM	WET SLUICE
ASH DISPOSAL METHOD	ON-SITE
STACK NUMBER	1-2
COAL DELIVERY METHODS	TRUCK
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1971
EMISSION (LB/MM BTU)	0.13
REMOVAL EFFICIENCY	97.9-99.4
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	2.0
SURFACE AREA (1000 SQ FT)	47.9
GAS EXIT RATE (1000 ACFM)	300
SCA (SQ FT/1000 ACFM)	159
OUTLET TEMPERATURE (°F)	300

disposed of in a new ash pond site (built in 1986) southwest of the coal pile. There are four roof mounted chimneys. The first two were used for the oil burning units and are retired while the other two serve units 5 and 6 (the coal burning units).

Lime/Limestone and Lime Spray Drying FGD Costs--

The six boilers are located beside each other with boiler 1 being the closest to the coal pile and boiler 6 the furthest. The retrofit ESPs for boilers 5 and 6 are located behind each unit between the boilers and the switchyard. The water intake and discharge structure is located on the other side of the boiler toward the river.

The absorbers for units 5 and 6 would be located beside the retrofit ESPs for unit 6 to the north of the plant. The sorbent preparation, storage, and handling area would be located behind the absorbers. There are no major obstacles/obstructions in the surrounding area and, as such, a base factor of 5 percent was assigned to general facilities. The existing ash pond site would be used for the FGD sludge disposal.

A low site access/congestion factor was assigned to the FGD absorber locations due to the easy accessibility and space availability north of unit 6. Because the chimneys are roof mounted and access to them is difficult, a new chimney would be constructed beside the absorbers. Over 300 feet of duct would be required to divert the flue gases from each of the units (5 and 6) to the absorbers and new chimney. A medium site access/congestion factor was assigned to the flue gas handling system because of the access difficulties to the boilers created by the close proximity of the units to each other and their respective ESPs.

LSD with reuse of the existing ESPs was not considered for this plant because the ESPs are small (SCA =159) and would require major upgrading and additional plate area to handle the increased PM generated from the LSD application. LSD with a new baghouse was not considered because the boilers are not burning low sulfur coal.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Table 7.2.3-2. Table 7.2.3-3 presents the process area retrofit factors and capital/operating costs for commercial FGD technologies. The low cost FGD option reduces costs due to eliminating

TABLE 7.2.3-2. SUMMARY OF RETROFIT FACTOR DATA FOR HUTSONVILLE UNIT 5 OR 6

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	NA
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			NA
BAGHOUSE			NA
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NA
ESTIMATED COST (1000$)	724	NA	NA
NEW CHIMNEY	YES	NA	NA
ESTIMATED COST (1000$)	525	0	0
OTHER	NO		
RETROFIT FACTORS			
FGD SYSTEM	1.44	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	0

Table 7.2.3-3. Summary of FGD Control Costs for the Hutsonville Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	5, 6	1.44	75	78	2.4	40.7	543.1	19.4	37.8	90.0	9868	1962.4
L/S FGD-C	5, 6	1.44	75	78	2.4	40.7	543.1	11.3	22.0	90.0	9868	1142.8
LC FGD	5-6	1.44	150	78	2.4	39.0	260.2	22.2	21.7	90.0	19736	1125.5
LC FGD-C	5-6	1.44	150	78	2.4	39.0	260.2	12.9	12.6	90.0	19736	653.7

spare absorber modules and economies of scale associated with combining process areas.

Coal Switching and Physical Coal Cleaning--

Table 7.2.3-4 presents the IAPCS results for CS at the Hutsonville plant. These costs do not include cost impacts for changes in boiler and pulverizer operation. PCC was not evaluated because this is not a mine mouth plant.

Low NO_x Combustion--

Units 5 and 6 are dry bottom tangential-fired boilers rated at 75 MW each. The combustion modification technique applied to all boilers was OFA. Tables 7.2.3-5 and 7.2.1-6 present the performance and cost results of retrofitting OFA at Hutsonville. The high NO_x removal performance is based on the low volumetric heat release rate for these boilers.

Selective Catalytic Reduction--

Cold side SCR reactors for units 5 and 6 would be located beside the unit 5 and 6 ESP boxes. Both reactors are located in medium site access/congestion areas. All reactors were assumed to be in areas with high underground obstructions. Duct length of 350 and 300 feet would be required for units 5 and 6, respectively. The ammonia storage system was placed close to the reactors north of the plant. No major demolition/relocation would be required for the SCR reactor location and, as such, a base factor of 13 percent was assigned to general facilities.

Table 7.2.3-5 presents the SCR process area retrofit factors and scope adder costs. Table 7.2.3-6 presents the estimated cost of retrofitting SCR at the Hutsonville plant.

Duct Spray Drying and Furnace Sorbent Injection--

The retrofit of FSI and DSD technologies at the Hutsonville steam plant for both units would be very difficult and were not considered for two major reasons: 1) the ESPs have small SCAs (<160); therefore, they would not be able to handle the increased PM and would require major upgrading and additional plate area; and 2) there is a short duct residence time between

Table 7.2.3-4. Summary of Coal Switching/Cleaning Costs for the Hutsonville Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	5, 6	1.00	75	78	2.4	3.6	48.5	7.9	15.5	66.0	7264	1090.9
CS/B+$15-C	5, 6	1.00	75	78	2.4	3.6	48.5	4.6	8.9	66.0	7264	627.3
CS/B+$5	5, 6	1.00	75	78	2.4	2.9	38.2	3.6	6.9	66.0	7264	489.5
CS/B+$5-C	5, 6	1.00	75	78	2.4	2.9	38.2	2.0	4.0	66.0	7264	282.2

TABLE 7.2.3-5. SUMMARY OF NOx RETROFIT RESULTS FOR HUTSONVILLE

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	5	6
FIRING TYPE	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA
FURNACE VOLUME (1000 CU FT)	49.2	49.2
BOILER INSTALLATION DATE	1953	1954
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	25	25
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	MEDIUM
SCOPE ADDER PARAMETERS--		
NEW CHIMNEY (1000$)	0	0
DUCTWORK DEMOLITION (1000$)	22	22
NEW DUCT LENGTH (Feet)	350	300
NEW DUCT COSTS (1000$)	1466	1256
NEW HEAT EXCHANGER (1000$)	1568	1568
TOTAL SCOPE ADDER COSTS (1000$)	3056	2846
RETROFIT FACTOR FOR SCR	1.34	1.34
GENERAL FACILITIES (PERCENT)	13	13

Table 7.2.3-6. NOx Control Cost Results for the Hutsonville Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	5, 6	1.00	75	78	2.4	0.6	7.4	0.1	0.2	25.0	439	274.8
LNC-OFA-C	5, 6	1.00	75	78	2.4	0.6	7.4	0.1	0.1	25.0	439	163.0
SCR-3	5	1.34	75	78	2.4	17.6	235.0	5.7	11.1	80.0	1406	4043.5
SCR-3	6	1.34	75	78	2.4	17.4	232.2	5.6	11.0	80.0	1406	4016.7
SCR-3-C	5	1.34	75	78	2.4	17.6	235.0	3.3	6.5	80.0	1406	2372.8
SCR-3-C	6	1.34	75	78	2.4	17.4	232.2	3.3	6.5	80.0	1406	2356.8
SCR-7	5	1.34	75	78	2.4	17.6	235.0	5.1	9.9	80.0	1406	3599.4
SCR-7	6	1.34	75	78	2.4	17.4	232.2	5.0	9.8	80.0	1406	3572.7
SCR-7-C	5	1.34	75	78	2.4	17.6	235.0	3.0	5.8	80.0	1406	2118.4
SCR-7-C	6	1.34	75	78	2.4	17.4	232.2	3.0	5.8	80.0	1406	2102.4

the boilers and ESPs making humidification (FSI application) and sorbent evaporation (DSD application) infeasible. In addition, ESPs are located close to the switchyard and in a highly congested area and adding plate area would be very difficult.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Hutsonville plant. Both units would be considered good candidates for retrofit/repowering because of their small boiler sizes.

7.2.4 Meredosia Steam Plant

The Meredosia steam plant is located in Morgan County, Illinois, as part of the Central Illinois Public Service Company system. The plant contains six boilers; five are coal-fired and one primarily fires oil. Units 1 to 5 have a net generating capacity of 354 MW. Unit 6 was not considered for FGD retrofit.

Table 7.2.4-1 presents operational data for the existing equipment at the Meredosia steam plant. Boilers 1-5 burn medium sulfur coal. Coal is delivered by truck from a local mine. Barge unloading facilities are also available on-site but no longer are used. The coal is stored in an area southeast of the plant.

PM emissions for units 1-5 are controlled with retrofit ESPs located behind each unit. Ash from the units is wet sluiced to ponds located south of the plant beside the coal pile. Units 1-4 are served by a common chimney located southeast of unit 1. Units 5 and 6 each have separate chimneys.

Lime/Limestone and Lime Spray Drying FGD Costs--

The switchyard is located behind the unit 1-4 ESPs making it impossible to place FGD absorbers behind these units. Therefore, the unit 1-4 absorbers were located south of the chimney, close to the coal pile. This location blocks the entrance to the plant; as such, a major plant road has to be relocated to make it possible to access the plant. Absorbers for

TABLE 7.2.4-1. MEREDOSIA STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1-4	5	6
GENERATING CAPACITY (MW,COMBINED)	115	239	210
CAPACITY FACTOR (PERCENT)	18-10	55	
INSTALLATION DATE	1948	1960	1975
FIRING TYPE	TANG	TANG	
FURNACE VOLUME (1000 CU FT)	NA	128.5	
LOW NOx COMBUSTION	NO	NO	
COAL SULFUR CONTENT (PERCENT)	2.6	2.6	OIL
COAL HEATING VALUE (BTU/LB)	11000	11000	BURNING
COAL ASH CONTENT (PERCENT)	8.0	8.0	UNIT
FLY ASH SYSTEM	WET SLUICE		
ASH DISPOSAL METHOD	POND/ON-SITE		
STACK NUMBER	1	2	3
COAL DELIVERY METHODS	TRUCK		
PARTICULATE CONTROL			
TYPE	ESP	ESP	NA
INSTALLATION DATE	1972	1970	
EMISSION (LB/MM BTU)	0.07	0.11	
REMOVAL EFFICIENCY	98.0	97.0	
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	2.9	2.9	
SURFACE AREA (1000 SQ FT)	54.7	116.6	
GAS EXIT RATE (1000 ACFM)	145	750	
SCA (SQ FT/1000 ACFM)	377	155	
OUTLET TEMPERATURE (°F)	390	289	

unit 5 were placed behind the unit to the north of the switchyard and the storage building. The limestone preparation/storage area and waste handling area were placed in an area remote from the absorbers east of the plant. A 10 percent general facilities was assigned to units 1-4 because of the entrance road relocation and 8 percent was assigned to unit 5 for general facilities due to relocation of a plant road.

Absorbers for units 1-4 were located close to the units in a high access/congestion area surrounded by a chimney, the coal pile, the coal conveyor, and the switchyard. Unit 5 absorbers were located in an open space to the north side of the switchyard with few access/congestion problems.

Because the absorbers for units 1-4 are located close to the chimney, short duct lengths would be required (less than 300 feet). Absorbers for unit 5 were located away from the chimney and north of the switchyard. Because the chimney is between the boiler and the ESPs, a duct length of about 500 feet was required with a high site access/congestion factor.

The LSD-FGD technology considered was LSD with reuse of the existing ESPs for units 1-4. Because the unit 5 ESPs are small (SCA =155) reuse of the existing ESPs would not be possible. Unit 5 burns a high sulfur coal; as such, LSD with a new baghouse option was not considered. LSD absorbers for units 1-4 would be located in the same location as conventional FGD absorbers and would have similar site access/congestion factors. Less than 600 feet and about 700 feet of duct lengths would be required for units 1-2 and 3-4, respectively, to be able to reuse the ESPs. A high access/congestion factor was assigned for ESP upgrades and for flue gas handling due to space limitation around the ESPs created by the chimney and switchyard.

The major scope adjustment costs and estimated retrofit factors for the FGD control technologies are presented in Tables 7.2.4-2 and 7.2.4-3. Table 7.2.4-4 presents the capital and operating costs for commercial FGD technologies. The low cost FGD option shows the reduced capital cost that occurs when eliminating spare absorbers and maximizing absorber size.

TABLE 7.2.4-2. SUMMARY OF RETROFIT FACTOR DATA FOR MEREDOSIA UNIT 1,2,3 OR 4

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	NA	HIGH
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE (1-2)			300-600
ESP REUSE (3-4)			600-1000
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	299	NA	299
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.55	NA	
ESP REUSE CASE (1,2; 3,4)			1.69,1.83
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	0	10

TABLE 7.2.4-3. SUMMARY OF RETROFIT FACTOR DATA FOR MEREDOSIA UNIT 5

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	NA
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			NA
BAGHOUSE			NA
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NA
ESTIMATED COST (1000$)	2047	NA	NA
NEW CHIMNEY	NO	NA	NA
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.46	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	0	0

Table 7.2.4-4. Summary of FGD Control Costs for the Meredosia Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1-4	1.55	115	15	2.6	55.7	484.1	20.8	137.6	90.0	3152	6598.2
L/S FGD	5	1.46	239	55	2.6	76.0	317.8	35.1	30.5	90.0	24021	1461.4
L/S FGD-C	1-4	1.55	115	15	2.6	55.7	484.1	12.2	80.5	90.0	3152	3859.5
L/S FGD-C	5	1.46	239	55	2.6	76.0	317.8	20.5	17.8	90.0	24021	851.5
LC FGD	1-4	1.55	115	15	2.6	38.9	338.1	15.3	100.9	90.0	3152	4839.2
LC FGD	5	1.46	239	55	2.6	59.0	247.0	29.6	25.7	90.0	24021	1230.2
LC FGD-C	1-4	1.55	115	15	2.6	38.9	338.1	8.9	59.0	90.0	3152	2827.9
LC FGD-C	5	1.46	239	55	2.6	59.0	247.0	17.2	14.9	90.0	24021	715.8
LSD+ESP	1, 2	1.69	29	18	2.6	10.7	367.9	5.8	126.4	76.0	809	7149.0
LSD+ESP	3, 4	1.83	29	10	2.6	11.4	392.0	5.9	232.2	76.0	449	13128.9
LSD+ESP-C	1, 2	1.69	29	18	2.6	10.7	367.9	3.4	73.5	76.0	809	4155.0
LSD+ESP-C	3, 4	1.83	29	10	2.6	11.4	392.0	3.4	135.0	76.0	449	7635.5

Coal Switching and Blending--

Table 7.2.4-5 presents the IAPCS results for CS at the Meredosia plant. These costs do not include reduced pulverizer operating costs or system modifications that may be necessary to handle deep cleaned coal. PCC was assumed to occur at the mine and was not evaluated here.

Low NO_x Combustion--

Units 1-5 are dry bottom, tangential-fired boilers. The combustion modification technique applied to boilers 1-5 was OFA. Tables 7.2.4-6 and 7.2.4-7 present the performance and cost results of retrofitting OFA at the Meredosia plant.

Selective Catalytic Reduction--

For units 1-4, the cold side reactors were located beside the chimney in an area of low access/congestion and 150 feet of duct length was estimated for the flue gas handling system. For unit 5, about 500 feet of duct length was required. All reactors were assumed to be in areas with high underground obstructions. Part of the parking area and a road beside the unit 1-4 chimney would be relocated for placement of the SCR reactors; as such, a factor of 20 percent was assigned to general facilities. For unit 5, a plant road must be relocated; therefore, 15 percent was assigned to general facilities. The ammonia storage system was placed northeast of the switchyard beside the sorbent preparation area.

Table 7.2.4-6 presents the SCR retrofit results for all units. Table 7.2.4-7 presents the cost results for retrofitting SCR at this plant.

Duct Spray Drying and Furnace Sorbent Injection--

The retrofit of DSD and FSI technologies at Meredosia plant would be possible for units 1-4 if the first ESP section could be modified to provide sufficient duct residence time for humidification or sorbent injection. Retrofit of DSD and FSI with reuse of the existing ESPs would not be possible for unit 5 because of the small SCA (<200) and insufficient duct residence time.

Table 7.2.4-8 presents a summary of site access/congestion factors, scope adders, and plant retrofit factors for DSD and FSI technologies at the

Table 7.2.4-5. Summary of Coal Switching/Cleaning Costs for the Meredosia Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1, 2	1.00	29	18	2.6	1.8	62.9	1.2	25.7	69.0	730	1611.9
CS/B+$15	3, 4	1.00	29	10	2.6	1.8	62.9	0.9	34.2	69.0	405	2141.4
CS/B+$15	5	1.00	239	55	2.6	9.6	40.1	17.5	15.2	69.0	18375	949.8
CS/B+$15-C	1, 2	1.00	29	18	2.6	1.8	62.9	0.7	14.9	69.0	730	934.6
CS/B+$15-C	3, 4	1.00	29	10	2.6	1.8	62.9	0.5	19.9	69.0	405	1247.0
CS/B+$15-C	5	1.00	239	55	2.6	9.6	40.1	10.0	8.7	69.0	18375	546.5
CS/B+$5	1, 2	1.00	29	18	2.6	1.5	52.5	0.7	16.3	69.0	730	1022.1
CS/B+$5	3, 4	1.00	29	10	2.6	1.5	52.5	0.6	23.8	69.0	405	1493.6
CS/B+$5	5	1.00	239	55	2.6	7.1	29.8	7.5	6.5	69.0	18375	408.6
CS/B+$5-C	1, 2	1.00	29	18	2.6	1.5	52.5	0.4	9.5	69.0	730	594.9
CS/B+$5-C	3, 4	1.00	29	10	2.6	1.5	52.5	0.4	13.9	69.0	405	872.5
CS/B+$5-C	5	1.00	239	55	2.6	7.1	29.8	4.3	3.8	69.0	18375	235.8

TABLE 7.2.4-6. SUMMARY OF NOx RETROFIT RESULTS FOR MEREDOSIA

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1-4	5
FIRING TYPE	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA
FURNACE VOLUME (1000 CU FT)	NA	128.5
BOILER INSTALLATION DATE	1948	1960
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	25	25
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	30	52
New Duct Length (Feet)	150	500
New Duct Costs (1000$)	807	4125
New Heat Exchanger (1000$)	2027	3144
TOTAL SCOPE ADDER COSTS (1000$)	2863	7320
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	20	15

Table 7.2.4-7. NOx Control Cost Results for the Meredosia Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	1,2	1.00	29	18	2.6	0.4	13.0	0.1	1.8	25.0	39	2102.2
LNC-OFA	3,4	1.00	29	10	2.6	0.4	13.0	0.1	3.2	25.0	22	3784.0
LNC-OFA	5	1.00	239	55	2.6	0.9	3.7	0.2	0.2	25.0	987	194.3
LNC-OFA-C	1,2	1.00	29	18	2.6	0.4	13.0	0.0	1.1	25.0	39	1247.6
LNC-OFA-C	3,4	1.00	29	10	2.6	0.4	13.0	0.0	1.9	25.0	22	2245.6
LNC-OFA-C	5	1.00	239	55	2.6	0.9	3.7	0.1	0.1	25.0	987	115.3
SCR-3	1-4	1.16	115	15	2.6	20.7	180.0	6.7	44.6	80.0	415	16250.8
SCR-3	5	1.16	239	55	2.6	37.9	158.6	12.8	11.1	80.0	3159	4063.8
SCR-3-C	1-4	1.16	115	15	2.6	20.7	180.0	4.0	26.2	80.0	415	9534.4
SCR-3-C	5	1.16	239	55	2.6	37.9	158.6	7.5	6.5	80.0	3159	2382.1
SCR-7	1-4	1.16	115	15	2.6	20.7	180.0	5.8	38.2	80.0	415	13941.2
SCR-7	5	1.16	239	55	2.6	37.9	158.6	10.8	9.4	80.0	3159	3434.0
SCR-7-C	1-4	1.16	115	15	2.6	20.7	180.0	3.4	22.5	80.0	415	8211.3
SCR-7-C	5	1.16	239	55	2.6	37.9	158.6	6.4	5.5	80.0	3159	2021.2

TABLE 7.2.4-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR MEREDOSIA UNIT 1, 2, 3 OR 4

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	299
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	12
TOTAL COST (1000$)	
ESP UPGRADE CASE	311
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Meredosia steam plant. Table 7.2.4-9 presents the cost estimated to retrofit DSD and FSI at the Meredosia plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

Boilers 1-5 at Meredosia would be considered good candidates for repowering or retrofit because of their small sizes. However, the congestion at this site will increase the cost of any major construction effort.

7.2.5 Newton Steam Plant

The Newton steam plant is located within Jasper County, Illinois, as part of the Central Illinois Public Service Company system. The plant contains two coal-fired boilers with a total gross generating capacity of 1,165 MW. Figure 7.2.5-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 7.2.5-1 presents operational data for the existing equipment at the Newton plant. Unit 1 is equipped with an FGD unit and unit 2 burns a low sulfur NSPS compliance coal. Coal shipments are received by railroad and conveyed to a coal storage and handling area located west of the plant.

Particulate matter emissions for the boilers are controlled with ESPs located behind each unit. The fly ash handling system is dry.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 7.2.5-1 shows the general layout and location of the FGD control system. Unit 1 has an FGD system and the process is dual-alkali built by General Electric Environmental Services. The absorbers for L/LS-FGD and LSD-FGD for unit 2 would be located between the powerhouse and chimney in a large open area. No demolition/relocation would be required; therefore, a factor of 5 percent was assigned to general facilities. The existing limestone storage/handling area and waste handling area for unit 1 would be expanded and used for unit 2 also.

Table 7.2.4-9. Summary of DSD/FSI Control Costs for the Meredosia Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1, 2	1.00	29	18	2.6	4.3	148.7	3.9	85.0	49.0	516	7538.8
DSD+ESP	3, 4	1.00	29	10	2.6	4.6	158.8	3.9	151.7	49.0	287	13450.8
DSD+ESP-C	1, 2	1.00	29	18	2.6	4.3	148.7	2.2	49.1	49.0	516	4356.8
DSD+ESP-C	3, 4	1.00	29	10	2.6	4.6	158.8	2.2	87.7	49.0	287	7778.8
FSI+ESP-50	1, 2	1.00	29	18	2.6	5.1	174.3	2.9	62.5	50.0	530	5394.1
FSI+ESP-50	3, 4	1.00	29	10	2.6	5.1	174.3	2.7	106.8	50.0	294	9215.1
FSI+ESP-50-C	1, 2	1.00	29	18	2.6	5.1	174.3	1.7	36.3	50.0	530	3133.2
FSI+ESP-50-C	3, 4	1.00	29	10	2.6	5.1	174.3	1.6	62.1	50.0	294	5356.5
FSI+ESP-70	1, 2	1.00	29	18	2.6	5.1	177.4	2.9	63.2	70.0	742	3894.0
FSI+ESP-70	3, 4	1.00	29	10	2.6	5.1	177.4	2.7	107.9	70.0	412	6647.5
FSI+ESP-70-C	1, 2	1.00	29	18	2.6	5.1	177.4	1.7	36.7	70.0	742	2262.1
FSI+ESP-70-C	3, 4	1.00	29	10	2.6	5.1	177.4	1.6	62.7	70.0	412	3864.6

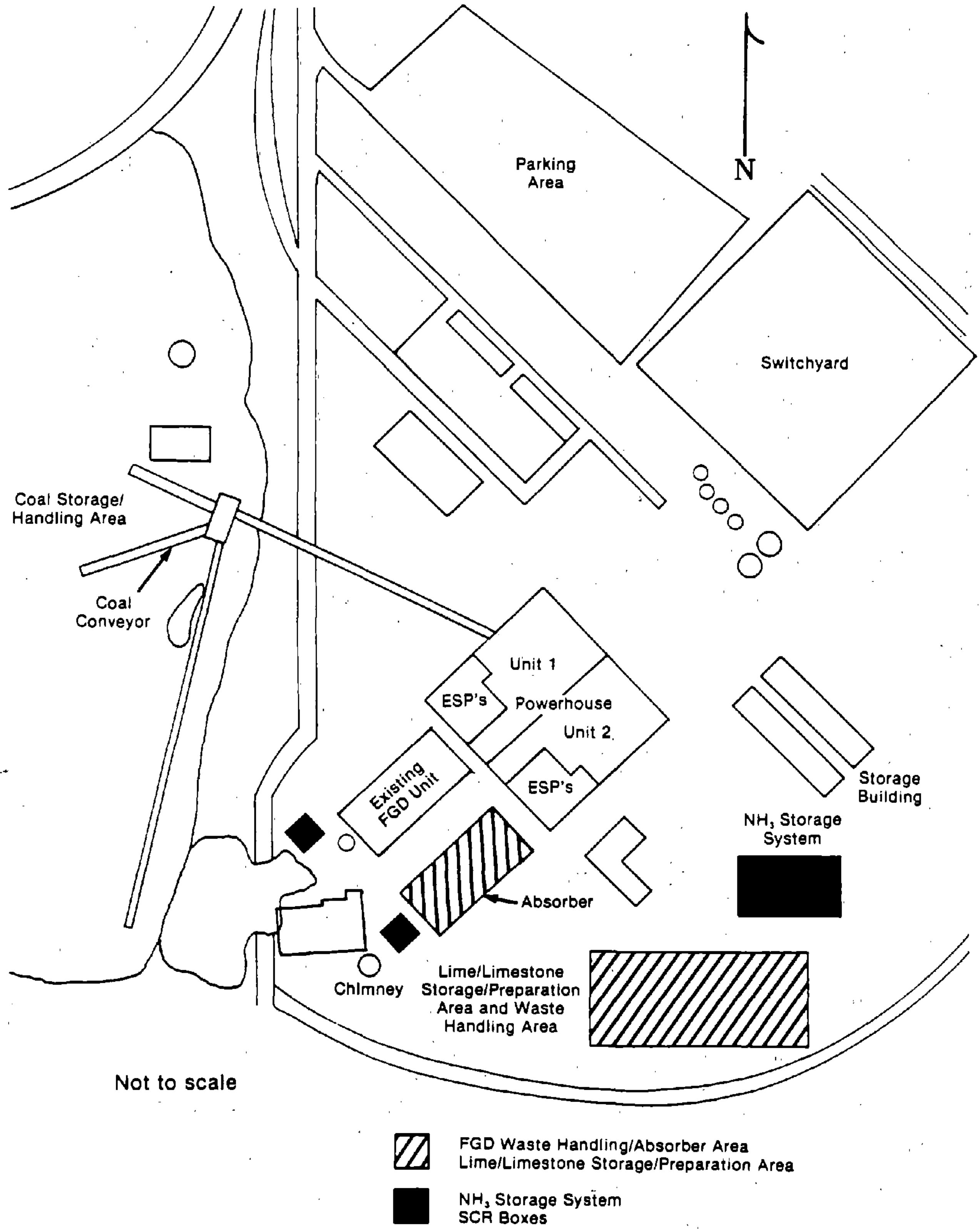

Figure 7.2.5-1. Newton plant plot plan

TABLE 7.2.5-1. NEWTON STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2
GENERATING CAPACITY (MW)	590	575
CAPACITY FACTOR (PERCENT)	50	29
INSTALLATION DATE	1977	1982
FIRING TYPE	TANG	TANG
COAL SULFUR CONTENT (PERCENT)	2.4	0.6
COAL HEATING VALUE (BTU/LB)	11618	1130
COAL ASH CONTENT (PERCENT)	10.8	6.3
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	ON-SITE LANDFILL	
STACK NUMBER	1	2
COAL DELIVERY METHODS	RAILROAD	
FGD SYSTEM	YES	NO
INSTALLATION DATE	1979	-
FGD TYPE	DUAL ALKALI	-
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1977	1982
EMMISION (LB/MM BTU)	0.05	0.07
REMOVAL EFFICIENCY	99.2	99.8
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	4.0	4.0
SURFACE AREA (1000 SQ FT)	642.6	783.4
GAS FLOW (1000 ACFM)	2290	2771.4
SCA (SQ FT/1000 ACFM)	280	282
OUTLET TEMPERATURE (°F)	310	310

Retrofit Difficulty and Scope Adder Costs--

A low site access/congestion factor was assigned to the absorber locations due to the absorbers being located in an open area close to the chimney with no major obstacles or obstructions.

