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

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

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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.

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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.

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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

ABBREVIATIONS AND SYMBOLS (Continued)

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

ABBREVIATIONS AND SYMBOLS (Continued)

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

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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 21.0 PENNSYLVANIA

21.1 ALLEGHENY POWER SERVICE CORP.

21.1.1 Armstrong Steam Plant

The Armstrong Steam Plant is located in Armstrong County, Pennsylvania, as part of the Allegheny Power Service Corp. system. The plant contains two coal-fired boilers with a total gross generating capacity of 352 MW. Tables 21.1.1-1 through 21.1.1-8 summarize the plant operational data and present the SO_2 and NO_x control cost and performance estimates.

TABLE 21.1.1-1. ARMSTRONG STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2
GENERATING CAPACITY (MW-EACH)	176
CAPACITY FACTOR (PERCENT)	75
INSTALLATION DATE	1958,59
FIRING TYPE	FRONT WALL
FURNACE VOLUME (1000 CU FT)	112
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	1.9
COAL HEATING VALUE (BTU/LB)	12500
COAL ASH CONTENT (PERCENT)	11
FLY ASH SYSTEM	DRY DISPOSAL
ASH DISPOSAL METHOD	LANDFILL/SOLD
STACK NUMBER	1
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP*
INSTALLATION DATE	1975
EMISSION (LB/MM BTU)	0.02
REMOVAL EFFICIENCY	99.5
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	2.0-2.4
SURFACE AREA (1000 SQ FT)	138.2
EXIT GAS FLOW RATE (1000 ACFM)	800
SCA (SQ FT/1000 ACFM)	NA
OUTLET TEMPERATURE (°F)	305

* Each boiler has 2 ESPs in series; the original and retrofit ESPs. An SCA size of 300 was assumed.

TABLE 21.1.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR ARMSTRONG UNITS 1 OR 2 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	MEDIUM, 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	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			1.55,1.68
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	0	10

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

Table 21.1.1-3. Summary of FGD Control Costs for the Armstrong 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	1-2	1.20	352	75	1.9	52.9	150.3	33.4	14.4	90.0	30444	1095.9
LC FGD-C	1-2	1.20	352	75	1.9	52.9	150.3	19.4	8.4	90.0	30444	635.7
LFGD	1,2	1.20	176	75	1.9	46.8	265.8	24.5	21.2	90.0	15222	1611.2
LFGD	1-2	1.20	352	75	1.9	67.4	191.4	38.0	16.4	90.0	30444	1247.3
LFGD-C	1,2	1.20	176	75	1.9	46.8	265.8	14.3	12.3	90.0	15222	936.9
LFGD-C	1-2	1.20	352	75	1.9	67.4	191.4	22.1	9.5	90.0	30444	724.5
LSD+ESP	1	1.55	176	75	1.9	27.4	155.9	13.9	12.0	76.0	12905	1077.9
LSD+ESP	2	1.68	176	75	1.9	29.4	167.1	14.5	12.5	76.0	12905	1122.4
LSD+ESP-C	1	1.55	176	75	1.9	27.4	155.9	8.1	7.0	76.0	12905	627.1
LSD+ESP-C	2	1.68	176	75	1.9	29.4	167.1	8.4	7.3	76.0	12905	653.3

Table 21.1.1-4. Summary of Coal Switching/Cleaning Costs for the Armstrong 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	176	75	1.9	7.0	39.6	16.9	14.6	51.0	8564	1971.6
CS/B+$15-C	1,2	1.00	176	75	1.9	7.0	39.6	9.7	8.4	51.0	8564	1133.2
CS/B+$5	1,2	1.00	176	75	1.9	5.2	29.3	7.0	6.1	51.0	8564	819.0
CS/B+$5-C	1,2	1.00	176	75	1.9	5.2	29.3	4.0	3.5	51.0	8564	471.9

TABLE 21.1.1-5. SUMMARY OF NOx RETROFIT RESULTS FOR ARMSTRONG

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1, 2
FIRING TYPE	FWF
TYPE OF NOx CONTROL	LNB
FURNACE VOLUME (1000 CU FT)	112
INSTALLATION DATE	1958,1959
SLAGGING PROBLEM	NO
ESTIMATED NOx REDUCTION (PERCENT)	47
SCR RETROFIT RESULTS *	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	41
New Duct Length (Feet)	200
New Duct Costs (1000$)	1379
New Heat Exchanger (1000$)	2616
TOTAL SCOPE ADDER COSTS (1000$)	
INDIVIDUAL CASE	4037
COMBINED CASE	6104
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	20

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

Table 21.1.1-6. NOx Control Cost Results for the Armstrong 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	176	75	1.9	3.2	18.2	0.7	0.6	47.0	2253	308.5
LNC-LNB-C	1,2	1.00	176	75	1.9	3.2	18.2	0.4	0.4	47.0	2253	183.1
SCR-3	1,2	1.16	176	75	1.9	27.9	158.4	9.8	8.5	80.0	3835	2555.3
SCR-3	1-2	1.16	352	75	1.9	46.2	131.2	17.2	7.4	80.0	7669	2237.2
SCR-3-C	1,2	1.16	176	75	1.9	27.9	158.4	5.7	5.0	80.0	3835	1496.6
SCR-3-C	1-2	1.16	352	75	1.9	46.2	131.2	10.0	4.3	80.0	7669	1308.8
SCR-7	1,2	1.16	176	75	1.9	27.9	158.4	8.4	7.2	80.0	3835	2180.3
SCR-7	1-2	1.16	352	75	1.9	46.2	131.2	14.3	6.2	80.0	7669	1862.4
SCR-7-C	1,2	1.16	176	75	1.9	27.9	158.4	4.9	4.3	80.0	3835	1281.8
SCR-7-C	1-2	1.16	352	75	1.9	46.2	131.2	8.4	3.6	80.0	7669	1094.0

TABLE 21.1.1-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR ARMSTRONG UNITS 1 AND 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$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	46

TOTAL COST (1000$)	
ESP UPGRADE CASE	46
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.16
NEW BAGHOUSE	NA

Table 21.1.1-8. Summary of DSD/FSI Control Costs for the Armstrong 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	176	75	1.9	8.6	49.0	8.1	7.0	49.0	8228	990.4
DSD+ESP-C	1,2	1.00	176	75	1.9	8.6	49.0	4.7	4.1	49.0	8228	572.1
FSI+ESP-50	1,2	1.00	176	75	1.9	9.4	53.7	8.9	7.7	50.0	8457	1047.9
FSI+ESP-50-C	1,2	1.00	176	75	1.9	9.4	53.7	5.1	4.4	50.0	8457	605.4
FSI+ESP-70	1,2	1.00	176	75	1.9	9.6	54.3	9.0	7.8	70.0	11839	761.2
FSI+ESP-70-C	1,2	1.00	176	75	1.9	9.6	54.3	5.2	4.5	70.0	11839	439.7

21.1.2 Hatfield's Ferry Steam Plant

The Hatfield Ferry steam plant is located within Greene County, Pennsylvania, as part of the Allegheny Power Service system and operated by the West Penn Power Company. The plant is located west of the Monongahela River and contains three coal-fired boilers with a total gross generating capacity of 1,660 MW.

Table 21.1.2-1 presents operational data for the existing equipment at the Hatfield Ferry plant. The boilers burn medium sulfur coal. Coal shipments are received by barge and transferred to a coal storage and handling area north of the plant and adjacent to the river.

PM emissions for the boilers are controlled with ESPs located behind each unit. The plant has a dry fly ash handling system. Almost all the fly ash is paid disposal. Units 1 through 3 are served by two chimneys. Chimney 1 serves unit 1 and half of the flue gas from unit 2 while chimney 2 serves the other half and unit 3.

Lime/Limestone and Lime Spray Drying FGD Costs--

The three boilers are located beside each other and parallel to the river. Boiler houses are close to the river while the chimneys and switchyard are away from the river. The absorbers for units 1 through 3 would be located behind the chimneys and ash removal equipment. The limestone preparation, storage, and handling area would be located on a open space south of the plant. To locate the absorbers behind the chimneys a storage building, training classroom building, and the wastewater impoundment tank has to be relocated; therefore, a factor of 15 percent was assigned to general facilities. In addition, extensive on-site building relocation would be necessary to locate sludge fixation facilities.

A medium site access/congestion factor was assigned to the FGD absorber locations because of the close proximity of electric power lines and excavation of the hillside. For flue gas handling, medium duct runs would be required for the L/LS-FGD case (over 300 feet). A medium site access/congestion factor was assigned to the flue gas handling system because of the obstruction caused by ash removal equipment and wastewater treatment facility around the existing chimney.

TABLE 21.1.2-1. HATFIELD FERRY STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1, 2, 3
GENERATING CAPACITY (MW-each)	555,555,550
CAPACITY FACTOR (PERCENT)	51,68,59
INSTALLATION DATE	1969,70,71
FIRING TYPE	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	335.5
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	2.4
COAL HEATING VALUE (BTU/LB)	12800
COAL ASH CONTENT (PERCENT)	10
FLY ASH SYSTEM	DRY HANDLING
ASH DISPOSAL METHOD	PAID DISPOSAL/SOLD
STACK NUMBER	1-2
COAL DELIVERY METHODS	BARGE
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1969,70,71
EMISSION (LB/MM BTU)	0.04
REMOVAL EFFICIENCY	NA
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	2.0-3.9
SURFACE AREA (1000 SQ FT)	311.2
GAS EXIT RATE (1000 ACFM)	1,733
SCA (SQ FT/1000 ACFM)	178
OUTLET TEMPERATURE (°F)	300

LSD with reuse of the existing ESPs was not considered for this plant because the ESPs are small (SCA =178) 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 also 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 21.1.2-2. Table 21.1.2-3 presents the process area retrofit factors and capital/operating costs for commercial FGD technologies. The low cost FGD option reduces capital costs due to eliminating spare absorber modules and economy of scale when combining FGD systems and using large absorber modules.

Coal Switching and Physical Coal Cleaning Costs--

Table 21.1.2-4 presents the IAPCS results for CS at the Hatfield Ferry 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 through 3 are dry bottom boilers rated at 555, 555, and 550 MW respectively. The combustion modification technique applied to all boilers was LNB. The NO_x performance estimate was based on the boiler volumetric heat release rate. Tables 21.1.2-5 and 21.1.2-6 present the NO_x reduction performance and cost results of retrofitting LNB at the Hatfield Ferry plant.

Selective Catalytic Reduction--

Cold side SCR reactors for all units would be located immediately behind the chimneys located in medium site access/congestion area, due to the close proximity of the electric power lines. For flue gas handling, a short duct length of about 200 feet would be required for each of the units. The ammonia storage system was placed south of the plant close to the sorbent preparation area. Although space is available behind the chimneys for SCR reactors, a road has to be relocated and, as such, a factor of 18 percent was assigned to general facilities.

TABLE 21.1.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR HATFIELD FERRY UNIT 1,2 OR 3

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	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	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	1.46	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 21.1.2-3. Summary of FGD Control Costs for the Hatfield 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	1.46	1660	59	2.4	231.7	139.6	131.6	15.3	90.0	139539	943.2
LC FGD-C	1-3	1.46	1660	59	2.4	231.7	139.6	76.4	8.9	90.0	139539	547.8
LFGD	1	1.46	555	51	2.4	117.9	212.4	56.2	22.7	90.0	40123	1401.9
LFGD	2	1.46	555	68	2.4	117.9	212.4	62.0	18.8	90.0	53498	1159.2
LFGD	3	1.46	550	59	2.4	117.3	213.2	58.6	20.6	90.0	45999	1273.8
LFGD-C	1	1.46	555	51	2.4	117.9	212.4	32.8	13.2	90.0	40123	816.3
LFGD-C	2	1.46	555	68	2.4	117.9	212.4	36.1	10.9	90.0	53498	674.0
LFGD-C	3	1.46	550	59	2.4	117.3	213.2	34.1	12.0	90.0	45999	741.3

Table 21.1.2-4. Summary of Coal Switching/Cleaning Costs for the Hatfield 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	555	51	2.4	19.2	34.5	36.5	14.7	60.0	26677	1369.9
CS/B+$15	2	1.00	555	68	2.4	19.2	34.5	47.3	14.3	60.0	35570	1330.5
CS/B+$15	3	1.00	550	59	2.4	19.0	34.5	41.3	14.5	60.0	30584	1348.8
CS/B+$15-C	1	1.00	555	51	2.4	19.2	34.5	21.0	8.5	60.0	26677	788.1
CS/B+$15-C	2	1.00	555	68	2.4	19.2	34.5	27.2	8.2	60.0	35570	764.7
CS/B+$15-C	3	1.00	550	59	2.4	19.0	34.5	23.7	8.3	60.0	30584	775.6
CS/B+$5	1	1.00	555	51	2.4	13.4	24.2	15.1	6.1	60.0	26677	564.5
CS/B+$5	2	1.00	555	68	2.4	13.4	24.2	19.0	5.8	60.0	35570	534.5
CS/B+$5	3	1.00	550	59	2.4	13.3	24.2	16.8	5.9	60.0	30584	548.4
CS/B+$5-C	1	1.00	555	51	2.4	13.4	24.2	8.7	3.5	60.0	26677	325.7
CS/B+$5-C	2	1.00	555	68	2.4	13.4	24.2	11.0	3.3	60.0	35570	307.9
CS/B+$5-C	3	1.00	550	59	2.4	13.3	24.2	9.7	3.4	60.0	30584	316.2

TABLE 21.1.2-5. SUMMARY OF NOx RETROFIT RESULTS FOR HATFIELD FERRY

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1, 2, 3
FIRING TYPE	OWF
TYPE OF NOx CONTROL	LNB
FURNACE VOLUME (1000 CU FT)	335.3
BOILER INSTALLATION DATE	1969, 1970, 1971
SLAGGING PROBLEM	NO
ESTIMATED NOx REDUCTION (PERCENT)	40
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	98
New Duct Length (Feet)	200
New Duct Costs (1000$)	2701
New Heat Exchanger (1000$)	5212
TOTAL SCOPE ADDER COSTS (1000$)	8010
RETROFIT FACTOR FOR SCR	1.34
GENERAL FACILITIES (PERCENT)	18

Table 21.1.2-6. NOx Control Cost Results for the Hatfield 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	555	51	2.4	5.1	9.1	1.1	0.4	40.0	4001	275.0
LNC-LNB	2	1.00	555	68	2.4	5.1	9.1	1.1	0.3	40.0	5335	206.2
LNC-LNB	3	1.00	550	59	2.4	5.1	9.2	1.1	0.4	40.0	4587	239.0
LNC-LNB-C	1	1.00	555	51	2.4	5.1	9.1	0.7	0.3	40.0	4001	163.2
LNC-LNB-C	2	1.00	555	68	2.4	5.1	9.1	0.7	0.2	40.0	5335	122.4
LNC-LNB-C	3	1.00	550	59	2.4	5.1	9.2	0.7	0.2	40.0	4587	141.8
SCR-3	1	1.34	555	51	2.4	73.1	131.8	26.4	10.6	80.0	8002	3297.1
SCR-3	2	1.34	555	68	2.4	73.2	131.8	27.0	8.2	80.0	10669	2527.9
SCR-3	3	1.34	550	59	2.4	72.7	132.2	26.5	9.3	80.0	9174	2884.2
SCR-3-C	1	1.34	555	51	2.4	73.1	131.8	15.4	6.2	80.0	8002	1930.0
SCR-3-C	2	1.34	555	68	2.4	73.2	131.8	15.8	4.8	80.0	10669	1479.0
SCR-3-C	3	1.34	550	59	2.4	72.7	132.2	15.5	5.4	80.0	9174	1688.0
SCR-7	1	1.34	555	51	2.4	73.1	131.8	21.9	8.8	80.0	8002	2732.5
SCR-7	2	1.34	555	68	2.4	73.2	131.8	22.5	6.8	80.0	10669	2104.5
SCR-7	3	1.34	550	59	2.4	72.7	132.2	22.0	7.7	80.0	9174	2396.2
SCR-7-C	1	1.34	555	51	2.4	73.1	131.8	12.9	5.2	80.0	8002	1606.5
SCR-7-C	2	1.34	555	68	2.4	73.2	131.8	13.2	4.0	80.0	10669	1236.5
SCR-7-C	3	1.34	550	59	2.4	72.7	132.2	12.9	4.5	80.0	9174	1408.4

Table 21.1.2-5 presents the SCR retrofit factors and scope adder costs. Table 21.1.2-6 presents the estimated cost of retrofitting SCR at the Hatfield Ferry boilers.

Duct Spray Drying and Furnace Sorbent Injection--

The retrofit of FSI and DSD technologies at the Hatfield Ferry steam plant for all units would be difficult for two major reasons. The ESPs have small SCAs (<200) and probably would not be able to handle the increased PM. Therefore, they would require major ESP upgrading and additional plate area. There is also a short duct residence time between the boilers and ESPs making the duct runs inadequate for humidification (FSI application) and sorbent evaporation (DSD application). Therefore, the 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 the Hatfield Ferry plant. None of the units would be considered good candidates for repowering or retrofit because of their large boiler sizes and high capacity factors.

21.1.3 Mitchell Steam Plant

Boiler 33 at the Mitchell plant is equipped with a Lime-FGD system; therefore, no further SO_2 control technologies were considered for this unit. Boilers 1-3 were not evaluated because they are not coal-fired. For NO_x control, both SCR and OFA were evaluated for boiler 33.

TABLE 21.1.3-1. MITCHELL STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1-3*	33
GENERATING CAPACITY (MW)	150	299
CAPACITY FACTOR (PERCENT)	OUT OF SERVICE	30
INSTALLATION DATE	1948 1949 1949	1963
FIRING TYPE	PETROLEUM	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	BURNING	NA
LOW NOx COMBUSTION		NO
COAL SULFUR CONTENT (PERCENT)		2.6
COAL HEATING VALUE (BTU/LB)		12200
COAL ASH CONTENT (PERCENT)		12
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	STORAGE/ON-SITE	
STACK NUMBER		4
COAL DELIVERY METHODS	BARGE/RAILROAD	
FGD SYSTEM (TYPE)		LIME FGD
FGD SYSTEM (INSTALLATION DATE)		1982

PARTICULATE CONTROL

TYPE	ESP
INSTALLATION DATE	1973
EMISSION (LB/MM BTU)	0.02
REMOVAL EFFICIENCY	99.5
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	2.0-3.0
SURFACE AREA (1000 SQ FT)	125.4
EXIT GAS FLOW RATE (1000 ACFM)	1100
SCA (SQ FT/1000 ACFM)	114
OUTLET TEMPERATURE (°F)	300

* Boiler Nos. 1, 2 and 3 are associated with generating Unit Nos. 1 and 2 which are rated at 75 MW each.

TABLE 21.1.3-2. SUMMARY OF NOx RETROFIT RESULTS FOR MITCHELL

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	33
FIRING TYPE	TANG
TYPE OF NOx CONTROL	OFA
FURNACE VOLUME (1000 CU FT)	NA
BOILER INSTALLATION DATE	1963
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$)	0
Ductwork Demolition (1000$)	61
New Duct Length (Feet)	200
New Duct Costs (1000$)	1881
New Heat Exchanger (1000$)	3596
TOTAL SCOPE ADDER COSTS (1000$)	5538
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	13

* Cold side SCR reactors for unit 33 would be located beside the unit 33 chimney.

Table 21.1.3-3. 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	33	1.00	299	30	2.6	1.0	3.2	0.2	0.3	25.0	598	348.4
LNC-OFA-C	33	1.00	299	30	2.6	1.0	3.2	0.1	0.2	25.0	598	206.8
SCR-3	33	1.16	299	30	2.6	41.3	138.0	14.2	18.0	80.0	1914	7407.2
SCR-3-C	33	1.16	299	30	2.6	41.3	138.0	8.3	10.6	80.0	1914	4340.6
SCR-7	33	1.16	299	30	2.6	41.3	138.0	11.7	14.9	80.0	1914	6126.6
SCR-7-C	33	1.16	299	30	2.6	41.3	138.0	6.9	8.8	80.0	1914	3606.9

21.2 DUQUESNE LIGHT COMPANY

21.2.1 Cheswick Steam Plant

The Cheswick steam plant is located in a somewhat congested residential, commercial, and industrial area about 16 miles northeast of Pittsburgh, PA at Springdale, PA, within Allegheny County, Pennsylvania, as part of the Duquesne Light Company system. The plant contains one coal-fired boiler with a total gross generating capacity of 600 MW (net generating capacity of 570 MW). Figure 21.2.1-1 presents the plant plot plan showing the location of the boiler and major associated auxiliary equipment.

Table 21.2.1-1 presents operational data for the existing equipment at the Cheswick plant. The boiler burns medium sulfur coal (1.6 percent sulfur). Coal shipments are received primarily by truck (barge secondary) and conveyed to a coal storage and handling area located north of the plant.

Particulate matter emissions for the boilers are controlled with ESPs located behind the unit. The plant has a dry fly ash handling system and is disposed in a landfill located five miles away from the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 21.2.1-1 shows the general layout and location of the FGD control system. The plant is located on a small site surrounded by residential housing on three sides and the Allegheny River to the south. The absorbers for L/LS-FGD and LSD-FGD for the unit would be located in available space west of the powerhouse between the chimney and coal storage and handling area. Some relocation or demolition of the existing equipment, as well as the coal pile, would be required; therefore, a factor of 15 percent was assigned to general facilities. The lime storage/preparation area would be located south of the plant close to the river with the waste handling area located adjacent to it.

Retrofit Difficulty and Scope Adder Costs--

The absorbers for L/LS-FGD and LSD-FGD technologies for the unit would be located adjacent to the chimney, close to the coal storage and handling

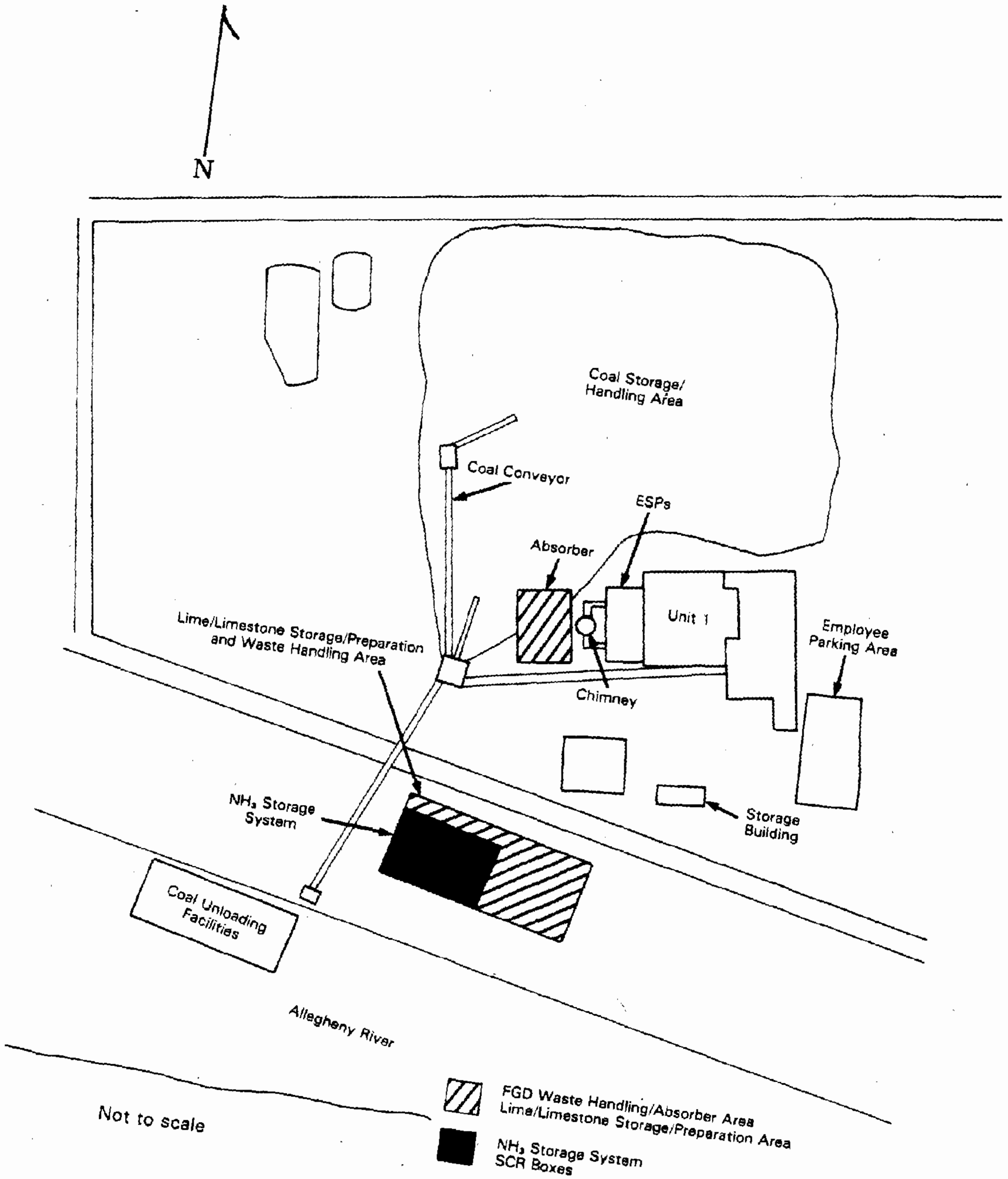

Figure 21.2.1-1. Cheswick plant plot plan

TABLE 21.2.1-1. CHESWICK STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1
GENERATING CAPACITY (MW)	600
CAPACITY FACTOR (PERCENT)	57
INSTALLATION DATE	1970
FIRING TYPE	TANG
COAL SULFUR CONTENT (PERCENT)	1.6
COAL HEATING VALUE (BTU/LB)	12283
COAL ASH CONTENT (PERCENT)	12.1
FLY ASH SYSTEM	DRY DISPOSAL
ASH DISPOSAL METHOD	OFF-SITE (5 MILES)
STACK NUMBER	1
COAL DELIVERY METHODS	TRUCK, BARGE
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1970
EMISSION (LB/MM BTU)	0.08
REMOVAL EFFICIENCY	98.9
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	1.8
SURFACE AREA (1000 SQ FT)	444
GAS EXIT RATE (1000 ACFM)	1982
SCA (SQ FT/1000 ACFM)	200
OUTLET TEMPERATURE (°F)	310

area. Another possible location for absorbers would be southwest of the chimney between the coal conveyor and the river.

A high site access/congestion factor was assigned to the absorbers location which reflects the congestion created by the surrounding coal conveyors, powerhouse, coal storage and handling area, sump drainage lines, towers and underground fuel lines. For flue gas handling, a short duct run would be required for L/LS-FGD cases since the absorbers are located directly behind the chimney.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Table 21.2.1-2. There are no large scope adder costs for the Cheswick plant. The overall retrofit factors determined for the L/LS-FGD cases were medium.

The absorbers for LSD-FGD would be located in the same location as L/LS-FGD cases. LSD-FGD with a new baghouse was the only LSD-FGD technology considered for the unit because of the difficulty to tie into the upstream of the ESPs. In addition, the ESPs are marginal in size and might not be able to handle the additional particulate load generated by applying LSD. The retrofit factor determined for the LSD technology case was moderate and did not include particulate control upgrading costs. A separate retrofit factor was developed for the new baghouse for the unit (1.58) and a high site access/congestion factor was designated which reflects the difficulty in locating the new baghouse. This factor was used in the IAPCS model to estimate particulate control costs.

Table 21.2.1-3 presents the estimated costs for L/LS-FGD and LSD-FGD cases. 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 module, and optimization of scrubber size. Plant personnel indicated that the disposal costs are $26/ton, and as such, this value was used by the Cheswick plant.

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 21.2.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR CHESWICK UNIT 1

	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)	0-100	0-100	
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	1.47	1.50	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.54
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.58
GENERAL FACILITIES (PERCENT)	15	15	15

*Chimney liner cost is included for relining of the existing chimney.

Table 21.2.1-3. Summary of FGD Control Costs for the Cheswick 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	1.47	600	57	1.6	98.9	164.8	53.7	17.9	90.0	33885	1585.3
LC FGD-C	1	1.47	600	57	1.6	98.9	164.8	31.2	10.4	90.0	33885	921.4
LFGD	1	1.47	600	57	1.6	123.7	206.2	61.8	20.6	90.0	33885	1822.6
LFGD-C	1	1.47	600	57	1.6	123.7	206.2	35.9	12.0	90.0	33885	1060.6
LSD+FF	1	1.54	600	57	1.6	142.0	236.6	58.4	19.5	87.0	32567	1793.6
LSD+FF-C	1	1.54	600	57	1.6	142.0	236.6	34.1	11.4	87.0	32567	1047.2

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 21.2.1-4.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Cheswick 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--

Unit 1 is a dry bottom, tangential-fired boiler rated at 565 MW. The combustion modification technique applied for this evaluation was OFA. As Table 21.2.1-5 shows, the OFA NO_x reduction performance for this unit was estimated at 15 percent. 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 21.2.1-6 presents the cost of retrofitting OFA at the Cheswick boiler.

Selective Catalytic Reduction--

Table 21.2.1-5 presents the SCR retrofit results for unit 1. 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 reactor for unit 1 would be located adjacent to the chimney, close to the coal storage and handling area in a relatively small area. Access to this area would be difficult. For this reason, the reactor was assigned a high access/congestion factor. The reactor was assumed to be in

Table 21.2.1-4. Summary of Coal Switching/Cleaning Costs for the Cheswick 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	600	57	1.6	19.5	32.5	44.5	14.9	43.0	16018	2780.4
CS/B+$15-C	1	1.00	600	57	1.6	19.5	32.5	25.6	8.5	43.0	16018	1598.5
CS/B+$5	1	1.00	600	57	1.6	13.3	22.1	18.7	6.2	43.0	16018	1167.6
CS/B+$5-C	1	1.00	600	57	1.6	13.3	22.1	10.8	3.6	43.0	16018	672.7

TABLE 21.2.1-5. SUMMARY OF NOx RETROFIT RESULTS FOR CHESWICK

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1
FIRING TYPE	TANG
TYPE OF NOx CONTROL	OFA
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	16
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	90.2
FURNACE RESIDENCE TIME (SECONDS)	2.74
ESTIMATED NOx REDUCTION (PERCENT)	25
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	104
New Duct Length (Feet)	150
New Duct Costs (1000$)	2120
New Heat Exchanger (1000$)	5461
TOTAL SCOPE ADDER COSTS (1000$)	7685
RETROFIT FACTOR FOR SCR	1.52
GENERAL FACILITIES (PERCENT)	17

Table 21.2.1-6. NOx Control Cost Results for the Cheswick 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	600	57	1.6	1.3	2.1	0.3	0.1	25.0	2263	121.5
LNC-OFA-C	1	1.00	600	57	1.6	1.3	2.1	0.2	0.1	25.0	2263	72.2
SCR-3	1	1.52	600	57	1.6	83.9	139.8	29.8	9.9	80.0	7240	4111.7
SCR-3-C	1	1.52	600	57	1.6	83.9	139.8	17.4	5.8	80.0	7240	2407.6
SCR-7	1	1.52	600	57	1.6	83.9	139.8	24.9	8.3	80.0	7240	3432.5
SCR-7-C	1	1.52	600	57	1.6	83.9	139.8	14.6	4.9	80.0	7240	2018.6

an area with high underground obstructions. The ammonia storage system was placed in a remote area having a low access/congestion factor.

In this study, all NO_x control techniques were evaluated independently from those evaluated for SO_2 control. As a result, for this plant the FGD absorbers were located in the same area as the SCR reactor. If both SO_2 and NO_x emissions have to be reduced at this plant, the SCR reactor would have to be located downstream of the FGD absorbers (i.e., west of the chimney) in an area surrounded by the coal conveyors. Once again, a high access/congestion factor would be assigned to this SCR reactor.
Table 21.2.1-6 presents the estimated cost of retrofitting SCR at the Cheswick boiler. Plant personnel indicated that fly ash coming out of the precipitator contain highly corrosive elements which might reduce the catalyst life. In addition, because of the close proximity of residential and commercial areas to the plant and possibility of ammonia slip, SCR may not be feasible at this plant.

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 west of the plant in a similar fashion as LSD-FGD. The retrofit of DSD and FSI technologies at the Cheswick steam plant for the unit would be very difficult because the upgrading of the ESPs would be difficult. Also, there is not sufficient flue gas ducting residence time between the boiler and the ESPs. Therefore, a new baghouse was considered for DSD, located in a high site access/congestion area between the chimney and the coal storage/handling area. In addition, 300 feet of duct run would be required to divert the flue gas from the boiler to the baghouse and back to the chimney. Additional duct residence time could be made available for DSD application if the existing ESPs were used. For FSI technology, ESP SCAs are small and upgrading of the ESPs would be very difficult and, as such, this technology was not considered for the Cheswick plant. Table 21.2.1-7 presents a summary of the site access/congestion factors for DSD technology at the Cheswick steam plant. Table 21.2.1-8 presents the costs estimated to retrofit DSD at the Cheswick 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 Cheswick plant. The boiler would not be considered a good candidate for AFBC retrofit due to its large boiler size (565 MW) and young age (built in 1970) and high capacity factor.

TABLE 21.2.1-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR CHESWICK UNIT 1

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE (FSI)	NA
NEW BAGHOUSE (DSD)	HIGH
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	300
ESTIMATED COST (1000$)	3931
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	115
TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	NA
A NEW BAGHOUSE CASE (DSD)	4046
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE (FSI)	NA
NEW BAGHOUSE (DSD)	1.58

Table 21.2.1-8. Summary of DSD/FSI Control Costs for the Cheswick 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	600	57	1.6	84.5	140.8	39.4	13.1	71.0	26638	1477.5
DSD+FF-C	1	1.00	600	57	1.6	84.5	140.8	22.9	7.7	71.0	26638	860.7

21.3 METROPOLITAN EDISON COMPANY

21.3.1 Portland Steam Plant

The Portland steam plant is located within North Hampton County, Pennsylvania, as part of the Metropolitan Edison Company system. The plant contains two coal-fired boilers with a total net generating capacity of 426 MW. The two units sit side-by-side parallel to the Delaware River. Figure 21.3.1-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 21.3.1-1 presents operational data for the existing equipment at the Portland plant. Both boilers burn medium sulfur coal (2.0 percent sulfur). Coal shipments are received by railroad and conveyed to a coal storage and handling area located south of the plant.

Particulate matter emissions from both units are controlled with retrofit ESPs which are located north of unit 2. The plant has a dry fly ash handling system and ash is disposed south of the plant below the coal pile.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 21.3.1-1 shows the general layout and location of the FGD control system. The absorbers for L/LS-FGD and LSD-FGD for both units could be located between the chimneys and the river but, because of the close proximity (chimneys to the river), they were located north of the retrofit ESPs. No major relocation or demolition would be required for either unit; therefore, a factor of 5 percent was assigned to general facilities. The lime storage/preparation area and waste handling area would be located north of the plant in a very large open area.

Retrofit Difficulty and Scope Adder Costs--

The absorbers for both units would be located in an open area north of the ESPs with no major obstacles or underground obstructions. The sites are very accessible and the absorbers were assigned a low site access/ congestion factor for L/LS-FGD and LSD-FGD technologies.

For flue gas handling, short duct runs for the units would be required for the L/LS-FGD cases. A low site access/congestion factor was assigned to

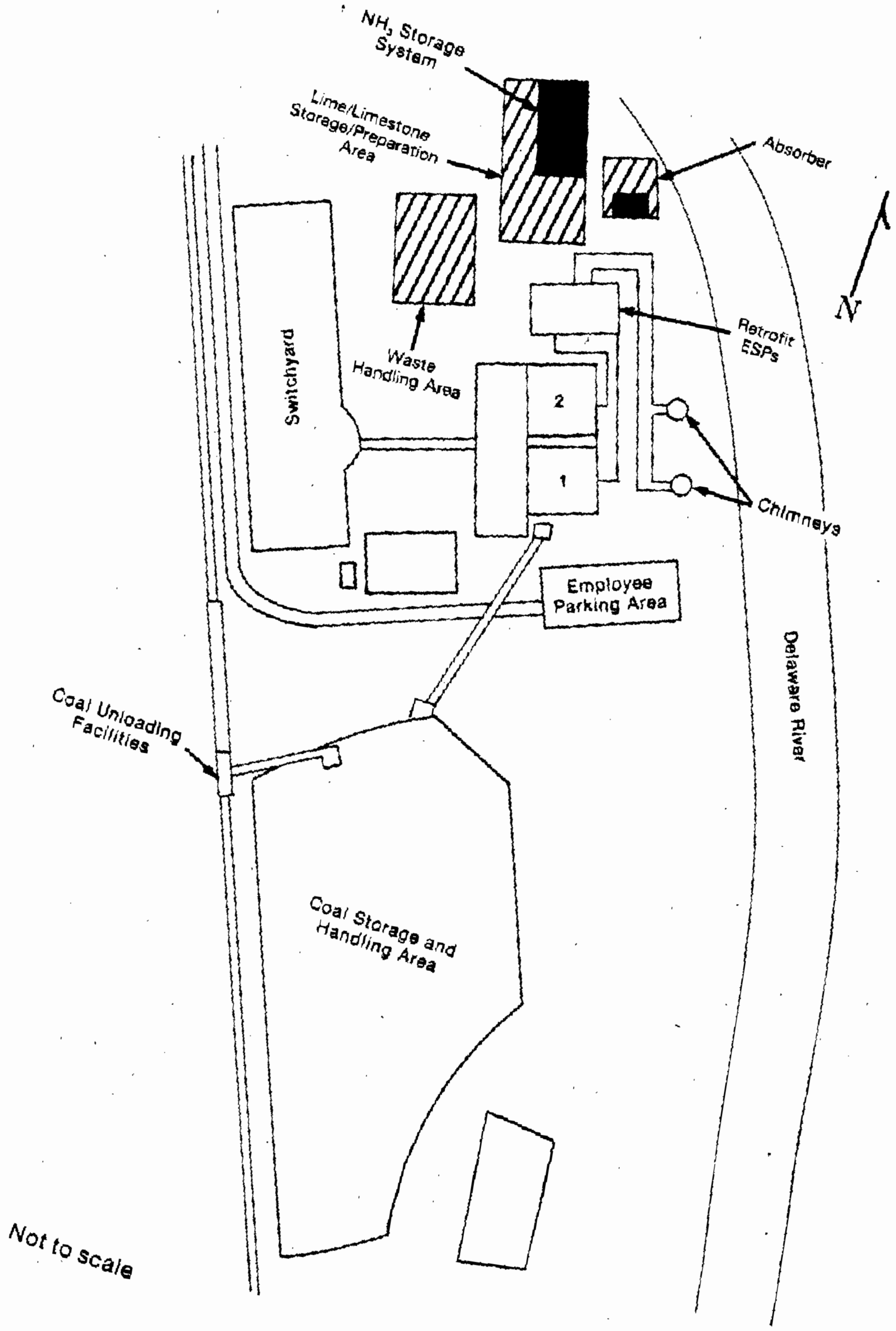

Figure 21.3.1-1 Portland plant plot plan

TABLE 21.3.1-1. PORTLAND STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2
GENERATING CAPACITY (MW)	171	255
CAPACITY FACTOR (PERCENT)	52	53
INSTALLATION DATE	1958	1962
FIRING TYPE	TANG	TANG
COAL SULFUR CONTENT (PERCENT)	2.0	2.0
COAL HEATING VALUE (BTU/LB)	12800	12800
COAL ASH CONTENT (PERCENT)	9.0	8.9
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	LANDFILL/ON-SITE	
STACK NUMBER	1	2
COAL DELIVERY METHODS	RAILROAD	
<u>PARTICULATE CONTROL</u>		
TYPE	ESP	ESP
INSTALLATION DATE	1987	1989
EMISSION (LB/MM BTU)	0.04	0.04
REMOVAL EFFICIENCY	99.6	99.6
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	1.0-2.3	1.0-2.3
SURFACE AREA (1000 SQ FT)	113	113
EXIT GAS FLOW RATE (1000 ACFM)	584	868
SCA (SQ FT/1000 ACFM)	166	243
OUTLET TEMPERATURE (°F)	266	266

the flue gas handling system due to the available space around the units with no obstructions.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Table 21.3.1-2. No large scope adder cost is required for the Portland plant. The overall retrofit factor determined for the L/LS-FGD cases was low.

The absorbers for LSD-FGD would be located in the same location as the L/LS-FGD cases. LSD-FGD with reuse of the existing ESPs was the only LSD-FGD technology considered for both units. For flue gas handling, moderate duct runs would be required and a low site access/congestion factor was assigned for both units in a similar fashion as L/LS-FGD. The retrofit factor determined for the LSD technology case was low and did not include additional costs which might be necessary if upgrading of the existing ESPs is required. A separate retrofit factor was developed for the ESP upgrading and was low because there are no major obstacles around the areas close to the ESPs and the sites are easily accessible. This factor was used in the IACPS model to estimate the upgrading costs.

Table 21.3.1-3 presents the cost estimates for L/LS and LSD-FGD cases. 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.

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 21.3.1-4.

TABLE 21.3.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR PORTLAND 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			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	1.20	1.20	
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 21.3.1-3. Summary of FGD Control Costs for the Portland 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	1-2	1.20	426	53	2.0	58.2	136.5	32.8	16.6	90.0	26671	1230.9
LC FGD-C	1-2	1.20	426	53	2.0	58.2	136.5	19.1	9.6	90.0	26671	715.0
LFGD	1	1.20	171	52	2.0	44.5	260.1	21.3	27.3	90.0	10504	2023.8
LFGD	2	1.20	255	53	2.0	57.1	224.0	27.8	23.5	90.0	15965	1739.9
LFGD-C	1	1.20	171	52	2.0	44.5	260.1	12.4	15.9	90.0	10504	1178.5
LFGD-C	2	1.20	255	53	2.0	57.1	224.0	16.2	13.7	90.0	15965	1012.9
LSD+ESP	1	1.27	171	52	2.0	24.3	142.1	11.7	15.0	76.0	8856	1317.3
LSD+ESP	2	1.27	255	53	2.0	32.7	128.4	15.3	12.9	76.0	13527	1132.5
LSD+ESP-C	1	1.27	171	52	2.0	24.3	142.1	6.8	8.7	76.0	8856	767.0
LSD+ESP-C	2	1.27	255	53	2.0	32.7	128.4	8.9	7.5	76.0	13527	659.7

Table 21.3.1-4. Summary of Coal Switching/Cleaning Costs for the Portland 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	171	52	2.0	7.1	41.3	12.1	15.5	52.0	6047	1993.2
CS/B+$15	2	1.00	255	53	2.0	8.9	35.0	17.7	14.9	52.0	9190	1920.7
CS/B+$15-C	1	1.00	171	52	2.0	7.1	41.3	6.9	8.9	52.0	6047	1147.2
CS/B+$15-C	2	1.00	255	53	2.0	8.9	35.0	10.2	8.6	52.0	9190	1104.8
CS/B+$5	1	1.00	171	52	2.0	5.3	30.9	5.3	6.8	52.0	6047	876.7
CS/B+$5	2	1.00	255	53	2.0	6.3	24.6	7.4	6.3	52.0	9190	805.2
CS/B+$5-C	1	1.00	171	52	2.0	5.3	30.9	3.1	3.9	52.0	6047	506.2
CS/B+$5-C	2	1.00	255	53	2.0	6.3	24.6	4.3	3.6	52.0	9190	464.4

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Portland 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 171 and 255 MW, respectively. The combustion modification technique applied for this evaluation was OFA. As Table 21.3.1-5 shows, the OFA NO_x reduction performance for each unit was estimated to be 20 percent. 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 21.3.1-6 presents the cost of retrofitting OFA at the Portland boilers.

Selective Catalytic Reduction--

Table 21.3.1-5 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 both units were located in an open area north of the ESPs with no major obstacles. For this reason, the reactors for units 1 and 2 were assigned low site access/congestion factors. The ammonia storage system was placed in a remote area having a low access/ congestion factor.

For this report, all NO_x control techniques were evaluated independently from those evaluated for SO_2 control. As a result for this plant, the FGD absorbers were in the same location as the SCR reactors. If both SO_2 and NO_x emissions have to be reduced at this plant, the SCR reactors would have to be located downstream of the FGD absorbers in an area having little obstructions and easy access. The access/congestion factors that would be assigned to each SCR reactor would be the same as that

TABLE 21.3.1-5. SUMMARY OF NOx RETROFIT RESULTS FOR PORTLAND

	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)	12.1	13.8
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	71.1	88.7
FURNACE RESIDENCE TIME (SECONDS)	2.74	2.97
ESTIMATED NOx REDUCTION (PERCENT)	20	20
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	41	55
New Duct Length (Feet)	200	200
New Duct Costs (1000$)	1361	1714
New Heat Exchanger (1000$)	2581	3268
TOTAL SCOPE ADDER COSTS (1000$)	3983	5037
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13

Table 21.3.1-6. NOx Control Cost Results for the Portland 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	171	52	2.0	0.8	4.5	0.2	0.2	20.0	449	370.5
LNC-OFA	2	1.00	255	53	2.0	0.9	3.5	0.2	0.2	20.0	682	286.4
LNC-OFA-C	1	1.00	171	52	2.0	0.8	4.5	0.1	0.1	20.0	449	219.9
LNC-OFA-C	2	1.00	255	53	2.0	0.9	3.5	0.1	0.1	20.0	682	170.0
SCR-3	1	1.16	171	52	2.0	26.5	155.1	9.0	11.6	80.0	1796	5030.8
SCR-3	2	1.16	255	53	2.0	36.1	141.5	12.6	10.6	80.0	2729	4606.8
SCR-3-C	1	1.16	171	52	2.0	26.5	155.1	5.3	6.8	80.0	1796	2948.6
SCR-3-C	2	1.16	255	53	2.0	36.1	141.5	7.4	6.2	80.0	2729	2698.7
SCR-7	1	1.16	171	52	2.0	26.5	155.1	7.6	9.8	80.0	1796	4255.7
SCR-7	2	1.16	255	53	2.0	36.1	141.5	10.5	8.9	80.0	2729	3846.3
SCR-7-C	2	1.16	255	53	2.0	36.1	141.5	6.2	5.2	80.0	2729	2263.0
SCR-70-C	1	1.16	171	52	2.0	26.5	155.1	4.5	5.8	80.0	1796	2504.4

discussed above. Table 21.3.1-6 presents the estimated cost of retrofitting SCR at the Portland 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 beside the ESPs. The retrofit of DSD and FSI technologies at the Portland steam plant for all units would be relatively easy. There is sufficient flue gas ducting residence time between the boilers and the ESPs for sorbent injection. A low retrofit factor was estimated for upgrading the existing ESPs since the sites are accessible with no obstacles or congestion. Tables 21.3.1-7 and 21.3.1-8 present a summary of the site access/congestion factors for DSD and FSI technologies at the Portland steam plant. Table 21.3.1-9 presents the costs estimated to retrofit DSD and FSI at the Portland 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 Portland plant. Both boilers would be considered good candidates for AFBC retrofit due to their small boiler sizes (<300 MW) and their old ages (built before 1960's).

TABLE 21.3.1-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR PORTLAND UNIT 1

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$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	45
TOTAL COST (1000$)	
ESP UPGRADE CASE	45
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.13
NEW BAGHOUSE	NA

TABLE 21.3.1-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR PORTLAND 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$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	60
TOTAL COST (1000$)	
ESP UPGRADE CASE	60
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.13
NEW BAGHOUSE	NA

Table 21.3.1-9. Summary of DSD/FSI Control Costs for the Portland 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	171	52	2.0	10.2	59.5	7.4	9.5	48.0	5654	1314.1
DSD+ESP	2	1.00	255	53	2.0	11.8	46.1	9.0	7.6	49.0	8626	1044.3
DSD+ESP-C	1	1.00	171	52	2.0	10.2	59.5	4.3	5.5	48.0	5654	761.0
DSD+ESP-C	2	1.00	255	53	2.0	11.8	46.1	5.2	4.4	49.0	8626	604.4
FSI+ESP-50	1	1.00	171	52	2.0	11.1	65.1	7.7	9.9	50.0	5836	1320.5
FSI+ESP-50	2	1.00	255	53	2.0	13.2	51.9	10.1	8.5	50.0	8869	1135.8
FSI+ESP-50-C	1	1.00	171	52	2.0	11.1	65.1	4.5	5.7	50.0	5836	765.1
FSI+ESP-50-C	2	1.00	255	53	2.0	13.2	51.9	5.8	4.9	50.0	8869	657.4
FSI+ESP-70	1	1.00	171	52	2.0	11.2	65.7	7.8	10.0	70.0	8170	956.9
FSI+ESP-70	2	1.00	255	53	2.0	13.4	52.4	10.2	8.6	70.0	12417	824.2
FSI+ESP-70-C	1	1.00	171	52	2.0	11.2	65.7	4.5	5.8	70.0	8170	554.4
FSI+ESP-70-C	2	1.00	255	53	2.0	13.4	52.4	5.9	5.0	70.0	12417	477.1

21.4 PENNSYLVANIA ELECTRIC COMPANY

21.4.1 Conemaugh Steam Plant

The Conemaugh steam plant is located within Indiana County, Pennsylvania, and operated by the Pennsylvania Electric Company system. The plant contains two coal-fired boilers with a total gross generating capacity of 1,872 MW. The two units sit side-by-side and are beside the Conemaugh River. Figure 21.4.1-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 21.4.1-1 presents operational data for the existing equipment at the Conemaugh plant. Both boilers burn medium sulfur coal (2.2 percent sulfur). Coal shipments are received by truck, rail, and conveyors from a nearby coal mine and conveyed to a coal storage and handling area located north of the plant.

Particulate matter emissions for all units are controlled with ESPs which are located behind each unit. The plant has a dry fly ash handling system and ash is disposed at a landfill located north of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 21.4.1-1 shows the general layout and location of the FGD control system. The boilers are situated such that space from the chimney to the Conemaugh River is available for the FGD equipment additions. There are two large recirculating absorbers with natural draft cooling towers located north of the powerhouse between the river and coal pile. The absorbers for L/LS-FGD would be located behind the chimneys (south) and, for LSD-FGD, the absorbers would be located on either side of the ESPs. No major relocation or demolition would be required for the L/LS-FGD absorbers; therefore, a factor of 5 percent was assigned to general facilities. However, a storage building and parking area would need to be demolished and relocated in order to make space available for the LSD absorbers. As such, a factor of 10 percent was assigned to LSD-FGD general facilities. The lime storage/preparation area and waste handling area would be located south of the plant in a very large open area between the coal storage/handling area and river.

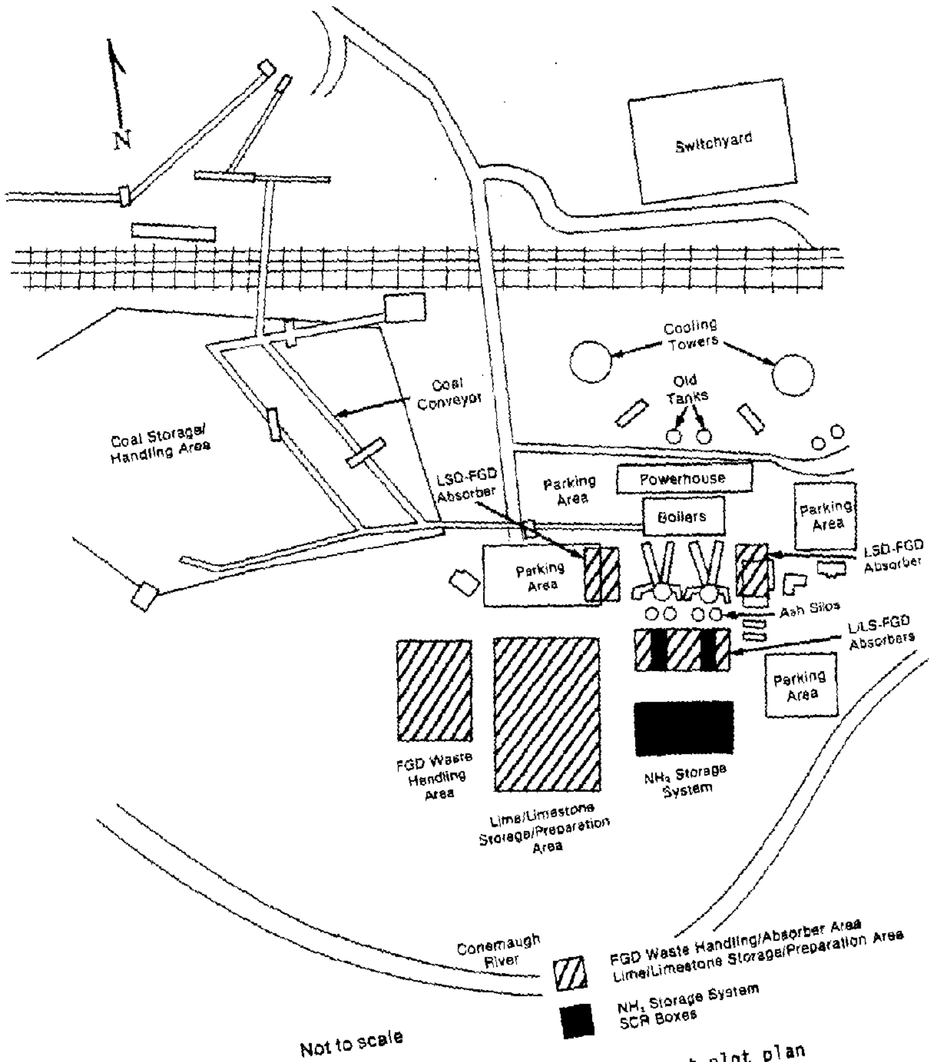

Figure 21.4.1-1. Conemaugh plant plot plan

TABLE 21.4.1-1. CONEMAUGH STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2
GENERATING CAPACITY (MW-each)	900
CAPACITY FACTOR (PERCENT)	87.8, 76.2
INSTALLATION DATE	1970,71
FIRING TYPE	TANGENTIAL
COAL SULFUR CONTENT (PERCENT)	2.3, 1.9
COAL HEATING VALUE (BTU/LB)	12300
COAL ASH CONTENT (PERCENT)	14.6
FLY ASH SYSTEM	DRY DISPOSAL
ASH DISPOSAL METHOD	LANDFILL/ON-SITE
STACK NUMBER	1-2
COAL DELIVERY METHODS	CONVEYOR,TRUCK,RAIL
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1970
EMISSION (LB/MM BTU)	0.05-0.09
REMOVAL EFFICIENCY	99.3
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	1.5
SURFACE AREA (1000 SQ FT)	557.4
GAS EXIT RATE (1000 ACFM)	3100
SCA (SQ FT/1000 ACFM)	185
OUTLET TEMPERATURE (°F)	340

Retrofit Difficulty and Scope Adder Costs--

The absorbers for both units would be located south of the plant immediately after the chimneys for both L/LS-FGD and LSD-FGD cases.

The absorbers were assigned a low site access/congestion factor for L/LS-FGD and LSD-FGD technologies which reflects no major obstacles or underground obstructions.

For flue gas handling, medium duct runs for both units would be required for L/LS-FGD cases. A low site access/congestion factor was assigned to the flue gas handling system due to the fact that there were no major obstructions around the chimneys.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Table 21.4.1-2. No large scope adder cost is required for the Conemaugh plant. The overall retrofit factor determined for the L/LS-FGD cases was low to medium (1.31).

The absorbers for LSD-FGD would be located on either side of the ESPs. After demolition and relocation of the storage area and employee parking area, space would be available for the LSD absorbers with low site access/congestion factors. LSD-FGD with reused ESP was originally considered, but with the limited information it was not clear if the ESPs could handle the increased PM; therefore, LSD with a new FF was considered for both units. For flue gas handling for LSD cases, moderate duct runs would be required and a low site access/congestion factor was assigned for both units. The retrofit factor determined for the LSD technology case was low (1.27) and did not include particulate control costs. A separate retrofit factor was developed for new FFs and a low site access/congestion factor was assigned. This factor was used in the IACPS model to estimate the new particulate control costs.

Table 21.4.1-3 presents the estimated costs for L/LS and LSD-FGD cases. The low cost control case reduces capital and annual operating costs. The significant reduction in costs is primarily due to the elimination of spare scrubber modules and the optimization of scrubber module 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

TABLE 21.4.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR CONEMAUGH 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	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	1.31	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	10

Table 21.4.1-3. Summary of FGD Control Costs for the Conemaugh 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	1-2	1.31	1800	82	1.9	216.9	120.5	146.5	11.3	90.0	173386	844.7
LC FGD-C	1-2	1.31	1800	82	1.9	216.9	120.5	84.9	6.6	90.0	173386	489.5
LFGD	1	1.31	900	88	2.3	143.6	159.6	93.1	13.4	90.0	112367	828.6
LFGD	2	1.31	900	76	1.9	141.6	157.3	83.0	13.8	90.0	80561	1030.1
LFGD-C	1	1.31	900	88	2.3	143.6	159.6	54.0	7.8	90.0	112367	480.4
LFGD-C	2	1.31	900	76	1.9	141.6	157.3	48.2	8.0	90.0	80561	598.1
LSD+FF	1	1.27	900	88	2.3	174.5	193.9	81.9	11.8	87.0	107997	758.4
LSD+FF	2	1.27	900	76	1.9	169.8	188.7	73.2	12.2	87.0	77428	945.3
LSD+FF-C	1	1.27	900	88	2.3	174.5	193.9	47.7	6.9	87.0	107997	441.7
LSD+FF-C	2	1.27	900	76	1.9	169.8	188.7	42.7	7.1	87.0	77428	551.4

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 21.4.1-4.

Table 21.4.1-4 presents the IAPCS cost results for physical coal cleaning at the Conemaugh 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 costs estimated for NO_x controls at the Conemaugh 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, each rated at 936 MW. The combustion modification technique applied for this evaluation was OFA. As Table 21.4.1-5 shows, the OFA NO_x reduction performance for each unit was estimated to be 20 percent. 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 21.4.1-6 presents the cost of retrofitting OFA at the Conemaugh boilers.

Selective Catalytic Reduction--

Table 21.4.1-5 presents the SCR retrofit results for each unit. The results include process area retrofit factors and scope adder costs. The

Table 21.4.1-4. Summary of Coal Switching/Cleaning Costs for the Conemaugh 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	900	88	2.3	32.5	36.1	95.0	13.7	60.0	74870	1269.2
CS/B+$15	2	1.00	900	76	1.9	32.5	36.1	83.4	13.9	52.0	46134	1808.2
CS/B+$15-C	1	1.00	900	88	2.3	32.5	36.1	54.6	7.9	60.0	74870	729.1
CS/B+$15-C	2	1.00	900	76	1.9	32.5	36.1	47.9	8.0	52.0	46134	1039.2
CS/B+$5	1	1.00	900	88	2.3	23.2	25.7	36.2	5.2	60.0	74870	483.7
CS/B+$5	2	1.00	900	76	1.9	23.2	25.7	32.2	5.4	52.0	46134	697.2
CS/B+$5-C	1	1.00	900	88	2.3	23.2	25.7	20.9	3.0	60.0	74870	278.5
CS/B+$5-C	2	1.00	900	76	1.9	23.2	25.7	18.5	3.1	52.0	46134	401.7
PCC	1	1.00	900	88	2.3	15.1	16.8	18.1	2.6	26.0	32988	549.8
PCC	2	1.00	900	76	1.9	15.1	16.8	16.2	2.7	11.0	9785	1658.4
PCC-C	1	1.00	900	88	2.3	15.1	16.8	10.5	1.5	26.0	32988	317.0
PCC-C	2	1.00	900	76	1.9	15.1	16.8	9.4	1.6	11.0	9785	957.1

TABLE 21.4.1-5. SUMMARY OF NOx RETROFIT RESULTS FOR CONEMAUGH

	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)	14.2	14.2
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	84	84
FURNACE RESIDENCE TIME (SECONDS)	3.41	3.41
ESTIMATED NOx REDUCTION (PERCENT)	20	20
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	140	140
New Duct Length (Feet)	325	325
New Duct Costs (1000$)	5823	5823
New Heat Exchanger (1000$)	6966	6966
TOTAL SCOPE ADDER COSTS (1000$)	12929	12929
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13

Table 21.4.1-6. NOx Control Cost Results for the Conemaugh 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	900	88	2.3	1.5	1.7	0.3	0.0	20.0	4176	77.5
LNC-OFA	2	1.00	900	76	1.9	1.5	1.7	0.3	0.1	20.0	3624	89.3
LNC-OFA-C	1	1.00	900	88	2.3	1.5	1.7	0.2	0.0	20.0	4176	46.0
LNC-OFA-C	2	1.00	900	76	1.9	1.5	1.7	0.2	0.0	20.0	3624	53.0
SCR-3	1	1.16	900	88	2.3	104.8	116.4	40.6	5.9	80.0	16703	2433.3
SCR-3	2	1.16	900	76	1.9	104.7	116.4	40.0	6.7	80.0	14496	2760.2
SCR-3-C	1	1.16	900	88	2.3	104.8	116.4	23.8	3.4	80.0	16703	1422.2
SCR-3-C	2	1.16	900	76	1.9	104.7	116.4	23.4	3.9	80.0	14496	1613.8
SCR-7	1	1.16	900	88	2.3	104.8	116.4	33.3	4.8	80.0	16703	1992.1
SCR-7	2	1.16	900	76	1.9	104.7	116.4	32.6	5.4	80.0	14496	2251.9
SCR-7-C	1	1.16	900	88	2.3	104.8	116.4	19.5	2.8	80.0	16703	1169.5
SCR-7-C	2	1.16	900	76	1.9	104.7	116.4	19.2	3.2	80.0	14496	1322.6

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 both units were located south of the plant immediately after the respective chimneys in an open area on either side of each unit. For this reason, the reactor locations 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. As a result, for this plant, the FGD absorbers were in the same location as the SCR reactors. If both SO_2 and NO_x emissions have to be reduced at this plant, the SCR reactors would have to be located downstream of the FGD absorbers in an area having little obstructions and easy access. The access/congestion factors that would be assigned to each SCR reactor would be the same as that discussed above. Table 21.4.1-6 presents the estimated cost of retrofitting SCR at the Conemaugh boilers.

Sorbent Injection and Repowering--

Both ESPs have marginal SCAs and are located in congested areas making their upgrades very difficult. As such, they were not considered good candidates for 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 Conemaugh plant. None of the boilers would be considered good candidates for AFBC retrofit due to their large sizes (936 MW), age (built after 1960), and high capacity factors.

21.4.2 Homer City Steam Plant

The Homer City steam plant is located within Indiana County, Pennsylvania, as part of the Pennslyvania Electric Company and New York State Electric & Gas. The plant contains three coal-fired boilers with a total gross generating capacity of 1,850 MW. Figure 21.4.2-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 21.4.2-1 presents operational data for the existing equipment at the Homer City plant. The boilers burn medium sulfur coal (1.3 to 2.2 percent sulfur). Coal shipments are received by trucks and conveyors from a nearby coal mine. Coal for unit 3 is extensively cleaned to achieve a boiler emission rate of 1.2 lb SO_2 per million Btu.

Particulate matter emissions for the boilers are controlled with ESPs located behind each unit. The plant has a dry fly ash handling system and is disposed at a landfill located west of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 21.4.2-1 shows the general layout and location of the FGD control system. Each unit is served by its own chimney. There are three natural draft cooling towers located south of the plant close to unit 3. The absorbers for L/LS-FGD and LSD-FGD for all units would be located immediately behind the chimneys in a relatively open area. No major relocation or demolition would be required for any of the units; therefore, a factor of 5 percent was assigned to general facilities. The lime storage/preparation area would be located west of the plant on the other side of the road and close to the absorbers; the waste handling area would be located adjacent to it.

Retrofit Difficulty and Scope Adder Costs--

The absorbers for all units would be located west of the plant behind the chimney. Ample space is available for the FGD absorbers. The absorber locations for all units were assigned a low site access/congestion factor which reflects no major obstacles/obstructions around the absorbers.

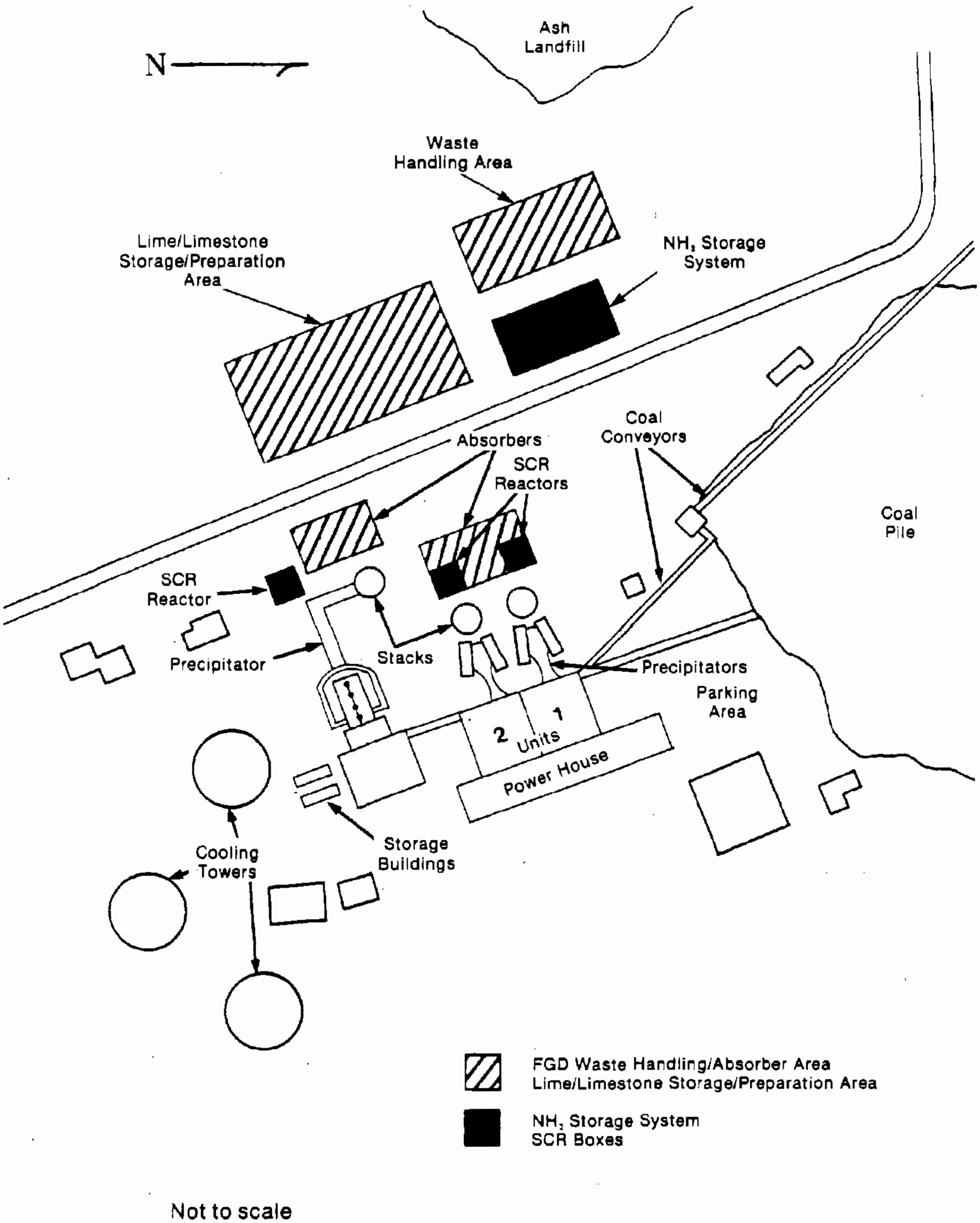

Figure 21.4.2-1. Homer City plot plan

TABLE 21.4.2-1. HOMER CITY STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3
GENERATING CAPACITY (MW-each)	600	650
CAPACITY FACTOR (PERCENT)	57.5,72.4	84.7
INSTALLATION DATE	1969	1977
FIRING TYPE	OWF	OWF
COAL SULFUR CONTENT (PERCENT)	1.6	1.6
COAL HEATING VALUE (BTU/LB)	11300	11900
COAL ASH CONTENT (PERCENT)	21.9	14.9
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	LANDFILL/ON-SITE	
STACK NUMBER	1-2	3
COAL DELIVERY METHODS	NEARBY MINE/CONVEYOR,TRUCK	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1969	1977
EMISSION (LB/MM BTU)	0.09-0.06	0.02
REMOVAL EFFICIENCY	99.5	99.3
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	2.8	2.1
SURFACE AREA (1000 SQ FT)	417.9	1144.8
EXIT GAS FLOW RATE (1000 ACFM)	2050	2600
SCA (SQ FT/1000 ACFM)	182	410
OUTLET TEMPERATURE (°F)	290	270

For flue gas handling, medium duct runs for all units would be required for L/LS-FGD cases since the absorbers are located close to the chimney. A low site access/congestion factor was assigned to the flue gas handling system due to major obstacles surrounding the chimney.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Table 21.4.2-2. There are no large scope adder costs for the Homer City plant. The overall retrofit factor determined for the L/LS-FGD cases was low.

The absorbers for LSD-FGD would be placed in the same low site access/congestion locations as L/LS-FGD cases. LSD-FGD with reused ESPs was the only LSD-FGD technology considered for all units because of their adequate ESP sizes (SCA~200). For flue gas handling for LSD cases, medium duct runs would be required to divert the flue gas from the upstream of the ESPs to the absorbers and back to the ESPs. A medium site access/congestion factor was assigned to the flue gas handling system for all units. For units 1-2, the congestion resulted due to the close proximity of the ESPs. For unit 3, the access difficulty to the upstream of the ESPs resulted from the close proximity of the ESPs and the powerhouse building. The retrofit factor determined for the LSD technology case was low (1.31) and did not include particulate control upgrading costs. Separate retrofit factors were developed for upgrading the ESPs; low to medium site access/congestion factors were designated which reflects the available space around the ESPs if additional plate area is required. The medium site access/congestion factor reflects the congestion created around units 1 and 2 due to the close proximity of the ESPs. These factors were used in the IAPCS model to estimate particulate control upgrading costs.

Table 21.4.2-3 presents the estimated costs for L/LS-FGD and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs for boilers 1-3. 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.

Coal Switching and Physical Coal Cleaning Costs--

Coal for unit 3 is already washed, therefore, was not considered in this study; only costs for units 1 and 2 are presented here. Coal switching can

TABLE 21.4.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR HOMER CITY UNITS 1,2, OR 3

	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			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE (1-2,3)	NA	NA	MEDIUM, 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	1.31	1.31	
ESP REUSE CASE			1.31
BAGHOUSE CASE			NA
ESP UPGRADE (1-2,3)	NA	NA	1.36, 1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	5	5

Table 21.4.2-3. Summary of FGD Control Costs for the Homer City 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	1.31	1850	72	1.6	218.8	118.3	137.6	11.8	90.0	142142	968.2
LC FGD-C	1-3	1.31	1850	72	1.6	218.8	118.3	79.8	6.9	90.0	142142	561.6
LFGD	1	1.31	600	58	1.6	104.0	173.4	52.9	17.5	90.0	37617	1406.0
LFGD	2	1.31	600	72	1.6	104.0	173.4	57.7	15.2	90.0	47365	1218.0
LFGD	3	1.31	650	85	1.6	111.0	170.7	66.1	13.7	90.0	56569	1168.8
LFGD-C	1	1.31	600	58	1.6	104.0	173.4	30.8	10.2	90.0	37617	817.9
LFGD-C	2	1.31	600	72	1.6	104.0	173.4	33.5	8.8	90.0	47365	707.7
LFGD-C	3	1.31	650	85	1.6	111.0	170.7	38.4	8.0	90.0	56569	678.4
LSD+ESP	1	1.31	600	58	1.6	75.5	125.9	33.0	10.9	54.0	22439	1470.6
LSD+ESP	2	1.31	600	72	1.6	75.5	125.9	35.4	9.3	54.0	28254	1253.1
LSD+ESP	3	1.31	660	85	1.6	67.7	102.6	34.7	7.1	61.0	38914	890.8
LSD+ESP-C	1	1.31	600	58	1.6	75.5	125.9	19.2	6.4	54.0	22439	857.7
LSD+ESP-C	2	1.31	600	72	1.6	75.5	125.9	20.6	5.4	54.0	28254	729.9
LSD+ESP-C	3	1.31	660	85	1.6	67.7	102.6	20.2	4.1	61.0	38914	518.2

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 21.4.2-4.

Table 21.4.2-4 presents the IAPCS cost results for physical coal cleaning at Homer City 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 costs estimated for NO_x controls at the Homer City 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 1-3 are dry bottom, opposed wall-fired boilers rated at 600, 600, and 650 MW, respectively. The combustion modification technique applied for these boilers was LNB. As Table 21.4.2-5 shows, the LNB NO_x reduction performance for each unit was estimated to be 50 percent. 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 21.4.2-6 presents the cost of retrofitting LNB at the Homer City boilers.

Table 21.4.2-4. Summary of Coal Switching/Cleaning Costs for the Homer City 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	600	58	1.6	17.5	29.2	41.6	13.8	48.0	19974	2081.2
CS/B+$15	2	1.00	600	72	1.6	17.5	29.2	51.4	13.5	48.0	25150	2042.6
CS/B+$15-C	1	1.00	600	58	1.6	17.5	29.2	23.9	7.9	48.0	19974	1196.3
CS/B+$15-C	2	1.00	600	72	1.6	17.5	29.2	29.5	7.8	48.0	25150	1173.4
CS/B+$5	1	1.00	600	58	1.6	11.3	18.8	15.5	5.1	48.0	19974	776.9
CS/B+$5	2	1.00	600	72	1.6	11.3	18.8	18.9	5.0	48.0	25150	749.6
CS/B+$5-C	1	1.00	600	58	1.6	11.3	18.8	8.9	3.0	48.0	19974	447.7
CS/B+$5-C	2	1.00	600	72	1.6	11.3	18.8	10.9	2.9	48.0	25150	431.5
PCC	1	1.00	600	58	1.6	9.4	15.7	8.0	2.6	21.0	8746	909.7
PCC	2	1.00	600	72	1.6	9.4	15.7	9.4	2.5	21.0	11013	855.0
PCC-C	1	1.00	600	58	1.6	9.4	15.7	4.6	1.5	21.0	8746	526.0
PCC-C	2	1.00	600	72	1.6	9.4	15.7	5.4	1.4	21.0	11013	493.7

TABLE 21.4.2-5. SUMMARY OF NOx RETROFIT RESULTS FOR HOMER CITY

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	3
FIRING TYPE	OWF	OWF	OWF
TYPE OF NOx CONTROL	LNB	LNB	LNB
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	14.8	14.8	11.9
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	79.2	79.2	73
FURNACE RESIDENCE TIME (SECONDS)	3.31	3.31	3.52
ESTIMATED NOx REDUCTION (PERCENT)	50	50	50
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	104	104	110
New Duct Length (Feet)	125	125	150
New Duct Costs (1000$)	1767	1767	2222
New Heat Exchanger (1000$)	5461	5461	5730
TOTAL SCOPE ADDER COSTS (1000$)	7332	7332	8062
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13	13

Table 21.4.2-6. NOx Control Cost Results for the Homer City 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	600	58	1.6	5.2	8.7	1.1	0.4	50.0	7033	161.4
LNC-LNB	2	1.00	600	72	1.6	5.2	8.7	1.1	0.3	50.0	8855	128.2
LNC-LNB	3	1.00	660	85	1.6	5.4	8.2	1.2	0.2	50.0	10739	109.8
LNC-LNB-C	1	1.00	600	58	1.6	5.2	8.7	0.7	0.2	50.0	7033	95.8
LNC-LNB-C	2	1.00	600	72	1.6	5.2	8.7	0.7	0.2	50.0	8855	76.1
LNC-LNB-C	3	1.00	660	85	1.6	5.4	8.2	0.7	0.1	50.0	10739	65.2
SCR-3	1	1.16	600	58	1.6	70.3	117.1	26.9	8.9	80.0	11253	2392.6
SCR-3	2	1.16	600	72	1.6	70.3	117.1	27.5	7.2	80.0	14169	1943.8
SCR-3	3	1.16	660	85	1.6	76.3	115.6	30.4	6.2	80.0	17182	1769.4
SCR-3-C	1	1.16	600	58	1.6	70.3	117.1	15.7	5.2	80.0	11253	1398.8
SCR-3-C	2	1.16	600	72	1.6	70.3	117.1	16.1	4.2	80.0	14169	1135.9
SCR-3-C	3	1.16	660	85	1.6	76.3	115.6	17.8	3.6	80.0	17182	1033.6
SCR-7	1	1.16	600	58	1.6	70.3	117.1	21.9	7.3	80.0	11253	1950.6
SCR-7	2	1.16	600	72	1.6	70.3	117.1	22.6	5.9	80.0	14169	1592.7
SCR-7	3	1.16	660	85	1.6	76.3	115.6	25.0	5.1	80.0	17182	1453.4
SCR-7-C	1	1.16	600	58	1.6	70.3	117.1	12.9	4.3	80.0	11253	1145.5
SCR-7-C	2	1.16	600	72	1.6	70.3	117.1	13.2	3.5	80.0	14169	934.8
SCR-7-C	3	1.16	660	85	1.6	76.3	115.6	14.6	3.0	80.0	17182	852.6

Selective Catalytic Reduction--

Table 21.4.2-5 presents the SCR retrofit results for units 1-3. 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 1-2 were located immediately behind their respective chimneys; whereas, the SCR reactor for unit 3 was located west of the ESPs for unit 3. The three reactors were located in easy access and open areas. No major relocation or demolition would be required for any of the units. Therefore, the reactors for units 1-3 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 evaluated for SO_2 control. 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 in an area immediately west of the absorbers. In this case, low access/congestion factors would again be assigned to all three SCR reactors. Table 21.4.2-6 presents the estimated cost of retrofitting SCR at the Homer City 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 west of the plant in a similar fashion as LSD-FGD. The retrofit of DSD and FSI technologies at the Homer City steam plant for all units would be difficult. This is due to insufficient flue gas ducting residence time between the boilers and the ESPs. In addition to the short duct residence time, units 1-2 have marginal size ESPs and, as such, they were not considered for sorbent injection technologies. By contrast, unit 3 ESPs are large and the first part of the ESPs could be modified for sorbent injection (E-SO_x technology) or humidification. Therefore, only unit 3 was considered for both DSD and FSI applications. Table 21.4.2-7 presents a summary of the site access/congestion factors for DSD and FSI technologies at the Homer City steam plant. Table 21.4.2-8 presents the costs estimated to retrofit DSD and FSI at the Homer City 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 Homer City plant. None of the boilers would be considered good candidates for AFBC retrofit due to their large sizes (>600 MW) and high capacity factors.

21.4.3 Keystone Steam Plant

The Keystone steam plant is located within Armstrong County, Pennsylvania, as part of the Pennsylvania Electric Company system. The plant contains two coal-fired boilers with a total gross generating capacity of 1,872 MW. Figure 21.4.3-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 21.4.3-1 presents operational data for the existing equipment at the Keystone plant. Both boilers burn medium sulfur coal (1.5 percent sulfur). Coal shipments are received by trucks and conveyors from a nearby coal mine and conveyed to a coal storage and handling area located north of the plant.

Particulate matter emissions for the boilers are controlled with ESPs between the boilers and the chimneys. The plant has a dry ash handling system and the ash is disposed at a landfill located east of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 21.4.3-1 shows the general layout and location of the FGD control system. Each boiler has its own chimney and there are four natural draft

TABLE 21.4.2-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR HOMER CITY UNIT 3

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$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	122
TOTAL COST (1000$)	
ESP UPGRADE CASE	122
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.13
NEW BAGHOUSE	NA

Table 21.4.2-8. Summary of DSD/FSI Control Costs for the Homer City 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	3	1.00	660	85	1.6	21.2	32.1	19.7	4.0	41.0	26158	752.3
DSD+ESP-C	3	1.00	660	85	1.6	21.2	32.1	11.4	2.3	41.0	26158	434.6
FSI+ESP-50	3	1.00	660	85	1.6	19.8	30.0	25.9	5.3	50.0	31910	812.3
FSI+ESP-50-C	3	1.00	660	85	1.6	19.8	30.0	14.9	3.1	50.0	31910	468.2
FSI+ESP-70	3	1.00	660	85	1.6	20.1	30.4	26.5	5.4	70.0	44674	592.3
FSI+ESP-70-C	3	1.00	660	85	1.6	20.1	30.4	15.2	3.1	70.0	44674	341.4

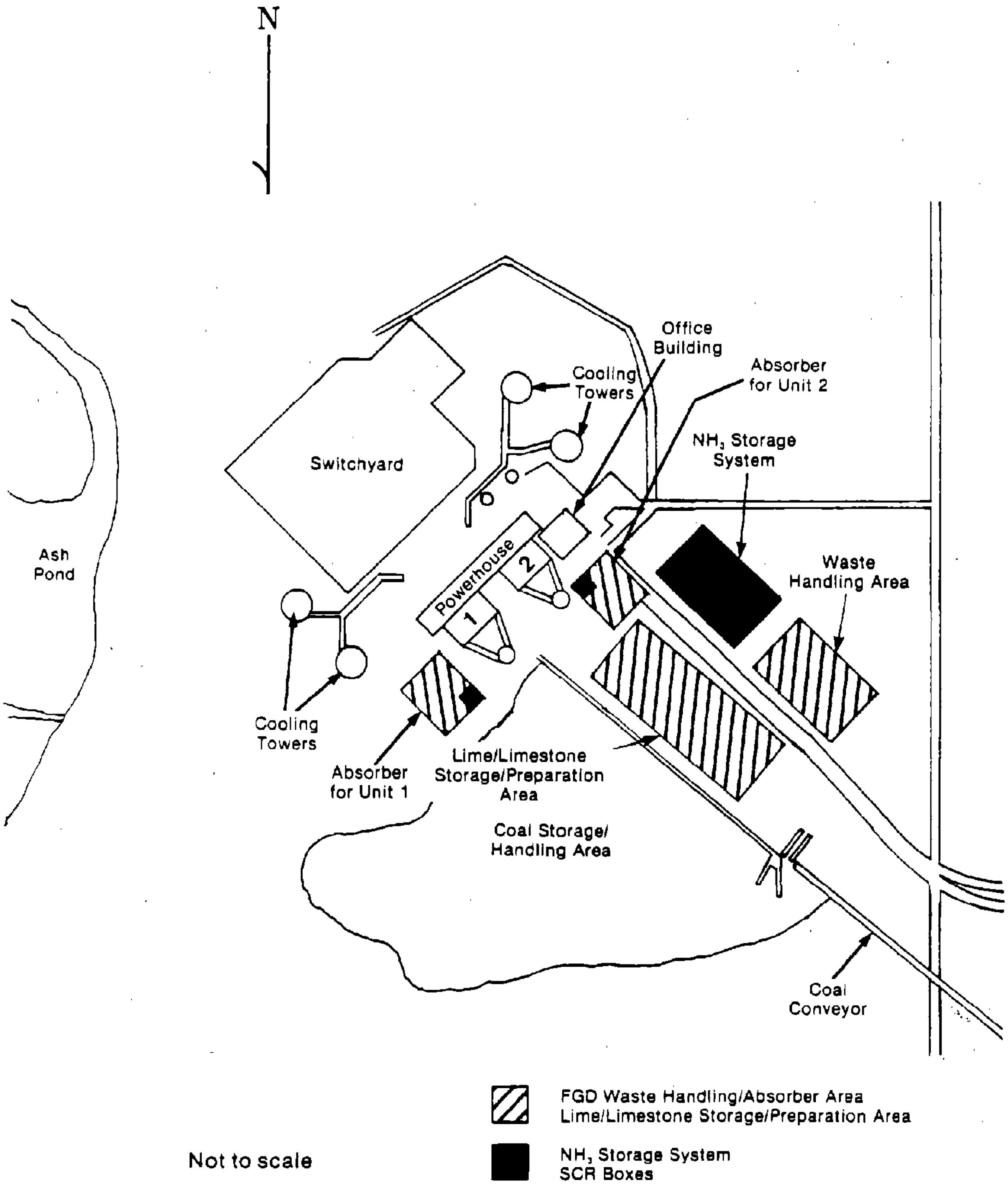

Figure 21.4.3-1. Keystone plant plot plan

TABLE 21.4.3-1. KEYSTONE STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2
GENERATING CAPACITY (MW-each)	936
CAPACITY FACTOR (PERCENT)	89.3, 72.7
INSTALLATION DATE	1967, 68
FIRING TYPE	TANGENTIAL
COAL SULFUR CONTENT (PERCENT)	1.5
COAL HEATING VALUE (BTU/LB)	12350
COAL ASH CONTENT (PERCENT)	14.1
FLY ASH SYSTEM	DRY
ASH DISPOSAL METHOD	ON-SITE/LANDFILL
STACK NUMBER	1-2
COAL DELIVERY METHODS	NEARBY MINE/CONVEYORS,TRUCK
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1967,1968
EMISSION (LB/MM BTU)	0.05
REMOVAL EFFICIENCY	99.3
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	1.3-1.5
SURFACE AREA (1000 SQ FT)	561.6
GAS EXIT RATE (1000 ACFM)	3000
SCA (SQ FT/1000 ACFM)	187
OUTLET TEMPERATURE (°F)	330

cooling towers (two on each side of the powerhouse). The absorbers for L/LS-FGD and LSD-FGD for both units would be located adjacent to the powerhouse and chimneys. The unit 1 absorbers would be located to the southwest of the unit 1 chimney while the absorber for unit 2 would be located to the east of the powerhouse, beside the unit 2 chimney. A factor of 5 percent was assigned to general facilities for unit 1 since there would be no major relocation/demolition required. For unit 2, relocation or demolition of a storage building and relocation of a road would be required; therefore, a factor of 8 percent was assigned to general facilities. The lime storage/preparation area would be located in a large open area south of the coal storage and handling area close to the unit 2 absorbers; the waste handling area would be located adjacent to the storage/preparation area.

Retrofit Difficulty and Scope Adder Costs--

The absorbers for unit 1 would be located immediately west of the respective chimney; the unit 2 absorbers would be located beside the chimney in a very large open area.

A low site access/congestion factor was assigned to the unit 1 absorbers since there will be no other obstructions in the area after demolition of the storage building. The location of the absorber for unit 2 was also assigned a low site access/congestion factor which reflects the available space behind the chimney.

For flue gas handling, medium duct runs for both units would be required for L/LS-FGD cases. A low site access/congestion factor was assigned to the flue gas handling system due to the close location of the absorbers to the chimneys with no major obstructions in the surrounding area.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Tables 21.4.3-2 and 21.4.3-3. No large scope adder cost is required for the Keystone plant. The overall retrofit factor determined for the L/LS-FGD cases was low to medium (1.31).

The absorbers for LSD-FGD would be located in the same location as L/LS-FGD cases. LSD-FGD with new FFs was the only LSD-FGD technology considered for both units. For flue gas handling for LSD cases, moderate duct runs would be required. A low site access/congestion factor was assigned to flue gas handling for both units. The retrofit factor determined

TABLE 21.4.3-2. SUMMARY OF RETROFIT FACTOR DATA FOR KEYSTONE UNIT 1

	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	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	1.31	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 21.4.3-3. SUMMARY OF RETROFIT FACTOR DATA FOR KEYSTONE 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			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	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	1.31	1.31	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.27
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	8	8	8

for the LSD technology case was low (1.27) and did not include new particulate control costs. A separate retrofit factor was developed for the new FFs (1.16). This factor was used in the IAPCS model to estimate new particulate control costs.

Table 21.4.3-4 presents the estimated costs for L/LS-FGD and LSD-FGD cases. The LSD-FGD costs include new FFs 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.

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.

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 21.4.3-5.

Table 21.4.3-5 presents the IAPCS cost results for physical coal cleaning at Keystone 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 costs estimated for NO_x controls at the Keystone 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.

Table 21.4.3-4. Summary of FGD Control Costs for the Keystone 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	1-2	1.31	1872	64	1.5	219.8	117.4	127.0	12.1	90.0	110594	1148.0
LC FGD-C	1-2	1.31	1872	81	1.5	219.9	117.5	82.5	6.2	90.0	139970	589.2
LFGD	1	1.31	936	89	1.5	142.5	152.2	87.3	11.9	90.0	77156	1131.2
LFGD	2	1.31	936	73	1.5	144.8	154.7	80.4	13.5	90.0	62814	1280.4
LFGD-C	1	1.31	936	89	1.5	142.5	152.2	50.6	6.9	90.0	77156	656.4
LFGD-C	2	1.31	936	73	1.5	144.8	154.7	46.7	7.8	90.0	62814	743.9
LSD+FF	1	1.27	936	89	1.5	170.0	181.6	74.9	10.2	87.0	74156	1009.4
LSD+FF	2	1.27	936	73	1.5	171.6	183.3	70.1	11.8	87.0	60371	1161.5
LSD+FF-C	1	1.27	936	89	1.5	170.0	181.6	43.6	6.0	87.0	74156	588.6
LSD+FF-C	2	1.27	936	73	1.5	171.6	183.3	40.9	6.9	87.0	60371	678.2

Table 21.4.3-5. Summary of Coal Switching/Cleaning Costs for the Keystone 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	936	89	1.5	33.2	35.5	100.4	13.7	38.0	32860	3056.9
CS/B+$15	2	1.00	936	73	1.5	33.2	35.5	83.1	13.9	38.0	26752	3107.9
CS/B+$15-C	1	1.00	936	89	1.5	33.2	35.5	57.7	7.9	38.0	32860	1756.0
CS/B+$15-C	2	1.00	936	73	1.5	33.2	35.5	47.8	8.0	38.0	26752	1786.2
CS/B+$5	1	1.00	936	89	1.5	23.5	25.2	38.3	5.2	38.0	32860	1164.8
CS/B+$5	2	1.00	936	73	1.5	23.5	25.2	32.2	5.4	38.0	26752	1203.9
CS/B+$5-C	1	1.00	936	89	1.5	23.5	25.2	22.0	3.0	38.0	32860	670.6
CS/B+$5-C	2	1.00	936	73	1.5	23.5	25.2	18.6	3.1	38.0	26752	693.7
PCC	1	1.00	936	89	1.5	17.2	18.4	19.4	2.6	28.0	24052	805.4
PCC	2	1.00	936	73	1.5	17.2	18.4	16.6	2.8	28.0	19581	845.5
PCC-C	1	1.00	936	89	1.5	17.2	18.4	11.2	1.5	28.0	24052	464.6
PCC-C	2	1.00	936	73	1.5	17.2	18.4	9.6	1.6	28.0	19581	488.3

Low NO_x Combustion--

Units 1 and 2 are dry bottom, tangential-fired boilers, each rated at 936 MW. The combustion modification technique applied for this evaluation was OFA. As Table 21.4.3-6 shows, the OFA NO_x reduction performance for each unit was estimated to be 20 percent. 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 21.4.3-7 presents the cost of retrofitting OFA at the Keystone boilers.

Selective Catalytic Reduction--

Table 21.4.3-6 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 building and 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 reactor for unit 1 would be located near the chimney for unit 1 and west of the coal storage and handling area. The SCR reactor for unit 2 would be located to the east of the powerhouse in an area near the chimney for unit 2. Demolition of a storage building would be needed for retrofitting the reactor. After demolition of the storage building, the reactor would be located in an easy access area having no major obstructions. Therefore, 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. As a result for this plant, the FGD absorbers were in the same location as the SCR reactors. If both SO_2 and NO_x emissions have to be reduced at this plant, the SCR reactors would have to be located downstream of the FGD absorbers in an area having little obstructions and easy access. The access/congestion factors that would be assigned to each SCR reactor would be the same as that discussed above. Table 21.4.3-7 presents the estimated cost of retrofitting SCR at the Keystone boilers.

TABLE 21.4.3-6. SUMMARY OF NOx RETROFIT RESULTS FOR KEYSTONE

	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)	14.4	14.4
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	84.2	84.2
FURNACE RESIDENCE TIME (SECONDS)	6.78	6.78
ESTIMATED NOx REDUCTION (PERCENT)	20	20
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	173	NA
Ductwork Demolition (1000$)	145	145
New Duct Length (Feet)	150	150
New Duct Costs (1000$)	2750	2750
New Heat Exchanger (1000$)	7131	7131
TOTAL SCOPE ADDER COSTS (1000$)	10199	10026
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13

Table 21.4.3-7. NOx Control Cost Results for the Keystone 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	936	89	1.5	1.5	1.6	0.3	0.0	20.0	4396	74.8
LNC-OFA	2	1.00	936	73	1.5	1.5	1.6	0.3	0.1	20.0	3579	91.9
LNC-OFA-C	1	1.00	936	89	1.5	1.5	1.6	0.2	0.0	20.0	4396	44.4
LNC-OFA-C	2	1.00	936	73	1.5	1.5	1.6	0.2	0.0	20.0	3579	54.5
SCR-3	1	1.16	936	89	1.5	105.3	112.5	41.7	5.7	80.0	17586	2369.3
SCR-3	2	1.16	936	73	1.5	105.1	112.3	40.7	6.8	80.0	14317	2843.1
SCR-3-C	1	1.16	936	89	1.5	105.3	112.5	24.3	3.3	80.0	17586	1384.3
SCR-3-C	2	1.16	936	73	1.5	105.1	112.3	23.8	4.0	80.0	14317	1661.8
SCR-7	1	1.16	936	89	1.5	105.3	112.5	34.0	4.6	80.0	17586	1933.8
SCR-7	2	1.16	936	73	1.5	105.1	112.3	33.0	5.5	80.0	14317	2308.2
SCR-7-C	1	1.16	936	89	1.5	105.3	112.5	20.0	2.7	80.0	17586	1134.8
SCR-7-C	2	1.16	936	73	1.5	105.1	112.3	19.4	3.3	80.0	14317	1355.3

Sorbent Injection and Repowering--

The ESPs are small and may not be able to handle the increased PM load if sorbent injection technologies are applied. As such, 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 the Keystone plant. Neither of the boilers would be considered good candidates for AFBC retrofit due to their large boiler sizes (>900 MW) and high capacity factors.

21.4.4 <u>Seward Steam Plant</u>

The Seward steam plant is located within Indiana County, Pennsylvania, as part of the Pennsylvania Electric Company system. The plant is bounded by the Conemaugh River and a railroad track. The plant contains two active coal-fired boilers with a total gross generating capacity of 200 MW. Figure 21.4.4-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 21.4.4-1 presents operational data for the existing equipment at the Seward plant. The boilers burn low to medium sulfur coal (1.5 percent sulfur). Coal shipments are received by truck and conveyed to a coal storage and handling area located south of the plant.

Particulate matter emissions for the boilers are controlled with ESPs located behind each unit. Flue gases from the ESPs are combined into one common chimney. The plant has a dry fly ash handling system and is disposed on-site at a landfill located beside the coal pile.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 21.4.4-1 shows the general layout and location of the FGD control system. The boilers share a common chimney located between the coal pile and powerhouse. The absorbers for L/LS-FGD and LSD-FGD for both units would be located in the current employee parking area east of the powerhouse. Part of the plant roads and employee parking area would need to be demolished/

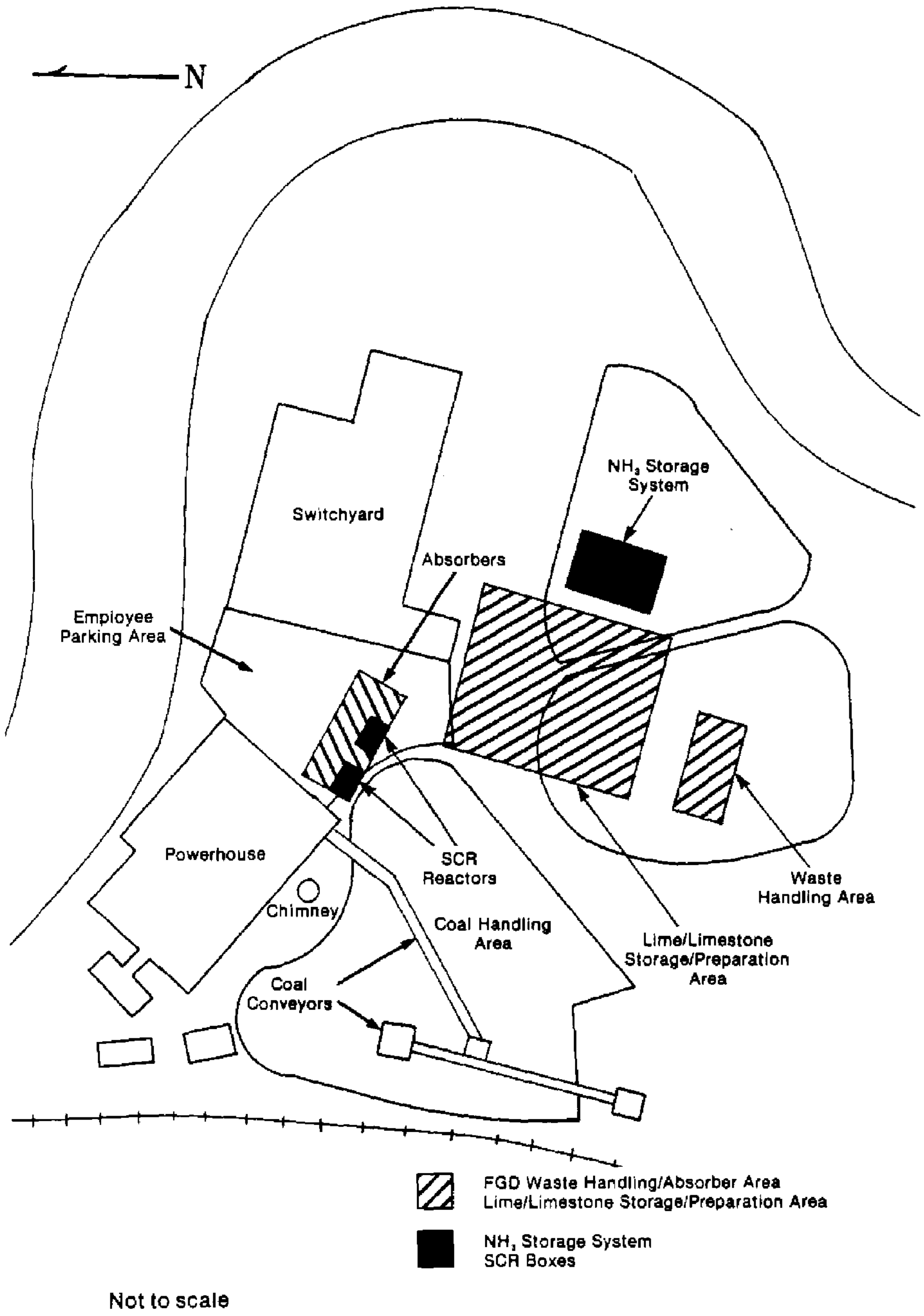

Figure 21.4.4-1. Seward plant plot plan

TABLE 21.4.4-1. SEWARD STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	4	5
GENERATING CAPACITY (MW)	63	137
CAPACITY FACTOR (PERCENT)	63.1	62.1
INSTALLATION DATE	1950	1957
FIRING TYPE	FRONT WALL	
COAL SULFUR CONTENT (PERCENT)	1.5	1.5
COAL HEATING VALUE (BTU/LB)	12100	12100
COAL ASH CONTENT (PERCENT)	13.5	13.5
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	ON-SITE LANDFILL	
STACK NUMBER	1	
COAL DELIVERY METHODS	TRUCK	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1960	1957
EMISSION (LB/MM BTU)	0.06	0.06
REMOVAL EFFICIENCY	99.5	99.4
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	NA	1.5
SURFACE AREA (1000 SQ FT)	29.6	180
EXIT GAS FLOW RATE (1000 ACFM)	200	580
SCA (SQ FT/1000 ACFM)	148	310
OUTLET TEMPERATURE (°F)	310	290-320

relocated; therefore, a factor of 10 percent was assigned to general facilities. The lime storage/handling area would be located adjacent to the coal pile south of the absorbers with the waste handling area located adjacent to the absorbers.

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 the employee parking area with no major obstacles or major underground obstruction close to the coal pile beside the powerhouse.

For flue gas handling, long duct runs for the units would be required for L/LS-FGD cases to divert the flue gas from the boilers 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 21.4.4-2. No large scope adder cost is required for the Seward plant. The overall retrofit factor determined for the L/LS-FGD cases was medium (1.37).

The absorbers for LSD-FGD would be located in a similar location as in L/LS-FGD cases. A long duct run would be required and a low site access/congestion factor was assigned for the same reasons as stated above in L/LS-FGD cases. The ESPs are located in a very high site access/congestion area and cannot be upgraded easily. Therefore, a new baghouse was the only LSD-FGD technology considered for the units. The baghouse location would be the same as for L/LS-FGD and a low site access/congestion factor was assigned to this location. For flue gas handling for LSD cases, long duct runs would be required to divert the flue gas from the boilers to the absorbers/baghouse and back to the chimney. The retrofit factor determined for the LSD technology case was medium (1.34) and did not include particulate control costs. A separate retrofit factor was developed for the new baghouse for the units. A low retrofit factor (1.16) was assigned to the baghouse location for the units due to its location in the present employee parking area. This factor was used in the IAPCS model to estimate particulate control costs.

TABLE 21.4.4-2. SUMMARY OF RETROFIT FACTOR DATA FOR SEWARD UNITS 4 OR 5

	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)	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	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	1.37	1.37	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.34
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	10	10	10

Table 21.4.4-3 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 4 and 5. 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.

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 21.4.4-4.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Seward 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 4 and 5 are dry bottom, front wall-fired boilers rated at 68 and 125 MW, respectively. The combustion modification technique applied for these boilers was LNB. As Table 21.4.4-5 shows, the LNB NO_x reduction performance for only unit 5 was estimated to be 50 percent. No boiler information could be found for unit 4 to assess its NO_x reduction

Table 21.4.4-3. Summary of FGD Control Costs for the Seward 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	4-5	1.37	200	62	1.5	37.1	185.3	20.4	18.6	90.0	11794	1726.1
LC FGD-C	4-5	1.37	200	62	1.5	37.1	185.3	11.8	10.8	90.0	11794	1003.0
LFGD	4	1.37	63	63	1.5	30.6	486.2	14.1	40.4	90.0	3757	3747.3
LFGD	5	1.37	137	62	1.5	44.3	323.2	20.7	27.8	90.0	8040	2580.7
LFGD	4-5	1.37	200	62	1.5	55.7	278.3	26.4	24.1	90.0	11794	2236.1
LFGD-C	4	1.37	63	63	1.5	30.6	486.2	8.2	23.6	90.0	3757	2183.5
LFGD-C	5	1.37	137	62	1.5	44.3	323.2	12.1	16.2	90.0	8040	1503.2
LFGD-C	4-5	1.37	200	62	1.5	55.7	278.3	15.4	14.0	90.0	11794	1302.3
LSD+FF	4	1.34	63	63	1.5	19.4	308.5	8.9	25.6	87.0	3611	2472.5
LSD+FF	5	1.34	137	62	1.5	33.5	244.6	14.1	18.9	87.0	7727	1826.4
LSD+FF-C	4	1.34	63	63	1.5	19.4	308.5	5.2	14.9	87.0	3611	1440.7
LSD+FF-C	5	1.34	137	62	1.5	33.5	244.6	8.2	11.1	87.0	7727	1065.8

Table 21.4.4-4. Summary of Coal Switching/Cleaning Costs for the Seward 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	1.00	63	63	1.5	3.1	48.5	5.5	15.9	40.0	1660	3326.2
CS/B+$15	5	1.00	137	62	1.5	4.9	35.9	10.9	14.6	40.0	3552	3068.1
CS/B+$15-C	4	1.00	63	63	1.5	3.1	48.5	3.2	9.1	40.0	1660	1914.0
CS/B+$15-C	5	1.00	137	62	1.5	4.9	35.9	6.3	8.4	40.0	3552	1764.0
CS/B+$5	4	1.00	63	63	1.5	2.4	38.1	2.5	7.3	40.0	1660	1524.2
CS/B+$5	5	1.00	137	62	1.5	3.5	25.6	4.5	6.0	40.0	3552	1265.0
CS/B+$5-C	4	1.00	63	63	1.5	2.4	38.1	1.5	4.2	40.0	1660	879.8
CS/B+$5-C	5	1.00	137	62	1.5	3.5	25.6	2.6	3.5	40.0	3552	729.2

TABLE 21.4.4-5. SUMMARY OF NOx RETROFIT RESULTS FOR SEWARD UNITS 4-5

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	4	5
FIRING TYPE	FWF	FWF
TYPE OF NOx CONTROL	LNB	LNB
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	NA	12.9
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	NA	49.8
FURNACE RESIDENCE TIME (SECONDS)	NA	3.01
ESTIMATED NOx REDUCTION (PERCENT)	25	50
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	19	34
New Duct Length (Feet)	550	600
New Duct Costs (1000$)	2080	3574
New Heat Exchanger (1000$)	1413	2251
TOTAL SCOPE ADDER COSTS (1000$)	3511	5860
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	25	25

performances. Since unit 4 is relatively old, it is estimated that a NO_x reduction of 20 to 30 percent can be achieved by this boiler retrofitted with LNB; unit 4 was installed in 1950. The reduction performance level for unit 5 was assessed by examining the effects of heat release rates and furnace residence time through the use of the simplified NO_x procedures.

Table 21.4.4-6 presents the cost of retrofitting LNB at the Seward boilers. The cost of retrofitting LNB for unit 4 was estimated assuming a 25 percent NO_x reduction.

Selective Catalytic Reduction--

Table 21.4.4-5 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 ESP to the reactor and from the reactor to the chimney.

The SCR reactors for units 4 and 5 would be located side-by-side in the current parking lot east of the powerhouse. Part of the plant road and employee parking lot would need to be demolished and relocated; therefore, a factor of 25 percent was assigned to general facilities for both reactors. Since the reactors were located in an open area having easy access with no major obstacles, the reactors for units 4 and 5 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. 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 needed to be reduced at this plant, the SCR reactors would have to be located downstream of the FGD absorbers (i.e., north of the absorbers) in an relatively open area. In this case, low access/congestion factors again would be assigned to both SCR reactors. Table 21.4.4-6 presents the estimated cost of retrofitting SCR at the Seward boilers.

Table 21.4.4-6. NOx Control Cost Results for the Seward 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	4	1.00	63	63	1.5	2.1	33.7	0.5	1.3	25.0	375	1229.8
LNC-LNB	5	1.00	137	62	1.5	2.9	21.1	0.6	0.8	50.0	1603	392.1
LNC-LNB-C	4	1.00	63	63	1.5	2.1	33.7	0.3	0.8	25.0	375	730.1
LNC-LNB-C	5	1.00	137	62	1.5	2.9	21.1	0.4	0.5	50.0	1603	232.8
SCR-3	4	1.16	63	63	1.5	15.9	252.9	4.9	14.2	80.0	1199	4125.2
SCR-3	5	1.16	137	62	1.5	26.2	191.0	8.5	11.4	80.0	2565	3310.3
SCR-3-C	4	1.16	63	63	1.5	15.9	252.9	2.9	8.3	80.0	1199	2423.0
SCR-3-C	5	1.16	137	62	1.5	26.2	191.0	5.0	6.7	80.0	2565	1942.3
SCR-7	4	1.16	63	63	1.5	15.9	252.9	4.4	12.7	80.0	1199	3693.9
SCR-7	5	1.16	137	62	1.5	26.2	191.0	7.4	9.9	80.0	2565	2872.0
SCR-7-C	4	1.16	63	63	1.5	15.9	252.9	2.6	7.5	80.0	1199	2175.9
SCR-7-C	5	1.16	137	62	1.5	26.2	191.0	4.3	5.8	80.0	2565	1691.2

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 retrofit of DSD and FSI technologies at the Seward steam plant for the units would be difficult. There is not sufficient duct residence time between the boilers and the ESPs, and the ESPs themselves are small as well. As such, 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 the Seward plant. Both boilers would be considered good candidates for AFBC retrofit because of their small boiler sizes (<130 MW) and ages (built before 1960).

21.4.5 Shawville Steam Plant

The Shawville steam plant is located on the Susquehanna River in Clearfield County, Pennsylvania, and is operated by the Pennsylvania Electric Company. The Shawville plant contains four coal-fired boilers with a gross generating capacity of 627 MW.

Table 21.4.5-1 presents operational data for the existing equipment at the Shawville plant. Coal shipments are received by truck and transferred to a coal storage and handling area east of the plant. PM emissions from the boilers are controlled by the retrofit ESPs which were added to the original ESPs. The ESPs for units 1 and 2 are roof mounted and for units 3 and 4 they are located behind the boilers. Flue gases from boilers 1 and 2 are directed to a chimney located between units 2 and 3. Another chimney located behind the ESPs/old chimneys serves units 3 and 4. Dry fly ash from the units is landfilled by the utility.

TABLE 21.4.5-1. SHAWVILLE STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3,4
GENERATING CAPACITY (MW-each)	132	181.5
CAPACITY FACTOR (PERCENT)	68.4,75.6	21.2,57.8
INSTALLATION DATE	1954	1959,60
FIRING TYPE	FRONT WALL	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	50.7	96
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	2.0	
COAL HEATING VALUE (BTU/LB)	12200	
COAL ASH CONTENT (PERCENT)	13.3	
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	LANDFILL	
STACK NUMBER	1	2
COAL DELIVERY METHODS	TRUCK	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1976	1976
EMISSION (LB/MM BTU)	0.04	0.06
REMOVAL EFFICIENCY	99.4	99.5
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	2.0	2.0
SURFACE AREA (1000 SQ FT)	124	206
GAS EXIT RATE (1000 ACFM)	550	660
SCA (SQ FT/1000 ACFM)	225	311
OUTLET TEMPERATURE (°F)	300	290

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for units 1 and 2 would be located behind the boilers. The general facilities factor is high (15 percent) for this location because several storage buildings and a parking lot would have to be relocated. The site access/congestion factor is also high for this location because of the proximity of the coal pile, coal conveyor, and the unit 3 and 4 ESPs. Between 300 and 600 feet of ductwork would be required to reach the roof- mounted ESPs for units 1 and 2. A high site access/congestion factor was assigned to flue gas handling because of the difficulty in accessing the chimney. L/LS-FGD absorbers for units 3 and 4 would be located west of the unit 3 and 4 chimney next to the coal pile. A high general facilities factor was assigned to this location because a large storage building would have to be relocated. The site access/congestion factor was high for this location because of the proximity of the coal pile and a railroad line. Between 300 and 600 feet of ductwork would be required and a high site access/congestion factor was assigned to flue gas handling.

LSD with reuse of the existing ESPs was not considered for units 1 and 2 because of the difficulty involved with upgrading the roof mounted ESPs. However, LSD with a new baghouse could be used for these units. The LSD-FGD absorbers and baghouses would be located similarly to the wet FGD absorbers with similar site access/congestion and general facilities factors as well as ductwork requirements. LSD-FGD with reuse of the existing ESPs was considered for units 3 and 4. The absorbers would be located similarly to the wet FGD absorbers for these units with similar site access/congestion and general facilities factors. About 700 to 900 feet of ductwork would be re-quired to access the upstream side of the unit 3 and 4 ESPs. A high site access/congestion factor was assigned to flue gas handling for both units because of the congestion caused by the ductwork between the ESPs and the old chimneys for these units.

Tables 21.4.5-2 through 21.4.5-4 present retrofit factor inputs to the IAPCS model and cost estimates for installation of conventional FGD technologies at the Shawville plant.

TABLE 21.4.5-2. SUMMARY OF RETROFIT FACTOR DATA FOR SHAWVILLE 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			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	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	YES		YES
RETROFIT FACTORS			
FGD SYSTEM	1.91	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.92
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.58
GENERAL FACILITIES (PERCENT)	15	0	15

TABLE 21.4.5-3. SUMMARY OF RETROFIT FACTOR DATA FOR SHAWVILLE 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	HIGH	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	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	YES		YES
RETROFIT FACTORS			
FGD SYSTEM	1.91	NA	
ESP REUSE CASE			2.06
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	15

Table 21.4.5-4. Summary of FGD Control Costs for the Shawville 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	1-2	1.91	264	72	2.0	61.0	231.1	32.6	19.6	90.0	23726	1376.1
LC FGD	3-4	1.91	363	40	2.0	83.2	229.3	36.7	29.2	90.0	17897	2050.1
LC FGD-C	1-2	1.91	264	72	2.0	61.0	231.1	19.0	11.4	90.0	23726	799.9
LC FGD-C	3-4	1.91	363	40	2.0	83.2	229.3	21.4	17.0	90.0	17897	1195.4
LFGD	1	1.91	132	68	2.0	62.0	469.4	27.5	34.8	90.0	11270	2438.9
LFGD	2	1.91	132	76	2.0	62.0	469.4	28.1	32.2	90.0	12456	2256.8
LFGD	3	1.91	182	21	2.0	74.3	409.3	27.8	82.5	90.0	4803	5789.4
LFGD	4	1.91	182	58	2.0	74.3	409.6	32.2	35.0	90.0	13094	2456.7
LFGD	1-2	1.91	264	72	2.0	93.7	354.9	43.3	26.0	90.0	23726	1824.6
LFGD	3-4	1.91	363	40	2.0	111.8	307.9	46.0	36.6	90.0	17897	2568.8
LFGD-C	1	1.91	132	68	2.0	62.0	469.4	16.0	20.3	90.0	11270	1422.0
LFGD-C	2	1.91	132	76	2.0	62.0	469.4	16.4	18.7	90.0	12456	1315.3
LFGD-C	3	1.91	182	21	2.0	74.3	409.3	16.3	48.3	90.0	4803	3386.3
LFGD-C	4	1.91	182	58	2.0	74.3	409.6	18.8	20.4	90.0	13094	1433.0
LFGD-C	1-2	1.91	264	72	2.0	93.7	354.9	25.2	15.1	90.0	23726	1063.1
LFGD-C	3-4	1.91	363	40	2.0	111.8	307.9	26.8	21.4	90.0	17897	1499.8
LSD+ESP	3	2.06	182	21	2.0	37.4	206.1	14.2	42.3	70.0	3732	3817.7
LSD+ESP	4	2.06	182	58	2.0	37.4	206.1	16.1	17.5	70.0	10176	1583.8
LSD+ESP-C	3	2.06	182	21	2.0	37.4	206.1	8.3	24.7	70.0	3732	2232.3
LSD+ESP-C	4	2.06	182	58	2.0	37.4	206.1	9.4	10.2	70.0	10176	923.9
LSD+FF	1	1.92	132	68	2.0	46.3	350.4	18.2	23.0	85.0	10627	1709.9
LSD+FF	2	1.92	132	76	2.0	46.3	350.4	18.5	21.2	85.0	11746	1576.9
LSD+FF-C	1	1.92	132	68	2.0	46.3	350.4	10.6	13.4	85.0	10627	999.2
LSD+FF-C	2	1.92	132	76	2.0	46.3	350.4	10.8	12.4	85.0	11746	921.1

Coal Switching and Physical Coal Cleaning Costs--

Table 21.4.5-5 summarizes the IAPCS cost results for CS at the Shawville plant. These costs do not include boiler and pulverizer operating cost changes or any coal handling system modifications that may be necessary. PCC was not evaluated because the Shawville plant is not a mine mouth plant.

NO_x Control Technologies--

LNBs were considered for control of NO_x emissions from units 1 and 2 which are front wall-fired boilers. OFA was considered for units 3 and 4 which are tangential-fired boilers. Tables 21.4.5-6 and 21.4.5-7 present NO_x performance and cost estimates for NO_x control technologies at the Shawville plant.

Selective Catalytic Reduction--

Cold side SCR reactors for the boilers at the Shawville plant would be located similarly to the wet FGD absorbers behind units 1 and 2 and west of the unit 3 and 4 chimney. High general facilities values (38 percent) and site access/congestion factors were assigned to all of the reactor locations. Approximately 400 feet of ductwork would be required to span the distance between the SCR reactors and the chimneys. Tables 21.4.5-6 and 21.4.5-7 present the retrofit factors and costs for installation of SCR at the Shawville plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) were not considered for units 1 and 2 because of the difficulty in upgrading and reusing the roof-mounted ESPs. FSI and DSD were considered for units 3 and 4 because there is sufficient duct residence time between the boilers and the ESPs and the ESPs are large enough to handle the additional particulate load.
Tables 21.4.5-8 and 21.4.5-9 present retrofit data and costs for installation of FSI and DSD technologies at the Shawville plant.

Table 21.4.5-5. Summary of Coal Switching/Cleaning Costs for the Shawville 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	132	68	2.0	4.8	36.5	11.5	14.5	54.0	6811	1689.1
CS/B+$15	2	1.00	132	76	2.0	4.8	36.5	12.6	14.4	54.0	7528	1673.5
CS/B+$15	3	1.00	182	21	2.0	6.3	34.5	5.8	17.2	54.0	2903	1998.7
CS/B+$15	4	1.00	182	58	2.0	6.3	34.5	13.4	14.5	54.0	7913	1689.3
CS/B+$15-C	1	1.00	132	68	2.0	4.8	36.5	6.6	8.4	54.0	6811	970.9
CS/B+$15-C	2	1.00	132	76	2.0	4.8	36.5	7.2	8.3	54.0	7528	961.7
CS/B+$15-C	3	1.00	182	21	2.0	6.3	34.5	3.4	9.9	54.0	2903	1154.8
CS/B+$15-C	4	1.00	182	58	2.0	6.3	34.5	7.7	8.4	54.0	7913	971.4
CS/B+$5	1	1.00	132	68	2.0	3.4	26.1	4.7	6.0	54.0	6811	694.7
CS/B+$5	2	1.00	132	76	2.0	3.4	26.1	5.1	5.9	54.0	7528	682.5
CS/B+$5	3	1.00	182	21	2.0	4.4	24.1	2.7	8.0	54.0	2903	925.9
CS/B+$5	4	1.00	182	58	2.0	4.4	24.1	5.4	5.9	54.0	7913	688.4
CS/B+$5-C	1	1.00	132	68	2.0	3.4	26.1	2.7	3.4	54.0	6811	400.3
CS/B+$5-C	2	1.00	132	76	2.0	3.4	26.1	3.0	3.4	54.0	7528	393.1
CS/B+$5-C	3	1.00	182	21	2.0	4.4	24.1	1.6	4.6	54.0	2903	537.2
CS/B+$5-C	4	1.00	182	58	2.0	4.4	24.1	3.1	3.4	54.0	7913	396.9

TABLE 21.4.5-6. SUMMARY OF NOx RETROFIT RESULTS FOR SHAWVILLE

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1,2	3,4
FIRING TYPE	FWF	TANG
TYPE OF NOx CONTROL	LNB	OFA
FURNACE VOLUME (1000 CU FT)	50.7	96
BOILER INSTALLATION DATE	1954	1959, 1960
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	26	25
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	33	42
New Duct Length (Feet)	400	400
New Duct Costs (1000$)	2332	2809
New Heat Exchanger (1000$)	2202	2665
TOTAL SCOPE ADDER COSTS (1000$)		
INDIVIDUAL CASE	4566	5516
COMBINED CASE	6890	8324
RETROFIT FACTOR FOR SCR	1.82	1.82
GENERAL FACILITIES (PERCENT)	38	38

Table 21.4.5-7. NOx Control Cost Results for the Shawville 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	132	68	2.0	2.9	21.6	0.6	0.8	26.0	877	706.5
LNC-LNB	2	1.00	132	76	2.0	2.9	21.6	0.6	0.7	26.0	969	639.3
LNC-LNB-C	1	1.00	132	68	2.0	2.9	21.6	0.4	0.5	26.0	877	419.4
LNC-LNB-C	2	1.00	132	76	2.0	2.9	21.6	0.4	0.4	26.0	969	379.4
LNC-OFA	3	1.00	182	21	2.0	0.8	4.3	0.2	0.5	25.0	257	665.0
LNC-OFA	4	1.00	182	58	2.0	0.8	4.3	0.2	0.2	25.0	700	243.9
LNC-OFA-C	3	1.00	182	21	2.0	0.8	4.3	0.1	0.3	25.0	257	394.8
LNC-OFA-C	4	1.00	182	58	2.0	0.8	4.3	0.1	0.1	25.0	700	144.8
SCR-3	1	1.82	132	68	2.0	33.2	251.3	10.3	13.1	80.0	2697	3831.2
SCR-3	2	1.82	132	76	2.0	33.2	251.4	10.4	11.9	80.0	2981	3487.9
SCR-3	3	1.82	182	21	2.0	41.3	227.4	12.5	37.2	80.0	821	15275.6
SCR-3	4	1.82	182	58	2.0	41.3	227.5	12.9	14.0	80.0	2238	5750.2
SCR-3	1-2	1.82	264	72	2.0	54.8	207.6	17.8	10.7	80.0	5678	3130.7
SCR-3	3-4	1.82	363	40	2.0	68.5	188.8	21.9	17.4	80.0	3059	7157.4
SCR-3-C	1	1.82	132	68	2.0	33.2	251.3	6.1	7.7	80.0	2697	2250.2
SCR-3-C	2	1.82	132	76	2.0	33.2	251.4	6.1	7.0	80.0	2981	2048.2
SCR-3-C	3	1.82	182	21	2.0	41.3	227.4	7.4	21.9	80.0	821	8977.3
SCR-3-C	4	1.82	182	58	2.0	41.3	227.5	7.6	8.2	80.0	2238	3377.1
SCR-3-C	1-2	1.82	264	72	2.0	54.8	207.6	10.4	6.3	80.0	5678	1836.9
SCR-3-C	3-4	1.82	363	40	2.0	68.5	188.8	12.9	10.2	80.0	3059	4201.2
SCR-7	1	1.82	132	68	2.0	33.2	251.3	9.3	11.7	80.0	2697	3430.0
SCR-7	2	1.82	132	76	2.0	33.2	251.4	9.3	10.7	80.0	2981	3124.9
SCR-7	3	1.82	182	21	2.0	41.3	227.4	11.1	32.8	80.0	821	13463.3
SCR-7	4	1.82	182	58	2.0	41.3	227.5	11.4	12.4	80.0	2238	5085.4
SCR-7	1-2	1.82	264	72	2.0	54.8	207.6	15.6	9.4	80.0	5678	2749.5
SCR-7	3-4	1.82	363	40	2.0	68.5	188.8	18.9	15.1	80.0	3059	6184.9
SCR-7-C	1	1.82	132	68	2.0	33.2	251.3	5.4	6.9	80.0	2697	2020.3
SCR-7-C	2	1.82	132	76	2.0	33.2	251.4	5.5	6.3	80.0	2981	1840.2
SCR-7-C	3	1.82	182	21	2.0	41.3	227.4	6.5	19.3	80.0	821	7939.0
SCR-7-C	4	1.82	182	58	2.0	41.3	227.5	6.7	7.3	80.0	2238	2996.3
SCR-7-C	1-2	1.82	264	72	2.0	54.8	207.6	9.2	5.5	80.0	5678	1618.6
SCR-7-C	3-4	1.82	363	40	2.0	68.5	188.8	11.1	8.9	80.0	3059	3643.9

TABLE 21.4.5-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR SHAWVILLE UNIT 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	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	48

TOTAL COST (1000$)	
ESP UPGRADE CASE	48
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Table 21.4.5-9. Summary of DSD/FSI Control Costs for the Shawville 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	3	1.00	182	21	2.0	10.0	54.8	6.2	18.3	45.0	2426	2535.7
DSD+ESP	4	1.00	182	58	2.0	10.0	54.9	7.8	8.5	45.0	6615	1185.5
DSD+ESP-C	3	1.00	182	21	2.0	10.0	54.8	3.6	10.6	45.0	2426	1471.2
DSD+ESP-C	4	1.00	182	58	2.0	10.0	54.9	4.5	4.9	45.0	6615	685.9
FSI+ESP-50	3	1.00	182	21	2.0	10.6	58.4	5.5	16.5	50.0	2668	2079.6
FSI+ESP-50	4	1.00	182	58	2.0	10.6	58.4	8.4	9.1	50.0	7275	1152.8
FSI+ESP-50-C	3	1.00	182	21	2.0	10.6	58.4	3.2	9.6	50.0	2668	1209.3
FSI+ESP-50-C	4	1.00	182	58	2.0	10.6	58.4	4.9	5.3	50.0	7275	667.0
FSI+ESP-70	3	1.00	182	21	2.0	10.7	59.1	5.6	16.7	70.0	3735	1505.3
FSI+ESP-70	4	1.00	182	58	2.0	10.7	59.2	8.5	9.3	70.0	10184	837.5
FSI+ESP-70-C	3	1.00	182	21	2.0	10.7	59.1	3.3	9.7	70.0	3735	875.3
FSI+ESP-70-C	4	1.00	182	58	2.0	10.7	59.2	4.9	5.4	70.0	10184	484.5

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

All four boilers at the Shawville power plant are good candidates for repowering technologies because of their small sizes and potentially short remaining useful lifetimes. However, the high capacity factors could result in high replacement power costs for extended downtime.

21.5 PENNSYLVANIA POWER AND LIGHT COMPANY

21.5.1 Brunner Island Steam Plant

The Brunner Island steam plant is located within York County, Pennsylvania, as part of the Pennsylvania Power and Light Company system. The plant contains three coal-fired boilers with a total gross generating capacity of 1,558 MW. Figure 21.5.1-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 21.5.1-1 presents operational data for the existing equipment at the Brunner Island plant. All boilers burn medium sulfur coal (1.9 percent sulfur). Coal shipments are received by railroad and conveyed to a single coal pile located north of the plant.

Particulate matter emissions for unit 1 is controlled with a retrofit baghouse located west of the plant away from the boiler building. Unit 2 ESPs are located at the back of the boiler house. The ESPs for unit 3 are directly behind the boiler house. There are two chimneys, one serving unit 1 and unit 2 and another chimney serving unit 3. Ash from all units is wet sluiced to a pond located south of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 21.5.1-1 shows the general layout and location of the FGD control system. The absorbers for L/LS-FGD and LSD-FGD for all units would be located west of the plant between the particulate controls and the railroad south of the coal pile. Warehouse buildings would need to be demolished/relocated; therefore, a factor of 8 percent was assigned to general facilities. The lime storage/preparation area would be located south of the absorbers between the railroad and ash pond. The waste handling area would be located adjacent to the storage/preparation area.

Retrofit Difficulty and Scope Adder Costs--

The absorbers for all units were located west of the plant, close to the railroad, and behind the ESPs/ baghouse.

After relocating the storage buildings, there would be no major obstacles but some underground obstructions. Plant personnel indicated that

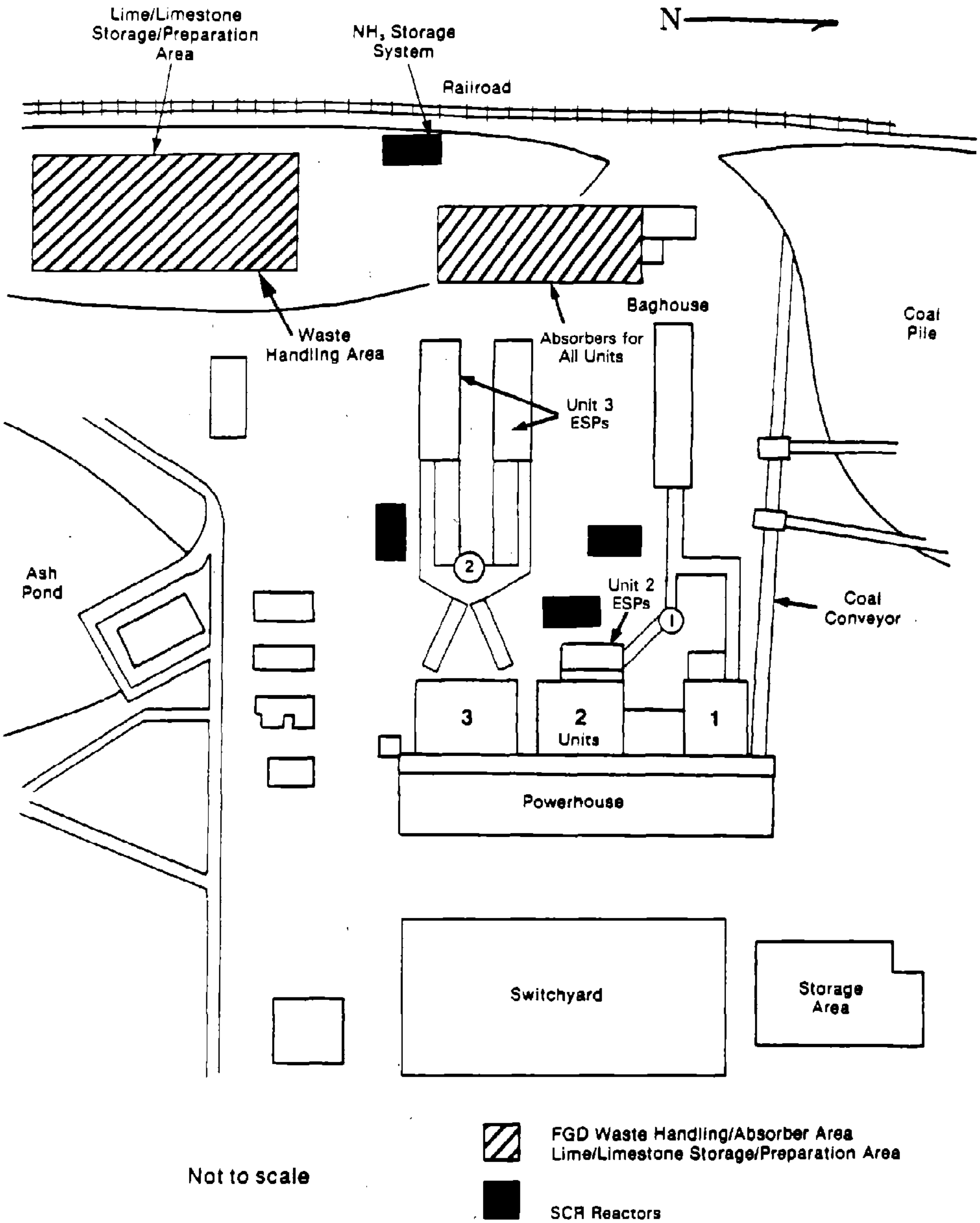

Figure 21.5.1-1. Brunner Island Plot Plan

TABLE 21.5.1-1. BRUNNER ISLAND STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2	3
GENERATING CAPACITY (MW)	363	405	790
CAPACITY FACTOR (PERCENT)	71	71	70
INSTALLATION DATE	1961	1965	1969
FIRING TYPE	TANG	TANG	TANG
COAL SULFUR CONTENT (PERCENT)	1.9	1.9	1.9
COAL HEATING VALUE (BTU/LB)	12500	12500	12500
COAL ASH CONTENT (PERCENT)	12.7	12.7	12.7
FLY ASH SYSTEM		WET SLUICE	
ASH DISPOSAL METHOD		POND/ON-SITE	
STACK NUMBER	1	1	2
COAL DELIVERY METHODS		RAILROAD	
<u>PARTICULATE CONTROL</u>			
TYPE	BAGHOUSE	ESP	ESP
INSTALLATION DATE	1980	1965	1969
EMMISION (LB/MM BTU)	0.05	0.05	0.05
REMOVAL EFFICIENCY	99.7	99.2	99.5
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	NA	-	-
SURFACE AREA (1000 SQ FT)	-	166+248	461+952
GAS EXIT RATE (1000 ACFM)	1100	560+840	2600+2600
SCA (SQ FT/1000 ACFM)	-	296	272
OUTLET TEMPERATURE (°F)	310	310	310

underground obstructions caused by running ducts and piping could be substantial. As a result, a medium site access/congestion factor was assigned to the absorber location.

For flue gas handling for L/LS-FGD cases, moderate duct runs for all units would be required since the absorbers are close to the particulate controls.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Tables 21.5.1-2 and 21.5.1-3. The largest scope adder for the Brunner Island plant would be the conversion of units 1-3 fly ash conveying/disposal system from wet to dry for conventional L/LS-FGD and LSD-FGD cases, and a new chimney for unit 2. It was assumed that dry fly ash would be necessary to stabilize scrubber sludge waste and to prevent plugging of sluice lines in the LSD-FGD for the baghouse/ESP reuse case. This conversion is not necessary for forced oxidation L/LS-FGD. The overall retrofit factors determined for the L/LS-FGD cases ranged from moderate to high (1.43-1.55).

LSD-FGD with a reused baghouse was considered for unit 1, while reused ESP was considered for units 2 and 3 (independent ESPs) due to the boilers presently having moderate size SCAs (>270) amd easy access. For flue gas handling for LSD cases, medium duct runs would be required for units 1 and 3, and longer ducts for unit 2. A low site access/congestion factor was assigned to the unit 1-3 flue gas handling system. The retrofit factors determined for the LSD technology case were high (1.47-1.55) and did not include particulate control upgrading costs for units 2 and 3. It was assumed that the unit 1 baghouse could be reused with no additional upgrading. A separate retrofit factor was developed for upgrading ESPs for units 2 and 3 (1.16). This factor was used in the IAPCS model to estimate particulate control upgrading costs for units 2 and 3.

FGD Retrofit Costs--

Table 21.5.1-4 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 2 and 3. The low cost control case reduces capital and annual operating costs due to the benefits of economies-of-scale when combining

TABLE 21.5.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR BRUNNER ISLAND UNIT 1 OR 3

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
S02 REMOVAL	MEDIUM	MEDIUM	MEDIUM
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			LOW
REUSE BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			300-600
REUSE BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
REUSE BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	2978,5980	NA	2978,5980
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.48	1.43	
ESP REUSE CASE			1.47
REUSE BAGHOUSE CASE			1.47
ESP UPGRADE	NA	NA	1.16
REUSE BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	8	8

TABLE 21.5.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR BRUNNER ISLAND UNIT 2

	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			LOW
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			600-1000
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	3285	NA	3285
NEW CHIMNEY	YES	YES	NO
ESTIMATED COST (1000$)	2835	2835	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.50	1.45	
ESP REUSE CASE			1.55
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	8	8

Table 21.5.1-4. Summary of FGD Control Costs for the Brunner Island 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	1.48	1558	65	1.9	211.5	135.8	121.4	13.7	90.0	116782	1039.7
LC FGD-C	1-3	1.48	1558	65	1.9	211.5	135.8	70.5	7.9	90.0	116782	603.8
LFGD	1	1.48	363	71	1.9	84.6	233.2	43.1	19.1	90.0	29721	1450.5
LFGD	2	1.50	405	71	1.9	91.2	225.2	46.8	18.6	90.0	33159	1410.2
LFGD	3	1.48	790	70	1.9	145.2	183.8	77.6	16.0	90.0	63770	1217.3
LFGD-C	1	1.48	363	71	1.9	84.6	233.2	25.1	11.1	90.0	29721	843.8
LFGD-C	2	1.50	405	71	1.9	91.2	225.2	27.2	10.8	90.0	33159	820.3
LFGD-C	3	1.48	790	70	1.9	145.2	183.8	45.1	9.3	90.0	63770	707.7
LSD+ESP	2	1.55	405	71	1.9	56.9	140.6	27.0	10.7	76.0	28112	959.4
LSD+ESP	3	1.47	790	70	1.9	97.9	123.9	46.3	9.6	76.0	54063	855.9
LSD+ESP-C	2	1.55	405	71	1.9	56.9	140.6	15.7	6.2	76.0	28112	558.8
LSD+ESP-C	3	1.47	790	70	1.9	97.9	123.9	26.9	5.6	76.0	54063	498.5
LSD+PFF	1	1.47	363	71	1.9	45.1	124.3	22.3	9.9	87.0	28565	781.4
LSD+PFF-C	1	1.47	363	71	1.9	45.1	124.3	13.0	5.8	87.0	28565	454.8

process areas, elimination of spare scrubber modules, and optimization of scrubber module 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 21.5.1-5.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Brunner Island 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, 2, and 3 are dry bottom, tangential-fired boilers rated at 363, 405, and 790 MW, respectively. The combustion modification technique applied for this evaluation was OFA. As Table 21.5.1-6 shows, the OFA NO_x reduction performances for units 1, 2, and 3 were estimated to be 25, 15, and 15 percent, respectively. These reduction performance levels were assessed by examining the effects of heat release rates and furnace residence time through the use of the simplified NO_x procedures. Table 21.5.1-7 presents the cost of retrofitting OFA at the Brunner Island boilers.

Table 21.5.1-5. Summary of Coal Switching/Cleaning Costs for the Brunner Island 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	363	71	1.9	9.7	26.6	30.3	13.4	51.0	16721	1809.2
CS/B+$15	2	1.00	405	71	1.9	12.8	31.6	35.2	14.0	51.0	18655	1887.0
CS/B+$15	3	1.00	790	70	1.9	23.6	29.8	67.0	13.8	51.0	35877	1867.3
CS/B+$15-C	1	1.00	363	71	1.9	9.7	26.6	17.4	7.7	51.0	16721	1039.2
CS/B+$15-C	2	1.00	405	71	1.9	12.8	31.6	20.2	8.0	51.0	18655	1084.2
CS/B+$15-C	3	1.00	790	70	1.9	23.6	29.8	38.5	7.9	51.0	35877	1072.8
CS/B+$5	1	1.00	363	71	1.9	5.9	16.3	10.9	4.8	51.0	16721	654.5
CS/B+$5	2	1.00	405	71	1.9	8.6	21.2	13.7	5.4	51.0	18655	732.3
CS/B+$5	3	1.00	790	70	1.9	15.4	19.5	25.5	5.3	51.0	35877	712.1
CS/B+$5-C	1	1.00	363	71	1.9	5.9	16.3	6.3	2.8	51.0	16721	376.6
CS/B+$5-C	2	1.00	405	71	1.9	8.6	21.2	7.9	3.1	51.0	18655	421.7
CS/B+$5-C	3	1.00	790	70	1.9	15.4	19.5	14.7	3.0	51.0	35877	409.9

TABLE 21.5.1-6. SUMMARY OF NOx RETROFIT RESULTS FOR BRUNNER ISLAND

	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)	13	15.8	14.8
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	80.8	118.6	92.5
FURNACE RESIDENCE TIME (SECONDS)	3.56	2.7	1.61
ESTIMATED NOx REDUCTION (PERCENT)	25	15	15
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	71	77	127
New Duct Length (Feet)	200	200	300
New Duct Costs (1000$)	2106	2246	4980
New Heat Exchanger (1000$)	4,040	4,314	6,441
TOTAL SCOPE ADDER COSTS (1000$)	6,218	6,637	11,548
RETROFIT FACTOR FOR SCR	1.52	1.52	1.16
GENERAL FACILITIES (PERCENT)	13	13	13

Table 21.5.1-7. NOx Control Cost Results for the Brunner Island 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	363	71	1.9	1.0	2.9	0.2	0.1	25.0	1671	134.6
LNC-OFA	2	1.00	405	71	1.9	1.1	2.7	0.2	0.1	15.0	1119	210.2
LNC-OFA	3	1.00	790	70	1.9	1.4	1.8	0.3	0.1	15.0	2152	142.8
LNC-OFA-C	1	1.00	363	71	1.9	1.0	2.9	0.1	0.1	25.0	1671	79.9
LNC-OFA-C	2	1.00	405	71	1.9	1.1	2.7	0.1	0.1	15.0	1119	124.8
LNC-OFA-C	3	1.00	790	70	1.9	1.4	1.8	0.2	0.0	15.0	2152	84.7
SCR-3	1	1.52	363	71	1.9	54.6	150.4	19.1	8.5	80.0	5348	3571.1
SCR-3	2	1.52	405	71	1.9	59.7	147.4	21.0	8.3	80.0	5967	3520.0
SCR-3	3	1.16	790	70	1.9	92.3	116.9	34.9	7.2	80.0	11475	3043.7
SCR-3-C	1	1.52	363	71	1.9	54.6	150.4	11.2	5.0	80.0	5348	2091.8
SCR-3-C	2	1.52	405	71	1.9	59.7	147.4	12.3	4.9	80.0	5967	2061.6
SCR-3-C	3	1.16	790	70	1.9	92.3	116.9	20.4	4.2	80.0	11475	1779.9
SCR-7	1	1.52	363	71	1.9	54.6	150.4	16.1	7.1	80.0	5348	3016.7
SCR-7	2	1.52	405	71	1.9	59.7	147.4	17.7	7.0	80.0	5967	2965.6
SCR-7	3	1.16	790	70	1.9	92.3	116.9	28.5	5.9	80.0	11475	2481.4
SCR-7-C	1	1.52	363	71	1.9	54.6	150.4	9.5	4.2	80.0	5348	1774.1
SCR-7-C	2	1.52	405	71	1.9	59.7	147.4	10.4	4.1	80.0	5967	1744.0
SCR-7-C	3	1.16	790	70	1.9	92.3	116.9	16.7	3.5	80.0	11475	1457.7

Selective Catalytic Reduction--

Table 21.5.1-6 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 building and ductwork demolition, new flue gas heat exchanger, and new duct runs to divert the flue gas from the PM control device to the reactor and from the reactor to the chimney.

The SCR reactors for units 1 and 2 were located west of unit 2 between the ESPs for unit 3 and the baghouse for unit 1. The SCR reactor for unit 3 was located south of the ESPs for unit 3 and west of the powerhouse. Reactors for units 1 and 2 were assigned high access/congestion factors because they were surrounded on two sides by the ESPs for unit 3 and the baghouse for unit 1. On the other hand, the SCR reactor for unit 3 was assigned a low access/congestion factor since it was in an easy access area surrounded only on one side by the ESPs for unit 3. All three 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. Table 21.5.1-7 presents the estimated cost of retrofitting SCR at the Brunner Island 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 west of the plant in a similar fashion as LSD-FGD. The retrofit of DSD and FSI technologies at the Brunner Island steam plant for units 1 and 3 would be easy. There is sufficient flue gas ducting residence time between the boilers and the particulate controls for units 1 and 3. Unit 2 has a short duct residence time and application of sorbent injection technologies would be difficult. It was assumed that the unit 1 baghouse can handle the increased particulate load; units 2-3 ESPs have adequate SCAs (>290). Unit 3 has a large amount of space available to upgrade with a low site access/congestion factor, however, the unit 2 ESPs would be more difficult to upgrade. The major scope adder cost for DSD and FSI would be the conversion of the fly ash handling system from wet to dry. Tables 21.5.1-8 through 21.5.1-10 present a summary of the site access/congestion factors for DSD and FSI technologies at the Brunner Island steam plant. Table 21.5.1-11 presents the costs estimated to retrofit DSD and FSI at the Brunner Island 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 Brunner Island plant. None of the boilers would be considered good candidates for AFBC retrofit due to their large boiler sizes (>300 MW) and high capacity factors.

21.5.2 Martins Creek Steam Plant

The Martins Creek steam plant is located within Northampton County, Pennsylvania, as part of the Pennsylvania Power and Light Company system. The plant contains four boilers with a total gross generating capacity of 2,013 MW; units 1 and 2 are coal-burning while units 3 and 4 are petroleum-burning boilers. Therefore, only boilers 1 and 2 were considered for this study. Figure 21.5.2-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 21.5.2-1 presents operational data for the existing equipment at the Martins Creek plant. Boilers 1 and 2 burn medium sulfur coal (1.9 percent sulfur). Coal shipments are received by railroad and conveyed to a coal storage and handling area located north of the plant.

Particulate matter emissions for the boilers are controlled with retrofit ESPs located behind each boiler. Ash from the units is wet sluiced to ponds located south of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 21.5.2-1 shows the general layout and location of the FGD control system. The two coal burning boilers are located beside each other parallel

TABLE 21.5.1-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR BRUNNER ISLAND UNIT 1

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	NA
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	2980
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	79

TOTAL COST (1000$)	
BAGHOUSE REUSE CASE	3059
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
BAGHOUSE UPGRADE	NA
NEW BAGHOUSE	NA

TABLE 21.5.1-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR BRUNNER ISLAND UNIT 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$)	3285
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	85

TOTAL COST (1000$)	
ESP UPGRADE CASE	3370
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

TABLE 21.5.1-10. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR BRUNNER ISLAND UNIT 3

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$)	5983
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	141

TOTAL COST (1000$)	
ESP UPGRADE CASE	6124
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.13
NEW BAGHOUSE	NA

Table 21.5.1-11. Summary of DSD/FSI Control Costs for the Brunner Island 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	405	71	1.9	20.9	51.7	15.4	6.1	49.0	17924	857.4
DSD+ESP	3	1.00	790	70	1.9	34.9	44.2	25.9	5.4	49.0	34471	752.4
DSD+ESP-C	2	1.00	405	71	1.9	20.9	51.7	8.9	3.5	49.0	17924	496.5
DSD+ESP-C	3	1.00	790	70	1.9	34.9	44.2	15.0	3.1	49.0	34471	435.6
DSD+PFF	1	1.00	363	71	1.9	15.0	41.3	12.2	5.4	71.0	23364	522.7
DSD+PFF-C	1	1.00	363	71	1.9	15.0	41.3	7.1	3.1	71.0	23364	302.3
FSI+ESP-50	2	1.00	405	71	1.9	20.0	49.4	17.4	6.9	50.0	18422	947.0
FSI+ESP-50	3	1.00	790	70	1.9	34.5	43.6	31.5	6.5	50.0	35428	887.7
FSI+ESP-50-C	2	1.00	405	71	1.9	20.0	49.4	10.1	4.0	50.0	18422	547.4
FSI+ESP-50-C	3	1.00	790	70	1.9	34.5	43.6	18.2	3.8	50.0	35428	513.0
FSI+ESP-70	2	1.00	405	71	1.9	21.9	54.1	18.2	7.2	70.0	25791	706.2
FSI+ESP-70	3	1.00	790	70	1.9	34.6	43.8	32.0	6.6	70.0	49599	645.3
FSI+ESP-70-C	2	1.00	405	71	1.9	21.9	54.1	10.5	4.2	70.0	25791	408.4
FSI+ESP-70-C	3	1.00	790	70	1.9	34.6	43.8	18.5	3.8	70.0	49599	372.9

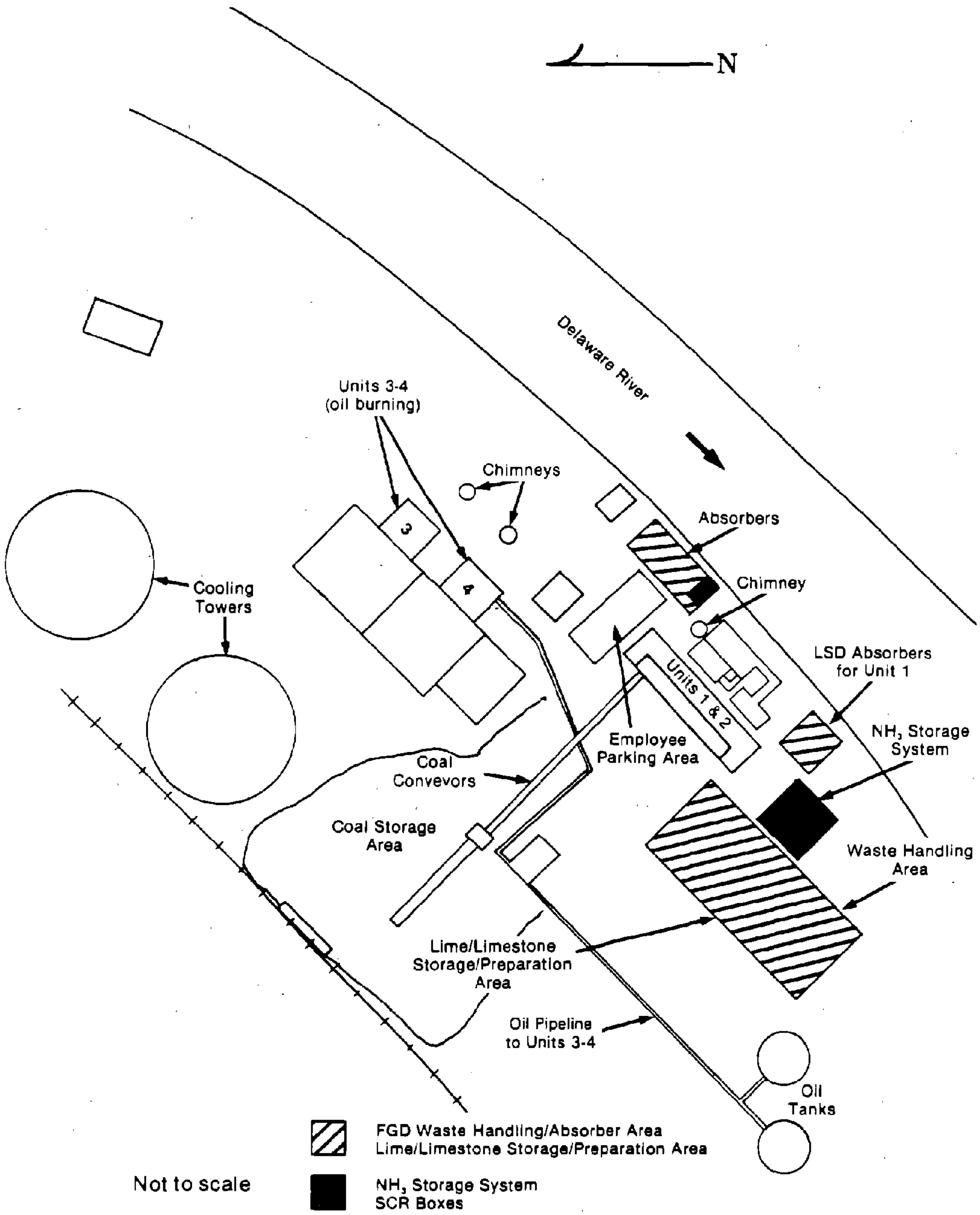

Figure 21.5.2-1. Martins Creek plant plot plan

TABLE 21.5.2-1. MARTINS CREEK STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2
GENERATING CAPACITY (MW-each)	156
CAPACITY FACTOR (PERCENT)	50
INSTALLATION DATE	1954,56
FIRING TYPE	FRONT WALL
COAL SULFUR CONTENT (PERCENT)	1.9
COAL HEATING VALUE (BTU/LB)	12500
COAL ASH CONTENT (PERCENT)	12.4
FLY ASH SYSTEM	WET SLUICE
ASH DISPOSAL METHOD	POND/ON-SITE
STACK NUMBER	1
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1971
EMISSION (LB/MM BTU)	0.09
REMOVAL EFFICIENCY	99.2-99.4
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	2.6
SURFACE AREA (1000 SQ FT)	165.2
GAS EXIT RATE (1000 ACFM)	550
SCA (SQ FT/1000 ACFM)	300(TESTED=270)
OUTLET TEMPERATURE (°F)	310

to the Delaware River and share a common chimney, while the two petroleum burning boilers are located further away beside each other. All four units are located parallel to the Delaware River. There are two natural draft cooling towers located northwest of the plant beside units 3 and 4, adjacent to the coal handling and storage area. The absorbers for L/LS-FGD and LSD-FGD for both units would be located between the powerhouse (for units 1 and 2) and the riverside. Some relocation or demolition (e.g. storage building) would be required for either unit; therefore, a factor of 10 percent was assigned to general facilities. The lime storage/preparation area would be located west of the plant and the temporary waste handling area would be located nearby.

Retrofit Difficulty and Scope Adder Costs--

The absorbers for L/LS-FGD would be located behind the common chimney parallel to the river. However, the LSD absorbers could also be located on either side of the ESPs for easier access to the upstream of the ESPs. A low site access/congestion factor was assigned to the absorber locations since there are no major obstacles/obstructions around the chimneys and ESPs.

For flue gas handling, short duct runs for both units would be required for L/LS-FGD cases. A low site access/congestion factor was assigned to the flue gas handling system due to the close location of the absorbers to the chimney with no major obstructions in the surrounding area.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Tables 21.5.2-2 and 21.5.2-3. The largest scope adder for the Martins Creek plant would be the conversion of fly ash conveying/disposal system from wet to dry for conventional L/LS-FGD and LSD-FGD. It was assumed that dry fly ash would be necessary to stabilize scrubber sludge waste and to prevent plugging of sluice lines in LSD-FGD system (for the ESP-reuse case). However, this conversion is not necessary for forced oxidation L/LS-FGD. The overall retrofit factors determined for the L/LS-FGD cases were low (1.20 to 1.27).

The absorbers for LSD-FGD would be located close to the ESPs in the same location and in similar fashion as L/LS-FGD cases. LSD-FGD with reused ESPs was the only LSD-FGD technology considered for both units due to the

TABLE 21.5.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR MARTINS CREEK UNIT 1

	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			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	100-300	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	1397	NA	1397
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	1.20	
ESP REUSE CASE			1.38
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	10	10

TABLE 21.5.2-3. SUMMARY OF RETROFIT FACTOR DATA FOR MARTINS CREEK 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			MEDIUM
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	YES	NO	YES
ESTIMATED COST (1000$)	1397	NA	1397
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	1.20	
ESP REUSE CASE			1.38
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	10	10

large ESP sizes (SCAs = 300). For flue gas handling for LSD cases, medium duct runs would be required and a low site access/congestion factor was assigned for both units in a similar fashion as L/LS-FGD. The retrofit factor determined for the LSD technology case was medium (1.38) and did not include particulate control upgrading costs. Two separate retrofit factors were developed for upgrading ESPs for each unit (1.36 for unit 1 and 1.16 for unit 2). For unit 1, a medium site access/congestion factor was associated with the upgrading which reflected the accessibility and congestion around the ESPs because of the duct runs, chimneys, and unit 2 ESPs. Unit 2 was assigned a low site access/congestion factor due to the available space around the ESPs. Both factors were used in the IAPCS model to estimate particulate control upgrading costs.

Table 21.5.2-4 presents the estimated costs for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs and ash handling systems 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.

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 21.5.2-5.

Table 21.5.2-4. Summary of FGD Control Costs for the Martins 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)
LC FGD	1-2	1.27	312	50	1.9	51.1	163.9	26.7	19.5	90.0	17990	1481.7
LC FGD-C	1-2	1.27	312	50	1.9	51.1	163.9	15.5	11.3	90.0	17990	861.7
LFGD	1	1.27	156	50	1.9	45.4	290.8	20.8	30.5	90.0	8995	2315.8
LFGD	2	1.27	156	50	1.9	45.4	290.8	20.8	30.5	90.0	8995	2315.8
LFGD	1-2	1.27	312	50	1.9	68.7	220.3	32.3	23.7	90.0	17990	1796.6
LFGD-C	1	1.27	156	50	1.9	45.4	290.8	12.1	17.8	90.0	8995	1349.4
LFGD-C	2	1.27	156	50	1.9	45.4	290.8	12.1	17.8	90.0	8995	1349.4
LFGD-C	1-2	1.27	312	50	1.9	68.7	220.3	18.8	13.8	90.0	17990	1046.4
LSD+ESP	1	1.38	156	50	1.9	23.4	150.3	11.3	16.5	76.0	7626	1482.9
LSD+ESP	2	1.38	156	50	1.9	23.1	148.4	11.2	16.4	76.0	7626	1473.1
LSD+ESP-C	1	1.38	156	50	1.9	23.4	150.3	6.6	9.6	76.0	7626	863.4
LSD+ESP-C	2	1.38	156	50	1.9	23.1	148.4	6.5	9.6	76.0	7626	857.6

Table 21.5.2-5. Summary of Coal Switching/Cleaning Costs for the Martins 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)
CS/B+$15	1	1.00	156	50	1.9	5.6	36.2	10.3	15.0	51.0	5060	2030.8
CS/B+$15	2	1.00	156	50	1.9	5.6	36.2	10.3	15.0	51.0	5060	2030.8
CS/B+$15-C	1	1.00	156	50	1.9	5.6	36.2	5.9	8.7	51.0	5060	1168.5
CS/B+$15-C	2	1.00	156	50	1.9	5.6	36.2	5.9	8.7	51.0	5060	1168.5
CS/B+$5	1	1.00	156	50	1.9	4.0	25.9	4.3	6.4	51.0	5060	859.6
CS/B+$5	2	1.00	156	50	1.9	4.0	25.9	4.3	6.4	51.0	5060	859.6
CS/B+$5-C	1	1.00	156	50	1.9	4.0	25.9	2.5	3.7	51.0	5060	496.1
CS/B+$5-C	2	1.00	156	50	1.9	4.0	25.9	2.5	3.7	51.0	5060	496.1

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Martins Creek 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 1 and 2 are dry bottom, front wall-fired boilers each rated at 156 MW. The combustion modification technique applied for these boilers was LNB. As Table 21.5.2-6 shows, the LNB NO_x reduction performance for each unit was estimated to be 40 percent. Table 21.5.2-7 presents the cost of retrofitting LNB at the Martins Creek boilers.

Selective Catalytic Reduction--

Table 21.5.2-6 presents the SCR retrofit results for units 1 and 2. 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 and 2 were located behind the common chimney. Since the reactors were located in open area having easy access with no major obstacles, the reactor locations 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 needed to be reduced at this plant, the SCR reactors would have to be located downstream of the FGD absorbers in an area north of the absorbers. In this case, low access/congestion factors would again be assigned to both SCR reactors. Table 21.5.2-7 presents the estimated cost of retrofitting SCR at the Martins Creek boilers.