For flue gas handling, a short to moderate duct run for the unit would be required for L/LS-FGD cases to divert the flue gas from the boiler to the absorbers and back to the chimney. A low site access/congestion factor was assigned to the flue gas handling system due to no major obstacles or obstructions in the surrounding area.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Table 7.2.5-2. No large scope adder cost is required for the Newton plant. The overall retrofit factor determined for the L/LS-FGD cases was low (1.24).

The absorbers for LSD-FGD would be located in a similar location as in L/LS-FGD cases. The technology evaluated at Newton was LSD with ESP reuse. This technology was selected because of the moderate SCA size (>280). For flue gas handling for LSD cases, a moderate duct run would be required to divert flue gas from the upstream of the ESPs to the absorbers and back to the ESPs. A low site access/congestion factor was assigned to the LSD-FGD flue gas handling system. The retrofit factor determined for the LSD technology case was low (1.27) and did not include particulate control upgrading costs. A separate retrofit factor was developed for upgrading the ESPs and was low (1.16) due to the available space around the ESPs. This factor was used in the IAPCS model to estimate particulate control costs.

Table 7.2.5-3 presents the cost estimates for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs for boiler 2. The low cost control case reduces capital and annual operating costs. The significant reduction in costs is primarily due to the benefits of economies-of-scale when combining process areas, elimination of spare scrubber, and optimization of scrubber size.

It is unlikely that unit 2 would remain firing a low sulfur coal if retrofit of FGD was desired. If the unit was switched to burning the coal fired at unit 1, the annual cost would increase by 18 percent and the SO_2 cost effectiveness would decrease by 70 percent.

TABLE 7.2.5-2. SUMMARY OF RETROFIT FACTOR DATA FOR NEWTON UNIT 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			LOW
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	100-300	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NO	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.24	1.24	
ESP REUSE CASE			1.27
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	5	5

Table 7.2.5-3. Summary of FGD Control Costs for the Newton Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	2	1.24	575	29	0.6	100.4	174.6	40.6	27.8	90.0	6604	6151.5
L/S FGD-C	2	1.24	575	29	0.6	100.4	174.6	23.7	16.2	90.0	6604	3592.6
LC FGD	2	1.24	575	29	0.6	79.7	138.7	33.9	23.2	90.0	6604	5133.3
LC FGD-C	2	1.24	575	29	0.6	79.7	138.7	19.8	13.5	90.0	6604	2995.2
LSD+ESP	2	1.27	575	29	0.6	56.5	98.3	21.5	14.7	76.0	5599	3841.7
LSD+ESP-C	2	1.27	575	29	0.6	56.5	98.3	12.6	8.6	76.0	5599	2246.3

Coal Switching Costs--

Newton plant unit 1 has an FGD system and unit 2 has already switched to a low sulfur coal and, as such, they would not be considered in this study.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Newton steam plant. These controls include LNC modification and SCR. The application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2. The NO_x technologies evaluated at the steam plant were: OFA and SCR.

Low NO_x Combustion--

Units 1 and 2 are dry bottom, tangential-fired boilers rated at 590 and 575 MW, respectively. The combustion modification technique applied for this evaluation was OFA. As Table 7.2.5-4 shows, the OFA NO_x reduction performance for each unit was estimated to be 25 percent. This reduction performance level was assessed by examining the effects of heat release rates ad furnace residence time on NO_x reduction through the use of the simplified NO_x procedures. Table 7.2.5-5 presents the cost of retrofitting OFA at the Newton boilers.

Selective Catalytic Reduction--

Table 7.2.5-4 presents the SCR retrofit results for each unit. The results include process area retrofit factors and scope adder costs. The scope adders include costs estimated for ductwork demolition, new flue gas heat exchanger, and new duct runs to divert the flue gas from the FGD absorbers for unit 1 and from the ESPs for unit 2 to each reactor and from each reactor to the chimney.

The SCR reactor for unit 1 would be located to the west of the FGD absorbers for unit 1 in an open area with no major obstacles; whereas, the SCR reactor for unit 2 would be located between the powerhouse and the chimney in a large open area. Because both reactors are in relatively open areas with no major obstructions, the reactors for units 1 and 2 were assigned low access/congestion factors. A general facility factor of 17 percent was assigned to the reactor for unit 1 because a road would need

TABLE 7.2.5-4. SUMMARY OF NOx RETROFIT RESULTS FOR NEWTON

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1	2
FIRING TYPE	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	10.7	10.7
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	72.8	72.8
FURNACE RESIDENCE TIME (SECONDS)	3.94	3.7
ESTIMATED NOx REDUCTION (PERCENT)	25	25
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	102	100
New Duct Length (Feet)	300	300
New Duct Costs (1000$)	4199	4136
New Heat Exchanger (1000$)	5407	5324
TOTAL SCOPE ADDER COSTS (1000$)	9708	9560
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	17	13

Table 7.2.5-5. NOx Control Cost Results for the Newton Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	1	1.00	590	50	2.4	1.3	2.1	0.3	0.1	25.0	2080	132.2
LNC-OFA	2	1.00	575	29	0.6	1.2	2.2	0.3	0.2	25.0	1176	231.6
LNC-OFA-C	1	1.00	590	50	2.4	1.3	2.1	0.2	0.1	25.0	2080	78.5
LNC-OFA-C	2	1.00	575	29	0.6	1.2	2.2	0.2	0.1	25.0	1176	137.4
SCR-3	1	1.16	590	50	2.4	72.5	122.9	26.6	10.3	80.0	6657	4001.5
SCR-3	2	1.16	575	29	0.6	70.1	122.0	25.2	17.3	80.0	3763	6702.3
SCR-3-C	1	1.16	590	50	2.4	72.5	122.9	15.6	6.0	80.0	6657	2341.4
SCR-3-C	2	1.16	575	29	0.6	70.1	122.0	14.8	10.1	80.0	3763	3923.5
SCR-7	1	1.16	590	50	2.4	72.5	122.9	21.8	8.4	80.0	6657	3269.8
SCR-7	2	1.16	575	29	0.6	70.1	122.0	20.5	14.0	80.0	3763	5440.7
SCR-7-C	1	1.16	590	50	2.4	72.5	122.9	12.8	5.0	80.0	6657	1922.2
SCR-7-C	2	1.16	575	29	0.6	70.1	122.0	12.0	8.2	80.0	3763	3200.7

to be relocated. Both reactors were assumed to be in areas with high underground obstructions. The ammonia storage system was placed in a remote area having a low access/congestion factor.

As discussed in Section 2, all NO_x control techniques were evaluated independently from those evaluated for SO_2 control. For unit 1, the results for SCR presented in Table 7.2.5-4 would remain unchanged since NO_x is the only pollutant needed to be controlled. For unit 2, the FGD absorbers were located in the same area as the SCR reactors. If both SO_2 and NO_x emissions needed to be reduced for this unit, the SCR reactor would have to be located downstream of the FGD absorbers (i.e., south of the chimney for unit 2) in an area having little obstructions and easy access. A low access/congestion factor again would be assigned to this SCR reactor. Table 7.2.5-5 presents the estimated cost of retrofitting SCR at the Newton boilers.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas were located in a similar fashion as LSD-FGD. The retrofit of FSI technology at the Newton steam plant for unit 2 would be easy. The ESPs are located in a low site access/congestion area and the upgraded ESPs could handle the increased load from FSI. A low retrofit factor (1.13) was assigned to the upgraded ESPs location for FSI. However, a combined particulate and SO_2 removal concept provides an alternative and low cost method to the new baghouse option. The ESPs can be used not only to collect particulate matter but to remove SO_2 as well (E-SO_x technology). Table 7.2.5-6 presents a summary of the site access/congestion factors for DSD and FSI technologies at the Newton steam plant. Table 7.2.5-7 presents the cost estimated to retrofit DSD and FSI at the Newton plant.

TABLE 7.2.5-6. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR NEWTON UNIT 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	LOW
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	111
TOTAL COST (1000$)	
ESP UPGRADE CASE	111
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.13
NEW BAGHOUSE	NA

Table 7.2.5-7. Summary of DSD/FSI Control Costs for the Newton Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	2	1.00	575	29	0.6	14.5	25.2	8.8	6.0	49.0	3570	2467.4
DSD+ESP-C	2	1.00	575	29	0.6	14.5	25.2	5.1	3.5	49.0	3570	1431.9
FSI+ESP-50	2	1.00	575	29	0.6	16.7	29.1	8.1	5.5	50.0	3669	2207.8
FSI+ESP-50-C	2	1.00	575	29	0.6	16.7	29.1	4.7	3.2	50.0	3669	1285.4
FSI+ESP-70	2	1.00	575	29	0.6	16.7	29.0	8.1	5.6	70.0	5137	1582.5
FSI+ESP-70-C	2	1.00	575	29	0.6	16.7	29.0	4.7	3.2	70.0	5137	921.2

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Newton plant. The unit 2 boiler would not be considered a good candidate for AFBC retrofit because of its large size (575 MW).

7.3 COMMONWEALTH EDISON COMPANY

7.3.1 Joliet 29 Steam Plant

Although retrofit factors were developed for units 7 and 8 at the Joliet 29 plant, costs are not presented since the low sulfur coal being fired would result in low captial/operating costs and high cost per ton of SO_2 removed. CS was not evaluated because the plant is currently burning a low sulfur coal. Sorbent injection technologies (FSI and DSD) were not considered for any boilers at the Joliet 29 plant due to the short duct residence time between the boilers and their respective ESPs and the small sizes of the ESPs.

TABLE 7.3.1-1. JOLIET 29 STEAM PLANT OPERATIONAL DATA *

UNIT NUMBER	7	8
BOILER NUMBER	71,72	81,82
GENERATING CAPACITY (MW/UNIT)	550	550
CAPACITY FACTOR (PERCENT)	30	29
INSTALLATION DATE	1965	1966
FIRING TYPE	TANGENTIAL	
FURNACE VOLUME (1000 CU FT)	510	510
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	0.44	0.45
COAL HEATING VALUE (BTU/LB)	9500	9500
COAL ASH CONTENT (PERCENT)	6.7	6.7
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	PAID/OFF-SITE	
STACK NUMBER	1	2
COAL DELIVERY METHODS	TRAIN	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1965	1966
EMISSION (LB/MM BTU)	0.03	0.04
REMOVAL EFFICIENCY	99.2	98.87
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	NA	NA
SURFACE AREA (1000 SQ FT)	139.4	139.4
EXIT GAS FLOW RATE (1000 ACFM)	856.3	856.3
SCA (SQ FT/1000 ACFM)	163	163
OUTLET TEMPERATURE (°F)	287	287

* Some information was obtained from plant personnel.

TABLE 7.3.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR JOLIET 29 UNIT 7 OR 8 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	MEDIUM
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			MEDIUM
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	MEDIUM
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	NA	NO
ESTIMATED COST (1000$)	3850	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.48	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.44
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.36
GENERAL FACILITIES (PERCENT)	10	0	10

* L/S-FGD absorbers, LSD-FGD absorbers, and new FFs would be located northeast of the unit 7 chimney for unit 7 and southwest of the unit 8 chimney for unit 8.

TABLE 7.3.1-3. SUMMARY OF NOx RETROFIT RESULTS FOR JOLIET 29

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	71,72,81,82
FIRING TYPE	TANG
TYPE OF NOx CONTROL	OFA
FURNACE VOLUME (1000 CU FT)	510
BOILER INSTALLATION DATE	1965
SLAGGING PROBLEM	NO
ESTIMATED NOx REDUCTION (PERCENT)	25
SCR RETROFIT RESULTS *	
UNIT NUMBER	7 OR 8
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	97
New Duct Length (Feet)	200
New Duct Costs (1000$)	2687
New Heat Exchanger (1000$)	5184
TOTAL SCOPE ADDER COSTS (1000$)	7967
RETROFIT FACTOR FOR SCR	1.34
GENERAL FACILITIES (PERCENT)	38

* Cold side SCR reactors for unit 7 would be located behind the unit 7 chimney, and the reactors for unit 8 would be located behind the unit 8 chimney.

Table 7.3.1-4. NOx Control Cost Results for the Joliet 29 Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	71,72	1.00	225	30	0.4	0.9	3.8	0.2	0.3	25.0	600	308.6
LNC-OFA	81,82	1.00	225	29	0.4	0.9	3.8	0.2	0.3	25.0	580	319.3
LNC-OFA-C	71,72	1.00	225	30	0.4	0.9	3.8	0.1	0.2	25.0	600	183.2
LNC-OFA-C	81,82	1.00	225	29	0.4	0.9	3.8	0.1	0.2	25.0	580	189.6
SCR-3	7	1.34	550	30	0.4	77.7	141.3	27.0	18.7	80.0	4692	5765.7
SCR-3	8	1.34	550	29	0.4	77.7	141.3	27.0	19.3	80.0	4535	5957.8
SCR-3-C	7	1.34	550	30	0.4	77.7	141.3	15.8	11.0	80.0	4692	3377.6
SCR-3-C	8	1.34	550	29	0.4	77.7	141.3	15.8	11.3	80.0	4535	3490.2
SCR-7	7	1.34	550	30	0.4	77.7	141.3	22.4	15.5	80.0	4692	4768.5
SCR-7	8	1.34	550	29	0.4	77.7	141.3	22.3	16.0	80.0	4535	4926.2
SCR-7-C	7	1.34	550	30	0.4	77.7	141.3	13.2	9.1	80.0	4692	2806.3
SCR-7-C	8	1.34	550	29	0.4	77.7	141.3	13.1	9.4	80.0	4535	2899.2

7.3.2 Kincaid Steam Plant

The Kincaid steam plant is located within Christian County, Illinois, as part of the Commonwealth Edison Company system. The plant contains two coal-fired boilers with a total gross generating capacity of 1,182 MW (originally designed for 1,320 MW). Figure 7.3.2-1 presents the plot plan used in the evaluation.

Table 7.3.2-1 presents operational data for the existing equipment at the plant. Both boilers burn high sulfur coal (3.3 percent sulfur). Coal is conveyed from a nearby mine to the storage/handling area located west of the plant.

Particulate matter emissions for the boilers at Kincaid are controlled with retrofit ESPs located behind (south) the old ESPs/chimneys. Fly ash from the boilers is handled dry and disposed of in an adjacent mine (coal source).

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 7.3.2-1 shows the general layout and location of the FGD control system. The absorbers for the boilers were located south of the powerhouse and adjacent to the existing retrofit ESPs for both L/LS and LSD-FGD technologies. The limestone preparation/storage area was placed to the east of the absorber for unit 2, west of the run-off storage basin and standby pond. The waste handling area was temporarily located to the west of the unit 1 absorber. Since the employee parking area would be relocated in order to make more space available for the location of the absorbers in the location discussed above, a factor of 10 percent was assigned to general facilities.

Retrofit Difficulty and Scope Adder Costs--

At the Kincaid plant the boilers are located west to east, side by side, and the retrofit ESPs sit directly behind (south) the old chimneys for each unit. A recently built chimney is shared by both units.

The absorbers were located in a general area south of the plant. They were located, more specifically, on both sides (west and east) of the retrofit ESPs. In addition, the absorber for unit 1 was located west of

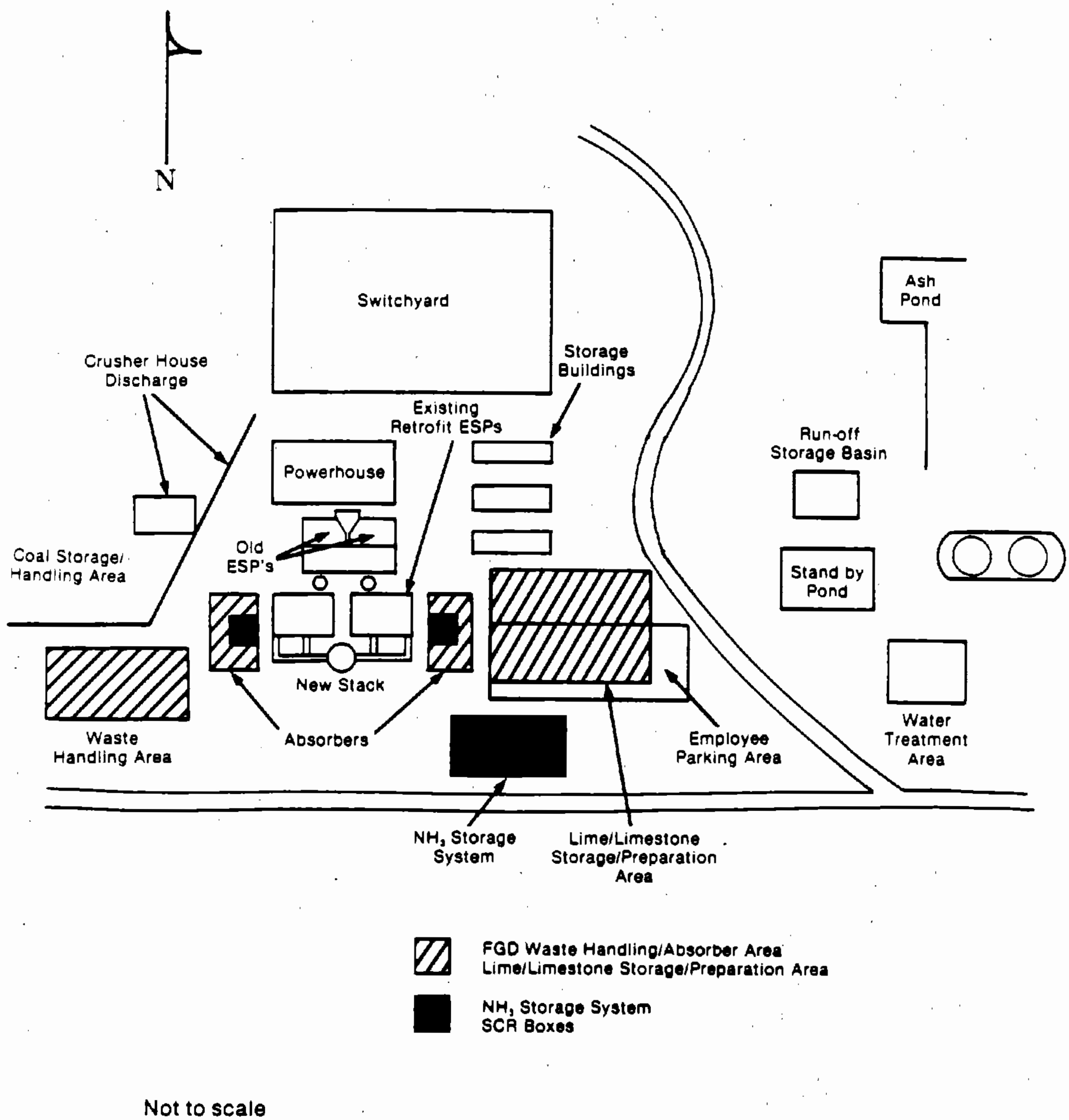

Figure 7.3.2-1. Kincaid plant plot plan

TABLE 7.3.2-1. KINCAID STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2
GENERATING CAPACITY (MW-each)	591
CAPACITY FACTOR (PERCENT)	46, 39
INSTALLATION DATE	1967,68
FIRING TYPE	CYCLONE
FURNACE VOLUME (1000 CU FT)	436
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	3.3
COAL HEATING VALUE (BTU/LB)	10300
COAL ASH CONTENT (PERCENT)	9.9
FLY ASH SYSTEM	PAID DRY DISPOSAL
ASH DISPOSAL METHOD	OFF-SITE
STACK NUMBER	1
COAL DELIVERY METHODS	CONVEYOR NEARBY COAL MINE
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1967,1982
EMISSION (LB/MM BTU)	0.05
REMOVAL EFFICIENCY	98.7
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	4.0
SURFACE AREA (1000 SQ FT)	851.6
GAS EXIT RATE (1000 ACFM)	2400
SCA (SQ FT/1000 ACFM)	355
OUTLET TEMPERATURE (°F)	310

the unit ESPs and the absorber for unit 2 was located to the east of its respective ESPs. Neither absorber would be congested by any major equipment, plant roads, etc.

Low site access/congestion factors were assigned to both absorber areas for all FGD technologies because no significant obstacles would surround the absorbers and no underground obstructions appear to exist in the designated location. Also, low site access/congestion factors were assigned to flue gas handling for both boilers for all FGD technologies because adequate space is available around the retrofit ESPs and chimney. A medium ductwork tie-in distance would be necessary for the retrofit of FGD technologies at the plant.

The major scope adjustment costs and estimated retrofit factors for the FGD control technologies are presented in Table 7.3.2-2. There are no significant scope adjustments and related costs required for the retrofit of FGD control technologies at Kincaid. The overall retrofit factors determined for the L/LS-FGD cases were low to moderate (1.31).

The LSD with ESP reuse was the only LSD-FGD case evaluated because the SCAs are large (468). The overall retrofit factor determined for the LSD-FGD cases was also low (1.27) excluding particulate control costs. The particulate control upgrade factor was low (1.16), reflecting the space available around the existing ESPs. This factor would be used in the IAPCS model if any additional plate area increase is required.

Table 7.3.2-3 presents the cost estimates for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs for boilers 1 and 2.

The low cost control case reduces capital and annual operating costs. The significant reduction in costs is primarily due to the benefits of economies-of-scale when combining process areas, elimination of spare scrubber, and optimization of scrubber size. However, there might be higher operating risks associated with this approach.