TABLE 21.5.2-6. SUMMARY OF NOx RETROFIT RESULTS FOR MARTINS CREEK

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	1-2
FIRING TYPE	FWF	FWF	NA
TYPE OF NOx CONTROL	LNB	LNB	NA
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	14.2	14.2	NA
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	20.7	20.7	NA
FURNACE RESIDENCE TIME (SECONDS)	3.49	3.49	NA
ESTIMATED NOx REDUCTION (PERCENT)	40	40	NA
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	38	38	63
New Duct Length (Feet)	140	120	140
New Duct Costs (1000$)	900	771	1350
New Heat Exchanger (1000$)	2434	2434	3689
TOTAL SCOPE ADDER COSTS (1000$)	3371	3243	5102
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13	13

Table 21.5.2-7. NOx Control Cost Results for the Martins 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	156	50	1.9	3.1	19.6	0.7	1.0	40.0	1133	584.4
LNC-LNB	2	1.00	156	50	1.9	3.1	19.6	0.7	1.0	40.0	1133	584.4
LNC-LNB-C	1	1.00	156	50	1.9	3.1	19.6	0.4	0.6	40.0	1133	346.9
LNC-LNB-C	2	1.00	156	50	1.9	3.1	19.6	0.4	0.6	40.0	1133	346.9
SCR-3	1	1.16	156	50	1.9	24.7	158.4	8.5	12.4	80.0	2266	3738.3
SCR-3	2	1.16	156	50	1.9	24.6	157.5	8.4	12.4	80.0	2266	3728.2
SCR-3	1-2	1.16	312	50	1.9	42.2	135.4	15.0	11.0	80.0	4532	3320.6
SCR-3-C	1	1.16	156	50	1.9	24.7	158.4	5.0	7.3	80.0	2266	2190.7
SCR-3-C	2	1.16	156	50	1.9	24.6	157.5	5.0	7.2	80.0	2266	2184.6
SCR-3-C	1-2	1.16	312	50	1.9	42.2	135.4	8.8	6.4	80.0	4532	1944.3
SCR-7	1	1.16	156	50	1.9	24.7	158.4	7.2	10.5	80.0	2266	3176.0
SCR-7	2	1.16	156	50	1.9	24.6	157.5	7.2	10.5	80.0	2266	3165.9
SCR-7	1-2	1.16	312	50	1.9	42.2	135.4	12.5	9.1	80.0	4532	2758.3
SCR-7-C	1	1.16	156	50	1.9	24.7	158.4	4.2	6.2	80.0	2266	1868.5
SCR-7-C	2	1.16	156	50	1.9	24.6	157.5	4.2	6.2	80.0	2266	1862.4
SCR-7-C	1-2	1.16	312	50	1.9	42.2	135.4	7.4	5.4	80.0	4532	1622.1

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 west of the coal pile in a similar fashion as LSD-FGD. The retrofit of DSD and FSI technologies at the Martins Creek steam plant for both units would be possible. This is due to the adequate flue gas ducting residence time between the boilers and the ESPs as well as the adequate size of the ESPs (SCAs = 300). It was assumed that the ESPs could also be upgraded for FSI technologies. Additionally, the conversion of the wet ash handling system to dry handling would be required for reusing ESPs. Tables 21.5.2-8 and 21.5.2-9 present a summary of the site access/congestion factors for DSD and FSI technologies at the Martins Creek steam plant. Table 21.5.2-10 presents the costs estimated to retrofit DSD and FSI at the Martins Creek 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 Martins Creek plant. Both boilers would be considered good candidates for AFBC repowering due to their small boiler sizes (156 MW) and old ages (built before 1960). However, the high capacity factors make these units not a good candidate because of replacement power costs during boiler downtime.

21.5.3 Montour Steam Plant

The Montour steam plant is located within Montour County, Pennsylvania, as part of the Pennsylvania Power and Light Company system. The plant contains two coal-fired boilers with a total gross generating capacity of 1,641 MW (net capacity is 1515 MW). Figure 21.5.3-1 presents the plant plot

TABLE 21.5.2-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR MARTINS CREEK UNIT 1

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$)	1397
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	42
TOTAL COST (1000$)	
ESP UPGRADE CASE	1439
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.36
NEW BAGHOUSE	NA

TABLE 21.5.2-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR MARTINS CREEK 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	YES
ESTIMATED COST (1000$)	1397
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	42

TOTAL COST (1000$)	
ESP UPGRADE CASE	1439
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.16
NEW BAGHOUSE	NA

Table 21.5.2-10. Summary of DSD/FSI Control Costs for the Martins 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	156	50	1.9	10.0	64.4	7.1	10.3	49.0	4862	1453.4
DSD+ESP	2	1.00	156	50	1.9	9.7	61.9	7.0	10.2	49.0	4862	1433.6
DSD+ESP-C	1	1.00	156	50	1.9	10.0	64.4	4.1	6.0	49.0	4862	842.0
DSD+ESP-C	2	1.00	156	50	1.9	9.7	61.9	4.0	5.9	49.0	4862	830.3
FSI+ESP-50	1	1.00	156	50	1.9	10.6	67.7	6.9	10.1	50.0	4997	1378.3
FSI+ESP-50	2	1.00	156	50	1.9	10.1	64.9	6.8	9.9	50.0	4997	1355.4
FSI+ESP-50-C	1	1.00	156	50	1.9	10.6	67.7	4.0	5.8	50.0	4997	799.1
FSI+ESP-50-C	2	1.00	156	50	1.9	10.1	64.9	3.9	5.7	50.0	4997	785.6
FSI+ESP-70	1	1.00	156	50	1.9	10.7	68.3	7.0	10.2	70.0	6996	998.3
FSI+ESP-70	2	1.00	156	50	1.9	10.2	65.4	6.9	10.1	70.0	6996	981.6
FSI+ESP-70-C	1	1.00	156	50	1.9	10.7	68.3	4.0	5.9	70.0	6996	578.8
FSI+ESP-70-C	2	1.00	156	50	1.9	10.2	65.4	4.0	5.8	70.0	6996	568.9

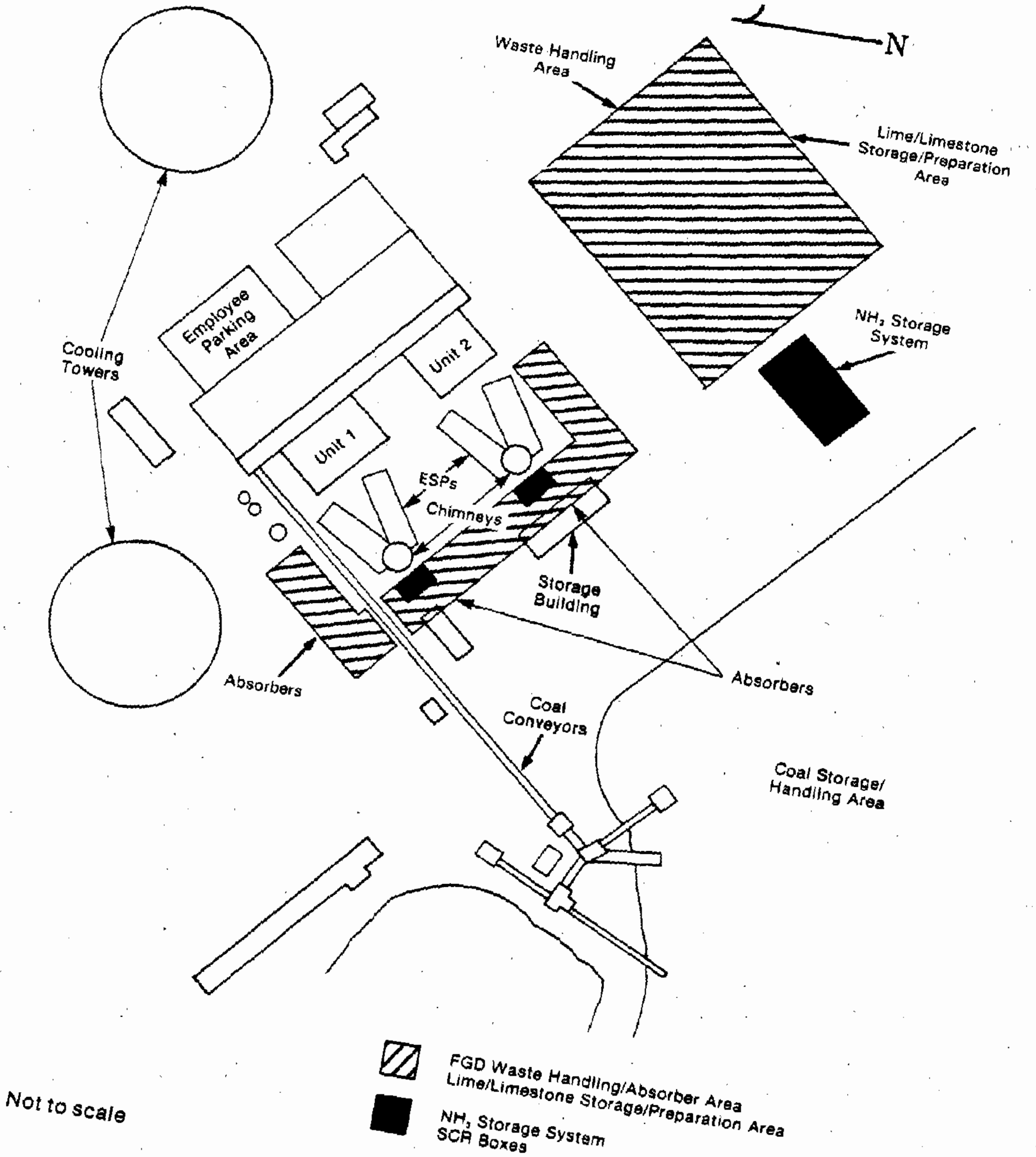

Figure 21.5.3-1. Montour plant plot plan

plan showing the location of all boilers and major associated auxiliary equipment.

Table 21.5.3-1 presents operational data for the existing equipment at the Montour plant. Both boilers burn medium sulfur coal (1.5 percent sulfur). Coal shipments are received by railroad and conveyed to a coal storage and handling area located southwest of the plant.

Particulate matter emissions for all units are controlled with ESPs which are located behind each unit. The plant has a dry fly ash handling system and ash is disposed to a storage area on-site. A large ash pond site is also available north of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 21.5.3-1 shows the general layout and location of the FGD control system. There are two natural draft cooling towers located northeast and northwest of the plant between the powerhouse and ash pond. The absorbers would be located between the chimneys and coal pile for L/LS-FGD and on either side relocation would be required for the storage area and auxiliary building; therefore, a factor of 8 percent was assigned to general facilities. The lime storage/preparation area would be located east of unit 2 and the waste handling area would be located adjacent to it.

Retrofit Difficulty and Scope Adder Costs--

The absorbers for both units would be located southwest of the plant between the chimneys and coal pile for L/LS-FGD and on either side of the ESPs for LSD-FGD cases.

The absorbers were assigned a low site access/congestion factor for L/LS-FGD and LSD-FGD technologies; other than part of the storage building which would need to be demolished, there are no additional major obstacles or obstructions.

For flue gas handling, short to moderate duct runs for the units would be required for L/LS-FGD cases. A low site access/congestion factor was assigned to the flue gas handling system due to the absorbers being located directly behind the chimneys.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Tables 21.5.3-2 and 21.5.3-3. No large

TABLE 21.5.3-1. MONTOUR STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2
GENERATING CAPACITY (MW-each)	822, 819
CAPACITY FACTOR (PERCENT)	75
INSTALLATION DATE	1972,73
FIRING TYPE	TANGENTIAL
COAL SULFUR CONTENT (PERCENT)	1.5
COAL HEATING VALUE (BTU/LB)	12600
COAL ASH CONTENT (PERCENT)	12.2
FLY ASH SYSTEM	DRY DISPOSAL
ASH DISPOSAL METHOD	STORAGE AREA/ON-SITE
STACK NUMBER	1,2
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1972-73
EMISSION (LB/MM BTU)	0.03
REMOVAL EFFICIENCY	99.5
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	2.7
SURFACE AREA (1000 SQ FT)	460.8
GAS EXIT RATE (1000 ACFM)	2260
SCA (SQ FT/1000 ACFM)	204
OUTLET TEMPERATURE (°F)	310

TABLE 21.5.3-2. SUMMARY OF RETROFIT FACTOR DATA FOR MONTOUR UNIT 1

	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			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	100-300	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
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			1.36
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	8	8

TABLE 21.5.3-3. SUMMARY OF RETROFIT FACTOR DATA FOR MONTOUR 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			MEDIUM
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			1.31
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	8	8

scope adder cost is required for the Montour plant. The overall retrofit factor determined for the L/LS-FGD cases was low (1.24).

The absorbers for LSD-FGD would be located on either side of the ESPs. LSD-FGD with reused ESP was the only LSD-FGD technology considered for both units. For flue gas handling for LSD cases, moderate duct runs would be required and a medium-to-high site access/congestion factor was assigned for both units. The retrofit factors determined for the LSD technology case were moderate (1.31-1.36) and did not include particulate control upgrading costs. Two separate retrofit factors were developed for upgrading ESPs. For unit 1, a medium site access/congestion factor was assigned (1.36) due to the ESPs being bounded by the coal conveyor on one side and the chimney on the other. Unit 2 was assigned a low site access/congestion factor (1.16) because of the large available space on either side of the ESPs. These factors were used in the IAPCS model to estimate the particulate control upgrading costs.

Table 21.5.3-4 presents the estimated costs for L/LS-FGD 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 due to the elimination of spare scrubber modules and the optimization of scrubber module 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 21.5.3-5.

Table 21.5.3-4. Summary of FGD Control Costs for the Montour 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	1-2	1.24	1641	75	1.5	185.7	113.2	118.1	11.0	90.0	111028	1063.5
LC FGD-C	1-2	1.24	1641	75	1.5	185.7	113.2	68.5	6.4	90.0	111028	616.8
LFGD	1	1.24	822	75	1.5	126.3	153.6	71.6	13.3	90.0	55615	1288.0
LFGD	2	1.24	819	75	1.5	125.8	153.5	71.4	13.3	90.0	55412	1288.1
LFGD-C	1	1.24	822	75	1.5	126.3	153.6	41.6	7.7	90.0	55615	748.1
LFGD-C	2	1.24	819	75	1.5	125.8	153.5	41.5	7.7	90.0	55412	748.2
LSD+ESP	1	1.36	822	75	1.5	98.9	120.3	45.5	8.4	76.0	47149	964.2
LSD+ESP	2	1.31	819	75	1.5	94.0	114.8	44.0	8.2	76.0	46977	937.4
LSD+ESP-C	1	1.36	822	75	1.5	98.9	120.3	26.5	4.9	76.0	47149	561.8
LSD+ESP-C	2	1.31	819	75	1.5	94.0	114.8	25.7	4.8	76.0	46977	546.1

Table 21.5.3-5. Summary of Coal Switching/Cleaning Costs for the Montour 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	822	75	1.5	25.2	30.7	74.7	13.8	37.0	22799	3277.4
CS/B+$15	2	1.00	819	75	1.5	25.1	30.7	74.5	13.8	37.0	22716	3277.6
CS/B+$15-C	1	1.00	822	75	1.5	25.2	30.7	42.9	7.9	37.0	22799	1882.7
CS/B+$15-C	2	1.00	819	75	1.5	25.1	30.7	42.8	7.9	37.0	22716	1882.8
CS/B+$5	1	1.00	822	75	1.5	16.7	20.3	28.6	5.3	37.0	22799	1255.5
CS/B+$5	2	1.00	819	75	1.5	16.7	20.3	28.5	5.3	37.0	22716	1255.6
CS/B+$5-C	1	1.00	822	75	1.5	16.7	20.3	16.5	3.1	37.0	22799	722.6
CS/B+$5-C	2	1.00	819	75	1.5	16.7	20.3	16.4	3.1	37.0	22716	722.7

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Montour 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 822 and 819 MW, respectively. The combustion modification technique applied for this evaluation was OFA. As Table 21.5.3-6 shows, the OFA NO_x reduction performance for each unit was estimated to be 20 percent. 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 21.5.3-7 presents the cost of retrofitting OFA at the Montour boilers.

Selective Catalytic Reduction--

Table 21.5.3-6 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 building and 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 both units were located southwest of the plant between the respective chimneys and the coal pile. The SCR reactor locations for units 1 and 2 were assigned a low access/congestion factor since the reactors would be located in a relatively open area. Other than a storage building which would be demolished, there are no major obstacles or obstructions; therefore, a factor of 20 percent was assigned to general facilities. 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.

TABLE 21.5.3-6. SUMMARY OF NOx RETROFIT RESULTS FOR MONTOUR

	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)	14.7	14.7
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	92.7	92.7
FURNACE RESIDENCE TIME (SECONDS)	3.64	3.64
ESTIMATED NOx REDUCTION (PERCENT)	20	20
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	376
Ductwork Demolition (1000$)	131	131
New Duct Length (Feet)	200	200
New Duct Costs (1000$)	3,401	3,391
New Heat Exchanger (1000$)	6,602	6,582
TOTAL SCOPE ADDER COSTS (1000$)	10,134	10,480
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	20	20

Table 21.5.3-7. NOx Control Cost Results for the Montour 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	822	75	1.5	1.4	1.7	0.3	0.1	20.0	3169	98.5
LNC-OFA	2	1.00	819	75	1.5	1.4	1.8	0.3	0.1	20.0	3157	98.8
LNC-OFA-C	1	1.00	822	75	1.5	1.4	1.7	0.2	0.0	20.0	3169	58.5
LNC-OFA-C	2	1.00	819	75	1.5	1.4	1.8	0.2	0.0	20.0	3157	58.6
SCR-3	1	1.16	822	75	1.5	95.6	116.4	36.6	6.8	80.0	12676	2886.4
SCR-3	2	1.16	819	75	1.5	95.7	116.9	36.5	6.8	80.0	12630	2893.1
SCR-3-C	1	1.16	822	75	1.5	95.6	116.4	21.4	4.0	80.0	12676	1687.5
SCR-3-C	2	1.16	819	75	1.5	95.7	116.9	21.4	4.0	80.0	12630	1691.5
SCR-7	1	1.16	822	75	1.5	95.6	116.4	29.9	5.5	80.0	12676	2357.4
SCR-7	2	1.16	819	75	1.5	95.7	116.9	29.9	5.5	80.0	12630	2364.0
SCR-7-C	1	1.16	822	75	1.5	95.6	116.4	17.5	3.2	80.0	12676	1384.4
SCR-7-C	2	1.16	819	75	1.5	95.7	116.9	17.5	3.3	80.0	12630	1388.4

As discussed in Section 2, all NO_x control techniques were evaluated independently from those evaluated for SO_2 control. As a result for this plant, the FGD absorbers were in the same location as the SCR reactors. If both SO_2 and NO_x emissions have to be reduced at this plant, the SCR reactors would have to be located downstream of the FGD absorbers in an area having little obstructions and easy access. A low access/congestion factor would be assigned to both SCR reactors. However, the duct runs to the chimney would be longer than that presented in Table 21.5.3-6. Table 21.5.3-7 presents the estimated cost of retrofitting SCR at the Montour 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. The retrofit of DSD and FSI technologies at the Montour steam plant for both units would be difficult. This difficulty reflects the insufficient duct residence time between the boilers and ESPs and inadequate ESP sizes. Therefore, costs of sorbent injection technologies were not developed for the Montour 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 Montour plant. None of the boilers would be considered good candidates for AFBC retrofit due to their large sizes (>800 MW), their ages (built after 1970), and high capacity factors.

21.5.4 Sunbury Steam Plant

The Sunbury steam plant is located within Snyder County, Pennsylvania, as part of the Pennsylvania Power and Light Company system. The plant contains four coal-fired boilers with a total gross generating capacity of 409 MW. The plant is located on a narrow site bounded by the railroad to the west and Susquehanna River to the east. Figure 21.5.4-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 21.5.4-1 presents operational data for the existing equipment at the Sunbury plant. Boilers 1 and 2 burn low sulfur coal (0.6 percent sulfur) as well as Petroleum, coke and anthracite (2.0 percent sulfur for overall fuel blend) while boilers 3 and 4 burn medium sulfur coal (1.9). Coal shipments are received by railroad and trucks and conveyed to a coal storage and handling area located north of the plant.

Particulate matter emissions for boilers 1 and 2 are controlled with retrofit baghouses; units 3 and 4 are controlled with retrofit ESPs. Ash from all units is wet sluiced to ponds located south of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 21.5.4-1 shows the general layout and location of the FGD control system. The absorbers for L/LS-FGD and LSD-FGD for all units would be located north of the plant between the coal pile and powerhouse. Major relocation or demolition would be required consisting of the oil tank, warehouses, a major part of the employee parking area (for the absorbers), and the preparation and storage area. Therefore, a high factor of 20 percent was assigned to general facilities. The lime storage/preparation area would be located northwest of the plant between the powerhouse and railroad track; the waste handling area would be located southwest of the storage/preparation area.

Retrofit Difficulty and Scope Adder Costs--

The absorbers for all units would be located north of plant between the coal pile and the powerhouse. However, units 1 and 2 are burning low sulfur coal (0.6 percent) and it is unlikely that these units would be scrubbed. As such, costs were not developed for these two units.

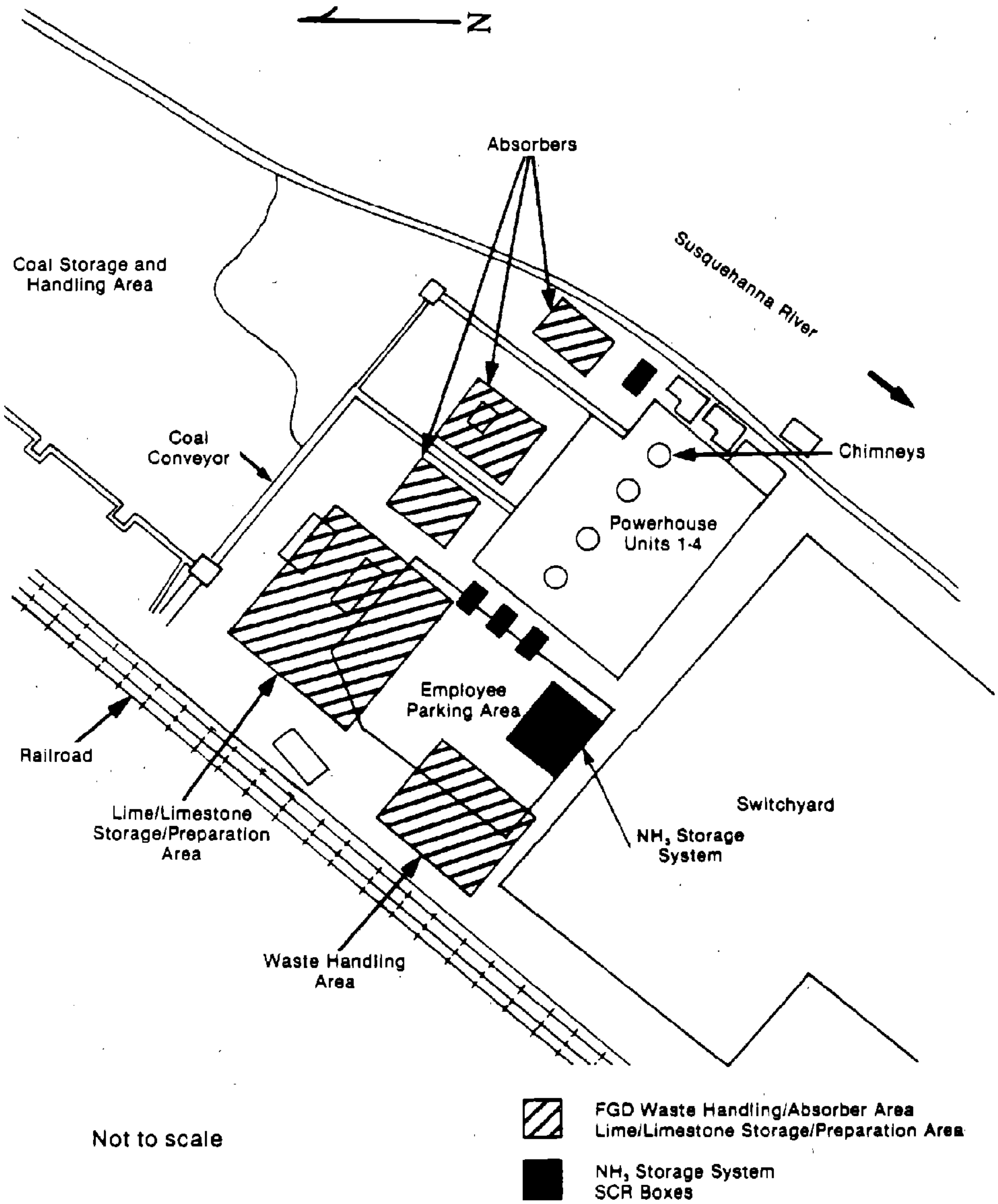

Figure 21.5.4-1. Sunbury plant plot plan

TABLE 21.5.4-1. SUNBURY STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3	4
GENERATING CAPACITY (MW-each)	75	103	156
CAPACITY FACTOR (PERCENT)	70	70	70
INSTALLATION DATE	1949	1951	1953
FIRING TYPE	VERTICAL DOWN-FIRED	FRONT WALL	
COAL SULFUR CONTENT (PERCENT)	0.6	1.9	1.9
COAL HEATING VALUE (BTU/LB)	9120	12400	12400
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	4
COAL DELIVERY METHODS		RAILROAD/TRUCK	
PARTICULATE CONTROL			
TYPE	BAGHOUSE	ESP	ESP
INSTALLATION DATE	1973	1979	1979
EMMISION (LB/MM BTU)	0.01	0.04	0.07
REMOVAL EFFICIENCY	99.7	98.8	97.0
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	-	0.8	0.8
SURFACE AREA (1000 SQ FT)	-	NA	NA
GAS EXIT RATE (1000 ACFM)	-	222	222
SCA (SQ FT/1000 ACFM)	-	NA	NA
OUTLET TEMPERATURE (°F)	310	310	310

The absorbers for all units were assigned a high site access/congestion factor which reflects the congestion created by the coal-conveyors, river, coal pile, and other auxiliary equipment around the site.

For flue gas handling, long duct runs for all units would be required for L/LS-FGD cases. A high site access/congestion factor was assigned to the flue gas handling system due to the high site access difficulty caused by the coal conveyors, an office building, and congestion around the powerhouse.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Tables 21.5.4-2 and 21.5.4-3. The largest scope adder for the Sunbury plant would be the conversion of units 1 to 4 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 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 high (1.73 to 1.76).

LSD-FGD with reused particulate controls (baghouse and ESPs) were the only LSD-FGD technologies considered for all units based on the presumption that baghouses for units 1 and 2 can handle the particulate load from LSD-FGD and the units 3 and 4 ESPs have large SCAs. For flue gas handling for LSD cases, long duct runs would be required and a high site access/congestion factor was assigned for all units in a similar fashion as L/LS-FGD. The retrofit factor determined for the LSD technology case was high (1.78) and did not include particulate control costs. A separate retrofit factor was developed for upgrading ESPs for units 3 and 4. This factor was high (1.58) and reflects the congestion around the ESPs due to the powerhouse building, auxiliary equipment, and coal conveyors. This factor was used in the IAPCS model to estimate particulate control upgrading costs.

Table 21.5.4-4 presents the estimated costs for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs for boilers 3 and 4 and ash handling systems for all boilers. As mentioned in the previous section, units 1 and 2 are burning low sulfur coal and it is unlikely that these units would need to be scrubbed. If, however, scrubbing is required, it

TABLE 21.5.4-2. SUMMARY OF RETROFIT FACTOR DATA FOR SUNBURY UNITS 1 OR 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	HIGH	HIGH
FLUE GAS HANDLING	HIGH	HIGH	
BAGHOUSE REUSE CASE			HIGH
NEW BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	600-1000	600-1000	
BAGHOUSE REUSE			600-1000
NEW BAGHOUSE			NA
BAGHOUSE REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	724	NA	724
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.76	1.73	
BAGHOUSE REUSE CASE			1.78
NEW BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	20	20	20

TABLE 21.5.4-3. SUMMARY OF RETROFIT FACTOR DATA FOR SUNBURY UNITS 3 OR 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			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	600-1000	600-1000	
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$)	967	NA	967
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.76	1.73	
ESP REUSE CASE			1.78
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	20	20	20

Table 21.5.4-4. Summary of FGD Control Costs for the Sunbury 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	3-4	1.76	259	70	1.9	57.8	223.1	30.8	19.4	90.0	21101	1461.6
LC FGD-C	3-4	1.76	259	70	1.9	57.8	223.1	17.9	11.3	90.0	21101	849.7
LFGD	3	1.76	103	70	1.9	51.0	495.2	22.8	36.1	90.0	8391	2717.0
LFGD	4	1.76	156	70	1.9	65.9	422.7	29.7	31.0	90.0	12709	2335.7
LFGD-C	3	1.76	103	70	1.9	51.0	495.2	13.3	21.0	90.0	8391	1583.9
LFGD-C	4	1.76	156	70	1.9	65.9	422.7	17.3	18.1	90.0	12709	1361.5
LSD+ESP	3	1.78	103	70	1.9	23.4	227.3	11.1	17.6	76.0	7114	1563.4
LSD+ESP	4	1.78	156	70	1.9	30.8	197.4	14.2	14.9	76.0	10775	1322.5
LSD+ESP-C	3	1.78	103	70	1.9	23.4	227.3	6.5	10.3	76.0	7114	910.5
LSD+ESP-C	4	1.78	156	70	1.9	30.8	197.4	8.3	8.7	76.0	10775	770.5

would be more cost effective to switch to a higher coal sulfur content, taking into consideration the fuel cost differential, in estimating cost effectiveness for these units.

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.

Coal Switching Costs--

Units 1 and 2 already have switched to low sulfur coal. As such, these two units were not considered for coal switching or coal cleaning. 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. Costs were generated to show the impact of two different coal fuel cost differentials. The costs associated with units 3 and 4 for the range of fuel cost differential are shown in Table 21.5.4-5.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Sunbury 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 1 and 2 are dry bottom, vertical/down-fired boilers each rated at 75 MW. Units 3 and 4 are dry bottom, front wall-fired boilers rated at 103 and 156 MW, respectively. The combustion modification technique applied for these boilers was LNB. As Tables 21.5.4-6 and 21.5.4-7 show, the LNB NO_x reduction performance for unit 4 was estimated to be 50 percent. No boiler information could be found for units 1 to 3 to assess their NO_x reduction performances. Since these boilers are relatively old, it is estimated that

Table 21.5.4-5. Summary of Coal Switching/Cleaning Costs for the Sunbury 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	103	70	1.9	4.2	40.7	9.5	15.0	51.0	4763	1994.8
CS/B+$15	4	1.00	156	70	1.9	5.8	37.2	14.0	14.7	51.0	7214	1943.4
CS/B+$15-C	3	1.00	103	70	1.9	4.2	40.7	5.5	8.6	51.0	4763	1146.8
CS/B+$15-C	4	1.00	156	70	1.9	5.8	37.2	8.1	8.4	51.0	7214	1117.1
CS/B+$5	3	1.00	103	70	1.9	3.1	30.3	4.1	6.5	51.0	4763	860.3
CS/B+$5	4	1.00	156	70	1.9	4.2	26.9	5.8	6.1	51.0	7214	808.9
CS/B+$5-C	3	1.00	103	70	1.9	3.1	30.3	2.4	3.7	51.0	4763	495.8
CS/B+$5-C	4	1.00	156	70	1.9	4.2	26.9	3.4	3.5	51.0	7214	466.1

TABLE 21.5.4-6. SUMMARY OF NOx RETROFIT RESULTS FOR SUNBURY UNITS 1-2

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1	2
FIRING TYPE	VERTICAL/DOWN-FIRED	
TYPE OF NOx CONTROL	LNB	LNB
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)	25	25
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	22	22
New Duct Length (Feet)	500	600
New Duct Costs (1000$)	2094	2512
New Heat Exchanger (1000$)	1568	1568
TOTAL SCOPE ADDER COSTS (1000$)	3684	4102
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	25	25

TABLE 21.5.4-7. SUMMARY OF NOx RETROFIT RESULTS FOR SUNBURY UNITS 3-4

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	3	4
FIRING TYPE	FWF	FWF
TYPE OF NOx CONTROL	LNB	LNB
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	NA	14.6
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	NA	28.4
FURNACE RESIDENCE TIME (SECONDS)	NA	5.43
ESTIMATED NOx REDUCTION (PERCENT)	25	50
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	HIGH
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	28	38
New Duct Length (Feet)	850	500
New Duct Costs (1000$)	4310	1607
New Heat Exchanger (1000$)	1908	2434
TOTAL SCOPE ADDER COSTS (1000$)	6246	5685
RETROFIT FACTOR FOR SCR	1.16	1.52
GENERAL FACILITIES (PERCENT)	25	13

a NO_x reduction of 20 to 30 percent can be achieved by these boilers retrofitted with LNB. Units 1 to 3 were installed between 1949 and 1951. The reduction performance level for unit 4 was assessed by examining the effects of heat release rates and furnace residence time through the use of the simplified NO_x procedures. Table 21.5.4-8 presents the cost of retrofitting LNB at the Sunbury boilers.

Selective Catalytic Reduction--

Tables 21.5.4-6 and 21.5.4-7 present 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 particulate matter control device to the reactor and from the reactor to the chimney.

The SCR reactors for units 1 to 3 were located west of the powerhouse in the parking lot. Since the reactors were located in open area having easy access with no major obstacles, the reactors for units 1 to 3 were assigned low access/congestion factors. However, a 25 percent general facilities factor was assigned to these reactors for relocating the parking lot in an area south or southwest of the powerhouse. The SCR reactor for unit 4 was located northeast of the powerhouse and bordering the river. A high access/congestion factor was assigned to the reactor for unit 4 since it is in a high congestion area with difficult access surrounded by the coal conveyor and the river. 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. Table 21.5.4-8 presents the estimated cost of retrofitting SCR at the Sunbury 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.

Table 21.5.4-8. NOx Control Cost Results for the Sunbury 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	75	70	0.6	2.3	30.3	0.5	1.1	25.0	684	721.6
LNC-LNB	2	1.00	75	70	0.6	2.3	30.3	0.5	1.1	25.0	684	721.6
LNC-LNB	3	1.00	103	70	1.9	2.6	25.1	0.6	0.9	25.0	661	848.9
LNC-LNB	4	1.00	156	70	1.9	3.1	19.6	0.7	0.7	50.0	2001	330.9
LNC-LNB-C	1	1.00	75	70	0.6	2.3	30.3	0.3	0.6	25.0	684	428.4
LNC-LNB-C	2	1.00	75	70	0.6	2.3	30.3	0.3	0.6	25.0	684	428.4
LNC-LNB-C	3	1.00	103	70	1.9	2.6	25.1	0.3	0.5	25.0	661	503.9
LNC-LNB-C	4	1.00	156	70	1.9	3.1	19.6	0.4	0.4	50.0	2001	196.4
SCR-3	1	1.16	75	70	0.6	17.4	232.4	5.6	12.3	80.0	2190	2577.0
SCR-3	2	1.16	75	70	0.6	17.9	238.0	5.7	12.4	80.0	2190	2611.1
SCR-3	3	1.16	103	70	1.9	22.9	222.5	7.2	11.3	80.0	2114	3384.4
SCR-3	4	1.52	156	70	1.9	31.5	201.9	10.2	10.7	80.0	3202	3184.3
SCR-3-C	1	1.16	75	70	0.6	17.4	232.4	3.3	7.2	80.0	2190	1512.1
SCR-3-C	2	1.16	75	70	0.6	17.9	238.0	3.4	7.3	80.0	2190	1532.5
SCR-3-C	3	1.16	103	70	1.9	22.9	222.5	4.2	6.7	80.0	2114	1987.6
SCR-3-C	4	1.52	156	70	1.9	31.5	201.9	6.0	6.3	80.0	3202	1868.5
SCR-7	1	1.16	75	70	0.6	17.4	232.4	5.0	10.9	80.0	2190	2283.9
SCR-7	2	1.16	75	70	0.6	17.9	238.0	5.1	11.0	80.0	2190	2318.0
SCR-7	3	1.16	103	70	1.9	22.9	222.5	6.3	10.0	80.0	2114	2985.9
SCR-7	4	1.52	156	70	1.9	31.5	201.9	8.9	9.3	80.0	3202	2785.8
SCR-7-C	1	1.16	75	70	0.6	17.4	232.4	2.9	6.4	80.0	2190	1344.2
SCR-7-C	2	1.16	75	70	0.6	17.9	238.0	3.0	6.5	80.0	2190	1364.6
SCR-7-C	3	1.16	103	70	1.9	22.9	222.5	3.7	5.9	80.0	2114	1759.3
SCR-7-C	4	1.52	156	70	1.9	31.5	201.9	5.3	5.5	80.0	3202	1640.2

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas were located northwest of the plant in a similar fashion as LSD-FGD. The retrofit of DSD and FSI technologies at the Sunbury steam plant for all units would be difficult. There is not sufficient flue gas ducting residence time between the boilers and the particulate controls; therefore, new baghouses were considered for all units. The new baghouses would be located north of the plant adjacent to the coal conveyor, river, and coal pile. A high retrofit factor was assigned to the new baghouses (1.55). Long duct runs would be needed (600 feet) to divert the flue gas from the boilers to the baghouses and back to the chimney. However, for FSI technology, it was assumed that the existing baghouses can handle the increased load and the ESPs could be upgraded at an equivalent cost of additional plate area and assuming a high site access/congestion factor (1.55). Additionally, the conversion of the wet ash handling system to dry handling would be required when reusing the ESPs/baghouses for FSI technology. Tables 21.5.4-9 through 21.5.4-11 present a summary of the site access/congestion factors for DSD and FSI technologies at the Sunbury steam plant. Table 21.5.4-12 presents the costs estimated to retrofit DSD and FSI at the Sunbury 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 Sunbury plant. All of the boilers would be considered candidates for AFBC retrofit due to their small sizes (<160 MW) and their old ages (built before 1960). However, the high capacity factors make these units poor candidates for repowering because of replacement power costs during boiler downtime.

TABLE 21.5.4-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR SUNBURY UNITS 1 OR 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	HIGH
BAGHOUSE UPGRADE (FSI)	NA
NEW BAGHOUSE (DSD)	HIGH
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	724
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	600
ESTIMATED COST (1000$)	2329
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	24
TOTAL COST (1000$)	
AN EXISTING BAGHOUSE CASE (FSI)	748
A NEW BAGHOUSE CASE (DSD)	2353
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.37
BAGHOUSE UPGRADE (FSI)	NA
NEW BAGHOUSE (DSD)	1.55

TABLE 21.5.4-10. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR SUNBURY UNIT 3

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	HIGH
ESP UPGRADE (FSI)	HIGH
NEW BAGHOUSE (DSD)	HIGH
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	967
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	600
ESTIMATED COST (1000$)	2812
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	31

TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	998
A NEW BAGHOUSE CASE (DSD)	2843
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.37
ESP UPGRADE (FSI)	1.55
NEW BAGHOUSE (DSD)	1.55

TABLE 21.5.4-11. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR SUNBURY UNIT 4

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	HIGH
ESP UPGRADE (FSI)	HIGH
NEW BAGHOUSE (DSD)	HIGH
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	1399
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	600
ESTIMATED COST (1000$)	3579
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	42

TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	1441
A NEW BAGHOUSE CASE (DSD)	3621
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.37
ESP UPGRADE (FSI)	1.55
NEW BAGHOUSE (DSD)	1.55

Table 21.5.4-12. Summary of DSD/FSI Control Costs for the Sunbury 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	75	70	0.6	18.8	251.1	8.3	18.0	71.0	2158	3827.5
DSD+FF	2	1.00	75	70	0.6	18.8	251.1	8.3	18.0	71.0	2158	3827.5
DSD+FF	3	1.00	103	70	1.9	23.5	228.6	10.5	16.5	71.0	6597	1584.6
DSD+FF	4	1.00	156	70	1.9	31.2	200.0	13.5	14.1	71.0	9991	1348.6
DSD+FF-C	1	1.00	75	70	0.6	18.8	251.1	4.8	10.5	71.0	2158	2232.0
DSD+FF-C	2	1.00	75	70	0.6	18.8	251.1	4.8	10.5	71.0	2158	2232.0
DSD+FF-C	3	1.00	103	70	1.9	23.5	228.6	6.1	9.6	71.0	6597	923.9
DSD+FF-C	4	1.00	156	70	1.9	31.2	200.0	7.9	8.2	71.0	9991	786.6
FSI+ESP-50	3	1.00	103	70	1.9	8.6	83.7	6.2	9.9	50.0	4662	1338.4
FSI+ESP-50	4	1.00	156	70	1.9	11.0	70.7	8.3	8.7	50.0	7061	1174.6
FSI+ESP-50-C	3	1.00	103	70	1.9	8.6	83.7	3.6	5.7	50.0	4662	775.1
FSI+ESP-50-C	4	1.00	156	70	1.9	11.0	70.7	4.8	5.0	50.0	7061	680.0
FSI+ESP-70	3	1.00	103	70	1.9	8.7	84.4	6.3	10.0	70.0	6527	969.0
FSI+ESP-70	4	1.00	156	70	1.9	11.1	71.2	8.4	8.8	70.0	9885	851.1
FSI+ESP-70-C	3	1.00	103	70	1.9	8.7	84.4	3.7	5.8	70.0	6527	561.2
FSI+ESP-70-C	4	1.00	156	70	1.9	11.1	71.2	4.9	5.1	70.0	9885	492.6
FSI+PFF-50	1	1.00	75	70	0.6	3.4	45.1	2.8	6.0	50.0	1525	1815.3
FSI+PFF-50	2	1.00	75	70	0.6	3.4	45.1	2.8	6.0	50.0	1525	1815.3
FSI+PFF-50-C	1	1.00	75	70	0.6	3.4	45.1	1.6	3.5	50.0	1525	1050.0
FSI+PFF-50-C	2	1.00	75	70	0.6	3.4	45.1	1.6	3.5	50.0	1525	1050.0
FSI+PFF-70	1	1.00	75	70	0.6	3.4	45.1	2.8	6.0	70.0	2135	1298.5
FSI+PFF-70	2	1.00	75	70	0.6	3.4	45.1	2.8	6.0	70.0	2135	1298.5
FSI+PFF-70-C	1	1.00	75	70	0.6	3.4	45.1	1.6	3.5	70.0	2135	751.1
FSI+PFF-70-C	2	1.00	75	70	0.6	3.4	45.1	1.6	3.5	70.0	2135	751.1

21.6 PENNSYLVANIA POWER COMPANY

21.6.1 Bruce Mansfield Steam Plant

The Bruce Mansfield steam plant is located within Beaver County, Pennsylvania, as part of the Pennsylvania Power Company system. The plant is located beside the Ohio River and contains three coal-fired boilers with a total gross generating capacity of 2,505 MW. Three natural draft cooling towers are located between the units and the river.

Table 21.6.1-1 presents operational data for the existing equipment at the Bruce Mansfield plant. The boilers burn high sulfur coal. Coal shipments are received by barge and transferred to a coal storage and handling area north of the plant and adjacent to the river.

PM emissions for the boilers are controlled with wet scrubbers for units 1-2 and ESPs for unit 3. The plant has a dry fly ash handling system. Fly ash is used to stabilize sludge produced by FGD. Units 1 and 2 are served by a common chimney while unit 3 is served by another chimney. All units are equipped with new FGD units and, as such, this plant was not considered for further SO_2 reduction.

Low NO_x Combustion--

Units 1 through 3 are dry bottom boilers with a gross unit rating of 835 MW each. Unit 3 is equipped with OFA. As such, NO_x reduction using combustion controls was not evaluated for this unit.

Selective Catalytic Reduction--

Cold side SCR reactors for units 1-2 would be located behind the chimneys and downstream of the existing FGD units to the east of units 1-2. The SCR reactors for unit 3, however, would be located on the side of unit 3 close to the employee parking area and beside the chimney. Because of the space availability for SCR reactors, a low site access/congestion factor was assigned to all the reactor locations. Approximately 450 feet of duct length would be needed for either of the units 1 or 2. For unit 3, 250 feet of duct length was estimated. All reactors were assumed to be in areas with high underground obstructions. The ammonia storage system was placed close

TABLE 21.6.1-1. BRUCE MANSFIELD STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1-3
GENERATING CAPACITY (MW-each)	780 net
CAPACITY FACTOR (PERCENT)	60,68,71
INSTALLATION DATE	1976,77,80
FIRING TYPE	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	734
LOW NOX COMBUSTION	NO,NO,OFA
COAL SULFUR CONTENT (PERCENT)	3.8
COAL HEATING VALUE (BTU/LB)	11900
COAL ASH CONTENT (PERCENT)	12.5
FLY ASH SYSTEM	DRY HANDLING
ASH DISPOSAL METHOD	PAID DISPOSAL
STACK NUMBER	1, 1, 2
COAL DELIVERY METHODS	BARGE
FGD SYSTEM	YES
FGD TYPE	VENTURI/SPRAY CHAMBER
FGD INSTALLATION DATE	1976,77,80
PARTICULATE CONTROL	
TYPE	WET SCRUBBER/ESP
INSTALLATION DATE	1976,77,80
EMISSION (LB/MM BTU)	0.04,0.08
REMOVAL EFFICIENCY	99.8,99.5
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	4.8
SURFACE AREA (1000 SQ FT,UNIT 3)	645
GAS EXIT RATE (1000 ACFM)	2610
SCA (SQ FT/1000 ACFM,UNIT 3)	247
OUTLET TEMPERATURE (°F)	126

to the FGD waste treatment area. A road and a small portion of the parking area have to be relocated for SCR reactor locations; therefore, a factor of 20 percent was assigned to general facilities.

Table 21.6.1-2 presents the SCR 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. Table 21.6.1-3 presents the estimated cost of retrofitting SCR at the Bruce Mansfield boilers.

21.6.2 New Castle Steam Plant

The New Castle steam plant is located within Lawrence County, Pennsylvania, as part of the Pennsylvania Power Company system, a subsidiary of Ohio Edison Company. The plant is located beside the Beaver River. The plant contains five coal-fired boilers with a total gross generating capacity of 425 MW. Figure 21.6.2-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 21.6.2-1 presents operational data for the existing equipment at the New Castle plant. The boilers burn low to medium sulfur coal. Coal shipments are received by truck and conveyed to a coal storage and handling area located northeast of the plant.

Particulate matter emissions for the boilers are controlled with retrofit ESPs located between unit 5 and a common chimney. The plant has a dry fly ash handling system and is disposed at a landfill located north of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 21.6.2-1 shows the general layout and location of the FGD control system. The boilers sit close to the river and flue gas from all units is converged into a common duct going into a single chimney. The absorbers for L/LS-FGD and LSD-FGD for all the units would be located immediately east of the chimney and south of the coal pile in a relatively open area. Part of the plant road and employee parking area would need to be demolished/ relocated; therefore, a factor of 8 percent was assigned to general

TABLE 21.6.1-2. SUMMARY OF NOx RETROFIT RESULTS FOR BRUCE MANSFIELD

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	3
FIRING TYPE	OWF	OWF	OWF
TYPE OF NOx CONTROL	LNB	LNB	OFA
FURNACE VOLUME (1000 CU FT)	734	734	734
BOILER INSTALLATION DATE	1976	1977	1980
SLAGGING PROBLEM	NO	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	50	50	NA
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	133	133	133
New Duct Length (Feet)	450	450	250
New Duct Costs (1000$)	7717	7717	4287
New Heat Exchanger (1000$)	6659	6659	6659
TOTAL SCOPE ADDER COSTS (1000$)	14509	14509	11079
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	20	20	20

Table 21.6.1-3. NOx Control Cost Results for the Bruce Mansfield 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	780	60	3.8	5.8	7.4	1.3	0.3	50.0	8990	140.2
LNC-LNB	2	1.00	780	68	3.8	5.8	7.4	1.3	0.3	50.0	10189	123.7
LNC-LNB-C	1	1.00	780	60	3.8	5.8	7.4	0.7	0.2	50.0	8990	83.2
LNC-LNB-C	2	1.00	780	68	3.8	5.8	7.4	0.7	0.2	50.0	10189	73.4
SCR-3	1	1.16	780	60	3.8	94.0	120.5	35.2	8.6	80.0	14385	2446.0
SCR-3	2	1.16	780	68	3.8	94.0	120.5	35.6	7.7	80.0	16303	2183.6
SCR-3	3	1.16	780	71	3.8	90.5	116.1	35.1	7.2	80.0	17022	2064.7
SCR-3-C	1	1.16	780	60	3.8	94.0	120.5	20.6	5.0	80.0	14385	1430.7
SCR-3-C	2	1.16	780	68	3.8	94.0	120.5	20.8	4.5	80.0	16303	1276.9
SCR-3-C	3	1.16	780	71	3.8	90.5	116.1	20.5	4.2	80.0	17022	1206.8
SCR-7	1	1.16	780	60	3.8	94.0	120.5	28.8	7.0	80.0	14385	1999.9
SCR-7	2	1.16	780	68	3.8	94.0	120.5	29.2	6.3	80.0	16303	1790.0
SCR-7	3	1.16	780	71	3.8	90.5	116.1	28.7	5.9	80.0	17022	1687.7
SCR-7-C	1	1.16	780	60	3.8	94.0	120.5	16.9	4.1	80.0	14385	1175.1
SCR-7-C	2	1.16	780	68	3.8	94.0	120.5	17.1	3.7	80.0	16303	1051.4
SCR-7-C	3	1.16	780	71	3.8	90.5	116.1	16.9	3.5	80.0	17022	990.8

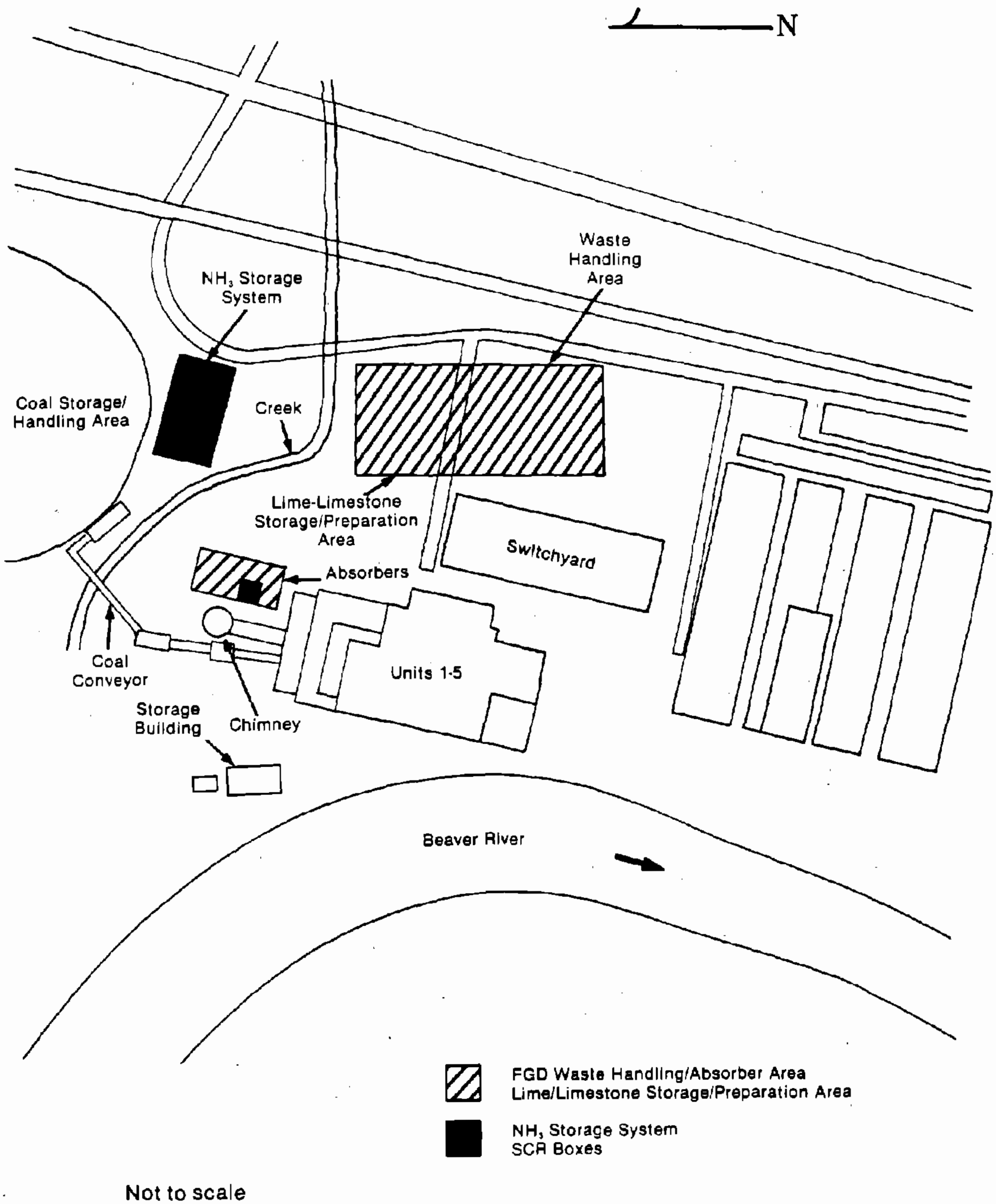

Figure 21.6.2-1. New Castle plant plot plan

TABLE 21.6.2-1. NEW CASTLE STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3	4,5
GENERATING CAPACITY (MW-each)	37.5-40	97.8	113-136
CAPACITY FACTOR (PERCENT)	20,20	51	49,44
INSTALLATION DATE	1939,47	1952	1958,64
FIRING TYPE	FWF	FWF	FWF
COAL SULFUR CONTENT (PERCENT)	1.5	1.5	1.5, 1.5
COAL HEATING VALUE (BTU/LB)	12200	12200	12200
COAL ASH CONTENT (PERCENT)	11.1	11.1	11.1
FLY ASH SYSTEM	DRY HANDLING		
ASH DISPOSAL METHOD	ON-SITE/LANDFILL		
STACK NUMBER	1		
COAL DELIVERY METHODS	TRUCK		
PARTICULATE CONTROL			
TYPE	ESP	ESP	ESP
INSTALLATION DATE	1978	1978	1977
EMMISION (LB/MM BTU)	0.02	0.02	0.01
REMOVAL EFFICIENCY	98.7	99.2	99.2
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	1.5-3.0	1.5-3.0	1.5-3.0
SURFACE AREA (1000 SQ FT)	161	146	146,200
GAS EXIT RATE (1000 ACFM)	520	450	432,635
SCA (SQ FT/1000 ACFM)	310	324	338,315
OUTLET TEMPERATURE (°F)	340	302	272,292

facilities. The lime storage/handling area would be located south of the absorbers and east of the powerhouse, with the waste handling area located adjacent to the absorbers.

Retrofit Difficulty and Scope Adder Costs--

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

For flue gas handling, short duct runs for the units would be required for L/LS-FGD cases since the absorbers would be close to the common duct run/chimney. A low 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 Table 21.6.2-2. No large scope adder cost is required for the New Castle plant. The overall retrofit factor determined for the L/LS-FGD cases was low (1.19).

The absorbers for LSD-FGD would be located in a similar location as in L/LS-FGD cases. Even though the total collection surface areas for ESPs were not available, the SCAs were assumed to be large enough based on the ESPs performance. Therefore, the ESPs could be reused for the LSD-FGD technology. For flue gas handling for LSD cases, short-moderate duct runs would be required to divert the flue gas from the absorbers to the boilers and back to the ESPs. A medium site access/congestion factor was assigned to the flue gas handling system which reflects moderate congestion created by the ESPs. The retrofit factor determined for the LSD technology case was low (1.24) and did not include particulate control upgrading costs. A separate retrofit factor was developed for upgrading the ESPs. A low retrofit factor (1.16) was assigned for upgrading ESPs for all units due to the available space around the ESPs with easy access and low congestion. This factor was used in the IAPCS model to estimate particulate control upgrading costs.

Table 21.6.2-3 presents the estimated costs for L/LS-FGD and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs for boilers 1-5. The low cost control case reduces capital and annual operating costs due to the elimination of spare scrubber modules and the optimization of scrubber module size.

TABLE 21.6.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR NEW CASTLE UNITS 1-5

	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			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	0-100	0-100	
ESP REUSE			100-300
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	1.19	1.19	
ESP REUSE CASE			1.24
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	8	8

* Chimney liner and boiler draft controls are included in retrofit factors.

Table 21.6.2-3. Summary of FGD Control Costs for the New Castle 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	1-5	1.19	424	43	1.5	58.5	137.9	29.6	18.5	90.0	17080	1733.4
LC FGD-C	1-5	1.19	424	43	1.5	58.5	137.9	17.2	10.8	90.0	17080	1008.5
LFGD	1	1.19	38	20	1.5	21.2	564.2	8.7	132.0	90.0	702	12350.7
LFGD	2	1.19	40	20	1.5	21.7	541.7	8.9	126.5	90.0	749	11840.8
LFGD	3	1.19	98	51	1.5	33.4	341.2	15.3	35.1	90.0	4669	3280.6
LFGD	4	1.19	113	49	1.5	34.7	306.6	16.0	33.0	90.0	5184	3084.4
LFGD	5	1.19	136	44	1.5	38.8	285.1	17.5	33.3	90.0	5602	3116.2
LFGD	1-5	1.19	424	43	1.4	78.5	185.0	36.0	22.5	90.0	16254	2213.2
LFGD-C	1	1.19	38	20	1.5	21.2	564.2	5.1	77.1	90.0	702	7211.2
LFGD-C	2	1.19	40	20	1.5	21.7	541.7	5.2	73.9	90.0	749	6913.6
LFGD-C	3	1.19	98	51	1.5	33.4	341.2	8.9	20.4	90.0	4669	1911.6
LFGD-C	4	1.19	113	49	1.5	34.7	306.6	9.3	19.2	90.0	5184	1797.1
LFGD-C	5	1.19	136	44	1.5	38.8	285.1	10.2	19.4	90.0	5602	1816.4
LFGD-C	1-5	1.19	424	43	1.4	78.5	185.0	21.0	13.1	90.0	16254	1289.7
LSD+ESP	1	1.24	38	20	1.5	8.2	218.3	4.9	75.0	76.0	595	8278.5
LSD+ESP	2	1.24	40	20	1.5	8.5	212.9	5.0	71.8	76.0	635	7928.6
LSD+ESP	3	1.24	98	51	1.5	14.7	149.9	7.8	17.9	76.0	3958	1970.9
LSD+ESP	4	1.24	113	49	1.5	15.9	140.6	8.2	17.0	74.0	4242	1940.8
LSD+ESP	5	1.24	136	44	1.5	18.3	134.2	9.1	17.3	76.0	4749	1907.8
LSD+ESP-C	1	1.24	38	20	1.5	8.2	218.3	2.9	43.5	76.0	595	4804.6
LSD+ESP-C	2	1.24	40	20	1.5	8.5	212.9	2.9	41.7	76.0	635	4602.6
LSD+ESP-C	3	1.24	98	51	1.5	14.7	149.9	4.5	10.4	76.0	3958	1145.8
LSD+ESP-C	4	1.24	113	49	1.5	15.9	140.6	4.8	9.9	74.0	4242	1128.7
LSD+ESP-C	5	1.24	136	44	1.5	18.3	134.2	5.3	10.1	76.0	4749	1110.3

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 21.6.2-4.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the New Castle 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 1 to 5 are dry bottom, front wall-fired boilers rated at 38, 40, 98, 114, 136 MW, respectively. The combustion modification technique applied for these boilers was LNB. As Tables 21.6.2-5 and 21.6.2-6 show, the LNB NO_x reduction performances for units 3 to 5 were estimated to be 40, 43, and 37 percent, respectively. No boiler information could be found for units 1 and 2 to assess their NO_x reduction performances. Since these boilers are relatively old (1939 to 1947 in-service dates), it is estimated that a NO_x reduction of 20 to 30 percent can be achieved by these boilers retrofitted with LNB. Units 1 and 2 were installed between 1937 and 1947. The reduction performance levels for units 3 to 5 were assessed by examining the effects of heat release rates and furnace residence time on NO_x reduction through the

Table 21.6.2-4. Summary of Coal Switching/Cleaning Costs for the New Castle 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	38	20	1.5	2.0	54.3	1.5	22.4	39.0	306	4821.9
CS/B+$15	2	1.00	40	20	1.5	2.1	53.0	1.5	22.1	39.0	326	4751.1
CS/B+$15	3	1.00	98	51	1.5	4.0	40.7	6.8	15.6	39.0	2033	3355.1
CS/B+$15	4	1.00	113	49	1.5	4.4	39.3	7.5	15.5	39.0	2257	3333.2
CS/B+$15	5	1.00	136	44	1.5	5.1	37.8	8.1	15.5	39.0	2439	3339.4
CS/B+$15-C	1	1.00	38	20	1.5	2.0	54.3	0.9	13.0	39.0	306	2792.5
CS/B+$15-C	2	1.00	40	20	1.5	2.1	53.0	0.9	12.8	39.0	326	2751.1
CS/B+$15-C	3	1.00	98	51	1.5	4.0	40.7	3.9	9.0	39.0	2033	1931.0
CS/B+$15-C	4	1.00	113	49	1.5	4.4	39.3	4.3	8.9	39.0	2257	1918.6
CS/B+$15-C	5	1.00	136	44	1.5	5.1	37.8	4.7	8.9	39.0	2439	1922.7
CS/B+$5	1	1.00	38	20	1.5	1.6	43.9	0.9	13.1	39.0	306	2824.2
CS/B+$5	2	1.00	40	20	1.5	1.7	42.7	0.9	12.8	39.0	326	2752.9
CS/B+$5	3	1.00	98	51	1.5	3.0	30.3	3.0	6.9	39.0	2033	1492.7
CS/B+$5	4	1.00	113	49	1.5	3.3	28.9	3.3	6.8	39.0	2257	1467.1
CS/B+$5	5	1.00	136	44	1.5	3.7	27.4	3.6	6.8	39.0	2439	1463.1
CS/B+$5-C	1	1.00	38	20	1.5	1.6	43.9	0.5	7.6	39.0	306	1642.1
CS/B+$5-C	2	1.00	40	20	1.5	1.7	42.7	0.5	7.4	39.0	326	1600.8
CS/B+$5-C	3	1.00	98	51	1.5	3.0	30.3	1.8	4.0	39.0	2033	861.7
CS/B+$5-C	4	1.00	113	49	1.5	3.3	28.9	1.9	3.9	39.0	2257	847.1
CS/B+$5-C	5	1.00	136	44	1.5	3.7	27.4	2.1	3.9	39.0	2439	845.2

TABLE 21.6.2-5. SUMMARY OF NOx RETROFIT RESULTS FOR NEW CASTLE UNITS

	BOILER NUMBER			
COMBUSTION MODIFICATION RESULTS				
	1, 2	3	4	5
FIRING TYPE	FWF	FWF	FWF	FWF
TYPE OF NOx CONTROL	LNB	LNB	LNB	LNB
VOLUMETRIC HEAT RELEASE RATE (1000 Btu/CU.FT-HR)	NA	20.2	18	21.2
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 Btu/SQ.FT-HR)	NA	44.8	63.6	77.5
FURNACE RESIDENCE TIME (SECONDS)	NA	NA	3.75	4.38
ESTIMATED NOx REDUCTION (PERCENT)	25	40	43	37
SCR RETROFIT RESULTS				
SITE ACCESS AND CONGESTION FOR SCR REACTOR	NA	NA	NA	NA
SCOPE ADDER PARAMETERS--				
Building Demolition (1000$)	NA	NA	NA	NA
Ductwork Demolition (1000$)	NA	NA	NA	NA
New Duct Length (Feet)	NA	NA	NA	NA
New Duct Costs (1000$)	NA	NA	NA	NA
New Heat Exchanger (1000$)	NA	NA	NA	NA
TOTAL SCOPE ADDER COSTS (1000$)	NA	NA	NA	NA
RETROFIT FACTOR FOR SCR	NA	NA	NA	NA
GENERAL FACILITIES (PERCENT)	NA	NA	NA	NA

TABLE 21.6.2-6. SUMMARY OF NOx RETROFIT RESULTS FOR NEW CASTLE UNITS 1-5

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1-5
FIRING TYPE	NA
TYPE OF NOx CONTROL	NA
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)	NA
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	80
New Duct Length (Feet)	250
New Duct Costs (1000$)	2892
New Heat Exchanger (1000$)	4447
TOTAL SCOPE ADDER COSTS (1000$)	7419
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	13

use of the simplified NO_x procedures. Table 21.6.2-7 presents the cost of retrofitting LNB at the New Castle boilers.

Selective Catalytic Reduction--

Tables 21.6.2-5 and 21.6.2-6 present the SCR retrofit results for reducing NO_x emissions from the total flue gas from units 1 to 5. Because the total flue gas from units 1 to 5 is ducted into one chimney, one SCR reactor is sized for the total flow rate instead of sizing an SCR reactor for each boiler flue gas. The results in Tables 21.6.2-5 and 21.6.2-6 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 common duct to the reactor and from the reactor to the chimney.

The SCR reactor for units 1 to 5 would be located east of the chimney and south of the coal pile in a relatively open area. Since the reactor was located in an open area having easy access with no major obstacles, the reactor for units 1 to 5 was assigned a low access/congestion factor. 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 reduced at this plant, the SCR reactor would have to be located downstream of the FGD absorbers (north of the absorbers) in an area having no major obstructions with easy access. In this case, a low access/congestion factor again would be assigned to this SCR reactor.
Table 21.6.2-7 presents the estimated cost of retrofitting SCR at the New Castle 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.

Table 21.6.2-7. NOx Control Cost Results for the New Castle 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	38	20	1.5	1.7	45.6	0.4	5.7	25.0	71	5305.7
LNC-LNB	2	1.00	40	20	1.5	1.8	44.3	0.4	5.5	25.0	75	5144.8
LNC-LNB	3	1.00	98	51	1.5	2.5	25.9	0.5	1.3	40.0	745	737.6
LNC-LNB	4	1.00	113	49	1.5	2.7	23.7	0.6	1.2	43.0	889	654.9
LNC-LNB	5	1.00	136	44	1.5	2.9	21.2	0.6	1.2	37.0	827	758.2
LNC-LNB-C	1	1.00	38	20	1.5	1.7	45.6	0.2	3.4	25.0	71	3149.0
LNC-LNB-C	2	1.00	40	20	1.5	1.8	44.3	0.2	3.3	25.0	75	3054.5
LNC-LNB-C	3	1.00	98	51	1.5	2.5	25.9	0.3	0.7	40.0	745	437.8
LNC-LNB-C	4	1.00	113	49	1.5	2.7	23.7	0.3	0.7	43.0	889	388.8
LNC-LNB-C	5	1.00	136	44	1.5	2.9	21.2	0.4	0.7	37.0	827	450.1
SCR-3	1-5	1.16	424	43	1.5	53.5	126.0	19.3	12.1	80.0	5450	3533.9
SCR-3-C	1-5	1.16	424	43	1.5	53.5	126.0	11.3	7.1	80.0	5450	2068.7
SCR-7	1-5	1.16	424	43	1.5	53.5	126.0	15.8	9.9	80.0	5450	2895.7
SCR-7-C	1-5	1.16	424	43	1.5	53.5	126.0	9.3	5.8	80.0	5450	1703.0

The sorbent receiving/storage/preparation areas were located in a similar fashion as LSD-FGD. The retrofit of DSD and FSI technologies at the New Castle steam plant for all the units would be easy. There is sufficient duct residence time between the boilers and the retrofit ESPs. Because the ESPs were reported to have good removal efficiencies, it was assumed that only an ESP upgrade would be required to handle the increased load from DSD and FSI. A low site access/congestion factor was assigned for upgrading the ESPs for the same reasons as mentioned in the previous section.
Tables 21.6.2-8 through 21.6.2-12 present a summary of the site access/ congestion factors for DSD and FSI technologies at the New Castle steam plant. Table 21.6.2-13 presents the costs estimated to retrofit DSD and FSI at the New Castle 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 New Castle plant. All the boilers would be considered good candidates for AFBC retrofit because of their small size (<140 MW) and their ages (built before 1960).

TABLE 21.6.2-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR NEW CASTLE UNIT 1

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$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	14
TOTAL COST (1000$)	
ESP UPGRADE CASE	14
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.13
NEW BAGHOUSE	NA

TABLE 21.6.2-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR NEW CASTLE 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$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	15
TOTAL COST (1000$)	
ESP UPGRADE CASE	15
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.13
NEW BAGHOUSE	NA

TABLE 21.6.2-10. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR NEW CASTLE UNIT 3

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$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	29

TOTAL COST (1000$)	
ESP UPGRADE CASE	29
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.13
NEW BAGHOUSE	NA

TABLE 21.6.2-11. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR NEW CASTLE UNIT 4

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$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	33

TOTAL COST (1000$)	
ESP UPGRADE CASE	33
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.13
NEW BAGHOUSE	NA

TABLE 21.6.2-12. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR NEW CASTLE UNIT 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$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	38

TOTAL COST (1000$)	
ESP UPGRADE CASE	38
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.13
NEW BAGHOUSE	NA

Table 21.6.2-13. Summary of DSD/FSI Control Costs for the New Castle 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	38	20	1.5	3.5	94.3	3.6	54.2	49.0	380	9377.3
DSD+ESP	2	1.00	40	20	1.5	3.6	91.1	3.6	51.4	49.0	405	8890.8
DSD+ESP	3	1.00	98	51	1.5	5.7	58.1	5.1	11.6	49.0	2524	2014.3
DSD+ESP	4	1.00	113	49	1.5	6.2	54.9	5.3	10.9	47.0	2726	1945.2
DSD+ESP	5	1.00	136	44	1.4	6.8	50.3	5.6	10.6	49.0	2885	1934.1
DSD+ESP-C	1	1.00	38	20	1.5	3.5	94.3	2.1	31.3	49.0	380	5414.5
DSD+ESP-C	2	1.00	40	20	1.5	3.6	91.1	2.1	29.7	49.0	405	5134.4
DSD+ESP-C	3	1.00	98	51	1.5	5.7	58.1	2.9	6.7	49.0	2524	1164.2
DSD+ESP-C	4	1.00	113	49	1.5	6.2	54.9	3.1	6.3	47.0	2726	1124.7
DSD+ESP-C	5	1.00	136	44	1.4	6.8	50.3	3.2	6.2	49.0	2885	1118.7
FSI+ESP-50	1	1.00	38	20	1.5	4.1	108.5	2.5	38.0	50.0	390	6408.9
FSI+ESP-50	2	1.00	40	20	1.5	4.2	103.9	2.5	36.2	50.0	416	6099.4
FSI+ESP-50	3	1.00	98	51	1.5	6.1	62.4	4.4	10.1	50.0	2594	1694.7
FSI+ESP-50	4	1.00	113	49	1.5	6.4	56.4	4.6	9.6	50.0	2880	1609.2
FSI+ESP-50	5	1.00	136	44	1.5	7.4	54.5	5.0	9.6	50.0	3112	1621.7
FSI+ESP-50-C	1	1.00	38	20	1.5	4.1	108.5	1.5	22.1	50.0	390	3718.7
FSI+ESP-50-C	2	1.00	40	20	1.5	4.2	103.9	1.5	21.0	50.0	416	3539.4
FSI+ESP-50-C	3	1.00	98	51	1.5	6.1	62.4	2.5	5.8	50.0	2594	981.5
FSI+ESP-50-C	4	1.00	113	49	1.5	6.4	56.4	2.7	5.5	50.0	2880	931.9
FSI+ESP-50-C	5	1.00	136	44	1.5	7.4	54.5	2.9	5.6	50.0	3112	939.8
FSI+ESP-70	1	1.00	38	20	1.5	4.1	110.0	2.5	38.4	70.0	546	4614.2
FSI+ESP-70	2	1.00	40	20	1.5	4.2	105.3	2.6	36.5	70.0	583	4392.1
FSI+ESP-70	3	1.00	98	51	1.5	6.2	63.0	4.5	10.2	70.0	3632	1225.4
FSI+ESP-70	4	1.00	113	49	1.5	6.5	57.1	4.7	9.7	70.0	4032	1164.7
FSI+ESP-70	5	1.00	136	44	1.5	7.5	55.2	5.1	9.8	70.0	4357	1174.4
FSI+ESP-70-C	1	1.00	38	20	1.5	4.1	110.0	1.5	22.3	70.0	546	2677.5
FSI+ESP-70-C	2	1.00	40	20	1.5	4.2	105.3	1.5	21.2	70.0	583	2548.8
FSI+ESP-70-C	3	1.00	98	51	1.5	6.2	63.0	2.6	5.9	70.0	3632	709.7
FSI+ESP-70-C	4	1.00	113	49	1.5	6.5	57.1	2.7	5.6	70.0	4032	674.5
FSI+ESP-70-C	5	1.00	136	44	1.5	7.5	55.2	3.0	5.7	70.0	4357	680.6

21.7 PHILADELPHIA ELECTRIC COMPANY

21.7.1 Eddystone Steam Plant

The Eddystone steam plant is located within Delaware County, Pennsylvania, as part of the Philadelphia Electric Company system. The plant contains four coal-fired boilers with a total gross generating capacity of 1,490 MW. Units 1 and 2 are coal-burning while units 3 and 4 are petroleum burning. Figure 21.7.1-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 21.7.1-1 presents operational data for the existing equipment at the Eddystone plant. The units 1 and 2 boilers burn medium sulfur coal (1.7 percent sulfur). Coal shipments are received by railroad and conveyed to a coal storage and handling area located south of units 1-2, adjacent to the Delaware River.

Particulate matter emissions for the boilers are controlled with ESPs located behind each unit. The plant has a dry fly ash handling system and is disposed off-site to a landfill.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 21.7.1-1 shows the general layout and location of the FGD control system. The coal-burning boilers (units 1-2) are located north of the coal pile and each have their own chimney. Units 3-4 are at a separate location west of units 1-2, close to two large oil tanks, and share a common chimney located south of the boiler buildings. Units 3-4 will not be considered in this study since they are petroleum-burning. Units 1-2 have a retrofit FGD system (built by United Engineers using magnesium oxide as sorbent) and would not be considered in this study.

Coal Switching and Physical Coal Cleaning Costs--

Coal switching/physical coal cleaning was not an option since a wet FGD system is already installed for units 1-2.

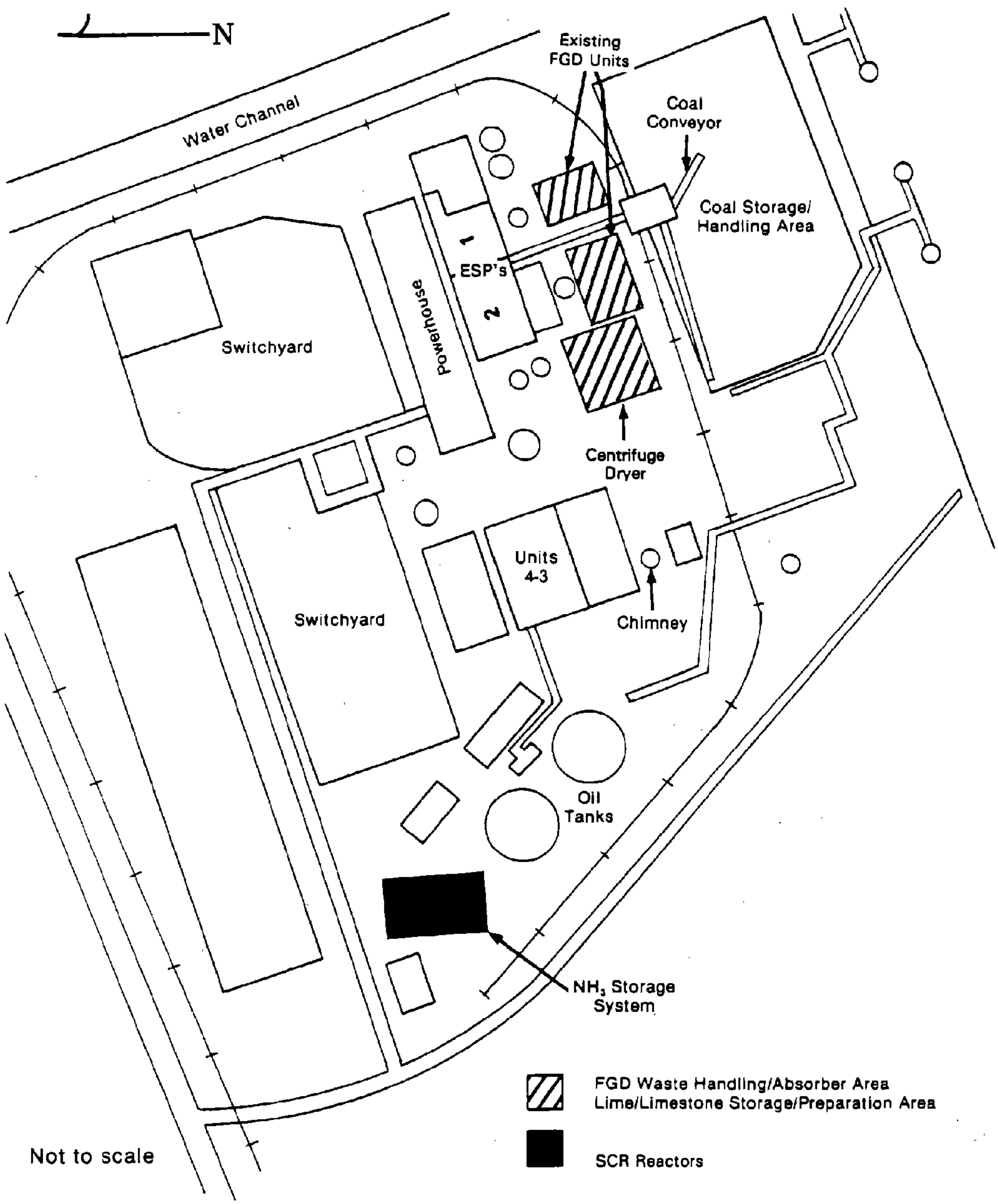

Figure 21.7.1-1. Eddystone plant plot plan

TABLE 21.7.1-1. EDDYSTONE STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2	3,4
FUEL TYPE	COAL	COAL	PET
GENERATING CAPACITY (MW-each)	354	354	391
CAPACITY FACTOR (PERCENT)	43	34	--
INSTALLATION DATE	1960	1960	1976
FIRING TYPE	TANG	TANG	TANG
COAL/PET SULFUR CONTENT (PERCENT)	1.5	1.4	0.5
COAL/PET HEATING VALUE (BTU/LB)	12700	13000	14900
COAL ASH CONTENT (PERCENT)	7.7	8.2	-
FLY ASH SYSTEM	DRY HANDLING		
ASH DISPOSAL METHOD	PAID/SOLD DISPOSAL/OFF-SITE		
STACK NUMBER	1	2	3
COAL DELIVERY METHODS	RAIL ROAD		
FGD SYSTEM	YES	YES	NO
INSTALLATION DATE	1982	1982	--
FGD TYPE	Mg OXIDE WET SCRUBBER		-
PARTICULATE CONTROL			
TYPE	ESP	ESP	ESP
INSTALLATION DATE	1981	1982	1974-76
EMISSION (LB/MM BTU)	0.04	0.04	0.01
REMOVAL EFFICIENCY	99.2	99.3	NA
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	2.6	2.6	0.5
SURFACE AREA (1000 SQ FT)	122.9	122.9	961
GAS EXIT RATE (1000 ACFM)	1050	1095	860
SCA (SQ FT/1000 ACFM)	117	112	112
OUTLET TEMPERATURE (°F)	122	125	650

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Eddystone 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, each rated at 354 MW. The combustion modification technique applied for this evaluation was OFA. As Table 21.7.1-2 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 and furnace residence time on NO_x reduction through the use of the simplified NO_x procedures. Table 21.7.1-3 presents the cost of retrofitting OFA at the Eddystone boilers.

Selective Catalytic Reduction--

Table 21.7.1-2 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 to the reactor and from the reactor to the chimney.

Space is limited for SCR reactors at Eddystone Plant. Therefore, both reactors have to be placed on the top of the existing FGD units by including additional support equipment. A high site access/congestion factor was assigned to the SCR reactor location. 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 this plant, FGD absorbers for both coal-fired units are already in place and currently are operating. Therefore, the above results for SCR would not change since NO_x would be the only pollutant to be controlled at this plant. Table 21.7.1-3 presents the estimated cost of retrofitting SCR at the Eddystone boilers.