Coal Switching and Physical Coal Cleaning Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be

TABLE 7.3.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR KINCAID UNITS 1-2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			LOW
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NO	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER (WASTE DISPOSAL)	YES	NO	YES
RETROFIT FACTORS			
FGD SYSTEM	1.41	1.31	
ESP REUSE CASE			1.37
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	10	10

Table 7.3.2-3. Summary of FGD Control Costs for the Kincaid Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.41	591	46	3.3	146.7	248.2	68.8	28.9	90.0	67998	1012.3
L/S FGD	2	1.41	591	39	3.3	146.7	248.2	65.8	32.6	90.0	57650	1140.8
L/S FGD-C	1	1.41	591	46	3.3	146.7	248.2	40.1	16.8	90.0	67998	589.7
L/S FGD-C	2	1.41	591	39	3.3	146.7	248.2	38.3	19.0	90.0	57650	665.0
LC FGD	1-2	1.41	1182	43	3.3	220.6	186.7	108.4	24.4	90.0	127126	853.0
LC FGD-C	1-2	1.41	1182	43	3.3	220.6	186.7	63.1	14.2	90.0	127126	496.5
LSD+ESP	1	1.37	591	46	3.3	123.4	208.9	51.2	21.5	74.0	56134	912.8
LSD+ESP	2	1.37	591	39	3.3	123.4	208.9	49.1	24.3	74.0	47592	1030.7
LSD+ESP-C	1	1.37	591	46	3.3	123.4	208.9	29.9	12.6	74.0	56134	532.8
LSD+ESP-C	2	1.37	591	39	3.3	123.4	208.9	28.7	14.2	74.0	47592	602.2

determined. This is particularly true for cyclone boilers; therefore, coal switching was not evaluated for the Kincaid plant.

Table 7.3.2-4 presents the IAPCS results for physical coal cleaning at the Kincaid plant. These costs do no include reduced pulverizer operating costs or system modifications that may be necessary to handle deep cleaned coal.

NO_x Control Technology Costs--

This section presents the performance and various related costs estimated for NO_x controls at Kincaid. These controls include LNC and SCR. The application of NO_x control technologies is affected by several site-specific factors which are discussed in Section 2. The NO_x technologies evaluated for the Kincaid station were: NGR and SCR.

Low NO_x Combustion--

Units 1 and 2 are wet bottom, cyclone-fired boilers rated at 591 MW each. The combustion modification technique applied to these units was NGR. Neither OFA nor LNB are applicable as NO_x combustion controls for cyclone boilers. As Table 7.3.2-5 shows, the NGR NO_x reduction performance for each unit was assumed to be 60 percent. Table 7.3.2-6 presents the cost of retrofitting NGR at the Kincaid plant.

Selective Catalytic Reduction--

Table 7.3.2-5 presents the SCR retrofit results for each unit. The results include process area retrofit difficulty factors and scope adder costs. The data includes scope adder costs estimated for ductwork demolition, new heat exchanger, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimney.

The reactors for units 1 and 2 were located south of the powerhouse behind the unit ESPs in a parking lot. This is a low access/congestion area with no significant underground obstructions. A general facilities factor of 25 percent was applied to both units, reflecting the need to replace part of the employee parking used to install the SCR reactors. The ammonia storage system, which would supply ammonia to the reactors to both units, was located southeast of the powerhouse in a relatively open area with no significant

Table 7.3.2-4. Summary of Coal Switching/Cleaning Costs for the Kincaid Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
PCC	1	1.00	591	46	3.3	39.4	66.6	17.4	7.3	23.0	17723	984.3
PCC	2	1.00	591	39	3.3	39.4	66.6	16.3	8.1	23.0	15026	1086.1
PCC-C	1	1.00	591	46	3.3	39.4	66.6	10.2	4.3	23.0	17723	573.9
PCC-C	2	1.00	591	39	3.3	39.4	66.6	9.5	4.7	23.0	15026	634.0

TABLE 7.3.2-5. SUMMARY OF NOx RETROFIT RESULTS FOR KINCAID

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1, 2
FIRING TYPE	CYCLONE
TYPE OF NOx CONTROL	NGR
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	NA
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	NA
FURNACE RESIDENCE TIME (SECONDS)	NA
ESTIMATED NOx REDUCTION (PERCENT)	60
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	102
New Duct Length (Feet)	450
New Duct Costs (1000$)	6304
New Heat Exchanger (1000$)	5412
TOTAL SCOPE ADDER COSTS (1000$)	11819
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	25

Table 7.3.2-6. NOx Control Cost Results for the Kincaid Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
NGR	1	1.00	591	46	3.3	8.5	14.3	13.5	5.7	60.0	11976	1130.5
NGR	2	1.00	591	39	3.3	8.5	14.3	11.6	5.8	60.0	10153	1146.8
NGR-C	1	1.00	591	46	3.3	8.5	14.3	7.8	3.3	60.0	11976	650.9
NGR-C	2	1.00	591	39	3.3	8.5	14.3	6.7	3.3	60.0	10153	660.8
SCR-3	1	1.16	591	46	3.3	77.0	130.4	28.7	12.1	80.0	15968	1800.2
SCR-3	2	1.16	591	39	3.3	77.0	130.3	28.4	14.0	80.0	13538	2095.0
SCR-3-C	1	1.16	591	46	3.3	77.0	130.4	16.8	7.1	80.0	15968	1053.0
SCR-3-C	2	1.16	591	39	3.3	77.0	130.3	16.6	8.2	80.0	13538	1225.8
SCR-7	1	1.16	591	46	3.3	77.0	130.4	23.8	10.0	80.0	15968	1489.1
SCR-7	2	1.16	591	39	3.3	77.0	130.3	23.4	11.6	80.0	13538	1728.1
SCR-7-C	1	1.16	591	46	3.3	77.0	130.4	14.0	5.9	80.0	15968	874.8
SCR-7-C	2	1.16	591	39	3.3	77.0	130.3	13.7	6.8	80.0	13538	1015.6

underground obstructions. Table 7.3.2-6 presents the estimated cost of retrofitting SCR at the Kincaid boilers.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas for both units were located south of the plant in a relatively open area in a similar fashion as LSD-FGD. The retrofit of DSD and FSI technologies at the Kincaid steam plant would be relatively easy because the ESP SCAs are large (>400) and there is 400 feet of flue gas ducting between the boilers and the retrofit ESPs. Additionally, the old ESP boxes could be used for the humidification or sorbent injection. If ESP plate area was required, the ESP upgrade access/congestion factor would be low (1.13). Table 7.3.2-7 presents a summary of site access/congestion factors, scope adders, and retrofit factors for DSD and FSI technologies at the Kincaid steam plant. Table 7.3.2-8 presents the costs estimated to retrofit DSD and FSI at the Kincaid plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Kincaid plant. The boilers at the Kincaid plant would not be considered good candidates for AFBC retrofit and AFBC/CG/combined cycle repowering because of their large size (660 MW).

7.3.3 Powerton Steam Plant

The Powerton steam plant is located within Tazewell County, Illinois, as part of the Commonwealth Edison Company system. The plant is located

TABLE 7.3.2-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR KINCAID UNITS 1-2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	LOW
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	113

TOTAL COST (1000$)	
ESP UPGRADE CASE	113
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.16
NEW BAGHOUSE	NA

Table 7.3.2-8. Summary of DSD/FSI Control Costs for the Kincaid Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	591	46	3.3	69.9	118.2	35.0	14.7	48.0	36000	971.1
DSD+ESP	2	1.00	591	39	3.3	69.9	118.2	32.9	16.3	48.0	30522	1077.4
DSD+ESP-C	1	1.00	591	46	3.3	69.9	118.2	20.3	8.5	48.0	36000	565.1
DSD+ESP-C	2	1.00	591	39	3.3	69.9	118.2	19.2	9.5	48.0	30522	627.6
FSI+ESP-50	1	1.00	591	46	3.3	53.2	90.1	39.5	16.6	50.0	37776	1044.9
FSI+ESP-50	2	1.00	591	39	3.3	53.2	90.1	35.7	17.7	50.0	32028	1114.0
FSI+ESP-50-C	1	1.00	591	46	3.3	53.2	90.1	22.9	9.6	50.0	37776	605.0
FSI+ESP-50-C	2	1.00	591	39	3.3	53.2	90.1	20.7	10.2	50.0	32028	645.7
FSI+ESP-70	1	1.00	591	46	3.3	53.6	90.7	40.1	16.8	70.0	52887	758.4
FSI+ESP-70	2	1.00	591	39	3.3	53.6	90.7	36.2	17.9	70.0	44839	808.1
FSI+ESP-70-C	1	1.00	591	46	3.3	53.6	90.7	23.2	9.8	70.0	52887	439.1
FSI+ESP-70-C	2	1.00	591	39	3.3	53.6	90.7	21.0	10.4	70.0	44839	468.3

adjacent to a pond beside the Illinois River and contains two steam turbine units (5,6) powered by four coal-fired boilers with a total gross generating capacity of 1,784 MW.

Table 7.3.3-1 presents operational data for the existing equipment at the Powerton plant. The boilers burn low sulfur coal received by railroad and transferred to a coal storage and handling area northwest of the units and adjacent to the pond.

PM emissions for the boilers are controlled with ESPs located behind each unit. The plant has a dry fly ash handling system. Fly ash is disposed of off-site. Flue gas from all boilers is ducted to a common chimney. A retrofit FGD scrubber unit with a new chimney for boiler 51 of unit 5 is no longer in operation.

Lime/Limestone and Lime Spray Drying FGD Costs--

The four boilers are located beside each other adjacent to the water channel. The absorbers for all boilers would be located behind and east of the chimney. The limestone preparation, storage, and handling area would be located behind the absorbers. Some of the roads have to be relocated; therefore, a factor of 10 percent was assigned to general facilities. A temporary waste handling area would be located approximately three quarters of a mile southwest of the plant. However, because of the limited space available, waste generated by the FGD absorbers must be transferred off-site in the same manner as the fly ash.

A low site access/congestion factor was assigned to the FGD absorber locations due to the accessibility and space availability behind the chimney. For flue gas handling, because absorbers are placed immediately behind the chimneys, short duct runs would be required for the L/LS-FGD case (less than 300 feet). A low site access/congestion factor was assigned to the flue gas handling system due to easy access to the existing chimney.

LSD with reuse of the existing ESPs was considered for this plant because the ESPs are adequate (SCA >207) and were assumed not to require major upgrading to handle the increased PM generated from the LSD application. The LSD absorbers would be located behind the common chimney. To route the flue gas from upstream of the existing ESPs to the absorbers and back to the ESPs, over 700 feet of duct length would be required. A

TABLE 7.3.3-1. POWERTON STEAM PLANT OPERATIONAL DATA

UNIT NUMBER	5	6
BOILER NUMBER	51,52	61,62
GENERATING CAPACITY (MW-each)	446	446
CAPACITY FACTOR (PERCENT)	37	42
INSTALLATION DATE	1972	1975
FIRING TYPE	CYCLONE	CYCLONE
FURNACE VOLUME (1000 CU FT)	285.4, 271	238, NA
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	0.6	0.6
COAL HEATING VALUE (BTU/LB)	9400	9400
COAL ASH CONTENT (PERCENT)	4.8	4.8
FLY ASH SYSTEM	DRY HANDLING	
ASH DISPOSAL METHOD	OFF-SITE	
STACK NUMBER	1	1
COAL DELIVERY METHODS	RAILROAD	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1972	1975
EMISSION (LB/MM BTU)	0.10	0.10
REMOVAL EFFICIENCY	98.6	99.3
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	0.7	0.7
SURFACE AREA (1000 SQ FT)	332	650
GAS EXIT RATE (1000 ACFM)	1605	1639
SCA (SQ FT/1000 ACFM)	207	397
OUTLET TEMPERATURE (°F)	300	300

high site access/congestion factor was assigned to the flue gas handling system in the case of LSD-FGD because of the congestion created by the ash silos, chimney, and close proximity of the ESPs to each other and to the boiler house.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Table 7.3.3-2. FGD cost estimates are not presented because it is unlikely that the current low sulfur coal would be used if scrubbing was required. FGD cost estimates based on the current coal would result in low estimates of capital/operating costs and high cost-effectiveness values. Additionally, it is unlikely that LSD-FGD with ESP reuse would be applied due to the very high access/congestion associated with the flue gas ducting and possible long boiler downtime.

Coal Switching and Physical Coal Cleaning Costs--

CS and PCC were not considered for this plant because the plant is already using a low sulfur coal.

Low NO_x Combustion--

All four boilers are cyclone-fired and are rated at 446 MW each. The combustion modification technique applied to all boilers was NGR. As Table 7.3.3-3 shows, the NGR NO_x reduction performance for each unit was assumed to be 60 percent. Table 7.3.3-4 presents the cost of retrofitting NGR at the Powerton plant.

Selective Catalytic Reduction--

Cold side SCR reactors for all boilers would be located immediately behind the chimney in low access/congestion areas. About 250 feet of duct length was estimated for the flue gas handling system. The ammonia storage system was placed close to the reactors east of the plant. No major equipment relocation would be needed and a base factor of 13 percent was assigned to general facilities.

Table 7.3.3-3 presents the SCR process area retrofit factors and scope adder costs. Table 7.3.3-4 presents the estimated cost of retrofitting SCR at the Powerton boilers.

TABLE 7.3.3-2. SUMMARY OF RETROFIT FACTOR DATA FOR POWERTON BOILERS 51,52,61,OR 62

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			600-1000
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY *	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER (WASTE DISPOSAL)	YES		YES
RETROFIT FACTORS			
FGD SYSTEM	1.30	NA	
ESP REUSE CASE			1.57
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	0	8

* Chimney liner cost is included in the FGD retrofit evaluation.

TABLE 7.3.3-3. SUMMARY OF NOx RETROFIT RESULTS FOR POWERTON

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	51,52,61,62
FIRING TYPE	CYC
TYPE OF NOx CONTROL	NGR
FURNACE VOLUME (1000 CU FT)	285.4,271,238,NA
BOILER INSTALLATION DATE	1972-1975
SLAGGING PROBLEM	NA
ESTIMATED NOx REDUCTION (PERCENT)	60
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	83
New Duct Length (Feet)	250
New Duct Costs (1000$)	2971
New Heat Exchanger (1000$)	4571
TOTAL SCOPE ADDER COSTS (1000$)	7625
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	13

Table 7.3.3-4. NOx Control Cost Results for the Powerton Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
NGR	51,52	1.00	446	37	0.6	6.8	15.3	8.5	5.9	60.0	8074	1055.6
NGR	61,62	1.00	446	42	0.6	6.8	15.3	9.6	5.8	60.0	9165	1042.1
NGR-C	51,52	1.00	446	37	0.6	6.8	15.3	4.9	3.4	60.0	8074	608.6
NGR-C	61,62	1.00	446	42	0.6	6.8	15.3	5.5	3.4	60.0	9165	600.4
SCR-3	51,52	1.16	446	37	0.6	56.6	126.9	21.2	14.6	80.0	10765	1965.3
SCR-3	61,62	1.16	446	42	0.6	56.6	126.9	21.4	13.0	80.0	12220	1749.5
SCR-3-C	51,52	1.16	446	37	0.6	56.6	126.9	12.4	8.6	80.0	10765	1149.5
SCR-3-C	61,62	1.16	446	42	0.6	56.6	126.9	12.5	7.6	80.0	12220	1023.1
SCR-7	51,52	1.16	446	37	0.6	56.6	126.9	17.4	12.0	80.0	10765	1612.3
SCR-7	61,62	1.16	446	42	0.6	56.6	126.9	17.6	10.7	80.0	12220	1438.5
SCR-7-C	51,52	1.16	446	37	0.6	56.6	126.9	10.2	7.1	80.0	10765	947.3
SCR-7-C	61,62	1.16	446	42	0.6	56.6	126.9	10.3	6.3	80.0	12220	844.9

Duct Spray Drying and Furnace Sorbent Injection--

The retrofit of FSI and DSD technologies at the Powerton steam plant would be difficult. This is caused by inadequate duct residence time between the boilers and the retrofit ESPs for either humidification (FSI application) or sorbent droplet evaporation (DSD application). However, the ESPs may be large enough to modify the first ESP section to be used for humidification or sorbent injection. A high site access/congestion factor was assigned to the ESP locations if additional plate area or upgrading/modification of the existing ESPs is required. The sorbent receiving/storage/preparation area was located east of the plant.

Table 7.3.3-5 presents a summary of the site access/congestion factors for FSI and DSD technologies at the Powerton plant. Table 7.3.3-6 presents the costs estimated to retrofit FSI and DSD at the Powerton plant. The estimated unit costs for all boilers are high because of the low sulfur content of the coal.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Powerton plant. Neither of units would be considered good candidates for repowering/retrofit because of their large boiler sizes.

7.3.4 Waukegan Steam Plant

L/S-FGD and LSD-FGD retrofit factors were evaluated for boilers 6, 7, and 8 at the Waukegan plant; however, costs are not presented because the low sulfur coal currently being fired would yield low capital/operating costs and high cost per ton of SO_2 removed. A new baghouse was used in conjunction with LSD instead of reusing the existing ESPs, since the ESPs for these boilers are congested and any upgrading would be difficult. CS was not evaluated because the plant is using a low sulfur coal. FSI and DSD were not considered for units 6 and 8 due to the short duct residence time between the boilers and their respective ESPs and due to the inadequate size of the ESPs. The unit 7 ESPs appear large enough for the application FSI and DSD, however, access to these are difficult and were not considered for sorbent injection technologies.

TABLE 7.3.3-5. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR POWERTON BOILERS 51,52,61,62

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	92
TOTAL COST (1000$)	
ESP UPGRADE CASE	92
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Table 7.3.3-6. Summary of DSD/FSI Control Costs for the Powerton Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	51,52	1.00	446	37	0.6	16.5	37.0	9.1	6.3	49.0	4506	2014.4
DSD+ESP	61,62	1.00	446	42	0.6	11.3	25.3	7.9	4.8	49.0	5115	1547.9
DSD+ESP-C	51,52	1.00	446	37	0.6	16.5	37.0	5.3	3.6	49.0	4506	1170.6
DSD+ESP-C	61,62	1.00	446	42	0.6	11.3	25.3	4.6	2.8	49.0	5115	896.7
FSI+ESP-50	51,52	1.00	446	37	0.6	18.2	40.8	9.1	6.3	50.0	4631	1957.2
FSI+ESP-50	61,62	1.00	446	42	0.6	13.4	30.0	8.1	5.0	50.0	5256	1548.2
FSI+ESP-50-C	51,52	1.00	446	37	0.6	18.2	40.8	5.3	3.6	50.0	4631	1138.9
FSI+ESP-50-C	61,62	1.00	446	42	0.6	13.4	30.0	4.7	2.9	50.0	5256	898.4
FSI+ESP-70	51,52	1.00	446	37	0.6	18.0	40.4	9.1	6.3	70.0	6483	1400.4
FSI+ESP-70	61,62	1.00	446	42	0.6	13.5	30.4	8.3	5.0	70.0	7359	1122.4
FSI+ESP-70-C	51,52	1.00	446	37	0.6	18.0	40.4	5.3	3.7	70.0	6483	814.8
FSI+ESP-70-C	61,62	1.00	446	42	0.6	13.5	30.4	4.8	2.9	70.0	7359	651.3

TABLE 7.3.4-1. WAUKEGAN STEAM PLANT OPERATIONAL DATA *

BOILER NUMBER	1-5	6	7	8
GENERATING CAPACITY (MW)	RETIRED	112	353	317
CAPACITY FACTOR (PERCENT)		7	44	18
INSTALLATION DATE		1952	1958	1962
FIRING TYPE		CYCLONE	TANGENTIAL	
FURNACE VOLUME (1000 CU FT)		43	510	506
LOW NOx COMBUSTION		NO	NO	NO
COAL SULFUR CONTENT (PERCENT)		0.47	0.4	0.42
COAL HEATING VALUE (BTU/LB)		9300	9500	9500
COAL ASH CONTENT (PERCENT)		5.04	7.4	7.4
FLY ASH SYSTEM			DRY DISPOSAL	
ASH DISPOSAL METHOD			PAID/OFF-SITE	
STACK NUMBER		1	2	3
COAL DELIVERY METHODS			RAILROAD	
PARTICULATE CONTROL				
TYPE		ESP	ESP	ESP
INSTALLATION DATE		1971	1976	1962
EMISSION (LB/MM BTU)		0.04	0.024	0.022
REMOVAL EFFICIENCY		96.88	99.57	99.57
DESIGN SPECIFICATION				
SULFUR SPECIFICATION (PERCENT)		0.5	0.5	0.5
SURFACE AREA (1000 SQ FT)		62.5	512.3	151.1
EXIT GAS FLOW RATE (1000 ACFM)		430	1700	1051
SCA (SQ FT/1000 ACFM)		136	439	134
OUTLET TEMPERATURE (°F)		295	700	284

* Some information was obtained from plant personnel.

TABLE 7.3.4-2. SUMMARY OF RETROFIT FACTOR DATA FOR WAUKEGAN UNIT 6 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			HIGH
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	784	0	784
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.41	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.43
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	10	0	10

* L/LS-FGD absorbers, LSD-FGD absorbers, and new FFs for unit 6 would be located east of the retired chimney for units 1-5.

TABLE 7.3.4-3. SUMMARY OF RETROFIT FACTOR DATA FOR WAUKEGAN UNIT 7 OR 8 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			HIGH
DUCT WORK DISTANCE (FEET)	600-1000	NA	
ESP REUSE			
BAGHOUSE			600-1000
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	2471,2219	0	2471,2219
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.53	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.54
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	10	0	10

* L/S-FGD absorbers, LSD-FGD absorbers, and new FFs for units 7 and 8 would be located east of the retired chimney for units 1-5.

TABLE 7.3.4-4. SUMMARY OF NOx RETROFIT RESULTS FOR WAUKEGAN

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	6	7	8
FIRING TYPE	CYCLONE	TANG	TANG
TYPE OF NOx CONTROL	NGR	OFA	OFA
FURNACE VOLUME (1000 CU FT)	NA	252	254
BOILER INSTALLATION DATE	1952	1958	1962
SLAGGING PROBLEM	NO	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	60	25	25
SCR RETROFIT RESULTS *			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH	HIGH
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	29	70	64
New Duct Length (Feet)	400	300	500
New Duct Costs (1000$)	2118	3109	4866
New Heat Exchanger (1000$)	1995	0	3724
TOTAL SCOPE ADDER COSTS (1000$)	4142	3178	8654
RETROFIT FACTOR FOR SCR	1.52	1.52	1.52
GENERAL FACILITIES (PERCENT)	38	38	38

* Cold side SCR reactors for unit 6 would be located behind the unit 6 chimney. Hot side SCR reactors for unit 7 and cold side SCR reactors for unit 8 would be located behind the unit 7 chimney.

Table 7.3.4-5. NOx Control Cost Results for the Waukegan Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	7	1.00	353	44	0.4	1.0	2.9	0.2	0.2	25.0	1380	162.4
LNC-OFA	8	1.00	317	18	0.4	1.0	3.1	0.2	0.4	25.0	507	423.5
LNC-OFA-C	7	1.00	353	44	0.4	1.0	2.9	0.1	0.1	25.0	1380	96.4
LNC-OFA-C	8	1.00	317	18	0.4	1.0	3.1	0.1	0.3	25.0	507	251.3
NGR	6	1.00	112	7	0.5	2.4	21.8	0.8	10.9	60.0	423	1776.4
NGR-C	6	1.00	112	7	0.5	2.4	21.8	0.4	6.4	60.0	423	1043.6
SCR-3	6	1.52	112	7	0.5	26.7	238.2	8.2	118.8	80.0	564	14477.7
SCR-3	7	1.52	353	44	0.4	57.6	163.1	19.9	14.6	80.0	4416	4495.3
SCR-3	8	1.52	317	18	0.4	57.7	182.1	18.5	37.0	80.0	1622	11388.5
SCR-3-C	6	1.52	112	7	0.5	26.7	238.2	4.8	69.8	80.0	564	8506.9
SCR-3-C	7	1.52	353	44	0.4	57.6	163.1	11.6	8.5	80.0	4416	2634.0
SCR-3-C	8	1.52	317	18	0.4	57.7	182.1	10.8	21.7	80.0	1622	6684.4
SCR-7	6	1.52	112	7	0.5	26.7	238.2	7.2	104.9	80.0	564	12781.4
SCR-7	7	1.52	353	44	0.4	57.6	163.1	16.8	12.4	80.0	4416	3815.4
SCR-7	8	1.52	317	18	0.4	57.7	182.1	15.8	31.6	80.0	1622	9726.5
SCR-7-C	6	1.52	112	7	0.5	26.7	238.2	4.2	61.8	80.0	564	7535.2
SCR-7-C	7	1.52	353	44	0.4	57.6	163.1	9.9	7.3	80.0	4416	2244.4
SCR-7-C	8	1.52	317	18	0.4	57.7	182.1	9.3	18.6	80.0	1622	5732.1

7.3.5 Will County Steam Plant

L/S-FGD and LSD-FGD retrofit factors were developed for the boilers at the Will County plant; however, costs are not presented since the low sulfur content of the coal being fired would result in low capital/operating costs and high cost per ton of SO_2 removed. The boilers already are firing a low sulfur coal hence CS was not considered. Sorbent injection technologies (FSI and DSD) were not evaluated due to the short duct residence time between the boilers and their respective ESPs and due to the difficulty involved in upgrading the existing ESPs.

TABLE 7.3.5-1. WILL COUNTY STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2	3	4
GENERATING CAPACITY (MW-each)	167	167	278	542
CAPACITY FACTOR (PERCENT)	9	13	18	34
INSTALLATION DATE	1955	1955	1957	1963
FIRING TYPE	CYCLONE		TANGENTIAL	
FURNACE VOLUME (1000 CU FT)	40.6	40.6	200	470
LOW NOx COMBUSTION	NO	NO	NO	NO
COAL SULFUR CONTENT (PERCENT)	0.46	0.46	0.43	0.42
COAL HEATING VALUE (BTU/LB)	9300	9300	9400	9400
COAL ASH CONTENT (PERCENT)	5.2	5.1	7.8	7.8
FLY ASH SYSTEM	DRY DISPOSAL			
ASH DISPOSAL METHOD	PAID/OFF-SITE			
STACK NUMBER	1	2	3	4
COAL DELIVERY METHODS	BARGE			
PARTICULATE CONTROL				
TYPE	ESP	ESP	ESP	ESP
INSTALLATION DATE	1984	1973	1973	1963
EMISSION (LB/MM BTU)	0.004	0.006	0.02	0.03
REMOVAL EFFICIENCY	99.7	99.6	99.7	98.9
DESIGN SPECIFICATION				
SULFUR SPECIFICATION (PERCENT)	0.5	0.5	0.5	0.5
SURFACE AREA (1000 SQ FT)	227.5	248.2	331.2	199.7
GAS EXIT RATE (1000 ACFM)	650	770	1425	1533
SCA (SQ FT/1000 ACFM)	365	322	330	130
OUTLET TEMPERATURE (°F)	320	355	675	286

TABLE 7.3.5-2. SUMMARY OF RETROFIT FACTOR DATA FOR WILL COUNTY UNIT 1*

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	MEDIUM
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	NA	NO
ESTIMATED COST (1000$)	1169	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.52	NA	
ESP REUSE CASE			1.49
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	15

* L/S-FGD and LSD-FGD absorbers for unit 1 would be located north of unit 1.

TABLE 7.3.5-3. SUMMARY OF RETROFIT FACTOR DATA FOR WILL COUNTY UNIT 2 OR 3*

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	MEDIUM
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE (Unit 2)			HIGH
BAGHOUSE CASE (Unit 3)			HIGH
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE (Unit 2)			600-1000
BAGHOUSE (Unit 3)			300-600
ESP REUSE (Unit 2)	NA	NA	HIGH
NEW BAGHOUSE (Unit 3)	NA	NA	MEDIUM
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	NA	YES (Unit 3)
ESTIMATED COST (1000$)	1169,1946	0	1946
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.52	NA	
ESP REUSE CASE (Unit 2)			1.62
BAGHOUSE CASE (Unit 3)			1.56
ESP UPGRADE (Unit 2)	NA	NA	1.58
NEW BAGHOUSE (Unit 3)	NA	NA	1.36
GENERAL FACILITIES (PERCENT)	15	0	15

* L/S-FGD and LSD-FGD absorbers for unit 2 would be located north of unit 1 and the absorbers for unit 3 would be located south of unit 4.

TABLE 7.3.5-4. SUMMARY OF RETROFIT FACTOR DATA FOR WILL COUNTY UNIT 4*

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	MEDIUM
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			MEDIUM
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			NA
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	MEDIUM
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	3794	0	3794
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.48	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.52
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.36
GENERAL FACILITIES (PERCENT)	15	0	15

* L/S-FGD absorbers, LSD-FGD absorbers, and new FFs for unit 4 would be located south of unit 4.

TABLE 7.3.5-5. SUMMARY OF NOx RETROFIT RESULTS FOR WILL COUNTY

	BOILER NUMBER			
COMBUSTION MODIFICATION RESULTS				
	1	2	3	4
FIRING TYPE	CYC	CYC	TANG	TANG
TYPE OF NOx CONTROL	NGR	NGR	OFA	OFA
FURNACE VOLUME (1000 CU FT)	40.6	40.6	200	470
BOILER INSTALLATION DATE	1955	1955	1957	1963
SLAGGING PROBLEM	NO	NO	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	60	60	25	25
SCR RETROFIT RESULTS*				
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH	HIGH	MEDIUM
SCOPE ADDER PARAMETERS--				
Building Demolition (1000$)	0	0	0	0
Ductwork Demolition (1000$)	40	40	58	96
New Duct Length (Feet)	200	200	200	300
New Duct Costs (1000$)	1338	1338	1802	3995
New Heat Exchanger (1000$)	2535	2535	0	5138
TOTAL SCOPE ADDER COSTS (1000$)	3913	3913	1861	9230
RETROFIT FACTOR FOR SCR	1.52	1.52	1.52	1.34
GENERAL FACILITIES (PERCENT)	38	38	38	38

* Cold side SCR reactors for units 1 and 2 would be located behind their respective chimnies. Hot side SCR reactors for unit 3 would be located behind the unit 3 chimney. Cold side SCR reactors for unit 4 would be located south of unit 4.

Table 7.3.5-6. NOx Control Cost Results for the Will County Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	3	1.00	278	18	0.4	0.9	3.4	0.2	0.5	25.0	450	452.8
LNC-OFA	4	1.00	542	34	0.4	1.2	2.2	0.3	0.2	25.0	1657	160.6
LNC-OFA-C	3	1.00	278	18	0.4	0.9	3.4	0.1	0.3	25.0	450	268.6
LNC-OFA-C	4	1.00	542	34	0.4	1.2	2.2	0.2	0.1	25.0	1657	95.3
NGR	1	1.00	167	9	0.5	3.3	19.5	1.2	9.0	60.0	810	1468.5
NGR	2	1.00	167	13	0.5	3.3	19.5	1.5	7.9	60.0	1170	1280.2
NGR-C	1	1.00	167	9	0.5	3.3	19.5	0.7	5.3	60.0	810	859.5
NGR-C	2	1.00	167	13	0.5	3.3	19.5	0.9	4.6	60.0	1170	745.9
SCR-3	1	1.52	167	9	0.5	33.8	202.2	10.7	81.6	80.0	1080	9940.8
SCR-3	2	1.52	167	13	0.5	34.0	203.8	10.9	57.1	80.0	1560	6963.7
SCR-3	3	1.52	278	18	0.4	46.3	166.5	15.6	35.6	80.0	1440	10822.7
SCR-3	4	1.34	542	34	0.4	78.0	143.9	27.3	16.9	80.0	5304	5148.4
SCR-3-C	1	1.52	167	9	0.5	33.8	202.2	6.3	47.9	80.0	1080	5835.5
SCR-3-C	2	1.52	167	13	0.5	34.0	203.8	6.4	33.5	80.0	1560	4087.5
SCR-3-C	3	1.52	278	18	0.4	46.3	166.5	9.1	20.8	80.0	1440	6344.8
SCR-3-C	4	1.34	542	34	0.4	78.0	143.9	16.0	9.9	80.0	5304	3015.6
SCR-7	1	1.52	167	9	0.5	33.8	202.2	9.3	70.7	80.0	1080	8621.3
SCR-7	2	1.52	167	13	0.5	34.0	203.8	9.4	49.6	80.0	1560	6050.1
SCR-7	3	1.52	278	18	0.4	46.3	166.5	13.2	30.2	80.0	1440	9178.2
SCR-7	4	1.34	542	34	0.4	78.0	143.8	22.7	14.1	80.0	5304	4277.8
SCR-7-C	1	1.52	167	9	0.5	33.8	202.2	5.5	41.7	80.0	1080	5079.6
SCR-7-C	2	1.52	167	13	0.5	34.0	203.8	5.6	29.2	80.0	1560	3564.1
SCR-7-C	3	1.52	278	18	0.4	46.3	166.5	7.8	17.7	80.0	1440	5402.5
SCR-7-C	4	1.34	542	34	0.4	78.0	143.8	13.3	8.3	80.0	5304	2516.8

7.4 ELECTRIC ENERGY INCORPORATION

7.4.1 Joppa Steam Plant

The Joppa steam plant is located within Massac County, Illinois, as part of the Electric Energy system. The plant contains six coal-fired boilers with a total gross generating capacity of 1,098 MW. Figure 7.4.1-1 presents the plant plot plan showing the location of the boilers and major associated auxiliary equipment. An aerial photograph was available for review in the evaluation.

Table 7.4.1-1 presents the operational data for the existing equipment at the Joppa plant. All boilers burn medium sulfur coal (2.0 percent sulfur). Coal shipments are received by freight barge and rail and then conveyed to a coal storage/handling area located east of the units.

Particulate matter emissions for all six boilers are controlled with ESPs located behind each unit. Ash from all units is wet sluiced to ponds on the far side (north) of the coal storage area. Small amounts of the fly ash go to a nearby cement plant for their use as a raw material. Limited space is available for future waste disposal; thus, future waste would be disposed off-site.

Lime/Limestone and Lime Spray Drying FGD Costs--

The Joppa plant includes three chimneys, each shared by two units located between the existing ESPs. The FGD absorbers were placed between the existing ESPs and chimneys and the coal storage/handling area. This location is presently occupied by warehouses. The relocation of the warehouses and plant roads would be required in order to place the absorbers in this location. The limestone preparation/storage area was located to the north of the powerhouses and the waste handling area was placed adjacent to the preparation/storage area.

Retrofit Difficulty and Scope Adder Costs--

The FGD absorbers for units 1, 2, 5 and 6 were assumed to be in areas of medium site access/congestion and units 3 and 4 were assumed to be in high site access/congestion areas. The medium site access/congestion factors

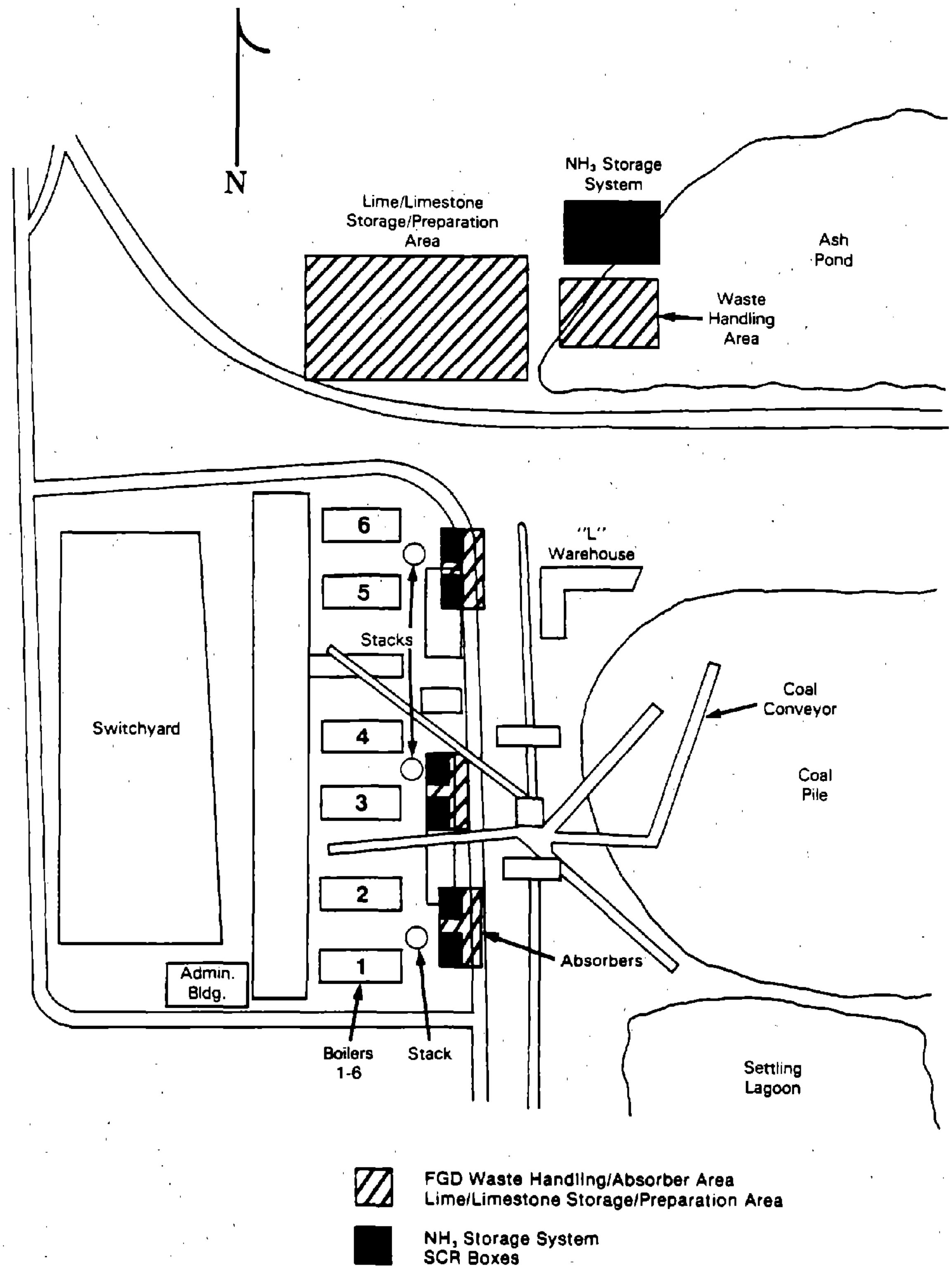

Figure 7.4.1-1. Joppa plant plot plan

TABLE 7.4.1-1. JOPPA STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1-6
GENERATING CAPACITY (MW-each)	183
CAPACITY FACTOR (PERCENT)	13, 15
FIRING TYPE	TANG
INSTALLATION DATE	1953-55
COAL SULFUR CONTENT (PERCENT)	2.0
COAL HEATING VALUE (BTU/LB)	11700
COAL ASH CONTENT (PERCENT)	9.0
FLY ASH SYSTEM	WET SLUICE
ASH DISPOSAL METHOD	ON-SITE
STACK NUMBER	1-3
COAL DELIVERY METHODS	BARGE
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1971-72
EMISSION (LB/MM BTU)	0.08-0.09
REMOVAL EFFICIENCY	98.8-98.6
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	2.0
SURFACE AREA (1000 SQ FT)	121
GAS EXIT RATE (1000 ACFM)	673
SCA (SQ FT/1000 ACFM)	180
OUTLET TEMPERATURE (°F)	310

reflect the access difficulty for units 1, 2, 5, and 6 because of the coal conveyor and the existing ESPs and chimneys. Units 3 and 4 are highly congested because the coal conveyors are both north and south and the existing ESPs and the chimney are to the west. A high underground obstruction factor was assigned to the placement of all absorbers because of the drain water switch lines and the ash disposal lines. The access/congestion factor assigned to the flue gas handling was low for units 1, 2, 5, and 6 and all FGD technologies because of the location of the absorbers and their accessibility to the chimneys and the fact that no significant duct work would be required. By contrast, due to access difficulties created by the coal conveyors to the unit 3 and 4 chimneys, high access/congestion factors were assigned to the flue gas handling system. Short ductwork would be required for the retrofit of L/LS-FGD technology at the plant. Finally, a 10 percent general facilities factor was assigned for all units and all FGD technologies because of the demolition and relocation of the storage warehouses and plant road required for the placement of the absorbers discussed above.

The major scope adjustment costs and estimated retrofit factors for the FGD control technologies are presented in Tables 7.4.1-2 and 7.4.1-3. The largest scope adder for the Joppa plant would be the conversion of wet to dry ash handling system for all units considered for conventional L/LS-FGD retrofit. It was assumed that dry fly ash would be necessary to stabilize the L/LS-FGD scrubber sludge waste. Dry ash handling is not necessary for forced oxidation L/LS-FGD and was not considered a scope adder for these cases. The overall retrofit factors determined for the L/LS-FGD cases were moderate (1.36 to 1.60).

A considerable ESP plate area addition would be required to upgrade the ESPs because of the SCA size (<200) and the ESPs location (high site access/congestion). As a result, the LSD-FGD case evaluated was LSD with a new baghouse. A medium duct run would be necessary for the new baghouse in LSD-FGD cases to divert the flue gas from the absorbers to the new baghouses and back to the existing chimneys. The estimated retrofit factors for this case were moderate (1.40 to 1.62) and did not include particulate control costs. Separate factors were estimated for new particulate controls. The same site access/congestion factors used for the absorbers were also assumed

TABLE 7.4.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR JOPPA UNITS 1,2,5,6

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	MEDIUM	MEDIUM
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	100-300	
ESP REUSE			NA
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	MEDIUM
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	NO
ESTIMATED COST (1000$)	1612	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.41	1.36	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.40
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.36
GENERAL FACILITIES (PERCENT)	10	10	10

TABLE 7.4.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR JOPPA UNITS 3-4

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	HIGH	HIGH
FLUE GAS HANDLING	HIGH	HIGH	
ESP REUSE CASE			NA
BAGHOUSE CASE			HIGH
DUCT WORK DISTANCE (FEET)	100-300	100-300	
ESP REUSE			NA
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	HIGH
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	NO
ESTIMATED COST (1000$)	1612	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.60	1.56	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.62
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.58
GENERAL FACILITIES (PERCENT)	10	10	10

for ESP upgrade, resulting in overall moderate to high retrofit factors (1.36 to 1.58). The factors determined for new particulate controls were used in the IAPCS model to estimate the particulate control costs.

Table 7.4.1-4 presents the cost estimates for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs and ash handling systems for boilers 1-6.

The low cost control case reduces capital and annual operating costs. The significant reduction in costs is primarily due to the benefits of economies-of-scale when combining process areas, elimination of spare scrubber, and optimization of scrubber size.

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined.

The ESP performance impacts were evaluated using the IAPCS model to estimate the needed plate area. This plate area was compared to the existing area to determine whether SO_3 conditioning or additional plate area was needed. SO_3 conditioning was assumed to reduce the needed plate area up to 25 percent.

Costs were generated to show the impact of two different coal fuel cost differentials. The costs associated with each boiler for the range of fuel cost differential are shown in Table 7.4.1-5.

NO_x Control Technology Costs--

This section presents the performance and various related costs estimated for NO_x controls at the Joppa steam plant. These controls include LNC and selective catalytic reduction. The application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2. The NO_x technologies evaluated at the steam plant were: OFA and SCR.

Table 7.4.1-4. Summary of FGD Control Costs for the Joppa Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1, 5	1.41	183	15	2.0	60.7	331.4	22.7	94.6	90.0	3595	6325.3
L/S FGD	2, 6	1.41	183	13	2.0	60.6	331.4	22.5	107.9	90.0	3116	7218.1
L/S FGD	3, 4	1.60	183	15	2.0	68.0	371.4	25.2	104.8	90.0	3595	7011.2
L/S FGD-C	1, 5	1.41	183	15	2.0	60.7	331.4	13.3	55.3	90.0	3595	3699.6
L/S FGD-C	2, 6	1.41	183	13	2.0	60.6	331.4	13.2	63.1	90.0	3116	4222.8
L/S FGD-C	3, 4	1.60	183	15	2.0	68.0	371.4	14.7	61.3	90.0	3595	4101.7
LC FGD	1-6	1.50	1100	14	2.0	183.1	166.4	68.2	50.6	90.0	20168	3382.6
LC FGD-C	1-6	1.50	1100	14	2.0	183.1	166.4	39.9	29.6	90.0	20168	1978.7
LSD+FF	1,5	1.40	183	15	2.0	45.9	250.8	15.9	66.3	87.0	3455	4612.1
LSD+FF	2,6	1.40	183	13	2.0	45.9	250.8	15.8	75.9	87.0	2994	5280.9
LSD+FF	3,4	1.62	183	15	2.0	52.8	288.7	17.9	74.2	87.0	3455	5167.3
LSD+FF-C	1,5	1.40	183	15	2.0	45.9	250.8	9.3	38.8	87.0	3455	2702.0
LSD+FF-C	2,6	1.40	183	13	2.0	45.9	250.8	9.3	44.5	87.0	2994	3094.3
LSD+FF-C	3,4	1.62	183	15	2.0	52.8	288.7	10.5	43.5	87.0	3455	3029.1

Table 7.4.1-5. Summary of Coal Switching/Cleaning Costs for the Joppa Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1,3,4	1.00	183	15	2.0	7.2	39.5	4.9	20.2	57.0	2258	2156.3
CS/B+$15	2,6	1.00	183	13	2.0	7.2	39.5	4.4	21.3	57.0	1957	2270.5
CS/B+$15-C	1,3,4	1.00	183	15	2.0	7.2	39.5	2.8	11.7	57.0	2258	1249.7
CS/B+$15-C	2,6	1.00	183	13	2.0	7.2	39.5	2.6	12.4	57.0	1957	1317.4
CS/B+$5	1,3,4	1.00	183	15	2.0	5.3	29.1	2.6	10.6	57.0	2258	1129.4
CS/B+$5	2,6	1.00	183	13	2.0	5.3	29.1	2.4	11.5	57.0	1957	1221.0
CS/B+$5-C	1,3,4	1.00	183	15	2.0	5.3	29.1	1.5	6.2	57.0	2258	657.6
CS/B+$5-C	2,6	1.00	183	13	2.0	5.3	29.1	1.4	6.7	57.0	1957	711.8

Low NO_x Combustion--

Units 1 to 6 are dry bottom, tangential-fired boilers rated at 183 MW each. The combustion modification technique applied for this evaluation was OFA. As Tables 7.4.1-6 and 7.4.1-7 show, the OFA NO_x reduction performance for units 1 to 6 was estimated to be 20 percent for all units. This reduction performance level was assessed by examining the effects of heat release rates and furnace residence time through the use of the simplified NO_x procedures. Table 7.4.1-8 presents the cost of retrofitting OFA at the Joppa plant.

Selective Catalytic Reduction--

Tables 7.4.1-6 and 7.4.1-7 present the SCR retrofit results for each unit. The results include process area retrofit difficulty factors and scope adder costs. For scope adders, costs were estimated for building and ductwork demolition, new heat exchanger, and new duct runs to divert the flue gas from the ESPs to the SCR reactor and from the reactor to the chimney. The estimate of the reactor sizes was based on an examination of the aerial photograph of the plant.

It was assumed that the reactors for units 1 to 6 would be located behind or beside respective chimneys. Some demolition and relocation would be involved with the placement of the reactors for units 1 to 6. A 25 percent general facilities factor was assigned to units 1 to 6 to account for road and building relocations.