TABLE 21.7.1-2. SUMMARY OF NOx RETROFIT RESULTS FOR EDDYSTONE

	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)	12.3	12.8
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	35.3	41.6
FURNACE RESIDENCE TIME (SECONDS)	2.89	2.78
ESTIMATED NOx REDUCTION (PERCENT)	25	25
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	70	70
New Duct Length (Feet)	400	400
New Duct Costs (1000$)	3,114	3,114
New Heat Exchanger (1000$)	3,979	3,979
TOTAL SCOPE ADDER COSTS (1000$)	7,163	7,163
RETROFIT FACTOR FOR SCR	1.52	1.52
GENERAL FACILITIES (PERCENT)	13	13

Table 21.7.1-3. NOx Control Cost Results for the Eddystone 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	354	43	1.5	1.0	2.9	0.2	0.2	25.0	969	229.9
LNC-OFA	2	1.00	354	34	1.4	1.0	2.9	0.2	0.2	25.0	746	298.6
LNC-OFA-C	1	1.00	354	43	1.5	1.0	2.9	0.1	0.1	25.0	969	136.4
LNC-OFA-C	2	1.00	354	34	1.4	1.0	2.9	0.1	0.1	25.0	746	177.2
SCR-3	1	1.52	354	43	1.5	54.8	154.9	18.4	13.8	80.0	3102	5931.6
SCR-3	2	1.52	354	34	1.4	54.8	154.8	18.2	17.3	80.0	2388	7628.7
SCR-3-C	1	1.52	354	43	1.5	54.8	154.9	10.8	8.1	80.0	3102	3477.7
SCR-3-C	2	1.52	354	34	1.4	54.8	154.8	10.7	10.1	80.0	2388	4473.6
SCR-7	1	1.52	354	43	1.5	54.8	154.9	15.5	11.6	80.0	3102	5001.6
SCR-7	2	1.52	354	34	1.4	54.8	154.8	15.3	14.5	80.0	2388	6424.6
SCR-7-C	1	1.52	354	43	1.5	54.8	154.9	9.1	6.8	80.0	3102	2944.8
SCR-7-C	2	1.52	354	34	1.4	54.8	154.8	9.0	8.6	80.0	2388	3783.8

Sorbent Injection and Repowering--

Duct spray drying, furnace sorbent injection, and AFBC retrofit were not options in this study since a wet FGD system is already installed for these units.

SECTION 22.0 SOUTH CAROLINA

22.1 SOUTH CAROLINA ELECTRIC & GAS

22.1.1 Canadys

Sorbent injection technologies (FSI and DSD) were not considered for the Canadys plant because of the small size of the existing ESPs and the short duct residence time between the boilers and ESPs.

TABLE 22.1.1-1. CANADYS STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3
GENERATING CAPACITY (MW-each)	136	220
CAPACITY FACTOR (PERCENT)	55,46	45
INSTALLATION DATE	1962,1964	1967
FIRING TYPE	TANGENTIAL	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	52.5	89
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	1.5	
COAL HEATING VALUE (BTU/LB)	13000	
COAL ASH CONTENT (PERCENT)	9.4	
FLY ASH SYSTEM	WET DISPOSAL	
ASH DISPOSAL METHOD	POND/ON-SITE	
STACK NUMBER	1,2	3
COAL DELIVERY METHODS	RAILROAD	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1972	1970
EMISSION (LB/MM BTU)	0.25	0.25
REMOVAL EFFICIENCY	95	95
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	1.5	1.5
SURFACE AREA (1000 SQ FT)	70.6	110
GAS EXIT RATE (1000 ACFM)	519	789
SCA (SQ FT/1000 ACFM)	182	186
OUTLET TEMPERATURE (°F)	255	285

TABLE 22.1.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR CANADYS 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			100-300
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	1235	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	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 unit 1 would be located north of unit 1; and absorbers and new FFs for unit 2 would be located north of the unit 2 chimney.

TABLE 22.1.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR CANADYS UNIT 3 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
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	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	1901	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.42	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.31
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	8	0	8

* Absorbers and new FFs for unit 3 would be located south of unit 3, beside the coal conveyor.

Table 22.1.1-4. Summary of FGD Control Costs for the Canadys 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	136	55	1.5	42.9	315.2	17.7	27.0	90.0	6510	2721.7
L/S FGD	2	1.27	136	46	1.5	42.9	315.1	17.1	31.2	90.0	5445	3137.0
L/S FGD	3	1.42	220	45	1.5	61.3	278.5	24.0	27.7	90.0	8616	2787.7
L/S FGD	1-2	1.27	272	51	1.5	63.6	233.8	26.4	21.7	90.0	12074	2188.3
L/S FGD-C	1	1.27	136	55	1.5	42.9	315.2	10.3	15.8	90.0	6510	1588.9
L/S FGD-C	2	1.27	136	46	1.5	42.9	315.1	10.0	18.2	90.0	5445	1832.6
L/S FGD-C	3	1.42	220	45	1.5	61.3	278.5	14.0	16.2	90.0	8616	1629.1
L/S FGD-C	1-2	1.27	272	51	1.5	63.6	233.8	15.4	12.7	90.0	12074	1277.4
LC FGD	1-2	1.27	272	51	1.5	42.3	155.4	20.1	16.5	90.0	12074	1664.3
LC FGD	3	1.42	220	45	1.5	41.9	190.6	18.3	21.0	90.0	8616	2118.1
LC FGD-C	1-2	1.27	272	51	1.5	42.3	155.4	11.7	9.6	90.0	12074	969.2
LC FGD-C	3	1.42	220	45	1.5	41.9	190.6	10.6	12.3	90.0	8616	1235.4
LSD+FF	1	1.16	136	55	1.5	28.4	208.7	11.0	16.8	86.0	6210	1777.0
LSD+FF	2	1.16	136	46	1.5	28.4	208.6	10.7	19.6	86.0	5194	2063.3
LSD+FF	3	1.31	220	45	1.5	46.6	211.9	16.3	18.8	87.0	8281	1971.4
LSD+FF-C	1	1.16	136	55	1.5	28.4	208.7	6.4	9.8	86.0	6210	1038.6
LSD+FF-C	2	1.16	136	46	1.5	28.4	208.6	6.3	11.4	86.0	5194	1206.7
LSD+FF-C	3	1.31	220	45	1.5	46.6	211.9	9.6	11.0	87.0	8281	1154.7

Table 22.1.1-5. Summary of Coal Switching/Cleaning Costs for the Canadys 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	136	55	1.5	5.7	41.6	10.1	15.4	35.0	2502	4024.6
CS/B+$15	2	1.00	136	46	1.5	5.7	41.6	8.6	15.7	35.0	2093	4123.1
CS/B+$15	3	1.00	220	45	1.5	8.4	38.0	13.3	15.4	35.0	3312	4022.7
CS/B+$15-C	1	1.00	136	55	1.5	5.7	41.6	5.8	8.8	35.0	2502	2316.0
CS/B+$15-C	2	1.00	136	46	1.5	5.7	41.6	5.0	9.1	35.0	2093	2374.4
CS/B+$15-C	3	1.00	220	45	1.5	8.4	38.0	7.7	8.8	35.0	3312	2316.0
CS/B+$5	1	1.00	136	55	1.5	4.2	31.2	4.4	6.7	35.0	2502	1762.9
CS/B+$5	2	1.00	136	46	1.5	4.2	31.2	3.9	7.0	35.0	2093	1842.1
CS/B+$5	3	1.00	220	45	1.5	6.1	27.6	5.8	6.6	35.0	3312	1739.0
CS/B+$5-C	1	1.00	136	55	1.5	4.2	31.2	2.5	3.9	35.0	2502	1017.6
CS/B+$5-C	2	1.00	136	46	1.5	4.2	31.2	2.2	4.1	35.0	2093	1064.5
CS/B+$5-C	3	1.00	220	45	1.5	6.1	27.6	3.3	3.8	35.0	3312	1004.5

TABLE 22.1.1-6. SUMMARY OF NOx RETROFIT RESULTS FOR CANADYS

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1,2	3	1-2
FIRING TYPE	TANG	OWF	NA
TYPE OF NOx CONTROL	OFA	LNB	NA
FURNACE VOLUME (1000 CU FT)	52.5	89	NA
BOILER INSTALLATION DATE	1962,64	1967	NA
SLAGGING PROBLEM	NO	NO	NA
ESTIMATED NOx REDUCTION (PERCENT)	25	28	NA
SCR RETROFIT RESULTS *			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	34	49	57
New Duct Length (Feet)	200	400	200
New Duct Costs (1000$)	1186	3144	1779
New Heat Exchanger (1000$)	2241	2991	3397
TOTAL SCOPE ADDER COSTS (1000$)	3462	6184	5234
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	20	20	20

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

Table 22.1.1-7. NOx Control Cost Results for the Canadys 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	220	45	1.5	3.5	15.9	0.7	0.8	28.0	962	763.0
LNC-LNB-C	3	1.00	220	45	1.5	3.5	15.9	0.4	0.5	28.0	962	453.5
LNC-OFA	1	1.00	136	55	1.5	0.7	5.1	0.1	0.2	25.0	464	316.8
LNC-OFA	2	1.00	136	46	1.5	0.7	5.1	0.1	0.3	25.0	388	378.8
LNC-OFA-C	1	1.00	136	55	1.5	0.7	5.1	0.1	0.1	25.0	464	188.3
LNC-OFA-C	2	1.00	136	46	1.5	0.7	5.1	0.1	0.2	25.0	388	225.1
SCR-3	1	1.16	136	55	1.5	22.8	167.9	7.4	11.3	80.0	1484	5000.5
SCR-3	2	1.16	136	46	1.5	22.8	167.9	7.4	13.4	80.0	1241	5929.0
SCR-3	3	1.16	220	45	1.5	34.4	156.5	11.2	12.9	80.0	2749	4084.4
SCR-3	1-2	1.16	272	51	1.5	38.5	141.6	13.0	10.7	80.0	2752	4727.0
SCR-3-C	1	1.16	136	55	1.5	22.8	167.9	4.4	6.6	80.0	1484	2934.0
SCR-3-C	2	1.16	136	46	1.5	22.8	167.9	4.3	7.9	80.0	1241	3479.4
SCR-3-C	3	1.16	220	45	1.5	34.4	156.5	6.6	7.6	80.0	2749	2396.2
SCR-3-C	1-2	1.16	272	51	1.5	38.5	141.6	7.6	6.3	80.0	2752	2771.1
SCR-7	1	1.16	136	55	1.5	22.8	167.9	6.3	9.6	80.0	1484	4256.3
SCR-7	2	1.16	136	46	1.5	22.8	167.9	6.3	11.4	80.0	1241	5039.1
SCR-7	3	1.16	220	45	1.5	34.4	156.5	9.4	10.9	80.0	2749	3434.6
SCR-7	1-2	1.16	272	51	1.5	38.5	141.6	10.8	8.9	80.0	2752	3924.3
SCR-7-C	1	1.16	136	55	1.5	22.8	167.9	3.7	5.7	80.0	1484	2507.6
SCR-7-C	2	1.16	136	46	1.5	22.8	167.9	3.7	6.7	80.0	1241	2969.5
SCR-7-C	3	1.16	220	45	1.5	34.4	156.5	5.6	6.4	80.0	2749	2024.0
SCR-7-C	1-2	1.16	272	51	1.5	38.5	141.6	6.4	5.2	80.0	2752	2311.2

22.1.2 Silas C. McMeekin Steam Plant

The McMeekin steam plant is located on Lake Murray in Lexington County, South Carolina, and is operated by the South Carolina Electric and Gas Company. The McMeekin plant contains two coal-fired boilers with a gross generating capacity of 294 MW.

Table 22.1.2-1 presents operational data for the existing equipment at the McMeekin plant. Coal shipments are received by railroad and transferred to a coal storage and handling area north of the plant. PM emissions from the boilers are controlled by retrofit ESPs located behind each boiler. Wet fly ash is ponded, then removed and landfilled.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for both boilers would be located beside their respective chimney. The site access/congestion factor is medium for both locations. No relocations or demolitions would be required for either location; hence, a low general facilities factor of 5 percent was assigned. For each unit, a short duct length of about 200 feet would be needed to span the distance from the chimney to the absorbers and back to the chimney. A low site access/congestion factor was assigned to flue gas handling for both boilers since there are no complications in accessing the duct.

LSD with reuse of the existing ESPs was not considered for the McMeekin plant since the ESPs are relatively small and would probably have trouble handling the additional load of LSD. Since the boilers at the McMeekin plant are burning a low to medium sulfur coal, LSD with a new baghouse was considered for both boilers. The LSD absorbers would have the same location as the L/LS-FGD absorbers; therefore, similar site access/congestion factors and general facility factors were assigned to these locations. The new FFs would be located adjacent to the LSD absorbers. A duct length of 100 to 300 feet would be required and the site access/congestion factor for flue gas handling would be low. Tables 22.1.2-2 and 22.1.2-3 present the retrofit factor input to the IAPCS model and cost estimates for installation of conventional FGD systems at the McMeekin plant.

TABLE 22.1.2-1. SILAS C. MCMEEKIN STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2
GENERATING CAPACITY (MW-each)	147
CAPACITY FACTOR (PERCENT)	80
INSTALLATION DATE	1958
FIRING TYPE	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	52.5
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	1.4
COAL HEATING VALUE (BTU/LB)	13000
COAL ASH CONTENT (PERCENT)	9.0
FLY ASH SYSTEM	WET DISPOSAL
ASH DISPOSAL METHOD	STORAGE/OFF-SITE
STACK NUMBER	1,2
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1970
EMISSION (LB/MM BTU)	NA
REMOVAL EFFICIENCY	94.0
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	1.5
SURFACE AREA (1000 SQ FT)	70.6
GAS EXIT RATE (1000 ACFM)	387
SCA (SQ FT/1000 ACFM)	182
OUTLET TEMPERATURE (°F)	255

TABLE 22.1.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR MCMEEKIN UNIT 1 OR 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			
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			
BAGHOUSE			100-300
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	MEDIUM
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	1324	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.37	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.29
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.36
GENERAL FACILITIES (PERCENT)	5	0	5

Table 22.1.2-3. Summary of FGD Control Costs for the McMeekin 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	1.37	147	80	1.4	46.8	318.1	20.9	20.3	90.0	9553	2190.1
L/S FGD	2	1.37	147	80	1.4	46.8	318.1	20.9	20.3	90.0	9553	2190.1
L/S FGD-C	1	1.37	147	80	1.4	46.8	318.1	12.2	11.8	90.0	9553	1276.7
L/S FGD-C	2	1.37	147	80	1.4	46.8	318.1	12.2	11.8	90.0	9553	1276.7
LC FGD	1-2	1.37	294	80	1.4	46.2	157.1	25.5	12.4	90.0	19106	1335.8
LC FGD-C	1-2	1.37	294	80	1.4	46.2	157.1	14.8	7.2	90.0	19106	776.2
LSD+FF	1	1.29	147	80	1.4	33.5	228.1	13.3	13.0	87.0	9181	1453.5
LSD+FF	2	1.29	147	80	1.4	33.5	228.1	13.3	13.0	87.0	9181	1453.5
LSD+FF-C	1	1.29	147	80	1.4	33.5	228.1	7.8	7.6	87.0	9181	849.2
LSD+FF-C	2	1.29	147	80	1.4	33.5	228.1	7.8	7.6	87.0	9181	849.2

Coal Switching and Physical Coal Cleaning Costs--

Table 22.1.2-4 presents the IAPCS cost results for CS at the McMeekin plant. These costs do not include reduced pulverizer operating costs or any system modifications that may be necessary for blending coals. PCC was not evaluated because the McMeekin plant is not a mine mouth plant.

NO_x Control Technologies--

OFA was considered for NO_x emissions control for the two tangential-fired boilers at the McMeekin plant. Tables 22.1.2-5 and 22.1.2-6 present the NO_x performance and cost estimates for installation of OFA at the McMeekin plant.

Selective Catalytic Reduction--

Cold side SCR reactors for each boiler would be located behind their respective chimney. As in the FGD case, low site access/congestion factors and low general facility values (13 percent) were assigned to each location. Approximately 200 feet of ductwork would be required to span the distance between the SCR reactors and the chimneys. Tables 22.1.2-5 and 22.1.2-6 present the retrofit factors and costs for installation of SCR at the McMeekin plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) were not considered for the McMeekin plant because the existing ESPs are too small to handle the additional load imposed by these technologies and the duct residence time between the boilers and ESPs is too short.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

Both boilers at the McMeekin plant would be candidates for repowering technologies because of their small boiler size and short remaining useful life. However, both boilers have relatively high capacity factors which might result in high replacement power costs in the case of extensive boiler downtime.

Table 22.1.2-4. Summary of Coal Switching/Cleaning Costs for the McMeekin 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	147	80	1.4	6.0	41.1	15.2	14.7	30.0	3176	4780.6
CS/B+$15	2	1.00	147	80	1.4	6.0	41.1	15.2	14.7	30.0	3176	4780.6
CS/B+$15-C	1	1.00	147	80	1.4	6.0	41.1	8.7	8.5	30.0	3176	2747.5
CS/B+$15-C	2	1.00	147	80	1.4	6.0	41.1	8.7	8.5	30.0	3176	2747.5
CS/B+$5	1	1.00	147	80	1.4	4.5	30.8	6.4	6.2	30.0	3176	2017.1
CS/B+$5	2	1.00	147	80	1.4	4.5	30.8	6.4	6.2	30.0	3176	2017.1
CS/B+$5-C	1	1.00	147	80	1.4	4.5	30.8	3.7	3.6	30.0	3176	1162.1
CS/B+$5-C	2	1.00	147	80	1.4	4.5	30.8	3.7	3.6	30.0	3176	1162.1

TABLE 22.1.2-5. SUMMARY OF NOx RETROFIT RESULTS FOR MCMEEKIN

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1,2
FIRING TYPE	TANG
TYPE OF NOx CONTROL	OFA
FURNACE VOLUME (1000 CU FT)	52.5
BOILER INSTALLATION DATE	1958
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$)	0
Ductwork Demolition (1000$)	36
New Duct Length (Feet)	200
New Duct Costs (1000$)	1242
New Heat Exchanger (1000$)	2349
TOTAL SCOPE ADDER COSTS (1000$)	3626
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	13

Table 22.1.2-6. NOx Control Cost Results for the McMeekin 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	147	80	1.4	0.7	4.9	0.2	0.1	25.0	729	207.8
LNC-OFA	2	1.00	147	80	1.4	0.7	4.9	0.2	0.1	25.0	729	207.8
LNC-OFA-C	1	1.00	147	80	1.4	0.7	4.9	0.1	0.1	25.0	729	123.5
LNC-OFA-C	2	1.00	147	80	1.4	0.7	4.9	0.1	0.1	25.0	729	123.5
SCR-3	1	1.16	147	80	1.4	23.6	160.6	8.0	7.7	80.0	2333	3411.4
SCR-3	2	1.16	147	80	1.4	23.6	160.6	8.0	7.7	80.0	2333	3411.4
SCR-3-C	1	1.16	147	80	1.4	23.6	160.6	4.7	4.5	80.0	2333	1999.8
SCR-3-C	2	1.16	147	80	1.4	23.6	160.6	4.7	4.5	80.0	2333	1999.8
SCR-7	1	1.16	147	80	1.4	23.6	160.6	6.8	6.6	80.0	2333	2899.6
SCR-7	2	1.16	147	80	1.4	23.6	160.6	6.8	6.6	80.0	2333	2899.6
SCR-7-C	1	1.16	147	80	1.4	23.6	160.6	4.0	3.9	80.0	2333	1706.6
SCR-7-C	2	1.16	147	80	1.4	23.6	160.6	4.0	3.9	80.0	2333	1706.6

22.1.3 Urquhart Steam Plant

Sorbent injection technologies (FSI and DSD) were not considered for the Urquhart plant because of the inadequate size of the ESPs and the short duct residence time between the boilers and the ESPs.

TABLE 22.1.3-1. URQUHART STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2, 3
GENERATING CAPACITY (MW-each)	75,75,100
CAPACITY FACTOR (PERCENT)	50,46,70
INSTALLATION DATE	1953,54,55
FIRING TYPE	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	44.6,44.6,60.9
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	1.2
COAL HEATING VALUE (BTU/LB)	12900
COAL ASH CONTENT (PERCENT)	9.2
FLY ASH SYSTEM	DRY DISPOSAL
ASH DISPOSAL METHOD	LANDFILL/ON-SITE
STACK NUMBER	1,2,3
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1968,68,69
EMISSION (LB/MM BTU)	0.33,0.38,0.29
REMOVAL EFFICIENCY	99.0
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	1.5
SURFACE AREA (1000 SQ FT)	45.0,45.0,60.0
GAS EXIT RATE (1000 ACFM)	315,344,494
SCA (SQ FT/1000 ACFM)	199,199,191
OUTLET TEMPERATURE (°F)	305,294,292

TABLE 22.1.3-2. SUMMARY OF RETROFIT FACTOR DATA FOR URQUHART UNIT 1, 2 OR 3 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
S02 REMOVAL	LOW	NA	LOW
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	LOW
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	1.35	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.31
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	5	0	5

* Absorbers and new FFs for each unit would be located behind their respective chimney.

Table 22.1.3-3. Summary of FGD Control Costs for the Urquhart 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	1.35	75	50	1.2	33.0	439.6	13.0	39.6	90.0	2634	4935.1
L/S FGD	2	1.35	75	46	1.2	32.9	439.1	12.8	42.4	90.0	2424	5292.8
L/S FGD	3	1.35	100	70	1.2	36.6	366.5	15.6	25.5	90.0	4917	3176.9
L/S FGD-C	1	1.35	75	50	1.2	33.0	439.6	7.6	23.1	90.0	2634	2883.6
L/S FGD-C	2	1.35	75	46	1.2	32.9	439.1	7.5	24.8	90.0	2424	3093.4
L/S FGD-C	3	1.35	100	70	1.2	36.6	366.5	9.1	14.9	90.0	4917	1853.6
LC FGD	1-3	1.35	250	57	1.2	41.8	167.1	19.8	15.9	90.0	10010	1982.3
LC FGD-C	1-3	1.35	250	57	1.2	41.8	167.1	11.6	9.3	90.0	10010	1154.4
LSD+FF	1	1.31	75	50	1.2	20.1	268.4	8.0	24.2	87.0	2532	3144.9
LSD+FF	2	1.31	75	46	1.2	20.0	266.4	7.8	26.0	87.0	2329	3370.0
LSD+FF	3	1.31	100	70	1.2	24.4	243.8	9.8	16.0	87.0	4726	2071.9
LSD+FF-C	1	1.31	75	50	1.2	20.1	268.4	4.7	14.2	87.0	2532	1837.4
LSD+FF-C	2	1.31	75	46	1.2	20.0	266.4	4.6	15.2	87.0	2329	1969.3
LSD+FF-C	3	1.31	100	70	1.2	24.4	243.8	5.7	9.3	87.0	4726	1210.2

Table 22.1.3-4. Summary of Coal Switching/Cleaning Costs for the Urquhart 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	75	50	1.2	3.5	46.6	5.3	16.3	19.0	555	9640.1
CS/B+$15	2	1.00	75	46	1.2	3.5	46.6	5.0	16.5	19.0	511	9765.5
CS/B+$15	3	1.00	100	70	1.2	4.4	43.9	9.3	15.2	19.0	1036	9023.0
CS/B+$15-C	1	1.00	75	50	1.2	3.5	46.6	3.1	9.4	19.0	555	5551.5
CS/B+$15-C	2	1.00	75	46	1.2	3.5	46.6	2.9	9.5	19.0	511	5625.8
CS/B+$15-C	3	1.00	100	70	1.2	4.4	43.9	5.4	8.8	19.0	1036	5188.6
CS/B+$5	1	1.00	75	50	1.2	2.7	36.3	2.5	7.6	19.0	555	4505.6
CS/B+$5	2	1.00	75	46	1.2	2.7	36.3	2.4	7.8	19.0	511	4609.5
CS/B+$5	3	1.00	100	70	1.2	3.4	33.6	4.1	6.7	19.0	1036	3958.5
CS/B+$5-C	1	1.00	75	50	1.2	2.7	36.3	1.4	4.4	19.0	555	2603.3
CS/B+$5-C	2	1.00	75	46	1.2	2.7	36.3	1.4	4.5	19.0	511	2664.9
CS/B+$5-C	3	1.00	100	70	1.2	3.4	33.6	2.4	3.9	19.0	1036	2282.5

TABLE 22.1.3-5. SUMMARY OF NOx RETROFIT RESULTS FOR URQUHART

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1,2		3
FIRING TYPE	TANG		TANG
TYPE OF NOx CONTROL	OFA		OFA
FURNACE VOLUME (1000 CU FT)	44.6		60.9
BOILER INSTALLATION DATE	1953,1954		1955
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$)	0		0
Ductwork Demolition (1000$)	22		27
New Duct Length (Feet)	300		300
New Duct Costs (1000$)	1257		1487
New Heat Exchanger (1000$)	1568		1864
TOTAL SCOPE ADDER COSTS (1000$)			
INDIVIDUAL CASE	2847		3378
COMBINED CASE (1-3)		5824	
RETROFIT FACTOR FOR SCR	1.16		1.16
GENERAL FACILITIES (PERCENT)	13		13

* Cold side SCR reactors for units 1,2 and 3 would be located behind the chimney for that unit.

Table 22.1.3-6. NOx Control Cost Results for the Urquhart 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	75	50	1.2	0.6	7.4	0.1	0.4	25.0	235	493.3
LNC-OFA	2	1.00	75	46	1.2	0.6	7.4	0.1	0.4	25.0	216	536.2
LNC-OFA	3	1.00	100	70	1.2	0.6	6.2	0.1	0.2	25.0	438	296.7
LNC-OFA-C	1	1.00	75	50	1.2	0.6	7.4	0.1	0.2	25.0	235	293.4
LNC-OFA-C	2	1.00	75	46	1.2	0.6	7.4	0.1	0.2	25.0	216	318.9
LNC-OFA-C	3	1.00	100	70	1.2	0.6	6.2	0.1	0.1	25.0	438	176.3
SCR-3	1	1.16	75	50	1.2	15.9	211.8	4.9	14.8	80.0	751	6496.5
SCR-3	2	1.16	75	46	1.2	15.9	211.6	4.9	16.1	80.0	691	7034.8
SCR-3	3	1.16	100	70	1.2	18.9	188.9	6.0	9.8	80.0	1401	4304.6
SCR-3	1-3	1.16	250	57	1.2	36.5	145.8	12.2	9.8	80.0	2852	4288.6
SCR-3-C	1	1.16	75	50	1.2	15.9	211.8	2.9	8.7	80.0	751	3817.0
SCR-3-C	2	1.16	75	46	1.2	15.9	211.6	2.9	9.4	80.0	691	4133.5
SCR-3-C	3	1.16	100	70	1.2	18.9	188.9	3.5	5.8	80.0	1401	2526.7
SCR-3-C	1-3	1.16	250	57	1.2	36.5	145.8	7.2	5.7	80.0	2852	2514.4
SCR-7	1	1.16	75	50	1.2	15.9	211.8	4.3	13.0	80.0	751	5684.1
SCR-7	2	1.16	75	46	1.2	15.9	211.6	4.2	14.1	80.0	691	6151.9
SCR-7	3	1.16	100	70	1.2	18.9	188.9	5.2	8.5	80.0	1401	3724.3
SCR-7	1-3	1.16	250	57	1.2	36.5	145.8	10.2	8.2	80.0	2852	3575.9
SCR-7-C	1	1.16	75	50	1.2	15.9	211.8	2.5	7.7	80.0	751	3351.5
SCR-7-C	2	1.16	75	46	1.2	15.9	211.6	2.5	8.3	80.0	691	3627.6
SCR-7-C	3	1.16	100	70	1.2	18.9	188.9	3.1	5.0	80.0	1401	2194.2
SCR-7-C	1-3	1.16	250	57	1.2	36.5	145.8	6.0	4.8	80.0	2852	2106.1

22.1.4 Wateree Steam Plant

Sorbent injection technologies were not considered for the Wateree plant because the boilers are equipped with small ESPs which might not be able to handle the increased load.

TABLE 22.1.4-1. WATEREE STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2
GENERATING CAPACITY (MW-each)	386	386
CAPACITY FACTOR (PERCENT)	65	65
INSTALLATION DATE	1970	1971
FIRING TYPE	OPPOSED WALL	
FURNACE VOLUME (1000 CU FT)	199	199
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	1.4	
COAL HEATING VALUE (BTU/LB)	12800	
COAL ASH CONTENT (PERCENT)	9.0	
FLY ASH SYSTEM	WET DISPOSAL/DRY	
ASH DISPOSAL METHOD	PONDS/ON-SITE/PAID	
STACK NUMBER	1	2
COAL DELIVERY METHODS	RAILROAD	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1970	1971
EMISSION (LB/MM BTU)	0.35	0.35
REMOVAL EFFICIENCY	97.1	96.9
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	1.5	1.5
SURFACE AREA (1000 SQ FT)	204.2	265.5
GAS EXIT RATE (1000 ACFM)	1232	1232
SCA (SQ FT/1000 ACFM)	166	143
OUTLET TEMPERATURE (°F)	280	270

TABLE 22.1.4-2. SUMMARY OF RETROFIT FACTOR DATA FOR WATEREE UNIT 1 OR 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			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$)	3147	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.48	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.40
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	5	0	5

* L/LS-FGD absorbers, LSD-FGD absorbers, and new FFs for units 1 and 2 would be located east of their respective chimney.

Table 22.1.4-3. Summary of FGD Control Costs for the Wateree 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	386	65	1.4	87.5	226.6	38.2	17.4	90.0	20747	1842.6
L/S FGD	2	1.48	386	65	1.4	87.4	226.5	38.3	17.4	90.0	20747	1844.5
L/S FGD-C	1	1.48	386	65	1.4	87.5	226.6	22.3	10.1	90.0	20747	1074.6
L/S FGD-C	2	1.48	386	65	1.4	87.4	226.5	22.3	10.2	90.0	20747	1075.7
LC FGD	1-2	1.48	772	65	1.4	110.6	143.3	55.1	12.5	90.0	41494	1328.8
LC FGD-C	1-2	1.48	772	65	1.4	110.6	143.3	32.1	7.3	90.0	41494	773.3
LSD+FF	1	1.40	386	65	1.4	70.5	182.6	26.2	11.9	87.0	19940	1313.7
LSD+FF	2	1.40	386	65	1.4	69.9	181.1	26.0	11.8	87.0	19940	1305.2
LSD+FF-C	1	1.40	386	65	1.4	70.5	182.6	15.3	7.0	87.0	19940	768.5
LSD+FF-C	2	1.40	386	65	1.4	69.9	181.1	15.2	6.9	87.0	19940	763.5

Table 22.1.4-4. Summary of Coal Switching/Cleaning Costs for the Wateree 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	386	65	1.4	14.3	37.0	32.0	14.6	31.0	7182	4454.3
CS/B+$15	2	1.00	386	65	1.4	15.0	38.8	32.2	14.6	31.0	7182	4481.7
CS/B+$15-C	1	1.00	386	65	1.4	14.3	37.0	18.4	8.4	31.0	7182	2560.9
CS/B+$15-C	2	1.00	386	65	1.4	15.0	38.8	18.5	8.4	31.0	7182	2577.1
CS/B+$5	1	1.00	386	65	1.4	10.3	26.6	13.1	6.0	31.0	7182	1829.0
CS/B+$5	2	1.00	386	65	1.4	11.0	28.4	13.3	6.1	31.0	7182	1856.4
CS/B+$5-C	1	1.00	386	65	1.4	10.3	26.6	7.6	3.4	31.0	7182	1054.3
CS/B+$5-C	2	1.00	386	65	1.4	11.0	28.4	7.7	3.5	31.0	7182	1070.5

TABLE 22.1.4-5. SUMMARY OF NOx RETROFIT RESULTS FOR WATEREE

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1, 2
FIRING TYPE	OWF
TYPE OF NOx CONTROL	LNB
FURNACE VOLUME (1000 CU FT)	199
BOILER INSTALLATION DATE	1970, 1971
SLAGGING PROBLEM	NO
ESTIMATED NOx REDUCTION (PERCENT)	35
SCR RETROFIT RESULTS*	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	74
New Duct Length (Feet)	300
New Duct Costs (1000$)	3276
New Heat Exchanger (1000$)	4191
TOTAL SCOPE ADDER COSTS (1000$)	7542
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	13

* Cold side SCR reactors for units 1 and 2 would be located east of their respective chimney.

Table 22.1.4-6. NOx Control Cost Results for the Wateree 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	386	65	1.4	4.4	11.4	0.9	0.4	35.0	3103	296.2
LNC-LNB	2	1.00	386	65	1.4	4.4	11.4	0.9	0.4	35.0	3103	296.2
LNC-LNB-C	1	1.00	386	65	1.4	4.4	11.4	0.5	0.2	35.0	3103	176.0
LNC-LNB-C	2	1.00	386	65	1.4	4.4	11.4	0.5	0.2	35.0	3103	176.0
SCR-3	1	1.16	386	65	1.4	49.6	128.6	17.7	8.1	80.0	7093	2499.5
SCR-3	2	1.16	386	65	1.4	49.6	128.6	17.7	8.1	80.0	7093	2499.5
SCR-3-C	1	1.16	386	65	1.4	49.6	128.6	10.4	4.7	80.0	7093	1463.4
SCR-3-C	2	1.16	386	65	1.4	49.6	128.6	10.4	4.7	80.0	7093	1463.4
SCR-7	1	1.16	386	65	1.4	49.6	128.6	14.6	6.6	80.0	7093	2056.6
SCR-7	2	1.16	386	65	1.4	49.6	128.6	14.6	6.6	80.0	7093	2056.5
SCR-7-C	1	1.16	386	65	1.4	49.6	128.6	8.6	3.9	80.0	7093	1209.7
SCR-7-C	2	1.16	386	65	1.4	49.6	128.6	8.6	3.9	80.0	7093	1209.6

22.2 SOUTH CAROLINA GENERATING

22.2.1 Arthur M. Williams Steam Plant

The 608 MW unit at the Arthur M. Williams power plant fires a low sulfur coal; therefore, CS was not evaluated. Retrofit factors were developed for FGD; however, costs are not shown since the low sulfur coal would result in low estimates of capital/operating costs and high cost per ton of SO_2 removed.

TABLE 22.2.1-1. ARTHUR M. WILLIAMS STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1
GENERATING CAPACITY (MW-each)	608
CAPACITY FACTOR (PERCENT)	70
INSTALLATION DATE	1973
FIRING TYPE	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	270
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	1.0
COAL HEATING VALUE (BTU/LB)	12900
COAL ASH CONTENT (PERCENT)	8.3
FLY ASH SYSTEM	DRY DISPOSAL
ASH DISPOSAL METHOD	LANDFILL/OFF-SITE
STACK NUMBER	1
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1984
EMISSION (LB/MM BTU)	0.02
REMOVAL EFFICIENCY	99.6
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	1.5
SURFACE AREA (1000 SQ FT)	637.6
GAS EXIT RATE (1000 ACFM)	2800
SCA (SQ FT/1000 ACFM)	228
OUTLET TEMPERATURE (°F)	310

TABLE 22.2.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR WILLIAMS UNIT 1 *

	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			LOW
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			300-600
BAGHOUSE			NA
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			1.27
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	0	8

* The L/LS-FGD absorbers would be located northeast of the chimney and the LSD-FGD absorbers would be located north of unit 1.

TABLE 22.2.1-3. SUMMARY OF NOx RETROFIT RESULTS FOR WILLIAMS

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1
FIRING TYPE	TANG
TYPE OF NOx CONTROL	OFA
FURNACE VOLUME (1000 CU FT)	270
BOILER INSTALLATION DATE	1973
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$)	0
Ductwork Demolition (1000$)	105
New Duct Length (Feet)	200
New Duct Costs (1000$)	2849
New Heat Exchanger (1000$)	5505
TOTAL SCOPE ADDER COSTS (1000$)	8458
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	20

* Cold side SCR reactors would be located northeast of the chimney.

Table 22.2.1-4. NOx Control Cost Results for the Williams 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	608	70	1.0	1.3	2.1	0.3	0.1	25.0	2662	100.5
LNC-OFA-C	1	1.00	608	70	1.0	1.3	2.1	0.2	0.0	25.0	2662	59.7
SCR-3	1	1.16	608	70	1.0	73.2	120.4	26.8	7.2	80.0	8518	3143.7
SCR-3-C	1	1.16	608	70	1.0	73.2	120.4	15.7	4.2	80.0	8518	1839.7
SCR-7	1	1.16	608	70	1.0	73.2	120.4	21.8	5.9	80.0	8518	2563.4
SCR-7-C	1	1.16	608	70	1.0	73.2	120.4	12.8	3.4	80.0	8518	1507.2

TABLE 22.2.1-5. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR ARTHUR M. WILLIAMS UNIT 1

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$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	116

TOTAL COST (1000$)	
ESP UPGRADE CASE	116
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.16
NEW BAGHOUSE	NA

FSI and DSD were considered due to the adequate size of the ESPs and the sufficient duct residence time between the boiler and ESPs.

Table 22.2.1-6. Summary of DSD/FSI Control Costs for the Williams 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	608	70	1.0	19.0	31.2	13.2	3.5	49.0	13467	976.8
DSD+ESP-C	1	1.00	608	70	1.0	19.0	31.2	7.6	2.0	49.0	13467	566.0
FSI+ESP-50	1	1.00	608	70	1.0	23.0	37.8	15.6	4.2	50.0	13841	1129.9
FSI+ESP-50-C	1	1.00	608	70	1.0	23.0	37.8	9.1	2.4	50.0	13841	654.8
FSI+ESP-70	1	1.00	608	70	1.0	22.9	37.7	15.8	4.2	70.0	19378	815.6
FSI+ESP-70-C	1	1.00	608	70	1.0	22.9	37.7	9.2	2.5	70.0	19378	472.6

22.3 SOUTH CAROLINA PUBLIC SERVICE

22.3.1 Grainger Steam Plant

The Grainger Steam Plant is located in Horry County, South Carolina, as part of the South Carolina Public Service system. The plant contains two coal-fired boilers with a total gross generating capacity of 164 MW. Tables 22.3.1-1 through 22.3.1-8 summarize the plant operational data and present the SO_2 and NO_x control cost and performance estimates.

TABLE 22.3.1-1. GRAINGER STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2
GENERATING CAPACITY (MW-each)	82
CAPACITY FACTOR (PERCENT)	44,50
INSTALLATION DATE	1966
FIRING TYPE	FRONT WALL
FURNACE VOLUME (1000 CU FT)	NA
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	1.8
COAL HEATING VALUE (BTU/LB)	12700
COAL ASH CONTENT (PERCENT)	10.2
FLY ASH SYSTEM	WET DISPOSAL
ASH DISPOSAL METHOD	POND/ON-SITE
STACK NUMBER	1,2
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1966
EMISSION (LB/MM BTU)	0.34,0.103
REMOVAL EFFICIENCY	95
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	1.2
SURFACE AREA (1000 SQ FT)	66.1
GAS EXIT RATE (1000 ACFM)	191.4
SCA (SQ FT/1000 ACFM)	345
OUTLET TEMPERATURE (°F)	300

TABLE 22.3.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR GRAINGER 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			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	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$)	785	NA	785
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	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	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10,5	0	10,5

* Absorbers for unit 1 would be located east of unit 1. Absorbers for unit 2 would be located south of the unit 2 chimney. The general facilities for unit 1 and 2 are 10 and 5 percent, respectively.

Table 22.3.1-3. Summary of FGD Control Costs for the Grainger 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	82	44	1.8	35.5	433.0	13.8	43.8	90.0	3871	3575.0
L/S FGD	2	1.27	82	50	1.8	34.5	420.3	13.8	38.5	90.0	4398	3141.8
L/S FGD-C	1	1.27	82	44	1.8	35.5	433.0	8.1	25.6	90.0	3871	2089.4
L/S FGD-C	2	1.27	82	50	1.8	34.5	420.3	8.1	22.5	90.0	4398	1835.2
LC FGD	1-2	1.27	164	47	1.8	33.4	203.4	15.0	22.3	90.0	8269	1818.8
LC FGD-C	1-2	1.27	164	47	1.8	33.4	203.4	8.8	13.0	90.0	8269	1060.1
LSD+ESP	1	1.43	82	44	1.8	15.5	188.6	7.0	22.3	76.0	3281	2144.3
LSD+ESP	2	1.43	82	50	1.8	15.1	183.8	7.1	19.6	76.0	3729	1892.3
LSD+ESP-C	1	1.43	82	44	1.8	15.5	188.6	4.1	13.0	76.0	3281	1249.7
LSD+ESP-C	2	1.43	82	50	1.8	15.1	183.8	4.1	11.4	76.0	3729	1102.3

Table 22.3.1-4. Summary of Coal Switching/Cleaning Costs for the Grainger 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	82	44	1.8	3.6	43.5	5.1	16.3	47.0	2018	2546.0
CS/B+$15	2	1.00	82	50	1.8	3.6	43.5	5.7	15.9	47.0	2294	2497.5
CS/B+$15-C	1	1.00	82	44	1.8	3.6	43.5	3.0	9.4	47.0	2018	1466.7
CS/B+$15-C	2	1.00	82	50	1.8	3.6	43.5	3.3	9.2	47.0	2294	1437.9
CS/B+$5	1	1.00	82	44	1.8	2.7	33.2	2.4	7.5	47.0	2018	1178.9
CS/B+$5	2	1.00	82	50	1.8	2.7	33.2	2.6	7.3	47.0	2294	1139.2
CS/B+$5-C	1	1.00	82	44	1.8	2.7	33.2	1.4	4.4	47.0	2018	681.5
CS/B+$5-C	2	1.00	82	50	1.8	2.7	33.2	1.5	4.2	47.0	2294	658.0

TABLE 22.3.1-5. SUMMARY OF NOx RETROFIT RESULTS FOR GRAINGER

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1	2
FIRING TYPE	FWF	FWF
TYPE OF NOx CONTROL	LNB	LNB
FURNACE VOLUME (1000 CU FT)	NA	NA
BOILER INSTALLATION DATE	1966	1966
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	40	40
SCR RETROFIT RESULTS *		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	23	23
New Duct Length (Feet)	200	200
New Duct Costs (1000$)	882	882
New Heat Exchanger (1000$)	1655	1655
TOTAL SCOPE ADDER COSTS (1000$)	2560	2560
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	20	13

* Cold side SCR reactors for unit 1 would be located east of unit 1, and cold side SCR reactors for unit 2 would be located south of the unit 2 chimney.

Table 22.3.1-6. NOx Control Cost Results for the Grainger 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	82	44	1.8	2.4	28.8	0.5	1.6	40.0	515	961.3
LNC-LNB	2	1.00	82	50	1.8	2.4	28.8	0.5	1.4	40.0	585	846.0
LNC-LNB-C	1	1.00	82	44	1.8	2.4	28.8	0.3	0.9	40.0	515	571.3
LNC-LNB-C	2	1.00	82	50	1.8	2.4	28.8	0.3	0.8	40.0	585	502.8
SCR-3	1	1.16	82	44	1.8	16.5	201.5	5.2	16.3	80.0	1029	5017.5
SCR-3	2	1.16	82	50	1.8	16.2	197.3	5.1	14.2	80.0	1170	4369.5
SCR-3-C	1	1.16	82	44	1.8	16.5	201.5	3.0	9.6	80.0	1029	2946.7
SCR-3-C	2	1.16	82	50	1.8	16.2	197.3	3.0	8.4	80.0	1170	2565.5
SCR-7	1	1.16	82	44	1.8	16.5	201.5	4.5	14.2	80.0	1029	4368.1
SCR-7	2	1.16	82	50	1.8	16.2	197.3	4.4	12.4	80.0	1170	3798.1
SCR-7-C	1	1.16	82	44	1.8	16.5	201.5	2.6	8.4	80.0	1029	2574.6
SCR-7-C	2	1.16	82	50	1.8	16.2	197.3	2.6	7.3	80.0	1170	2238.1

TABLE 22.3.1-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR GRAINGER 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$)	785
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	26
TOTAL COST (1000$)	
ESP UPGRADE CASE	811
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Short duct residence time exists between the boilers and ESPs. Although ESPs are of an adequate size, the space around the ESPs for upgrading is limited and a high factor was assigned to ESP upgrade.

Table 22.3.1-8. Summary of DSD/FSI Control Costs for the Grainger 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	82	44	1.8	6.8	82.4	4.5	14.3	49.0	2092	2161.6
DSD+ESP	2	1.00	82	50	1.8	6.8	82.4	4.6	12.9	49.0	2378	1951.1
DSD+ESP-C	1	1.00	82	44	1.8	6.8	82.4	2.6	8.3	49.0	2092	1252.9
DSD+ESP-C	2	1.00	82	50	1.8	6.8	82.4	2.7	7.5	49.0	2378	1130.6
FSI+ESP-50	1	1.00	82	44	1.8	7.0	84.9	4.0	12.5	50.0	2150	1843.6
FSI+ESP-50	2	1.00	82	50	1.8	7.0	84.9	4.1	11.5	50.0	2444	1697.1
FSI+ESP-50-C	1	1.00	82	44	1.8	7.0	84.9	2.3	7.3	50.0	2150	1070.7
FSI+ESP-50-C	2	1.00	82	50	1.8	7.0	84.9	2.4	6.7	50.0	2444	985.1
FSI+ESP-70	1	1.00	82	44	1.8	7.1	86.2	4.0	12.7	70.0	3010	1336.0
FSI+ESP-70	2	1.00	82	50	1.8	7.1	86.2	4.2	11.7	70.0	3421	1230.3
FSI+ESP-70-C	1	1.00	82	44	1.8	7.1	86.2	2.3	7.4	70.0	3010	776.0
FSI+ESP-70-C	2	1.00	82	50	1.8	7.1	86.2	2.4	6.8	70.0	3421	714.1

22.3.2 Jefferies Steam Plant

The Jefferies Steam Plant is located in Berkley County, South Carolina, as part of the South Carolina Public Service system. The plant contains two coal-fired boilers with a total gross generating capacity of 346 MW. Tables 22.3.2-1 through 22.3.2-9 summarize the plant operational data and present the SO_2 and NO_x control cost and performance estimates.

TABLE 22.3.2-1. JEFFERIES STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1, 2	3, 4
GENERATING CAPACITY (MW-each)	50	173
CAPACITY FACTOR (PERCENT)	PETROLEUM	34,45
INSTALLATION DATE	BURNING	1970
FIRING TYPE		FRONT WALL
FURNACE VOLUME (1000 CU FT)		82
LOW NOx COMBUSTION		NO
COAL SULFUR CONTENT (PERCENT)		1.6
COAL HEATING VALUE (BTU/LB)		12200
COAL ASH CONTENT (PERCENT)		11.0
FLY ASH SYSTEM		WET DISPOSAL
ASH DISPOSAL METHOD		POND/ON-SITE
STACK NUMBER		3, 4
COAL DELIVERY METHODS		RAILROAD
PARTICULATE CONTROL		
TYPE		ESP
INSTALLATION DATE		1978
EMISSION (LB/MM BTU)		0.079,0.061
REMOVAL EFFICIENCY		94.6,98.2
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)		1.5-1.9
SURFACE AREA (1000 SQ FT)		78.9
GAS EXIT RATE (1000 ACFM)		307
SCA (SQ FT/1000 ACFM)		257
OUTLET TEMPERATURE (°F)		300

TABLE 22.3.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR JEFFERIES UNIT 3 *

	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			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$)	1532	NA	1532
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.53	NA	
ESP REUSE CASE			1.56
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	0	8

* Absorbers for unit 3 would be placed east of unit 3, south of the coal pile.

TABLE 22.3.2-3. SUMMARY OF RETROFIT FACTOR DATA FOR JEFFERIES UNIT 4 *

	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			600-1000
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	1532	NA	1532
NEW CHIMNEY	YES	NA	NO
ESTIMATED COST (1000$)	1211	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.59	NA	
ESP REUSE CASE			1.69
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	0	8

* Absorbers for unit 4 would be located east of unit 4, south of the coal pile.

Table 22.3.2-4. Summary of FGD Control Costs for the Jefferies 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	3	1.53	173	34	1.6	59.8	345.8	22.0	42.6	90.0	5873	3738.8
L/S FGD	4	1.59	173	45	1.6	62.0	358.2	23.6	34.6	90.0	7774	3038.3
L/S FGD	3-4	1.56	346	39	1.6	90.3	261.0	34.3	29.0	90.0	13474	2548.2
L/S FGD-C	3	1.53	173	34	1.6	59.8	345.8	12.8	24.9	90.0	5873	2187.7
L/S FGD-C	4	1.59	173	45	1.6	62.0	358.2	13.8	20.3	90.0	7774	1776.5
L/S FGD-C	3-4	1.56	346	39	1.6	90.3	261.0	20.1	17.0	90.0	13474	1490.0
LC FGD	3-4	1.56	346	39	1.6	68.0	196.4	27.7	23.4	90.0	13474	2054.4
LC FGD-C	3-4	1.56	346	39	1.6	68.0	196.4	16.2	13.7	90.0	13474	1199.6
LSD+ESP	3	1.56	173	34	1.6	27.7	160.2	10.8	21.0	76.0	4979	2176.4
LSD+ESP	4	1.69	173	45	1.6	29.6	171.1	11.8	17.3	76.0	6590	1794.8
LSD+ESP-C	3	1.56	173	34	1.6	27.7	160.2	6.3	12.3	76.0	4979	1271.9
LSD+ESP-C	4	1.69	173	45	1.6	29.6	171.1	6.9	10.1	76.0	6590	1048.5

Table 22.3.2-5. Summary of Coal Switching/Cleaning Costs for the Jefferies 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	173	34	1.6	6.3	36.1	8.2	15.8	43.0	2806	2907.6
CS/B+$15	4	1.00	173	45	1.6	6.3	36.1	10.4	15.2	43.0	3713	2788.4
CS/B+$15-C	3	1.00	173	34	1.6	6.3	36.1	4.7	9.1	43.0	2806	1675.9
CS/B+$15-C	4	1.00	173	45	1.6	6.3	36.1	6.0	8.7	43.0	3713	1605.1
CS/B+$5	3	1.00	173	34	1.6	4.5	25.8	3.6	7.0	43.0	2806	1278.6
CS/B+$5	4	1.00	173	45	1.6	4.5	25.8	4.4	6.5	43.0	3713	1186.8
CS/B+$5-C	3	1.00	173	34	1.6	4.5	25.8	2.1	4.0	43.0	2806	739.7
CS/B+$5-C	4	1.00	173	45	1.6	4.5	25.8	2.5	3.7	43.0	3713	685.3

TABLE 22.3.2-6. SUMMARY OF NOx RETROFIT RESULTS FOR JEFFERIES

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	3	4
FIRING TYPE	FWF	FWF
TYPE OF NOx CONTROL	LNB	LNB
FURNACE VOLUME (1000 CU FT)	82	82
BOILER INSTALLATION DATE	1970	1970
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	33	33
SCR RETROFIT RESULTS *		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	41	41
New Duct Length (Feet)	300	600
New Duct Costs (1000$)	2048	4097
New Heat Exchanger (1000$)	2590	2590
TOTAL SCOPE ADDER COSTS (1000$)	4679	6727
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	20	20

* Cold side SCR reactors for units 3 and 4 would be located east of unit 3, south of the coal pile.

Table 22.3.2-7. NOx Control Cost Results for the Jefferies 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	173	34	1.6	3.2	18.4	0.7	1.3	33.0	725	920.0
LNC-LNB	4	1.00	173	45	1.6	3.2	18.4	0.7	1.0	33.0	959	695.1
LNC-LNB-C	3	1.00	173	34	1.6	3.2	18.4	0.4	0.8	33.0	725	546.8
LNC-LNB-C	4	1.00	173	45	1.6	3.2	18.4	0.4	0.6	33.0	959	413.1
SCR-3	3	1.16	173	34	1.6	28.1	162.5	9.1	17.6	80.0	1757	5154.3
SCR-3	4	1.16	173	45	1.6	30.2	174.6	9.5	14.0	80.0	2325	4100.4
SCR-3-C	3	1.16	173	34	1.6	28.1	162.5	5.3	10.3	80.0	1757	3024.8
SCR-3-C	4	1.16	173	45	1.6	30.2	174.6	5.6	8.2	80.0	2325	2407.5
SCR-7	3	1.16	173	34	1.6	28.1	162.5	7.6	14.8	80.0	1757	4347.2
SCR-7	4	1.16	173	45	1.6	30.2	174.6	8.1	11.9	80.0	2325	3490.6
SCR-7-C	3	1.16	173	34	1.6	28.1	162.5	4.5	8.7	80.0	1757	2562.4
SCR-7-C	4	1.16	173	45	1.6	30.2	174.6	4.8	7.0	80.0	2325	2058.1

TABLE 22.3.2-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR JEFFERIES UNIT 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$)	1532
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	45
TOTAL COST (1000$)	
ESP UPGRADE CASE	1577
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Short duct residence time exists between boilers 3 and 4 and their respective ESPs. ESP upgrade for both units was high because of the lack of available space around the ESPs.

Table 22.3.2-9. Summary of DSD/FSI Control Costs for the Jefferies 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	3	1.00	173	34	1.6	11.2	64.7	6.1	11.8	49.0	3175	1919.8
DSD+ESP	4	1.00	173	45	1.6	11.2	64.7	6.5	9.6	49.0	4202	1554.0
DSD+ESP-C	3	1.00	173	34	1.6	11.2	64.7	3.5	6.9	49.0	3175	1115.8
DSD+ESP-C	4	1.00	173	45	1.6	11.2	64.7	3.8	5.6	49.0	4202	902.3
FSI+ESP-50	3	1.00	173	34	1.6	12.5	72.1	6.0	11.6	50.0	3263	1824.8
FSI+ESP-50	4	1.00	173	45	1.6	12.5	72.1	6.6	9.7	50.0	4319	1532.1
FSI+ESP-50-C	3	1.00	173	34	1.6	12.5	72.1	3.5	6.7	50.0	3263	1062.6
FSI+ESP-50-C	4	1.00	173	45	1.6	12.5	72.1	3.8	5.6	50.0	4319	890.7
FSI+ESP-70	3	1.00	173	34	1.6	12.6	72.8	6.0	11.7	70.0	4568	1320.4
FSI+ESP-70	4	1.00	173	45	1.6	12.6	72.8	6.7	9.8	70.0	6046	1109.7
FSI+ESP-70-C	3	1.00	173	34	1.6	12.6	72.8	3.5	6.8	70.0	4568	768.8
FSI+ESP-70-C	4	1.00	173	45	1.6	12.6	72.8	3.9	5.7	70.0	6046	645.1

22.3.3 Winyah Steam Plant

Units 2, 3, and 4 at the Winyah plant are equipped with FGD systems; therefore no further SO_2 control technologies were evaluated for these units. All units are equipped with LNBs for NO_x control, hence SCR was the only NO_x control evaluated for these units. Although cost estimates are presented for DSD and FSI, the short straight duct run distance for unit 1 makes application of these technologies difficult without enlarging the duct work.

TABLE 22.3.3-1. WINYAH STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2	3	4
GENERATING CAPACITY (MW)	315	315	315	315
CAPACITY FACTOR (PERCENT)	58	34	28	24
INSTALLATION DATE	1975	1977	1980	1981
FIRING TYPE	FRONT WALL	OPPOSED WALL		
FURNACE VOLUME (1000 CU FT)	NA	NA	NA	NA
LOW NOx COMBUSTION	YES	YES	YES	YES
COAL SULFUR CONTENT (PERCENT)		1.1		
COAL HEATING VALUE (BTU/LB)		12300		
COAL ASH CONTENT (PERCENT)		10		
FLY ASH SYSTEM		WET DISPOSAL		
ASH DISPOSAL METHOD		POND/ON-SITE		
STACK NUMBER	1	2	3	4
COAL DELIVERY METHODS		RAILROAD		
FGD SYSTEM (TYPE)	NA	TRAY TYPE		LS-FGD
FGD SYSTEM (INSTALLATION DATE)	NA	1977	1980	1981
PARTICULATE CONTROL				
TYPE	ESP	ESP	ESP	ESP
INSTALLATION DATE	1975	1977	1981	1981
EMISSION (LB/MM BTU)	0.132	0.045	0.037	0.044
REMOVAL EFFICIENCY	99.0	99.4	99.4	99.4
DESIGN SPECIFICATION				
SULFUR SPECIFICATION (PERCENT)	2.0	2.0	2.0	2.0
SURFACE AREA (1000 SQ FT)	305	285	285	285
EXIT GAS FLOW RATE (1000 ACFM)	881	881.5	881.5	881.5
SCA (SQ FT/1000 ACFM)	343	323	323	323
OUTLET TEMPERATURE (°F)	277	270	270	270

TABLE 22.3.3-2. SUMMARY OF RETROFIT FACTOR DATA FOR WINYAH UNIT 1 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	MEDIUM	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$)	2622	NA	2622
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.35	NA	
ESP REUSE CASE			1.35
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	15

* L/S-FGD and LSD-FGD absorbers for unit 1 would be located behind or beside the unit 1 chimney.

Table 22.3.3-3. Summary of FGD Control Costs for the Winyah 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	1.35	315	58	1.1	77.1	244.6	32.1	20.1	90.0	12426	2584.9
L/S FGD-C	1	1.35	315	58	1.1	77.1	244.6	18.7	11.7	90.0	12426	1508.8
LC FGD	1	1.35	315	58	1.1	57.8	183.5	26.4	16.5	90.0	12426	2123.4
LC FGD-C	1	1.35	315	58	1.1	57.8	183.5	15.4	9.6	90.0	12426	1237.4
LSD+ESP	1	1.35	315	58	1.1	37.3	118.4	15.4	9.6	76.0	10534	1460.0
LSD+ESP-C	1	1.35	315	58	1.1	37.3	118.4	9.0	5.6	76.0	10534	852.4

Table 22.3.3-4. Summary of Coal Switching/Cleaning Costs for the Winyah 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	315	58	1.1	10.5	33.4	23.2	14.5	16.0	2250	10300.1
CS/B+$15-C	1	1.00	315	58	1.1	10.5	33.4	13.3	8.3	16.0	2250	5922.3
CS/B+$5	1	1.00	315	58	1.1	7.3	23.1	9.4	5.9	16.0	2250	4169.7
CS/B+$5-C	1	1.00	315	58	1.1	7.3	23.1	5.4	3.4	16.0	2250	2403.5

TABLE 22.3.3-5. SUMMARY OF NOx RETROFIT RESULTS FOR WINYAH

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2, 3	4
FIRING TYPE	NA	NA	NA
TYPE OF NOx CONTROL	NA	NA	NA
FURNACE VOLUME (1000 CU FT)	NA	NA	NA
BOILER INSTALLATION DATE	NA	NA	NA
SLAGGING PROBLEM	NA	NA	NA
ESTIMATED NOx REDUCTION (PERCENT)	NA	NA	NA
SCR RETROFIT RESULTS *			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	HIGH	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	64	64	64
New Duct Length (Feet)	200	200	200
New Duct Costs (1000$)	1939	1939	1939
New Heat Exchanger (1000$)	3710	3710	3710
TOTAL SCOPE ADDER COSTS (1000$)	5713	5713	5713
RETROFIT FACTOR FOR SCR	1.16	1.52	1.16
GENERAL FACILITIES (PERCENT)	38	38	38

* Cold side SCR reactors for unit 1 would be located behind the unit 1 chimney. Cold side SCR reactors for units 2, 3, and 4 would be located behind their respective FGD system.

Table 22.3.3-6. NOx Control Cost Results for the Winyah 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	315	58	1.1	45.7	145.1	15.7	9.8	80.0	5407	2898.9
SCR-3	2	1.52	315	34	1.1	53.9	171.1	17.2	18.3	80.0	3169	5417.4
SCR-3	3	1.52	315	28	1.1	53.9	171.1	17.1	22.1	80.0	2610	6537.6
SCR-3	4	1.16	315	24	1.1	45.7	145.0	15.0	22.7	80.0	2237	6723.0
SCR-3-C	1	1.16	315	58	1.1	45.7	145.1	9.2	5.7	80.0	5407	1698.8
SCR-3-C	2	1.52	315	34	1.1	53.9	171.1	10.1	10.7	80.0	3169	3180.1
SCR-3-C	3	1.52	315	28	1.1	53.9	171.1	10.0	13.0	80.0	2610	3838.2
SCR-3-C	4	1.16	315	24	1.1	45.7	145.0	8.8	13.3	80.0	2237	3943.4
SCR-7	1	1.16	315	58	1.1	45.7	145.1	13.1	8.2	80.0	5407	2421.9
SCR-7	2	1.52	315	34	1.1	53.9	171.1	14.6	15.6	80.0	3169	4603.6
SCR-7	3	1.52	315	28	1.1	53.9	171.1	14.5	18.7	80.0	2610	5549.4
SCR-7	4	1.16	315	24	1.1	45.7	145.0	12.5	18.8	80.0	2237	5570.2
SCR-7-C	1	1.16	315	58	1.1	45.7	145.1	7.7	4.8	80.0	5407	1425.5
SCR-7-C	2	1.52	315	34	1.1	53.9	171.1	8.6	9.2	80.0	3169	2713.8
SCR-7-C	3	1.52	315	28	1.1	53.9	171.1	8.5	11.1	80.0	2610	3272.0
SCR-7-C	4	1.16	315	24	1.1	45.7	145.0	7.3	11.1	80.0	2237	3282.9

TABLE 22.3.3-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR WINYAH UNIT 1

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$)	2622
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	71

TOTAL COST (1000$)	
ESP UPGRADE CASE	2693
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.36
NEW BAGHOUSE	NA

The duct residence time between unit 1 and the unit 1 ESPs is short; however, the ESPs are of an adequate size for sorbent injection technologies.

Table 22.3.3-8. Summary of DSD/FSI Control Costs for the Winyah 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	315	58	1.1	13.6	43.2	8.4	5.2	49.0	6717	1245.3
DSD+ESP-C	1	1.00	315	58	1.1	13.6	43.2	4.9	3.0	49.0	6717	722.5
FSI+ESP-50	1	1.00	315	58	1.1	14.0	44.6	8.6	5.3	50.0	6903	1239.1
FSI+ESP-50-C	1	1.00	315	58	1.1	14.0	44.6	5.0	3.1	50.0	6903	719.0
FSI+ESP-70	1	1.00	315	58	1.1	14.2	45.0	8.7	5.4	70.0	9664	899.1
FSI+ESP-70-C	1	1.00	315	58	1.1	14.2	45.0	5.0	3.2	70.0	9664	521.7

* Application of these technologies will be difficult due to the short, straight duct run distance between the airheater and ESP unless the ductwork is enlarged. The above costs do not include this expense.

SECTION 23.0 TENNESSEE

23.1 TENNESSEE VALLEY AUTHORITY

23.1.1 Allen Steam Plant

The Allen steam plant is located within Shelby County, Tennessee, as part of the TVA system. The plant contains three coal-fired boilers with a total gross generating capacity of 990 MW. Figure 23.1.1-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 23.1.1-1 presents operational data for the existing equipment at the Allen steam plant. All boilers burn medium sulfur coal (2.20 percent sulfur). Coal shipments are received by freight barge and conveyed to a coal storage and handling area located east of the plant.

Particulate matter emissions for all three boilers are controlled with ESPs located directly behind each boiler. Ash from all units is wet sluiced to ponds located northwest of the plant. On-site waste disposal availability is a significant problem and TVA is considering two options to address the future problem: the purchase of more land adjacent to the plant or dry disposing of the waste off-site.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 23.1.1-1 shows the general layout and location of the FGD control system. Absorbers for L/LS-FGD and LSD-FGD for all three units would be located behind the chimneys north of each unit. The storage area would need to be demolished and relocated to make more space available for the FGD equipment. The limestone and lime preparation/storage and waste handling areas were located in the open area west of unit 1. A factor of 10 percent was assigned to general facilities because of the demolition and relocation of the storage area.

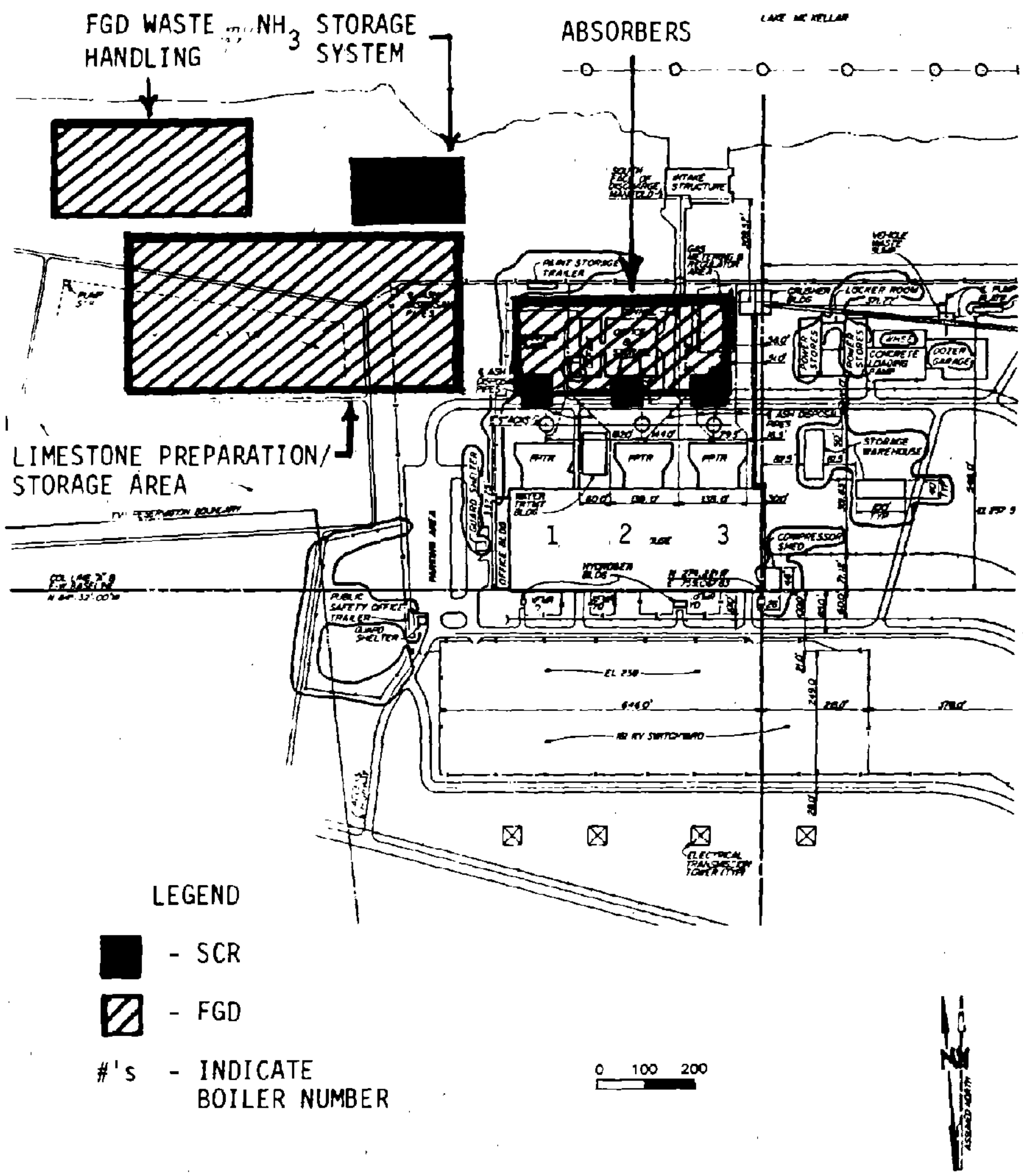

Figure 23.1.1-1. Allen plant plot plan

TABLE 23.1.1-1. ALLEN STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1-3
GENERATING CAPACITY (MW-each)	330
CAPACITY FACTOR (PERCENT)	44, 51, 39
INSTALLATION DATE	1959
FIRING TYPE	CYC
COAL SULFUR CONTENT (PERCENT)	2.20
COAL HEATING VALUE (BTU/LB)	11700
COAL ASH CONTENT (PERCENT)	9.0
FLY ASH SYSTEM	WET SLUICE
ASH DISPOSAL METHOD	POND/ON-SITE
STACK NUMBER	1, 2, 3
COAL DELIVERY METHODS	BARGE
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1972
EMISSION (LB/MM BTU)	0.06-0.09
REMOVAL EFFICIENCY	95-97.0
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	2.5
SURFACE AREA (1000 SQ FT)	253.4
GAS EXIT RATE (1000 ACFM)	1265
SCA (SQ FT/1000 ACFM)	200
OUTLET TEMPERATURE (°F)	310

Retrofit Difficulty and Scope Adder Costs--

The FGD control equipment/absorbers were located in the area directly behind (north) the ESPs and powerhouse. The absorber location for unit 1 was assigned a low site access/congestion factor because the designated location is currently an open area/parking lot. The location of the absorbers for units 2 and 3 was assigned a medium to high site access/congestion factor for two reasons. First, the water intakes are located close to (on the north side) units 2 and 3 and, second, the coal conveyor is also close to unit 3. All units were assigned a low site access/congestion factor for L/LS-FGD and LSD-FGD flue gas handling. Short to moderate duct runs would be required for all technologies. The limestone storage and preparation area was located in a low site access/congestion area west of unit 1. This area is an abandoned ash pond site. The sludge dewatering area was located in a low site access/ congestion area just north of the limestone storage and preparation area.

The major scope adjustment costs and retrofit factors estimated for the FGD control technologies are presented in Tables 23.1.1-2 through 23.1.1-4. The largest scope adder for the Allen plant would be the conversion of units 1 to 3 fly ash conveying/disposal system from wet to dry for conventional L/LS-FGD cases. 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 ranged from low to moderate (1.24 to 1.51).

LSD-FGD with a new baghouse was the only LSD case considered for the Allen plant because the ESPs are small and the access/congestion factor for ducting to the front of the ESPs would be very high. The retrofit factors determined for the LSD technology case ranged from low to moderate (1.27 to 1.53). Separate retrofit factors were estimated for new particulate controls. These factors were low to high (1.16 to 1.58) for units 1 to 3 and reflect the access/congestion associated with the location of the new particulate controls. The factors were used by the IAPCS model to estimate additional costs required for installation of new baghouses.

Table 23.1.1-5 presents the costs estimated for L/LS and LSD-FGD cases. The LSD-FGD costs include installing new baghouses to handle the additional particulate loading for boilers 1-3.

TABLE 23.1.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR ALLEN UNIT 1

	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)	100-300	100-300	
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$)	2734	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.31	1.24	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.27
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	10	10	10

TABLE 23.1.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR ALLEN UNIT 2

	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$)	2734	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	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 23.1.1-4. SUMMARY OF RETROFIT FACTOR DATA FOR ALLEN UNIT 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			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	HIGH
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	NO
ESTIMATED COST (1000$)	2734	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.51	1.48	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.53
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.58
GENERAL FACILITIES (PERCENT)	10	10	10

Table 23.1.1-5. Summary of FGD Control Costs for the Allen 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	1.31	330	44	2.2	81.2	246.0	33.8	26.6	90.0	20917	1616.7
L/S FGD	2	1.41	330	51	2.2	86.6	262.4	36.8	25.0	90.0	24244	1518.2
L/S FGD	3	1.51	330	39	2.2	92.0	278.7	36.2	32.1	90.0	18540	1954.6
L/S FGD-C	1	1.31	330	44	2.2	81.2	246.0	19.7	15.5	90.0	20917	943.7
L/S FGD-C	2	1.41	330	51	2.2	86.6	262.4	21.5	14.6	90.0	24244	885.9
L/S FGD-C	3	1.51	330	39	2.2	92.0	278.7	21.2	18.8	90.0	18540	1142.1
LC FGD	1-3	1.41	990	45	2.2	155.7	157.3	71.3	18.3	90.0	64176	1110.9
LC FGD-C	1-3	1.41	990	45	2.2	155.7	157.3	41.5	10.6	90.0	64176	647.3
LSD+FF	1	1.27	330	44	2.2	65.2	197.5	24.0	18.8	87.0	20103	1191.7
LSD+FF	2	1.40	330	51	2.2	73.1	221.6	26.8	18.2	87.0	23301	1151.3
LSD+FF	3	1.53	330	39	2.2	81.7	247.6	27.6	24.5	87.0	17819	1551.2
LSD+FF-C	1	1.27	330	44	2.2	65.2	197.5	14.0	11.0	87.0	20103	697.3
LSD+FF-C	2	1.40	330	51	2.2	73.1	221.6	15.7	10.6	87.0	23301	673.7
LSD+FF-C	3	1.53	330	39	2.2	81.7	247.6	16.2	14.4	87.0	17819	909.3

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, optimization of scrubber 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. This is particularly true for cyclone boilers because obtaining a low sulfur bituminous coal having the correct ash fusion temperature may be quite expensive due to limited availability or transportation distance. Therefore, Allen plant was not considered for the coal switching option.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Allen steam plant. These controls include NGR and SCR. NGR was the LNC modification control for the Allen units because LNB and OFA are not applicable to cyclone-fired boilers.

Low NO_x Combustion--

Units 1-3 are wet bottom, cyclone-fired boilers rated at 330 MW. The combustion modification technique applied to all three boilers was NGR. As Table 23.1.1-6 shows, the NGR NO_x reduction performance for the boilers was estimated to be 60 percent.

Table 23.1.1-7 presents the cost of retrofitting NGR at the Allen plant.

Selective Catalytic Reduction--

Table 23.1.1-6 presents the SCR retrofit results for each unit. The results include a process area retrofit factor and scope adder costs. The scope adders include costs estimated for building and 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.

TABLE 23.1.1-6. SUMMARY OF NOx RETROFIT RESULTS FOR ALLEN

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	3
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	LOW	MEDIUM	HIGH
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	117	0
Ductwork Demolition (1000$)	66	66	66
New Duct Length (Feet)	100	100	100
New Duct Costs (1000$)	996	996	996
New Heat Exchanger (1000$)	3,815	3,815	3,815
TOTAL SCOPE ADDER COSTS (1000$)	4,877	4,994	4,877
RETROFIT FACTOR FOR SCR	1.16	1.34	1.52
GENERAL FACILITIES (PERCENT)	13	13	13

Table 23.1.1-7. NOx Control Cost Results for the Allen 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	330	44	2.2	5.4	16.2	7.3	5.7	60.0	5526	1314.3
NGR	2	1.00	330	51	2.2	5.4	16.2	8.3	5.6	60.0	6405	1295.0
NGR	3	1.00	330	39	2.2	5.4	16.2	6.5	5.8	60.0	4898	1332.3
NGR-C	1	1.00	330	44	2.2	5.4	16.2	4.2	3.3	60.0	5526	757.3
NGR-C	2	1.00	330	51	2.2	5.4	16.2	4.8	3.2	60.0	6405	745.7
NGR-C	3	1.00	330	39	2.2	5.4	16.2	3.8	3.3	60.0	4898	768.2
SCR-3	1	1.16	330	44	2.2	44.1	133.5	15.7	12.4	80.0	7368	2137.5
SCR-3	2	1.34	330	51	2.2	48.0	145.4	16.9	11.4	80.0	8540	1976.2
SCR-3	3	1.52	330	39	2.2	51.6	156.5	17.4	15.5	80.0	6530	2669.8
SCR-3-C	1	1.16	330	44	2.2	44.1	133.5	9.2	7.2	80.0	7368	1251.4
SCR-3-C	2	1.34	330	51	2.2	48.0	145.4	9.9	6.7	80.0	8540	1157.4
SCR-3-C	3	1.52	330	39	2.2	51.6	156.5	10.2	9.1	80.0	6530	1565.1
SCR-7	1	1.16	330	44	2.2	44.1	133.5	13.0	10.2	80.0	7368	1768.1
SCR-7	2	1.34	330	51	2.2	48.0	145.4	14.2	9.6	80.0	8540	1657.5
SCR-7	3	1.52	330	39	2.2	51.6	156.5	14.7	13.1	80.0	6530	2253.0
SCR-7-C	1	1.16	330	44	2.2	44.1	133.5	7.7	6.0	80.0	7368	1039.8
SCR-7-C	2	1.34	330	51	2.2	48.0	145.4	8.3	5.6	80.0	8540	974.9
SCR-7-C	3	1.52	330	39	2.2	51.6	156.5	8.7	7.7	80.0	6530	1326.3

All reactors were located directly behind the chimneys (south of each unit). The reactor for unit 1 was located in a relatively open area bounded on one side by the parking lot and on another by the reactor for unit 2. The reactor for unit 2 was located in a more congested area blocked on two sides by the chimney and the office/storage building. The reactor for unit 3 was located in a severely congested area blocked on three sides by the chimney, the gas metering/regulating area, and the coal conveyor. The ammonia storage system was located northwest of the plant, close to the old ash disposal area.

As discussed previously, the SCR reactors were placed in various access/congestion areas. The reactor for unit 1 was assigned a low factor, the reactor for unit 2 assigned a medium factor, and the reactor for unit 3 had a high factor. All reactors were located in areas with high underground obstructions. The ammonia storage system was located in a low access/congestion area with no significant underground obstructions. Table 23.1.1-7 presents the estimated cost of retrofitting SCR at units 1 to 3.

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 northeast of the plant in a relatively open area in the same manner as LSD-FGD technology. The retrofit of DSD at the Allen steam plant would be difficult because of the short duct residence time (<1 second) between the boilers and the ESPs. Also, the marginal size ESPs (SCAs = 200) might not be able to handle the increased particulate load from DSD. However, space is available to upgrade the ESPs by adding plate area, assuming a medium to high site access/congestion factor for ESP upgrade. Additionally, the conversion of the wet ash handling system to dry handling would be required when reusing the ESPs for FSI. Sufficient duct residence time could be made available for DSD if the existing ESPs were used to provide duct residence time and fabric filters were installed behind the chimneys. The fabric filters would be located in low to high access/congestion areas.

Tables 23.1.1-8 through 23.1.1-10 present a summary of site access/congestion factors, scope adders, and retrofit factors estimated for DSD and FSI technologies at the Allen steam plant. Table 23.1.1-11 presents the costs estimated to retrofit DSD and FSI at the Allen plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability were determined using the criteria presented in Section 2. The boilers at the Allen plant are marginal candidates for AFBC retrofit because the boilers are larger than 300 MW, are of moderate age, have moderate capacity factors, and have small furnace volumes.

23.1.2 Bull Run Steam Plant

The Bull Run steam plant is located within Anderson County, Tennessee, as part of the TVA system. The plant contains one coal-fired boiler with a total gross generating capacity of 950 MW. Figure 23.1.2-1 presents the plant plot plan showing the location of the boiler and major associated auxiliary equipment.

Table 23.1.2-1 presents operational data for the existing equipment at the Bull Run steam plant. The boiler burns low sulfur coal (0.80 percent sulfur). Coal shipments are received by rail and conveyed to a coal storage and handling area located east of the plant.