The reactors for units 1, 2, 5 and 6 were assigned a low access/congestion factor and units 3 and 4 were assigned a high factor because the reactors for units 3 and 4 would be surrounded by the chimneys and the coal conveyors. The ammonia storage system was placed in a remote area near the inlet channel (low access/congestion). The reactors were assumed to be in areas with high underground obstructions while the ammonia system was not. Table 7.4.1-8 presents the estimated cost of retrofitting SCR at the Joppa boilers.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on

TABLE 7.4.1-6. SUMMARY OF NOx RETROFIT RESULTS FOR JOPPA UNITS 1-3

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	3
FIRING TYPE	TANG	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA	OFA
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	14.5	14.5	14.5
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	31.6	31.6	31.6
FURNACE RESIDENCE TIME (SECONDS)	3.06	3.06	3.06
ESTIMATED NOx REDUCTION (PERCENT)	20	20	20
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	HIGH
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	163	163
Ductwork Demolition (1000$)	43	43	43
New Duct Length (Feet)	130	130	130
New Duct Costs (1000$)	917	917	917
New Heat Exchanger (1000$)	2,678	2,678	2,678
TOTAL SCOPE ADDER COSTS (1000$)	3,638	3,801	3,801
RETROFIT FACTOR FOR SCR	1.16	1.16	1.52
GENERAL FACILITIES (PERCENT)	25	25	25

TABLE 7.4.1-7. SUMMARY OF NOx RETROFIT RESULTS FOR JOPPA UNITS 4-6

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	4	5	6
FIRING TYPE	TANG	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA	OFA
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	14.5	14.5	14.5
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	31.6	31.6	31.6
FURNACE RESIDENCE TIME (SECONDS)	3.06	3.06	3.06
ESTIMATED NOx REDUCTION (PERCENT)	20	20	20
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	LOW	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	81	163	0
Ductwork Demolition (1000$)	43	43	43
New Duct Length (Feet)	130	130	130
New Duct Costs (1000$)	917	917	917
New Heat Exchanger (1000$)	2,678	2,678	2,678
TOTAL SCOPE ADDER COSTS (1000$)	3,719	3,801	3,638
RETROFIT FACTOR FOR SCR	1.52	1.16	1.16
GENERAL FACILITIES (PERCENT)	25	25	25

Table 7.4.1-8. NOx Control Cost Results for the Joppa Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	1,3,4	1.00	183	15	2.0	0.8	4.3	0.2	0.7	20.0	154	1122.9
LNC-OFA	2,6	1.00	183	13	2.0	0.8	4.3	0.2	0.8	20.0	133	1295.6
LNC-OFA-C	1,3,4	1.00	183	15	2.0	0.8	4.3	0.1	0.4	20.0	154	666.6
LNC-OFA-C	2,6	1.00	183	13	2.0	0.8	4.3	0.1	0.5	20.0	133	769.1
SCR-3	1	1.16	183	15	2.0	28.7	156.9	9.6	39.8	80.0	615	15575.5
SCR-3	2	1.16	183	13	2.0	28.9	157.8	9.6	46.0	80.0	533	17996.5
SCR-3	3	1.52	183	15	2.0	34.1	186.2	10.9	45.4	80.0	615	17766.9
SCR-3	4	1.52	183	15	2.0	34.0	185.8	10.9	45.3	80.0	615	17743.0
SCR-3	5	1.16	183	15	2.0	28.9	157.8	9.6	39.9	80.0	615	15622.8
SCR-3	6	1.16	183	13	2.0	28.7	156.9	9.6	45.8	80.0	533	17941.7
SCR-3-C	1	1.16	183	15	2.0	28.7	156.9	5.6	23.3	80.0	615	9133.2
SCR-3-C	2	1.16	183	13	2.0	28.9	157.8	5.6	27.0	80.0	533	10553.9
SCR-3-C	3	1.52	183	15	2.0	34.1	186.2	6.4	26.6	80.0	615	10427.8
SCR-3-C	4	1.52	183	15	2.0	34.0	185.8	6.4	26.6	80.0	615	10413.7
SCR-3-C	5	1.16	183	15	2.0	28.9	157.8	5.6	23.4	80.0	615	9161.6
SCR-3-C	6	1.16	183	13	2.0	28.7	156.9	5.6	26.9	80.0	533	10521.1
SCR-7	1	1.16	183	15	2.0	28.7	156.9	8.1	33.5	80.0	615	13119.3
SCR-7	2	1.16	183	13	2.0	28.9	157.8	8.1	38.7	80.0	533	15162.5
SCR-7	3	1.52	183	15	2.0	34.1	186.2	9.4	39.1	80.0	615	15310.7
SCR-7	4	1.52	183	15	2.0	34.0	185.8	9.4	39.1	80.0	615	15286.8
SCR-7	5	1.16	183	15	2.0	28.9	157.8	8.1	33.6	80.0	615	13166.7
SCR-7	6	1.16	183	13	2.0	28.7	156.9	8.0	38.6	80.0	533	15107.6
SCR-7-C	1	1.16	183	15	2.0	28.7	156.9	4.7	19.7	80.0	615	7725.9
SCR-7-C	2	1.16	183	13	2.0	28.9	157.8	4.8	22.8	80.0	533	8930.1
SCR-7-C	3	1.52	183	15	2.0	34.1	186.2	5.5	23.1	80.0	615	9020.6
SCR-7-C	4	1.52	183	15	2.0	34.0	185.8	5.5	23.0	80.0	615	9006.3
SCR-7-C	5	1.16	183	15	2.0	28.9	157.8	4.8	19.8	80.0	615	7754.4
SCR-7-C	6	1.16	183	13	2.0	28.7	156.9	4.7	22.7	80.0	533	8897.4

commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas for all units would be located between the powerhouse and the coal storage/handling area in a layout similar to that for LSD-FGD. The retrofit of DSD at Joppa would be difficult for several reasons. The ESP SCAs are small (121) and there is little duct residence time (<1 second) between the boilers and the ESPs. A new baghouse would be required for DSD retrofit and would be located in the congested area behind the ESPs, close to the chimneys. Finally, a 30 foot duct run would be required to reroute the flue gas from the existing ESPs to the new baghouse and then back to the chimney. It was assumed that the existing ESPs could not be cost effectively upgraded for FSI with additional plate area due to the high site access/congestion caused by the close proximity of the ESPs to each other and the chimneys. Table 7.4.1-9 and 7.4.1-10 present a summary of the site access/congestion factors, scope adders, and retrofit factors for DSD and FSI at the Joppa steam plant. Only costs for DSD with new fabric filters are presented in Table 7.4.1-11.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Joppa plant. The boilers at Joppa would be considered good candidates for AFBC retrofit and AFBC or CG/combined cycle repowering because of their small boiler sizes (<200) and their age (pre-1960 installation date). These boilers also have low capacity factors indicating that replacement power costs for extended boiler outage would be minimal. Additionally, the low capacity factor would indicate that these boilers have high heat rates and a significant improvement in unit heat rate could result from retrofit or repowering of these boilers.

TABLE 7.4.1-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR JOPPA UNITS 1,2,5,6

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE (FSI)	HIGH
NEW BAGHOUSE (DSD)	MEDIUM
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	1,612
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	300
ESTIMATED COST (1000$)	1,963
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	47
TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	1,659
A NEW BAGHOUSE CASE (DSD)	2,010
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE (FSI)	1.55
NEW BAGHOUSE (DSD)	1.34

TABLE 7.4.1-10. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR JOPPA UNITS 3-4

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE (FSI)	HIGH
NEW BAGHOUSE (DSD)	HIGH
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	1612
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	300
ESTIMATED COST (1000$)	1,963
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	47
TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	1,659
A NEW BAGHOUSE CASE (DSD)	2,010
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE (FSI)	1.55
NEW BAGHOUSE (DSD)	1.55

Table 7.4.1-11. Summary of DSD/FSI Control Costs for the Joppa Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+FF	1,5	1.00	183	15	2.0	29.9	163.3	11.0	45.8	71.0	2826	3895.9
DSD+FF	2,6	1.00	183	13	2.0	29.9	163.3	10.9	52.3	71.0	2449	4448.7
DSD+FF	3,4	1.00	183	15	2.0	33.2	181.5	11.9	49.4	71.0	2826	4201.0
DSD+FF-C	1,5	1.00	183	15	2.0	29.9	163.3	6.4	26.8	71.0	2826	2279.5
DSD+FF-C	2,6	1.00	183	13	2.0	29.9	163.3	6.4	30.6	71.0	2449	2603.5
DSD+FF-C	3,4	1.00	183	15	2.0	33.2	181.5	7.0	28.9	71.0	2826	2459.5

7.5 ILLINOIS POWER COMPANY

7.5.1 Baldwin Steam Plant

The Baldwin plant is located within Randolph County, Illinois, as part of the Illinois Power Company system. The plant contains three coal-fired boilers with a net generating capacity of 1,680 MW. Figure 7.5.1-1 presents the plant plot plan showing the location of all the boilers and major associated auxiliary equipment.

Table 7.5.1-1 presents operational data for the existing equipment at the Baldwin steam plant. All boilers burn high sulfur coal (2.8 percent sulfur). Coal shipments are received by rail and conveyed to a coal storage and handling area located northeast of unit 1.

Particulate matter emissions for all three boilers are controlled with ESPs located behind each unit. Ash from all units is wet sluiced to ponds located southwest of the plant. Limited space is available for waste disposal and excess furnace waste may need to be dry disposed of off-site.

Lime/Limestone and Lime Spray Drying FGD Costs--
Figure 7.5.1-1 shows the general layout and location of the FGD control system. The ESPs for each unit are directly behind the boilers, followed by the chimneys (one for each boiler), in front of the cooling water reservoir. The absorber for unit 1 was located north of the unit 1 chimney beside the water treatment area. There is limited space between units 2-3 and the cooling water reservoir to locate the absorbers for these units; therefore, the absorbers would be located in an area to the south of unit 3. Plant roads and an employee parking area would need to be relocated to accommodate the placement of the FGD absorbers. Finally, the limestone preparation/ storage and waste handling areas were placed directly south of the unit 2 and 3 absorbers. Because of the relocation of the employee parking area and plant roads for unit 1, a factor of 10 percent was assigned to general facilities. No major demolition/relocation would be required for units 2 and 3 FGD system and a factor of 5 percent was assigned to general facilities.

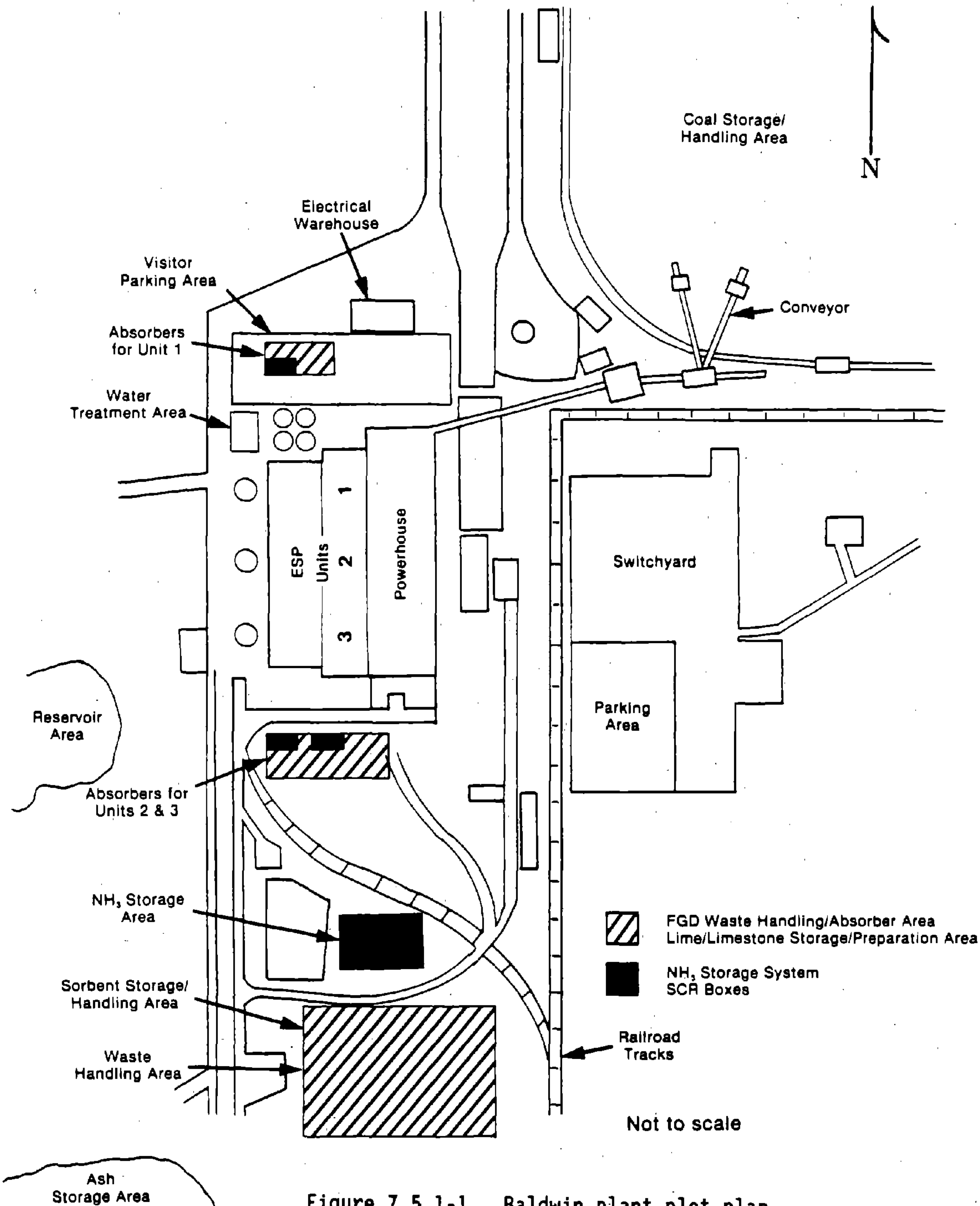

Figure 7.5.1-1. Baldwin plant plot plan

TABLE 7.5.1-1. BALDWIN STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2	3
GENERATING CAPACITY (MW)	560	560	560
CAPACITY FACTOR (PERCENT)	62.3	63.7	68.3
INSTALLATION DATE	1970	1973	1975
FIRING TYPE	CYC	CYC	TANG
COAL SULFUR CONTENT (PERCENT)	2.8	2.8	2.8
COAL HEATING VALUE (BTU/LB)	10700	10700	10700
COAL ASH CONTENT (PERCENT)	10.5	10.5	10.5
FLY ASH SYSTEM		WET SLUICE	
ASH DISPOSAL METHOD		POND/ON-SITE	
STACK NUMBER	1	2	3
COAL DELIVERY METHODS		RAILROAD	
<u>PARTICULATE CONTROL</u>			
TYPE	ESP	ESP	ESP
INSTALLATION DATE	1970	1973	1975
EMISSION LIMIT (LB/MM BTU)	0.20	0.20	0.10
REMOVAL EFFICIENCY	90.3	94.7	99.5
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	4.5	4.5	4.0
SURFACE AREA (1000 SQ FT)	311	311	542
GAS EXIT RATE (1000 ACFM)	1730	1730	2190
SCA (SQ FT/1000 ACFM)	180	180	247
OUTLET TEMPERATURE (°F)	310	310	310

Retrofit Difficulty and Scope Adder Costs--

The absorber locations for all units were assigned low site access/congestion factors. The absorbers for unit 1 would be located north of the respective unit in an area with no major obstacles/obstructions. The absorbers for units 2 and 3 were located in an area slightly remote from the chimneys south of unit 3. A medium flue gas handling factor was assigned to unit 1, due to the congestion created by the water treatment area. A high site access/congestion factor was assigned to unit 2 flue gas handling system because of the access difficulty caused by the unit 3 chimney/ESP. A moderate site congestion factor was assigned to unit 3 flue gas handling system because of the limited space availability around the chimney. A moderate duct length was required for unit 3, while long duct runs would be needed for units 1 and 2.

The major scope adjustment costs and estimated retrofit factors for the FGD control technologies are presented in Tables 7.5.1-2 through 7.5.1-4. The largest scope adder for the Baldwin plant would be the conversion of units 1 through 3 fly ash conveying/disposal system from wet to dry for conventional L/LS-FGD cases. It was assumed that dry fly ash would be used to stabilize part of the conventional L/LS-FGD scrubber sludge waste. The overall retrofit factors determined for the L/LS-FGD cases were moderate (1.35 to 1.53). The conversion of wet to dry ash handling is not required for L/LS forced oxidation application.

For the LSD-FGD reuse ESP case, a large plate area addition would be required to upgrade the ESPs for units 1 and 2 due to the small SCAs (<200). Because the existing ESPs are located in a highly congested area, LSD with a new baghouse was the only LSD-FGD case evaluated for units 1 and 2. However, unit 3 ESPs are moderate in size (>240) and LSD reuse ESP was the only case considered for unit 3. The retrofit factors determined for the LSD technology were moderate (1.38 to 1.43) and did not include particulate control costs. Separate retrofit factors were estimated for upgrading ESPs (1.58) and the new baghouses (1.16) to reflect the access/congestion associated with their locations. These factors were used in the IAPCS model to estimate the new particulate control costs.

TABLE 7.5.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR BALDWIN UNIT 1

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	MEDIUM	MEDIUM	
ESP REUSE CASE			NA
BAGHOUSE CASE			MEDIUM
DUCT WORK DISTANCE (FEET)	600-1000	600-1000	
ESP REUSE			NA
BAGHOUSE			600-1000
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	NO
ESTIMATED COST (1000$)	4393	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.49	1.42	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.38
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	10	10	10

TABLE 7.5.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR BALDWIN UNIT 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	HIGH	HIGH	
ESP REUSE CASE			NA
BAGHOUSE CASE			HIGH
DUCT WORK DISTANCE (FEET)	600-1000	600-1000	
ESP REUSE			NA
BAGHOUSE			600-1000
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	NO
ESTIMATED COST (1000$)	4393	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.58	1.50	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.47
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	5	5	5

TABLE 7.5.1-4. SUMMARY OF RETROFIT FACTOR DATA FOR BALDWIN UNIT 3

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	MEDIUM	MEDIUM	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	4393	NA	4393
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.42	1.35	
ESP REUSE CASE			1.38
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	5	5

FGD Retrofit Costs--

Table 7.5.1-5 presents the cost estimates for L/LS and LSD-FGD cases. The LSD-FGD costs include installing new baghouses to handle the additional particulate loading for boilers 1 and 2 and upgrading the ESPs and ash handling systems for boiler 3.

The low cost control case was evaluated separately for unit 1 and combined for units 2 and 3. For unit 1, the significant reduction in costs is primarily due to the elimination of spare scrubber module and optimization of scrubber size. For units 2 and 3, an additional reduction in cost occurs due to the benefit of economies-of-scale when combining process areas.

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined. This is particularly true for cyclone boilers. As such, coal switching was not evaluated for units 1 and 2. The transportation cost differential might be substantial resulting in a higher fuel price differential as assumed in this report.

Unit 3 ESP performance impacts were evaluated using the IAPCS model to estimate the needed plate area. This plate area was compared to the existing area to determine whether SO_3 conditioning or additional plate area was needed. SO_3 conditioning was assumed to reduce the needed plate area up to 25 percent. Costs were generated to show the impact of two different coal fuel cost differentials. The costs associated with each boiler for the range of fuel cost differential are shown in Table 7.5.1-6.

NO_x Control Technology Costs--

This section presents the performance and various related costs estimated for NO_x controls at the Baldwin plant. These controls include LNC and SCR. The application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2. The NO_x technologies evaluated at the Baldwin plant were: NGR - units 1 and 2, OFA - unit 3, and SCR - all units.

Table 7.5.1-5. Summary of FGD Control Costs for the Baldwin Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.49	560	62	2.8	142.1	253.7	70.5	23.1	90.0	70872	995.0
L/S FGD	2	1.58	560	64	2.8	145.3	259.5	72.1	23.1	90.0	72464	995.3
L/S FGD	3	1.42	560	68	2.8	132.5	236.5	69.5	20.7	90.0	77697	894.4
L/S FGD-C	1	1.49	560	62	2.8	142.1	253.7	41.0	13.4	90.0	70872	579.0
L/S FGD-C	2	1.58	560	64	2.8	145.3	259.5	42.0	13.4	90.0	72464	579.2
L/S FGD-C	3	1.42	560	68	2.8	132.5	236.5	40.4	12.1	90.0	77697	520.1
LC FGD	1	1.49	560	62	2.8	115.4	206.1	61.8	20.2	90.0	70872	871.5
LC FGD	2-3	1.50	1120	66	2.8	198.2	176.9	112.2	17.3	90.0	150162	747.3
LC FGD-C	1	1.49	560	62	2.8	115.4	206.1	35.9	11.7	90.0	70872	506.6
LC FGD-C	2-3	1.50	1120	66	2.8	198.2	176.9	65.2	10.1	90.0	150162	434.1
LSD+ESP	3	1.38	560	68	2.8	79.8	142.5	41.2	12.3	72.0	61973	664.2
LSD+ESP-C	3	1.38	560	68	2.8	79.8	142.5	23.9	7.1	72.0	61973	386.3
LSD+FF	1	1.38	560	62	2.8	115.4	206.0	48.5	15.9	87.0	68115	712.2
LSD+FF	2	1.47	560	64	2.8	117.5	209.8	49.5	15.8	87.0	69646	710.1
LSD+FF-C	1	1.38	560	62	2.8	115.4	206.0	28.3	9.3	87.0	68115	415.6
LSD+FF-C	2	1.47	560	64	2.8	117.5	209.8	28.9	9.2	87.0	69646	414.4

Table 7.5.1-6. Summary of Coal Switching/Cleaning Costs for the Baldwin Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	3	1.00	560	68	2.8	17.2	30.7	46.7	13.9	72.0	62137	752.1
CS/B+$15-C	3	1.00	560	68	2.8	17.2	30.7	26.9	8.0	72.0	62137	432.1
CS/B+$5	3	1.00	560	68	2.8	11.4	20.3	18.0	5.4	72.0	62137	290.3
CS/B+$5-C	3	1.00	560	68	2.8	11.4	20.3	10.4	3.1	72.0	62137	167.2

Low NO_x Combustion--

Units 1 and 2 are wet bottom, cyclone-fired boilers rated at 560 MW each. The combustion modification technique applied to both boilers was NGR. Unit 3 is a dry bottom, tangential-fired boiler rated at 635 MW. The combustion modification technique applied for this unit was OFA. The NO_x reduction performance estimated for unit 3 was 25 percent. Table 7.5.1-7 presents the results for all boilers evaluated for NO_x control applicability at the Baldwin plant. Table 7.5.1-8 presents the cost of retrofitting NGR and OFA at the Baldwin plant. For this study it was assumed that the plant has access to a natural gas pipeline. However, plant personnel indicated that 18 miles of pipeline and interconnection is expected to add at least 10 million dollars to the capital cost. This additional cost was added as a scope adder to the NGR capital cost.

Selective Catalytic Reduction--

Table 7.5.1-7 presents the SCR retrofit results for each unit. The results include process area retrofit difficulty factors and scope adder costs. The scope adders include costs estimated for ductwork demolition, new heat exchanger, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimney. A 25 percent general facilities factor was assigned to unit 1. Part of the visitor parking area and the roadway would have to be relocated.

The reactor for unit 1 was located north of the unit 1 chimney beside the water treatment area. Because the location of the reactor is in an open area with no major obstructions, this reactor was assigned a low access/congestion factor. The SCR reactors for units 2 and 3 would be located south of unit 3 in an open area with no major obstructions where the fourth unit would be built. Access to this area is relatively easy. For this reason, both reactors were assigned low access/congestion factors. All reactors were located in areas with high underground obstructions. Finally, the ammonia storage system, which would supply ammonia to the reactors for all three units, would be located southeast of the reactors for units 2 and 3 in an area with low access/congestion and no significant underground obstructions.

As discussed in Section 2, all NO_x control techniques were evaluated independently from those techniques evaluated for SO_2 control. In this case,

TABLE 7.5.1-7. SUMMARY OF NOx RETROFIT RESULTS FOR BALDWIN

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	3
FIRING TYPE	CY	CY	TANG
TYPE OF NOx CONTROL	NGR	NGR	OFA
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	NA	NA	10.8
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	NA	NA	72.4
FURNACE RESIDENCE TIME (SECONDS)	NA	NA	4.17
ESTIMATED NOx REDUCTION (PERCENT)	60	60	25
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	98	98	98
New Duct Length (Feet)	800	1000	650
New Duct Costs (1000$)	10860	13575	8824
New Heat Exchanger (1000$)	5240	5240	5240
TOTAL SCOPE ADDER COSTS (1000$)	16198	18913	14162
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	25	13	13

Table 7.5.1-8. NOx Control Cost Results for the Baldwin Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	3	1.00	560	68	2.8	1.2	2.2	0.3	0.1	25.0	2965	91.0
LNC-OFA-C	3	1.00	560	68	2.8	1.2	2.2	0.2	0.0	25.0	2965	54.0
NGR	1	1.00	560	62	2.8	8.1	14.4	16.7	5.5	60.0	16009	1043.6
NGR	2	1.00	560	64	2.8	8.1	14.4	17.1	5.5	60.0	16369	1042.2
NGR-C	1	1.00	560	62	2.8	8.1	14.4	9.6	3.1	60.0	16009	600.2
NGR-C	2	1.00	560	64	2.8	8.1	14.4	9.8	3.1	60.0	16369	599.3
SCR-3	1	1.16	560	62	2.8	78.3	139.9	29.1	9.5	80.0	21345	1364.7
SCR-3	2	1.16	560	64	2.8	78.8	140.8	29.1	9.3	80.0	21825	1333.6
SCR-3	3	1.16	560	68	2.8	73.7	131.6	26.9	8.0	80.0	9487	2835.0
SCR-3-C	1	1.16	560	62	2.8	78.3	139.9	17.0	5.6	80.0	21345	798.3
SCR-3-C	2	1.16	560	64	2.8	78.8	140.8	17.0	5.4	80.0	21825	780.2
SCR-3-C	3	1.16	560	68	2.8	73.7	131.6	15.7	4.7	80.0	9487	1659.1
SCR-7	1	1.16	560	62	2.8	78.3	139.9	24.4	8.0	80.0	21345	1145.4
SCR-7	2	1.16	560	64	2.8	78.8	140.8	24.4	7.8	80.0	21825	1119.1
SCR-7	3	1.16	560	68	2.8	73.7	131.6	22.2	6.6	80.0	9487	2341.7
SCR-7-C	1	1.16	560	62	2.8	78.3	139.9	14.4	4.7	80.0	21345	672.7
SCR-7-C	2	1.16	560	64	2.8	78.8	140.8	14.3	4.6	80.0	21825	657.4
SCR-7-C	3	1.16	560	68	2.8	73.7	131.6	13.1	3.9	80.0	9487	1376.4

the three SCR reactors are located in the same areas as the FGD absorbers. If both SO_2 and NO_x emissions needed to be reduced at this plant, the SCR reactors would have to be located downstream of the FGD absorbers using this scheme. The SCR reactor for unit 1 would be located east of the FGD absorbers for unit 1; whereas, the SCR reactors for units 2 and 3 would be located immediately south of the FGD absorbers for units 2 and 3. The new locations of the reactors are generally in open areas having easy access. Therefore, low access/congestion factors again would be assigned to these reactors. Table 7.5.1-8 presents the estimated cost of retrofitting SCR at the Baldwin boilers. SCR application on cyclone boilers burning high sulfur coal would have a high degree of uncertainty because of the lack of commercial experience.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas for all units were located south of the plant. The layout and location would be similar to that for LSD-FGD. The retrofit of DSD at Baldwin would be difficult. The SCAs for units 1 and 2 are small (<200) for DSD application. Even though the SCA for unit 3 is moderate in size and might be sufficient to handle the increased particulate load resulting from sorbent injection application, there is short duct residence time between the boiler and the ESP in addition to the location of the ESP in a high access/congestion area. Therefore, it was assumed that new particulate controls would be needed for the DSD technology. Over 400 feet of duct runs would be required to divert the flue gas from the boilers to the baghouses and back to the existing chimneys. It was assumed that the ESPs could be upgraded for FSI for unit 3 but not for units 1 and 2 which would require additional plate area. As such, FSI costs for units 1 and 2 were not reported. The conversion of wet to dry ash handling system would be required for reusing the ESPs for FSI technology. Tables 7.5.1-9 through 7.5.1-11 present a summary of site access/congestion factors, scope adders, and retrofit factors for DSD and FSI technologies at the Baldwin steam plant. The costs are shown on a dollar ($) per boiler basis. Table 7.5.1-12 presents the costs estimated to retrofit DSD with new fabric filter and FSI on unit 3 for the Baldwin plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Baldwin plant. The boilers at Baldwin would not be considered candidates for AFBC retrofit and AFBC/CG/combined cycle repowering because all boilers are large (MW >600) and were built after 1970.

7.5.2 Hennepin Steam Plant

The Hennepin steam plant is located within Putnam County, Illinois, as part of the Illinois Power Company system. The plant is located beside the Illinois River and contains two coal-fired boilers with a total gross generating capacity of 280 MW.

Table 7.5.2-1 presents operational data for the existing equipment at the Hennepin plant. The boilers burn high sulfur coal. Coal shipments are received by barge and transferred to a coal storage and handling area west of the plant and adjacent to the river.

PM emissions for the boilers are controlled with retrofit ESPs located behind each unit. The plant has a wet fly ash handling system. Fly ash is disposed of on-site in an ash pond located east of the plant. Both units are ducted to a common chimney located beside the river.

Lime/Limestone and Lime Spray Drying FGD Costs--

Boilers 1 and 2 are located beside each other, parallel to the river, with the water intake and discharge structure located directly behind the chimney. The FGD absorbers would be placed east of unit 2 which will require relocating some railroad tracks to make sufficient space available

TABLE 7.5.1-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR BALDWIN UNIT 1

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE (FSI)	NA
NEW BAGHOUSE (DSD)	LOW
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	0
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	600
ESTIMATED COST (1000$)	7551
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	109
TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	0
A NEW BAGHOUSE CASE (DSD)	7660
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE (FSI)	NA
NEW BAGHOUSE (DSD)	1.16

TABLE 7.5.1-10. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR BALDWIN UNIT 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE (FSI)	NA
NEW BAGHOUSE (DSD)	LOW
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	0
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	900
ESTIMATED COST (1000$)	11,326
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	109

TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	0
A NEW BAGHOUSE CASE (DSD)	11,435
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE (FSI)	NA
NEW BAGHOUSE (DSD)	1.16

TABLE 7.5.1-11. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR BALDWIN UNIT 3

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE (FSI)	HIGH
NEW BAGHOUSE (DSD)	LOW
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	4,393
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	600
ESTIMATED COST (1000$)	7,551
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	109

TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	4,502
A NEW BAGHOUSE CASE (DSD)	7,660
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE (FSI)	1.58
NEW BAGHOUSE (DSD)	1.16

Table 7.5.1-12. Summary of DSD/FSI Control Costs for the Baldwin Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+FF	1	1.00	560	62	2.8	72.6	129.6	34.6	11.3	71.0	55713	621.4
DSD+FF	2	1.00	560	64	2.8	76.5	136.7	35.6	11.4	71.0	56965	625.5
DSD+FF	3	1.00	560	68	2.8	76.6	136.8	38.7	11.5	69.0	59968	644.6
DSD+FF-C	1	1.00	560	62	2.8	72.6	129.6	20.2	6.6	71.0	55713	361.8
DSD+FF-C	2	1.00	560	64	2.8	76.5	136.7	20.8	6.6	71.0	56965	364.4
DSD+FF-C	3	1.00	560	68	2.8	76.6	136.8	22.5	6.7	69.0	59968	375.1
FSI+ESP-50	3	1.00	560	68	2.8	33.6	59.9	35.7	10.7	50.0	43165	827.2
FSI+ESP-50-C	3	1.00	560	68	2.8	33.6	59.9	20.6	6.2	50.0	43165	477.4
FSI+ESP-70	3	1.00	560	68	2.8	33.2	59.3	36.2	10.8	70.0	60431	599.7
FSI+ESP-70-C	3	1.00	560	68	2.8	33.2	59.3	20.9	6.2	70.0	60431	346.0

TABLE 7.5.2-1. HENNEPIN STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2
GENERATING CAPACITY (MW)	70	210
CAPACITY FACTOR (PERCENT)	42.6	64.6
INSTALLATION DATE	1953	1959
FIRING TYPE	TANGENTIAL	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	49.8	128.5
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	2.67	2.67
COAL HEATING VALUE (BTU/LB)	10800	10800
COAL ASH CONTENT (PERCENT)	10.5	10.5
FLY ASH SYSTEM	WET HANDLING	
ASH DISPOSAL METHOD	ON-SITE	
STACK NUMBER	1	
COAL DELIVERY METHODS	BARGE	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1974	1972
EMISSION (LB/MM BTU)	0.06	0.12
REMOVAL EFFICIENCY	98.7	97.5
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	2.8	2.8
SURFACE AREA (1000 SQ FT)	64.8	147
GAS EXIT RATE (1000 ACFM)	290	750
SCA (SQ FT/1000 ACFM)	223	196
OUTLET TEMPERATURE (°F)	305	335

for the absorbers. A low site access/congestion factor was assigned to the FGD absorber locations. The sorbent preparation, storage, and handling area would be located beside the absorbers. Because railroad tracks have to be relocated, a factor of 10 percent was assigned to general facilities. A temporary waste handling area would be located close to the storage area. However, because of the limited space available, waste generated by the FGD application has to be transferred off-site.

It was assumed that a new chimney would be constructed beside the absorbers to reduce the required flue gas duct length to approximately 500 feet of duct. A high site access/congestion factor was assigned to the flue gas handling system reflecting the congestion around the units.

LSD with reuse of the existing ESPs was not considered for this plant because the ESPs are small (SCAs <225) and would require major upgrading and additional plate area to handle the increased PM generated from the LSD application. In addition, access to the upstream of the ESPs is very difficult. LSD with a new baghouse was not considered because the boilers are not burning low sulfur coal.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Table 7.5.2-2. Table 7.5.2-3 presents the process area retrofit factors and capital/operating costs for commercial L/LS-FGD technologies. The low cost FGD case shows the reduction in cost associated with eliminating spare absorbers and maximizing absorber size.

Coal Switching and Physical Coal Cleaning Costs--

Table 7.5.2-4 presents the IAPCS results for CS at the Hennepin plant. These costs do not include impacts due to changes in boiler and pulverizer operating costs; however, does include ESP upgrade costs. PCC was not evaluated because this is not a mine mouth plant.

Low NO_x Combustion--

Units 1 and 2 are dry bottom tangential-fired boilers rated at 70 and 210 MW. The combustion modification technique applied to both boilers was OFA. Tables 7.5.2-5 and 7.5.2-6 present the NO_x reduction performance and cost results of retrofitting OFA at Hennepin. Although furnace volume data

TABLE 7.5.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR HENNEPIN UNITS 1 OR 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	NA
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			NA
BAGHOUSE			NA
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NA
ESTIMATED COST (1000$)	681, 1823	NA	NA
NEW CHIMNEY	YES	NA	NA
ESTIMATED COST (1000$)	490, 1470	0	0
OTHER	NO		
RETROFIT FACTORS			
FGD SYSTEM	1.48	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	0	0

Table 7.5.2-3. Summary of FGD Control Costs for the Hennepin Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.48	70	43	2.7	42.3	604.4	17.8	68.1	90.0	5779	3078.6
L/S FGD	2	1.48	210	65	2.7	72.4	344.7	34.4	29.0	90.0	26291	1309.3
L/S FGD	1-2	1.48	280	59	2.7	87.7	313.1	41.1	28.3	90.0	32071	1281.1
L/S FGD-C	1	1.48	70	43	2.7	42.3	604.4	10.4	39.7	90.0	5779	1796.6
L/S FGD-C	2	1.48	210	65	2.7	72.4	344.7	20.0	16.9	90.0	26291	762.5
L/S FGD-C	1-2	1.48	280	59	2.7	87.7	313.1	23.9	16.5	90.0	32071	746.2
LC FGD	1-2	1.48	280	59	2.7	66.6	237.8	34.2	23.6	90.0	32071	1065.0
LC FGD-C	1-2	1.48	280	59	2.7	66.6	237.8	19.9	13.7	90.0	32071	619.5

Table 7.5.2-4. Summary of Coal Switching/Cleaning Costs for the Hennepin Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	70	43	2.7	3.0	43.4	4.3	16.5	71.0	4535	950.9
CS/B+$15	2	1.00	210	65	2.7	8.5	40.4	17.5	14.7	71.0	20632	848.8
CS/B+$15-C	1	1.00	70	43	2.7	3.0	43.4	2.5	9.5	71.0	4535	547.8
CS/B+$15-C	2	1.00	210	65	2.7	8.5	40.4	10.1	8.5	71.0	20632	488.1
CS/B+$5	1	1.00	70	43	2.7	2.3	33.1	2.0	7.8	71.0	4535	447.1
CS/B+$5	2	1.00	210	65	2.7	6.3	30.0	7.3	6.2	71.0	20632	354.6
CS/B+$5-C	1	1.00	70	43	2.7	2.3	33.1	1.2	4.5	71.0	4535	258.5
CS/B+$5-C	2	1.00	210	65	2.7	6.3	30.0	4.2	3.6	71.0	20632	204.5

TABLE 7.5.2-5. SUMMARY OF NOx RETROFIT RESULTS FOR HENNEPIN

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	1-2
FIRING TYPE	TANG	TANG	NA
TYPE OF NOx CONTROL	OFA	OFA	NA
FURNACE VOLUME (1000 CU FT)	49.8	128.5	NA
BOILER INSTALLATION DATE	1953	1959	NA
SLAGGING PROBLEM	NO	NO	NA
ESTIMATED NOx REDUCTION (PERCENT)	25	25	NA
SCR RETROFIT RESULTS (COMBINED)			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	LOW
SCOPE ADDER PARAMETERS--			
New Chimney (1000$)	NO	NO	NO
Ductwork Demolition (1000$)	21	47	59
New Duct Length (Feet)	500	500	500
New Duct Costs (1000$)	2011	3824	4525
New Heat Exchanger (1000$)	1505	2909	3457
TOTAL SCOPE ADDER COSTS (1000$)	3536	6780	8040
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13	13

Table 7.5.2-6. NOx Control Cost Results for the Hennepin Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	1	1.00	70	43	2.7	0.5	7.7	0.1	0.4	25.0	229	512.1
LNC-OFA	2	1.00	210	65	2.7	0.8	4.0	0.2	0.2	25.0	1040	175.1
LNC-OFA-C	1	1.00	70	43	2.7	0.5	7.7	0.1	0.3	25.0	229	303.9
LNC-OFA-C	2	1.00	210	65	2.7	0.8	4.0	0.1	0.1	25.0	1040	103.9
SCR-3	1	1.16	70	43	2.7	16.2	231.8	5.1	19.4	80.0	732	6922.6
SCR-3	2	1.16	210	65	2.7	33.8	160.7	11.5	9.7	80.0	3329	3463.7
SCR-3	1-2	1.16	280	59	2.7	42.3	151.0	14.6	10.1	80.0	4061	3593.0
SCR-3-C	1	1.16	70	43	2.7	16.2	231.8	3.0	11.4	80.0	732	4065.6
SCR-3-C	2	1.16	210	65	2.7	33.8	160.7	6.8	5.7	80.0	3329	2029.9
SCR-3-C	1-2	1.16	280	59	2.7	42.3	151.0	8.5	5.9	80.0	4061	2105.2
SCR-7	1	1.16	70	43	2.7	16.2	231.8	4.5	17.2	80.0	732	6124.2
SCR-7	2	1.16	210	65	2.7	33.8	160.7	9.8	8.2	80.0	3329	2937.2
SCR-7	1-2	1.16	280	59	2.7	42.3	151.0	12.3	8.5	80.0	4061	3017.5
SCR-7-C	1	1.16	70	43	2.7	16.2	231.8	2.6	10.1	80.0	732	3608.2
SCR-7-C	2	1.16	210	65	2.7	33.8	160.7	5.8	4.8	80.0	3329	1728.3
SCR-7-C	1-2	1.16	280	59	2.7	42.3	151.0	7.2	5.0	80.0	4061	1775.5

was not available for unit 1, it was assumed to have a low volumetric heat release rate typical of the 1950's boiler design.

Selective Catalytic Reduction--

Cold side SCR reactors for both units would be located west of unit 1. Both reactors are located in a low access/congestion area requiring about 500 feet of flue gas ducting and flue gas reheater. A base factor of 13 percent was assigned to general facilities. The ammonia storage system was placed close to the reactors, east of the plant.

Table 7.5.2-5 presents the SCR factors and scope adder costs. Table 7.5.2-6 presents the estimated cost of retrofitting SCR at the Hennepin boilers.

Duct Spray Drying and Furnace Sorbent Injection--

The retrofit of FSI or DSD technologies at the Hennepin plant for both units would be very difficult for two major reasons: 1) the ESPs have small SCAs (<225); hence, they probably would not be able to handle the increased PM and would require major upgrading and additional plate area; 2) the short duct residence time between the boilers and ESPs would not be sufficient for humidification (FSI application) or sorbent evaporation (DSD application). In addition, the ESPs are located in a high congestion area making it difficult to add plate area. Therefore, sorbent injection technologies were not considered for this plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at Hennepin. Both units would be considered potential candidates for retrofit/repowering because of their small boiler sizes. However, the high capacity factors could result in significant replacement power cost.

7.5.3 Vermilion Steam Plant

The Vermilion steam plant is located within Vermilion County, Illinois, as part of the Illinois Power Company system. The plant contains two coal-fired boilers with a total gross generating capacity of 165 MW. Figure 7.5.3-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 7.5.3-1 presents operational data for the existing equipment at the Vermilion plant. The boilers burn medium sulfur coal (2.4 percent sulfur). Coal shipments are received by truck and conveyed to a coal storage and handling area located east of the powerhouse.

Particulate matter emissions for the boilers are controlled with retrofit ESPs. Fly ash is wet sluiced to ponds located west of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 7.5.3-1 shows the general layout and location of the FGD control system. The boilers share a common chimney. The absorbers for L/LS-FGD and LSD-FGD for both units would be located north of the chimney on the other side of the railroad track. No demolition/relocation would be required; therefore, a factor of 5 percent was assigned to general facilities. However, a small amount of demolition/
relocation would be needed for the fire pump house and well water storage tank. The limestone storage/handling area and waste handling area would be located to the north of the absorbers.

Retrofit Difficulty and Scope Adder Costs--

A low site access/congestion factor was assigned to the absorber locations. Because the absorbers would be located on the other side of the railroad, the railroad would not need to be relocated.

For flue gas handling, however, moderate duct runs for the units would be required for L/LS-FGD cases to divert the flue gas from the downstream of the ESP outlets to the absorbers and back to the chimney. A low site access/congestion factor was assigned to the flue gas handling system due to no major obstacles or obstructions in the surrounding area.

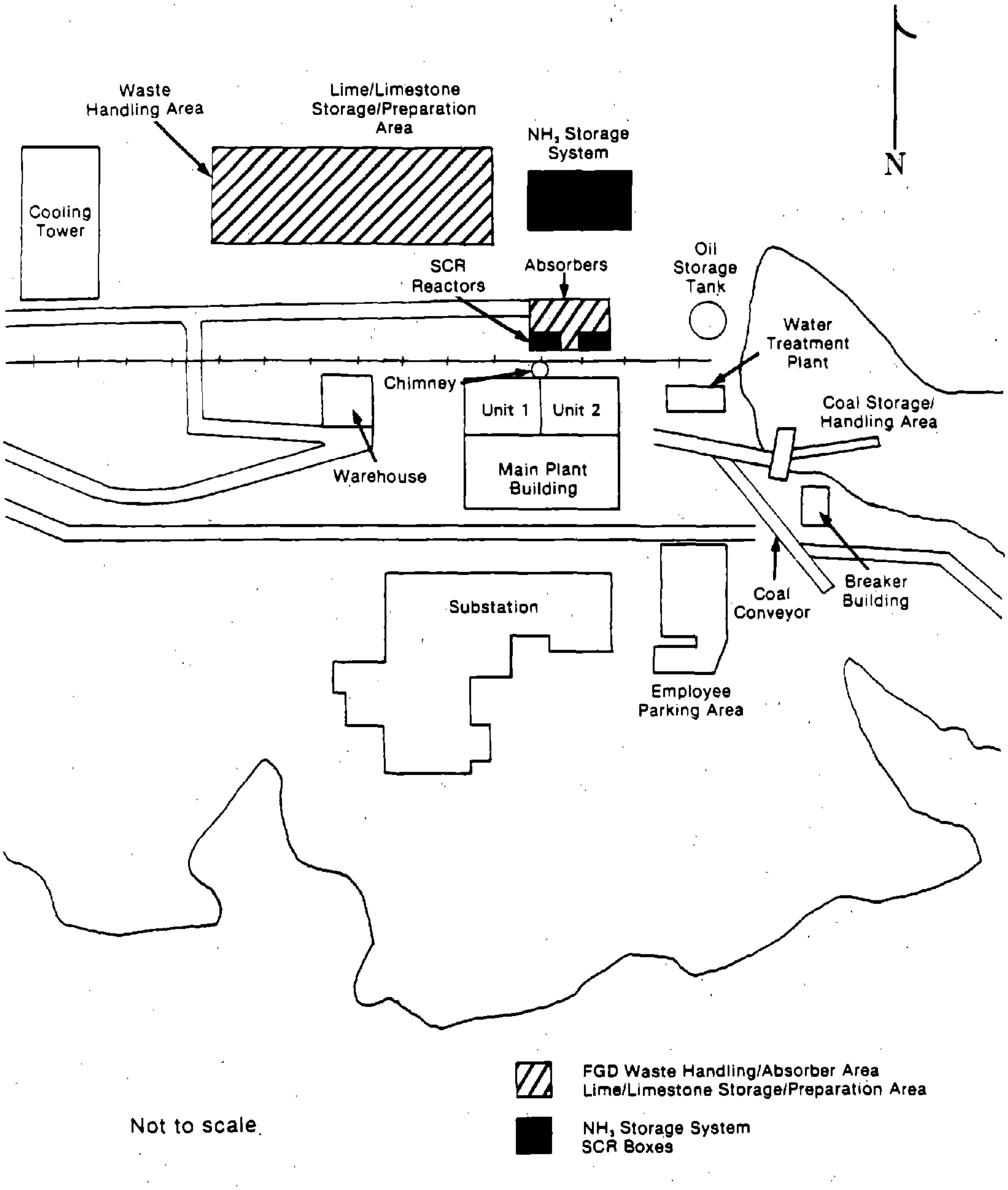

Figure 7.5.3-1. Vermilion plant plot plan

TABLE 7.5.3-1. VERMILION STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2
GENERATING CAPACITY (MW)	70	95
CAPACITY FACTOR (PERCENT)	53.4	66.1
INSTALLATION DATE	1955	1956
FIRING TYPE	TANG	TANG
COAL SULFUR CONTENT (PERCENT)	2.4	2.4
COAL HEATING VALUE (BTU/LB)	10775	10775
COAL ASH CONTENT (PERCENT)	11.2	11.2
FLY ASH SYSTEM	WET SLUICE	
ASH DISPOSAL METHOD	POND/ON-SITE	
STACK NUMBER	1	
COAL DELIVERY METHODS	TRUCK	
<u>PARTICULATE CONTROL</u>		
TYPE	ESP	ESP
INSTALLATION DATE	1973	1974
EMISSION LIMIT (LB/MM BTU)	0.118	0.10
REMOVAL EFFICIENCY	99.0	99.7
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	2.8	2.8
SURFACE AREA (1000 SQ FT)	55.1	97.2
EXIT GAS FLOW RATE (1000 ACFM)	254	425
SCA (SQ FT/1000 ACFM)	217	229
OUTLET TEMPERATURE (°F)	310	310

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Table 7.5.3-2. The largest scope adder for the Vermilion plant would be the conversion of units 1-2 fly ash conveying/disposal system from wet to dry for conventional L/LS-FGD cases. It was assumed that dry fly ash would be necessary to stabilize scrubber sludge waste. This conversion is not necessary for forced oxidation L/LS-FGD. The overall retrofit factors determined for the L/LS-FGD cases were low to medium (1.31 to 1.38).

The absorbers for LSD-FGD would be located in a similar location as in L/LS-FGD cases. Because the sizes are marginal and the ESPs are roof-mounted, upgrading would be difficult. The LSD-FGD technology with a new baghouse was the only case considered. For flue gas handling for LSD cases, moderate duct runs would be required the same as for L/LS-FGD cases. The retrofit factor determined for the LSD technology case was low (1.27) and did not include the new baghouse costs. A separate retrofit factor was developed for the new baghouses for the units. The baghouse locations would be adjacent to the absorbers with a low site access/congestion factor; therefore, a retrofit factor (1.16) was designated to the baghouse locations. This factor was used in the IAPCS model to estimate particulate control costs.

Table 7.5.3-3 presents the cost estimates for L/LS and LSD-FGD cases. The LSD-FGD costs include installing new baghouses to handle the additional particulate loading for boilers 1 and 2. The low cost control case reduces capital and annual operating costs. The significant reduction in costs is primarily due to the benefits of economies-of-scale when combining process areas, elimination of spare scrubber module, optimization of scrubber module size, and use of organic acid additives.

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined.

TABLE 7.5.3-2. SUMMARY OF RETROFIT FACTOR DATA FOR VERMILION UNITS 1 OR 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			NA
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	NO
ESTIMATED COST (1000$)	1300	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.38	1.31	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.27
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	5	5	5

Table 7.5.3-3. Summary of FGD Control Costs for the Vermilion Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.38	70	53	2.4	39.5	564.2	17.2	52.4	90.0	6457	2657.3
L/S FGD	2	1.38	95	66	2.4	45.9	482.7	20.9	38.1	90.0	10847	1931.0
L/S FGD	1-2	1.38	165	61	2.4	58.8	356.3	27.3	31.1	90.0	17300	1575.5
L/S FGD-C	1	1.38	70	53	2.4	39.5	564.2	10.0	30.6	90.0	6457	1549.9
L/S FGD-C	2	1.38	95	66	2.4	45.9	482.7	12.2	22.2	90.0	10847	1125.3
L/S FGD-C	1-2	1.38	165	61	2.4	58.8	356.3	15.9	18.1	90.0	17300	917.9
LC FGD	1-2	1.38	165	61	2.4	42.4	256.9	21.7	24.7	90.0	17300	1251.9
LC FGD-C	1-2	1.38	165	61	2.4	42.4	256.9	12.6	14.4	90.0	17300	728.2
LSD+FF	1	1.27	70	53	2.4	20.9	299.0	9.8	30.0	85.0	6085	1614.6
LSD+FF	2	1.27	95	66	2.4	26.2	275.7	12.3	22.4	85.0	10222	1207.6
LSD+FF-C	1	1.27	70	53	2.4	20.9	299.0	5.7	17.5	85.0	6085	940.5
LSD+FF-C	2	1.27	95	66	2.4	26.2	275.7	7.2	13.1	85.0	10222	703.4

The ESP performance impacts were evaluated using the IAPCS model to estimate the needed plate area. This plate area was compared to the existing area to determine whether SO_3 conditioning or additional plate area was needed. SO_3 conditioning was assumed to reduce the needed plate area up to 25 percent.

Costs were generated to show the impact of two different coal fuel cost differentials. The costs associated with each boiler for the range of fuel cost differential are shown in Table 7.5.3-4.

Currently the plant receives coal by truck. To be able to switch to a low sulfur coal, the existing railroad facilities would have to be upgraded. This upgrading of the existing railroad track was added as a scope adder to the capital cost.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Vermilion plant. These controls include LNC modification and SCR. The application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2. The NO_x technologies evaluated at the steam plant were: OFA and SCR.

Low NO_x Combustion--

Units 1 and 2 are dry bottom, tangential-fired boilers rated at 70 and 95 MW, respectively. The combustion modification technique applied for this evaluation was OFA. As Table 7.5.3-5 shows, the OFA NO_x reduction performances for units 1 and 2 were estimated to be 25 and 30 percent, respectively. Both reduction performance levels were assessed by examining the effects of heat release rates and furnace residence time on NO_x reduction through the use of the simplified NO_x procedures. Table 7.5.3-6 presents the cost of retrofitting OFA at the Vermilion boilers.