Particulate matter emissions are controlled with retrofit ESPs located behind the old ESPs. Ash is wet sluiced to ponds located southwest of the plant. On-site waste disposal is limited and TVA is considering two future options: the purchase of more land adjacent to the plant or dry disposing the waste off-site.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 23.1.2-1 shows the general layout and location of the FGD control system. Absorbers for L/LS-FGD and LSD-FGD could be located in three

TABLE 23.1.1-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR ALLEN UNIT 1

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE (FSI)	MEDIUM
NEW BAGHOUSE (DSD)	LOW
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	2734
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	300
ESTIMATED COST (1000$)	2771
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	73

TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	2807
A NEW BAGHOUSE CASE (DSD)	2844
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE (FSI)	1.34
NEW BAGHOUSE (DSD)	1.13

TABLE 23.1.1-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR ALLEN UNIT 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE (FSI)	HIGH
NEW BAGHOUSE (DSD)	MEDIUM
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	2734
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	300
ESTIMATED COST (1000$)	2771
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	73

TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	2807
A NEW BAGHOUSE CASE (DSD)	2844
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE (FSI)	1.55
NEW BAGHOUSE (DSD)	1.34

TABLE 23.1.1-10. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR ALLEN UNIT 3

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE (FSI)	HIGH
NEW BAGHOUSE (DSD)	HIGH
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	2734
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	300
ESTIMATED COST (1000$)	2771
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	73

TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	2807
A NEW BAGHOUSE CASE (DSD)	2844
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE (FSI)	1.55
NEW BAGHOUSE (DSD)	1.55

Table 23.1.1-11. Summary of DSD/FSI Control Costs for the Allen 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	330	44	2.2	40.8	123.6	16.8	13.2	71.0	16443	1020.8
DSD+FF	2	1.00	330	51	2.2	45.4	137.7	18.7	12.7	71.0	19059	981.1
DSD+FF	3	1.00	330	39	2.2	50.3	152.5	18.6	16.5	71.0	14574	1274.6
DSD+FF-C	1	1.00	330	44	2.2	40.8	123.6	9.8	7.7	71.0	16443	596.0
DSD+FF-C	2	1.00	330	51	2.2	45.4	137.7	10.9	7.4	71.0	19059	572.8
DSD+FF-C	3	1.00	330	39	2.2	50.3	152.5	10.9	9.6	71.0	14574	745.7
FSI+ESP-50	1	1.00	330	44	2.2	22.7	68.9	13.6	10.7	50.0	11620	1170.8
FSI+ESP-50	2	1.00	330	51	2.2	24.0	72.9	15.1	10.2	50.0	13469	1119.6
FSI+ESP-50	3	1.00	330	39	2.2	24.0	72.9	13.1	11.6	50.0	10300	1273.0
FSI+ESP-50-C	1	1.00	330	44	2.2	22.7	68.9	7.9	6.2	50.0	11620	679.6
FSI+ESP-50-C	2	1.00	330	51	2.2	24.0	72.9	8.7	5.9	50.0	13469	649.4
FSI+ESP-50-C	3	1.00	330	39	2.2	24.0	72.9	7.6	6.8	50.0	10300	739.8
FSI+ESP-70	1	1.00	330	44	2.2	22.6	68.6	13.7	10.8	70.0	16268	845.0
FSI+ESP-70	2	1.00	330	51	2.2	23.9	72.5	15.2	10.3	70.0	18857	808.3
FSI+ESP-70	3	1.00	330	39	2.2	23.9	72.5	13.2	11.7	70.0	14420	917.3
FSI+ESP-70-C	1	1.00	330	44	2.2	22.6	68.6	8.0	6.3	70.0	16268	490.3
FSI+ESP-70-C	2	1.00	330	51	2.2	23.9	72.5	8.8	6.0	70.0	18857	468.8
FSI+ESP-70-C	3	1.00	330	39	2.2	23.9	72.5	7.7	6.8	70.0	14420	533.0

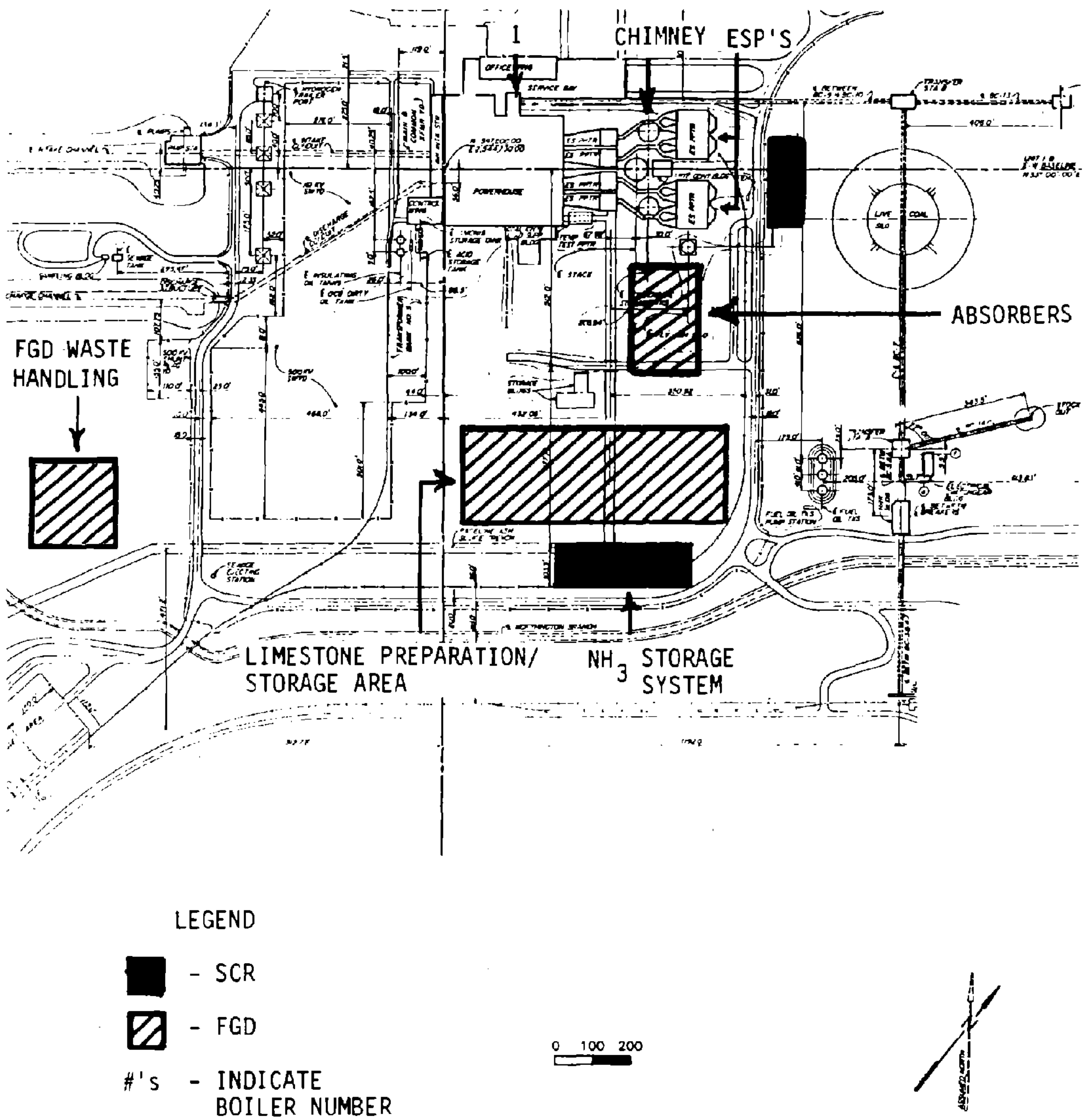

Figure 23.1.2-1. Bull Run plant plot plan

TABLE 23.1.2-1. BULL RUN STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1
GENERATING CAPACITY (MW)	950
CAPACITY FACTOR (PERCENT)	62
INSTALLATION DATE	1967
FIRING TYPE	TANG
COAL SULFUR CONTENT (PERCENT)	0.80
COAL HEATING VALUE (BTU/LB)	11400
COAL ASH CONTENT (PERCENT)	13.5
FLY ASH SYSTEM	WET SLUICE
ASH DISPOSAL METHOD	POND/OFF-SITE
STACK NUMBER	1
COAL DELIVERY METHODS	RAIL
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1977
EMISSION (LB/MM BTU)	0.02
REMOVAL EFFICIENCY	99.7
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	0.60
SURFACE AREA (1000 SQ FT)	1472.7
GAS EXIT RATE (1000 ACFM)	2600
SCA (SQ FT/1000 ACFM)	566
OUTLET TEMPERATURE (°F)	310

different locations: north, east, or south of unit 1. For this evaluation, the absorbers were located south of the precipitators which would require the relocation of a plant road and employee parking lot; therefore, a factor of 7 percent was assigned to general facilities. The limestone and lime preparation/storage area was located south of the powerhouse and the waste handling area was placed directly west of the preparation/storage area.

Retrofit Difficulty and Scope Adder Costs--

Since the Bull Run plant already has switched to a low-sulfur coal, it is unlikely that scrubbing is needed. However, should this become necessary, it would be more cost effective to switch to a higher sulfur content coal, taking into account the fuel cost differential in estimating cost effectiveness. Costs presented in this report, consequently, are variable and could change, being dependent upon type of coal utilized, as well as acid rain legislation.

As mentioned above, the FGD control equipment for unit 1 could be located to the north, east, or south of the plant. There is high ductwork access/congestion north of the plant because of the coal conveyor. There is moderate site access/congestion east of the plant and the railroad would have to be relocated. It seemed most appropriate to locate the equipment south of the ESPs where it would be in a low site access/congestion area (employee parking lot) with no major underground obstructions. However, this location reduces the space available for an additional unit of similar size. Moderate duct runs would be required for routing the flue gas from the units to the absorbers.

The major scope adjustment costs and retrofit factors estimated for the FGD control technologies are presented in Table 23.1.2-2. The most significant scope adder for Bull Run would be the conversion of unit 1 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 conventional L/LS-FGD 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 moderate (1.31 to 1.38).

The LSD with reused ESP was the only LSD-FGD technology evaluated at Bull Run. The retrofit factor determined for this technology was

TABLE 23.1.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR BULL RUN UNIT 1

	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			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	7055	NA	7055
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.38	1.31	
ESP REUSE CASE			1.38
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	7	7	7

moderate (1.38). Medium access/congestion was assigned to the flue gas handling system for this case because there is little space available between the ESPs and the existing boiler. Although no ESP plate area addition is expected due to the large SCA (>500) of the existing retrofit ESPs, a separate factor was developed for the upgrade of the ESPs and used by the IAPCS model to estimate any additional plate area costs, if required. This factor, estimated for the ESP upgrading cost, was medium (1.36) and reflects the congestion which exists around the existing ESPs because of the close proximity of the coal conveyor/chimney.

Table 23.1.2-3 presents the cost estimated for L/LS-FGD and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs and ash handling systems for boiler 1.

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--

The Bull Run steam plant has already switched to low sulfur coal.

NO_x Control Technology Costs--

This section presents the performance and various related costs estimated for NO_x controls evaluated at the Bull Run plant. These controls include LNC and SCR. The application of NO_x controls is determined by several site-specific factors which are discussed in Section 2. The NO_x technologies applied at Bull Run were: OFA and SCR.

Low NO_x Combustion--

Unit 1 is a dry bottom, tangential-fired boiler with a net generating capacity of 950 MW. The NO_x combustion control considered in the analysis for this unit was OFA. Minimal data was available in both the EIA-767 form and POWER and, as a result, NO_x reduction performance could not be assessed using the simplified procedures as presented in Table 23.1.2-4. However, other boilers of this size and age are estimated to have NO_x reductions in

Table 23.1.2-3. Summary of FGD Control Costs for the Bull Run 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	950	62	0.8	159.2	167.6	72.5	14.1	90.0	31788	2281.7
L/S FGD-C	1	1.38	950	62	0.8	159.2	167.6	42.3	8.2	90.0	31788	1329.7
LC FGD	1	1.38	950	62	0.8	132.4	139.4	64.4	12.5	90.0	31788	2026.9
LC FGD-C	1	1.38	950	62	0.8	132.4	139.4	37.5	7.3	90.0	31788	1179.9
LSD+ESP	1	1.38	950	62	0.8	100.6	105.9	40.9	7.9	76.0	26949	1516.6
LSD+ESP-C	1	1.38	950	62	0.8	100.6	105.9	23.9	4.6	76.0	26949	885.6

TABLE 23.1.2-4. SUMMARY OF NOx RETROFIT RESULTS FOR BULL RUN

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1
FIRING TYPE	TANG
TYPE OF NOx CONTROL	OFA
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)	25
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	146
New Duct Length (Feet)	550
New Duct Costs (1000$)	10171
New Heat Exchanger (1000$)	7195
TOTAL SCOPE ADDER COSTS (1000$)	17513
RETROFIT FACTOR FOR SCR	1.22
GENERAL FACILITIES (PERCENT)	13

the range of 25 to 30 percent. Table 23.1.2-5 presents the estimated cost of retrofitting OFA to this boiler.

Selective Catalytic Reduction--

Table 23.1.2-4 presents the SCR retrofit results for unit 1. The results include a process area retrofit factor 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.

The SCR reactor and the ammonia storage system were placed in low access/congestion areas with no significant underground obstructions. The reactor was located to the east of the plant/ESPs and in close proximity to part of the railroad. The ammonia storage system location was similar to that of the limestone storage/preparation area: adjacent to the live coal storage area (southwest) and directly south of the ESPs and fly ash silo. Table 23.1.2-5 presents the estimated cost of retrofitting SCR at this boiler.

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 south of the plant in a relatively open area in the same manner as LSD-FGD technology. The retrofit of DSD and FSI technologies at the Bull Run steam plant would be relatively easy due to the sufficient flue gas ducting residence time (4.3 seconds) between the boilers and the retrofit ESPs. No additional particulate controls would be needed. The conversion of the wet ash handling system to dry handling would be required when reusing the ESPs for DSD and FSI technologies. Table 23.1.2-6 presents a summary of site access/congestion factors, scope adders, and retrofit factors for DSD and FSI

Table 23.1.2-5. NOx Control Cost Results for the Bull Run 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	950	62	0.8	1.5	1.6	0.3	0.1	25.0	4245	75.9
LNC-OFA-C	1	1.00	950	62	0.8	1.5	1.6	0.2	0.0	25.0	4245	45.1
SCR-3	1	1.22	950	62	0.8	117.3	123.5	42.4	8.2	80.0	13584	3118.4
SCR-3-C	1	1.22	950	62	0.8	117.3	123.5	24.8	4.8	80.0	13584	1825.3
SCR-7	1	1.22	950	62	0.8	117.3	123.5	34.5	6.7	80.0	13584	2539.3
SCR-7-C	1	1.22	950	62	0.8	117.3	123.5	20.3	3.9	80.0	13584	1493.6

TABLE 23.1.2-6. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR BULL RUN UNIT 1

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$)	7055
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	100
DEMOLITION COST (1000$)	324

TOTAL COST (1000$)	
ESP UPGRADE CASE	7379
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.34
NEW BAGHOUSE	NA

technologies at the Bull Run steam plant. Table 23.1.2-7 presents the estimated cost of retrofitting DSD and FSI at this boiler.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

Using the applicability criteria for AFBC retrofit and AFBC/coal gasification/combined cycle repowering discussed in Section 2, the boiler at the Bull Run plant is too large to be considered a candidate for retrofit or repowering. The boiler would not be considered a candidate for AFBC/CG repowering retrofit because the boiler size is much larger than 300 MW with moderate age and high to moderate capacity factor.

23.1.3 Cumberland Steam Plant

Information on Cumberland 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).

23.1.4 Gallatin Steam Plant

The Gallatin steam plant is located within Summer County, Tennessee, as part of the TVA system. The plant contains four boilers with a total gross generating capacity of 1,256 MW. Figure 23.1.4-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 23.1.4-1 presents operational data for the existing equipment at the Gallatin steam plant. All four boilers burn medium to high sulfur coal (2.8 percent sulfur). Coal shipments are received by rail and conveyed to a coal storage and handling area located west of the plant.

Particulate matter emissions for all four boilers are controlled with retrofit ESPs located behind each unit. Ash from all units is wet sluiced to ponds on the far side of the coal storage area south of the plant. A very large on-site waste disposal area is available.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 23.1.4-1 shows the general layout and location of the FGD control system. Absorbers for L/LS-FGD and LSD-FGD for units 1 and 2 were located in

Table 23.1.2-7. Summary of DSD/FSI Control Costs for the Bull Run 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	950	62	0.8	33.4	35.2	20.1	3.9	49.0	17183	1172.5
DSD+ESP-C	1	1.00	950	62	0.8	33.4	35.2	11.7	2.3	49.0	17183	680.5
FSI+ESP-50	1	1.00	950	62	0.8	30.8	32.4	19.4	3.8	50.0	17660	1100.4
FSI+ESP-50-C	1	1.00	950	62	0.8	30.8	32.4	11.3	2.2	50.0	17660	638.2
FSI+ESP-70	1	1.00	950	62	0.8	31.0	32.6	19.8	3.8	70.0	24723	799.0
FSI+ESP-70-C	1	1.00	950	62	0.8	31.0	32.6	11.5	2.2	70.0	24723	463.4

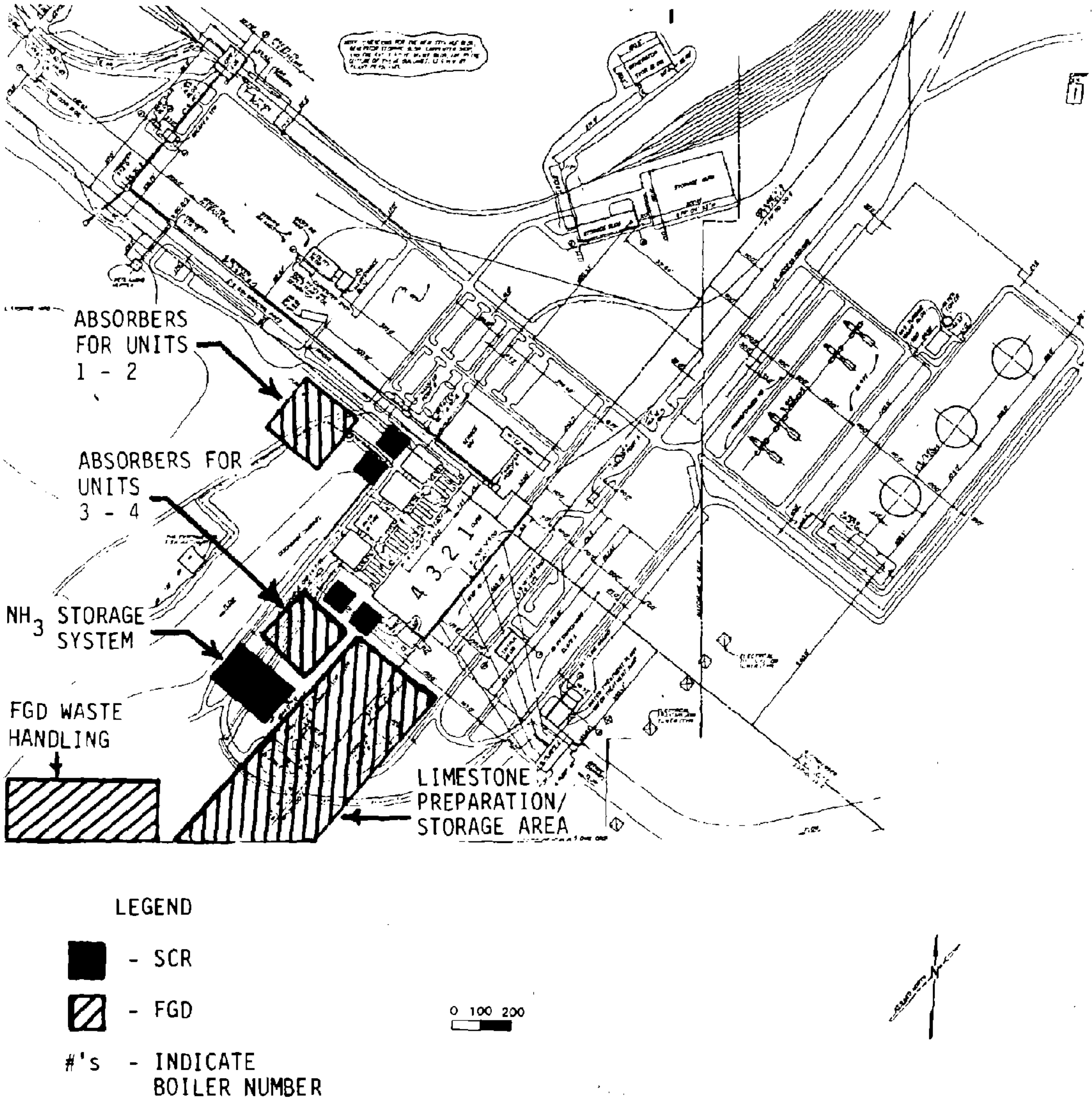

Figure 23.1.4-1. Gallatin plant plot plan

TABLE 23.1.4-1. GALLATIN STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3,4
GENERATING CAPACITY (MW-each)	300	328
CAPACITY FACTOR (PERCENT)	52, 57	72, 76
INSTALLATION DATE	1956-57	1959
FIRING TYPE	TANG	TANG
COAL SULFUR CONTENT (PERCENT)	2.8, 2.7	2.8, 2.7
COAL HEATING VALUE (BTU/LB)	12300	12300
COAL ASH CONTENT (PERCENT)	8.5	8.5
FLY ASH SYSTEM	WET SLUICE	
ASH DISPOSAL METHOD	POND/ON-SITE	
STACK NUMBER	1	2
COAL DELIVERY METHODS	RAILROAD	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1979-78	1979
EMISSION (LB/MM BTU)	0.02	0.0235
REMOVAL EFFICIENCY	99.5	99.5
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	1.0	1.0
SURFACE AREA (1000 SQ FT)	391.7	391.7
GAS EXIT RATE (1000 ACFM)	920	1000
SCA (SQ FT/1000 ACFM)	425	427
OUTLET TEMPERATURE (°F)	310	310

a relatively open area west of and adjacent to the units 1 and 2 precipitators between the plant cooling water discharge channel and the coal storage area. Absorbers for units 3 and 4 were located in a large open area south of unit 4. The lime and limestone preparation/storage area and the waste handling area were placed south of unit 4. No significant demolition/relocation was associated with the retrofit of FGD control technologies at Gallatin; therefore, a low factor of 5 percent was assigned to general facilities.

Retrofit Difficulty and Scope Adder Costs--

Due to the location of the coal conveyor and discharge channel, a medium access/congestion factor was assigned to the FGD control equipment for units 1 and 2. The absorbers for units 3 and 4 were located in a large, open area, south of the plant and the location was assigned a low site access/ congestion factor. For flue gas handling, moderate duct runs for the units would be required for L/LS-FGD cases since the absorbers are located close to the ESPs. Medium access/congestion factors were assigned to the L/LS-FGD flue gas handling for all units reflecting the limited accessibility associated with routing the duct runs from the ESPs to the absorbers and back to the chimneys.

The major scope adjustment costs and estimated retrofit factors for the FGD control technologies are presented in Tables 23.1.4-2 and 23.1.4-3. The largest scope adder for Gallatin would be the conversion of units 1 through 4 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 conventional L/LS-FGD scrubber sludge waste and to prevent plugging of the sluice lines in LSD-FGD cases. However, this conversion would not be necessary for the application of forced oxidation L/LS-FGD. The overall retrofit factors determined for the L/LS-FGD cases were moderate (1.35 to 1.53).

The LSD with reused ESP was the only LSD-FGD technology considered because the existing ESPs have large SCAs (>400). The absorbers would be located in the similar locations as in L/LS-FGD cases. High access/ congestion factors were assigned to the LSD-FGD flue gas handling because of the need for duct runs from each boiler to the LSD chambers and back to the

TABLE 23.1.4-2. SUMMARY OF RETROFIT FACTOR DATA FOR GALLATIN UNITS 1-2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	MEDIUM	MEDIUM
FLUE GAS HANDLING	MEDIUM	MEDIUM	
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	YES	NO	YES
ESTIMATED COST (1000$)	2510	NA	2510
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.53	1.47	
ESP REUSE CASE			1.56
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	5	5

TABLE 23.1.4-3. SUMMARY OF RETROFIT FACTOR DATA FOR GALLATIN UNITS 3-4

	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			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	YES	NO	YES
ESTIMATED COST (1000$)	2719	NA	2719
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.42	1.35	
ESP REUSE CASE			1.43
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	5	5

ESPs. The retrofit factors determined for the LSD technologies were moderate (1.43 to 1.56). A separate factor of 1.58 was estimated for particulate control upgrading. This factor reflects the ESPs plate area addition difficulty caused by the access/congestion associated with the close proximity of the existing ESPs and was used by the IAPCS model to determine new particulate control upgrading costs.

Table 23.1.4-4 presents the costs estimated for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs and ash handling systems for boilers 1-4.

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--

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 23.1.4-5.

NO_x Control Technology Costs--

This section presents the performance and various related costs estimated for NO_x controls at Gallatin. 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 Gallatin were: OFA and SCR.

Table 23.1.4-4. Summary of FGD Control Costs for the Gallatin 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	1.53	300	52	2.8	85.0	283.3	36.1	26.5	90.0	27006	1338.5
L/S FGD	2	1.53	300	57	2.7	84.7	282.5	36.8	24.6	90.0	28545	1290.1
L/S FGD	3	1.42	328	72	2.8	83.6	254.9	40.3	19.5	90.0	40883	985.9
L/S FGD	4	1.42	328	76	2.7	83.3	254.1	40.8	18.7	90.0	41613	980.3
L/S FGD-C	1	1.53	300	52	2.8	85.0	283.3	21.1	15.4	90.0	27006	781.0
L/S FGD-C	2	1.53	300	57	2.7	84.7	282.5	21.5	14.3	90.0	28545	752.5
L/S FGD-C	3	1.42	328	72	2.8	83.6	254.9	23.5	11.3	90.0	40883	574.0
L/S FGD-C	4	1.42	328	76	2.7	83.3	254.1	23.7	10.9	90.0	41613	570.6
LC FGD	1-2	1.53	600	55	2.7	109.3	182.2	52.5	18.2	90.0	55088	953.4
LC FGD	3-4	1.42	655	74	2.7	108.8	166.1	60.8	14.3	90.0	80912	751.1
LC FGD-C	1-2	1.53	600	55	2.7	109.3	182.2	30.6	10.6	90.0	55088	555.2
LC FGD-C	3-4	1.42	655	74	2.7	108.8	166.1	35.3	8.3	90.0	80912	436.4
LSD+ESP	1	1.56	300	52	2.8	46.3	154.4	20.3	14.9	76.0	22895	886.6
LSD+ESP	2	1.56	300	57	2.7	46.0	153.4	20.6	13.7	76.0	24200	850.5
LSD+ESP	3	1.43	328	72	2.8	45.3	138.0	22.9	11.1	76.0	34659	661.7
LSD+ESP	4	1.43	328	76	2.7	45.0	137.1	23.1	10.6	76.0	35278	653.9
LSD+ESP-C	1	1.56	300	52	2.8	46.3	154.4	11.8	8.7	76.0	22895	517.0
LSD+ESP-C	2	1.56	300	57	2.7	46.0	153.4	12.0	8.0	76.0	24200	495.8
LSD+ESP-C	3	1.43	328	72	2.8	45.3	138.0	13.3	6.4	76.0	34659	385.0
LSD+ESP-C	4	1.43	328	76	2.7	45.0	137.1	13.4	6.1	76.0	35278	380.4

Table 23.1.4-5. Summary of Coal Switching/Cleaning Costs for the Gallatin 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	300	52	2.8	10.3	34.2	20.2	14.8	67.0	20139	1004.9
CS/B+$15	2	1.00	300	57	2.7	10.3	34.2	22.0	14.7	66.0	20901	1051.2
CS/B+$15	3	1.00	328	72	2.8	11.1	33.8	29.6	14.3	67.0	30487	971.8
CS/B+$15	4	1.00	328	76	2.7	11.1	33.8	31.1	14.3	66.0	30469	1022.1
CS/B+$15-C	1	1.00	300	52	2.8	10.3	34.2	11.6	8.5	67.0	20139	578.1
CS/B+$15-C	2	1.00	300	57	2.7	10.3	34.2	12.6	8.4	66.0	20901	604.5
CS/B+$15-C	3	1.00	328	72	2.8	11.1	33.8	17.0	8.2	67.0	30487	558.4
CS/B+$15-C	4	1.00	328	76	2.7	11.1	33.8	17.9	8.2	66.0	30469	587.2
CS/B+$5	1	1.00	300	52	2.8	7.2	23.8	8.4	6.2	67.0	20139	417.4
CS/B+$5	2	1.00	300	57	2.7	7.2	23.8	9.1	6.0	66.0	20901	433.2
CS/B+$5	3	1.00	328	72	2.8	7.7	23.4	11.9	5.8	67.0	30487	391.8
CS/B+$5	4	1.00	328	76	2.7	7.7	23.4	12.5	5.7	66.0	30469	410.6
CS/B+$5-C	1	1.00	300	52	2.8	7.2	23.8	4.8	3.5	67.0	20139	240.7
CS/B+$5-C	2	1.00	300	57	2.7	7.2	23.8	5.2	3.5	66.0	20901	249.7
CS/B+$5-C	3	1.00	328	72	2.8	7.7	23.4	6.9	3.3	67.0	30487	225.6
CS/B+$5-C	4	1.00	328	76	2.7	7.7	23.4	7.2	3.3	66.0	30469	236.4

Low NO_x Combustion--

Units 1 to 4 are dry bottom, tangential-fired boilers. Units 1 and 2 are rated at 300 MW each and units 3 and 4 are rated at 328 MW each. The NO_x combustion control considered in this analysis was OFA. Tables 23.1.4-6 and 23.1.4-7 present the OFA NO_x reduction performance results for units 1-2 and 3-4. The NO_x reduction performance estimated for units 1 and 2, was 25 percent. The NO_x reduction for units 3 and 4 was estimated to be 15 percent. The NO_x reduction performance for units 3 and 4 was lower than that for units 1 and 2 because units 3 and 4 have higher heat release rates and lower furnace residence time than units 1 and 2. Table 23.1.4-8 presents the estimated cost of retrofitting OFA at units 1-4.

Selective Catalytic Reduction--

Tables 23.1.4-6 and 23.1.4-7 also present 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 heat exchanger, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimneys.

The SCR reactors for units 1 and 2 were located west of the plant in a relatively high access/congestion area. They would be bounded by the coal conveyor and water discharge channel. The SCR reactors for units 3 and 4 were located southwest of the plant in a relatively low access/congestion area. The ammonia storage system for all units was also located southwest of the plant in a relatively open area.

A high access/congestion factor was assigned to the reactors for units 1 and 2, because each is blocked on three sides by the ESPs, the coal conveyor, and the discharge channel. Reactors for units 3 and 4 were assigned a low access/congestion factor because they were located in an easily accessible and relatively open area adjacent to boiler/ESPs of unit 4. All reactors were assumed to be in areas with high underground obstructions. Table 23.1.4-8 presents the estimated cost of retrofitting SCR at units 1-4.

TABLE 23.1.4-6. SUMMARY OF NOx RETROFIT RESULTS FOR GALLATIN 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)	15.4	15.4	16.4
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	34.8	34.8	68.7
FURNACE RESIDENCE TIME (SECONDS)	3.85	3.85	2.89
ESTIMATED NOx REDUCTION (PERCENT)	25	25	15
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	62	62	66
New Duct Length (Feet)	500	500	490
New Duct Costs (1000$)	4711	4711	4864
New Heat Exchanger (1000$)	3603	3603	3801
TOTAL SCOPE ADDER COSTS (1000$)	8376	8376	8732
RETROFIT FACTOR FOR SCR	1.52	1.52	1.16
GENERAL FACILITIES (PERCENT)	13	13	13

TABLE 23.1.4-7. SUMMARY OF NOx RETROFIT RESULTS FOR GALLATIN UNIT 4

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	4
FIRING TYPE	TANG
TYPE OF NOx CONTROL	OFA
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	16.4
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	68.7
FURNACE RESIDENCE TIME (SECONDS)	2.89
ESTIMATED NOx REDUCTION (PERCENT)	15
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	66
New Duct Length (Feet)	290
New Duct Costs (1000$)	2879
New Heat Exchanger (1000$)	3801
TOTAL SCOPE ADDER COSTS (1000$)	6746
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	13

Table 23.1.4-8. NOx Control Cost Results for the Gallatin 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	300	52	2.8	1.0	3.2	0.2	0.1	25.0	1030	197.2
LNC-OFA	2	1.00	300	57	2.7	1.0	3.2	0.2	0.1	25.0	1130	179.9
LNC-OFA	3	1.00	328	72	2.8	1.0	3.0	0.2	0.1	15.0	936	225.1
LNC-OFA	4	1.00	328	76	2.7	1.0	3.0	0.2	0.1	15.0	988	213.3
LNC-OFA-C	1	1.00	300	52	2.8	1.0	3.2	0.1	0.1	25.0	1030	117.1
LNC-OFA-C	2	1.00	300	57	2.7	1.0	3.2	0.1	0.1	25.0	1130	106.9
LNC-OFA-C	3	1.00	328	72	2.8	1.0	3.0	0.1	0.1	15.0	936	133.8
LNC-OFA-C	4	1.00	328	76	2.7	1.0	3.0	0.1	0.1	15.0	988	126.7
SCR-3	1	1.52	300	52	2.8	51.3	170.9	16.4	12.0	80.0	3297	4984.5
SCR-3	2	1.52	300	57	2.7	51.3	170.9	16.5	11.0	80.0	3615	4569.3
SCR-3	3	1.16	328	72	2.8	47.5	144.8	16.3	7.9	80.0	4992	3260.1
SCR-3	4	1.16	328	76	2.7	45.5	138.6	16.0	7.3	80.0	5269	3035.6
SCR-3-C	1	1.52	300	52	2.8	51.3	170.9	9.6	7.1	80.0	3297	2925.5
SCR-3-C	2	1.52	300	57	2.7	51.3	170.9	9.7	6.5	80.0	3615	2681.5
SCR-3-C	3	1.16	328	72	2.8	47.5	144.8	9.5	4.6	80.0	4992	1910.5
SCR-3-C	4	1.16	328	76	2.7	45.5	138.6	9.4	4.3	80.0	5269	1777.9
SCR-7	1	1.52	300	52	2.8	51.3	170.9	14.0	10.2	80.0	3297	4239.6
SCR-7	2	1.52	300	57	2.7	51.3	170.9	14.1	9.4	80.0	3615	3889.8
SCR-7	3	1.16	328	72	2.8	47.5	144.8	13.6	6.6	80.0	4992	2722.2
SCR-7	4	1.16	328	76	2.7	45.5	138.6	13.3	6.1	80.0	5269	2526.0
SCR-7-C	1	1.52	300	52	2.8	51.3	170.9	8.2	6.0	80.0	3297	2498.7
SCR-7-C	2	1.52	300	57	2.7	51.3	170.9	8.3	5.5	80.0	3615	2292.2
SCR-7-C	3	1.16	328	72	2.8	47.5	144.8	8.0	3.9	80.0	4992	1602.3
SCR-7-C	4	1.16	328	76	2.7	45.5	138.6	7.8	3.6	80.0	5269	1485.9

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 west of the plant for units 1 and 2 and south of the plant for units 3 and 4 in relatively open areas where they would be close to the units. The retrofit of DSD and FSI technologies at the Gallatin steam plant would be possible primarily because the retrofit ESPs are large (SCA >400). For reusing the ESPs, the conversion of wet to dry fly ash handling system would be required for FSI and DSD technologies. Tables 23.1.4-9 and 23.1.4-10 present a summary of site access/congestion factors, scope adders, and retrofit factors for DSD and FSI technologies at Gallatin steam plant.

Table 23.1.4-11 presents the costs estimated to retrofit DSD and FSI at the Gallatin plant. Where additional ESP plate area was needed, a high access/congestion factor (1.55) was applied.

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 Gallatin units. Because boiler sizes at the Gallatin plant are not less than 300 MW and the units have moderate/high capacity factors, they were not considered good candidates for AFBC retrofit and AFBC or CG/combined cycle repowering.

23.1.5 Johnsonville Steam Plant

Information on Johnsonville 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).

TABLE 23.1.4-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR GALLATIN UNITS 1-2

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$)	2510
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	68

TOTAL COST (1000$)	
ESP UPGRADE CASE	2578
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE	1.55
NEW BAGHOUSE	NA

TABLE 23.1.4-10. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR GALLATIN UNITS 3-4

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$)	2719
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	73

TOTAL COST (1000$)	
ESP UPGRADE CASE	2792
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.55
NEW BAGHOUSE	NA

Table 23.1.4-11. Summary of DSD/FSI Control Costs for the Gallatin 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	300	52	2.8	18.4	61.4	12.0	8.8	49.0	14598	824.4
DSO+ESP	2	1.00	300	57	2.7	18.2	60.6	12.3	8.2	49.0	15430	797.3
DSD+ESP	3	1.00	328	72	2.8	19.5	59.3	15.0	7.3	49.0	22099	680.1
DSD+ESP	4	1.00	328	76	2.7	19.2	58.5	15.1	6.9	49.0	22494	673.5
DSD+ESP-C	1	1.00	300	52	2.8	18.4	61.4	7.0	5.1	49.0	14598	478.0
DSD+ESP-C	2	1.00	300	57	2.7	18.2	60.6	7.1	4.8	49.0	15430	462.1
DSD+ESP-C	3	1.00	328	72	2.8	19.5	59.3	8.7	4.2	49.0	22099	393.6
DSD+ESP-C	4	1.00	328	76	2.7	19.2	58.5	8.8	4.0	49.0	22494	389.7
FSI+ESP-50	1	1.00	300	52	2.8	17.4	58.0	14.2	10.4	50.0	15003	947.0
FSI+ESP-50	2	1.00	300	57	2.7	17.2	57.4	14.7	9.8	50.0	15859	926.8
FSI+ESP-50	3	1.00	328	72	2.8	18.6	56.8	19.2	9.3	50.0	22713	844.9
FSI+ESP-50	4	1.00	328	76	2.7	18.4	56.2	19.4	8.9	50.0	23118	839.5
FSI+ESP-50-C	1	1.00	300	52	2.8	17.4	58.0	8.2	6.0	50.0	15003	547.8
FSI+ESP-50-C	2	1.00	300	57	2.7	17.2	57.4	8.5	5.7	50.0	15859	535.9
FSI+ESP-50-C	3	1.00	328	72	2.8	18.6	56.8	11.1	5.4	50.0	22713	487.7
FSI+ESP-50-C	4	1.00	328	76	2.7	18.4	56.2	11.2	5.1	50.0	23118	484.5
FSI+ESP-70	1	1.00	300	52	2.8	17.7	58.8	14.5	10.6	70.0	21005	690.2
FSI+ESP-70	2	1.00	300	57	2.7	17.5	58.2	15.0	10.0	70.0	22202	675.5
FSI+ESP-70	3	1.00	328	72	2.8	18.9	57.6	19.6	9.5	70.0	31798	616.3
FSI+ESP-70	4	1.00	328	76	2.7	18.7	57.0	19.8	9.1	70.0	32365	612.4
FSI+ESP-70-C	1	1.00	300	52	2.8	17.7	58.8	8.4	6.1	70.0	21005	399.2
FSI+ESP-70-C	2	1.00	300	57	2.7	17.5	58.2	8.7	5.8	70.0	22202	390.5
FSI+ESP-70-C	3	1.00	328	72	2.8	18.9	57.6	11.3	5.5	70.0	31798	355.8
FSI+ESP-70-C	4	1.00	328	76	2.7	18.7	57.0	11.4	5.2	70.0	32365	353.4

23.1.6 Kingston Steam Plant

The Kingston steam plant is located within Roane County, Tennessee, as part of the TVA system. The plant contains nine coal-fired boilers with a total gross generating capacity of 1700 MW. Figure 23.1.6-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 23.1.6-1 presents operational data for the existing equipment at the Kingston steam plant. All boilers burn low sulfur coal (1.1 percent sulfur). Coal shipments are received by rail and conveyed to a coal storage and handling area located west of the plant. Coal can also be received by truck.

Particulate matter emissions for all boilers are controlled with retrofit ESPs located west of the old ESPs and chimneys. Ash from all units is wet sluiced to a new off-site ash pond.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 23.1.6-1 shows the general layout and location of the FGD control system. The absorbers for units 1 to 4 for L/LS-FGD would be located northwest of the plant in a relatively open area. The location of the absorbers for units 5 to 9 west of the plant would involve the costly demolition and relocation of the plant railroad. The absorbers were, as a result, placed south of the unit 9 powerhouse. The absorbers for units 1 to 9 for LSD-FGD technology would be located in the area between the old ESPs/chimneys and the retrofit ESPs. The old ESPs/chimneys would have to be demolished to make space available for LSD-FGD absorbers.

The limestone and lime preparation/storage area and waste handling area for units 1-4 were located north of units 1-4. The limestone and lime preparation/storage area and the waste handling area for units 5-9 were placed adjacent to the absorbers for units 5 to 9.

Retrofit Difficulty and Scope Adder Costs--

The FGD equipment for all units was assigned a low access/congestion factor. The absorbers for units 1 to 4 were placed on what is currently an employee parking lot while the absorbers for units 5 to 9 were placed in an

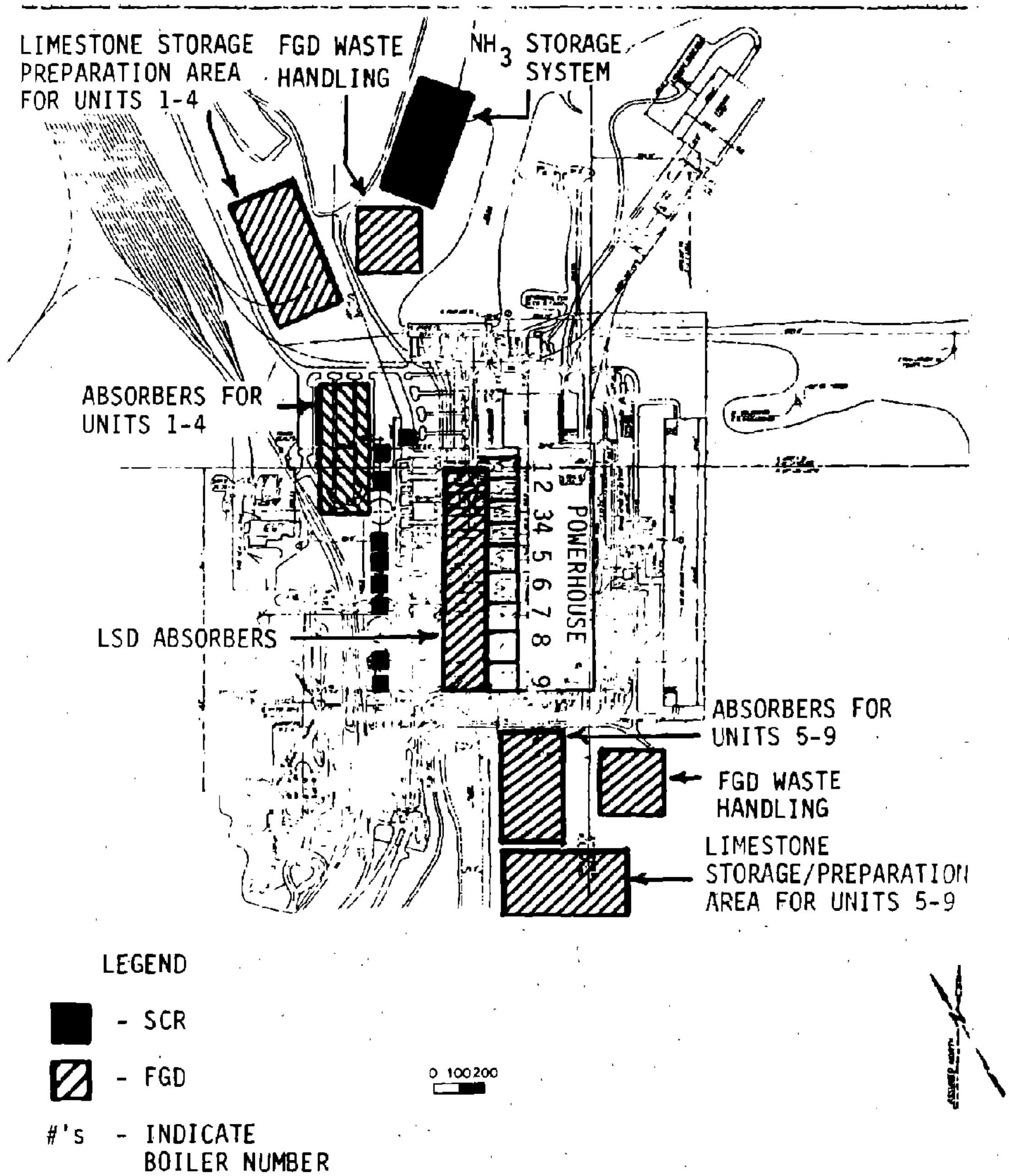

Figure 23.1.6-1. Kingston plant plot plan

TABLE 23.1.6-1. KINGSTON STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1-4	5-9
GENERATING CAPACITY (MW-each)	175	200
CAPACITY FACTOR (PERCENT)	50-53	50-67
INSTALLATION DATE	1954	1955
FIRING TYPE	TANG	TANG
COAL SULFUR CONTENT (PERCENT)	1.10	1.10
COAL HEATING VALUE (BTU/LB)	12000	12000
COAL ASH CONTENT (PERCENT)	12	12
FLY ASH SYSTEM	WET SLUICE	
ASH DISPOSAL METHOD	POND/OFF-SITE	
STACK NUMBER	1	2
COAL DELIVERY METHODS	RAIL/TRUCK	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1977-76	1976
EMISION (LB/MM BTU)	0.02	0.01
REMOVAL EFFICIENCY	99.9	99.9
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	0.9	0.9
SURFACE AREA (1000 SQ FT)	287.6	388.8
GAS EXIT RATE (1000 ACFM)	500	700
SCA (SQ FT/1000 ACFM)	575	555
OUTLET TEMPERATURE (°F)	310	310

open area below (south) the powerhouse. For flue gas handling, short duct runs for units 1-4 would be required for L/LS-FGD because the absorbers are located close to the chimney. Long duct runs for units 5-9 would be required because absorbers are located away from the ESPs. A low flue gas handling factor was assigned to units 1 to 4 for L/LS-FGD and a medium factor was assigned to units 5 to 9. The low flue gas handling factor reflects the location of the absorber next to the chimney and the fact that no significant ductwork would be required to route the flue gas from the absorbers to the chimney. On the other hand, the location chosen for the units 5 to 9 absorbers would involve routing the flue gas around units 8 and 9 and then to the absorbers. Also, the duct runs would be adjacent to the coal conveyor.

The major scope adjustment costs and estimated retrofit factors for the FGD control technologies are presented in Tables 23.1.6-2 and 23.1.6-3. The largest scope adder for Kingston was the conversion of units 1 through 9 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 conventional L/LS-FGD scrubber sludge waste and to prevent plugging of the sluice lines for 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 ranged from low (1.24 for units 1-4) to high (1.71 for units 5-9).

The only LSD-FGD case evaluated was LSD with ESP reuse. The LSD-FGD absorbers were located in a high site access/congestion area between the old ESPs/chimney and retrofit ESPs. To reduce the boiler's downtime, a bypass duct would be used to reroute the flue gas around each absorber under construction. This bypass duct could also be used for other absorbers during construction. For flue gas handling short duct runs would be required and a medium site access/congestion factor was assigned to the flue gas handling system because of access difficulty created by the powerhouse, ESPs, and existing duct runs. The retrofit factors estimated were medium (1.53) for all units and did not include particulate control upgrading costs. A separate retrofit factor was developed for the ESPs upgrade and used by the IAPCS model to estimate the particulate control upgrading costs. This factor, estimated for the ESP upgrading cost, was

TABLE 23.1.6-2. SUMMARY OF RETROFIT FACTOR DATA FOR KINGSTON UNITS 1-4

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	HIGH
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	100-300	
ESP REUSE			0-100
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	1548	NA	1548
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER (old ESP's demolition)	NO	NO	YES
RETROFIT FACTORS			
FGD SYSTEM	1.31	1.24	
ESP REUSE CASE			1.53
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	7	7	10

TABLE 23.1.6-3. SUMMARY OF RETROFIT FACTOR DATA FOR KINGSTON UNITS 5-9

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	HIGH
FLUE GAS HANDLING	MEDIUM	MEDIUM	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	1000 +	1000 +	
ESP REUSE			0-100
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	1745	NA	1745
NEW CHIMNEY	YES	YES	NO
ESTIMATED COST (1000$)	1400	1400	0
OTHER (old ESP's demolition)	NO	NO	YES
RETROFIT FACTORS			
FGD SYSTEM	1.71	1.63	
ESP REUSE CASE			1.53
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	5	10

high (1.58) and reflects the congestion which exists around the existing ESPs because of the close proximity of ESPs.

Table 23.1.6-4 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 1-9.

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--

The plant has already switched to low sulfur coal.

NO_x Control Technology Costs--

This section presents the performance and various related costs estimated for NO_x controls at Kingston. 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 Kingston were: OFA and SCR.

Low NO_x Combustion--

Units 1 to 9 are dry bottom, tangential wall-fired boilers. Units 1 to 4 are rated at 175 MW each and units 5 to 9 are rated at 200 MW each. The NO_x combustion control considered in this analysis was OFA. Tables 23.1.6-5 through 23.1.6-7 present the estimated OFA NO_x reduction performance levels for units 1 to 9. The NO_x reduction performance estimated for each of the nine units was 20 percent which was obtained by examining the effects of heat release rate and furnace residence time on NO_x reduction using the simplified NO_x procedures. Table 23.1.6-8 presents the costs estimated for retrofitting OFA at the Kingston plant nine boilers.

Selective Catalytic Reduction--

Tables 23.1.6-5 through 23.1.6-7 also present the SCR retrofit results for each unit. The results include a process area retrofit factor and scope

Table 23.1.6-4. Summary of FGD Control Costs for the Kingston 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	1.31	700	53	1.1	120.3	171.8	52.8	16.2	90.0	25957	2033.8
L/S FGD	5-9	1.71	1000	67	1.1	207.9	207.9	91.5	15.6	90.0	46876	1951.0
L/S FGD-C	1-4	1.31	700	53	1.1	120.3	171.8	30.8	9.5	90.0	25957	1186.0
L/S FGD-C	5-9	1.71	1000	67	1.1	207.9	207.9	53.3	9.1	90.0	46876	1137.7
LC FGD	1-4	1.31	700	53	1.1	96.2	137.4	45.5	14.0	90.0	25957	1753.0
LC FGD	5-9	1.71	1000	67	1.1	161.0	161.0	77.1	13.1	90.0	46876	1645.8
LC FGD-C	1-4	1.31	700	53	1.1	96.2	137.4	26.5	8.2	90.0	25957	1021.0
LC FGD-C	5-9	1.71	1000	67	1.1	161.0	161.0	44.9	7.7	90.0	46876	958.3
LSD+ESP	1	1.53	175	50	1.1	26.3	150.5	11.1	14.4	76.0	5190	2132.4
LSD+ESP	2	1.53	175	40	1.1	26.3	150.5	10.7	17.5	76.0	4152	2578.5
LSD+ESP	3	1.53	175	60	1.1	26.3	150.5	11.4	12.4	76.0	6228	1835.3
LSD+ESP	4	1.53	175	63	1.1	26.3	150.5	11.5	11.9	76.0	6539	1764.6
LSD+ESP	5	1.53	200	55	1.1	31.6	157.8	13.0	13.5	76.0	6525	1986.8
LSD+ESP	6	1.53	200	79	1.1	31.6	157.8	14.0	10.1	76.0	9372	1490.0
LSD+ESP	7	1.53	200	61	1.1	31.6	157.8	13.2	12.4	76.0	7236	1825.8
LSD+ESP	8	1.53	200	60	1.1	31.6	157.8	13.2	12.5	76.0	7118	1850.4
LSD+ESP	9	1.53	200	80	1.1	31.6	157.8	14.0	10.0	76.0	9490	1475.8
LSD+ESP-C	1	1.53	175	50	1.1	26.3	150.5	6.5	8.4	76.0	5190	1244.5
LSD+ESP-C	2	1.53	175	40	1.1	26.3	150.5	6.3	10.2	76.0	4152	1505.7
LSD+ESP-C	3	1.53	175	60	1.1	26.3	150.5	6.7	7.2	76.0	6228	1070.5
LSD+ESP-C	4	1.53	175	63	1.1	26.3	150.5	6.7	7.0	76.0	6539	1029.1
LSD+ESP-C	5	1.53	200	55	1.1	31.6	157.8	7.6	7.9	76.0	6525	1160.0
LSD+ESP-C	6	1.53	200	79	1.1	31.6	157.8	8.1	5.9	76.0	9372	868.8
LSD+ESP-C	7	1.53	200	61	1.1	31.6	157.8	7.7	7.2	76.0	7236	1065.6
LSD+ESP-C	8	1.53	200	60	1.1	31.6	157.8	7.7	7.3	76.0	7118	1080.0
LSD+ESP-C	9	1.53	200	80	1.1	31.6	157.8	8.2	5.8	76.0	9490	860.5

TABLE 23.1.6-5. SUMMARY OF NOx RETROFIT RESULTS FOR KINGSTON UNTIS 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)	30.2	30.2	30.2
FURNACE RESIDENCE TIME (SECONDS)	3.01	3.01	3.01
ESTIMATED NOx REDUCTION (PERCENT)	20	20	20
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	MEDIUM
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	41	41	41
New Duct Length (Feet)	267	267	200
New Duct Costs (1000$)	1835	1835	1375
New Heat Exchanger (1000$)	2608	2608	2608
TOTAL SCOPE ADDER COSTS (1000$)	4484	4484	4024
RETROFIT FACTOR FOR SCR	1.16	1.16	1.34
GENERAL FACILITIES (PERCENT)	13	13	13

TABLE 23.1.6-6. SUMMARY OF NOx RETROFIT RESULTS FOR KINGSTON 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	16.1	16.1
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	30.2	25.4	25.4
FURNACE RESIDENCE TIME (SECONDS)	3.01	2.58	2.58
ESTIMATED NOx REDUCTION (PERCENT)	20	20	20
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	LOW	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	41	45	45
New Duct Length (Feet)	167	250	333
New Duct Costs (1000$)	1148	1858	2475
New Heat Exchanger (1000$)	2608	2825	2825
TOTAL SCOPE ADDER COSTS (1000$)	3797	4729	5346
RETROFIT FACTOR FOR SCR	1.34	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13	13

TABLE 23.1.6-7. SUMMARY OF NOx RETROFIT RESULTS FOR KINGSTON UNITS 7-9

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	7	8	9
FIRING TYPE	TANG	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA	OFA
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	16.1	16.1	16.1
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	25.4	25.4	25.4
FURNACE RESIDENCE TIME (SECONDS)	2.58	2.58	2.58
ESTIMATED NOx REDUCTION (PERCENT)	20	20	20
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	MEDIUM	HIGH
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	45	45	45
New Duct Length (Feet)	267	167	267
New Duct Costs (1000$)	1985	1241	1985
New Heat Exchanger (1000$)	2825	2825	2825
TOTAL SCOPE ADDER COSTS (1000$)	4855	4112	4855
RETROFIT FACTOR FOR SCR	1.34	1.34	1.52
GENERAL FACILITIES (PERCENT)	25	25	25

Table 23.1.6-8. NOx Control Cost Results for the Kingston 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	175	50	1.1	0.8	4.4	0.2	0.2	20.0	476	344.6
LNC-OFA	2	1.00	175	40	1.1	0.8	4.4	0.2	0.3	20.0	381	430.7
LNC-OFA	3	1.00	175	60	1.1	0.8	4.4	0.2	0.2	20.0	571	287.1
LNC-OFA	4	1.00	175	63	1.1	0.8	4.4	0.2	0.2	20.0	599	273.5
LNC-OFA	5	1.00	200	55	1.1	0.8	4.1	0.2	0.2	20.0	598	289.3
LNC-OFA	6	1.00	200	79	1.1	0.8	4.1	0.2	0.1	20.0	859	201.4
LNC-OFA	7	1.00	200	61	1.1	0.8	4.1	0.2	0.2	20.0	663	260.9
LNC-OFA	8	1.00	200	60	1.1	0.8	4.1	0.2	0.2	20.0	652	265.2
LNC-OFA	9	1.00	200	80	1.1	0.8	4.1	0.2	0.1	20.0	870	198.9
LNC-OFA-C	1	1.00	175	50	1.1	0.8	4.4	0.1	0.1	20.0	476	204.8
LNC-OFA-C	2	1.00	175	40	1.1	0.8	4.4	0.1	0.2	20.0	381	256.0
LNC-OFA-C	3	1.00	175	60	1.1	0.8	4.4	0.1	0.1	20.0	571	170.6
LNC-OFA-C	4	1.00	175	63	1.1	0.8	4.4	0.1	0.1	20.0	599	162.5
LNC-OFA-C	5	1.00	200	55	1.1	0.8	4.1	0.1	0.1	20.0	598	171.7
LNC-OFA-C	6	1.00	200	79	1.1	0.8	4.1	0.1	0.1	20.0	859	119.6
LNC-OFA-C	7	1.00	200	61	1.1	0.8	4.1	0.1	0.1	20.0	663	154.9
LNC-OFA-C	8	1.00	200	60	1.1	0.8	4.1	0.1	0.1	20.0	652	157.4
LNC-OFA-C	9	1.00	200	80	1.1	0.8	4.1	0.1	0.1	20.0	870	118.1
SCR-3	1	1.16	175	50	1.1	27.7	158.3	9.2	12.0	80.0	1903	4814.8
SCR-3	2	1.16	175	40	1.1	27.7	158.3	9.1	14.8	80.0	1522	5959.1
SCR-3	3	1.34	175	60	1.1	29.6	169.3	9.7	10.6	80.0	2283	4268.8
SCR-3	4	1.34	175	63	1.1	29.4	167.9	9.7	10.1	80.0	2397	4060.8
SCR-3	5	1.16	200	55	1.1	30.4	152.1	10.2	10.6	80.0	2392	4274.5
SCR-3	6	1.16	200	79	1.1	31.1	155.3	10.6	7.7	80.0	3436	3088.3
SCR-3	7	1.34	200	61	1.1	34.3	171.6	11.2	10.5	80.0	2653	4231.4
SCR-3	8	1.34	200	60	1.1	33.6	167.8	11.1	10.5	80.0	2609	4246.7
SCR-3	9	1.52	200	80	1.1	37.1	185.4	12.1	8.6	80.0	3479	3481.6
SCR-3-C	1	1.16	175	50	1.1	27.7	158.3	5.4	7.0	80.0	1903	2823.8
SCR-3-C	2	1.16	175	40	1.1	27.7	158.3	5.3	8.7	80.0	1522	3495.8
SCR-3-C	3	1.34	175	60	1.1	29.6	169.3	5.7	6.2	80.0	2283	2503.9

continued . . .

Table 23.1.6-8. NOx Control Cost Results for the Kingston 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	4	1.34	175	63	1.1	29.4	167.9	5.7	5.9	80.0	2397	2381.5
SCR-3-C	5	1.16	200	55	1.1	30.4	152.1	6.0	6.2	80.0	2392	2506.1
SCR-3-C	6	1.16	200	79	1.1	31.1	155.3	6.2	4.5	80.0	3436	1809.9
SCR-3-C	7	1.34	200	61	1.1	34.3	171.6	6.6	6.2	80.0	2653	2482.3
SCR-3-C	8	1.34	200	60	1.1	33.6	167.8	6.5	6.2	80.0	2609	2490.8
SCR-3-C	9	1.52	200	80	1.1	37.1	185.4	7.1	5.1	80.0	3479	2042.5
SCR-7	1	1.16	175	50	1.1	27.7	158.3	7.7	10.1	80.0	1903	4058.9
SCR-7	2	1.16	175	40	1.1	27.7	158.3	7.6	12.4	80.0	1522	5014.1
SCR-7	3	1.34	175	60	1.1	29.6	169.3	8.3	9.0	80.0	2283	3638.9
SCR-7	4	1.34	175	63	1.1	29.4	167.9	8.3	8.6	80.0	2397	3460.9
SCR-7	5	1.16	200	55	1.1	30.4	152.1	8.6	8.9	80.0	2392	3587.5
SCR-7	6	1.16	200	79	1.1	31.1	155.3	9.0	6.5	80.0	3436	2610.0
SCR-7	7	1.34	200	61	1.1	34.3	171.6	9.6	9.0	80.0	2653	3611.9
SCR-7	8	1.34	200	60	1.1	33.6	167.8	9.4	9.0	80.0	2609	3617.0
SCR-7	9	1.52	200	80	1.1	37.1	185.4	10.5	7.5	80.0	3479	3009.2
SCR-7-C	1	1.16	175	50	1.1	27.7	158.3	4.5	5.9	80.0	1903	2390.7
SCR-7-C	2	1.16	175	40	1.1	27.7	158.3	4.5	7.3	80.0	1522	2954.4
SCR-7-C	3	1.34	175	60	1.1	29.6	169.3	4.9	5.3	80.0	2283	2143.0
SCR-7-C	4	1.34	175	63	1.1	29.4	167.9	4.9	5.1	80.0	2397	2037.8
SCR-7-C	5	1.16	200	55	1.1	30.4	152.1	5.1	5.2	80.0	2392	2112.4
SCR-7-C	6	1.16	200	79	1.1	31.1	155.3	5.3	3.8	80.0	3436	1535.9
SCR-7-C	7	1.34	200	61	1.1	34.3	171.6	5.6	5.3	80.0	2653	2127.4
SCR-7-C	8	1.34	200	60	1.1	33.6	167.8	5.6	5.3	80.0	2609	2129.9
SCR-7-C	9	1.52	200	80	1.1	37.1	185.4	6.2	4.4	80.0	3479	1771.9

adder costs. The scope adders include costs estimated for ductwork demolition, a new flue gas heat exchanger, and new duct runs to divert the flue gas from the ESP outlets to the reactor and from the reactor to the chimney.

The reactor for unit 1 was located north of the units near the ESPs between both parking lots in a relatively low access/congestion area. The reactors for units 2 to 9 were located northwest of the plant approximately behind the ESPs of each unit in low to high access/congestion areas. The ammonia storage system was located north of the plant in a relatively open area.

Reactors for units 1, 2, 5 and 6 were located in low access/congestion areas. Reactors for units 1 to 2 were located close to the parking lots and those for units 5 and 6 were located between the ESPs and the railroad tracks. The reactors for units 3, 4, 7 and 8 were in medium access/congestion areas because they were placed on either side of the chimneys. The reactor for unit 9 was located in a high access/congestion area being blocked on three sides by the ESPs, railroad tracks, and a building. All reactors were assumed to be in areas with high underground obstructions. Table 23.1.6-8 presents the costs estimated for retrofitting SCR at the Kingston plant 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 would be located west of the plant similar to the LSD-FGD equipment layout. The retrofit of DSD and FSI technologies at the Kingston steam plant would be relatively easy because of sufficient flue gas ducting residence time (5 seconds) before the retrofit ESPs and no additional particulate controls would be needed because of the large ESP sizes (SCA >500). Tables 23.1.6-9

TABLE 23.1.6-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR KINGSTON UNITS 1-4

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$)	1548
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	46

TOTAL COST (1000$)	
ESP UPGRADE CASE	1594
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.55
NEW BAGHOUSE	NA

and 23.1.6-10 present a summary of site access/congestion factors, scope adders, and retrofit factors for DSD and FSI technologies at the Kingston steam plant. Table 23.1.6-11 presents the costs estimated for retrofitting DSD and FSI at the Kingston plant.

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, the boilers at Kingston would be considered good candidates because of their small boiler sizes (<300 MW) and their age (built prior to 1960). However, the high capacity factor could result in large downtime penalties, if reserve capacity or purchase power is not available at an equipment cost.

23.1.7 John Sevier Steam Plant

The John Sevier steam plant is located within Hawkins County, Tennessee, as part of the TVA system. The plant contains four coal-fired boilers with a total gross generating capacity of 846 MW. Figure 23.1.7-1 presents the plant plot plan showing the location of the four boilers and major associated auxiliary equipment.

Table 23.1.7-1 presents operational data for the existing equipment at the John Sevier steam plant. All boilers burn medium sulfur coal (1.3 percent sulfur). Coal is received by rail and conveyed to a coal storage and handling area located southwest of the plant. All units share the same conveyor.

Particulate matter emissions for all four boilers are controlled with ESPs located directly behind each boiler. Ash from all units is wet sluiced to ponds located on the opposite side of the water discharge channel, west of the plant. On-site waste disposal is limited and TVA is considering two options to address this problem: the purchase of more land adjacent to the plant or dry disposing of the waste off-site.

TABLE 23.1.6-10. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR KINGSTON UNITS 5-9

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$)	1745
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	50
TOTAL COST (1000$)	
ESP UPGRADE CASE	1795
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.55
NEW BAGHOUSE	NA

Table 23.1.6-11. Summary of DSD/FSI Control Costs for the Kingston 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	175	50	1.1	9.9	56.3	6.2	8.0	49.0	3309	1862.4
DSD+ESP	2	1.00	175	40	1.1	9.9	56.3	5.8	9.5	49.0	2647	2207.3
DSD+ESP	3	1.00	175	60	1.1	9.9	56.3	6.5	7.0	49.0	3971	1632.7
DSD+ESP	4	1.00	175	63	1.1	9.9	56.3	6.6	6.8	49.0	4170	1578.1
DSD+ESP	5	1.00	200	55	1.1	11.0	54.9	6.9	7.1	49.0	4160	1648.3
DSD+ESP	6	1.00	200	79	1.1	11.0	54.9	7.7	5.6	49.0	5976	1295.0
DSD+ESP	7	1.00	200	61	1.1	11.0	54.9	7.1	6.6	49.0	4614	1533.8
DSD+ESP	8	1.00	200	60	1.1	11.0	54.9	7.0	6.7	49.0	4538	1551.3
DSD+ESP	9	1.00	200	80	1.1	11.0	54.9	7.8	5.5	49.0	6051	1284.9
DSD+ESP-C	1	1.00	175	50	1.1	9.9	56.3	3.6	4.7	49.0	3309	1080.4
DSD+ESP-C	2	1.00	175	40	1.1	9.9	56.3	3.4	5.5	49.0	2647	1281.3
DSD+ESP-C	3	1.00	175	60	1.1	9.9	56.3	3.8	4.1	49.0	3971	946.6
DSD+ESP-C	4	1.00	175	63	1.1	9.9	56.3	3.8	3.9	49.0	4170	914.8
DSD+ESP-C	5	1.00	200	55	1.1	11.0	54.9	4.0	4.1	49.0	4160	956.2
DSD+ESP-C	6	1.00	200	79	1.1	11.0	54.9	4.5	3.2	49.0	5976	750.2
DSD+ESP-C	7	1.00	200	61	1.1	11.0	54.9	4.1	3.8	49.0	4614	889.4
DSD+ESP-C	8	1.00	200	60	1.1	11.0	54.9	4.1	3.9	49.0	4538	899.6
DSD+ESP-C	9	1.00	200	80	1.1	11.0	54.9	4.5	3.2	49.0	6051	744.3
FSI+ESP-50	1	1.00	175	50	1.1	9.8	56.0	5.5	7.2	50.0	3401	1618.1
FSI+ESP-50	2	1.00	175	40	1.1	9.8	56.0	5.1	8.3	50.0	2721	1864.5
FSI+ESP-50	3	1.00	175	60	1.1	9.8	56.0	5.9	6.5	50.0	4081	1454.2
FSI+ESP-50	4	1.00	175	63	1.1	9.8	56.0	6.1	6.3	50.0	4285	1415.3
FSI+ESP-50	5	1.00	200	55	1.1	10.7	53.5	6.3	6.5	50.0	4276	1464.1
FSI+ESP-50	6	1.00	200	79	1.1	10.7	53.5	7.4	5.4	50.0	6141	1212.7
FSI+ESP-50	7	1.00	200	61	1.1	10.7	53.5	6.6	6.1	50.0	4742	1382.5
FSI+ESP-50	8	1.00	200	60	1.1	10.7	53.5	6.5	6.2	50.0	4664	1394.9
FSI+ESP-50	9	1.00	200	80	1.1	10.7	53.5	7.5	5.3	50.0	6219	1205.6
FSI+ESP-50-C	1	1.00	175	50	1.1	9.8	56.0	3.2	4.2	50.0	3401	940.0
FSI+ESP-50-C	2	1.00	175	40	1.1	9.8	56.0	3.0	4.8	50.0	2721	1084.4
FSI+ESP-50-C	3	1.00	175	60	1.1	9.8	56.0	3.4	3.7	50.0	4081	843.9

continued . . .

Table 23.1.6-11. Summary of DSD/FSI Control Costs for the Kingston 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 ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
FSI+ESP-50-C	4	1.00	175	63	1.1	9.8	56.0	3.5	3.6	50.0	4285	821.1
FSI+ESP-50-C	5	1.00	200	55	1.1	10.7	53.5	3.6	3.8	50.0	4276	850.0
FSI+ESP-50-C	6	1.00	200	79	1.1	10.7	53.5	4.3	3.1	50.0	6141	702.6
FSI+ESP-50-C	7	1.00	200	61	1.1	10.7	53.5	3.8	3.6	50.0	4742	802.2
FSI+ESP-50-C	8	1.00	200	60	1.1	10.7	53.5	3.8	3.6	50.0	4664	809.5
FSI+ESP-50-C	9	1.00	200	80	1.1	10.7	53.5	4.3	3.1	50.0	6219	698.4
FSI+ESP-70	1	1.00	175	50	1.1	9.9	56.7	5.6	7.3	70.0	4761	1172.6
FSI+ESP-70	2	1.00	175	40	1.1	9.9	56.7	5.1	8.4	70.0	3809	1350.1
FSI+ESP-70	3	1.00	175	60	1.1	9.9	56.7	6.0	6.6	70.0	5714	1054.5
FSI+ESP-70	4	1.00	175	63	1.1	9.9	56.7	6.2	6.4	70.0	5999	1026.5
FSI+ESP-70	5	1.00	200	55	1.1	10.8	54.2	6.4	6.6	70.0	5986	1061.6
FSI+ESP-70	6	1.00	200	79	1.1	10.8	54.2	7.6	5.5	70.0	8598	880.5
FSI+ESP-70	7	1.00	200	61	1.1	10.8	54.2	6.7	6.2	70.0	6639	1002.8
FSI+ESP-70	8	1.00	200	60	1.1	10.8	54.2	6.6	6.3	70.0	6530	1011.8
FSI+ESP-70	9	1.00	200	80	1.1	10.8	54.2	7.6	5.4	70.0	8707	875.4
FSI+ESP-70-C	1	1.00	175	50	1.1	9.9	56.7	3.2	4.2	70.0	4761	681.2
FSI+ESP-70-C	2	1.00	175	40	1.1	9.9	56.7	3.0	4.9	70.0	3809	785.2
FSI+ESP-70-C	3	1.00	175	60	1.1	9.9	56.7	3.5	3.8	70.0	5714	611.9
FSI+ESP-70-C	4	1.00	175	63	1.1	9.9	56.7	3.6	3.7	70.0	5999	595.5
FSI+ESP-70-C	5	1.00	200	55	1.1	10.8	54.2	3.7	3.8	70.0	5986	616.4
FSI+ESP-70-C	6	1.00	200	79	1.1	10.8	54.2	4.4	3.2	70.0	8598	510.1
FSI+ESP-70-C	7	1.00	200	61	1.1	10.8	54.2	3.9	3.6	70.0	6639	581.9
FSI+ESP-70-C	8	1.00	200	60	1.1	10.8	54.2	3.8	3.6	70.0	6530	587.1
FSI+ESP-70-C	9	1.00	200	80	1.1	10.8	54.2	4.4	3.2	70.0	8707	507.1

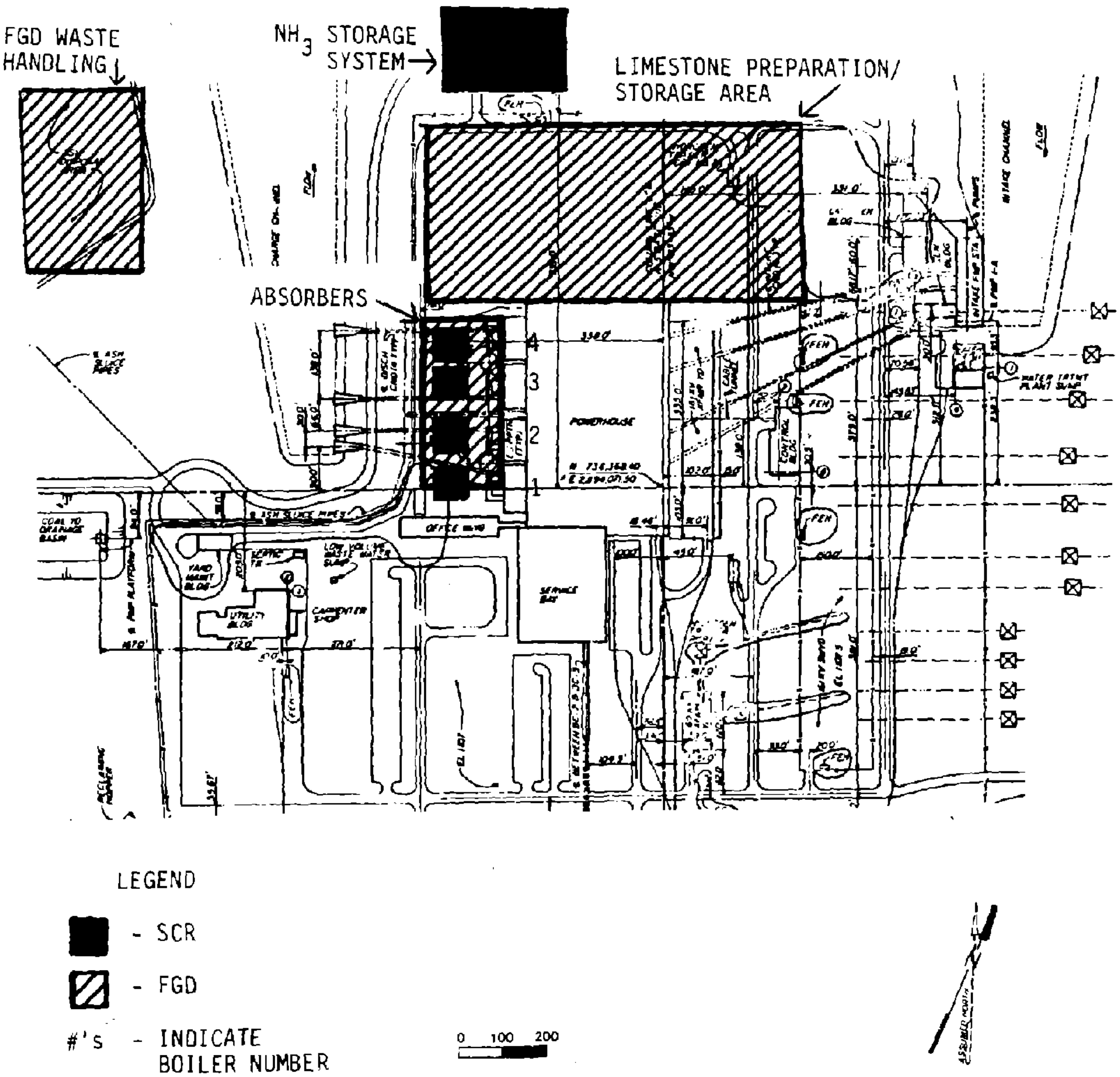

Figure 23.1.7-1. John Sevier plant plot plan

TABLE 23.1.7-1. JOHN SEVIER STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1-4
GENERATING CAPACITY (MW-each)	200, 200, 223, 223
CAPACITY FACTOR (PERCENT)	68, 68, 83, 85
INSTALLATION DATE	1955-57
FIRING TYPE	TANG
COAL SULFUR CONTENT (PERCENT)	1.30
COAL HEATING VALUE (BTU/LB)	12500
COAL ASH CONTENT (PERCENT)	11.0
FLY ASH SYSTEM	WET SLUICE
ASH DISPOSAL METHOD	POND/ON-SITE
STACK NUMBER	1-2
COAL DELIVERY METHODS	RAIL
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1973-74
EMISSION (LB/MM BTU)	0.02-0.03
REMOVAL EFFICIENCY	99.6-99.7
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	1.0
SURFACE AREA (1000 SQ FT)	315
GAS EXIT RATE (1000 ACFM)	920
SCA (SQ FT/1000 ACFM)	342
OUTLET TEMPERATURE (°F)	310

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 23.1.7-1 shows the general layout and location of the FGD control system. Absorbers for L/LS-FGD and LSD-FGD would be located west and northwest of the plant in a relatively open area. The limestone preparation/storage area was located directly north of the powerhouse with the waste handling area being located west of the preparation/storage area.

Retrofit Difficulty and Scope Adder Costs--

Most of the FGD control equipment would be located in a relatively low to medium site access/congestion area with high underground obstruction created by the cooling water intakes. For flue gas handling, a low access/congestion factor was assumed for all the L/LS-FGD cases evaluated because there are no obstructions between the absorber locations and the ESPs/chimneys.

The major scope adjustment costs and estimated retrofit factors for the FGD control technologies are presented in Table 23.1.7-2. The largest scope adder for the John Sevier steam plant was the conversion of units 1 to 4 fly ash conveying/disposal systems 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 the L/LS-FGD scrubber sludge waste and to prevent plugging of the sluice lines in LSD-FGD cases. However, this conversion is not necessary for forced oxidation L/LS-FGD. The overall retrofit factors determined for the L/LS-FGD cases were moderate (1.33 to 1.38).

The LSD with a new baghouse was the only LSD-FGD technology considered. Though large (SCA >300), reuse of the ESPs is not possible given the high access difficulty for routing of the flue gas from upstream of the ESPs to the LSD absorbers and back. For the LSD-FGD with a new baghouse case, the retrofit factor was also moderate (1.51). A medium site access/congestion factor was assigned to the location of the new baghouses and flue gas handling systems. This factor reflects congestion created by the designed LSD chambers.

Table 23.1.7-3 presents the cost estimated for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs and ash handling systems for boilers 1-4.

TABLE 23.1.7-2. SUMMARY OF RETROFIT FACTOR DATA FOR JOHN SEVIER UNITS 1-4

	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			MEDIUM
DUCT WORK DISTANCE (FEET)	0-100	0-100	
ESP REUSE			NA
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	MEDIUM
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	1,745	NA	1,745
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	YES	YES	YES
RETROFIT FACTORS			
FGD SYSTEM	1.38	1.33	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.51
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.34
GENERAL FACILITIES (PERCENT)	7	7	7

Table 23.1.7-3. Summary of FGD Control Costs for the John Sevier 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	1.38	200	68	1.3	57.0	285.0	25.0	21.0	90.0	10731	2326.4
L/S FGD	3	1.38	223	83	1.3	60.5	271.1	28.2	17.4	90.0	14604	1930.0
L/S FGD	4	1.38	223	85	1.3	60.5	271.1	28.4	17.1	90.0	14956	1898.5
L/S FGD-C	1, 2	1.38	200	68	1.3	57.0	285.0	14.6	12.2	90.0	10731	1356.7
L/S FGD-C	3	1.38	223	83	1.3	60.5	271.1	16.4	10.1	90.0	14604	1124.3
L/S FGD-C	4	1.38	223	85	1.3	60.5	271.1	16.5	10.0	90.0	14956	1105.8
LC FGD	1-4	1.38	846	76	1.3	112.6	133.0	61.7	11.0	90.0	50730	1217.0
LC FGD-C	1-4	1.38	846	76	1.3	112.6	133.0	35.9	6.4	90.0	50730	707.2
LSD+FF	1, 2	1.51	200	68	1.3	50.7	253.6	18.8	15.8	87.0	10313	1820.9
LSD+FF	3	1.51	223	83	1.3	55.3	247.9	21.3	13.1	87.0	14036	1518.3
LSD+FF	4	1.51	223	85	1.3	55.3	247.9	21.4	12.9	87.0	14374	1491.5
LSD+FF-C	1, 2	1.51	200	68	1.3	50.7	253.6	11.0	9.2	87.0	10313	1065.3
LSD+FF-C	3	1.51	223	83	1.3	55.3	247.9	12.5	7.7	87.0	14036	887.6
LSD+FF-C	4	1.51	223	85	1.3	55.3	247.9	12.5	7.5	87.0	14374	871.8

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--

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 different coal fuel cost differentials. The costs associated with each boiler for the range of fuel cost differential are shown in Table 23.1.7-4.