Selective Catalytic Reduction--

Table 7.5.3-5 presents the SCR retrofit results for each unit. The results include process area retrofit factors and scope adder costs. The scope adders include costs estimated for ductwork demolition, new flue gas

Table 7.5.3-4. Summary of Coal Switching/Cleaning Costs for the Vermilion Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	70	53	2.4	6.0	86.3	5.7	17.5	67.0	4810	1189.2
CS/B+$15	2	1.00	95	66	2.4	6.8	71.6	8.8	16.0	67.0	8080	1086.6
CS/B+$15-C	1	1.00	70	53	2.4	6.0	86.3	3.3	10.1	67.0	4810	687.0
CS/B+$15-C	2	1.00	95	66	2.4	6.8	71.6	5.1	9.2	67.0	8080	626.4
CS/B+$5	1	1.00	70	53	2.4	5.3	75.9	2.9	8.8	67.0	4810	600.5
CS/B+$5	2	1.00	95	66	2.4	5.8	61.3	4.1	7.4	67.0	8080	502.9
CS/B+$5-C	1	1.00	70	53	2.4	5.3	75.9	1.7	5.1	67.0	4810	349.0
CS/B+$5-C	2	1.00	95	66	2.4	5.8	61.3	2.4	4.3	67.0	8080	291.4

TABLE 7.5.3-5. SUMMARY OF NOx RETROFIT RESULTS FOR VERMILION

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	1-2
FIRING TYPE	TANG	TANG	NA
TYPE OF NOx CONTROL	OFA	OFA	NA
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	14.3	13.2	NA
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	21.6	44.9	NA
FURNACE RESIDENCE TIME (SECONDS)	3.44	3.23	NA
ESTIMATED NOx REDUCTION (PERCENT)	25	30	NA
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	21	26	39
New Duct Length (Feet)	300	300	300
New Duct Costs (1000$)	1207	1443	1992
New Heat Exchanger (1000$)	1505	1807	2517
TOTAL SCOPE ADDER COSTS (1000$)	2732	3276	4549
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13	13

Table 7.5.3-6. NOx Control Cost Results for the Vermilion Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	1	1.00	70	53	2.4	0.5	7.7	0.1	0.4	25.0	287	407.4
LNC-OFA	2	1.00	95	66	2.4	0.6	6.4	0.1	0.2	30.0	579	228.9
LNC-OFA-C	1	1.00	70	53	2.4	0.5	7.7	0.1	0.2	25.0	287	241.8
LNC-OFA-C	2	1.00	95	66	2.4	0.6	6.4	0.1	0.1	30.0	579	135.8
SCR-3	1	1.16	70	53	2.4	15.4	219.5	5.0	15.1	80.0	920	5388.9
SCR-3	2	1.16	95	66	2.4	18.5	194.2	6.1	11.2	80.0	1545	3975.0
SCR-3	1-2	1.16	165	61	2.4	26.9	162.9	9.2	10.5	80.0	2464	3743.6
SCR-3-C	1	1.16	70	53	2.4	15.4	219.5	2.9	8.9	80.0	920	3162.4
SCR-3-C	2	1.16	95	66	2.4	18.5	194.2	3.6	6.5	80.0	1545	2331.0
SCR-3-C	1-2	1.16	165	61	2.4	26.9	162.9	5.4	6.2	80.0	2464	2193.7
SCR-7	1	1.16	70	53	2.4	15.4	219.5	4.4	13.4	80.0	920	4753.5
SCR-7	2	1.16	95	66	2.4	18.5	194.2	5.3	9.7	80.0	1545	3461.7
SCR-7	1-2	1.16	165	61	2.4	26.9	162.9	7.8	8.9	80.0	2464	3184.6
SCR-7-C	1	1.16	70	53	2.4	15.4	219.5	2.6	7.9	80.0	920	2798.4
SCR-7-C	2	1.16	95	66	2.4	18.5	194.2	3.1	5.7	80.0	1545	2036.9
SCR-7-C	1-2	1.16	165	61	2.4	26.9	162.9	4.6	5.3	80.0	2464	1873.4

heat exchanger, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimney.

The SCR reactors for both units would be located north of the chimney on the other side of the railroad track in a relatively open area having easy access. For this reason, the reactors for units 1 and 2 were assigned low access/congestion factors. Both reactors were assumed to be in areas with high underground obstructions. The ammonia storage system was placed in a remote area having a low access/congestion factor.

As discussed in Section 2, all NO_x control techniques were evaluated independently from those evaluated for SO_2 control. If both SO_2 and NO_x emissions have to be reduced at this plant, the results presented for SCR in Table 7.5.3-5 would not change since the reactors would be located downstream of the FGD absorbers in same area as discussed before. Table 7.5.3-6 presents the estimated cost of retrofitting SCR at the Vermilion boilers.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas were located north of the plant in a similar fashion as LSD-FGD. The retrofit of DSD and FSI technologies at the Vermilion steam plant for the units would be very difficult. The ESPs are marginal in size, resulting in insufficient duct residence time between the boilers and the ESPs for DSD application. Therefore, new baghouses were assumed for the DSD cases which would be located north of the plant in a similar fashion as LSD-FGD cases. The new baghouses would require 400 feet of duct run to divert the flue gas from the boilers to the baghouses and back to the chimney. For FSI, upgrading the ESPs or plate area addition would be very difficult because the ESPs are squeezed between the boiler building and the chimney. As such, the retrofit factor estimated for upgrading the ESPs for FSI was high (1.58). Also, the conversion of wet to dry fly ash would be needed for reusing the ESPs to prevent plugging of sluice lines. Therefore, FSI costs were not developed for this plant. Tables 7.5.3-7 and 7.5.3-8 present a summary of the site access/congestion factors for DSD and FSI technologies at the Vermilion steam plant. Table 7.5.3-9 presents the costs estimated to retrofit DSD at the Vermilion plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Vermilion plant. Both boilers would be considered good candidates for AFBC retrofit because of their small sizes (<110 MW). However, the high capacity factors for these units could result in significant replacement power costs for extended downtime.

TABLE 7.5.3-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR VERMILION UNIT 1

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE (FSI)	HIGH
NEW BAGHOUSE (DSD)	LOW
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	1300
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	400
ESTIMATED COST (1000$)	1491
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	23

TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	1323
A NEW BAGHOUSE CASE (DSD)	1514
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE (FSI)	1.58
NEW BAGHOUSE (DSD)	1.16

TABLE 7.5.3-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR VERMILION UNIT 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE (FSI)	HIGH
NEW BAGHOUSE (DSD)	LOW
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	1300
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	400
ESTIMATED COST (1000$)	1783
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	29

TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	1329
A NEW BAGHOUSE CASE (DSD)	1812
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE (FSI)	1.58
NEW BAGHOUSE (DSD)	1.16

Table 7.5.3-9. Summary of DSD/FSI Control Costs for the Vermilion Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+FF	1	1.16	70	53	2.4	14.1	201.9	7.6	23.2	70.0	5015	1517.6
DSD+FF	2	1.16	95	66	2.4	17.5	184.3	9.5	17.3	70.0	8425	1127.6
DSD+FF-C	1	1.16	70	53	2.4	14.1	201.9	4.4	13.5	70.0	5015	882.1
DSD+FF-C	2	1.16	95	66	2.4	17.5	184.3	5.5	10.0	70.0	8425	655.3

7.5.4 Wood River Steam Plant

Both coal burning boilers at the Wood River plant are firing a low sulfur coal; therefore, CS was not evaluated. In addition, FGD costs are not presented since the low sulfur coal would result in low capital/operating costs and high cost per ton of SO_2 removed. Sorbent injection technologies were not considered because of the short duct residence time between the boilers and ESPs, the small size of the ESPs, and the difficulty in accessing the ESPs.

TABLE 7.5.4-1. WOOD RIVER STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2,3	4	5
GENERATING CAPACITY (MW-each)	46	92	340
CAPACITY FACTOR (PERCENT)	2.2	24.7	42.4
INSTALLATION DATE	1949,49,50	1954	1964
FIRING TYPE	PETROLEUM	TANGENTIAL	
FURNACE VOLUME (1000 CU FT)	BURNING	NA	182.9
LOW NOx COMBUSTION		NO	NO
COAL SULFUR CONTENT (PERCENT)		1.0	
COAL HEATING VALUE (BTU/LB)		12100	
COAL ASH CONTENT (PERCENT)		5.0	
FLY ASH SYSTEM		WET DISPOSAL	
ASH DISPOSAL METHOD		POND/ON-SITE	
STACK NUMBER		2	3
COAL DELIVERY METHODS		RAILROAD/TRUCK	
PARTICULATE CONTROL			
TYPE		ESP & CYCLONE	ESP
INSTALLATION DATE		1967	1970
EMISSION (LB/MM BTU)		0.07	0.06
REMOVAL EFFICIENCY		98.3	97.2
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)		4.1-0.0	4.1-0.0
SURFACE AREA (1000 SQ FT)		NA	200.3
GAS EXIT RATE (1000 ACFM)		410.9	1205
SCA (SQ FT/1000 ACFM)		NA	166
OUTLET TEMPERATURE (°F)		335	291

TABLE 7.5.4-2. SUMMARY OF RETROFIT FACTOR DATA FOR WOOD RIVER UNIT 4 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	NA	HIGH
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			HIGH
DUCT WORK DISTANCE (FEET)	600-1000	NA	
ESP REUSE			
BAGHOUSE			600-1000
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	HIGH
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	870	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	644	0	644
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.84	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.83
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.58
GENERAL FACILITIES (PERCENT)	15	0	15

* L/LS-FGD and LSD-FGD absorbers for unit 4 would be located east of unit 5.

TABLE 7.5.4-3. SUMMARY OF RETROFIT FACTOR DATA FOR WOOD RIVER UNIT 5 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	NA	HIGH
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			HIGH
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	HIGH
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	2808	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	2380	0	2380
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.70	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.69
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.58
GENERAL FACILITIES (PERCENT)	15	0	15

* L/LS-FGD and LSD-FGD absorbers for unit 5 would be located east of unit 5.

TABLE 7.5.4-4. SUMMARY OF NOx RETROFIT RESULTS FOR WOOD RIVER

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	4	5
FIRING TYPE	TANG	TANG/TWIN FURNACE DESIGN
TYPE OF NOx CONTROL	OFA	NA
FURNACE VOLUME (1000 CU FT)	NA	182.9
BOILER INSTALLATION DATE	1954	1964
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	25	NA
SCR RETROFIT RESULTS *		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	25	68
New Duct Length (Feet)	200	200
New Duct Costs (1000$)	944	2028
New Heat Exchanger (1000$)	1773	3884
TOTAL SCOPE ADDER COSTS (1000$)	2742	5979
RETROFIT FACTOR FOR SCR	1.52	1.52
GENERAL FACILITIES (PERCENT)	38	38

* Cold side SCR reactors for units 4 and 5 would be located behind their respective chimneys.

Table 7.5.4-5. NOx Control Cost Results for the Wood River Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	4	1.00	92	25	1.0	0.6	6.5	0.1	0.6	25.0	155	844.9
LNC-OFA-C	4	1.00	92	25	1.0	0.6	6.5	0.1	0.4	25.0	155	501.9
SCR-3	4	1.52	92	25	1.0	22.6	245.2	7.0	34.5	80.0	495	14030.8
SCR-3	5	1.52	340	42	1.0	57.7	169.6	19.2	15.3	80.0	3076	6229.6
SCR-3-C	4	1.52	92	25	1.0	22.6	245.2	4.1	20.3	80.0	495	8242.8
SCR-3-C	5	1.52	340	42	1.0	57.7	169.6	11.2	9.0	80.0	3076	3653.2
SCR-7	4	1.52	92	25	1.0	22.6	245.2	6.2	30.8	80.0	495	12506.5
SCR-7	5	1.52	340	42	1.0	57.7	169.6	16.4	13.1	80.0	3076	5322.3
SCR-7-C	4	1.52	92	25	1.0	22.6	245.2	3.7	18.1	80.0	495	7369.6
SCR-7-C	5	1.52	340	42	1.0	57.7	169.6	9.6	7.7	80.0	3076	3133.4

7.6 SOUTHERN ILLINOIS POWER COMPANY

7.6.1 Marion Steam Plant

The Marion steam plant is located within Williamson County, Illinois, as part of the Southern Illinois Power Cooperative system. The plant contains four coal-fired boilers with a total gross generating capacity of 272 MW. Figure 7.6.1-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 7.6.1-1 presents operational data for the existing equipment at the Marion plant. The boilers burn high sulfur coal (3.0-4.0 percent sulfur). Coal shipments are received by truck and conveyed to a coal storage and handling area located west of the plant.

Particulate matter emissions for the boilers are controlled with retrofit ESPs located behind each unit. Fly ash for units 1-3 is wet sluiced to ponds located north of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 7.6.1-1 shows the general layout and location of the FGD control system. The plant is located on a large site northwest of Lake Egypt. Units 1-2 share one chimney. Unit 4 has a new FGD system (Venturi scrubber) installed in 1978, using limestone as sorbent and built by Babcock and Wilcox. Therefore, unit 4 will not be considered in this study. The absorbers for L/LS-FGD and LSD-FGD for units 1-3 would be located east of the powerhouse and unit 1, toward Lake Egypt. Part of the parking area, a warehouse, and some auxiliary equipment close to the powerhouse would need to be demolished and relocated; therefore, a factor of 15 percent was assigned to general facilities. The limestone storage/handling area and waste handling area for unit 4 would be expanded and also used for units 1-3.

Retrofit Difficulty and Scope Adder Costs--

A high site congestion factor was assigned to the absorber locations because of congestion created by conveyors on two sides, the powerhouse, and an assumed high underground obstruction. This assumption is based on the absorber locations being close to a water intake structure.

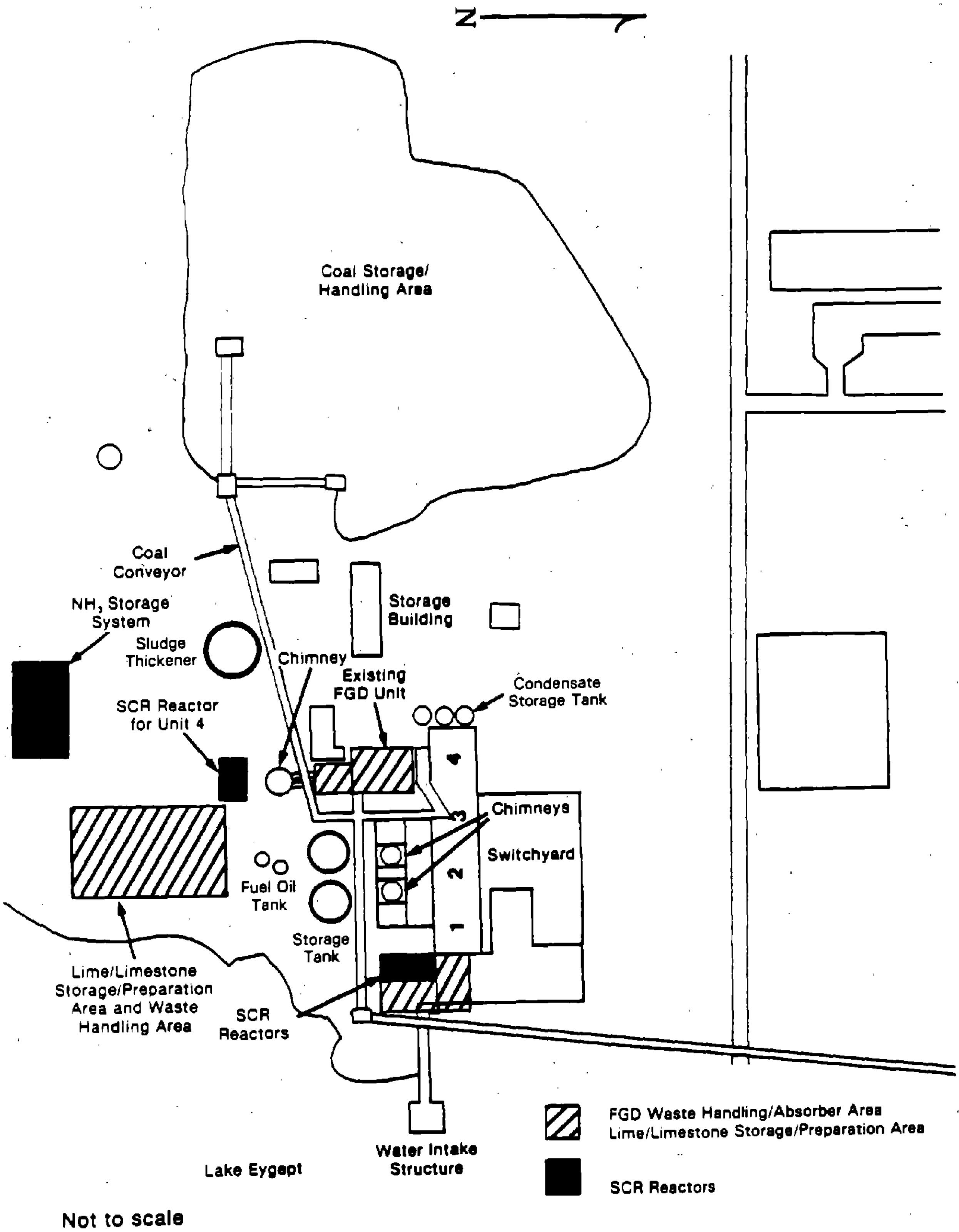

Figure 7.6.1-1. Marion plant plot plan

TABLE 7.6.1-1. MARION STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1-3	4
GENERATING CAPACITY (MW-each)	33	173
CAPACITY FACTOR (PERCENT)	28	67
INSTALLATION DATE	1963	1978
FIRING TYPE	CYC	CYC
COAL SULFUR CONTENT (PERCENT)	3.0-4.0	3.0-4.0
COAL HEATING VALUE (BTU/LB)	10210	10210
COAL ASH CONTENT (PERCENT)	16.3	16.3
FLY ASH SYSTEM	DRY/WET SLUICE	
ASH DISPOSAL METHOD	POND/ON-SITE	
STACK NUMBER	1,1,2	3
COAL DELIVERY METHODS	TRUCK	
FGD UNIT	NO	YES
INSTALLATION DATE	-	1979
FGD TYPE	-	LIMESTONE WET SCRUBBER
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1972	1978
EMISSION (LB/MM BTU)	0.2	0.1
REMOVAL EFFICIENCY	99.2-99.0	99.4
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	4.0	4.0
SURFACE AREA (1000 SQ FT)	34.6	203.8
EXIT GAS FLOW RATE (1000 ACFM)	121.6	605
SCA (SQ FT/1000 ACFM)	285	337
OUTLET TEMPERATURE (°F)	300-310	300

For flue gas handling, a short duct run for the unit 1 absorbers would be required for L/LS-FGD cases. A medium site access/congestion factor was assigned to the flue gas handling system for unit 1 due to the chimney location close to the powerhouse in a high site access/congestion area. Units 2-3 would require moderate duct runs because the absorbers are located away from the units. A high site access/congestion factor was assigned to the flue gas handling system for units 2-3 because the units are located in a congested area between units 1 and 4.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Tables 7.6.1-2 and 7.6.1-3. It was assumed that dry fly ash would be necessary to stabilize scrubber sludge waste and to prevent the plugging of sluice lines. This conversion is not necessary for forced oxidation L/LS-FGD. The overall retrofit factors determined for the L/LS-FGD cases were medium to high.

The absorbers for LSD-FGD would be located in a similar location as in L/LS-FGD cases. Reused ESPs was the only LSD-FGD technology case considered for the units because of their moderate size (SCA >200). For flue gas handling for LSD cases, a short duct run would be required for unit 1; a high site access/congestion factor was assigned due to the difficulty to tie into the upstream of the ESPs to divert flue gas from the boilers to the absorbers and back to the ESPs. Units 2-3 would require a medium duct run with a high site access/congestion factor for the same reasons as stated above for unit 1. The retrofit factors determined for the LSD technology case were moderate to high (1.61 to 1.69) and did not include particulate control upgrading costs. Separate retrofit factors were developed for the upgrading of ESPs. The ESPs units 1-3 were designated a high retrofit factor because of their close proximity to each other and the powerhouse/chimneys. These factors were used in the IAPCS model to estimate particulate control upgrading costs.

Table 7.6.1-4 presents the cost estimates for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs and ash handling systems for boilers 1-3. The low cost control case reduces capital and annual operating costs significantly due to the benefits of economies-of-scale when combining process areas, elimination of spare scrubber modules, and optimization of scrubber module size.

TABLE 7.6.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR MARION UNIT 1

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	HIGH	HIGH
FLUE GAS HANDLING	MEDIUM	MEDIUM	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	100-300	
ESP REUSE			100-300
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NO	NO
ESTIMATED COST (1000$)	0	NA	0
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.48	1.52	
ESP REUSE CASE			1.54
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	15	15

TABLE 7.6.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR MARION UNITS 2 OR 3

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	HIGH	HIGH
FLUE GAS HANDLING	HIGH	HIGH	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NO	NO
ESTIMATED COST (1000$)	0	NA	0
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.61	1.64	
ESP REUSE CASE			1.62
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	15	15

Table 7.6.1-4. Summary of FGD Control Costs for the Marion Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.48	33	28	3.0	30.0	909.0	12.2	150.7	90.0	2122	5745.9
L/S FGD	2	1.61	33	28	3.0	32.5	984.6	13.0	161.0	90.0	2122	6141.2
L/S FGD	3	1.61	33	28	3.0	32.5	984.6	13.0	161.0	90.0	2122	6141.2
L/S FGD-C	1	1.48	33	28	3.0	30.0	909.0	7.1	88.0	90.0	2122	3355.4
L/S FGD-C	2	1.61	33	28	3.0	32.5	984.6	7.6	94.1	90.0	2122	3587.2
L/S FGD-C	3	1.61	33	28	3.0	32.5	984.6	7.6	94.1	90.0	2122	3587.2
LC FGD	1-3	1.57	99	28	3.0	38.4	387.8	16.2	66.8	90.0	6367	2549.0
LC FGD-C	1-3	1.57	99	28	3.0	38.4	387.8	9.5	39.0	90.0	6367	1487.5
LSD+ESP	1	1.54	33	28	3.0	10.8	326.6	6.0	74.1	76.0	1799	3333.1
LSD+ESP	2	1.62	33	28	3.0	11.3	341.5	6.1	75.9	76.0	1799	3414.7
LSD+ESP	3	1.62	33	28	3.0	11.3	341.5	6.1	75.9	76.0	1799	3414.7
LSD+ESP-C	1	1.54	33	28	3.0	10.8	326.6	3.5	43.0	76.0	1799	1936.5
LSD+ESP-C	2	1.62	33	28	3.0	11.3	341.5	3.6	44.1	76.0	1799	1984.5
LSD+ESP-C	3	1.62	33	28	3.0	11.3	341.5	3.6	44.1	76.0	1799	1984.5

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined. This is particularly true for cyclone boilers; as such, coal switching was not evaluated for the Marion plant.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Marion steam plant. These controls include LNC modification and SCR. The application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2. The NO_x technologies evaluated at the steam plant were: NGR and SCR.

Low NO_x Combustion--

Units 1 to 4 are wet bottom, cyclone-fired boilers; units 1 to 3 are each rated at 33 MW and unit 4 is rated at 173 MW. The combustion modification technique applied to all boilers was NGR. As Table 7.6.1-5 shows, the NGR NO_x reduction performance for each unit was estimated to be 60 percent. Table 7.6.1-6 presents the cost of retrofitting NGR at the Marion plant.

Selective Catalytic Reduction--

Table 7.6.1-5 presents the SCR retrofit results for units 1 to 4. The results include process area retrofit factors and scope adder costs. The scope adders include costs estimated for ductwork demolition, new flue gas heat exchanger, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimney.