NO_x Control Technology Costs--

This section presents the performance and various related costs estimated for NO_x controls at the John Sevier steam 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 steam plant were: OFA and SCR.

Low NO_x Combustion--

Units 1 to 4 are dry bottom, tangential-fired boilers. Units 1 and 2 are each rated at 200 MW while units 3 and 4 are each rated at 223 MW. The NO_x combustion control considered in this analysis was OFA. Tables 23.1.7-5 and 23.1.7-6 present the OFA NO_x estimated reduction performance results for units 1 to 4. The estimated NO_x reduction performance, using the simplified NO_x procedures, was 20 percent for each unit. This performance was used

Table 23.1.7-4. Summary of Coal Switching/Cleaning Costs for the John Sevier 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	200	68	1.3	7.1	35.4	17.2	14.5	28.0	3320	5184.8
CS/B+$15	3	1.00	223	83	1.3	7.8	34.8	23.0	14.2	28.0	4519	5079.2
CS/B+$15	4	1.00	223	85	1.3	7.8	34.8	23.5	14.1	28.0	4628	5070.3
CS/B+$15-C	1, 2	1.00	200	68	1.3	7.1	35.4	9.9	8.3	28.0	3320	2980.1
CS/B+$15-C	3	1.00	223	83	1.3	7.8	34.8	13.2	8.1	28.0	4519	2917.8
CS/B+$15-C	4	1.00	223	85	1.3	7.8	34.8	13.5	8.1	28.0	4628	2912.5
CS/B+$5	1, 2	1.00	200	68	1.3	5.0	25.0	7.0	5.9	28.0	3320	2111.8
CS/B+$5	3	1.00	223	83	1.3	5.4	24.4	9.2	5.6	28.0	4519	2026.1
CS/B+$5	4	1.00	223	85	1.3	5.4	24.4	9.3	5.6	28.0	4628	2019.3
CS/B+$5-C	1, 2	1.00	200	68	1.3	5.0	25.0	4.0	3.4	28.0	3320	1216.7
CS/B+$5-C	3	1.00	223	83	1.3	5.4	24.4	5.3	3.3	28.0	4519	1166.2
CS/B+$5-C	4	1.00	223	85	1.3	5.4	24.4	5.4	3.2	28.0	4628	1162.2

TABLE 23.1.7-5. SUMMARY OF NOx RETROFIT RESULTS FOR SEVIER UNITS 1-2

	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)	16.1	16.1
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	25.4	25.4
FURNACE RESIDENCE TIME (SECONDS)	3.02	3.02
ESTIMATED NOx REDUCTION (PERCENT)	20	20
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	NA
Ductwork Demolition (1000$)	45	45
New Duct Length (Feet)	93	93
New Duct Costs (1000$)	691	691
New Heat Exchanger (1000$)	2825	2825
TOTAL SCOPE ADDER COSTS (1000$)	3562	3562
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13

TABLE 23.1.7-6. SUMMARY OF NOx RETROFIT RESULTS FOR SEVIER UNITS 3-4

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	3	4
FIRING TYPE	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	16.1	16.3
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	25.4	25.2
FURNACE RESIDENCE TIME (SECONDS)	3.02	3.01
ESTIMATED NOx REDUCTION (PERCENT)	20	20
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	NA	0
Ductwork Demolition (1000$)	45	45
New Duct Length (Feet)	93	93
New Duct Costs (1000$)	691	691
New Heat Exchanger (1000$)	2825	2825
TOTAL SCOPE ADDER COSTS (1000$)	3562	3562
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13

based on examining the effects of heat release rates and furnace residence time on NO_x reduction using the simplified procedure. Table 23.1.7-7 presents the costs estimated for retrofitting OFA at the John Sevier plant boilers.

Selective Catalytic Reduction--

Tables 23.1.7-5 and 23.1.7-6 present 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 drive the flue gas from the ESPs to the reactors and from the reactors to the chimney.

The SCR reactors and ammonia system were located in a relatively low access/congestion area. Specifically, the reactors were located west of the plant behind each unit's ESPs while the ammonia system was located northwest of the powerhouse. Although the reactors were assigned a low access/congestion, they were assumed to be in areas with high underground obstruction. Table 23.1.7-7 presents the costs estimated for retrofitting SCR at the John Sevier plant 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 located west of the plant in a relatively open area. The short duct runs from the boiler to the ESPs do not provide sufficient duct residence time. However, developments in particulate control technology may be used to modify the existing ESPs by combining advanced ESP technology and spray dryer technology to remove SO_2 and particulate (E-SO_x technology). Since all units have large ESP sizes (SCA >340), it was assumed that DSD with ESP reuse is an alternative low cost method to the new baghouse option. A high

Table 23.1.7-7. NOx Control Cost Results for the John Sevier 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	200	68	1.3	0.8	4.1	0.2	0.1	20.0	706	245.2
LNC-OFA	3	1.00	223	83	1.3	0.9	3.8	0.2	0.1	20.0	960	188.0
LNC-OFA	4	1.00	223	85	1.3	0.9	3.8	0.2	0.1	20.0	983	183.6
LNC-OFA-C	1, 2	1.00	200	68	1.3	0.8	4.1	0.1	0.1	20.0	706	145.6
LNC-OFA-C	3	1.00	223	83	1.3	0.9	3.8	0.1	0.1	20.0	960	111.7
LNC-OFA-C	4	1.00	223	85	1.3	0.9	3.8	0.1	0.1	20.0	983	109.0
SCR-3	1, 2	1.16	200	68	1.3	29.2	146.1	10.1	8.5	80.0	2822	3586.7
SCR-3	3	1.16	223	83	1.3	31.6	141.6	11.2	6.9	80.0	3841	2927.3
SCR-3	4	1.16	223	85	1.3	31.6	141.6	11.3	6.8	80.0	3933	2865.2
SCR-3-C	1, 2	1.16	200	68	1.3	29.2	146.1	5.9	5.0	80.0	2822	2101.3
SCR-3-C	3	1.16	223	83	1.3	31.6	141.6	6.6	4.1	80.0	3841	1714.0
SCR-3-C	4	1.16	223	85	1.3	31.6	141.6	6.6	4.0	80.0	3933	1677.6
SCR-7	1, 2	1.16	200	68	1.3	29.2	146.1	8.5	7.1	80.0	2822	3007.8
SCR-7	3	1.16	223	83	1.3	31.6	141.6	9.4	5.8	80.0	3841	2453.1
SCR-7	4	1.16	223	85	1.3	31.6	141.6	9.4	5.7	80.0	3933	2402.2
SCR-7-C	1, 2	1.16	200	68	1.3	29.2	146.1	5.0	4.2	80.0	2822	1769.7
SCR-7-C	3	1.16	223	83	1.3	31.6	141.6	5.5	3.4	80.0	3841	1442.3
SCR-7-C	4	1.16	223	85	1.3	31.6	141.6	5.6	3.3	80.0	3933	1412.3

site access/congestion factor was assigned to the ESP upgrade for the same reason specified in the LSD-FGD section. The conversion of wet to dry ash handling system would also be required for reusing the ESPs for the FSI and DSD technologies. Table 23.1.7-8 presents a summary of site access/ congestion factors, scope adders, and retrofit factors for DSD and FSI technologies at the John Sevier plant. Table 23.1.7-9 presents the costs estimated for retrofitting FSI and DSD at the John Sevier plant.

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, all boilers at John Sevier would be considered potential candidates for AFBC retrofit and AFBC and CG/combined cycle repowering because of their small boiler sizes. However, the high capacity factors of the units indicates marginal benefits for retrofit/repowering due to downtime cost penalties and minimal heat rate improvements.

TABLE 23.1.7-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR JOHN SEVIER UNITS 1-4

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$)	1,745
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	200
ESTIMATED COST (1000$)	1,378
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	50

TOTAL COST (1000$)	
ESP UPGRADE CASE	1,795
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE	1.55
NEW BAGHOUSE	NA

Table 23.1.7-9. Summary of DSD/FSI Control Costs for the John Sevier 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	200	68	1.3	10.9	54.4	7.4	6.2	49.0	5800	1278.3
DSD+ESP	3	1.00	223	83	1.3	11.6	52.1	8.6	5.3	49.0	7894	1083.6
DSD+ESP	4	1.00	223	85	1.3	11.6	52.1	8.6	5.2	49.0	8084	1068.7
DSD+ESP-C	1, 2	1.00	200	68	1.3	10.9	54.4	4.3	3.6	49.0	5800	740.8
DSD+ESP-C	3	1.00	223	83	1.3	11.6	52.1	5.0	3.1	49.0	7894	627.4
DSD+ESP-C	4	1.00	223	85	1.3	11.6	52.1	5.0	3.0	49.0	8084	618.7
FSI+ESP-50	1, 2	1.00	200	68	1.3	11.0	55.2	7.4	6.2	50.0	5961	1238.9
FSI+ESP-50	3	1.00	223	83	1.3	11.7	52.5	8.9	5.5	50.0	8113	1097.0
FSI+ESP-50	4	1.00	223	85	1.3	11.7	52.5	9.0	5.4	50.0	8309	1086.1
FSI+ESP-50-C	1, 2	1.00	200	68	1.3	11.0	55.2	4.3	3.6	50.0	5961	718.1
FSI+ESP-50-C	3	1.00	223	83	1.3	11.7	52.5	5.2	3.2	50.0	8113	635.0
FSI+ESP-50-C	4	1.00	223	85	1.3	11.7	52.5	5.2	3.1	50.0	8309	628.6
FSI+ESP-70	1, 2	1.00	200	68	1.3	11.1	55.3	7.5	6.3	70.0	8346	895.4
FSI+ESP-70	3	1.00	223	83	1.3	11.7	52.5	9.0	5.6	70.0	11358	793.8
FSI+ESP-70	4	1.00	223	85	1.3	11.7	52.5	9.1	5.5	70.0	11632	786.1
FSI+ESP-70-C	1, 2	1.00	200	68	1.3	11.1	55.3	4.3	3.6	70.0	8346	519.0
FSI+ESP-70-C	3	1.00	223	83	1.3	11.7	52.5	5.2	3.2	70.0	11358	459.4
FSI+ESP-70-C	4	1.00	223	85	1.3	11.7	52.5	5.3	3.2	70.0	11632	454.9

SECTION 24.0 VIRGINIA

24.1 APPALACHIAN POWER COMPANY

24.1.1 <u>Clinch River</u>

The boilers at the Clinch River plant have large roof-mounted ESPs which are difficult to access; therefore, LSD-FGD with a new baghouse was considered for these units. Due to the low sulfur coal being fired at this plant, FGD costs were not presented and CS was not evaluated. Sorbent injection technologies were not considered because of the short duct residence time between the boilers and ESPs and the difficulty in accessing the roof-mounted ESPs. For NO_x control, neither LNB nor OFA were an option since these technologies are not applicable to roof-fired boilers.

TABLE 24.1.1-1. CLINCH RIVER STEAM PLANT OPERATIONAL DATA *

BOILER NUMBER	1,2,3
GENERATING CAPACITY (MW-each)	240
CAPACITY FACTOR (PERCENT)	82,88,70
INSTALLATION DATE	1958,58,61
FIRING TYPE	ROOF-FIRED
FURNACE VOLUME (1000 CU FT)	NA
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	0.8
COAL HEATING VALUE (BTU/LB)	12800
COAL ASH CONTENT (PERCENT)	11.6
FLY ASH SYSTEM	DRY DISPOSAL
ASH DISPOSAL METHOD	LANDFILL/SOLD
STACK NUMBER	1,1,2
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1975,74,74
EMISSION (LB/MM BTU)	0.05,0.06,0.06
REMOVAL EFFICIENCY	98.9,99.5,99.7
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	0.5
SURFACE AREA (1000 SQ FT)	722.3
GAS EXIT RATE (1000 ACFM)	900
SCA (SQ FT/1000 ACFM)	803
OUTLET TEMPERATURE (°F)	250

* Some information was obtained from plant personnel.

TABLE 24.1.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR CLINCH RIVER UNIT 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	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$)	NA	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	1680	0	1680
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.41	NA	
ESP REUSE CASE			NO
BAGHOUSE CASE			1.43
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	10,10,15	0	10,10,15

* L/LS-FGD and LSD-FGD absorbers would be located north of unit 1, on either side of the coal conveyor.

TABLE 24.1.1-3. SUMMARY OF NOx RETROFIT RESULTS FOR CLINCH RIVER

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1,2,3	1-2
FIRING TYPE	ROOF-FIRED	NA
TYPE OF NOx CONTROL	NA	NA
FURNACE VOLUME (1000 CU FT)	NA	NA
BOILER INSTALLATION DATE	1958,58,61	NA
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$)	0	0
Ductwork Demolition (1000$)	52	88
New Duct Length (Feet)	400	400
New Duct Costs (1000$)	3308	4962
New Heat Exchanger (1000$)	3152	4777
TOTAL SCOPE ADDER COSTS (1000$)	6511	9826
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	20,20,38	20

* Cold side SCR reactors for units 1 and 2 would be located north of unit 1, west of the coal conveyor. Cold side SCR reactors for unit 3 would be located north of unit 3, east of the coal conveyor.

Table 24.1.1-4. NOx Control Cost Results for the Clinch 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)
SCR-3	1	1.16	240	82	0.8	36.6	152.7	12.7	7.4	80.0	5564	2278.5
SCR-3	2	1.16	240	88	0.8	36.6	152.7	12.8	6.9	80.0	5971	2139.9
SCR-3	3	1.16	240	70	0.8	38.3	159.7	12.9	8.8	80.0	4749	2717.2
SCR-3	1-2	1.16	480	85	0.8	61.9	128.9	22.8	6.4	80.0	11534	1974.1
SCR-3-C	1	1.16	240	82	0.8	36.6	152.7	7.4	4.3	80.0	5564	1335.0
SCR-3-C	2	1.16	240	88	0.8	36.6	152.7	7.5	4.0	80.0	5971	1253.5
SCR-3-C	3	1.16	240	70	0.8	38.3	159.7	7.6	5.1	80.0	4749	1593.0
SCR-3-C	1-2	1.16	480	85	0.8	61.9	128.9	13.3	3.7	80.0	11534	1155.1
SCR-7	1	1.16	240	82	0.8	36.6	152.7	10.7	6.2	80.0	5564	1927.4
SCR-7	2	1.16	240	88	0.8	36.6	152.7	10.8	5.8	80.0	5971	1812.7
SCR-7	3	1.16	240	70	0.8	38.3	159.7	11.0	7.4	80.0	4749	2305.9
SCR-7	1-2	1.16	480	85	0.8	61.9	128.9	18.9	5.3	80.0	11534	1635.4
SCR-7-C	1	1.16	240	82	0.8	36.6	152.7	6.3	3.7	80.0	5564	1133.8
SCR-7-C	2	1.16	240	88	0.8	36.6	152.7	6.4	3.4	80.0	5971	1066.1
SCR-7-C	3	1.16	240	70	0.8	38.3	159.7	6.4	4.4	80.0	4749	1357.3
SCR-7-C	1-2	1.16	480	85	0.8	61.9	128.9	11.1	3.1	80.0	11534	961.0

24.2 VIRGINIA ELECTRIC & POWER

24.2.1 Chesterfield

The four coal firing boilers considered for this evaluation are firing a low sulfur coal, hence FGD costs were not presented and CS was not evaluated.

TABLE 24.2.1-1. CHESTERFIELD STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	3	4	5	6	7
GENERATING CAPACITY (MW-each)	112	188	359	694	210
CAPACITY FACTOR (PERCENT)	27	58	67	46	COMBINED
INSTALLATION DATE	1952	1960	1964	1969	CYCLE
FIRING TYPE		TANGENTIAL			PLANNED
FURNACE VOLUME (1000 CU FT)	39	NA	154.5	330	
LOW NOx COMBUSTION	NO	NO	NO	NO	
COAL SULFUR CONTENT (PERCENT)		1.0			
COAL HEATING VALUE (BTU/LB)		12700			
COAL ASH CONTENT (PERCENT)		8.5			
FLY ASH SYSTEM		WET DISPOSAL			
ASH DISPOSAL METHOD		POND/ON-SITE			
STACK NUMBER	1	2	3	4	
COAL DELIVERY METHODS		RAILROAD			

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

* It was assumed that units 3, 4, 5, and 6 are equipped with ESPs.

TABLE 24.2.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR CHESTERFIELD UNIT 3, 4, OR 5 *

	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	YES	NA	NO
ESTIMATED COST (1000$)	1038-2949	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	784-2513	0	784-2513
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.60	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/LS-FGD absorbers, LSD-FGD absorbers and new FFs for units 3, 4 and 5 would be located west of unit 6. LSD with a new baghouse was considered because access to the upstream of the existing ESPs is difficult.

TABLE 24.2.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR CHESTERFIELD 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	YES	NA	NO
ESTIMATED COST (1000$)	5324	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	2513
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.46	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

* L/LS-FGD and LSD-FGD absorbers for unit 6 would be located west of unit 6.

TABLE 24.2.1-4. SUMMARY OF NOx RETROFIT RESULTS FOR CHESTERFIELD

	BOILER NUMBER			
COMBUSTION MODIFICATION RESULTS				
	3	4	5	6
FIRING TYPE	TANG	TANG	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA	OFA	OFA
FURNACE VOLUME (1000 CU FT)	39	NA	154.5	330
BOILER INSTALLATION DATE	1952	1960	1964	1969
SLAGGING PROBLEM	NO	NO	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	25	25	25	25
SCR RETROFIT RESULTS *				
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH	HIGH	LOW
SCOPE ADDER PARAMETERS--				
Building Demolition (1000$)	0	0	0	0
Ductwork Demolition (1000$)	29	43	71	116
New Duct Length (Feet)	250	400	600	500
New Duct Costs (1000$)	1324	2867	6280	7695
New Heat Exchanger (1000$)	1995	2722	4013	5960
TOTAL SCOPE ADDER COSTS (1000$)	3348	5633	10363	13770
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 3, 4 and 5 would be located north of the unit 3 chimney. Cold side SCR reactors for unit 6 would be located west of unit 6.

Table 24.2.1-5. NOx Control Cost Results for the Chesterfield 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	112	27	1.0	0.6	5.8	0.1	0.5	25.0	193	711.5
LNC-OFA	4	1.00	188	58	1.0	0.8	4.2	0.2	0.2	25.0	694	242.8
LNC-OFA	5	1.00	359	67	1.0	1.0	2.9	0.2	0.1	25.0	1532	142.5
LNC-OFA	6	1.00	694	46	1.0	1.3	1.9	0.3	0.1	25.0	2033	139.7
LNC-OFA-C	3	1.00	112	27	1.0	0.6	5.8	0.1	0.3	25.0	193	422.8
LNC-OFA-C	4	1.00	188	58	1.0	0.8	4.2	0.1	0.1	25.0	694	144.2
LNC-OFA-C	5	1.00	359	67	1.0	1.0	2.9	0.1	0.1	25.0	1532	84.6
LNC-OFA-C	6	1.00	694	46	1.0	1.3	1.9	0.2	0.1	25.0	2033	83.0
SCR-3	3	1.52	112	27	1.0	25.6	229.0	7.7	28.9	80.0	616	12431.2
SCR-3	4	1.52	188	58	1.0	37.8	200.9	11.7	12.3	80.0	2222	5283.5
SCR-3	5	1.52	359	67	1.0	62.5	174.0	20.1	9.6	80.0	4901	4111.1
SCR-3	6	1.16	694	46	1.0	86.7	125.0	30.3	10.9	80.0	6505	4665.6
SCR-3-C	3	1.52	112	27	1.0	25.6	229.0	4.5	17.0	80.0	616	7308.8
SCR-3-C	4	1.52	188	58	1.0	37.8	200.9	6.9	7.2	80.0	2222	3103.3
SCR-3-C	5	1.52	359	67	1.0	62.5	174.0	11.8	5.6	80.0	4901	2412.5
SCR-3-C	6	1.16	694	46	1.0	86.7	125.0	17.8	6.4	80.0	6505	2732.9
SCR-7	3	1.52	112	27	1.0	25.6	229.0	6.7	25.5	80.0	616	10949.9
SCR-7	4	1.52	188	58	1.0	37.8	200.9	10.2	10.7	80.0	2222	4594.0
SCR-7	5	1.52	359	67	1.0	62.5	174.0	17.2	8.2	80.0	4901	3514.2
SCR-7	6	1.16	694	46	1.0	86.7	125.0	24.7	8.8	80.0	6505	3796.2
SCR-7-C	3	1.52	112	27	1.0	25.6	229.0	4.0	15.0	80.0	616	6460.2
SCR-7-C	4	1.52	188	58	1.0	37.8	200.9	6.0	6.3	80.0	2222	2708.3
SCR-7-C	5	1.52	359	67	1.0	62.5	174.0	10.1	4.8	80.0	4901	2070.5
SCR-7-C	6	1.16	694	46	1.0	86.7	125.0	14.5	5.2	80.0	6505	2234.8

24.2.2 Portsmouth Steam Plant

FGD retrofit factors were developed for units 3 and 4 at the Portsmouth plant; however, costs are not shown since the boilers fire a low sulfur coal. In addition, CS was not evaluated. Units 1 and 2 were not evaluated because they are oil-fired.

TABLE 24.2.2-1. PORTSMOUTH STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2	3	4
GENERATING CAPACITY (MW)	113	113	185	239
CAPACITY FACTOR (PERCENT)	RESERVE SHUTDOWN		45	44
INSTALLATION DATE	1953	1954	1959	1962
FIRING TYPE	TANGENTIAL		FRONT WALL	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	PETROLEUM		84.7	122
LOW NOx COMBUSTION	BURNING		NO	NO
COAL SULFUR CONTENT (PERCENT)			1.0	
COAL HEATING VALUE (BTU/LB)			12800	
COAL ASH CONTENT (PERCENT)			7.5	
FLY ASH SYSTEM			WET	
ASH DISPOSAL METHOD			POND/OFF-SITE	
STACK NUMBER	1	2	3	4
COAL DELIVERY METHODS			RAILROAD	
PARTICULATE CONTROL				
TYPE			ESP	ESP*
INSTALLATION DATE			NA	NA
EMISSION (LB/MM BTU)			NA	NA
REMOVAL EFFICIENCY			NA	NA
DESIGN SPECIFICATION				
SULFUR SPECIFICATION (PERCENT)			NA	NA
SURFACE AREA (1000 SQ FT)			NA	NA
EXIT GAS FLOW RATE (1000 ACFM)			NA	NA
SCA (SQ FT/1000 ACFM)			NA	NA
OUTLET TEMPERATURE (°F)			NA	NA

* The SCA size of the ESPs was assumed to be 300.

TABLE 24.2.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR PORTSMOUTH 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	HIGH	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	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	1627,2047	NA	1627,2047
NEW CHIMNEY	YES	NA	NO
ESTIMATED COST (1000$)	1295,1673	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.41	NA	
ESP REUSE CASE			1.43
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	0	10

* L/S-FGD and LSD-FGD absorbers for units 3 and 4 would be located east of the chimneys behind the retrofit ESPs.

TABLE 24.2.2-3. SUMMARY OF NOx RETROFIT RESULTS FOR PORTSMOUTH

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	3	4
FIRING TYPE	FWF	TANG
TYPE OF NOx CONTROL	LNB	OFA
FURNACE VOLUME (1000 CU FT)	84.7	122
BOILER INSTALLATION DATE	1959	1962
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	31	25
SCR RETROFIT RESULTS *		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	43	52
New Duct Length (Feet)	200	200
New Duct Costs (1000$)	1420	1650
New Heat Exchanger (1000$)	2696	3144
TOTAL SCOPE ADDER COSTS (1000$)	4159	4846
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	20	20

* Cold side SCR reactors for units 3 and 4 would be located beside the retrofit ESPs.

Table 24.2.2-4. NOx Control Cost Results for the Portsmouth 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	185	45	1.0	3.3	17.6	0.7	0.9	31.0	912	756.5
LNC-LNB-C	3	1.00	185	45	1.0	3.3	17.6	0.4	0.6	31.0	912	449.5
LNC-OFA	4	1.00	239	44	1.0	0.9	3.7	0.2	0.2	25.0	664	279.4
LNC-OFA-C	4	1.00	239	44	1.0	0.9	3.7	0.1	0.1	25.0	664	166.1
SCR-3	3	1.16	185	45	1.0	28.7	155.3	9.6	13.1	80.0	2353	4060.3
SCR-3	4	1.16	239	44	1.0	35.1	146.7	11.7	12.7	80.0	2124	5520.9
SCR-3-C	3	1.16	185	45	1.0	28.7	155.3	5.6	7.7	80.0	2353	2381.0
SCR-3-C	4	1.16	239	44	1.0	35.1	146.7	6.9	7.5	80.0	2124	3237.2
SCR-7	3	1.16	185	45	1.0	28.7	155.3	8.1	11.0	80.0	2353	3420.5
SCR-7	4	1.16	239	44	1.0	35.1	146.7	9.8	10.6	80.0	2124	4604.8
SCR-7-C	3	1.16	185	45	1.0	28.7	155.3	4.7	6.5	80.0	2353	2014.4
SCR-7-C	4	1.16	239	44	1.0	35.1	146.7	5.8	6.3	80.0	2124	2712.2

TABLE 24.2.2-5. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR PORTSMOUTH 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$)	1627,2047
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	47,57
TOTAL COST (1000$)	
ESP UPGRADE CASE	1674,2104
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.16
NEW BAGHOUSE	NA

Long duct residence time exists between the boilers and their respective ESPs. A low factor was assigned to ESP upgrade since space is available.

Table 24.2.2-6. Summary of DSD/FSI Control Costs for the Portsmouth 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	3	1.00	185	45	1.0	8.4	45.4	5.3	7.3	49.0	2658	2008.0
DSD+ESP	4	1.00	239	44	1.0	10.0	41.9	6.0	6.6	49.0	3357	1797.4
DSD+ESP-C	3	1.00	185	45	1.0	8.4	45.4	3.1	4.2	49.0	2658	1164.6
DSD+ESP-C	4	1.00	239	44	1.0	10.0	41.9	3.5	3.8	49.0	3357	1043.2
FSI+ESP-50	3	1.00	185	45	1.0	10.2	55.0	5.2	7.1	50.0	2732	1899.4
FSI+ESP-50	4	1.00	239	44	1.0	12.2	50.9	6.1	6.6	50.0	3451	1769.3
FSI+ESP-50-C	3	1.00	185	45	1.0	10.2	55.0	3.0	4.1	50.0	2732	1105.0
FSI+ESP-50-C	4	1.00	239	44	1.0	12.2	50.9	3.6	3.9	50.0	3451	1029.5
FSI+ESP-70	3	1.00	185	45	1.0	10.3	55.5	5.3	7.2	70.0	3824	1373.1
FSI+ESP-70	4	1.00	239	44	1.0	12.3	51.4	6.2	6.7	70.0	4831	1279.5
FSI+ESP-70-C	3	1.00	185	45	1.0	10.3	55.5	3.1	4.2	70.0	3824	798.8
FSI+ESP-70-C	4	1.00	239	44	1.0	12.3	51.4	3.6	3.9	70.0	4831	744.5

24.2.3 Possum Point Steam Plant

Retrofit factors were developed for units 3 and 4 at the Possum Point plant; however, costs are not shown due to the low sulfur content of the coal. CS was not evaluated since the boilers currently fire a low sulfur coal. Sorbent injection technologies (FSI and DSD) were not considered for unit 3 due to the short duct residence time between the boilers and the small size of the ESPs.

TABLE 24.2.3-1. POSSUM POINT STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2	3	4	5
GENERATING CAPACITY (MW)	69	69	114	239	882
CAPACITY FACTOR (PERCENT)	RESERVE	SHUTDOWN	31	50	6
INSTALLATION DATE	1948	1951	1955	1962	1975
FIRING TYPE			TANGENTIAL		
FURNACE VOLUME (1000 CU FT)	PETROLEUM		41	124	PETROLEUM
LOW NOx COMBUSTION	BURNING		NO	NO	BURNING
COAL SULFUR CONTENT (PERCENT)			1.0		
COAL HEATING VALUE (BTU/LB)			12800		
COAL ASH CONTENT (PERCENT)			8.2		
FLY ASH SYSTEM			WET DISPOSAL		
ASH DISPOSAL METHOD			POND/ON-SITE		
STACK NUMBER	1	2	3	4	5
COAL DELIVERY METHODS			RAILROAD		
PARTICULATE CONTROL					
TYPE			ESP	ESP	
INSTALLATION DATE			1955	1982	
EMISSION (LB/MM BTU)			0.2	0.02	
REMOVAL EFFICIENCY			96	99.7	
DESIGN SPECIFICATION					
SULFUR SPECIFICATION (PERCENT)			1.0	0.7	
SURFACE AREA (1000 SQ FT)			44.6	615.6	
EXIT GAS FLOW RATE (1000 ACFM)			360	951	
SCA (SQ FT/1000 ACFM)			124	647	
OUTLET TEMPERATURE (°F)			300	265	

TABLE 24.2.3-2. SUMMARY OF RETROFIT FACTOR DATA FOR POSSUM POINT UNIT 3 *

	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	YES	NA	NO
ESTIMATED COST (1000$)	1054	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	798	0	798
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.55	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.51
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 for unit 3 would be located south of unit 1.

TABLE 24.2.3-3. SUMMARY OF RETROFIT FACTOR DATA FOR POSSUM POINT 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			MEDIUM
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$)	2047	NA	2047
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	1673	0	1673
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.55	NA	
ESP REUSE CASE			1.58
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	0	10

* L/S-FGD and LSD-FGD absorbers for unit 4 would be located south of unit 1.

TABLE 24.2.3-4. SUMMARY OF NOx RETROFIT RESULTS FOR POSSUM POINT

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	3	4
FIRING TYPE	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA
FURNACE VOLUME (1000 CU FT)	41	124
BOILER INSTALLATION DATE	1955	1962
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$)	0	0
Ductwork Demolition (1000$)	30	52
New Duct Length (Feet)	200	200
New Duct Costs (1000$)	1070	1650
New Heat Exchanger (1000$)	2016	3144
TOTAL SCOPE ADDER COSTS (1000$)	3116	4846
RETROFIT FACTOR FOR SCR	1.52	1.52
GENERAL FACILITIES (PERCENT)	38	38

* Cold side SCR reactors for units 3 and 4 would be located behind the chimney for that unit.

Table 24.2.3-5. NOx Control Cost Results for the Possum Point 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	114	31	1.0	0.7	5.7	0.1	0.4	25.0	223	617.9
LNC-OFA	4	1.00	239	50	1.0	0.9	3.7	0.2	0.2	25.0	754	245.9
LNC-OFA-C	3	1.00	114	31	1.0	0.7	5.7	0.1	0.3	25.0	223	367.3
LNC-OFA-C	4	1.00	239	50	1.0	0.9	3.7	0.1	0.1	25.0	754	146.1
SCR-3	3	1.52	114	31	1.0	25.6	224.8	7.7	24.9	80.0	714	10813.0
SCR-3	4	1.52	239	50	1.0	43.4	181.7	13.8	13.2	80.0	2413	5726.0
SCR-3-C	3	1.52	114	31	1.0	25.6	224.8	4.5	14.7	80.0	714	6356.2
SCR-3-C	4	1.52	239	50	1.0	43.4	181.7	8.1	7.7	80.0	2413	3361.3
SCR-7	3	1.52	114	31	1.0	25.6	224.8	6.8	21.9	80.0	714	9512.7
SCR-7	4	1.52	239	50	1.0	43.4	181.7	11.9	11.3	80.0	2413	4919.7
SCR-7-C	3	1.52	114	31	1.0	25.6	224.8	4.0	12.9	80.0	714	5611.1
SCR-7-C	4	1.52	239	50	1.0	43.4	181.7	7.0	6.7	80.0	2413	2899.4

TABLE 24.2.3-6. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR POSSUM POINT 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$)	2047
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	57

TOTAL COST (1000$)	
ESP UPGRADE CASE	2104
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Short duct residence time exists between unit 4 and the unit 4 retrofit ESPs. A high factor was assigned to ESP upgrade since little space is available for upgrading.

Table 24.2.3-7. Summary of DSD/FSI Control Costs for the Possum Point 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-C	4	1.00	239	50	1.0	10.9	45.6	3.8	3.6	49.0	3815	987.2
FSI+ESP-50-C	4	1.00	239	50	1.0	11.7	48.9	3.6	3.5	50.0	3921	928.4
FSI+ESP-70-C	4	1.00	239	50	1.0	11.8	49.5	3.7	3.5	70.0	5490	672.7

SECTION 25.0 WISCONSIN

25.1 DAIRYLAND POWER COOPERATIVE

25.1.1 Genoa #3 Steam Plant

The Genoa #3 steam plant is located on the Mississippi River in Vernon County, Wisconsin, and is operated by the Dairyland Power Cooperative. The Genoa #3 plant contains one coal-fired boiler with a gross generating capacity of 346 MW.

Table 25.1.1-1 presents operational data for the existing equipment at the Genoa #3 plant. Coal shipments are received by barge and transferred to a coal storage and handling area south of the plant. PM emissions are controlled by ESPs installed at the time the unit was constructed. The ESPs are located behind the boiler. Flue gases from the unit are directed to a chimney behind the ESPs. Wet fly ash from the unit is disposed of in a pond south of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for the unit would be located at the north end of the unit. The general facilities factor would be medium (8 percent) for the FGD absorber location because of a plant road relocation. The site access/congestion factor would be low for this location. Approximately 400 feet of ductwork would be required for installation of the L/LS-FGD system. A low site access/congestion factor was assigned to flue gas handling for the unit.

LSD with reuse of the existing ESPs was not considered for this unit because of the small ESP size and poor performance of the existing ESPs, LSD with a new FF was considered instead. The LSD absorbers would be located similarly to the wet FGD absorbers with similar general facilities and site access/congestion factors as well as ductwork requirements.

Tables 25.1.1-2 and 25.1.1-3 present the retrofit factors and cost estimates for installation of FGD technologies at the Genoa #3 plant.

TABLE 25.1.1-1. GENOA #3 STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1
GENERATING CAPACITY (MW-each)	346
CAPACITY FACTOR (PERCENT)	51
INSTALLATION DATE	1969
FIRING TYPE	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	205
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	1.8
COAL HEATING VALUE (BTU/LB)	10500
COAL ASH CONTENT (PERCENT)	9.0
FLY ASH SYSTEM	WET DISPOSAL
ASH DISPOSAL METHOD	ON-SITE/SOLD
STACK NUMBER	1
COAL DELIVERY METHODS	BARGE
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1969
EMISSION (LB/MM BTU)	0.2
REMOVAL EFFICIENCY	97.1
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	3.0
SURFACE AREA (1000 SQ FT)	173
GAS EXIT RATE (1000 ACFM)	1200
SCA (SQ FT/1000 ACFM)	144
OUTLET TEMPERATURE (°F)	335

TABLE 25.1.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR GENOA #3 UNIT 1

	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$)	2853	NA	0
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	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

Table 25.1.1-3. Summary of FGD Control Costs for the Genoa 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	346	51	1.8	91.8	265.3	39.8	25.8	90.0	23548	1690.7
L/S FGD-C	1	1.38	346	51	1.8	91.8	265.3	23.2	15.0	90.0	23548	986.2
LC FGD	1	1.38	346	51	1.8	69.6	201.2	32.9	21.3	90.0	23548	1398.0
LC FGD-C	1	1.38	346	51	1.8	69.6	201.2	19.2	12.4	90.0	23548	814.2
LSD+FF	1	1.27	346	51	1.8	69.9	202.1	26.9	17.4	87.0	22633	1187.7
LSD+FF-C	1	1.27	346	51	1.8	69.9	202.1	15.7	10.2	87.0	22633	694.3

Coal Switching and Physical Coal Cleaning Costs--

Table 25.1.1-4 presents the IAPCS cost results for CS at the Genoa #3 plant. These costs do not include the effect of any changes to the boiler and pulverizer operation. PCC was not considered at the Genoa #3 plant because it is not a mine mouth plant.

NO_x Control Technologies--

The Genoa #3 unit 1 is a dry bottom, tangential-fired boiler rated at 346 MW. OFA was considered for NO_x emission control at the Genoa #3 plant. Performance and cost estimates developed for OFA at unit 1 are presented in Tables 25.1.1-5 and 25.1.1-6.

Selective catalytic Reduction--

Hot side SCR reactors for the Genoa #3 plant would be located north of the unit close to the ESPs. A medium general facilities value (20 percent) was assigned to the location. A low site access/congestion factor was assigned to the absorber location. Approximately 200 feet of ductwork would be required to span the distance between the SCR reactors and the chimney. Tables 25.1.1-5 and 25.1.1-6 present the retrofit factors and cost for installation of SCR at the Genoa #3 plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) were not considered for the Genoa #3 plant because of the insufficient duct residence time between the boilers and the ESPs and the small sizes of the ESPs.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The 346 MW boiler at the Genoa #3 plant is large and has a long remaining service life and would not likely be considered as a near term candidate for AFBC/CG repowering.

Table 25.1.1-4. Summary of Coal Switching/Cleaning Costs for the Genoa 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	346	51	1.8	15.1	43.5	23.6	15.3	57.0	15003	1574.1
CS/B+$15-C	1	1.00	346	51	1.8	15.1	43.5	13.6	8.8	57.0	15003	906.4
CS/B+$5	1	1.00	346	51	1.8	11.5	33.2	10.2	6.6	57.0	15003	681.2
CS/B+$5-C	1	1.00	346	51	1.8	11.5	33.2	5.9	3.8	57.0	15003	393.7

TABLE 25.1.1-5. SUMMARY OF NOx RETROFIT RESULTS FOR GENOA #3

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1
FIRING TYPE	TANG
TYPE OF NOx CONTROL	OFA
FURNACE VOLUME (1000 CU FT)	205
BOILER INSTALLATION DATE	1969
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$)	0
Ductwork Demolition (1000$)	69
New Duct Length (Feet)	200
New Duct Costs (1000$)	2048
New Heat Exchanger (1000$)	0
TOTAL SCOPE ADDER COSTS (1000$)	2117
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	20

Table 25.1.1-6. NOx Control Cost Results for the Genoa 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	346	51	1.8	1.0	2.9	0.2	0.1	25.0	1398	155.5
LNC-OFA-C	1	1.00	346	51	1.8	1.0	2.9	0.1	0.1	25.0	1398	92.4
SCR-3	1	1.16	346	51	1.8	41.9	121.2	15.6	10.1	80.0	4473	3489.6
SCR-3-C	1	1.16	346	51	1.8	41.9	121.2	9.1	5.9	80.0	4473	2041.3
SCR-7	1	1.16	346	51	1.8	41.9	121.2	12.7	8.2	80.0	4473	2841.3
SCR-7-C	1	1.16	346	51	1.8	41.9	121.2	7.5	4.8	80.0	4473	1669.9

25.2 WISCONSIN ELECTRIC POWER COMPANY

25.2.1 North Oak Creek Steam Plant

The North Oak Creek steam plant is located on Lake Michigan in Milwaukee County, Wisconsin, and is operated by the Wisconsin Electric Power Company. The North Oak Creek plant contains four coal-fired boilers with a gross generating capacity of 500 MW. Units 3 and 4 are retired and units 1 and 2 will be retired in 1990.

Table 25.2.1-1 presents operational data for the existing equipment at the North Oak Creek plant. Coal shipments are received by railroad and transferred to two coal storage and handling areas east and west of the plant. PM emissions are controlled by retrofit ESPs located behind the boilers. Flue gases from units 1 and 2 are directed to one chimney and flue gases from units 3 and 4 are directed to another chimney. Both chimneys are located behind the ESPs. Dry fly ash is stored in silos.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for units 1-2 would be located at the north end of the plant between the two coal piles. The general facilities factor would be high for the FGD absorber location because relocation of a storage silo and demineralization building would be necessary. The site access/congestion factor would be medium for the L/LS-FGD absorber locations. Because of the difficulty in accessing the old chimneys and the length of ductwork that would be required, a new chimney would be constructed at the north end of the plant. After construction of the new chimney, close to 600 feet of ductwork would be required for installation of the L/LS-FGD system for units 1 and 2. A high site access/congestion factor was assigned to flue gas handling for all units because of the obstruction caused by the coal conveyor and the congestion around the existing chimneys.

LSD was not considered for the North Oak Creek plant because of the lack of access to the ductwork between the boilers and the ESPs and the small size of the existing ESPs. LSD with a new baghouse was not considered because of the medium to high sulfur content of the coal being burned at the plant.

TABLE 25.2.1-1. NORTH OAK CREEK STEAM PLANT OPERATIONAL DATA

BOILER NUMBER+	1,2	3,4
GENERATING CAPACITY (MW-each)	120	130
CAPACITY FACTOR (PERCENT)	28,32	RETIRED
INSTALLATION DATE	1953,54	1957
FIRING TYPE	ARCH	ARCH
FURNACE VOLUME (1000 CU FT)	107	
LOW NOx COMBUSTION	NO	
COAL SULFUR CONTENT (PERCENT)*	1.6	
COAL HEATING VALUE (BTU/LB)	12200	
COAL ASH CONTENT (PERCENT)	7.2	
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	ON-SITE/STORED	
STACK NUMBER	1	
COAL DELIVERY METHODS	RAILROAD	
PARTICULATE CONTROL		
TYPE	ESP	
INSTALLATION DATE	1970	
EMISSION (LB/MM BTU)	0.03,0.07	
REMOVAL EFFICIENCY	99.4,99.2	
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	2.5	
SURFACE AREA (1000 SQ FT)	123.1	
GAS EXIT RATE (1000 ACFM)	600	
SCA (SQ FT/1000 ACFM)	205	
OUTLET TEMPERATURE (°F)	290	

+ Units 1 and 2 will be retired in 1990, units 3 and 4 were retired in 1988.
* Based on 1988 data.

Table 25.2.1-2 presents the retrofit factors for installation of L/LS-FGD at the North Oak Creek plant. Costs were not developed because both units will be retired soon.

Coal Switching and Physical Coal Cleaning Costs--

Costs were not devloped for CS because both units will be retired soon.

NO_x Control Technologies--

Both units are dry bottom, arch-fired boilers having low NO_x emission levels. As such, LNC technologies were not considered for this plant.

Selective Catalytic Reduction

Cold side SCR reactors for the North Oak Creek plant would be located beside the chimneys toward the coal pile. High site access/congestion and general facility factors (38 percent) were assigned to the SCR reactor locations. Approximately 300 feet of ductwork would be required for the SCR reactors. Table 25.2.1-3 summarizes the retrofit factors for installation of SCR at the North Oak Creek plant. Again, costs were not presented since the units will be retired soon.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) were not considered for the North Oak Creek plant because of the lack of access to the ductwork between the boilers and the ESPs and the small size of the ESPs.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

All boilers at the North Oak Creek plant would be good candidates for AFBC/CG repowering because of their small boiler sizes (120-130 MW) and likely short remaining useful lives.

TABLE 25.2.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR NORTH OAK CREEK UNIT 1 OR 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	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	NO	NA	NA
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	NA	NA
ESTIMATED COST (1000$)	840	0	0
OTHER	NO		
RETROFIT FACTORS			
FGD SYSTEM	1.41	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 25.2.1-3. SUMMARY OF NOx RETROFIT RESULTS FOR NORTH OAK CREEK

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1,2	3,4
FIRING TYPE	ARCH	ARCH
TYPE OF NOx CONTROL	NA	NA
FURNACE VOLUME (1000 CU FT)	106	107,106
BOILER INSTALLATION DATE	1953,54	1955,57
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	NA	NA
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	31	33
New Duct Length (Feet)	300	300
New Duct Costs (1000$)	1654	1733
New Heat Exchanger (1000$)	2079	2182
TOTAL SCOPE ADDER COSTS (1000$)		
INDIVIDUAL CASE	3764	3948
COMBINED CASE	5685	5962
RETROFIT FACTOR FOR SCR	1.52	1.52
GENERAL FACILITIES (PERCENT)	38	38

25.2.2 Pleasant Prairie Steam Plant

Retrofit factors were developed for the two units at the Pleasant Prairie plant, however, costs are not presented since the low coal sulfur content would yield low capital/operating costs and high cost per ton of SO_2 removal. Sorbent injection technologies were not considered because of the short duct residence time between the boilers and ESPs and difficulties in upgrading the existing ESPs due to the congestion around the units.

TABLE 25.2.2-1. PLEASANT PRAIRIE STEAM PLANT OPERATIONAL DATA *

BOILER NUMBER	1,2
GENERATING CAPACITY (MW-each)	617
CAPACITY FACTOR (PERCENT)	68,74
INSTALLATION DATE	1980,1985
FIRING TYPE	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	869.9
LOW NOx COMBUSTION	YES
COAL SULFUR CONTENT (PERCENT)	0.4
COAL HEATING VALUE (BTU/LB)	8400
COAL ASH CONTENT (PERCENT)	6.4
FLY ASH SYSTEM	DRY DISPOSAL
ASH DISPOSAL METHOD	SOLD/ON-SITE
STACK NUMBER	1
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1980,1985
EMISSION (LB/MM BTU)	0.03,0.01
REMOVAL EFFICIENCY	<100
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	0.4
SURFACE AREA (1000 SQ FT)	1223.4
GAS EXIT RATE (1000 ACFM)	4000
SCA (SQ FT/1000 ACFM)	306
OUTLET TEMPERATURE (°F)	280

* Based on 1988 data.

TABLE 25.2.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR PLEASANT PRAIRIE UNIT 1*

	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)	300-600	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
RETROFIT FACTORS			
FGD SYSTEM	1.31	NA	
ESP REUSE CASE			1.47
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	0	8

* Absorbers for unit 1 would be located beside the common chimney.

TABLE 25.2.2-3. SUMMARY OF RETROFIT FACTOR DATA FOR PLEASANT PRAIRIE UNIT 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			MEDIUM
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	1.31	NA	
ESP REUSE CASE			1.31
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	0	8

* Absorbers for unit 2 would be located beside the common chimney.

TABLE 25.2.2-4. SUMMARY OF NOx RETROFIT RESULTS FOR PLEASANT PRAIRIE

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	1-2
FIRING TYPE	OWF	OWF	NA
TYPE OF NOx CONTROL	EQUIPPED WITH LNB		NA
FURNACE VOLUME (1000 CU FT)	869.9	869.9	NA
BOILER INSTALLATION DATE	1980	1985	NA
SLAGGING PROBLEM	NA	NA	NA
ESTIMATED NOx REDUCTION (PERCENT)	NA	NA	NA
SCR RETROFIT RESULTS*			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	106	106	178
New Duct Length (Feet)	300	200	250
New Duct Costs (1000$)	4310	2873	5388
New Heat Exchanger (1000$)	5554	5554	8418
TOTAL SCOPE ADDER COSTS (1000$)	9970	8533	13983
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	20	20	20

* Cold side SCR reactors for both units would be located beside the common chimney.

Table 25.2.2-5. NOx Control Cost Results for the Pleasant Prairie 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	617	68	0.4	77.0	124.7	29.8	8.1	80.0	19237	1548.4
SCR-3	2	1.16	617	74	0.4	75.5	122.4	29.9	7.5	80.0	20934	1426.0
SCR-3	1-2	1.16	1234	71	0.4	142.1	115.1	57.2	7.5	80.0	40171	1424.2
SCR-3-C	1	1.16	617	68	0.4	77.0	124.7	17.4	4.7	80.0	19237	905.1
SCR-3-C	2	1.16	617	74	0.4	75.5	122.4	17.4	4.4	80.0	20934	833.2
SCR-3-C	1-2	1.16	1234	71	0.4	142.1	115.1	33.4	4.4	80.0	40171	831.8
SCR-7	1	1.16	617	68	0.4	77.0	124.7	24.4	6.7	80.0	19237	1270.6
SCR-7	2	1.16	617	74	0.4	75.5	122.4	24.5	6.1	80.0	20934	1170.6
SCR-7	1-2	1.16	1234	71	0.4	142.1	115.1	46.5	6.1	80.0	40171	1158.1
SCR-7-C	1	1.16	617	68	0.4	77.0	124.7	14.3	3.9	80.0	19237	745.9
SCR-7-C	2	1.16	617	74	0.4	75.5	122.4	14.4	3.6	80.0	20934	686.9
SCR-7-C	1-2	1.16	1234	71	0.4	142.1	115.1	27.3	3.6	80.0	40171	679.4

25.2.3 Port Washington Steam Plant

The Port Washington steam plant is located within Ozaukee County, Wisconsin, as part of the Wisconsin Electric Power Company system. Located on the western side of Lake Michigan, the plant contains five coal-fired boilers with a total gross generating capacity of 400 MW.

Table 25.2.3-1 presents operational data for the existing equipment at the Port Washington plant. The boilers burn medium sulfur coal. Coal shipments are received by barge and transferred to a coal storage and handling area east of the plant and adjacent to the lake.

PM emissions for the boilers are controlled with retrofit ESPs located behind each unit. The plant has a dry fly ash handling system. Fly ash is disposed of in a landfill five miles away from the plant. Bottom ash is dewatered in a settling basin east of the plant and south of the coal pile and then trucked to a landfill with the fly ash. Units 1 through 3 are served by a common chimney while units 4 and 5 are served by another chimney.

Lime/Limestone and Lime Spray Drying FGD Costs--

The five boilers are located beside each other parallel to Lake Michigan. The absorbers for units 1 through 5 would be located behind the chimneys south of the settling basin. The limestone preparation, storage, and handling area would be located behind the absorbers. Some of the roads east of the plant and the bottom ash settling pond would have to be relocated; therefore, a factor of 15 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 absorbers would have to be disposed of off-site in the same manner as the fly ash.

A high site access/congestion factor was assigned to the FGD absorber locations due to the access difficulty to this area created by the water intake, discharge channel, and the units. The area is surrounded by water from three sides making it difficult to access.

For flue gas handling, because the absorbers are placed behind the chimneys, short duct runs would be required (about 200 feet). A high site

TABLE 25.2.3-1. PORT WASHINGTON STEAM PLANT OPERATIONAL DATA*

BOILER NUMBER	1,2,3,4,5
GENERATING CAPACITY (MW-each)	80
CAPACITY FACTOR	9,23,18,20,10+
INSTALLATION DATE	1935,43,48,49,50
FIRING TYPE	ARCH-FIRED
FURNACE VOLUME (1000 CU FT)	72
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	1.6
COAL HEATING VALUE (BTU/LB)	13200
COAL ASH CONTENT (PERCENT)	6.0
FLY ASH SYSTEM	DRY HANDLING
ASH DISPOSAL METHOD	OFF-SITE
STACK NUMBER	7,7,7,6,6
COAL DELIVERY METHODS	SHIP
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1965-68
EMISSION (LB/MM BTU)	0.05-0.1
REMOVAL EFFICIENCY	98.6-99.3
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	3.1
SURFACE AREA (1000 SQ FT)	87,87,87,91,87
GAS EXIT RATE (1000 ACFM)	450
SCA (SQ FT/1000 ACFM)	193,193,193,202,193
OUTLET TEMPERATURE (°F)	390,450,450,390,390

* Based on 1988 data.
+ 1985 data used for boiler 5.

access/congestion factor was assigned to the flue gas handling system due to access difficulty for this location.

LSD with reuse of the existing ESPs was not considered for this plant because the ESPs are small (SCA=193) and would require major upgrading and plate area additions to handle the increased PM generated from the LSD application. LSD with a new baghouse was also 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 25.2.3-2. Table 25.2.3-3 presents the capital and operating costs for commercial FGD technologies. The low cost FGD option reduces capital costs due to combining the FGD systems, eliminating spare absorber modules, and maximizing the absorber modules size.

Coal Switching and Physical Coal Cleaning Costs--

Table 25.2.3-4 presents the IAPCS cost results for CS at the Port Washington 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 through 5 are dry bottom, arch-fired boilers rated at 80 MW each. The arch-fired boilers have very low NO_x levels (<0.5 lb per million Btu). As such, LNC technologies were not considered for the Port Washington boilers.

Selective Catalytic Reduction--

Cold side SCR reactors for all units would be located immediately behind the chimneys. All five reactors are located in high site congestion areas for the same reasons as were outlined in the FGD section. All reactors were assumed to be in areas with high underground obstructions. Duct lengths of 200 feet would be required for the unit 1 through 5 SCR reactors. Because a plant road and part of the bottom ash pond relocation was required, a factor of 38 percent was assigned to general facilities. The ammonia storage system was placed close to the reactors east of the plant.

TABLE 25.2.3-2. SUMMARY OF RETROFIT FACTOR DATA FOR PORT WASHINGTON UNITS 1-5 (EACH)

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
<u>SITE ACCESS/CONGESTION</u>			
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
<u>SCOPE ADJUSTMENTS</u>			
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		
<u>RETROFIT FACTORS</u>			
FGD SYSTEM	1.53	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 25.2.3-3. Summary of FGD Control Costs for the Port Washington 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	1-5	1.53	400	16	1.6	71.3	178.3	26.3	46.9	90.0	5838	4504.3
LC FGD-C	1-5	1.53	400	16	1.6	71.3	178.3	15.4	27.4	90.0	5838	2635.5
LFGD	1	1.53	80	9	1.6	39.2	490.6	13.7	217.3	90.0	657	20870.6
LFGD	2	1.53	80	23	1.6	39.5	494.0	14.6	90.8	90.0	1678	8721.3
LFGD	3	1.53	80	18	1.6	39.5	493.9	14.3	113.7	90.0	1314	10923.7
LFGD	4	1.53	80	20	1.6	39.3	490.8	14.4	102.7	90.0	1460	9865.9
LFGD	5	1.53	80	10	1.6	39.3	490.6	13.8	196.6	90.0	730	18877.7
LFGD	1-5	1.53	400	16	1.6	95.7	239.3	33.9	60.4	90.0	5838	5804.3
LFGD	1-3	1.53	240	17	1.6	69.8	290.8	24.9	69.7	90.0	3722	6691.6
LFGD	4-5	1.53	160	15	1.6	54.6	341.5	19.4	92.3	90.0	2189	8867.7
LFGD-C	1	1.53	80	9	1.6	39.2	490.6	8.0	127.3	90.0	657	12225.3
LFGD-C	2	1.53	80	23	1.6	39.5	494.0	8.6	53.1	90.0	1678	5102.3
LFGD-C	3	1.53	80	18	1.6	39.5	493.9	8.4	66.6	90.0	1314	6393.5
LFGD-C	4	1.53	80	20	1.6	39.3	490.8	8.4	60.1	90.0	1460	5773.1
LFGD-C	5	1.53	80	10	1.6	39.3	490.6	8.1	115.1	90.0	730	11056.8
LFGD-C	1-5	1.53	400	16	1.6	95.7	239.3	19.8	35.4	90.0	5838	3399.0
LFGD-C	1-3	1.53	240	17	1.6	69.8	290.8	14.6	40.8	90.0	3722	3917.9
LFGD-C	4-5	1.53	160	15	1.6	54.6	341.5	11.4	54.1	90.0	2189	5192.5

Table 25.2.3-4. Summary of Coal Switching/Cleaning Costs for the Port Washington 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	80	9	1.6	4.3	54.0	1.9	30.4	38.0	274	6978.9
CS/B+$15	2	1.00	80	23	1.6	4.2	52.0	3.3	20.2	38.0	701	4635.9
CS/B+$15	3	1.00	80	18	1.6	4.2	52.0	2.8	21.9	38.0	549	5028.8
CS/B+$15	4	1.00	80	20	1.6	4.3	53.1	3.0	21.2	38.0	610	4884.1
CS/B+$15	5	1.00	80	10	1.6	4.3	54.0	2.0	28.7	38.0	305	6603.2
CS/B+$15-C	1	1.00	80	9	1.6	4.3	54.0	1.1	17.7	38.0	274	4069.0
CS/B+$15-C	2	1.00	80	23	1.6	4.2	52.0	1.9	11.7	38.0	701	2682.5
CS/B+$15-C	3	1.00	80	18	1.6	4.2	52.0	1.6	12.7	38.0	549	2915.2
CS/B+$15-C	4	1.00	80	20	1.6	4.3	53.1	1.7	12.3	38.0	610	2829.6
CS/B+$15-C	5	1.00	80	10	1.6	4.3	54.0	1.2	16.7	38.0	305	3846.8
CS/B+$5	1	1.00	80	9	1.6	3.5	43.6	1.2	19.8	38.0	274	4549.7
CS/B+$5	2	1.00	80	23	1.6	3.3	41.6	1.8	11.0	38.0	701	2529.9
CS/B+$5	3	1.00	80	18	1.6	3.3	41.6	1.6	12.5	38.0	549	2865.3
CS/B+$5	4	1.00	80	20	1.6	3.4	42.8	1.7	11.9	38.0	610	2746.9
CS/B+$5	5	1.00	80	10	1.6	3.5	43.6	1.3	18.4	38.0	305	4227.6
CS/B+$5-C	1	1.00	80	9	1.6	3.5	43.6	0.7	11.6	38.0	274	2663.9
CS/B+$5-C	2	1.00	80	23	1.6	3.3	41.6	1.0	6.4	38.0	701	1470.7
CS/B+$5-C	3	1.00	80	18	1.6	3.3	41.6	0.9	7.3	38.0	549	1668.9
CS/B+$5-C	4	1.00	80	20	1.6	3.4	42.8	1.0	7.0	38.0	610	1599.0
CS/B+$5-C	5	1.00	80	10	1.6	3.5	43.6	0.8	10.8	38.0	305	2473.3

Table 25.2.3-5 presents the SCR process area retrofit factors and scope adder costs. Table 25.2.3-6 presents the estimated cost of retrofitting SCR at the Port Washington boilers.

Duct Spray Drying and Furnace Sorbent Injection--

The retrofit of FSI and DSD technologies at the Port Washington steam plant for all units would be difficult for two major reasons: 1) The ESPs have small SCAs (<200) and probably would not be able to handle the increased PM thereby requiring major upgrading and plate area additions; 2) the short duct residence time between the boilers and ESPs would not be sufficient for either humidification (for FSI application) or sorbent droplet evaporation (for DSD application). Therefore, costs were not developed for sorbent injection technologies for the Port Washington 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 Port Washington plant. All units might be considered candidates for repowering retrofit because of their small boiler sizes, age, and low capacity factors.

25.2.4 South Oak Creek Steam Plant

The South Oak Creek steam plant is located on Lake Michigan, south of the North Oak Creek plant, in Milwaukee County, Wisconsin, and is operated by the Wisconsin Electric Power Company. The South Oak Creek plant contains four coal-fired boilers with a gross generating capacity of 1,170 MW.

Table 25.2.4-1 presents operational data for the existing equipment at the South Oak Creek plant. Coal shipments are received by barge and transferred to a coal storage and handling area northeast of the plant. PM emissions are controlled by retrofit ESPs for units 5 and 6 and ESPs installed at the time of construction for units 7 and 8 (retrofit ESPs are currently being installed for units 7 and 8). Flue gases from the units 5 and 6 are directed to one chimney and flue gases from units 7 and 8 are directed to another chimney. Both chimneys are located behind the ESPs. Dry fly ash is stored in silos.

TABLE 25.2.3-5. SUMMARY OF NOx RETROFIT RESULTS FOR PORT WASHINGTON

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1-5 (each)
FIRING TYPE	ARCH
TYPE OF NOx CONTROL	NA
FURNACE VOLUME (CUBIC FT)	NA
BOILER INSTALLATION DATE	1935-50
SLAGGING PROBLEM	NO
ESTIMATED NOx REDUCTION (PERCENT)	NA
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	23
New Duct Length (Feet)	200
New Duct Costs (1000$)	870
New Heat Exchanger (1000$)	1630
TOTAL SCOPE ADDER COSTS (1000$)	
INDIVIDUAL	2523
COMBINED (1-3)	3814
COMBINED (4-5)	4858
COMBINED (1-5)	6588
RETROFIT FACTOR FOR SCR	1.52
GENERAL FACILITIES (PERCENT)	38

Table 25.2.3-6. NOx Control Cost Results for the Port Washington 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	1.52	80	9	1.6	20.7	259.0	6.1	96.8	80.0	140	43494.0
SCR-3	2	1.52	80	23	1.6	21.0	262.3	6.2	38.5	80.0	359	17314.9
SCR-3	3	1.52	80	18	1.6	21.0	262.3	6.2	49.1	80.0	281	22064.4
SCR-3	4	1.52	80	20	1.6	20.7	259.0	6.1	43.8	80.0	312	19689.3
SCR-3	5	1.52	80	10	1.6	20.7	259.0	6.1	87.2	80.0	156	39167.7
SCR-3	1-3	1.52	240	17	1.6	43.3	180.6	13.6	38.1	80.0	795	17139.1
SCR-3	4-5	1.52	160	15	1.6	33.6	210.1	10.1	48.2	80.0	468	21676.5
SCR-3	1-5	1.52	400	16	1.6	64.2	160.6	20.6	36.8	80.0	1248	16547.0
SCR-3-C	1	1.52	80	9	1.6	20.7	259.0	3.6	56.9	80.0	140	25580.8
SCR-3-C	2	1.52	80	23	1.6	21.0	262.3	3.7	22.7	80.0	359	10182.5
SCR-3-C	3	1.52	80	18	1.6	21.0	262.3	3.6	28.9	80.0	281	12976.7
SCR-3-C	4	1.52	80	20	1.6	20.7	259.0	3.6	25.8	80.0	312	11578.7
SCR-3-C	5	1.52	80	10	1.6	20.7	259.0	3.6	51.3	80.0	156	23036.2
SCR-3-C	1-3	1.52	240	17	1.6	43.3	180.6	8.0	22.4	80.0	795	10063.9
SCR-3-C	4-5	1.52	160	15	1.6	33.6	210.1	6.0	28.4	80.0	468	12741.2
SCR-3-C	1-5	1.52	400	16	1.6	64.2	160.6	12.1	21.6	80.0	1248	9711.1
SCR-7	1	1.52	80	9	1.6	19.6	244.8	5.2	82.0	80.0	140	36835.3
SCR-7	2	1.52	80	23	1.6	21.0	262.3	5.6	34.5	80.0	359	15507.4
SCR-7	3	1.52	80	18	1.6	21.0	262.3	5.5	44.0	80.0	281	19755.1
SCR-7	4	1.52	80	20	1.6	20.7	259.0	5.5	39.2	80.0	312	17610.9
SCR-7	5	1.52	80	10	1.6	20.7	259.0	5.5	77.9	80.0	156	35010.2
SCR-7	1-3	1.52	240	17	1.6	43.3	180.6	11.7	32.7	80.0	795	14693.7
SCR-7	4-5	1.52	160	15	1.6	33.6	210.1	8.8	42.1	80.0	468	18904.8
SCR-7	1-5	1.52	400	16	1.6	64.2	160.6	17.4	31.0	80.0	1248	13949.0
SCR-7-C	1	1.52	80	9	1.6	19.6	244.8	3.0	48.4	80.0	140	21729.5
SCR-7-C	2	1.52	80	23	1.6	21.0	262.3	3.3	20.4	80.0	359	9146.9
SCR-7-C	3	1.52	80	18	1.6	21.0	262.3	3.3	25.9	80.0	281	11653.6
SCR-7-C	4	1.52	80	20	1.6	20.7	259.0	3.2	23.1	80.0	312	10387.8
SCR-7-C	5	1.52	80	10	1.6	20.7	259.0	3.2	46.0	80.0	156	20654.5
SCR-7-C	1-3	1.52	240	17	1.6	43.3	180.6	6.9	19.3	80.0	795	8662.7
SCR-7-C	4-5	1.52	160	15	1.6	33.6	210.1	5.2	24.8	80.0	468	11153.4
SCR-7-C	1-5	1.52	400	16	1.6	64.2	160.6	10.3	18.3	80.0	1248	8222.6

TABLE 25.2.4-1. SOUTH OAK CREEK STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	5,6	7,8
GENERATING CAPACITY (MW-each)	275	310
CAPACITY FACTOR (PERCENT)*	58,43	48,38
INSTALLATION DATE	1959,61	1965,67
FIRING TYPE	ARCH	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	172	136
LOW NOx COMBUSTION	NO	LNC+
COAL SULFUR CONTENT (PERCENT)	1.6	1.6
COAL HEATING VALUE (BTU/LB)	12200	12200
COAL ASH CONTENT (PERCENT)	7.2	7.2
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	STORED IN SILOS	
STACK NUMBER	3	4
COAL DELIVERY METHODS	BARGE	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1972	1965,67
EMISSION (LB/MM BTU)	0.09,0.01	0.09,0.10
REMOVAL EFFICIENCY	98.6,98.9	98.5,98.6
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	2.0	2.5
SURFACE AREA (1000 SQ FT)	413.3	155.5
GAS EXIT RATE (1000 ACFM)	1200	840
SCA (SQ FT/1000 ACFM)	344	185
OUTLET TEMPERATURE (°F)	280	275

* Based on 1988 data.
\+ Installed in 1985-86.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for all of the units would be located at the south end of the plant close to retrofit ESPs. The general facilities factor would be medium (10 percent) for the FGD absorber location because relocation of some storage buildings and roads would be necessary. The site access/congestion factor would be medium for the L/LS-FGD absorber location. More than 1000 feet of ductwork would be required for installation of the L/LS-FGD system for units 5 and 6 and 500 feet would be required for units 7 and 8. A high site access/congestion factor was assigned to flue gas handling for all units because of the proximity of Lake Michigan and the obstruction caused by the ash silos and the unit 7 and 8 chimney. A new chimney would be constructed beside the absorbers to reduce duct length and congestion created around the units.

LSD with reuse of the existing ESPs was not considered for the South Oak Creek plant because of the lack of access to the ductwork between the boilers and the ESPs.

Tables 25.2.4-2 through 25.2.4-4 present the retrofit factors and cost estimates for installation of L/LS-FGD at the South Oak Creek plant.

Coal Switching and Physical Coal Cleaning Costs--

Table 25.2.4-5 presents the IAPCS cost results for CS at the South Oak Creek plant. PCC was not considered at the South Oak Creek plant because it is not a mine mouth plant. These costs do not include changes in boiler and pulverizer operating cost changes or any system modifications that may be necessary for coal handling.

NO_x Control Technologies--

Units 5 and 6 are arch-fired boilers having low NO_x emission levels and were not considered for LNC. Units 7 and 8 were retrofitted with LNC in 1985-86.

Selective Catalytic Reduction--

Cold side SCR reactors for units 5-7 would be located behind the respective ESPs and close to the chimneys. SCR reactors for unit 8 would be located close to the unit, south of the retrofit ESPs. A high general

TABLE 25.2.4-2. SUMMARY OF RETROFIT FACTOR DATA FOR SOUTH OAK CREEK UNIT 5 OR 6

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	NA
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	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$)	NA	NA	NA
NEW CHIMNEY	YES	NA	NA
ESTIMATED COST (1000$)	1925	0	0
OTHER	NO		
RETROFIT FACTORS			
FGD SYSTEM	1.82	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 25.2.4-3. SUMMARY OF RETROFIT FACTOR DATA FOR SOUTH OAK CREEK UNIT 7 OR 8

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	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	NO	NA	NA
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	NA	NA
ESTIMATED COST (1000$)	2170	0	0
OTHER	NO		
RETROFIT FACTORS			
FGD SYSTEM	1.52	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 25.2.4-4. Summary of FGD Control Costs for the South Oak 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	5	1.82	275	58	1.6	93.6	340.4	38.5	27.6	90.0	15927	2419.5
L/S FGD	6	1.82	275	43	1.6	93.6	340.3	36.4	35.2	90.0	11808	3084.0
L/S FGD	7	1.52	310	48	1.6	84.9	273.9	35.1	26.9	90.0	14859	2359.7
L/S FGD	8	1.52	310	38	1.6	84.9	273.8	33.5	32.4	90.0	11763	2846.1
L/S FGD	5-6	1.82	550	50	1.6	143.5	261.0	59.0	24.5	90.0	27460	2147.8
L/S FGD	7-8	1.52	620	43	1.6	131.9	212.8	54.6	23.4	90.0	26621	2052.2
L/S FGD-C	5	1.82	275	58	1.6	93.6	340.4	22.5	16.1	90.0	15927	1412.6
L/S FGD-C	6	1.82	275	43	1.6	93.6	340.3	21.3	20.5	90.0	11808	1802.5
L/S FGD-C	7	1.52	310	48	1.6	84.9	273.9	20.5	15.7	90.0	14859	1377.6
L/S FGD-C	8	1.52	310	38	1.6	84.9	273.8	19.6	19.0	90.0	11763	1663.0
L/S FGD-C	5-6	1.82	550	50	1.6	143.5	261.0	34.4	14.3	90.0	27460	1254.0
L/S FGD-C	7-8	1.52	620	43	1.6	131.9	212.8	31.9	13.7	90.0	26621	1198.0
LC FGD	5-8	1.66	1170	47	1.6	198.1	169.3	87.5	18.2	90.0	54910	1593.5
LC FGD-C	5-8	1.66	1170	47	1.6	198.1	169.3	51.0	10.6	90.0	54910	929.1

Table 25.2.4-5. Summary of Coal Switching/Cleaning Costs for the South Oak 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)
CS/B+$15	5	1.00	275	58	1.6	9.7	35.1	20.7	14.8	43.0	7608	2718.2
CS/B+$15	6	1.00	275	43	1.6	9.7	35.1	15.9	15.3	43.0	5640	2815.2
CS/B+$15	7	1.00	310	48	1.6	11.4	36.8	19.8	15.2	43.0	7097	2791.9
CS/B+$15	8	1.00	310	38	1.6	11.4	36.8	16.2	15.7	43.0	5619	2884.9
CS/B+$15-C	5	1.00	275	58	1.6	9.7	35.1	11.9	8.5	43.0	7608	1563.1
CS/B+$15-C	6	1.00	275	43	1.6	9.7	35.1	9.1	8.8	43.0	5640	1620.6
CS/B+$15-C	7	1.00	310	48	1.6	11.4	36.8	11.4	8.7	43.0	7097	1606.8
CS/B+$15-C	8	1.00	310	38	1.6	11.4	36.8	9.3	9.0	43.0	5619	1662.0
CS/B+$5	5	1.00	275	58	1.6	6.8	24.7	8.6	6.2	43.0	7608	1135.6
CS/B+$5	6	1.00	275	43	1.6	6.8	24.7	6.8	6.6	43.0	5640	1209.6
CS/B+$5	7	1.00	310	48	1.6	8.2	26.4	8.5	6.5	43.0	7097	1195.5
CS/B+$5	8	1.00	310	38	1.6	8.2	26.4	7.1	6.9	43.0	5619	1267.7
CS/B+$5-C	5	1.00	275	58	1.6	6.8	24.7	5.0	3.6	43.0	7608	654.6
CS/B+$5-C	6	1.00	275	43	1.6	6.8	24.7	3.9	3.8	43.0	5640	698.5
CS/B+$5-C	7	1.00	310	48	1.6	8.2	26.4	4.9	3.8	43.0	7097	690.2
CS/B+$5-C	8	1.00	310	38	1.6	8.2	26.4	4.1	4.0	43.0	5619	732.8

facilities value (38 percent) was assigned to units 5-7 due to relocation and demolition of ash silos and a plant road. A medium general facilities value (20 percent) was assigned to units 7-8 because of a plant road relocation. A high site access/congestion factor was assigned to unit 5-7 SCR reactor locations because of the congestion created by the lake and ESPs/chimneys. Some space is available for unit 8 SCR reactor and a medium site access/congestion factor was assigned to this location. About 300 feet of ductwork would be required for all units. Tables 25.2.4-6 and 25.2.4-7 present the retrofit factors and cost estimates for installation of SCR at the South Oak Creek plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) were not considered for units 7 and 8 because of the lack of access to the ductwork between the boilers and the ESPs and the small ESP size. However, sorbent injection technologies were considered for units 5 and 6 because of the large size ESPs. It is assumed that the first section of the ESPs could possibly be modified for slurry injection (E-SO_x). Tables 25.2.4-8 and 25.2.4-9 present retrofit factors and costs for FSI and DSD technologies for units 5 and 6.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

Units 5 and 6 would be considered good candidates for AFBC/CG repowering because of their small boiler size (<300 MW). Units 7 and 8 would be less likely candidates because of their larger size (>300 MW) and higher capacity factors. Plant/boiler site congestion would significantly increase the cost of repowering for all the boilers.

TABLE 25.2.4-6. SUMMARY OF NOx RETROFIT RESULTS FOR SOUTH OAK CREEK

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	5,6	7,8
FIRING TYPE	ARCH	TANGENTIAL
TYPE OF NOx CONTROL	NA	LNC
FURNACE VOLUME (1000 CU FT)	173	136
BOILER INSTALLATION DATE	1959,61	1965,67
SLAGGING PROBLEM	NO	YES
ESTIMATED NOx REDUCTION (PERCENT)	NA	NA
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH,MEDIUM
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	61	63
New Duct Length (Feet)	300	300
New Duct Costs (1000$)	2799	2881
New Heat Exchanger (1000$)	3567	3675
TOTAL SCOPE ADDER COSTS (1000$)	6427	6619
RETROFIT FACTOR FOR SCR	1.52	1.52,1.34
GENERAL FACILITIES (PERCENT)	38	38,20

Table 25.2.4-7. NOx Control Cost Results for the South Oak 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)
SCR-3	5	1.52	275	58	1.6	49.5	180.0	16.0	11.5	80.0	3403	4708.9
SCR-3	6	1.52	275	43	1.6	49.5	180.0	15.8	15.3	80.0	2523	6265.9
SCR-3	7	1.52	310	48	1.6	54.3	175.0	17.5	13.5	80.0	3175	5524.6
SCR-3	8	1.34	310	38	1.6	47.8	154.2	15.8	15.3	80.0	2513	6281.8
SCR-3-C	5	1.52	275	58	1.6	49.5	180.0	9.4	6.7	80.0	3403	2763.1
SCR-3-C	6	1.52	275	43	1.6	49.5	180.0	9.3	9.0	80.0	2523	3677.9
SCR-3-C	7	1.52	310	48	1.6	54.3	175.0	10.3	7.9	80.0	3175	3241.8
SCR-3-C	8	1.34	310	38	1.6	47.8	154.2	9.3	9.0	80.0	2513	3684.4
SCR-7	5	1.52	275	58	1.6	49.5	180.0	13.8	9.9	80.0	3403	4046.5
SCR-7	6	1.52	275	43	1.6	49.5	180.0	13.6	13.1	80.0	2523	5372.4
SCR-7	7	1.52	310	48	1.6	54.3	175.0	15.0	11.5	80.0	3175	4724.2
SCR-7	8	1.34	310	38	1.6	47.8	154.2	13.2	12.8	80.0	2513	5270.8
SCR-7-C	5	1.52	275	58	1.6	49.5	180.0	8.1	5.8	80.0	3403	2383.6
SCR-7-C	6	1.52	275	43	1.6	49.5	180.0	8.0	7.7	80.0	2523	3166.0
SCR-7-C	7	1.52	310	48	1.6	54.3	175.0	8.8	6.8	80.0	3175	2783.3
SCR-7-C	8	1.34	310	38	1.6	47.8	154.2	7.8	7.6	80.0	2513	3105.1

TABLE 25.2.4-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR SOUTH OAK CREEK UNIT 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$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	64
TOTAL COST (1000$)	
ESP UPGRADE CASE	64
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Table 25.2.4-9. Summary of DSD/FSI Control Costs for the South Oak 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	5	1.00	275	58	1.6	11.3	40.9	8.6	6.1	49.0	8609	997.5
DSD+ESP	6	1.00	275	43	1.6	11.3	40.9	7.7	7.5	49.0	6383	1210.0
DSD+ESP-C	5	1.00	275	58	1.6	11.3	40.9	5.0	3.6	49.0	8609	577.4
DSD+ESP-C	6	1.00	275	43	1.6	11.3	40.9	4.5	4.3	49.0	6383	701.1
FSI+ESP-50	5	1.00	275	58	1.6	12.0	43.7	9.6	6.8	50.0	8848	1079.8
FSI+ESP-50	6	1.00	275	43	1.6	12.0	43.7	8.1	7.9	50.0	6560	1240.7
FSI+ESP-50-C	5	1.00	275	58	1.6	12.0	43.7	5.5	4.0	50.0	8848	624.8
FSI+ESP-50-C	6	1.00	275	43	1.6	12.0	43.7	4.7	4.6	50.0	6560	719.1
FSI+ESP-70	5	1.00	275	58	1.6	12.2	44.3	9.7	7.0	70.0	12387	784.7
FSI+ESP-70	6	1.00	275	43	1.6	12.2	44.3	8.3	8.0	70.0	9184	900.6
FSI+ESP-70-C	5	1.00	275	58	1.6	12.2	44.3	5.6	4.0	70.0	12387	454.0
FSI+ESP-70-C	6	1.00	275	43	1.6	12.2	44.3	4.8	4.6	70.0	9184	522.0

25.2.5 Valley Steam Plant

LSD with reuse of the existing ESPs was not considered for the Valley plant because the ESPs are small and would not be able to handle the additional load. Space around the Valley plant is very limited; therefore, LSD with a new baghouse was not evaluated. Furnace sorbent injection technologies were not considered since the ESPs are not of an adequate size to be reused and the duct residence time between the boilers and ESPs is short.

TABLE 25.2.5-1. VALLEY STEAM PLANT OPERATIONAL DATA *

BOILER NUMBER	1,2	3,4
GENERATING CAPACITY (MW-each)	68	68
CAPACITY FACTOR (PERCENT)	26	27
INSTALLATION DATE	1968	1969
FIRING TYPE	FRONT WALL	
FURNACE VOLUME (1000 CU FT)	41.5	41.5
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	1.4	
COAL HEATING VALUE (BTU/LB)	12700	
COAL ASH CONTENT (PERCENT)	9.1	
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	LANDFILL/OFF-SITE	
STACK NUMBER	1	2
COAL DELIVERY METHODS	SHIP/BARGE	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1968	1969
EMISSION (LB/MM BTU)	0.05,0.11	0.1,0.11
REMOVAL EFFICIENCY	99.3,98.4	98.6,99.1
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	2.5	2.5
SURFACE AREA (1000 SQ FT)	50.5	50.5
GAS EXIT RATE (1000 ACFM)	277	277
SCA (SQ FT/1000 ACFM)	182	182
OUTLET TEMPERATURE (°F)	310	310

* Based on 1988 data.

TABLE 25.2.5-2. SUMMARY OF RETROFIT FACTOR DATA FOR VALLEY UNITS 1-2 OR 3-4*

	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	NO	NA	NA
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NA
ESTIMATED COST (1000$)	0	0	0
OTHER	YES		
RETROFIT FACTORS			
FGD SYSTEM	1.73	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	0

* L/LS-FGD absorbers for units 1-2 and 3-4 would be located behind the common chimney for units 1-2 and 3-4, respectively.