The SCR reactors for units 1 to 3 would be located east of the powerhouse and unit 1, toward Lake Egypt in a relatively high congested area having easy access. Medium access/congestion factors were assigned to these reactors because of congestion created by the sludge conveyors and the powerhouse. A 25 percent general facility factor was also assigned to each reactor because part of a warehouse and some auxiliary equipment close to the

TABLE 7.6.1-5. SUMMARY OF NOx RETROFIT RESULTS FOR MARION

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2, 3	4
FIRING TYPE	CY	CY	CY
TYPE OF NOx CONTROL	NGR	NGR	NGR
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	NA	NA	NA
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	NA	NA	NA
FURNACE RESIDENCE TIME (SECONDS)	NA	NA	NA
ESTIMATED NOx REDUCTION (PERCENT)	60	60	60
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	MEDIUM	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	12	12	41
New Duct Length (Feet)	250	450	170
New Duct Costs (1000$)	648	1166	1195
New Heat Exchanger (1000$)	958	958	2590
TOTAL SCOPE ADDER COSTS (1000$)	1618	2136	3825
RETROFIT FACTOR FOR SCR	1.34	1.34	1.16
GENERAL FACILITIES (PERCENT)	25	25	13

Table 7.6.1-6. NOx Control Cost Results for the Marion Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
NGR	1	1.00	33	28	3.0	1.0	31.2	0.6	7.3	60.0	447	1327.8
NGR	2	1.00	33	28	3.0	1.0	31.2	0.6	7.3	60.0	447	1327.8
NGR	3	1.00	33	28	3.0	1.0	31.2	0.6	7.3	60.0	447	1327.8
NGR	4	1.00	173	67	3.0	3.3	19.1	5.7	5.6	60.0	5613	1008.2
NGR-C	1	1.00	33	28	3.0	1.0	31.2	0.3	4.3	60.0	447	771.1
NGR-C	2	1.00	33	28	3.0	1.0	31.2	0.3	4.3	60.0	447	771.1
NGR-C	3	1.00	33	28	3.0	1.0	31.2	0.3	4.3	60.0	447	771.1
NGR-C	4	1.00	173	67	3.0	3.3	19.1	3.3	3.2	60.0	5613	580.3
SCR-3	1	1.34	33	28	3.0	11.9	360.4	3.6	44.6	80.0	597	6054.6
SCR-3	2	1.34	33	28	3.0	12.4	376.7	3.7	45.8	80.0	597	6214.1
SCR-3	3	1.34	33	28	3.0	12.4	376.7	3.7	45.8	80.0	597	6214.1
SCR-3	4	1.16	173	67	3.0	27.1	156.7	10.1	9.9	80.0	7484	1344.2
SCR-3-C	1	1.34	33	28	3.0	11.9	360.4	2.1	26.2	80.0	597	3558.3
SCR-3-C	2	1.34	33	28	3.0	12.4	376.7	2.2	26.9	80.0	597	3653.7
SCR-3-C	3	1.34	33	28	3.0	12.4	376.7	2.2	26.9	80.0	597	3653.7
SCR-3-C	4	1.16	173	67	3.0	27.1	156.7	5.9	5.8	80.0	7484	786.4
SCR-7	1	1.34	33	28	3.0	11.9	360.4	3.3	41.2	80.0	597	5589.1
SCR-7	2	1.34	33	28	3.0	12.4	376.7	3.4	42.4	80.0	597	5748.6
SCR-7	3	1.34	33	28	3.0	12.4	376.7	3.4	42.4	80.0	597	5748.6
SCR-7	4	1.16	173	67	3.0	27.1	156.7	8.6	8.5	80.0	7484	1149.7
SCR-7-C	1	1.34	33	28	3.0	11.9	360.4	2.0	24.3	80.0	597	3291.6
SCR-7-C	2	1.34	33	28	3.0	12.4	376.7	2.0	25.0	80.0	597	3387.0
SCR-7-C	3	1.34	33	28	3.0	12.4	376.7	2.0	25.0	80.0	597	3387.0
SCR-7-C	4	1.16	173	67	3.0	27.1	156.7	5.1	5.0	80.0	7484	674.9

powerhouse would have to be demolished or relocated. The SCR reactor for unit 4 would be located in a relatively open area south of both the existing FGD unit and chimney for unit 4. A low access/congestion factor was assigned to this reactor. All reactors were assumed to be in areas with high underground obstructions. The ammonia storage system was placed in a remote area having a low access/congestion factor.

As discussed in Section 2, all NO_x control techniques were evaluated independently from those evaluated for SO_2 control. If both SO_2 and NO_x emissions were needed to be reduced at this plant for units 1 to 3, the SCR reactors would have to be located downstream of the FGD absorbers (north) in relatively the same area as discussed above. Therefore, the results listed above for retrofitting SCR to this boiler would be applied in this case. For unit 4, NO_x is the only pollutant to be controlled since SO_2 emissions are already controlled by an FGD system. Therefore, the results in Table 7.6.1-5 would remain unchanged for this reactor. Table 7.6.1-6 presents the estimated cost of retrofitting SCR at the Marion boilers.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas were located east of the plant in a similar fashion as LSD-FGD. Sufficient duct residence time could be made available for DSD if the old ESPs were used to provide duct residence time between the boilers and retrofit ESPs. It was assumed that the ESPs could be upgraded to handle the increased load from DSD and FSI. To upgrade the ESPs, a high site access/congestion factor was assigned to units 1-3. To reuse the ESPs, the conversion of wet to dry fly ash would be needed to prevent plugging of sluice lines. Table 7.6.1-7 presents a summary of the site access/congestion factors for DSD and FSI technologies at the

TABLE 7.6.1-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR MARION UNITS 1,2 OR 3

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	0
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	13
TOTAL COST (1000$)	
ESP UPGRADE CASE	13
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE	1.55
NEW BAGHOUSE	NA

Marion steam plant. Table 7.6.1-8 presents the costs estimated to retrofit DSD and FSI at the Marion plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Marion plant. Boilers 1 through 3 would be considered good candidates for AFBC retrofit because they are small, old, and have low capacity factors. However, boiler 4 would not be considered since it has an existing FGD unit.

Table 7.6.1-8. Summary of DSD/FSI Control Costs for the Marion Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	33	28	3.0	4.6	138.8	4.2	51.3	49.0	1147	3622.7
DSD+ESP	2	1.00	33	28	3.0	4.6	138.9	4.2	51.4	49.0	1147	3623.6
DSD+ESP	3	1.00	33	28	3.0	4.6	138.9	4.2	51.4	49.0	1147	3623.6
DSD+ESP-C	1	1.00	33	28	3.0	4.6	138.8	2.4	29.7	49.0	1147	2093.5
DSD+ESP-C	2	1.00	33	28	3.0	4.6	138.9	2.4	29.7	49.0	1147	2094.0
DSD+ESP-C	3	1.00	33	28	3.0	4.6	138.9	2.4	29.7	49.0	1147	2094.0
FSI+ESP-50	1	1.00	33	28	3.0	5.4	163.4	3.4	41.6	50.0	1179	2852.8
FSI+ESP-50	2	1.00	33	28	3.0	5.4	163.6	3.4	41.6	50.0	1179	2854.2
FSI+ESP-50	3	1.00	33	28	3.0	5.4	163.6	3.4	41.6	50.0	1179	2854.2
FSI+ESP-50-C	1	1.00	33	28	3.0	5.4	163.4	2.0	24.1	50.0	1179	1655.0
FSI+ESP-50-C	2	1.00	33	28	3.0	5.4	163.6	2.0	24.1	50.0	1179	1655.8
FSI+ESP-50-C	3	1.00	33	28	3.0	5.4	163.6	2.0	24.1	50.0	1179	1655.8
FSI+ESP-70	1	1.00	33	28	3.0	5.5	166.3	3.4	42.1	70.0	1651	2062.9
FSI+ESP-70	2	1.00	33	28	3.0	5.5	166.0	3.4	42.0	70.0	1651	2060.9
FSI+ESP-70	3	1.00	33	28	3.0	5.5	166.0	3.4	42.0	70.0	1651	2060.9
FSI+ESP-70-C	1	1.00	33	28	3.0	5.5	166.3	2.0	24.4	70.0	1651	1196.8
FSI+ESP-70-C	2	1.00	33	28	3.0	5.5	166.0	2.0	24.4	70.0	1651	1195.6
FSI+ESP-70-C	3	1.00	33	28	3.0	5.5	166.0	2.0	24.4	70.0	1651	1195.6

7.7 SPRINGFIELD CITY OF WATER

7.7.1 <u>Dallman Steam Plant</u>

The Dallman steam plant is located within Sangamon County, Illinois, as part of the Springfield City Water, Light, and Power Company system. The plant contains three coal-fired boilers with a total gross generating capacity of 352 MW. Figure 7.7.1-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 7.7.1-1 presents operational data for the existing equipment at the Dallman plant. The boilers burn medium to high sulfur coal (2.9 percent sulfur). Coal shipments are received by railroad and conveyed to a coal storage and handling area located east of the plant.

Particulate matter emissions for the boilers are controlled with ESPs located in front of each unit. Fly ash from all units is wet sluiced.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 7.7.1-1 shows the general layout and location of the FGD control system. Although there are three coal-fired boilers at the Dallman plant, only units 1 and 2 were considered for FGD retrofit in this study. Unit 3 is equipped with recently installed (1980) scrubber modules that presently operate with a removal efficiency of 85 percent at full load. The absorbers for units 1 and 2 were located north of the respective units, west of the coal pile, and close to the coal conveyors. Some plant roads and auxiliary equipment would need to be demolished/relocated; therefore, a factor of 10 percent was assigned to general facilities. The limestone storage/handling and waste handling areas would be located to the south of the units 1 and 2, close to the coal storage and handling area.

Retrofit Difficulty and Scope Adder Costs--

The plant is bounded by Springfield Lake on three sides and a major highway on the other. Units 1 and 2 are located close to each other on the edge of a small peninsula north of Springfield Lake.

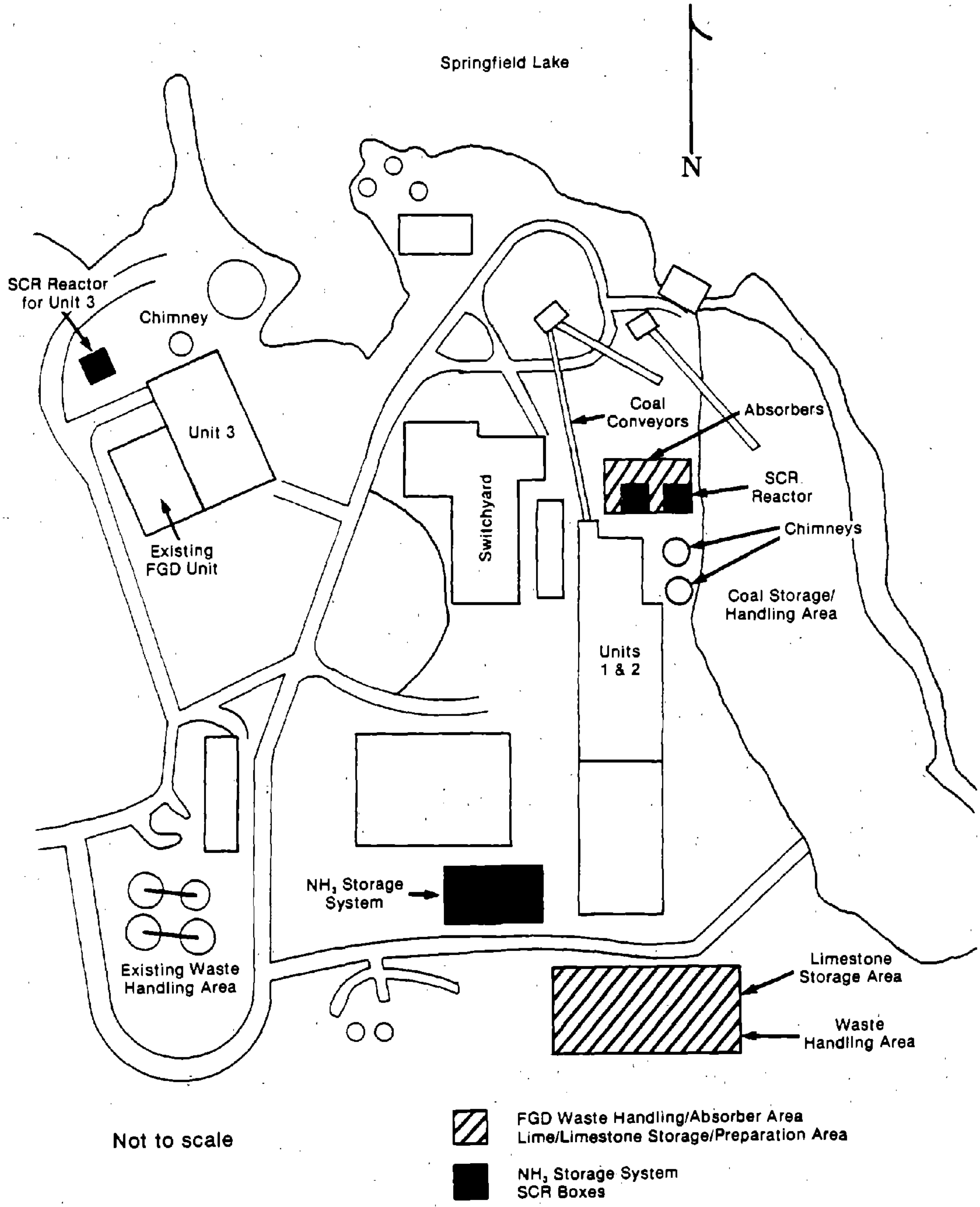

Figure 7.7.1-1. Dallman plant plot plan

TABLE 7.7.1-1. DALLMAN STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2	3
GENERATING CAPACITY (MW)	80	80	192
CAPACITY FACTOR (PERCENT)	23	25	54
FIRING TYPE	CYC	CYC	TANG
INSTALLATION DATE	1968	1972	1978
COAL SULFUR CONTENT (PERCENT)	2.9	2.9	2.9
COAL HEATING VALUE (BTU/LB)	10351	10351	10351
COAL ASH CONTENT (PERCENT)	9.2	9.2	9.2
FLY ASH SYSTEM		WET SLUICE	
ASH DISPOSAL METHOD		POND/ON-SITE	
STACK NUMBER	1	2	3
COAL DELIVERY METHODS		RAILROAD	
FGD SYSTEM	NO	NO	YES
INSTALLATION DATE	-	-	1980
FGD TYPE	-	-	LIMESTONE WET SCRUBBER
PARTICULATE CONTROL			
TYPE	ESP	ESP	ESP
INSTALLATION DATE	1972	1972	1978
EMISSION (LB/MM BTU)	0.24		
REMOVAL EFFICIENCY	67.4	60.7	97.2
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	3.9	3.9	3.9
SURFACE AREA (1000 SQ FT)	35.3	39.5	244
GAS EXIT RATE (1000 ACFM)	325	325	775
SCA (SQ FT/1000 ACFM)	109	118	315
OUTLET TEMPERATURE (°F)	300	200	140

A high site access/congestion factor was assigned to the absorber locations because they are bounded by the coal conveyors on two sides, the coal storage/handling area, and the powerhouse.

For flue gas handling, moderate duct runs for the units would be required for L/LS-FGD cases to divert the flue gas from the absorbers to the chimneys. A medium site access/congestion factor was assigned to the flue gas handling system due to some major obstacles and obstructions in the surrounding area.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Table 7.7.1-2. The largest scope adder for the Dallman plant would be the conversion of units 1-2 fly ash conveying/ disposal system from wet to dry for conventional L/LS-FGD cases. It was assumed that dry fly ash would be necessary to stabilize scrubber sludge waste. This conversion is not necessary for forced oxidation L/LS-FGD. The overall retrofit factors determined for the L/LS-FGD cases were medium (1.60 to 1.64).

The absorbers for LSD-FGD would be located in a similar location as in L/LS-FGD cases. A considerable ESP plate area addition would be required to upgrade the ESPs on units 1-2 due to the small SCA size (<120). Therefore, LSD with new baghouses was the only LSD-FGD technology considered for the units. For flue gas handling for LSD cases, moderate duct runs would be required, the same as for L/LS-FGD cases. The retrofit factor determined for the LSD technology case was medium (1.58) and did not include the new baghouse costs. A separate retrofit factor was developed for the new baghouses for the units and was high (1.58). This reflects the congestion around the baghouses created by the coal conveyors, coal pile, chimneys, and powerhouse. This factor was used in the IAPCS model to estimate particulate control costs.

Table 7.7.1-3 presents the cost estimates for L/LS and LSD-FGD cases. The LSD-FGD costs include installing new baghouses to handle the additional particulate loading for boilers 1 and 2. The low cost control case reduces capital and annual operating costs due to the benefits of economies-of-scale when combining process areas, elimination of spare scrubber modules, and optimization of scrubber module size.

TABLE 7.7.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR DALLMAN UNITS 1-2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	HIGH	HIGH
FLUE GAS HANDLING	MEDIUM	MEDIUM	
ESP REUSE CASE			NA
BAGHOUSE CASE			MEDIUM
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			NA
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	HIGH
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	NO
ESTIMATED COST (1000$)	768	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.64	1.60	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.58
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.58
GENERAL FACILITIES (PERCENT)	10	10	10

Table 7.7.1-3. Summary of FGD Control Costs for the Dallman Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.64	80	23	2.9	51.5	643.6	19.9	123.4	90.0	4022	4944.0
L/S FGD	2	1.64	80	25	2.9	50.9	636.7	19.9	113.6	90.0	4371	4553.1
L/S FGD-C	1	1.64	80	23	2.9	51.5	643.6	11.6	72.1	90.0	4022	2890.0
L/S FGD-C	2	1.64	80	25	2.9	50.9	636.7	11.6	66.4	90.0	4371	2660.9
LC FGD	1-2	1.64	160	24	2.9	48.9	305.9	20.3	60.5	90.0	8393	2423.2
LC FGD-C	1-2	1.64	160	24	2.9	48.9	305.9	11.9	35.3	90.0	8393	1414.5
LSD+FF	1	1.58	80	23	2.9	30.5	381.6	11.8	72.9	87.0	3865	3041.4
LSD+FF	2	1.58	80	25	2.9	25.5	319.2	9.9	56.7	66.0	3185	3120.9
LSD+FF-C	1	1.58	80	23	2.9	30.5	381.6	6.9	42.6	87.0	3865	1777.9
LSD+FF-C	2	1.58	80	25	2.9	25.5	319.2	5.8	33.2	66.0	3185	1824.0

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined. This is particularly true with cyclone boilers and, as a result, coal switching was not evaluated for the Dallman power plant.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Dallman steam plant. These controls include LNC modification and SCR. The application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2. The NO_x technologies evaluated at the steam plant were: NGR - units 1 and 2; OFA - unit 3; and SCR - all units. Unit 3 was considered in the study, even though it should meet the 1972 NSPS for NO_x emissions.

Low NO_x Combustion--

Units 1 and 2 are wet bottom, cyclone-fired boilers each rated at 80 MW. The combustion modification technique applied to both boilers was NGR. Unit 3 is dry bottom, tangential wall-fired boiler rated at 192 MW. The combustion modification technique applied for this unit was OFA. As Table 7.7.1-4 shows, the NGR NO_x reduction performance for units 1 and 2 was estimated to be 60 percent. No boiler information was available in POWER to assess the OFA NO_x reduction performance for unit 3. However, since this boiler was recently installed (1978), it is estimated that a 20 to 30 percent NO_x reduction can be achieved for this boiler retrofitted with OFA. If unit 3 already uses OFA to meet the NSPS, further NO_x reductions may be possible but would likely be much less than 20 to 30 percent. Table 7.7.1-5 presents the cost of retrofitting NGR and OFA at the Dallman plant. A 25 percent NO_x reduction was assumed for unit 3 using OFA.

Selective Catalytic Reduction--

Table 7.7.1-4 presents the SCR retrofit results for units 1 to 3. The results include process area retrofit factors and scope adder costs. The

TABLE 7.7.1-4. SUMMARY OF NOx RETROFIT RESULTS FOR DALLMAN

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	3
FIRING TYPE	CY	CY	TANG
TYPE OF NOx CONTROL	NGR	NGR	OFA
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	NA	NA	NA
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	NA	NA	NA
FURNACE RESIDENCE TIME (SECONDS)	NA	NA	NA
ESTIMATED NOx REDUCTION (PERCENT)	60	60	25
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	23	23	44
New Duct Length (Feet)	300	500	200
New Duct Costs (1000$)	1305	2174	1451
New Heat Exchanger (1000$)	1630	1630	2757
TOTAL SCOPE ADDER COSTS (1000$)	2958	3827	4252
RETROFIT FACTOR FOR SCR	1.52	1.52	1.16
GENERAL FACILITIES (PERCENT)	25	25	20

Table 7.7.1-5. NOx Control Cost Results for the Dallman Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	3	1.00	192	54	2.9	0.8	4.2	0.2	0.2	25.0	835	210.5
LNC-OFA-C	3	1.00	192	54	2.9	0.8	4.2	0.1	0.1	25.0	835	124.9
NGR	1	1.00	80	23	2.9	1.9	23.9	1.1	7.1	60.0	806	1421.7
NGR	2	1.00	80	25	2.9	1.9	23.9	1.2	7.0	60.0	876	1390.6
NGR-C	1	1.00	80	23	2.9	1.9	23.9	0.7	4.1	60.0	806	825.1
NGR-C	2	1.00	80	25	2.9	1.9	23.9	0.7	4.0	60.0	876	806.5
SCR-3	1	1.52	80	23	2.9	20.3	253.9	6.3	39.0	80.0	1075	5854.7
SCR-3	2	1.52	80	25	2.9	21.1	264.0	6.4	36.8	80.0	1168	5516.3
SCR-3	3	1.16	192	54	2.9	29.2	152.0	10.6	11.7	80.0	6055	1749.9
SCR-3-C	1	1.52	80	23	2.9	20.3	253.9	3.7	22.9	80.0	1075	3439.1
SCR-3-C	2	1.52	80	25	2.9	21.1	264.0	3.8	21.6	80.0	1168	3241.6
SCR-3-C	3	1.16	192	54	2.9	29.2	152.0	6.2	6.8	80.0	6055	1024.2
SCR-7	1	1.52	80	23	2.9	20.3	253.9	5.6	34.9	80.0	1075	5229.4
SCR-7	2	1.52	80	25	2.9	21.1	264.0	5.8	32.9	80.0	1168	4941.0
SCR-7	3	1.16	192	54	2.9	29.2	152.0	9.0	9.9	80.0	6055	1483.6
SCR-7-C	1	1.52	80	23	2.9	20.3	253.9	3.3	20.5	80.0	1075	3080.8
SCR-7-C	2	1.52	80	25	2.9	21.1	264.0	3.4	19.4	80.0	1168	2911.9
SCR-7-C	3	1.16	192	54	2.9	29.2	152.0	5.3	5.8	80.0	6055	871.6

scope adders include costs estimated for ductwork demolition, new flue gas heat exchanger, new duct runs to divert the flue gas of units 1 and 2 from the ESPs to the reactors and from the reactors to their respective chimneys, and new duct runs to divert the flue gas of unit 3 from the FGD absorbers to the reactors and from the reactor to the chimney.

The SCR reactors for units 1 and 2 would be located north of the respective units, west of the coal pile, and close to the coal conveyors. Access to this area is difficult because of the proximity of the coal storage and handling area; therefore, high access/congestion factors were assigned to both reactors. A 25 percent general facility factor was assigned to each reactor because some plant roads and auxiliary equipment would have to be demolished or relocated. For unit 3, the SCR reactor would be located north of the chimney in an relatively open area. Therefore, a low access/congestion factor was assigned to this reactor. A 20 percent general facilities factor was assigned to this reactor because a plant road would have to be relocated. All reactors were assumed to be in areas with high underground obstructions. The ammonia storage system was placed in a remote area having a low access/congestion factor.

As discussed in Section 2, all NO_x control techniques were evaluated independently from those evaluated for SO_2 control. However, if SO_2 and NO_x emissions both were to be controlled for units 1 and 2, the SCR reactors would have to be located downstream (north) of the FGD absorbers in a highly congested area between the coal conveyors. Therefore, high access/congestion factors would be assigned for both reactors in this case instead of assigning medium access/congestion factors. For unit 3, NO_x is the only pollutant to be controlled since this unit is equipped with an FGD system. Hence, the results in Table 7.7.1-4 would remain unchanged for this unit. Table 7.7.1-5 presents the estimated cost of retrofitting SCR at the Dallman boilers.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas were located north of the plant. The retrofit of DSD and FSI technologies at the Dallman steam plant for the units would be difficult. There is not sufficient duct residence time between the boilers and the ESPs, as well as the ESPs are very small (SCA <120). Therefore, only DSD with new fabric filters was considered with the baghouses being located north of units 1 and 2 in a similar fashion as LSD-FGD cases. The new baghouses would require 400 feet of duct run to divert the flue gas from the boilers to the baghouses and back to the chimneys. A high retrofit factor was designated for the baghouses for DSD for the same reasons as stated above in LSD-FGD cases. The FSI was assumed not to be applicable because the ESPs would not be good candidates for upgrade by adding plate area because the retrofit factor for upgrading the ESPs is high (1.55). Also, the conversion of wet to dry fly ash would be needed for reusing the ESPs to prevent plugging of sluice lines. Table 7.7.1-6 presents a summary of the site access/congestion factors for DSD and FSI technologies at the Dallman steam plant. Table 7.7.1-7 presents the costs estimated to retrofit DSD at the Dallman plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Dallman plant. Both boilers would be considered good candidates for AFBC retrofit because of their small sizes (<300 MW).

TABLE 7.7.1-6. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR DALLMAN UNITS 1-2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE (FSI)	HIGH
NEW BAGHOUSE (DSD)	HIGH
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	768
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	400
ESTIMATED COST (1000$)	1613
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	25
TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	793
A NEW BAGHOUSE CASE (DSD)	1638
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE (FSI)	1.55
NEW BAGHOUSE (DSD)	1.55

Table 7.7.1-7. Summary of DSD/FSI Control Costs for the Dallman Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+FF	1	1.00	80	23	2.9	20.3	254.3	8.6	53.1	71.0	3161	2705.7
DSD+FF	2	1.00	80	25	2.9	16.9	210.9	7.2	41.0	60.0	2928	2454.3
DSD+FF-C	1	1.00	80	23	2.9	20.3	254.3	5.0	31.0	71.0	3161	1579.1
DSD+FF-C	2	1.00	80	25	2.9	16.9	210.9	4.2	23.9	60.0	2928	1432.0