Table 25.2.5-3. Summary of FGD Control Costs for the Valley 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	1.73	136	26	1.4	60.3	443.1	21.9	70.7	90.0	2950	7419.3
L/S FGD	3-4	1.73	136	27	1.4	60.3	443.1	22.0	68.3	90.0	3064	7169.8
L/S FGD-C	1-2	1.73	136	26	1.4	60.3	443.1	12.8	41.4	90.0	2950	4342.4
L/S FGD-C	3-4	1.73	136	27	1.4	60.3	443.1	12.9	40.0	90.0	3064	4196.0
LC FGD	1-2	1.73	136	26	1.4	41.5	305.3	16.0	51.7	90.0	2950	5425.2
LC FGD	3-4	1.73	136	27	1.4	41.5	305.3	16.1	50.0	90.0	3064	5249.5
LC FGD-C	1-2	1.73	136	26	1.4	41.5	305.3	9.4	30.2	90.0	2950	3171.3
LC FGD-C	3-4	1.73	136	27	1.4	41.5	305.3	9.4	29.2	90.0	3064	3068.4

Table 25.2.5-4. Summary of Coal Switching/Cleaning Costs for the Valley 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	68	26	1.4	3.4	49.4	3.0	19.1	32.0	521	5681.4
CS/B+$15	3,4	1.00	68	27	1.4	3.4	49.4	3.0	18.9	32.0	541	5625.0
CS/B+$15-C	1,2	1.00	68	26	1.4	3.4	49.4	1.7	11.0	32.0	521	3283.9
CS/B+$15-C	3,4	1.00	68	27	1.4	3.4	49.4	1.8	10.9	32.0	541	3250.7
CS/B+$5	1,2	1.00	68	26	1.4	2.7	39.0	1.6	10.0	32.0	521	2987.6
CS/B+$5	3,4	1.00	68	27	1.4	2.7	39.0	1.6	9.9	32.0	541	2940.0
CS/B+$5-C	1,2	1.00	68	26	1.4	2.7	39.0	0.9	5.8	32.0	521	1734.6
CS/B+$5-C	3,4	1.00	68	27	1.4	2.7	39.0	0.9	5.7	32.0	541	1706.4

TABLE 25.2.5-5. SUMMARY OF NOx RETROFIT RESULTS FOR VALLEY

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1-2	3-4
FIRING TYPE	FWF	FWF
TYPE OF NOx CONTROL	LNB	LNB
FURNACE VOLUME (1000 CU FT)	41.5	41.5
BOILER INSTALLATION DATE	1968	1969
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	42	40
SCR RETROFIT RESULTS*		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	34	34
New Duct Length (Feet)	200	200
New Duct Costs (1000$)	1186	1186
New Heat Exchanger (1000$)	2241	2241
TOTAL SCOPE ADDER COSTS (1000$)	3462	3462
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 behind the unit 1-2 and 3-4 chimney, respectively.

Table 25.2.5-6. NOx Control Cost Results for the Valley 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	68	26	1.4	2.2	32.2	0.5	3.0	42.0	265	1764.9
LNC-LNB	3,4	1.00	68	27	1.4	2.2	32.2	0.5	2.9	40.0	262	1784.5
LNC-LNB-C	1,2	1.00	68	26	1.4	2.2	32.2	0.3	1.8	42.0	265	1048.5
LNC-LNB-C	3,4	1.00	68	27	1.4	2.2	32.2	0.3	1.7	40.0	262	1060.1
SCR-3	1-2	1.52	136	26	1.4	28.7	211.2	8.8	28.6	80.0	1009	8771.4
SCR-3	3-4	1.52	136	27	1.4	28.7	211.2	8.9	27.5	80.0	1047	8453.6
SCR-3-C	1-2	1.52	136	26	1.4	28.7	211.2	5.2	16.8	80.0	1009	5153.1
SCR-3-C	3-4	1.52	136	27	1.4	28.7	211.2	5.2	16.2	80.0	1047	4966.3
SCR-7	1-2	1.52	136	26	1.4	28.7	211.2	7.7	25.0	80.0	1009	7672.8
SCR-7	3-4	1.52	136	27	1.4	28.7	211.2	7.7	24.1	80.0	1047	7395.6
SCR-7-C	1-2	1.52	136	26	1.4	28.7	211.2	4.6	14.7	80.0	1009	4523.7
SCR-7-C	3-4	1.52	136	27	1.4	28.7	211.2	4.6	14.2	80.0	1047	4360.1

25.3 WISCONSIN POWER AND LIGHT

25.3.1 Columbia Steam Plant

The Columbia steam plant is located on the Wisconsin River in Columbia County, Wisconsin, and is operated by Wisconsin Power and Light. The Columbia plant contains two coal-fired boilers with a gross generating capacity of 1054 MW.

Table 25.3.1-1 presents the operational data for the existing equipment at the Columbia plant. Coal shipments are received by railroad and transferred to a coal storage and handling area south of the plant. PM emissions from the unit 1 boiler are controlled by the original hot-side ESP located behind the unit. PM emissions from the unit 2 boiler are controlled by the modified ESP that was converted from hot-side to cold-side operation in 1988. Flue gases from the units are directed to separate chimneys located behind the ESPs. Dry fly ash is disposed of in landfills east of the plant or sold.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for both units would be located behind their respective chimney. A low site access/congestion factor was assigned to these locations. A plant road and ash silos would have to be relocated for the unit 1 absorbers; therefore, 15 percent was assigned to general facilities. For unit 2, a plant road would need relocating; therefore, 8 percent was assigned to general facilities. For each unit, a duct length of 100 to 300 feet would be required to span the distance from the chimney to the absorbers and back to the chimney. A low site access/congestion factor was assigned to flue gas handling. New chimneys were considered because the existing chimneys are carbon steel.

LSD with reuse of the existing ESPs was not considered for unit 1 because the unit is equipped with hot side ESPs. LSD with a new baghouse was considered for unit 1. LSD with reuse of the existing ESPs was considered for unit 2. The LSD absorbers would have the same location as the wet FGD absorbers; hence, similar site access/congestion and general facility factors were assigned to the locations. The new FFs for unit 1

TABLE 25.3.1-1. COLUMBIA STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2
GENERATING CAPACITY (MW-each)	527
CAPACITY FACTOR (PERCENT)	55,70*
INSTALLATION DATE	1975,1978
FIRING TYPE	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	421
LOW NOx COMBUSTION	NA
COAL SULFUR CONTENT (PERCENT)	0.6,0.3
COAL HEATING VALUE (BTU/LB)	8800
COAL ASH CONTENT (PERCENT)	8.4,4.6
FLY ASH SYSTEM	DRY DISPOSAL
ASH DISPOSAL METHOD	LANDFILL/SOLD
STACK NUMBER	1,2
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	HOT ESP, COLD ESP
INSTALLATION DATE	1975,1978
EMISSION (LB/MM BTU)	0.08,0.02
REMOVAL EFFICIENCY	99.1,99.5
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	0.7,0.4
SURFACE AREA (1000 SQ FT)	743
GAS EXIT RATE (1000 ACFM)	3800,2200
SCA (SQ FT/1000 ACFM)	196,338
OUTLET TEMPERATURE (°F)	800,275

* 1990 estimate.

would be adjacent to the LSD absorbers. Duct lengths of 200 and 500 feet would be needed for units 1 and 2, respectively. The site access/congestion factor for flue gas handling was low for unit 1 and high for unit 2.

Table 25.3.1-2 presents the retrofit factor results for the Columbia plant. However, costs are not estimated since the boilers at the Columbia plant are burning a low sulfur coal and it is unlikely that the current low sulfur coal would be used if scrubbing were required. FGD cost estimates based on the current low sulfur coal would result in low estimates of capital and operating costs and high unit costs.

Coal Switching and Physical Coal Cleaning Costs--

CS and PCC were not considered for the Columbia plant since the boilers are currently burning a low sulfur coal. Plant personnel indicated that switching to a very low sulfur coal would require conversion of the unit 1 ESP to cold side operation.

NO_x Control Technologies--

The boilers at the Columbia plant are probably already meeting the 1971 NSPS emissions and were not considered for any combustion modification in order to reduce NO_x emissions.

Selective Catalytic Reduction--

Hot side and cold side SCR reactors for units 1 and 2, respectively, would be located behind each chimney, similar to the L/LS-FGD absorbers. As before, the site access/congestion factor for both locations was low. For unit 1, a high general facilities factor of 38 percent was assigned due to the need to relocate a plant road and ash silos. A plant road would need to be relocated for unit 2; hence, a medium factor of 20 percent was assigned to general facilities. For each unit, approximately 200 feet of duct would be required to span the distance between the reactors and the chimneys. The site access/congestion factor for flue gas handling was low.
Tables 25.3.1-3 and 25.3.1-4 present the retrofit factors and cost for installation of SCR at the Columbia plant.

TABLE 25.3.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR COLUMBIA 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 (UNIT 2)			HIGH
BAGHOUSE CASE (UNIT 1)			LOW
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE (UNIT 2)			300-600
BAGHOUSE (UNIT 1)			100-300
ESP REUSE (UNIT 2)	NA	NA	MEDIUM
NEW BAGHOUSE (UNIT 1)	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	3689	0	3689
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.22	NA	
ESP REUSE CASE (UNIT 2)			1.43
BAGHOUSE CASE (UNIT 1)			1.23
ESP UPGRADE (UNIT 2)	NA	NA	1.36
NEW BAGHOUSE (UNIT 1)	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	15,8	0	15,8

TABLE 25.3.1-3. SUMMARY OF NOx RETROFIT RESULTS FOR COLUMBIA

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1	2
FIRING TYPE	NA	NA
TYPE OF NOx CONTROL	NA	NA
FURNACE VOLUME (1000 CU FT)	NA	NA
BOILER INSTALLATION DATE	NA	NA
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$)	0	0
Ductwork Demolition (1000$)	94	94
New Duct Length (Feet)	200	200
New Duct Costs (1000$)	2620	2620
New Heat Exchanger (1000$)	0	5052
TOTAL SCOPE ADDER COSTS (1000$)	2715	7767
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	38	20

Table 25.3.1-4. NOx Control Cost Results for the Columbia 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	527	55	0.6	68.6	130.1	25.4	10.0	80.0	8999	2826.3
SCR-3	2	1.16	527	70	0.3	65.5	124.3	24.9	7.7	80.0	11453	2175.6
SCR-3-C	1	1.16	527	55	0.6	68.6	130.1	14.9	5.9	80.0	8999	1653.4
SCR-3-C	2	1.16	527	70	0.3	65.5	124.3	14.6	4.5	80.0	11453	1272.1
SCR-7	1	1.16	527	55	0.6	68.6	130.1	20.9	8.2	80.0	8999	2322.4
SCR-7	2	1.16	527	70	0.3	65.5	124.3	20.4	6.3	80.0	11453	1779.7
SCR-7-C	1	1.16	527	55	0.6	68.6	130.1	12.3	4.8	80.0	8999	1364.8
SCR-7-C	2	1.16	527	70	0.3	65.5	124.3	12.0	3.7	80.0	11453	1045.3

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) were not considered for unit 1 because the boiler is equipped with hot side ESPs. Both technologies were considered for unit 2 because of the sufficient ESP SCA size and duct residence time. Tables 25.3.1-5 and 25.3.1-6 present retrofit data and costs for installation of FSI and DSD technologies for unit 2 at the Columbia plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The two 527 MW boilers at the Columbia plant are too large and their remaining useful life is too long to be considered good candidates for AFBC/CG repowering.

25.3.2 Edgewater Steam Plant

The Edgewater steam plant is located on Lake Michigan in Sheboygan County, Wisconsin, and is operated by the Wisconsin Power and Light Company. The Edgewater plant contains three coal-fired boilers with a gross generating capacity of 770 MW.

Table 25.3.2-1 presents operational data for the existing equipment at the Edgewater plant. Coal shipments are received by railroad and transferred to a coal storage and handling area south of the plant. PM emissions from units 3 and 4 are controlled by a retrofit ESP on unit 3 and the original ESP on unit 4. Emissions from unit 5 are controlled by ESPs which were installed at the time of construction. All of the ESPs are located behind the boilers. Flue gases from boilers 3 and 4 are directed to a chimney located behind the units and flue gases from unit 5 are directed to a chimney located behind unit 5. Dry fly ash from the units is landfilled or sold by the utility.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for all of the units would be located south of unit 3, northeast of the coal pile. The general facilities factor is high (15 percent) for this location because several storage buildings, silos, and a road would have to be relocated. The site access/congestion factor is

TABLE 25.3.1-5. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR COLUMBIA UNIT 2

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$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	104
TOTAL COST (1000$)	
ESP UPGRADE CASE	104
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.34
NEW BAGHOUSE	NA

Table 25.3.1-6. Summary of DSD/FSI Control Costs for the Columbia 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	527	70	0.3	10.7	20.3	8.3	2.6	49.0	5433	1524.4
DSD+ESP-C	2	1.00	527	70	0.3	10.7	20.3	4.8	1.5	49.0	5433	882.2
FSI+ESP-50	2	1.00	527	70	0.3	13.1	24.8	8.2	2.5	50.0	5583	1475.7
FSI+ESP-50-C	2	1.00	527	70	0.3	13.1	24.8	4.8	1.5	50.0	5583	856.0
FSI+ESP-70	2	1.00	527	70	0.3	13.2	25.0	8.4	2.6	70.0	7817	1068.3
FSI+ESP-70-C	2	1.00	527	70	0.3	13.2	25.0	4.8	1.5	70.0	7817	619.6

TABLE 25.3.2-1. EDGEWATER STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	3	4	5
GENERATING CAPACITY (MW-each)	60	330	380
CAPACITY FACTOR (PERCENT)	40	72	61
INSTALLATION DATE	1951	1969	1985
FIRING TYPE	CYCLONE		OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	24.1	137	355
LOW NOx COMBUSTION	NO	NO	NO
COAL SULFUR CONTENT (PERCENT)	2.0	2.0	0.4
COAL HEATING VALUE (BTU/LB)	10800	10800	8200
COAL ASH CONTENT (PERCENT)	9.3	9.3	5.6
FLY ASH SYSTEM	DRY DISPOSAL		
ASH DISPOSAL METHOD	LANDFILL/SOLD		
STACK NUMBER	1,2	1,2	3
COAL DELIVERY METHODS	RAILROAD		
PARTICULATE CONTROL			
TYPE	ESP	ESP	ESP
INSTALLATION DATE	1972	1969	1985
EMISSION (LB/MM BTU)	0.11	0.15	0.009
REMOVAL EFFICIENCY	93.6	94.9	99.96
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	2.9	2.8	0.48
SURFACE AREA (1000 SQ FT)	95	172.8	958.5
GAS EXIT RATE (1000 ACFM)	300	1050	1700
SCA (SQ FT/1000 ACFM)	317	165	564
OUTLET TEMPERATURE (°F)	330	275	279

medium for this location because of the proximity of the coal conveyor and the lake. In addition, there is some underground obstruction in this area. About 500 feet of ductwork would be required for units 3 and 4 and 400 feet of ductwork with a new chimney would be required for unit 5. A low site access/congestion factor was assigned to flue gas handling for units 3 and 4, and a high site access/congestion factor was assigned to unit 5 because of the obstruction due to the unit 3 and 4 chimney.

LSD with reuse of the existing ESPs was not considered for units 3-5 because of the difficultly in accessing the existing ESPs and the inadequate SCA for additional grain loading of LSD. LSD with a new FF was considered for these units. LSD-FGD absorbers for units 3-5 would be located similarly to the wet FGD absorbers south of unit 3. As in the L/LS-FGD case, a high general facilities factor and a high site access/congestion factor were assigned to this location. About 400 to 500 feet of ductwork would be required for units 3-5 with a new chimney for unit 5. A high site access/congestion factor was assigned to flue gas handling for units 3-5 because of the limited space between the boiler and the ESPs.

Tables 25.3.2-2 through 25.3.2-4 present retrofit factor inputs to the IAPCS model and cost estimates for installation of conventional FGD technologies at the Edgewater plant. Costs for unit 5 are not presented since unit 5 is burning a low sulfur coal and would yield high unit costs.

Coal Switching and Physical Coal Cleaning Costs--

CS was not considered for unit 5 of the Edgewater plant because this unit already fires a very low sulfur coal. CS was not considered for units 3 and 4 because a low ash fusion temperature and low sulfur coals required for cyclone boilers are not readily available in the eastern United States. PCC also was not evaluated because the Edgewater plant is not a mine mouth plant. Plant personnel indicated that switching to a lower sulfur coal is currently under investigation for units 3 and 4.

NO_x Control Technologies--

NGR was considered for control of NO_x emissions from units 3 and 4 which are cyclone-fired. Unit 5 is an NSPS unit and probably meets NO_x emission limits using LNB. Tables 25.3.2-5 and 25.3.2-6 give a summary of

TABLE 25.3.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR EDGEWATER 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	LOW	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	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	1.52	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

TABLE 25.3.2-3. SUMMARY OF RETROFIT FACTOR DATA FOR EDGEWATER 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	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	2660	0	2660
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.63	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

Table 25.3.2-4. Summary of FGD Control Costs for the Edgewater 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	3	1.52	60	40	2.0	39.5	658.3	15.4	73.1	90.0	3445	4461.4
L/S FGD	4	1.52	330	72	2.0	98.9	299.6	46.1	22.2	90.0	34110	1351.9
L/S FGD	3-4	1.52	390	67	2.0	109.6	280.9	50.5	22.1	90.0	37513	1347.1
L/S FGD-C	3	1.52	60	40	2.0	39.5	658.3	9.0	42.7	90.0	3445	2607.5
L/S FGD-C	4	1.52	330	72	2.0	98.9	299.6	26.9	12.9	90.0	34110	787.5
L/S FGD-C	3-4	1.52	390	67	2.0	109.6	280.9	29.4	12.9	90.0	37513	784.9
LC FGD	3-4	1.52	390	67	2.0	83.1	213.2	42.3	18.5	90.0	37513	1128.0
LC FGD-C	3-4	1.52	390	67	2.0	83.1	213.2	24.6	10.8	90.0	37513	656.2
LSD+FF	3	1.62	60	40	2.0	24.0	400.1	9.3	44.1	87.0	3311	2798.0
LSD+FF	4	1.62	330	72	2.0	80.4	243.5	30.5	14.7	87.0	32783	931.9
LSD+FF-C	3	1.62	60	40	2.0	24.0	400.1	5.4	25.8	87.0	3311	1635.6
LSD+FF-C	4	1.62	330	72	2.0	80.4	243.5	17.9	8.6	87.0	32783	544.9

TABLE 25.3.2-5. SUMMARY OF NOx RETROFIT RESULTS FOR EDGEWATER

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	3	4	5
FIRING TYPE	CYCLONE	CYCLONE	NA
TYPE OF NOx CONTROL	NGR	NGR	NA
FURNACE VOLUME (1000 CU FT)	24.1	137	NA
BOILER INSTALLATION DATE	1951	1969	NA
SLAGGING PROBLEM	NO	NO	NA
ESTIMATED NOx REDUCTION (PERCENT)	60	60	NA
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	MEDIUM	HIGH
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	18	66	74
New Duct Length (Feet)	500	500	100
New Duct Costs (1000$)	1838	4981	1082
New Heat Exchanger (1000$)	1372	3815	4152
TOTAL SCOPE ADDER COSTS (1000$)	3228	8863	5308
COMBINED CASE	9785		
RETROFIT FACTOR FOR SCR	1.34	1.34	1.52
GENERAL FACILITIES (PERCENT)	38	38	38

Table 25.3.2-6. NOx Control Cost Results for the Edgewater 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	3	1.00	60	40	2.0	1.6	26.0	1.3	6.4	60.0	1090	1233.9
NGR	4	1.00	330	72	2.0	5.4	16.3	11.5	5.5	60.0	10787	1062.5
NGR-C	3	1.00	60	40	2.0	1.6	26.0	0.8	3.7	60.0	1090	713.3
NGR-C	4	1.00	330	72	2.0	5.4	16.3	6.6	3.2	60.0	10787	611.0
SCR-3	3	1.34	60	40	2.0	17.5	291.2	5.2	24.8	80.0	1453	3592.8
SCR-3	4	1.34	330	72	2.0	55.4	167.9	19.5	9.4	80.0	14382	1355.7
SCR-3	3-4	1.34	390	67	2.0	61.3	157.3	21.9	9.6	80.0	15817	1383.0
SCR-3	5	1.52	380	61	0.4	60.8	160.0	21.5	10.6	80.0	10926	1970.2
SCR-3-C	3	1.34	60	40	2.0	17.5	291.2	3.1	14.6	80.0	1453	2112.4
SCR-3-C	4	1.34	330	72	2.0	55.4	167.9	11.4	5.5	80.0	14382	794.0
SCR-3-C	3-4	1.34	390	67	2.0	61.3	157.3	12.8	5.6	80.0	15817	809.8
SCR-3-C	5	1.52	380	61	0.4	60.8	160.0	12.6	6.2	80.0	10926	1153.8
SCR-7	3	1.34	60	40	2.0	17.5	291.2	4.7	22.4	80.0	1453	3248.2
SCR-7	4	1.34	330	72	2.0	55.4	167.9	16.7	8.0	80.0	14382	1164.2
SCR-7	3-4	1.34	390	67	2.0	61.3	157.3	18.6	8.1	80.0	15817	1177.3
SCR-7	5	1.52	380	61	0.4	60.8	160.0	18.2	9.0	80.0	10926	1667.8
SCR-7-C	3	1.34	60	40	2.0	17.5	291.2	2.8	13.2	80.0	1453	1914.8
SCR-7-C	4	1.34	330	72	2.0	55.4	167.9	9.8	4.7	80.0	14382	684.3
SCR-7-C	3-4	1.34	390	67	2.0	61.3	157.3	10.9	4.8	80.0	15817	691.9
SCR-7-C	5	1.52	380	61	0.4	60.8	160.0	10.7	5.3	80.0	10926	980.5

retrofit factors and costs, respectively, for NO_x control technologies at the Edgewater plant.

Selective Catalytic Reduction--

Cold side SCR reactors for units 3 and 4 at the Edgewater plant would be located south of unit 1. A high general facilities factor (38 percent) and a medium site access/congestion factor were assigned to the reactor location. A cold side SCR reactor for unit 5 would be located beside its chimney with a high site access/congestion and general facilities factor assigned to it. Approximately 500 feet of ductwork would be required to span the distance between the SCR reactors and the chimney for units 3 and 4 and about 100 feet would be required for unit 5. Tables 25.3.2-5 and 25.3.2-6 present the retrofit factors and costs for installation of SCR at the Edgewater plant.

Furnace Sorbent Injection and Duct Spray Drying Costs--

FSI and DSD were not considered for units 3 through 5 because of the short duct residence time and/or the ESPs not being large enough to handle the additional particulate load.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability-

Unit 3 is the only boiler at the Edgewater plant which is old enough to be considered a good candidate for repowering. Units 4 and 5 are large and have long remaining useful lives; therefore, are not considered good candidates for AFBC/CG technologies.

25.3.3 Nelson Dewey Steam Plant

The units at the Nelson Dewey plant have hot side ESPs for control of their particulate matter, hence LSD with reuse of the existing particulate control was not an option. Sorbent injection technologies were not considered again because the existing particulate control device cannot be reused.

TABLE 25.3.3-1. NELSON DEWEY STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2
GENERATING CAPACITY (MW-each)	100
CAPACITY FACTOR (PERCENT)	54,60
INSTALLATION DATE	1959,62
FIRING TYPE	CYCLONE
FURNACE VOLUME (1000 CU FT)	NA
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	1.4,0.7
COAL HEATING VALUE (BTU/LB)	11400,10400
COAL ASH CONTENT (PERCENT)	5.5,6.0
FLY ASH SYSTEM	WET SLUICE
ASH DISPOSAL METHOD	LANDFILL/ON-SITE
STACK NUMBER	1
COAL DELIVERY METHODS	BARGE
<u>PARTICULATE CONTROL</u>	
TYPE	HOT SIDE ESP
INSTALLATION DATE	1974
EMISSION (LB/MM BTU)	0.10
REMOVAL EFFICIENCY	95
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	2.6
SURFACE AREA (1000 SQ FT)	132.8
GAS EXIT RATE (1000 ACFM)	487
SCA (SQ FT/1000 ACFM)	273
OUTLET TEMPERATURE (°F)	500,550

TABLE 25.3.3-2. SUMMARY OF RETROFIT FACTOR DATA FOR NELSON DEWEY 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	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	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NA
ESTIMATED COST (1000$)	938	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	700	0	700
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.48	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.43
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	5	0	5

* Absorbers for units 1 and 2 would be placed southeast of unit 2.

Table 25.3.3-3. Summary of FGD Control Costs for the Nelson Dewey 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	100	54	1.4	45.0	450.4	18.3	38.8	90.0	5100	3596.7
L/S FGD	2	1.48	100	60	0.7	45.0	449.7	18.4	35.1	90.0	3148	5854.3
L/S FGD	1-2	1.48	200	57	1.0	67.3	336.6	27.9	28.0	90.0	8544	3267.5
L/S FGD-C	1	1.48	100	54	1.4	45.0	450.4	10.7	22.6	90.0	5100	2100.3
L/S FGD-C	2	1.48	100	60	0.7	45.0	449.7	10.8	20.5	90.0	3148	3418.2
L/S FGD-C	1-2	1.48	200	57	1.0	67.3	336.6	16.3	16.3	90.0	8544	1907.4
LC FGD	1-2	1.48	200	57	1.0	45.7	228.5	21.2	21.2	90.0	8544	2480.9
LC FGD-C	1-2	1.48	200	57	1.0	45.7	228.5	12.4	12.4	90.0	8544	1445.4
LSD+FF	1	1.43	100	54	1.4	29.4	294.2	11.2	23.6	87.0	4902	2279.7
LSD+FF	2	1.43	100	60	0.7	29.8	297.8	11.0	20.9	87.0	3026	3637.7
LSD+FF-C	1	1.43	100	54	1.4	29.4	294.2	6.5	13.8	87.0	4902	1333.0
LSD+FF-C	2	1.43	100	60	0.7	29.8	297.8	6.4	12.3	87.0	3026	2128.3

TABLE 25.3.3-4. SUMMARY OF NOx RETROFIT RESULTS FOR NELSON DEWEY

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1,2
FIRING TYPE	CYC
TYPE OF NOx CONTROL	NGR
FURNACE VOLUME (1000 CU FT)	NA
BOILER INSTALLATION DATE	1959,1962
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$)	0
Ductwork Demolition (1000$)	27
New Duct Length (Feet)	450
New Duct Costs (1000$)	2230
New Heat Exchanger (1000$)	1864
TOTAL SCOPE ADDER COSTS (1000$)	
INDIVIDUAL CASE	4121
COMBINED CASE	6215
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	13

* Cold side SCR reactors for units 1 and 2 would be located southeast of unit 2.

Table 25.3.3-5. NOx Control Cost Results for the Nelson Dewey 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	100	54	1.4	6.3	63.2	3.5	7.4	60.0	2304	1525.5
NGR	2	1.00	100	60	0.7	6.3	63.2	3.8	7.2	60.0	2845	1339.3
NGR-C	1	1.00	100	54	1.4	6.3	63.2	2.0	4.3	60.0	2304	886.3
NGR-C	2	1.00	100	60	0.7	6.3	63.2	2.2	4.2	60.0	2845	777.3
SCR-3	1	1.16	100	54	1.4	20.2	202.2	6.6	13.9	80.0	3072	2135.9
SCR-3	2	1.16	100	60	0.7	20.4	204.2	6.7	12.8	80.0	3793	1773.3
SCR-3	1-2	1.16	200	57	1.0	33.4	166.9	11.5	11.5	80.0	7206	1596.3
SCR-3-C	1	1.16	100	54	1.4	20.2	202.2	3.9	8.1	80.0	3072	1253.2
SCR-3-C	2	1.16	100	60	0.7	20.4	204.2	3.9	7.5	80.0	3793	1040.1
SCR-3-C	1-2	1.16	200	57	1.0	33.4	166.9	6.7	6.7	80.0	7206	935.4
SCR-7	1	1.16	100	54	1.4	20.2	202.2	5.7	12.1	80.0	3072	1866.4
SCR-7	2	1.16	100	60	0.7	20.4	204.2	5.9	11.2	80.0	3793	1552.1
SCR-7	1-2	1.16	200	57	1.0	33.4	166.9	9.8	9.8	80.0	7206	1363.4
SCR-7-C	1	1.16	100	54	1.4	20.2	202.2	3.4	7.1	80.0	3072	1098.8
SCR-7-C	2	1.16	100	60	0.7	20.4	204.2	3.5	6.6	80.0	3793	913.4
SCR-7-C	1-2	1.16	200	57	1.0	33.4	166.9	5.8	5.8	80.0	7206	801.9

25.3.4 Rock River Steam Plant

Coal switching was not evaluated for the Rock River plant because the units are cyclone boilers requiring low sulfur bitiminous coals having low ash fusion temperatures which are not readily available in the east (plant personnel indicated that coal switching is currently under investigation by the plant). The duct residence time between the boilers and the roof-mounted ESPs is short for both units and the ESPs are small; therefore, sorbent injection technologies (FSI and DSD) were also not considered.

TABLE 25.3.4-1. ROCK RIVER STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2
GENERATING CAPACITY (MW-each)	75
CAPACITY FACTOR (PERCENT)	49,39
INSTALLATION DATE	1954,55
FIRING TYPE	CYCLONE
FURNACE VOLUME (1000 CU FT)	17.3
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	2.0
COAL HEATING VALUE (BTU/LB)	11000
COAL ASH CONTENT (PERCENT)	8.1
FLY ASH SYSTEM	WET SLUICE
ASH DISPOSAL METHOD	LANDFILL/ON-SITE
STACK NUMBER	1,2
COAL DELIVERY METHODS	RAILROAD
<u>PARTICULATE CONTROL</u>	
TYPE	ESP
INSTALLATION DATE	1971,72
EMISSION (LB/MM BTU)	0.10,0.07
REMOVAL EFFICIENCY	95.3,98.6
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	3.1
SURFACE AREA (1000 SQ FT)	63.2
GAS EXIT RATE (1000 ACFM)	297
SCA (SQ FT/1000 ACFM)	213
OUTLET TEMPERATURE (°F)	290,300

TABLE 25.3.4-2. SUMMARY OF RETROFIT FACTOR DATA FOR ROCK RIVER 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	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	YES	NA	NO
ESTIMATED COST (1000$)	724	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	525	0	525
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.48	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.43
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	5	0	5

* Absorbers and new FFs for units 1 and 2 would be located on either side of unit 1 and 2, respectively.

Table 25.3.4-3. Summary of FGD Control Costs for the Rock 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)
L/S FGD	1	1.48	75	49	2.0	41.5	552.7	16.8	52.3	90.0	5166	3260.1
L/S FGD	2	1.48	75	39	2.0	41.5	553.1	16.3	63.5	90.0	4112	3959.9
L/S FGD	1-2	1.48	150	44	2.0	57.8	385.3	23.4	40.5	90.0	9278	2525.5
L/S FGD-C	1	1.48	75	49	2.0	41.5	552.7	9.8	30.5	90.0	5166	1903.8
L/S FGD-C	2	1.48	75	39	2.0	41.5	553.1	9.5	37.1	90.0	4112	2314.0
L/S FGD-C	1-2	1.48	150	44	2.0	57.8	385.3	13.7	23.7	90.0	9278	1474.9
LC FGD	1-2	1.48	150	44	2.0	39.7	264.5	17.8	30.8	90.0	9278	1917.8
LC FGD-C	1-2	1.48	150	44	2.0	39.7	264.5	10.4	17.9	90.0	9278	1118.0
LSD+FF	1	1.43	75	49	2.0	21.2	283.2	8.9	27.6	87.0	4965	1791.4
LSD+FF	2	1.43	75	39	2.0	21.4	285.1	8.7	34.0	87.0	3952	2203.9
LSD+FF	1-2	1.43	150	44	2.0	35.0	233.2	13.3	23.1	87.0	8917	1494.7
LSD+FF-C	1	1.43	75	49	2.0	21.2	283.2	5.2	16.1	87.0	4965	1045.6
LSD+FF-C	2	1.43	75	39	2.0	21.4	285.1	5.1	19.8	87.0	3952	1286.9
LSD+FF-C	1-2	1.43	150	44	2.0	35.0	233.2	7.8	13.5	87.0	8917	873.9

TABLE 25.3.4-4. SUMMARY OF NOx RETROFIT RESULTS FOR ROCK RIVER

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1,2
FIRING TYPE	CYCLONE
TYPE OF NOx CONTROL	NGR
FURNACE VOLUME (1000 CU FT)	17.3
BOILER INSTALLATION DATE	1954,1955
SLAGGING PROBLEM	NO
ESTIMATED NOx REDUCTION (PERCENT)	60
SCR RETROFIT RESULTS *	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	22
New Duct Length (Feet)	400
New Duct Costs (1000$)	1675
New Heat Exchanger (1000$)	1568
TOTAL SCOPE ADDER COSTS (1000$)	
INDIVIDUAL CASE	3265
COMBINED CASE	4926
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	13

* Cold side SCR reactors for units 1 and 2 would be located on either sides of the unit 1 and 2 ESPs, respectively.

Table 25.3.4-5. NOx Control Cost Results for the Rock 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)
NGR	1	1.00	75	49	2.0	1.8	24.3	2.0	6.1	60.0	1634	1199.0
NGR	2	1.00	75	39	2.0	1.8	24.3	1.6	6.3	60.0	1300	1246.6
NGR-C	1	1.00	75	49	2.0	1.8	24.3	1.1	3.5	60.0	1634	692.0
NGR-C	2	1.00	75	39	2.0	1.8	24.3	0.9	3.7	60.0	1300	720.5
SCR-3	1	1.16	75	49	2.0	16.4	218.7	5.2	16.3	80.0	2178	2408.6
SCR-3	2	1.16	75	39	2.0	16.4	218.7	5.2	20.2	80.0	1734	2985.5
SCR-3	1-2	1.16	150	44	2.0	25.8	171.8	8.6	14.9	80.0	3912	2202.0
SCR-3-C	1	1.16	75	49	2.0	16.4	218.7	3.1	9.6	80.0	2178	1413.7
SCR-3-C	2	1.16	75	39	2.0	16.4	218.7	3.0	11.9	80.0	1734	1752.9
SCR-3-C	1-2	1.16	150	44	2.0	25.8	171.8	5.1	8.7	80.0	3912	1291.1
SCR-7	1	1.16	75	49	2.0	16.4	218.7	4.6	14.4	80.0	2178	2122.1
SCR-7	2	1.16	75	39	2.0	16.4	218.7	4.6	17.8	80.0	1734	2625.5
SCR-7	1-2	1.16	150	44	2.0	25.8	171.8	7.4	12.7	80.0	3912	1882.8
SCR-7-C	1	1.16	75	49	2.0	16.4	218.7	2.7	8.5	80.0	2178	1249.6
SCR-7-C	2	1.16	75	39	2.0	16.4	218.7	2.7	10.5	80.0	1734	1546.7
SCR-7-C	1-2	1.16	150	44	2.0	25.8	171.8	4.3	7.5	80.0	3912	1108.3

25.4 WISCONSIN PUBLIC SERVICE CORPORATION

25.4.1 J. P. Pulliam Steam Plant

The J. P. Pulliam steam plant is located on Green Bay in Brown County, Wisconsin, and is operated by the Wisconsin Public Service Corporation. The J. P. Pulliam plant contains six coal-fired boilers with a gross generating capacity of 373 MW.

Table 25.4.1-1 presents operational data for the existing equipment at the J. P. Pulliam plant. Coal shipments are received by rail and lake and transferred to a coal storage and handling area south of the plant. PM emissions from units 3, 4, and 5 are controlled by retrofit ESPs and emissions from units 6, 7, and 8 are controlled by ESPs installed at the time of construction. All of the ESPs are located behind their respective boilers. Flue gases from units 3-6 are directed to a common chimney built in 1985 and units 7 and 8 each have a separate chimney. Dry fly ash from the units is stored in silos for use in road construction or disposal off-site.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for units 3-7 would be located behind the common chimney east of the units and north of the coal pile toward the bay. Absorbers for unit 8 would be located west of the coal pile and south of unit 8. The general facilities factor would be low (5 percent) for units 3-7 and medium (8 percent) for unit 8 because of the relocation of a plant road for the FGD absorber locations. A low site access/congestion factor was assigned to the FGD absorber locations. Approximately 200 feet of ductwork would be required for installation of the L/LS-FGD system for units 3-6, 500 feet for unit 7, and 400 feet for unit 8. A low site access/congestion factor was assigned to flue gas handling for units 3-6. A medium site access/congestion factor was assigned to flue gas handling for units 7-8 because of the obstruction caused by the coal conveyor and the coal pile.

LSD with reuse of the existing ESPs was not considered for the J. P. Pulliam plant because of the small sizes of the existing ESPs. The medium

TABLE 25.4.1-1. PULLIAM STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	3,4	5	6	7	8
GENERATING CAPACITY (MW-each)	30	50	63	75	125
CAPACITY FACTOR (PERCENT)	5,7	20	21	52	55
INSTALLATION DATE	1943,47	1949	1951	1958	1964
FIRING TYPE		FRONT WALL			
FURNACE VOLUME (1000 CU FT)	NA	NA	NA	46.1	72.7
LOW NOx COMBUSTION		NO			
COAL SULFUR CONTENT (PERCENT)		2.2			
COAL HEATING VALUE (BTU/LB)		11400			
COAL ASH CONTENT (PERCENT)		9.4			
FLY ASH SYSTEM		DRY DISPOSAL			
ASH DISPOSAL METHOD		ON-SITE			
STACK NUMBER	1	1	1	2	3
COAL DELIVERY METHODS		RAIL/LAKE			
<u>PARTICULATE CONTROL</u>					
TYPE	ESP	ESP	ESP	ESP	ESP
INSTALLATION DATE	1958,55	1953	1951	1958	1964
EMISSION (LB/MM BTU)	NA	NA	NA	NA	NA
REMOVAL EFFICIENCY	97.6,99	99.3	98.8	98.3	99.4
DESIGN SPECIFICATION					
SULFUR SPECIFICATION (PERCENT)	2.3	2.3	2.3	2.3	2.3
SURFACE AREA (1000 SQ FT)	33,29	51	63	45	112
GAS EXIT RATE (1000 ACFM)	187,163	268	345	285	580
SCA (SQ FT/1000 ACFM)	176,178	190	183	158	193
OUTLET TEMPERATURE (°F)	360,335	370	370	300	350

to high sulfur content of the coal being burned at the plant would not be ideal for LSD with a new baghouse. Therefore LSD-FGD was not considered for this plant.

Tables 25.4.1-2 through 25.4.1-4 present retrofit factors and cost estimates for installation of L/LS-FGD at the J. P. Pulliam plant.

Coal Switching and Physical Coal Cleaning Costs--

Table 25.4.1-5 presents the IAPCS cost results for CS at the J. P. Pulliam plant. These costs do not include the effect of any changes to boiler and pulverizer operation. PCC was not considered at the J. P. Pulliam plant because it is not a mine mouth plant.

NO_x Control Technologies--

LNBs were considered for NO_x control for the six front wall-fired, dry bottom boilers at the J. P. Pulliam plant. Performance results and costs developed for the six units are presented in Tables 25.4.1-6 and 25.4.1-7. For those boilers that furnace volumes were not available, furnace volumes were estimated based on similar size and age boilers.

Selective Catalytic Reduction--

Cold side SCR reactors for the J. P. Pulliam plant would be located beside the common chimney for units 3-6 and south of unit 8 and west of the coal pile for unit 8. As in the FGD case, low general facility values (13 percent) and site access/congestion factors were assigned to the reactor locations for units 3-7. For unit 8, a medium general facilities value (20 percent) was assigned and a low site access/congestion factor was assigned because a plant road has to be relocated. Approximately 200 feet of ductwork would be required for units 3-6, 500 feet for unit 7, and about 400 feet for unit 8. Tables 25.4.1-6 and 25.4.1-7 present the retrofit factors and cost estimates for installation of SCR at the J. P. Pulliam plant.

TABLE 25.4.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR J. P. PULLIAM UNIT 3,4,5, OR 6

	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)	100-300	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	1.20	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 25.4.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR J. P. PULLIAM UNIT 7 OR 8

	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	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	1.35	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5,8	0	0

Table 25.4.1-4. Summary of FGD Control Costs for the Pulliam 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	3	1.20	30	5	2.2	21.6	720.2	7.8	591.4	90.0	223	34910.7
L/S FGD	4	1.20	30	7	2.2	21.6	719.1	7.9	427.4	90.0	312	25226.9
L/S FGD	5	1.20	50	20	2.2	26.6	531.2	10.2	115.9	90.0	1484	6841.3
L/S FGD	6	1.20	63	21	2.2	31.2	495.6	11.8	101.9	90.0	1963	6016.5
L/S FGD	7	1.35	75	52	2.2	37.4	499.3	15.7	46.0	90.0	5788	2713.1
L/S FGD	8	1.35	125	55	2.2	48.5	388.1	20.7	34.4	90.0	10203	2032.7
L/S FGD	3-6	1.20	173	16	2.2	50.6	292.4	18.4	75.9	90.0	4108	4482.5
L/S FGD-C	3	1.20	30	5	2.2	21.6	720.2	4.5	346.2	90.0	223	20436.7
L/S FGD-C	4	1.20	30	7	2.2	21.6	719.1	4.6	250.1	90.0	312	14763.7
L/S FGD-C	5	1.20	50	20	2.2	26.6	531.2	5.9	67.8	90.0	1484	3999.8
L/S FGD-C	6	1.20	63	21	2.2	31.2	495.6	6.9	59.6	90.0	1963	3518.4
L/S FGD-C	7	1.35	75	52	2.2	37.4	499.3	9.2	26.8	90.0	5788	1583.4
L/S FGD-C	8	1.35	125	55	2.2	48.5	388.1	12.1	20.1	90.0	10203	1185.9
L/S FGD-C	3-6	1.20	173	16	2.2	50.6	292.4	10.8	44.4	90.0	4108	2623.4
LC FGD	3-7	1.25	248	27	2.2	49.4	199.1	20.3	34.6	90.0	9938	2044.0
LC FGD	8	1.35	125	55	2.2	33.8	270.7	16.2	26.8	90.0	10203	1583.8
LC FGD-C	3-7	1.25	248	27	2.2	49.4	199.1	11.9	20.2	90.0	9938	1193.4
LC FGD-C	8	1.35	125	55	2.2	33.8	270.7	9.4	15.6	90.0	10203	922.3

Table 25.4.1-5. Summary of Coal Switching/Cleaning Costs for the Pulliam 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	30	5	2.2	2.1	69.3	0.7	55.1	62.0	153	4750.3
CS/B+$15	4	1.00	30	7	2.2	2.0	68.2	0.8	43.2	62.0	214	3724.3
CS/B+$15	5	1.00	50	20	2.2	2.9	57.9	2.0	22.3	62.0	1017	1921.8
CS/B+$15	6	1.00	63	21	2.2	3.5	55.0	2.5	21.2	62.0	1345	1824.2
CS/B+$15	7	1.00	75	52	2.2	3.7	49.0	5.6	16.3	62.0	3964	1405.8
CS/B+$15	8	1.00	125	55	2.2	5.7	45.9	9.4	15.6	62.0	6988	1347.6
CS/B+$15-C	3	1.00	30	5	2.2	2.1	69.3	0.4	32.3	62.0	153	2782.8
CS/B+$15-C	4	1.00	30	7	2.2	2.0	68.2	0.5	25.3	62.0	214	2176.9
CS/B+$15-C	5	1.00	50	20	2.2	2.9	57.9	1.1	12.9	62.0	1017	1113.8
CS/B+$15-C	6	1.00	63	21	2.2	3.5	55.0	1.4	12.3	62.0	1345	1056.7
CS/B+$15-C	7	1.00	75	52	2.2	3.7	49.0	3.2	9.4	62.0	3964	809.6
CS/B+$15-C	8	1.00	125	55	2.2	5.7	45.9	5.4	9.0	62.0	6988	775.8
CS/B+$5	3	1.00	30	5	2.2	1.8	58.9	0.6	42.7	62.0	153	3680.0
CS/B+$5	4	1.00	30	7	2.2	1.7	57.9	0.6	32.0	62.0	214	2756.9
CS/B+$5	5	1.00	50	20	2.2	2.4	47.5	1.1	13.0	62.0	1017	1120.7
CS/B+$5	6	1.00	63	21	2.2	2.8	44.6	1.4	11.9	62.0	1345	1027.4
CS/B+$5	7	1.00	75	52	2.2	2.9	38.7	2.6	7.7	62.0	3964	659.6
CS/B+$5	8	1.00	125	55	2.2	4.4	35.6	4.2	7.0	62.0	6988	603.3
CS/B+$5-C	3	1.00	30	5	2.2	1.8	58.9	0.3	25.1	62.0	153	2160.4
CS/B+$5-C	4	1.00	30	7	2.2	1.7	57.9	0.3	18.7	62.0	214	1615.7
CS/B+$5-C	5	1.00	50	20	2.2	2.4	47.5	0.7	7.6	62.0	1017	652.5
CS/B+$5-C	6	1.00	63	21	2.2	2.8	44.6	0.8	6.9	62.0	1345	598.0
CS/B+$5-C	7	1.00	75	52	2.2	2.9	38.7	1.5	4.4	62.0	3964	381.2
CS/B+$5-C	8	1.00	125	55	2.2	4.4	35.6	2.4	4.0	62.0	6988	348.5

TABLE 25.4.1-6. SUMMARY OF NOx RETROFIT RESULTS FOR J. P. PULLIAM

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	3,4,5,OR,6	7	8
FIRING TYPE	FWF	FWF	FWF
TYPE OF NOx CONTROL	LNB	LNB	LNB
FURNACE VOLUME (1000 CU FT)	NA	46.1	72.7
BOILER INSTALLATION DATE	1943,43,47,51	1958	1964
SLAGGING PROBLEM	NO	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	40	42	40
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	41	22	32
New Duct Length (Feet)	200	500	400
New Duct Costs (1000$)	1366	2094	2258
New Heat Exchanger (1000$)	2590	1568	2131
TOTAL SCOPE ADDER COSTS (1000$)			
INDIVIDUAL CASE	NA	3684	4421
COMBINED CASE	3996	NA	NA
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13	20

Table 25.4.1-7. NOx Control Cost Results for the Pulliam 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	30	5	2.2	1.6	52.6	0.3	25.6	40.0	24	13907.9
LNC-LNB	4	1.00	30	7	2.2	1.6	52.6	0.3	18.3	40.0	34	9934.2
LNC-LNB	5	1.00	50	20	2.2	1.9	38.7	0.4	4.7	40.0	161	2558.8
LNC-LNB	6	1.00	63	21	2.2	2.1	33.7	0.5	3.9	40.0	214	2122.8
LNC-LNB	7	1.00	75	52	2.2	2.3	30.3	0.5	1.4	42.0	661	735.0
LNC-LNB	8	1.00	125	55	2.2	2.8	22.3	0.6	1.0	40.0	1110	537.4
LNC-LNB-C	3	1.00	30	5	2.2	1.6	52.6	0.2	15.2	40.0	24	8258.9
LNC-LNB-C	4	1.00	30	7	2.2	1.6	52.6	0.2	10.9	40.0	34	5899.2
LNC-LNB-C	5	1.00	50	20	2.2	1.9	38.7	0.2	2.8	40.0	161	1520.0
LNC-LNB-C	6	1.00	63	21	2.2	2.1	33.7	0.3	2.3	40.0	214	1260.4
LNC-LNB-C	7	1.00	75	52	2.2	2.3	30.3	0.3	0.8	42.0	661	436.5
LNC-LNB-C	8	1.00	125	55	2.2	2.8	22.3	0.4	0.6	40.0	1110	319.2
SCR-3	3-6	1.16	173	16	2.2	27.4	158.1	8.9	36.8	80.0	894	9973.7
SCR-3	7	1.16	75	52	2.2	16.8	223.8	5.2	15.3	80.0	1259	4138.8
SCR-3	8	1.16	125	55	2.2	23.1	185.1	7.5	12.5	80.0	2220	3384.4
SCR-3-C	3-6	1.16	173	16	2.2	27.4	158.1	5.2	21.6	80.0	894	5851.5
SCR-3-C	7	1.16	75	52	2.2	16.8	223.8	3.1	9.0	80.0	1259	2431.0
SCR-3-C	8	1.16	125	55	2.2	23.1	185.1	4.4	7.3	80.0	2220	1985.8
SCR-7	3-6	1.16	173	16	2.2	27.4	158.1	7.5	30.9	80.0	894	8370.8
SCR-7	7	1.16	75	52	2.2	16.8	223.8	4.6	13.4	80.0	1259	3645.7
SCR-7	8	1.16	125	55	2.2	23.1	185.1	6.5	10.8	80.0	2220	2918.2
SCR-7-C	3-6	1.16	173	16	2.2	27.4	158.1	4.4	18.2	80.0	894	4933.2
SCR-7-C	7	1.16	75	52	2.2	16.8	223.8	2.7	7.9	80.0	1259	2148.5
SCR-7-C	8	1.16	125	55	2.2	23.1	185.1	3.8	6.3	80.0	2220	1718.7

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) were not considered for the J. P. Pulliam plant because of the small sizes of the ESPs and short duct residence time between the boilers and the ESPs.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

All units would be good candidates for AFBC/CG repowering because of their small boiler size and limited remaining useful life. This is particularly true for units 3-6 which have low capacity factors.

25.4.2 Weston Unit 1,2,3 Steam Plant

Although FGD was evaluated for unit 3, costs were not presented since the unit is firing a low sulfur coal. In addition, due to the low sulfur coal, CS was not evaluated for unit 3. Sorbent injection technologies were not considered for units 1 and 2 due to the inadequate size of the ESPs for these units. For unit 3, SCR was the only NO_x control considered since the unit is equipped with OFA.

TABLE 25.4.2-1. WESTON UNIT 1, 2, 3 STEAM PLANT OPERATIONAL DATA *

BOILER NUMBER	1	2	3
GENERATING CAPACITY (MW-each)	60	75	322
CAPACITY FACTOR (PERCENT)	35	61	78
INSTALLATION DATE	1954	1960	1981
FIRING TYPE	FRONT WALL		TANGENTIAL
FURNACE VOLUME (1000 CU FT)	NA	49.3	NA
LOW NOx COMBUSTION	NO	NO	YES
COAL SULFUR CONTENT (PERCENT)	1.8		0.4
COAL HEATING VALUE (BTU/LB)	11000		9000
COAL ASH CONTENT (PERCENT)	8.5		4.6
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	1972	1973	1981
EMISSION (LB/MM BTU)	NA	NA	NA
REMOVAL EFFICIENCY	99.2	99.5	99.5
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	1.9	1.9	0.3
SURFACE AREA (1000 SQ FT)	NA	NA	404
GAS EXIT RATE (1000 ACFM)	NA	NA	1405
SCA (SQ FT/1000 ACFM)	NA	NA	287
OUTLET TEMPERATURE (°F)	410	330	353

* Some information obtained from plant personnel.

TABLE 25.4.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR WESTON 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	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			NA
BAGHOUSE CASE			1.27
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	8	0	8

* L/LS-FGD and LSD-FGD absorbers for units 1 and 2 would be located on either side of the units. The new FFs would be located adjacent to the LSD-FGD absorbers.

TABLE 25.4.2-3. SUMMARY OF RETROFIT FACTOR DATA FOR WESTON UNIT 3*

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			MEDIUM
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	1.35	NA	
ESP REUSE CASE			1.31
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	0	8

* L/LS-FGD and LSD-FGD absorbers for unit 3 would be located east of unit 3.

Table 25.4.2-4. Summary of FGD Control Costs for the Weston 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	1.20	60	35	1.8	30.4	507.1	12.2	66.1	90.0	2657	4577.1
L/S FGD	2	1.20	75	61	1.8	34.7	463.2	15.2	38.0	90.0	5788	2632.7
L/S FGD	1-2	1.20	135	50	1.8	46.2	342.4	19.7	33.6	90.0	8471	2325.2
L/S FGD-C	1	1.20	60	35	1.8	30.4	507.1	7.1	38.6	90.0	2657	2673.7
L/S FGD-C	2	1.20	75	61	1.8	34.7	463.2	8.9	22.2	90.0	5788	1535.3
L/S FGD-C	1-2	1.20	135	50	1.8	46.2	342.4	11.5	19.6	90.0	8471	1356.7
LC FGD	1-2	1.20	135	50	1.8	31.8	235.8	15.2	26.0	90.0	8471	1798.3
LC FGD-C	1-2	1.20	135	50	1.8	31.8	235.8	8.9	15.1	90.0	8471	1047.2
LSD+FF	1	1.27	60	35	1.8	19.7	328.4	8.1	44.1	87.0	2553	3174.1
LSD+FF	2	1.27	75	61	1.8	21.7	289.6	9.5	23.6	87.0	5563	1701.8
LSD+FF-C	1	1.27	60	35	1.8	19.7	328.4	4.7	25.7	87.0	2553	1853.2
LSD+FF-C	2	1.27	75	61	1.8	21.7	289.6	5.5	13.8	87.0	5563	992.5

Table 25.4.2-5. Summary of Coal Switching/Cleaning Costs for the Weston 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	35	1.8	2.9	47.8	3.3	17.7	55.0	1624	2010.4
CS/B+$15	2	1.00	75	61	1.8	3.4	44.8	6.3	15.7	55.0	3537	1783.7
CS/B+$15-C	1	1.00	60	35	1.8	2.9	47.8	1.9	10.2	55.0	1624	1159.7
CS/B+$15-C	2	1.00	75	61	1.8	3.4	44.8	3.6	9.1	55.0	3537	1026.2
CS/B+$5	1	1.00	60	35	1.8	2.2	37.4	1.6	8.9	55.0	1624	1007.3
CS/B+$5	2	1.00	75	61	1.8	2.6	34.4	2.9	7.1	55.0	3537	809.4
CS/B+$5-C	1	1.00	60	35	1.8	2.2	37.4	0.9	5.1	55.0	1624	583.3
CS/B+$5-C	2	1.00	75	61	1.8	2.6	34.4	1.7	4.1	55.0	3537	467.0

TABLE 25.4.2-6. SUMMARY OF NOx RETROFIT RESULTS FOR WESTON

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	3
FIRING TYPE	FWF	FWF	NA
TYPE OF NOx CONTROL	LNB	LNB	NA
FURNACE VOLUME (1000 CU FT)	NA	49.3	NA
BOILER INSTALLATION DATE	1954	1960	NA
SLAGGING PROBLEM	NO	NO	NA
ESTIMATED NOx REDUCTION (PERCENT)	40	45	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	22	65
New Duct Length (Feet)	300	300	400
New Duct Costs (1000$)	1103	1256	3928
New Heat Exchanger (1000$)	1372	1568	3759
TOTAL SCOPE ADDER COSTS (1000$)	2493	2846	7753
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	20	20	20

* Cold side SCR reactors for units 1 and 2 would be located on either side of the units. Cold side SCR reactors for unit 3 would be located east of unit 3.

Table 25.4.2-7. NOx Control Cost Results for the Weston 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	60	35	1.8	2.1	34.7	0.4	2.4	40.0	353	1258.7
LNC-LNB	2	1.00	75	61	1.8	2.3	30.3	0.5	1.2	45.0	866	561.3
LNC-LNB-C	1	1.00	60	35	1.8	2.1	34.7	0.3	1.4	40.0	353	747.4
LNC-LNB-C	2	1.00	75	61	1.8	2.3	30.3	0.3	0.7	45.0	866	333.4
SCR-3	1	1.16	60	35	1.8	14.5	242.2	4.5	24.2	80.0	706	6304.0
SCR-3	2	1.16	75	61	1.8	16.3	217.0	5.2	13.0	80.0	1539	3381.9
SCR-3	3	1.16	322	78	0.4	45.7	141.9	16.5	7.5	80.0	7599	2176.3
SCR-3-C	1	1.16	60	35	1.8	14.5	242.2	2.6	14.2	80.0	706	3704.1
SCR-3-C	2	1.16	75	61	1.8	16.3	217.0	3.1	7.6	80.0	1539	1985.0
SCR-3-C	3	1.16	322	78	0.4	45.7	141.9	9.7	4.4	80.0	7599	1273.8
SCR-7	1	1.16	60	35	1.8	14.5	242.2	4.0	21.5	80.0	706	5597.1
SCR-7	2	1.16	75	61	1.8	16.3	217.0	4.6	11.4	80.0	1539	2976.3
SCR-7	3	1.16	322	78	0.4	45.7	141.9	13.8	6.3	80.0	7599	1812.9
SCR-7-C	1	1.16	60	35	1.8	14.5	242.2	2.3	12.7	80.0	706	3299.1
SCR-7-C	2	1.16	75	61	1.8	16.3	217.0	2.7	6.7	80.0	1539	1752.7
SCR-7-C	3	1.16	322	78	0.4	45.7	141.9	8.1	3.7	80.0	7599	1065.7

TABLE 25.4.2-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR WESTON UNIT 3

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$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	72

TOTAL COST (1000$)	
ESP UPGRADE CASE	72
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 unit 3 and the unit 3 ESPs. A medium factor was assigned to ESP upgrade due to the congestion around the ESPs.

Table 25.4.2-9. Summary of DSD/FSI Control Costs for the Weston 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	3	1.00	322	78	0.4	8.3	25.7	7.0	3.2	49.0	4806	1462.1
DSD+ESP-C	3	1.00	322	78	0.4	8.3	25.7	4.1	1.8	49.0	4806	845.4
FSI+ESP-50	3	1.36	322	78	0.4	10.9	33.8	7.2	3.3	50.0	4939	1460.0
FSI+ESP-50-C	3	1.36	322	78	0.4	10.9	33.8	4.2	1.9	50.0	4939	846.4
FSI+ESP-70	3	1.36	322	78	0.4	11.0	34.1	7.3	3.3	70.0	6915	1057.3
FSI+ESP-70-C	3	1.36	322	78	0.4	11.0	34.1	4.2	1.9	70.0	6915	612.9

SECTION 26.0 WEST VIRGINIA

26.1 ALLEGHENY POWER SERVICE CORPORATION

26.1.1 Albright

The Albright Steam Plant is located in Preston County, West Virginia, as part of the Allegheny Power Service Corp. system. The plant contains three coal-fired boilers with a total gross generating capacity of 278 MW. Tables 26.1.1-1 through 26.1.1-10 summarize the plant operational data and present the SO_2 and NO_x control cost and performance estimates.

TABLE 26.1.1-1. ALBRIGHT STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3
GENERATING CAPACITY (MW-each)	69	140
CAPACITY FACTOR (PERCENT)	81,82	86
INSTALLATION DATE	1952	1954
FIRING TYPE	FRONT WALL	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	44.2	93
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	1.7	
COAL HEATING VALUE (BTU/LB)	12300	
COAL ASH CONTENT (PERCENT)	12.8	
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	LANDFILL/OFF-SITE	
STACK NUMBER	1,2	3
COAL DELIVERY METHODS	TRUCK	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1975	1975
EMISSION (LB/MM BTU)	0.02	0.02
REMOVAL EFFICIENCY	NA	NA
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	1.0-1.3	
SURFACE AREA (1000 SQ FT)	144	259.2
GAS EXIT RATE (1000 ACFM)	375	675
SCA (SQ FT/1000 ACFM)	384	384
OUTLET TEMPERATURE (°F)	400	385

TABLE 26.1.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR ALBRIGHT 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			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	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$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	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	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	0	10

* Absorbers for units 1 and 2 would be located behind their respective chimneys.

TABLE 26.1.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR ALBRIGHT 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			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	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			1.31
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	0	10

* Absorbers for unit 3 would be located behind the unit 3 chimney.

Table 26.1.1-4. Summary of FGD Control Costs for the Albright 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	1.20	69	81	1.7	30.0	434.3	14.4	29.5	90.0	5874	2457.3
L/S FGD	2	1.20	69	82	1.7	30.0	434.3	14.5	29.2	90.0	5947	2434.2
L/S FGD	3	1.20	140	86	1.7	42.6	304.5	21.4	20.3	90.0	12654	1692.2
L/S FGD-C	1	1.20	69	81	1.7	30.0	434.3	8.4	17.2	90.0	5874	1430.8
L/S FGD-C	2	1.20	69	82	1.7	30.0	434.3	8.4	17.0	90.0	5947	1417.3
L/S FGD-C	3	1.20	140	86	1.7	42.6	304.5	12.5	11.8	90.0	12654	984.6
LC FGD	1-3	1.20	278	84	1.7	42.6	153.2	26.0	12.7	90.0	24543	1060.3
LC FGD-C	1-3	1.20	278	84	1.7	42.6	153.2	15.1	7.4	90.0	24543	615.3
LSD+ESP	1	1.36	69	81	1.7	14.3	207.1	8.0	16.3	76.0	4980	1605.5
LSD+ESP	2	1.36	69	82	1.7	14.3	207.2	8.0	16.2	76.0	5042	1589.8
LSD+ESP	3	1.31	140	86	1.7	21.7	154.9	11.9	11.2	76.0	10728	1105.1
LSD+ESP-C	1	1.36	69	81	1.7	14.3	207.1	4.6	9.5	76.0	4980	932.7
LSD+ESP-C	2	1.36	69	82	1.7	14.3	207.2	4.7	9.4	76.0	5042	923.6
LSD+ESP-C	3	1.31	140	86	1.7	21.7	154.9	6.9	6.5	76.0	10728	642.2

Table 26.1.1-5. Summary of Coal Switching/Cleaning Costs for the Albright 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	69	81	1.7	3.0	43.0	7.4	15.1	46.0	2992	2471.3
CS/B+$15	2	1.00	69	82	1.7	3.0	43.0	7.5	15.1	46.0	3029	2468.5
CS/B+$15	3	1.00	140	86	1.7	5.1	36.5	15.1	14.3	46.0	6445	2335.5
CS/B+$15-C	1	1.00	69	81	1.7	3.0	43.0	4.2	8.7	46.0	2992	1420.4
CS/B+$15-C	2	1.00	69	82	1.7	3.0	43.0	4.3	8.7	46.0	3029	1418.7
CS/B+$15-C	3	1.00	140	86	1.7	5.1	36.5	8.6	8.2	46.0	6445	1341.6
CS/B+$5	1	1.00	69	81	1.7	2.2	32.6	3.2	6.6	46.0	2992	1077.8
CS/B+$5	2	1.00	69	82	1.7	2.2	32.6	3.3	6.6	46.0	3029	1075.5
CS/B+$5	3	1.00	140	86	1.7	3.7	26.2	6.1	5.8	46.0	6445	944.4
CS/B+$5-C	1	1.00	69	81	1.7	2.2	32.6	1.9	3.8	46.0	2992	620.9
CS/B+$5-C	2	1.00	69	82	1.7	2.2	32.6	1.9	3.8	46.0	3029	619.5
CS/B+$5-C	3	1.00	140	86	1.7	3.7	26.2	3.5	3.3	46.0	6445	543.6

TABLE 26.1.1-6. SUMMARY OF NOx RETROFIT RESULTS FOR ALBRIGHT

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1,2	3
FIRING TYPE	FWF	TANG
TYPE OF NOx CONTROL	LNB	OFA
FURNACE VOLUME (1000 CU FT)	44.2	93
BOILER INSTALLATION DATE	1952	1954
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	44	25
SCR RETROFIT RESULTS *		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	20	35
New Duct Length (Feet)	200	200
New Duct Costs (1000$)	798	1207
New Heat Exchanger (1000$)	1492	2281
TOTAL SCOPE ADDER COSTS (1000$)	2310	3522
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	20	20

* Cold side SCR reactors for all units would be located behind their respective chimneys.

Table 26.1.1-7. NOx Control Cost Results for the Albright 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	69	81	1.7	2.2	31.9	0.5	1.0	44.0	910	524.3
LNC-LNB	2	1.00	69	82	1.7	2.2	31.9	0.5	1.0	44.0	921	517.9
LNC-LNB-C	1	1.00	69	81	1.7	2.2	31.9	0.3	0.6	44.0	910	311.2
LNC-LNB-C	2	1.00	69	82	1.7	2.2	31.9	0.3	0.6	44.0	921	307.4
LNC-OFA	3	1.00	140	86	1.7	0.7	5.1	0.2	0.1	25.0	795	193.0
LNC-OFA-C	3	1.00	140	86	1.7	0.7	5.1	0.1	0.1	25.0	795	114.7
SCR-3	1	1.16	69	81	1.7	15.2	220.2	5.0	10.2	80.0	1654	3031.7
SCR-3	2	1.16	69	82	1.7	15.2	220.2	5.0	10.1	80.0	1674	2997.6
SCR-3	3	1.16	140	86	1.7	23.9	170.4	8.2	7.8	80.0	2545	3231.6
SCR-3-C	1	1.16	69	81	1.7	15.2	220.2	2.9	6.0	80.0	1654	1778.2
SCR-3-C	2	1.16	69	82	1.7	15.2	220.2	2.9	5.9	80.0	1674	1758.1
SCR-3-C	3	1.16	140	86	1.7	23.9	170.4	4.8	4.6	80.0	2545	1893.5
SCR-7	1	1.16	69	81	1.7	15.2	220.2	4.4	9.1	80.0	1654	2690.1
SCR-7	2	1.16	69	82	1.7	15.2	220.2	4.5	9.0	80.0	1674	2660.2
SCR-7	3	1.16	140	86	1.7	23.9	170.4	7.1	6.7	80.0	2545	2781.3
SCR-7-C	1	1.16	69	81	1.7	15.2	220.2	2.6	5.3	80.0	1654	1582.4
SCR-7-C	2	1.16	69	82	1.7	15.2	220.2	2.6	5.3	80.0	1674	1564.8
SCR-7-C	3	1.16	140	86	1.7	23.9	170.4	4.2	3.9	80.0	2545	1635.5

TABLE 26.1.1-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR ALBRIGHT 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	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	23
TOTAL COST (1000$)	
ESP UPGRADE CASE	23
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

ESP size was adequate and sufficient duct residence time exists between the boilers and their respective ESPs.

TABLE 26.1.1-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR ALBRIGHT UNIT 3

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$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	38

TOTAL COST (1000$)	
ESP UPGRADE CASE	38
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.36
NEW BAGHOUSE	NA

ESP size was adequate and sufficient duct residence time exists between boiler 3 and the unit 3 ESPs.

Table 26.1.1-10. Summary of DSD/FSI Control Costs for the Albright 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	69	81	1.7	5.7	82.6	5.4	10.9	49.0	3175	1687.0
DSD+ESP	2	1.00	69	82	1.7	5.7	82.6	5.4	10.8	49.0	3215	1671.8
DSD+ESP	3	1.00	140	86	1.7	8.0	56.9	7.6	7.2	49.0	6841	1108.2
DSD+ESP-C	1	1.00	69	81	1.7	5.7	82.6	3.1	6.3	49.0	3175	974.6
DSD+ESP-C	2	1.00	69	82	1.7	5.7	82.6	3.1	6.3	49.0	3215	965.8
DSD+ESP-C	3	1.00	140	86	1.7	8.0	56.9	4.4	4.2	49.0	6841	640.1
FSI+ESP-50	1	1.00	69	81	1.7	5.8	84.8	4.7	9.7	50.0	3264	1455.3
FSI+ESP-50	2	1.00	69	82	1.7	5.8	84.8	4.8	9.6	50.0	3304	1445.5
FSI+ESP-50	3	1.00	140	86	1.7	7.8	55.8	7.6	7.2	50.0	7030	1079.7
FSI+ESP-50-C	1	1.00	69	81	1.7	5.8	84.8	2.7	5.6	50.0	3264	841.9
FSI+ESP-50-C	2	1.00	69	82	1.7	5.8	84.8	2.8	5.6	50.0	3304	836.1
FSI+ESP-50-C	3	1.00	140	86	1.7	7.8	55.8	4.4	4.2	50.0	7030	623.6
FSI+ESP-70	1	1.00	69	81	1.7	6.0	86.2	4.8	9.9	70.0	4569	1055.7
FSI+ESP-70	2	1.00	69	82	1.7	6.0	86.2	4.8	9.8	70.0	4625	1048.5
FSI+ESP-70	3	1.00	140	86	1.7	7.9	56.7	7.7	7.3	70.0	9843	784.8
FSI+ESP-70-C	1	1.00	69	81	1.7	6.0	86.2	2.8	5.7	70.0	4569	610.7
FSI+ESP-70-C	2	1.00	69	82	1.7	6.0	86.2	2.8	5.7	70.0	4625	606.5
FSI+ESP-70-C	3	1.00	140	86	1.7	7.9	56.7	4.5	4.2	70.0	9843	453.3

26.1.2 Fort Martin Steam Plant

The Fort Martin steam plant is located on the Monongahela River in Monongalia County, West Virginia, as part of the Allegheny Power Service system and is operated by the Monongahela Power Company. The Fort Martin plant contains two coal-fired boilers with a gross generating capacity of 1,107 MW.

Table 26.1.2-1 presents operational data for the existing equipment at the Fort Martin plant. Coal shipments are received by barge and transferred to a coal storage and handling area east of the plant. PM emissions from the boilers are controlled by retrofit ESPs which augment ESPs put in at the time of construction. The old and new ESPs are installed in series behind the boilers. Flue gases from each boiler are directed to a chimney between the old and new ESPs. The utility landfills the dry fly ash from the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers would be located beside the boilers at the east and west sides of the respective units. The general facilities factor is high (15 percent) for the FGD absorber locations because several storage buildings and plant roads would have to be relocated to accomodate space for a sorbent preparation, waste handling area, and absorbers. The site access/congestion factor is high for these locations because of interferences caused by acid/caustic storage, fuel oil storage, miscellaneous buildings, transmission line and wastewater treatment tank. Approximately 400 feet of ductwork would be required to span the distance from the chimneys to the absorbers and back to the chimneys. A medium site access/congestion factor was assigned to flue gas handling because of the congestion around the chimneys due to the ESPs.

LSD-FGD with reuse of the existing ESPs was considered for the Fort Martin plant. The LSD absorbers would be located similarly to the wet FGD absorbers with similar site access/congestion and general facilities factors as well as ductwork requirements.

Tables 26.1.2-2 and 26.1.2-3 present retrofit factor and cost results for installation of FGD technologies at the Fort Martin plant. The low cost option shows the effect of eliminating spare absorber modules and large absorber size (-300 MW).

TABLE 26.1.2-1. FORT MARTIN STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2
GENERATING CAPACITY (MW-each)	552	555
CAPACITY FACTOR (PERCENT)	72	68
INSTALLATION DATE	1967	1968
FIRING TYPE	TANGENTIAL	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	NA	NA
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	1.8	1.8
COAL HEATING VALUE (BTU/LB)	12500	12500
COAL ASH CONTENT (PERCENT)	11.3	11.3
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	LANDFILL	
STACK NUMBER	1	2
COAL DELIVERY METHODS	BARGE	
<u>PARTICULATE CONTROL</u>		
TYPE	ESP	ESP
INSTALLATION DATE	1967,82	1968,82
EMISSION (LB/MM BTU)	0.01	0.01
REMOVAL EFFICIENCY	99.7	99.7
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	1.5-3.5	1.5-3.5
SURFACE AREA (1000 SQ FT)	475.5	475.5
GAS EXIT RATE (1000 ACFM)	2150	2150
SCA (SQ FT/1000 ACFM)	221	221
OUTLET TEMPERATURE (°F)	310	310

TABLE 26.1.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR FORT MARTIN 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			MEDIUM
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	1.57	NA	
ESP REUSE CASE			1.58
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	15

Table 26.1.2-3. Summary of FGD Control Costs for the Fort Martin 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	1.57	552	72	1.8	128.1	232.1	61.3	17.6	90.0	43419	1412.7
L/S FGD	2	1.57	555	68	1.8	128.5	231.6	60.5	18.3	90.0	41230	1467.3
L/S FGD-C	1	1.57	552	72	1.8	128.1	232.1	35.7	10.3	90.0	43419	822.6
L/S FGD-C	2	1.57	555	68	1.8	128.5	231.6	35.2	10.7	90.0	41230	854.7
LC FGD	1	1.57	552	72	1.8	95.0	172.2	50.7	14.6	90.0	43419	1167.2
LC FGD	2	1.57	555	68	1.8	95.5	172.0	49.8	15.1	90.0	41230	1209.0
LC FGD-C	1	1.57	552	72	1.8	95.0	172.2	29.5	8.5	90.0	43419	678.6
LC FGD-C	2	1.57	555	68	1.8	95.5	172.0	29.0	8.8	90.0	41230	703.0
LSD+ESP	1	1.58	552	72	1.8	79.4	143.8	35.7	10.3	76.0	36810	969.6
LSD+ESP	2	1.58	555	68	1.8	79.6	143.5	35.2	10.7	76.0	34954	1007.8
LSD+ESP-C	1	1.58	552	72	1.8	79.4	143.8	20.8	6.0	76.0	36810	565.2
LSD+ESP-C	2	1.58	555	68	1.8	79.6	143.5	20.5	6.2	76.0	34954	587.6

Coal Switching and Physical Coal Cleaning Costs--

Table 26.1.2-4 presents the IAPCS cost results for CS at the Fort Martin plant. These costs do not include boiler and pulverizer operating cost changes or any coal handling system modifications that may be necessary. PCC was not considered for this plant because it is not a mine mouth plant.

NO_x Control Technologies--

OFAs and LNBs were considered for NO_x emissions control for boilers 1 and 2, respectively. Furnace values were not available for units 1 and 2 and were estimated based on similar size and age boilers. Tables 26.1.2-5 and 26.1.2-6 present performance and cost estimates for installation of LNC technologies at the Fort Martin plant.

Selective Catalytic Reduction--

Cold side SCR reactors for boilers at the Fort Martin plant would be located adjacent to the ESPs and chimney. A medium site access/congestion factor was assigned to the locations. Approximately 400 feet of ductwork would be required to span the distance between the SCR reactors and the chimneys for a cold side application. Tables 26.1.2-5 and 26.1.2-6 present the retrofit factor inputs to the IAPCS model and cost estimates for installation of SCR at the Fort Martin plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) were considered for the Fort Martin plant because of the long duct residence time between the old and retrofit ESPs. A medium site access/congestion factor was assigned to the ESP locations because of the proximity of the ESPs to the river. However, plate area can be added on the east or west side of the ESPs, if required. Tables 26.1.2-7 and 26.1.2-8 presents retrofit factor inputs to the IAPCS model and costs for installation of sorbent injection technologies at the Fort Martin plant.

Table 26.1.2-4. Summary of Coal Switching/Cleaning Costs for the Fort Martin 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	552	72	1.8	17.2	31.1	48.7	14.0	48.0	23104	2106.7
CS/B+$15	2	1.00	555	68	1.8	17.2	31.1	46.4	14.0	48.0	21939	2115.9
CS/B+$15-C	1	1.00	552	72	1.8	17.2	31.1	28.0	8.0	48.0	23104	1210.4
CS/B+$15-C	2	1.00	555	68	1.8	17.2	31.1	26.7	8.1	48.0	21939	1215.8
CS/B+$5	1	1.00	552	72	1.8	11.4	20.7	18.9	5.4	48.0	23104	818.7
CS/B+$5	2	1.00	555	68	1.8	11.5	20.7	18.1	5.5	48.0	21939	825.4
CS/B+$5-C	1	1.00	552	72	1.8	11.4	20.7	10.9	3.1	48.0	23104	471.3
CS/B+$5-C	2	1.00	555	68	1.8	11.5	20.7	10.4	3.2	48.0	21939	475.3

TABLE 26.1.2-5. SUMMARY OF NOx RETROFIT RESULTS FOR FORT MARTIN

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1	2
FIRING TYPE	TANG	OWF
TYPE OF NOx CONTROL	OFA	LNB
FURNACE VOLUME (1000 CU FT)	NA	NA
BOILER INSTALLATION DATE	1967	1968
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	25	40
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	MEDIUM
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	97	98
New Duct Length (Feet)	400	400
New Duct Costs (1000$)	5384	5402
New Heat Exchanger (1000$)	5195	5212
TOTAL SCOPE ADDER COSTS (1000$)	10677	10711
RETROFIT FACTOR FOR SCR	1.34	1.34
GENERAL FACILITIES (PERCENT)	20	20

Table 26.1.2-6. NOx Control Cost Results for the Fort Martin 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	555	68	1.8	5.1	9.1	1.1	0.3	40.0	5482	200.3
LNC-LNB-C	2	1.00	555	68	1.8	5.1	9.1	0.7	0.2	40.0	5482	118.9
LNC-OFA	1	1.00	552	72	1.8	1.2	2.2	0.3	0.1	25.0	2577	103.1
LNC-OFA-C	1	1.00	552	72	1.8	1.2	2.2	0.2	0.0	25.0	2577	61.2
SCR-3	1	1.34	552	72	1.8	76.3	138.2	27.3	7.8	80.0	8247	3309.7
SCR-3	2	1.34	555	68	1.8	76.7	138.1	27.7	8.4	80.0	10963	2522.7
SCR-3-C	1	1.34	552	72	1.8	76.3	138.2	16.0	4.6	80.0	8247	1937.7
SCR-3-C	2	1.34	555	68	1.8	76.7	138.1	16.2	4.9	80.0	10963	1476.7
SCR-7	1	1.34	552	72	1.8	76.3	138.2	22.8	6.5	80.0	8247	2763.0
SCR-7	2	1.34	555	68	1.8	76.7	138.1	23.1	7.0	80.0	10963	2109.3
SCR-7-C	1	1.34	552	72	1.8	76.3	138.2	13.4	3.8	80.0	8247	1624.5
SCR-7-C	2	1.34	555	68	1.8	76.7	138.1	13.6	4.1	80.0	10963	1239.8

TABLE 26.1.2-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR FORT MARTIN UNIT 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	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	1.36
NEW BAGHOUSE	NA

Table 26.1.2-8. Summary of DSD/FSI Control Costs for the Fort Martin 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	552	72	1.8	24.6	44.6	19.0	5.5	49.0	23470	808.6
DSD+ESP	2	1.00	555	68	1.8	24.7	44.6	18.5	5.6	49.0	22287	830.4
DSD+ESP-C	1	1.00	552	72	1.8	24.6	44.6	11.0	3.2	49.0	23470	468.0
DSD+ESP-C	2	1.00	555	68	1.8	24.7	44.6	10.7	3.2	49.0	22287	480.7
FSI+ESP-50	1	1.00	552	72	1.8	26.5	48.0	23.1	6.6	50.0	24122	956.3
FSI+ESP-50	2	1.00	555	68	1.8	26.6	47.9	22.3	6.8	50.0	22905	974.7
FSI+ESP-50-C	1	1.00	552	72	1.8	26.5	48.0	13.3	3.8	50.0	24122	552.8
FSI+ESP-50-C	2	1.00	555	68	1.8	26.6	47.9	12.9	3.9	50.0	22905	563.6
FSI+ESP-70	1	1.00	552	72	1.8	26.5	48.0	23.4	6.7	70.0	33770	693.6
FSI+ESP-70	2	1.00	555	68	1.8	26.6	47.9	22.7	6.9	70.0	32068	706.7
FSI+ESP-70-C	1	1.00	552	72	1.8	26.5	48.0	13.5	3.9	70.0	33770	400.9
FSI+ESP-70-C	2	1.00	555	68	1.8	26.6	47.9	13.1	4.0	70.0	32068	408.6

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The boilers at the Fort Martin plant are too large and new to be considered for repowering technologies.

26.1.3 Harrison Steam Plant

The Harrison steam plant is located on the West Fork River in Harrison County, West Virginia, as part of the Allegheny Power Service system and operated by Monongahela Power Company. The Harrison plant contains three coal-fired boilers with a gross generating capacity of 1920 MW.

Table 26.1.3-1 presents operational data for the existing equipment at the Harrison 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 which were installed at the same time as the boilers. The ESPs are located behind the boilers. Flue gases from the three boilers are directed to two chimneys located behind the ESPs. The first chimney serves unit 1 and the second chimney serves unit 3. Flue gases from unit 2 are distributed between the two chimneys. Dry fly ash from the units is landfilled by the utility.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for the three units would be located west of unit 3 in a relatively open area. The general facilities factor is medium (8 percent) for the FGD absorber location because several plant roads would have to be relocated. The site access/congestion factor is low for this location. From 300 feet (for unit 3) and 600 feet (for unit 1) of ductwork would be required to span the distance from the chimneys, to the absorbers, to a new chimney for each of the units. Because of the access difficulties and duct length required to reuse the existing chimneys, a new chimney would be constructed adjacent to the absorbers. A high site access/congestion factor was assigned to flue gas handling.

LSD-FGD with reuse of the existing ESPs was not considered for the Harrison plant because of the small sizes of the ESPs. LSD with new baghouses was not considered because of the high sulfur content of the coal being burned.

TABLE 26.1.3-1. HARRISON STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2,3
GENERATING CAPACITY (MW-each)	640
CAPACITY FACTOR (PERCENT)	59,65,48
INSTALLATION DATE	1972,73,74
FIRING TYPE	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	431
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	3.0
COAL HEATING VALUE (BTU/LB)	13000
COAL ASH CONTENT (PERCENT)	7.7
FLY ASH SYSTEM	DRY DISPOSAL
ASH DISPOSAL METHOD	LANDFILL
STACK NUMBER	1;1,2;2
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1972,73,74
EMISSION (LB/MM BTU)	0.01
REMOVAL EFFICIENCY	99.5
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	2.5-4.5
SURFACE AREA (1000 SQ FT)	187.2
GAS EXIT RATE (1000 ACFM)	2060
SCA (SQ FT/1000 ACFM)	91
OUTLET TEMPERATURE (°F)	270

Tables 26.1.3-2 and 26.1.3-3 give a summary of retrofit data and costs, respectively, for installation of L/LS-FGD technologies at the Harrison plant.

Coal Switching and Physical Coal Cleaning Costs--

Table 26.1.3-4 summarizes the IAPCS results for CS at the Harrison plant. These costs do not include boiler and pulverizer operating cost changes or any coal handling system modifications that may be necessary. PCC was not evaluated because the Harrison plant is not a mine mouth plant.

NO_x Control Technologies--

LNBs were considered for control of NO_x emissions from the three opposed wall-fired furnaces. Tables 26.1.3-5 and 26.1.3-6 give a summary of performance and cost results, respectively, for NO_x control technologies at the Harrison plant.

Selective Catalytic Reduction--

Cold side SCR reactors for the boilers at the Harrison plant would be located behind the chimneys. A medium general facilities value of 20 percent and a medium site access/congestion factor were assigned to the reactor locations. Approximately 300 feet of ductwork would be required to span the distance between the SCR reactors and the chimneys. Tables 26.1.3-5 and 26.1.3-6 summarize the retrofit factors and costs for installation of SCR at the Harrison plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) were not considered for the boilers at the Harrison plant because of the small size of the ESPs and short duct residence time between the boilers and the ESPs.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The three 640 MW boilers at the Harrison plant are too large to be considered for AFBC/CG technologies.

TABLE 26.1.3-2. SUMMARY OF RETROFIT FACTOR DATA FOR HARRISON UNIT 1,2 OR 3

	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	NO	NA	NA
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	NA	NA
ESTIMATED COST (1000$)	4480	0	0
OTHER	NO		
RETROFIT FACTORS			
FGD SYSTEM	1.41	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 26.1.3-3. Summary of FGD Control Costs for the Harrison 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	640	59	3.0	129.3	202.1	63.8	19.3	90.0	65729	970.0
L/S FGD	2	1.41	640	65	3.0	129.3	202.1	65.9	18.1	90.0	72413	910.5
L/S FGD	3	1.41	640	48	3.0	129.3	202.0	59.8	22.2	90.0	53474	1117.7
L/S FGD	1-3	1.41	1920	57	3.0	294.9	153.6	152.8	15.9	90.0	190502	802.3
L/S FGD-C	1	1.41	640	59	3.0	129.3	202.1	37.1	11.2	90.0	65729	564.6
L/S FGD-C	2	1.41	640	65	3.0	129.3	202.1	38.4	10.5	90.0	72413	529.6
L/S FGD-C	3	1.41	640	48	3.0	129.3	202.0	34.8	12.9	90.0	53474	651.2
L/S FGD-C	1-3	1.41	1920	57	3.0	294.9	153.6	88.9	9.3	90.0	190502	466.6
LC FGD	1-3	1.41	1920	57	3.0	263.3	137.2	142.8	14.9	90.0	190502	749.4
LC FGD-C	1-3	1.41	1920	57	3.0	263.3	137.2	83.0	8.7	90.0	190502	435.5

Table 26.1.3-4. Summary of Coal Switching/Cleaning Costs for the Harrison 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	640	59	3.0	26.7	41.7	49.8	15.0	67.0	49146	1012.6
CS/B+$15	2	1.00	640	65	3.0	26.7	41.7	54.2	14.9	67.0	54144	1001.3
CS/B+$15	3	1.00	640	48	3.0	26.7	41.7	41.6	15.5	67.0	39983	1040.6
CS/B+$15-C	1	1.00	640	59	3.0	26.7	41.7	28.6	8.7	67.0	49146	582.6
CS/B+$15-C	2	1.00	640	65	3.0	26.7	41.7	31.2	8.6	67.0	54144	575.9
CS/B+$15-C	3	1.00	640	48	3.0	26.7	41.7	24.0	8.9	67.0	39983	599.2
CS/B+$5	1	1.00	640	59	3.0	20.1	31.3	21.3	6.4	67.0	49146	433.1
CS/B+$5	2	1.00	640	65	3.0	20.1	31.3	23.0	6.3	67.0	54144	424.0
CS/B+$5	3	1.00	640	48	3.0	20.1	31.3	18.2	6.8	67.0	39983	455.6
CS/B+$5-C	1	1.00	640	59	3.0	20.1	31.3	12.3	3.7	67.0	49146	249.9
CS/B+$5-C	2	1.00	640	65	3.0	20.1	31.3	13.2	3.6	67.0	54144	244.6
CS/B+$5-C	3	1.00	640	48	3.0	20.1	31.3	10.5	3.9	67.0	39983	263.3

TABLE 26.1.3-5. SUMMARY OF NOx RETROFIT RESULTS FOR HARRISON

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1,2 OR 3
FIRING TYPE	OWF
TYPE OF NOx CONTROL	LNB
FURNACE VOLUME (1000 CU FT)	431
BOILER INSTALLATION DATE	1972,1973,1974
SLAGGING PROBLEM	NO
ESTIMATED NOx REDUCTION (PERCENT)	43
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	109
New Duct Length (Feet)	300
New Duct Costs (1000$)	4403
New Heat Exchanger (1000$)	5677
TOTAL SCOPE ADDER COSTS (1000$)	10189
RETROFIT FACTOR FOR SCR	1.34
GENERAL FACILITIES (PERCENT)	20

Table 26.1.3-6. NOx Control Cost Results for the Harrison 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	640	59	3.0	5.4	8.4	1.2	0.4	43.0	5636	206.3
LNC-LNB	2	1.00	640	65	3.0	5.4	8.4	1.2	0.3	43.0	6210	187.2
LNC-LNB	3	1.00	640	48	3.0	5.4	8.4	1.2	0.4	43.0	4586	253.5
LNC-LNB-C	1	1.00	640	59	3.0	5.4	8.4	0.7	0.2	43.0	5636	122.4
LNC-LNB-C	2	1.00	640	65	3.0	5.4	8.4	0.7	0.2	43.0	6210	111.1
LNC-LNB-C	3	1.00	640	48	3.0	5.4	8.4	0.7	0.3	43.0	4586	150.5
SCR-3	1	1.34	640	59	3.0	84.4	131.9	30.6	9.2	80.0	10486	2913.4
SCR-3	2	1.34	640	65	3.0	84.4	131.9	30.8	8.4	80.0	11553	2665.2
SCR-3	3	1.34	640	48	3.0	84.4	131.9	30.1	11.2	80.0	8531	3531.5
SCR-3-C	1	1.34	640	59	3.0	84.4	131.9	17.9	5.4	80.0	10486	1705.3
SCR-3-C	2	1.34	640	65	3.0	84.4	131.9	18.0	4.9	80.0	11553	1559.8
SCR-3-C	3	1.34	640	48	3.0	84.4	131.9	17.6	6.6	80.0	8531	2067.7
SCR-7	1	1.34	640	59	3.0	84.4	131.9	25.4	7.7	80.0	10486	2417.8
SCR-7	2	1.34	640	65	3.0	84.4	131.9	25.6	7.0	80.0	11553	2215.3
SCR-7	3	1.34	640	48	3.0	84.4	131.9	24.9	9.3	80.0	8531	2922.4
SCR-7-C	1	1.34	640	59	3.0	84.4	131.9	14.9	4.5	80.0	10486	1421.4
SCR-7-C	2	1.34	640	65	3.0	84.4	131.9	15.0	4.1	80.0	11553	1302.0
SCR-7-C	3	1.34	640	48	3.0	84.4	131.9	14.7	5.4	80.0	8531	1718.7

26.1.4 Pleasants Steam Plant

Both units at the Pleasants plant are equipped with a Lime Tray FGD system; therefore, no further SO_2 control technologies were considered for these units. Unit 2 has LNBs so SCR was the only NO_x control considered for this unit.

TABLE 26.1.4-1. PLEASANTS STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1, 2
GENERATING CAPACITY (MW-each)	684
CAPACITY FACTOR (PERCENT)	81, 80
INSTALLATION DATE	1979, 1980
FIRING TYPE	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	503
LOW NOx COMBUSTION	NO, YES
COAL SULFUR CONTENT (PERCENT)	2.7
COAL HEATING VALUE (BTU/LB)	12400
COAL ASH CONTENT (PERCENT)	12
FLY ASH SYSTEM	DRY DISPOSAL
ASH DISPOSAL METHOD	STORAGE/ON-SITE
STACK NUMBER	1, 2
COAL DELIVERY METHODS	RAILROAD/BARGE
FGD SYSTEM (TYPE)	WET LIME FGD
FGD SYSTEM (INSTALLATION DATE)	1979, 1980
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1979, 1980
EMISSION (LB/MM BTU)	0.02
REMOVAL EFFICIENCY	NA
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	1.8-3.5
SURFACE AREA (1000 SQ FT)	746.5
GAS EXIT RATE (1000 ACFM)	2400
SCA (SQ FT/1000 ACFM)	311
OUTLET TEMPERATURE (°F)	200-300

TABLE 26.1.4-2. SUMMARY OF NOx RETROFIT RESULTS FOR PLEASANTS

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1	2
FIRING TYPE	OWF	OWF
TYPE OF NOx CONTROL	LNB	EQUIPPED WITH LNB
FURNACE VOLUME (1000 CU FT)	503	503
BOILER INSTALLATION DATE	1979	1980
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	51	NA
SCR RETROFIT RESULTS *		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	114	114
New Duct Length (Feet)	300	300
New Duct Costs (1000$)	4578	4578
New Heat Exchanger (1000$)	5908	5908
TOTAL SCOPE ADDER COSTS (1000$)	10600	10600
RETROFIT FACTOR FOR SCR	1.52	1.16
GENERAL FACILITIES (PERCENT)	20	20

* Cold side SCR reactors for unit 1 would be located northeast of the unit 1 chimney beyond the coal conveyor. Cold side SCR reactors for unit 2 would be located southwest of the unit 2 chimney next to the coal pile.

Table 26.1.4-3. NOx Control Cost Results for the Pleasants 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	684	81	2.7	5.5	8.1	1.2	0.2	51.0	10355	115.3
LNC-LNB-C	1	1.00	684	81	2.7	5.5	8.1	0.7	0.1	51.0	10355	68.4
SCR-3	1	1.52	684	81	2.7	97.4	142.4	35.6	7.3	80.0	16244	2189.0
SCR-3	2	1.16	684	80	2.7	82.9	121.2	31.9	6.7	80.0	16043	1987.3
SCR-3-C	1	1.52	684	81	2.7	97.4	142.4	20.8	4.3	80.0	16244	1281.1
SCR-3-C	2	1.16	684	80	2.7	82.9	121.2	18.6	3.9	80.0	16043	1161.8
SCR-7	1	1.52	684	81	2.7	97.4	142.4	30.0	6.2	80.0	16244	1844.7
SCR-7	2	1.16	684	80	2.7	82.9	121.2	26.3	5.5	80.0	16043	1638.7
SCR-7-C	1	1.52	684	81	2.7	97.4	142.4	17.6	3.6	80.0	16244	1083.8
SCR-7-C	2	1.16	684	80	2.7	82.9	121.2	15.4	3.2	80.0	16043	962.0

26.2 APPALACHIAN POWER COMPANY

26.2.1 J.E. Amos Steam Plant

Retrofit factors for FGD were evaluated for the boilers at the Amos plant; however, costs are not presented due to the low sulfur content of the coal that is presently being fired. CS was not evaluated since the boilers currently fire a low sulfur coal.

TABLE 26.2.1-1. AMOS STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2	3
GENERATING CAPACITY (MW)	816	816	1300
CAPACITY FACTOR (PERCENT)	44	71	56
INSTALLATION DATE	1971	1972	1973
FIRING TYPE	OPPOSED WALL		
FURNACE VOLUME (1000 CU FT)	NA	480	NA
LOW NOx COMBUSTION	NO	NO	NO
COAL SULFUR CONTENT (PERCENT)	0.7		
COAL HEATING VALUE (BTU/LB)	12260		
COAL ASH CONTENT (PERCENT)	10.8		
FLY ASH SYSTEM	DRY	DRY	WET
ASH DISPOSAL METHOD	LANDFILL		POND
STACK NUMBER	1	1	2
COAL DELIVERY METHODS	BARGE/RAILROAD		
PARTICULATE CONTROL			
TYPE	ESP	ESP	ESP
INSTALLATION DATE	1978	1977	1973
EMISSION (LB/MM BTU)	0.01	0.01	0.05
REMOVAL EFFICIENCY	99.8	99.8	99.5
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	0.8	0.8	0.8
SURFACE AREA (1000 SQ FT)	2194.9	2194.9	1773.9
EXIT GAS FLOW RATE (1000 ACFM)	3000	3000	4402
SCA (SQ FT/1000 ACFM)	732	732	403
OUTLET TEMPERATURE (°F)	370	370	328

TABLE 26.2.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR AMOS UNITS 1 AND 2 *

	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			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM, 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	1.38	NA	
ESP REUSE CASE			1.49
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.37, 1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	15

* L/S-FGD and LSD-FGD absorbers for units 1 and 2 would be located behind the common chimney and ESPs for units 1 and 2, after relocating a warehouse and maintenance buildings. A medium site access/congestion factor was selected (instead of low) to account for moving the above mentioned buildings.

TABLE 26.2.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR AMOS 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			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			100-300
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	9346	NA	9346
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	NA	
ESP REUSE CASE			1.35
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	0	8

* L/S-FGD and LSD-FGD absorbers for unit 3 would be located beside the unit 3 chimney. The LSD-FGD absorbers would be located beside the ESPs.

TABLE 26.2.1-4. SUMMARY OF NOx RETROFIT RESULTS FOR AMOS

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1, 2	3
FIRING TYPE	OWF	OWF
TYPE OF NOx CONTROL	LNB	LNB
FURNACE VOLUME (1000 CU FT)	NA, 480	NA
BOILER INSTALLATION DATE	1971, 1972	1973
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	40	55
SCR RETROFIT RESULTS *		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	131	185
New Duct Length (Feet)	300	200
New Duct Costs (1000$)	5076	4444
New Heat Exchanger (1000$)	6568	8685
TOTAL SCOPE ADDER COSTS (1000$)		
INDIVIDUAL CASE	11774	13314
COMBINED CASE	17788	NA
RETROFIT FACTOR FOR SCR	1.34	1.16
GENERAL FACILITIES (PERCENT)	38	20

* Cold side SCR reactors for units 1 and 2 would be located beside their common chimney. Cold side SCR reactors for unit 3 would be located beside the unit 3 chimney.

Table 26.2.1-5. NOx Control Cost Results for the Amos 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	816	44	0.7	5.9	7.2	1.3	0.4	40.0	5332	240.3
LNC-LNB	2	1.00	816	71	0.7	5.9	7.2	1.3	0.3	40.0	8604	148.9
LNC-LNB	3	1.00	1300	56	0.7	7.1	5.5	1.5	0.2	55.0	14866	103.8
LNC-LNB-C	1	1.00	816	44	0.7	5.9	7.2	0.8	0.2	40.0	5332	142.6
LNC-LNB-C	2	1.00	816	71	0.7	5.9	7.2	0.8	0.1	40.0	8604	88.4
LNC-LNB-C	3	1.00	1300	56	0.7	7.1	5.5	0.9	0.1	55.0	14866	61.6
SCR-3	1	1.34	816	44	0.7	111.8	137.0	39.4	12.5	80.0	10665	3698.4
SCR-3	2	1.34	816	71	0.7	111.8	137.1	40.8	8.0	80.0	17209	2373.2
SCR-3	1-2	1.34	1632	58	0.7	210.6	129.0	77.2	9.3	80.0	28116	2747.4
SCR-3	3	1.16	1300	56	0.7	146.0	112.3	56.1	8.8	80.0	21624	2592.8
SCR-3-C	1	1.34	816	44	0.7	111.8	137.0	23.1	7.3	80.0	10665	2165.9
SCR-3-C	2	1.34	816	71	0.7	111.8	137.1	23.9	4.7	80.0	17209	1388.8
SCR-3-C	1-2	1.34	1632	58	0.7	210.6	129.0	45.2	5.5	80.0	28116	1607.6
SCR-3-C	3	1.16	1300	56	0.7	146.0	112.3	32.8	5.1	80.0	21624	1515.8
SCR-7	1	1.34	816	44	0.7	111.8	137.0	32.8	10.4	80.0	10665	3071.6
SCR-7	2	1.34	816	71	0.7	111.8	137.1	34.2	6.7	80.0	17209	1984.8
SCR-7	1-2	1.34	1632	58	0.7	210.6	129.0	63.9	7.7	80.0	28116	2271.9
SCR-7	3	1.16	1300	56	0.7	146.0	112.3	45.4	7.1	80.0	21624	2100.4
SCR-7-C	1	1.34	816	44	0.7	111.8	137.0	19.3	6.1	80.0	10665	1806.8
SCR-7-C	2	1.34	816	71	0.7	111.8	137.1	20.1	4.0	80.0	17209	1166.3
SCR-7-C	1-2	1.34	1632	58	0.7	210.6	129.0	37.5	4.5	80.0	28116	1335.2
SCR-7-C	3	1.16	1300	56	0.7	146.0	112.3	26.7	4.2	80.0	21624	1233.7

TABLE 26.2.1-6. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR AMOS UNITS 1 AND 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$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	144

TOTAL COST (1000$)	
ESP UPGRADE CASE	144
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.16
NEW BAGHOUSE	NA

Long duct residence time exists between the units and their respective ESPs.

TABLE 26.2.1-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR AMOS UNIT 3

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$)	9346
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	205

TOTAL COST (1000$)	
ESP UPGRADE CASE	9551
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.16
NEW BAGHOUSE	NA

Short duct residence time exists between unit 3 and the unit 3 ESPs. A low factor was assigned to ESP upgrade since space is available around the ESPs. If the duct residence time at full load is less than 1-2 seconds, these technologies will not be able to achieve 50-70% reduction.

Table 26.2.1-8. Summary of DSD/FSI Control Costs for the Amos 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	816	44	0.7	19.1	23.4	12.6	4.0	49.0	8431	1495.4
DSD+ESP	2	1.00	816	71	0.7	19.1	23.4	15.6	3.1	49.0	13605	1143.2
DSD+ESP	3	1.00	816	56	0.7	29.0	35.5	15.6	3.9	49.0	10730	1449.5
DSD+ESP-C	1	1.00	816	44	0.7	19.1	23.4	7.3	2.3	49.0	8431	866.9
DSD+ESP-C	2	1.00	816	71	0.7	19.1	23.4	9.0	1.8	49.0	13605	661.3
DSD+ESP-C	3	1.00	816	56	0.7	29.0	35.5	9.0	2.3	49.0	10730	842.6
FSI+ESP-50	1	1.00	816	44	0.7	20.3	24.9	12.2	3.9	50.0	8665	1402.3
FSI+ESP-50	2	1.00	816	71	0.7	20.3	24.9	15.7	3.1	50.0	13982	1122.3
FSI+ESP-50	3	1.00	1300	56	0.7	38.5	29.6	21.8	3.4	50.0	17569	1242.8
FSI+ESP-50-C	1	1.00	816	44	0.7	20.3	24.9	7.1	2.2	50.0	8665	813.9
FSI+ESP-50-C	2	1.00	816	71	0.7	20.3	24.9	9.1	1.8	50.0	13982	649.6
FSI+ESP-50-C	3	1.00	1300	56	0.7	38.5	29.6	12.7	2.0	50.0	17569	721.9
FSI+ESP-70	1	1.00	816	44	0.7	20.5	25.1	12.3	3.9	70.0	12131	1015.5
FSI+ESP-70	2	1.00	816	71	0.7	20.5	25.1	15.9	3.1	70.0	19575	814.3
FSI+ESP-70	3	1.00	1300	56	0.7	38.7	29.8	22.2	3.5	70.0	24597	900.7
FSI+ESP-70-C	1	1.00	816	44	0.7	20.5	25.1	7.1	2.3	70.0	12131	589.4
FSI+ESP-70-C	2	1.00	816	71	0.7	20.5	25.1	9.2	1.8	70.0	19575	471.2
FSI+ESP-70-C	3	1.00	1300	56	0.7	38.7	29.8	12.9	2.0	70.0	24597	523.1

26.2.2 Mountaineer Steam Plant

The Mountaineer steam plant is located on the Ohio River in Mason County, West Virginia, and is operated by the Appalachian Power Company. The Mountaineer plant contains one coal-fired boiler with a gross generating capacity of 1,300 MW.

Table 26.2.2-1 presents operational data for the existing equipment at the Mountaineer plant. Coal shipments are received by barge and transferred to a coal storage and handling area north of the plant. PM emissions from the boiler are controlled by ESPs which were built at the same time as the boiler. The ESPs are located behind the boiler. Flue gases from the boiler are directed to a chimney behind the ESPs. The utility pays for disposal of fly ash off-site. Because the boiler complies with the 1971 NSPS, SO_2 and NO_x control costs were not developed for many of the technologies.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers would be located behind the chimney. The general facilities factor is medium (8 percent) for the FGD absorber location because a plant road would have to be relocated. The site access/congestion factor is low for this location. Approximately 200 feet of ductwork would be required to span the distance from the chimney to the absorber and back to the chimney. A low site access/congestion factor was assigned to flue gas handling.

LSD with reuse of the existing ESPs was considered for the Mountaineer plant because of the large size of the existing ESPs. The LSD absorbers would be located on the north side of the ductwork leading from the boiler to the ESPs. The general facilities value for this location is medium (8 percent) because a road would have to be relocated. The site access/congestion factor for the location is low. Approximately 400 feet of ductwork would be required and the site access/congestion factor for flue gas handling is low.

Table 26.2.2-2 presents the retrofit factor data for installing L/LS and LSD-FGD technologies at the Mountaineer plant. FGD cost estimates 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 low

TABLE 26.2.2-1. MOUNTAINEER STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1
GENERATING CAPACITY (MW-each)	1300
CAPACITY FACTOR (PERCENT)	79
INSTALLATION DATE	1980
FIRING TYPE	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	NA
LOW NOx COMBUSTION	YES
COAL SULFUR CONTENT (PERCENT)	0.7
COAL HEATING VALUE (BTU/LB)	12600
COAL ASH CONTENT (PERCENT)	10.2
FLY ASH SYSTEM	DRY
ASH DISPOSAL METHOD	PAID DISPOSAL
STACK NUMBER	1
COAL DELIVERY METHODS	BARGE
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1980
EMISSION (LB/MM BTU)	0.01
REMOVAL EFFICIENCY	99.9
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	0.0-1.0
SURFACE AREA (1000 SQ FT)	4390
GAS EXIT RATE (1000 ACFM)	5100
SCA (SQ FT/1000 ACFM)	861
OUTLET TEMPERATURE (°F)	355

TABLE 26.2.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR MOUNTAINEER UNIT 1

	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			LOW
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			300-600
BAGHOUSE			NA
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			1.27
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	0	8

sulfur coal would result in low estimates of capital/operating costs and high cost effectiveness values.

Coal Switching and Physical Coal Cleaning Costs--

CS and PCC were not considered for the Mountaineer plant because low sulfur coal is already being burned at the plant.

NO_x Control Technologies--

The Mountaineer plant has LNBs installed; therefore, additional combustion modification techniques for control of NO_x emissions were not considered.

Selective Catalytic Reduction--

Hot side SCR reactors for the boiler at the Mountaineer plant would be located adjacent to the ESPs north of the air preheaters. A medium general facilities value (20 percent) and a low site access/congestion factor were assigned to the location. About 300 feet of ductwork would be required to span the distance between the SCR reactors and the ESPs. Tables 26.2.2-3 and 26.2.2-4 present the retrofit factors and cost estimates for installation of SCR at the Mountaineer plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) would be particularly well suited for the Mountaineer plant because of the sufficient duct residence time between the boiler and the ESPs and the large size of the ESPs. Tables 26.2.2-5 and 26.2.2-6 present retrofit factors and costs for installation of sorbent injection technologies at the Mountaineer plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The 1,300 MW boiler at the Mountaineer plant is too large and new to be considered for AFBC/CG repowering.

TABLE 26.2.2-3. SUMMARY OF NOx RETROFIT RESULTS FOR MOUNTAINEER

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1
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$)	0
Ductwork Demolition (1000$)	185
New Duct Length (Feet)	300
New Duct Costs (1000$)	6665
New Heat Exchanger (1000$)	0
TOTAL SCOPE ADDER COSTS (1000$)	6851
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	20

Table 26.2.2-4. NOx Control Cost Results for the Mountaineer 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	1300	79	0.7	139.9	107.6	56.8	6.3	80.0	29562	1921.6
SCR-3-C	1	1.16	1300	79	0.7	139.9	107.6	33.2	3.7	80.0	29562	1122.2
SCR-7	1	1.16	1300	79	0.7	139.9	107.6	46.2	5.1	80.0	29562	1562.8
SCR-7-C	1	1.16	1300	79	0.7	139.9	107.6	27.1	3.0	80.0	29562	916.6

TABLE 26.2.2-5. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR MOUNTAINEER UNIT 1

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$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	205

TOTAL COST (1000$)	
ESP UPGRADE CASE	205
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.16
NEW BAGHOUSE	NA

Table 26.2.2-6. Summary of DSD/FSI Control Costs for the Mountaineer 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	1300	79	0.7	27.0	20.8	23.1	2.6	49.0	23371	987.1
DSD+ESP-C	1	1.00	1300	79	0.7	27.0	20.8	13.3	1.5	49.0	23371	570.7
FSI+ESP-50	1	1.00	1300	79	0.7	29.4	22.6	24.7	2.7	50.0	24019	1028.0
FSI+ESP-50-C	1	1.00	1300	79	0.7	29.4	22.6	14.3	1.6	50.0	24019	594.5
FSI+ESP-70	1	1.00	1300	79	0.7	29.6	22.8	25.1	2.8	70.0	33627	746.7
FSI+ESP-70-C	1	1.00	1300	79	0.7	29.6	22.8	14.5	1.6	70.0	33627	431.7

26.3 CENTRAL OPERATING COMPANY

26.3.1 Philip Sporn Steam Plant

The Philip Sporn steam plant is located on the Ohio River in Mason County, West Virginia, and is operated by the Central Operating Company. The Philip Sporn plant contains five coal-fired boilers with a total gross generating capacity of 1,108 MW.

Table 26.3.1-1 presents operational data for the existing equipment at the Sporn plant. Coal shipments are received by barge and transferred to a coal storage and handling area north of the plant. PM emissions from the boilers are controlled by retrofit ESPs. The ESPs are located behind the boilers and stacks. Flue gases from the boilers are directed to two chimneys; one for units 1-4 and one for unit 5. The chimney for units 1-4 is located between the unit 2 and unit 3 ESPs. The chimney for unit 5 is located behind the unit 5 boiler. Fly ash from the units is disposed of in ponds to the north of the plant or stored in ash silos.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for units 1-4 would be located behind the unit 1-4 chimney and absorbers for unit 5 would be located on the west side of the unit 5 ESPs. The general facilities factor is high (15 percent) for the unit 1-4 L/LS-FGD absorber location because a plant road, several ash silos, and part of an employee parking area would have to be relocated. The general facilities value is medium (8 percent) for the unit 5 location because a storage building would have to be relocated. The site access/congestion factor is low for all the absorber locations. Approximately 400 feet of ductwork would be required to span the distance from the chimney to the absorber and back to the chimney for units 1-5. A medium site access/congestion factor was assigned to flue gas handling for the L/LS-FGD absorbers for all units because of the obstruction caused by the ESPs.

LSD with reuse of the existing ESPs was considered for units 1-5 at the Philip Sporn plant because of the adequate sizes of the existing ESPs. The LSD absorbers for units 1 and 4 would be located on the north and south sides of the unit 1 and 4 ESPs, respectively. The absorbers for

TABLE 26.3.1-1. PHILIP SPORN STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2,3,4	5
GENERATING CAPACITY (MW-each)	153	496
CAPACITY FACTOR (PERCENT)	39,32,45,36	50
INSTALLATION DATE	1950,50,51,52	1960
FIRING TYPE	FRONT WALL	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	NA	NA
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	1.0	1.0
COAL HEATING VALUE (BTU/LB)	12300	12300
COAL ASH CONTENT (PERCENT)	11.5	11.5
FLY ASH SYSTEM	DRY	WET
ASH DISPOSAL METHOD	SILOS	POND
STACK NUMBER	1	2
COAL DELIVERY METHODS	BARGE	
<u>PARTICULATE CONTROL</u>		
TYPE	ESP	ESP
INSTALLATION DATE	1980,80,79,79	1978
EMISSION (LB/MM BTU)	0.01	0.01
REMOVAL EFFICIENCY	99.6	99.6
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	2.0	2.0
SURFACE AREA (1000 SQ FT)	424.2	424.2
GAS EXIT RATE (1000 ACFM)	600	1759
SCA (SQ FT/1000 ACFM)	707	241
OUTLET TEMPERATURE (°F)	315	310

units 2 and3 would be located between the unit 2 and 3 ESPs and the unit 5 absorbers would be located on the west side of the unit 5 boiler. The general facilities value for the unit 1, 3, 4, and 5 locations is medium (8 percent) and high (15 percent) for unit 2 because several ash silos and a plant road would have to be relocated. The site access/congestion factor is low for these locations. The flue gas handling site access/congestion factor is low for units 1-4 absorber locations and medium for the unit 5 location because of the limited space between the ESPS and the boiler for this unit. About 300 feet of ductwork would be required for installation of the LSD system for units 1-4 and 400 feet would be required for unit 5.

Tables 26.3.1-2 through 26.3.1-5 present the retrofit factors and cost estimates for installation of conventional FGD technologies at the Philip Sporn steam plant.

Coal Switching and Physical Coal Cleaning Costs--

CS and PCC were not considered for the Philip Sporn plant because low sulfur coal is already being burned at the plant.

NO_x Control Technologies--

LNBs were considered for NO_x emissions control for the four front wall-fired furnaces and one opposed wall-fired furnace at the Philip Sporn plant. Tables 26.3.1-6 and 26.3.1-7 present performance and cost estimates for installation of NO_x emission control technologies at the Philip Sporn plant.

Selective Catalytic Reduction--

Cold side SCR reactors for the boilers at the Philip Sporn plant would be located beside the ESPs. A medium general facilities value (20 percent) and a low site access/congestion factor were assigned to the reactor locations. About 400 feet of ductwork would be required to span the distance between the SCR reactors and the chimneys. Tables 26.3.1-6 and 26.3.1-7 present the retrofit factors and cost estimates for installation of SCR at the Philip Sporn plant.

TABLE 26.3.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR PHILIP SPORN UNIT 1, 3 OR 4

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	MEDIUM	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	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	1.35	NA	
ESP REUSE CASE			1.27
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	8

TABLE 26.3.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR PHILIP SPORN UNIT 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	MEDIUM	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	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	1.35	NA	
ESP REUSE CASE			1.27
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	15

TABLE 26.3.1-4. SUMMARY OF RETROFIT FACTOR DATA FOR PHILIP SPORN UNIT 5

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			MEDIUM
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	YES	NA	YES
ESTIMATED COST (1000$)	3940	NA	3940
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.42	NA	
ESP REUSE CASE			1.38
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	0	8

Table 26.3.1-5. Summary of FGD Control Costs for the Sporn 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	1.35	153	39	1.0	50.2	327.9	20.4	39.1	90.0	3689	5533.5
L/S FGD	2	1.35	153	32	1.0	50.2	327.8	19.9	46.3	90.0	3027	6562.8
L/S FGD	3	1.35	153	45	1.0	50.2	327.9	20.9	34.6	90.0	4257	4904.2
L/S FGD	4	1.35	153	36	1.0	50.2	327.8	20.2	41.8	90.0	3405	5926.0
L/S FGD	5	1.42	496	50	1.0	100.1	201.8	43.6	20.1	90.0	15333	2842.8
L/S FGD	1-4	1.35	612	38	1.0	115.7	189.1	47.7	23.4	90.0	14379	3319.3
L/S FGD-C	1	1.35	153	39	1.0	50.2	327.9	11.9	22.8	90.0	3689	3231.3
L/S FGD-C	2	1.35	153	32	1.0	50.2	327.8	11.6	27.1	90.0	3027	3834.3
L/S FGD-C	3	1.35	153	45	1.0	50.2	327.9	12.2	20.2	90.0	4257	2862.6
L/S FGD-C	4	1.35	153	36	1.0	50.2	327.8	11.8	24.4	90.0	3405	3461.2
L/S FGD-C	5	1.42	496	50	1.0	100.1	201.8	25.4	11.7	90.0	15333	1658.0
L/S FGD-C	1-4	1.35	612	38	1.0	115.7	189.1	27.9	13.7	90.0	14379	1937.8
LC FGD	1-4	1.35	612	38	1.0	92.1	150.6	40.2	19.7	90.0	14379	2793.8
LC FGD	5	1.42	496	50	1.0	75.2	151.7	35.6	16.4	90.0	15333	2323.5
LC FGD-C	1-4	1.35	612	38	1.0	92.1	150.6	23.4	11.5	90.0	14379	1629.4
LC FGD-C	5	1.42	496	50	1.0	75.2	151.7	20.7	9.6	90.0	15333	1353.2
LSD+ESP	1	1.27	153	39	1.0	19.6	128.4	9.1	17.4	76.0	3128	2911.7
LSD+ESP	2	1.27	153	32	1.0	20.4	133.1	9.1	21.3	76.0	2566	3553.7
LSD+ESP	3	1.27	153	45	1.0	19.6	128.4	9.3	15.4	76.0	3609	2571.3
LSD+ESP	4	1.27	153	36	1.0	19.6	128.4	9.0	18.7	76.0	2887	3124.6
LSD+ESP	5	1.38	496	50	1.0	57.7	116.3	23.5	10.8	76.0	12999	1807.8
LSD+ESP-C	1	1.27	153	39	1.0	19.6	128.4	5.3	10.2	76.0	3128	1696.4
LSD+ESP-C	2	1.27	153	32	1.0	20.4	133.1	5.3	12.4	76.0	2566	2071.6
LSD+ESP-C	3	1.27	153	45	1.0	19.6	128.4	5.4	9.0	76.0	3609	1497.6
LSD+ESP-C	4	1.27	153	36	1.0	19.6	128.4	5.3	10.9	76.0	2887	1820.7
LSD+ESP-C	5	1.38	496	50	1.0	57.7	116.3	13.7	6.3	76.0	12999	1055.7

TABLE 26.3.1-6. SUMMARY OF NOx RETROFIT RESULTS FOR PHILIP SPORN

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1,2,3,4	5
FIRING TYPE	FWF	OWF
TYPE OF NOx CONTROL	LNB	LNB
FURNACE VOLUME (1000 CU FT)	NA	NA
BOILER INSTALLATION DATE	1950,50,51,52	1960
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	40	40
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	37	90
New Duct Length (Feet)	400	400
New Duct Costs (1000$)	2537	5058
New Heat Exchanger (1000$)	2401	4872
TOTAL SCOPE ADDER COSTS (1000$)		
INDIVIDUAL CASE	4975	10020
COMBINED CASE	11351	NA
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	20	20

Table 26.3.1-7. NOx Control Cost Results for the Sporn 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	153	39	1.0	3.0	19.8	0.7	1.3	40.0	883	742.9
LNC-LNB	2	1.00	153	32	1.0	3.0	19.8	0.7	1.5	40.0	724	905.4
LNC-LNB	3	1.00	153	45	1.0	3.0	19.8	0.7	1.1	40.0	1019	643.9
LNC-LNB	4	1.00	153	36	1.0	3.0	19.8	0.7	1.4	40.0	815	804.8
LNC-LNB	5	1.00	496	50	1.0	4.8	9.8	1.0	0.5	40.0	3669	286.1
LNC-LNB-C	1	1.00	153	39	1.0	3.0	19.8	0.4	0.7	40.0	883	441.1
LNC-LNB-C	2	1.00	153	32	1.0	3.0	19.8	0.4	0.9	40.0	724	537.5
LNC-LNB-C	3	1.00	153	45	1.0	3.0	19.8	0.4	0.6	40.0	1019	382.2
LNC-LNB-C	4	1.00	153	36	1.0	3.0	19.8	0.4	0.8	40.0	815	477.8
LNC-LNB-C	5	1.00	496	50	1.0	4.8	9.8	0.6	0.3	40.0	3669	169.9
SCR-3	1	1.16	153	39	1.0	26.4	172.8	8.6	16.5	80.0	1766	4890.9
SCR-3	2	1.16	153	32	1.0	26.4	172.8	8.6	20.0	80.0	1449	5917.9
SCR-3	3	1.16	153	45	1.0	26.4	172.8	8.7	14.4	80.0	2037	4265.7
SCR-3	4	1.16	153	36	1.0	26.4	172.8	8.6	17.8	80.0	1630	5282.0
SCR-3	1-4	1.16	612	38	1.0	76.7	125.3	27.5	13.5	80.0	6882	3989.0
SCR-3	5	1.16	496	50	1.0	64.2	129.5	23.0	10.6	80.0	7339	3130.7
SCR-3-C	1	1.16	153	39	1.0	26.4	172.8	5.1	9.7	80.0	1766	2869.3
SCR-3-C	2	1.16	153	32	1.0	26.4	172.8	5.0	11.7	80.0	1449	3472.4
SCR-3-C	3	1.16	153	45	1.0	26.4	172.8	5.1	8.5	80.0	2037	2502.1
SCR-3-C	4	1.16	153	36	1.0	26.4	172.8	5.1	10.5	80.0	1630	3099.0
SCR-3-C	1-4	1.16	612	38	1.0	76.7	125.3	16.1	7.9	80.0	6882	2335.4
SCR-3-C	5	1.16	496	50	1.0	64.2	129.5	13.5	6.2	80.0	7339	1832.9
SCR-7	1	1.16	153	39	1.0	26.4	172.8	7.4	14.1	80.0	1766	4181.5
SCR-7	2	1.16	153	32	1.0	26.4	172.8	7.3	17.1	80.0	1449	5053.2
SCR-7	3	1.16	153	45	1.0	26.4	172.8	7.4	12.3	80.0	2037	3650.8
SCR-7	4	1.16	153	36	1.0	26.4	172.8	7.4	15.2	80.0	1630	4513.4
SCR-7	1-4	1.16	612	38	1.0	76.7	125.3	22.4	11.0	80.0	6882	3260.9
SCR-7	5	1.16	496	50	1.0	64.2	129.5	18.9	8.7	80.0	7339	2577.4
SCR-7-C	1	1.16	153	39	1.0	26.4	172.8	4.3	8.3	80.0	1766	2462.8
SCR-7-C	2	1.16	153	32	1.0	26.4	172.8	4.3	10.1	80.0	1449	2977.0
SCR-7-C	3	1.16	153	45	1.0	26.4	172.8	4.4	7.3	80.0	2037	2149.9
SCR-7-C	4	1.16	153	36	1.0	26.4	172.8	4.3	9.0	80.0	1630	2658.6
SCR-7-C	1-4	1.16	612	38	1.0	76.7	125.3	13.2	6.5	80.0	6882	1918.3
SCR-7-C	5	1.16	496	50	1.0	64.2	129.5	11.1	5.1	80.0	7339	1515.9

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) would be well suited for units 1-4 at the Philip Sporn plant because of the length of ductwork between the boilers and the ESPs and the large sizes of the ESPs. Unit 5 was not considered for sorbent injection technologies because of the small size of the ESPs and short duct residence time before the ESPs. Tables 26.3.1-8 and 26.3.1-9 present the retrofit factors and costs for installation of sorbent injection technologies for units 1-4 at the Philip Sporn plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The four 153 MW boilers at the Philip Sporn plant would be considered good candidates for AFBC/CG repowering. The unit 5 boiler is too large to be considered for AFBC/CG repowering. Two of the units will be repowered with a 330 MW Pressurized Fluidized Bed Combustion (PFBC) unit under the clean coal technology program.

TABLE 26.3.1-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR PHILIP SPORN UNITS 1,2,3 OR 4

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$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	41

TOTAL COST (1000$)	
ESP UPGRADE CASE	41
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.16
NEW BAGHOUSE	NA

Table 26.3.1-9. Summary of DSD/FSI Control Costs for the Sporn 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	153	39	1.0	6.7	43.6	5.2	10.0	49.0	1994	2628.1
DSD+ESP	2	1.00	153	32	1.0	6.7	43.6	5.1	11.8	49.0	1636	3094.8
DSD+ESP	3	1.00	153	45	1.0	6.7	43.6	5.4	8.9	49.0	2301	2343.8
DSD+ESP	4	1.00	153	36	1.0	6.7	43.6	5.2	10.7	49.0	1841	2805.9
DSD+ESP-C	1	1.00	153	39	1.0	6.7	43.6	3.0	5.8	49.0	1994	1520.8
DSD+ESP-C	2	1.00	153	32	1.0	6.7	43.6	2.9	6.8	49.0	1636	1791.4
DSD+ESP-C	3	1.00	153	45	1.0	6.7	43.6	3.1	5.2	49.0	2301	1355.8
DSD+ESP-C	4	1.00	153	36	1.0	6.7	43.6	3.0	6.2	49.0	1841	1623.9
FSI+ESP-50	1	1.00	153	39	1.0	6.9	45.2	4.3	8.2	50.0	2050	2088.1
FSI+ESP-50	2	1.00	153	32	1.0	6.9	45.2	4.0	9.4	50.0	1682	2405.6
FSI+ESP-50	3	1.00	153	45	1.0	6.9	45.2	4.5	7.4	50.0	2365	1894.7
FSI+ESP-50	4	1.00	153	36	1.0	6.9	45.2	4.2	8.7	50.0	1892	2209.1
FSI+ESP-50-C	1	1.00	153	39	1.0	6.9	45.2	2.5	4.8	50.0	2050	1211.4
FSI+ESP-50-C	2	1.00	153	32	1.0	6.9	45.2	2.3	5.5	50.0	1682	1396.7
FSI+ESP-50-C	3	1.00	153	45	1.0	6.9	45.2	2.6	4.3	50.0	2365	1098.7
FSI+ESP-50-C	4	1.00	153	36	1.0	6.9	45.2	2.4	5.0	50.0	1892	1282.1
FSI+ESP-70	1	1.00	153	39	1.0	7.0	45.7	4.3	8.3	70.0	2869	1509.5
FSI+ESP-70	2	1.00	153	32	1.0	7.0	45.7	4.1	9.5	70.0	2354	1737.8
FSI+ESP-70	3	1.00	153	45	1.0	7.0	45.8	4.5	7.5	70.0	3311	1370.4
FSI+ESP-70	4	1.00	153	36	1.0	7.0	45.7	4.2	8.8	70.0	2649	1596.4
FSI+ESP-70-C	1	1.00	153	39	1.0	7.0	45.7	2.5	4.8	70.0	2869	875.8
FSI+ESP-70-C	2	1.00	153	32	1.0	7.0	45.7	2.4	5.5	70.0	2354	1009.0
FSI+ESP-70-C	3	1.00	153	45	1.0	7.0	45.8	2.6	4.4	70.0	3311	794.6
FSI+ESP-70-C	4	1.00	153	36	1.0	7.0	45.7	2.5	5.1	70.0	2649	926.5

26.4 OHIO POWER COMPANY

26.4.1 Kammer Steam Plant

The Kammer steam plant is located on the Ohio River in Marshall County, West Virginia, and is operated by the Ohio Power Company. The Kammer plant contains three coal-fired boilers with a gross generating capacity of 714 MW.

Table 26.4.1-1 presents operational data for the existing equipment at the Kammer plant. Coal shipments are received by barge and transferred to a coal storage and handling area north of the plant. PM emissions from the three units are controlled by retrofit ESPs. The ESPs are located beside boiler 3, west of the plant. Flue gases from the units are directed to a common chimney beside unit 3. Wet fly ash from the unit is disposed of in a pond west of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for the three units would be located at the west end of the units beside the unit 3 boiler and retrofit ESPs. The general facilities factor would be low (5 percent) for the FGD absorber location. The site access/congestion factor would also be low for this location. Approximately 500 feet of ductwork would be required for installation of the L/LS-FGD system. A medium site access/congestion factor was assigned to flue gas handling.

LSD-FGD with reuse of the existing ESPs was considered for the Kammer plant. The LSD absorbers would be located similarly to the wet FGD absorbers with similar general facilities and site access/congestion factors. About 200 feet of ductwork would be required for installation of LSD absorbers for all units. The flue gas handling site access/congestion factor is low for installation of LSD for all units. A low site access/congestion factor was also assigned to the ESP location for upgrading.

Tables 26.4.1-2 and 26.4.1-3 give a summary of retrofit factor inputs to the IAPCS model and estimated costs for installation of conventional FGD technologies at the Kammer plant.

TABLE 26.4.1-1. KAMMER STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2,3
GENERATING CAPACITY (MW-each)	238
CAPACITY FACTOR (PERCENT)	72,73,76
INSTALLATION DATE	1958
FIRING TYPE	CYCLONE
FURNACE VOLUME (1000 CU FT)	NA
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	4.2
COAL HEATING VALUE (BTU/LB)	11900
COAL ASH CONTENT (PERCENT)	14.0
FLY ASH SYSTEM	WET DISPOSAL
ASH DISPOSAL METHOD	PONDS/ON-SITE
STACK NUMBER	1
COAL DELIVERY METHODS	BARGE
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1978
EMISSION (LB/MM BTU)	0.05
REMOVAL EFFICIENCY	99.8
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	1.0-6.0
SURFACE AREA (1000 SQ FT)	925.3
GAS EXIT RATE (1000 ACFM)	835
SCA (SQ FT/1000 ACFM)	1108
OUTLET TEMPERATURE (°F)	360

TABLE 26.4.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR KAMMER UNIT 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	MEDIUM	NA	
ESP REUSE CASE			LOW
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			100-300
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	2040	NA	2040
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.42	NA	
ESP REUSE CASE			1.23
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	5

Table 26.4.1-3. Summary of FGD Control Costs for the Kammer 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	1.42	238	72	4.2	70.7	297.1	36.4	24.2	90.0	46217	786.8
L/S FGD	2	1.42	238	73	4.2	70.7	297.1	36.5	24.0	90.0	46859	779.7
L/S FGD	3	1.42	238	76	4.2	70.7	297.2	37.0	23.4	90.0	48785	759.5
L/S FGD	1-3	1.42	714	74	4.2	148.4	207.9	84.1	18.2	90.0	142503	590.4
L/S FGD-C	1	1.42	238	72	4.2	70.7	297.1	21.2	14.1	90.0	46217	457.6
L/S FGD-C	2	1.42	238	73	4.2	70.7	297.1	21.2	14.0	90.0	46859	453.5
L/S FGD-C	3	1.42	238	76	4.2	70.7	297.2	21.5	13.6	90.0	48785	441.6
L/S FGD-C	1-3	1.42	714	74	4.2	148.4	207.9	48.9	10.6	90.0	142503	343.0
LC FGD	1-3	1.42	714	74	4.2	122.2	171.1	75.7	16.4	90.0	142503	531.4
LC FGD-C	1-3	1.42	714	74	4.2	122.2	171.1	43.9	9.5	90.0	142503	308.3
LSD+ESP	1	1.23	238	72	4.2	35.7	150.0	20.9	13.9	76.0	39183	534.4
LSD+ESP	2	1.23	238	73	4.2	35.7	150.0	21.1	13.8	76.0	39727	530.0
LSD+ESP	3	1.23	238	76	4.2	35.7	150.0	21.4	13.5	76.0	41359	517.7
LSD+ESP-C	1	1.23	238	72	4.2	35.7	150.0	12.2	8.1	76.0	39183	310.2
LSD+ESP-C	2	1.23	238	73	4.2	35.7	150.0	12.2	8.0	76.0	39727	307.7
LSD+ESP-C	3	1.23	238	76	4.2	35.7	150.0	12.4	7.8	76.0	41359	300.5

Coal Switching and Physical Coal Cleaning Costs--

CS was not considered for the three cyclone boilers at the Kammer plant because low sulfur, low ash fusion temperature bituminous coals are not readily available in the eastern United States. PCC was not considered at the Kammer plant because it is not a mine mouth plant.

NO_x Control Technologies--

NGR was considered for NO_x emissions control at the Kammer plant. Performance results and costs developed for the three 238 MW cyclone boilers are presented in Tables 26.4.1-4 and 26.4.1-5.

Selective Catalytic Reduction--

Cold side SCR reactors for the Kammer plant would be located adjacent to the common chimney. As in the FGD case, a low general facilities value (13 percent) was assigned to the location. A low site access/congestion factor was also assigned to the reactor location. Approximately 200 feet of ductwork would be required to span the distance between the SCR reactors and the chimney for the units. A low site access/congestion factor was assigned to the flue gas handling system. Tables 26.4.1-4 and 26.4.1-5 summarize the retrofit factors and costs for installation of SCR at the Kammer plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) were considered for the Kammer plant. The ESPs are large and the extensive ductwork distance between the boilers and the ESPs make these units particularly well suited for sorbent injection technologies. Tables 26.4.1-6 and 26.4.1-7 summarize the retrofit factors and costs, respectively, for installation of sorbent injection technologies at the Kammer plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The three boilers at the Kammer plant would be good candidates for AFBC/CG repowering because of their small boiler size and likely short remaining service life. However, the high capacity factors could result in high replacement power costs for extended downtime.

TABLE 26.4.1-4. SUMMARY OF NOx RETROFIT RESULTS FOR KAMMER

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1,2 OR 3
FIRING TYPE	CYC
TYPE OF NOx CONTROL	NGR
FURNACE VOLUME (1000 CU FT)	NA
BOILER INSTALLATION DATE	1958
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$)	0
Ductwork Demolition (1000$)	52
New Duct Length (Feet)	200
New Duct Costs (1000$)	1646
New Heat Exchanger (1000$)	3136
TOTAL SCOPE ADDER COSTS (1000$)	
INDIVIDUAL CASE	4833
COMBINED CASE	9302
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	13

TABLE 26.4.1-6. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR KAMMER UNIT 1,2 OR 3

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$)	2040
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	57
TOTAL COST (1000$)	
ESP UPGRADE CASE	2097
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.16
NEW BAGHOUSE	NA

Table 26.4.1-7. Summary of DSD/FSI Control Costs for the Kammer 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	238	72	4.2	17.9	75.0	15.3	10.2	49.0	24983	611.4
DSD+ESP	2	1.00	238	73	4.2	17.9	75.0	15.4	10.1	49.0	25330	607.5
DSD+ESP	3	1.00	238	76	4.2	17.9	75.0	15.7	9.9	49.0	26371	596.4
DSD+ESP-C	1	1.00	238	72	4.2	17.9	75.0	8.8	5.9	49.0	24983	353.5
DSD+ESP-C	2	1.00	238	73	4.2	17.9	75.0	8.9	5.8	49.0	25330	351.2
DSD+ESP-C	3	1.00	238	76	4.2	17.9	75.0	9.1	5.7	49.0	26371	344.8
FSI+ESP-50	1	1.00	238	72	4.2	16.8	70.6	20.7	13.8	50.0	25677	807.9
FSI+ESP-50	2	1.00	238	73	4.2	16.8	70.6	21.0	13.8	50.0	26033	805.2
FSI+ESP-50	3	1.00	238	76	4.2	16.8	70.6	21.6	13.6	50.0	27103	797.4
FSI+ESP-50-C	1	1.00	238	72	4.2	16.8	70.6	12.0	8.0	50.0	25677	465.8
FSI+ESP-50-C	2	1.00	238	73	4.2	16.8	70.6	12.1	7.9	50.0	26033	464.2
FSI+ESP-50-C	3	1.00	238	76	4.2	16.8	70.6	12.5	7.9	50.0	27103	459.6
FSI+ESP-70	1	1.00	238	72	4.2	17.1	71.7	21.2	14.1	70.0	35947	589.6
FSI+ESP-70	2	1.00	238	73	4.2	17.1	71.7	21.4	14.1	70.0	36447	587.7
FSI+ESP-70	3	1.00	238	76	4.2	17.1	71.7	22.1	13.9	70.0	37944	582.0
FSI+ESP-70-C	1	1.00	238	72	4.2	17.1	71.7	12.2	8.1	70.0	35947	340.0
FSI+ESP-70-C	2	1.00	238	73	4.2	17.1	71.7	12.3	8.1	70.0	36447	338.8
FSI+ESP-70-C	3	1.00	238	76	4.2	17.1	71.7	12.7	8.0	70.0	37944	335.5

26.4.2 Mitchell Steam Plant

The Mitchell steam plant is located on the Ohio River in Marshall County, West Virginia, and is operated by the Ohio Power Company. The Mitchell plant contains two coal-fired boilers with a gross generating capacity of 1,632 MW.

Table 26.4.2-1 presents operational data for the existing equipment at the Mitchell plant. Coal shipments are received by either barge or railroad and transferred to a coal storage and handling area north of the plant. PM emissions from the two units are controlled by retrofit ESPs. The ESPs are located behind the boilers. Flue gases from the units are directed to a common chimney located between the ESPs. Wet fly ash from the units is disposed of in ponds to the south of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for the two units would be located at the north and south ends of the ESPs. The general facilities factor would be low (5 percent) for the unit 1 FGD absorber location and medium (8 percent) for the unit 2 location. A parking lot and road would have to be relocated before installation of the unit 2 absorbers. The site access/congestion factor was low for these locations. Less than 200 feet of ductwork would be required for installation of the L/LS-FGD system for either unit and a low site access/congestion factor was assigned to flue gas handling.

LSD-FGD with reuse of the existing ESPs was also considered for the Mitchell plant. The LSD absorbers would be located at the north and south ends of the plant beside the boilers. A low site access/congestion factor was assigned to both locations. A low general facilities factor was assigned to the unit 1 absorber location. A medium general facilities factor was assigned to the unit 2 absorber location since a road would have to be relocated before LSD absorbers could be installed. Between 300 and 600 feet of ductwork would be required for installation of LSD absorbers. The flue gas handling site access/congestion factor would be low for unit 1 but medium for unit 2 because of the obstruction caused by the coal conveyor.
Tables 26.4.2-2 through 26.4.2-4 present retrofit factor and cost estimates for installation of conventional FGD technologies at the Mitchell plant.

TABLE 26.4.2-1. MITCHELL STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2
GENERATING CAPACITY (MW-each)	816
CAPACITY FACTOR (PERCENT)	51,52
INSTALLATION DATE	1971
FIRING TYPE	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	477
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	1.4
COAL HEATING VALUE (BTU/LB)	11950
COAL ASH CONTENT (PERCENT)	15.6
FLY ASH SYSTEM	WET DISPOSAL
ASH DISPOSAL METHOD	PONDS/ON-SITE
STACK NUMBER	1
COAL DELIVERY METHODS	BARGE/RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1978
EMISSION (LB/MM BTU)	0.02
REMOVAL EFFICIENCY	99.8
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	1.0-6.0
SURFACE AREA (1000 SQ FT)	2195
GAS EXIT RATE (1000 ACFM)	3000
SCA (SQ FT/1000 ACFM)	731.5
OUTLET TEMPERATURE (°F)	370

TABLE 26.4.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR MITCHELL UNIT 1

	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			LOW
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	6156	NA	6156
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	NA	
ESP REUSE CASE			1.34
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	5

TABLE 26.4.2-3. SUMMARY OF RETROFIT FACTOR DATA FOR MITCHELL UNIT 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			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	6156	NA	6156
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	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	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	0	8

Table 26.4.2-4. 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	1.27	816	51	1.4	131.0	160.5	60.5	16.6	90.0	37234	1623.8
L/S FGD	2	1.27	816	52	1.4	133.2	163.3	61.5	16.6	90.0	37964	1621.0
L/S FGD-C	1	1.27	816	51	1.4	131.0	160.5	35.2	9.7	90.0	37234	946.1
L/S FGD-C	2	1.27	816	52	1.4	133.2	163.3	35.9	9.6	90.0	37964	944.5
LC FGD	1	1.27	816	51	1.4	102.9	126.1	51.5	14.1	90.0	37234	1382.6
LC FGD	2	1.27	816	52	1.4	104.6	128.2	52.4	14.1	90.0	37964	1380.1
LC FGD-C	1	1.27	816	51	1.4	102.9	126.1	30.0	8.2	90.0	37234	804.5
LC FGD-C	2	1.27	816	52	1.4	104.6	128.2	30.5	8.2	90.0	37964	803.0
LSD+ESP	1	1.34	816	51	1.4	92.5	113.4	39.8	10.9	76.0	31567	1261.4
LSD+ESP	2	1.38	816	52	1.4	96.6	118.4	41.2	11.1	76.0	32186	1281.1
LSD+ESP-C	1	1.34	816	51	1.4	92.5	113.4	23.2	6.4	76.0	31567	735.8
LSD+ESP-C	2	1.38	816	52	1.4	96.6	118.4	24.1	6.5	76.0	32186	747.4

Coal Switching and Physical Coal Cleaning Costs--

CS was considered for the Mitchell plant. Table 26.4.2-5 presents costs for CS. These costs do not include boiler and pulverizer operating cost changes or any coal handling system modifications that may be necessary. PCC was not considered at the Mitchell plant because it is not a mine mouth plant.

NO_x Control Technologies--

LNBs were considered for NO_x emissions control at the Mitchell plant. Performance and cost estimates developed for the two 816 MW opposed wall-fired boilers are presented in Tables 26.4.2-6 and 26.4.2-7.

Selective Catalytic Reduction--

Cold side SCR reactors for the Mitchell plant would be located at the north and south sides of the boilers. A low general facilities value (13 percent) was assigned to the unit 1 location and a medium general facilities value (20 percent) was assigned to the unit 2 location. A low site access/congestion factor was also assigned to the absorber locations. Approximately 400 feet of ductwork would be required to span the distance between the SCR reactors and the chimney. A low site access/congestion factor was assigned to flue gas handling for the units. Tables 26.4.2-6 and 26.4.2-7 present the retrofit factors and costs for installation of SCR at the Mitchell plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

The Mitchell plant would be a good candidate for sorbent injection technologies (FSI and DSD). The ESPs are large and the extensive ductwork distance between the boilers and the ESPs make these units particularly well suited for FSI or DSD technologies. Tables 26.4.2-8 and 26.4.2-9 present the retrofit factors and cost estimates, respectively, for installation of sorbent injection technologies at the Mitchell plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The two 816 MW boilers at the Mitchell plant are too large to be considered good candidates for AFBC/CG repowering.

Table 26.4.2-5. 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	1.00	816	51	1.4	23.2	28.4	50.7	13.9	36.0	15049	3366.2
CS/B+$15	2	1.00	816	52	1.4	23.2	28.4	51.6	13.9	36.0	15344	3359.9
CS/B+$15-C	1	1.00	816	51	1.4	23.2	28.4	29.1	8.0	36.0	15049	1935.5
CS/B+$15-C	2	1.00	816	52	1.4	23.2	28.4	29.6	8.0	36.0	15344	1931.8
CS/B+$5	1	1.00	816	51	1.4	14.7	18.0	19.1	5.2	36.0	15049	1266.8
CS/B+$5	2	1.00	816	52	1.4	14.7	18.0	19.4	5.2	36.0	15344	1262.5
CS/B+$5-C	1	1.00	816	51	1.4	14.7	18.0	11.0	3.0	36.0	15049	730.2
CS/B+$5-C	2	1.00	816	52	1.4	14.7	18.0	11.2	3.0	36.0	15344	727.6

TABLE 26.4.2-6. SUMMARY OF NOx RETROFIT RESULTS FOR MITCHELL

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1	2
FIRING TYPE	OWF	OWF
TYPE OF NOx CONTROL	LNB	LNB
FURNACE VOLUME (1000 CU FT)	477	477
BOILER INSTALLATION DATE	1971	1971
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	40	40
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	131	131
New Duct Length (Feet)	400	400
New Duct Costs (1000$)	6768	6768
New Heat Exchanger (1000$)	6568	6568
TOTAL SCOPE ADDER COSTS (1000$)	13466	13466
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	20

Table 26.4.2-7. 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-LNB	1	1.00	816	51	1.4	5.9	7.2	1.3	0.4	40.0	6365	201.3
LNC-LNB	2	1.00	816	52	1.4	5.9	7.2	1.3	0.3	40.0	6490	197.4
LNC-LNB-C	1	1.00	816	51	1.4	5.9	7.2	0.8	0.2	40.0	6365	119.5
LNC-LNB-C	2	1.00	816	52	1.4	5.9	7.2	0.8	0.2	40.0	6490	117.2
SCR-3	1	1.16	816	51	1.4	97.8	119.9	36.2	9.9	80.0	12730	2843.2
SCR-3	2	1.16	816	52	1.4	87.3	107.0	34.6	9.3	80.0	12980	2661.9
SCR-3-C	1	1.16	816	51	1.4	97.8	119.9	21.2	5.8	80.0	12730	1663.4
SCR-3-C	2	1.16	816	52	1.4	87.3	107.0	20.2	5.4	80.0	12980	1555.3
SCR-7	1	1.16	816	51	1.4	97.8	119.9	29.5	8.1	80.0	12730	2316.2
SCR-7	2	1.16	816	52	1.4	87.3	107.0	27.8	7.5	80.0	12980	2145.0
SCR-7-C	1	1.16	816	51	1.4	97.8	119.9	17.3	4.8	80.0	12730	1361.5
SCR-7-C	2	1.16	816	52	1.4	87.3	107.0	16.3	4.4	80.0	12980	1259.1

TABLE 26.4.2-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR MITCHELL UNIT 1 OR 2

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$)	6156
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	144

TOTAL COST (1000$)	
ESP UPGRADE CASE	6300
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.16
NEW BAGHOUSE	NA

Table 26.4.2-9. 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	1.00	816	51	1.4	34.3	42.1	21.1	5.8	49.0	20128	1049.2
DSD+ESP	2	1.00	816	52	1.4	34.3	42.1	21.3	5.7	49.0	20522	1038.4
DSD+ESP-C	1	1.00	816	51	1.4	34.3	42.1	12.3	3.4	49.0	20128	608.8
DSD+ESP-C	2	1.00	816	52	1.4	34.3	42.1	12.4	3.3	49.0	20522	602.4
FSI+ESP-50	1	1.00	816	51	1.4	30.3	37.2	21.4	5.9	50.0	20686	1032.6
FSI+ESP-50	2	1.00	816	52	1.4	30.3	37.2	21.6	5.8	50.0	21092	1024.8
FSI+ESP-50-C	1	1.00	816	51	1.4	30.3	37.2	12.4	3.4	50.0	20686	598.2
FSI+ESP-50-C	2	1.00	816	52	1.4	30.3	37.2	12.5	3.4	50.0	21092	593.6
FSI+ESP-70	1	1.00	816	51	1.4	30.6	37.5	21.7	6.0	70.0	28961	750.4
FSI+ESP-70	2	1.00	816	52	1.4	30.6	37.5	22.0	5.9	70.0	29528	744.8
FSI+ESP-70-C	1	1.00	816	51	1.4	30.6	37.5	12.6	3.5	70.0	28961	434.6
FSI+ESP-70-C	2	1.00	816	52	1.4	30.6	37.5	12.7	3.4	70.0	29528	431.4

26.5 VIRGINIA ELECTRIC AND POWER COMPANY

26.5.1 Mount Storm Steam Plant

The Mount Storm steam plant is located on the Stony River in Grant County, West Virginia, and is operated by the Virginia Electric and Power Company. The Mount Storm plant contains three coal-fired boilers with a gross generating capacity of 1,662 MW.

Table 26.5.1-1 presents operational data for the existing equipment at the Mount Storm plant. Coal shipments are received by railroad and transferred to a coal storage and handling area north of the plant. PM emissions are controlled by ESPs located behind the boilers. Units 1 and 2 have retrofit ESPs which were installed behind the original chimneys for the units. Flue gases exiting these ESPs are directed to a new chimney. Flue gas from unit 3 is directed to a chimney located behind the unit 3 ESPs. Dry fly ash from the units is landfilled by the utility.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for units 1 and 2 would be located on the north side of the unit 1 and 2 chimney and the absorbers for unit 3 would be located on the south side of the unit 3 ESPs. The general facilities factor is low (5 percent) for both locations because no major demolition or relocation would be required. The site access/congestion factor is low for the unit 1 and 2 FGD absorber locations. The site access/congestion factor is low for the unit 3 location. Between 300 and 600 feet of ductwork would be required for installation of the unit 1 and 2 absorbers and between 100 and 300 feet would be required for the unit 3 absorbers. A low site access/congestion factor was assigned to flue gas handling for all of the units.

LSD-FGD with reuse of the existing ESPs was considered for the Mount Storm plant. It was assumed that the existing ESPs would be large enough to handle the additional load imposed by LSD. The LSD absorbers would be located similarly to the wet FGD absorbers at the north and south ends of the units. Low general facilities factors were assigned to both locations. A low site access/congestion factor was assigned to the unit 1 and 2 location and to the unit 3 location. Approximately 500 feet of ductwork

TABLE 26.5.1-1. MOUNT STORM STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3
GENERATING CAPACITY (MW-each)	570	522
CAPACITY FACTOR (PERCENT)	66,75	71
INSTALLATION DATE	1965,66	1973
FIRING TYPE	TANGENTIAL	
FURNACE VOLUME (1000 CU FT)	310	313
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	1.8	1.8
COAL HEATING VALUE (BTU/LB)	12100	12100
COAL ASH CONTENT (PERCENT)	14.5	14.5
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	LANDFILL	
STACK NUMBER	1	3
COAL DELIVERY METHODS	RAILROAD	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	NA	NA
EMISSION (LB/MM BTU)	NA	NA
REMOVAL EFFICIENCY	NA	NA
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	NA	NA
SURFACE AREA (1000 SQ FT)	NA	NA
GAS EXIT RATE (1000 ACFM)	NA	NA
SCA (SQ FT/1000 ACFM)	NA	NA
OUTLET TEMPERATURE (°F)	NA	NA

would be required to access the upstream side of the retrofit ESPs for unit 1, 800 feet would be required for unit 2, and about 400 feet would be required for unit 3. A medium site access/congestion factor was assigned to flue gas handling for units 1 and 3 and a high site access/congestion factor was assigned to unit 2 because of the congestion between the old and new ESPs.

Tables 26.5.1-2 through 26.5.1-5 present a summary of retrofit data and costs for installation of conventional FGD technologies at the Mount Storm plant.

Coal Switching and Physical Coal Cleaning Costs--

Table 26.5.1-6 summarizes the IAPCS cost results for CS at the Mount Storm plant. These costs do not include pulverizer and boiler operating cost changes or any system modifications that may be necessary for coal blending. PCC was not evaluated because the Mount Storm plant is not a mine mouth plant.

NO_x Control Technologies--

OFA was considered for control of NO_x emissions from the three tangential-fired boilers. Tables 26.5.1-7 and 26.5.1-8 present performance and cost estimates for NO_x control technologies at the Mount Storm plant.

Selective Catalytic Reduction--

Cold side SCR reactors for units 1 and 2 and cold side SCR reactors for unit 3 at the Mount Storm plant would be located similarly to the wet FGD absorbers. The unit 1 and 2 reactors would be located beside the unit 1 retrofit ESPs and the unit 3 reactors would be located beside the unit 3 ESPs. As in the FGD case, low general facilities values of 13 percent were assigned to both of the reactor locations. Low site access/congestion factors were also assigned to the reactor locations. Approximately 200 feet of ductwork would be required to span the distance between the SCR reactors and the unit 1 and 2 chimney and about 300 feet would be required for the unit 3 reactors. Low site access/congestion factors were assigned to flue gas handling for the three units. Tables 26.5.1-7 and 26.5.1-8 present the retrofit factors and costs for installation of SCR at the Mount Storm plant.

TABLE 26.5.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR MOUNT STORM UNIT 1

	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)	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	1.31	NA	
ESP REUSE CASE			1.31
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	5

TABLE 26.5.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR MOUNT STORM UNIT 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			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			600-1000
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	1.31	NA	
ESP REUSE CASE			1.47
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	5

TABLE 26.5.1-4. SUMMARY OF RETROFIT FACTOR DATA FOR MOUNT STORM 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			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	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			1.31
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	5

Table 26.5.1-5. Summary of FGD Control Costs for the Mount Storm 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	1.31	570	66	1.8	104.7	183.6	52.6	15.9	90.0	42662	1232.0
L/S FGD	2	1.31	570	75	1.8	104.7	183.7	55.0	14.7	90.0	48480	1134.8
L/S FGD	3	1.20	522	71	1.8	92.3	176.9	48.4	14.9	90.0	42029	1152.2
L/S FGD	1-2	1.31	1140	71	1.8	183.6	161.0	96.5	13.6	90.0	91788	1051.6
L/S FGD-C	1	1.31	570	66	1.8	104.7	183.6	30.6	9.3	90.0	42662	716.9
L/S FGD-C	2	1.31	570	75	1.8	104.7	183.7	32.0	8.5	90.0	48480	659.9
L/S FGD-C	3	1.20	522	71	1.8	92.3	176.9	28.2	8.7	90.0	42029	670.0
L/S FGD-C	1-2	1.31	1140	71	1.8	183.6	161.0	56.1	7.9	90.0	91788	611.5
LC FGD	1-2	1.31	1140	71	1.8	151.6	132.9	86.3	12.2	90.0	91788	940.0
LC FGD	3	1.20	522	71	1.8	68.8	131.7	40.9	12.6	90.0	42029	972.9
LC FGD-C	1-2	1.31	1140	71	1.8	151.6	132.9	50.1	7.1	90.0	91788	545.9
LC FGD-C	3	1.20	522	71	1.8	68.8	131.7	23.7	7.3	90.0	42029	564.7
LSD+ESP	1	1.31	570	66	1.8	65.0	114.1	31.3	9.5	71.0	33818	926.7
LSD+ESP	2	1.47	570	75	1.8	72.0	126.2	34.8	9.3	71.0	38430	905.2
LSD+ESP	3	1.31	522	71	1.8	58.0	111.1	29.2	9.0	71.0	33317	875.6
LSD+ESP-C	1	1.31	570	66	1.8	65.0	114.1	18.2	5.5	71.0	33818	539.5
LSD+ESP-C	2	1.47	570	75	1.8	72.0	126.2	20.3	5.4	71.0	38430	527.0
LSD+ESP-C	3	1.31	522	71	1.8	58.0	111.1	17.0	5.2	71.0	33317	509.5

Table 26.5.1-6. Summary of Coal Switching/Cleaning Costs for the Mount Storm 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	570	66	1.8	16.9	29.7	45.4	13.8	50.0	23606	1922.2
CS/B+$15	2	1.00	570	75	1.8	16.9	29.7	51.1	13.6	50.0	26825	1903.8
CS/B+$15	3	1.00	522	71	1.8	15.6	29.9	44.5	13.7	50.0	23256	1914.2
CS/B+$15-C	1	1.00	570	66	1.8	16.9	29.7	26.1	7.9	50.0	23606	1104.5
CS/B+$15-C	2	1.00	570	75	1.8	16.9	29.7	29.3	7.8	50.0	26825	1093.6
CS/B+$15-C	3	1.00	522	71	1.8	15.6	29.9	25.6	7.9	50.0	23256	1099.7
CS/B+$5	1	1.00	570	66	1.8	11.0	19.3	17.1	5.2	50.0	23606	725.3
CS/B+$5	2	1.00	570	75	1.8	11.0	19.3	19.1	5.1	50.0	26825	712.2
CS/B+$5	3	1.00	522	71	1.8	10.2	19.5	16.8	5.2	50.0	23256	720.4
CS/B+$5-C	1	1.00	570	66	1.8	11.0	19.3	9.9	3.0	50.0	23606	417.6
CS/B+$5-C	2	1.00	570	75	1.8	11.0	19.3	11.0	2.9	50.0	26825	409.9
CS/B+$5-C	3	1.00	522	71	1.8	10.2	19.5	9.6	3.0	50.0	23256	414.7

TABLE 26.5.1-7. SUMMARY OF NOx RETROFIT RESULTS FOR MOUNT STORM

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1,2	3
FIRING TYPE	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA
FURNACE VOLUME (1000 CU FT)	310	313
BOILER INSTALLATION DATE	1965,66	1973
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$)	0	0
Ductwork Demolition (1000$)	100	93
New Duct Length (Feet)	200	300
New Duct Costs (1000$)	2743	3909
New Heat Exchanger (1000$)	5296	5024
TOTAL SCOPE ADDER COSTS (1000$)		
INDIVIDUAL CASE	8139	9026
COMBINED CASE	12310	NA
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13

Table 26.5.1-8. NOx Control Cost Results for the Mount Storm 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	570	66	1.8	1.2	2.2	0.3	0.1	25.0	2532	106.3
LNC-OFA	2	1.00	570	75	1.8	1.2	2.2	0.3	0.1	25.0	2877	93.5
LNC-OFA	3	1.00	522	71	1.8	1.2	2.3	0.3	0.1	25.0	2495	104.1
LNC-OFA-C	1	1.00	570	66	1.8	1.2	2.2	0.2	0.0	25.0	2532	63.1
LNC-OFA-C	2	1.00	570	75	1.8	1.2	2.2	0.2	0.0	25.0	2877	55.5
LNC-OFA-C	3	1.00	522	71	1.8	1.2	2.3	0.2	0.0	25.0	2495	61.8
SCR-3	1	1.16	570	66	1.8	68.1	119.4	25.6	7.8	80.0	8103	3158.1
SCR-3	2	1.16	570	75	1.8	68.1	119.4	25.9	6.9	80.0	9208	2811.4
SCR-3	3	1.16	522	71	1.8	64.3	123.2	24.0	7.4	80.0	7983	3005.2
SCR-3	1-2	1.16	1140	71	1.8	126.3	110.8	49.1	6.9	80.0	17433	2818.9
SCR-3-C	1	1.16	570	66	1.8	68.1	119.4	15.0	4.5	80.0	8103	1847.1
SCR-3-C	2	1.16	570	75	1.8	68.1	119.4	15.1	4.0	80.0	9208	1643.9
SCR-3-C	3	1.16	522	71	1.8	64.3	123.2	14.0	4.3	80.0	7983	1757.9
SCR-3-C	1-2	1.16	1140	71	1.8	126.3	110.8	28.7	4.1	80.0	17433	1647.5
SCR-7	1	1.16	570	66	1.8	68.1	119.4	20.9	6.3	80.0	8103	2580.8
SCR-7	2	1.16	570	75	1.8	68.1	119.4	21.2	5.7	80.0	9208	2303.4
SCR-7	3	1.16	522	71	1.8	64.3	123.2	19.7	6.1	80.0	7983	2468.6
SCR-7	1-2	1.16	1140	71	1.8	126.3	110.8	39.8	5.6	80.0	17433	2282.2
SCR-7-C	1	1.16	570	66	1.8	68.1	119.4	12.3	3.7	80.0	8103	1516.3
SCR-7-C	2	1.16	570	75	1.8	68.1	119.4	12.5	3.3	80.0	9208	1352.8
SCR-7-C	3	1.16	522	71	1.8	64.3	123.2	11.6	3.6	80.0	7983	1450.4
SCR-7-C	1-2	1.16	1140	71	1.8	126.3	110.8	23.4	3.3	80.0	17433	1340.0

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) were considered for the boilers at the Mount Storm plant. There is sufficient duct residence time between the old and new ESPs for units 1 and 2 but limited residence time exists before the unit 3 ESPs. Although ESP data was not available, the ESPs appear to be large enough to accommodate the additional particulate load. Tables 26.5.1-9 and 26.5.1-10 present the retrofit factors and costs for installation of sorbent injection technologies at the Mount Storm plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The boilers at the Mount Storm power plant are too large and have too long a remaining useful lifetime to currently be considered as candidates for AFBC/CG repowering.

TABLE 26.5.1-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR MOUNT STORM UNIT 1, 2 OR 3

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$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	110
TOTAL COST (1000$)	
ESP UPGRADE CASE	110
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.36
NEW BAGHOUSE	NA

Table 26.5.1-10. Summary of DSD/FSI Control Costs for the Mount Storm 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	570	66	1.8	21.9	38.5	17.9	5.4	46.0	21886	817.3
DSD+ESP	2	1.00	570	75	1.8	21.9	38.5	19.2	5.1	46.0	24871	770.8
DSD+ESP	3	1.00	522	71	1.8	20.1	38.6	17.2	5.3	46.0	21562	799.5
DSD+ESP-C	1	1.00	570	66	1.8	21.9	38.5	10.3	3.1	46.0	21886	472.7
DSD+ESP-C	2	1.00	570	75	1.8	21.9	38.5	11.1	3.0	46.0	24871	445.6
DSD+ESP-C	3	1.00	522	71	1.8	20.1	38.6	10.0	3.1	46.0	21562	462.2
FSI+ESP-50	1	1.00	570	66	1.8	22.4	39.4	21.6	6.5	50.0	23701	910.0
FSI+ESP-50	2	1.00	570	75	1.8	22.5	39.4	23.6	6.3	50.0	26933	875.6
FSI+ESP-50	3	1.00	522	71	1.8	20.9	40.1	21.0	6.5	50.0	23349	898.2
FSI+ESP-50-C	1	1.00	570	66	1.8	22.4	39.4	12.5	3.8	50.0	23701	525.6
FSI+ESP-50-C	2	1.00	570	75	1.8	22.5	39.4	13.6	3.6	50.0	26933	505.4
FSI+ESP-50-C	3	1.00	522	71	1.8	20.9	40.1	12.1	3.7	50.0	23349	518.6
FSI+ESP-70	1	1.00	570	66	1.8	22.6	39.7	22.0	6.7	70.0	33181	662.1
FSI+ESP-70	2	1.00	570	75	1.8	22.6	39.7	24.0	6.4	70.0	37706	637.4
FSI+ESP-70	3	1.00	522	71	1.8	21.1	40.5	21.4	6.6	70.0	32689	653.7
FSI+ESP-70-C	1	1.00	570	66	1.8	22.6	39.7	12.7	3.9	70.0	33181	382.4
FSI+ESP-70-C	2	1.00	570	75	1.8	22.6	39.7	13.9	3.7	70.0	37706	367.9
FSI+ESP-70-C	3	1.00	522	71	1.8	21.1	40.5	12.3	3.8	70.0	32689	377.4