FAX NUMBERS: 913-339-2934 913-339-2936 913-339-2939

F A C S I M I L E   T R A N S M I S S I O N

TO: Jim Pennington

COMPANY: Florida Department of Environmental Regulation

FAX NUMBER: (904) 922-6979

TELEPHONE NUMBER:

FROM:

EXTENSION: LOCATION:

B&V PROJECT: 16805

B&V PHASE: 030

B&V FILE:

DATE:

NUMBER OF PAGES, INCLUDING THIS COVER SHEET:

NOTE TO RECEIVING OPERATOR

In the event of incomplete transmission, please call (913) 339-7218.

TRANSMITTAL DATE/TIME: OPERATOR'S INITIALS:

SUBJECT: Sulfur Dioxide Emission Potential of Kentucky coals.

MESSAGE: Dear Mr. Pennington:

In case you didn't receive my message, phone number to James Cobb, Senior Geologist, Lexington, KY is (606) 257-5500.

I located a report that he worked on which shows the distribution of coal resources (not economically recoverable reserves) by their sulfur content. See attached Figures 1, 2. As you can see there is a marked difference between the quality and quantity of E. KY and W. KY coals.

I have also enclosed the data which was used to compute the quantity of recoverable Coal reserves in East KY and West KY.

If you have any questions, pelase contact me at (913) 339-2838.

Very truly yours

~~BLACK~~ & VEATCH

K. E. Carlson

ISSN 0075-5583

KENTUCKY GEOLOGICAL SURVEY
UNIVERSITY OF KENTUCKY, LEXINGTON
Donald C. Haney, Director and State Geologist

COMPLIANCE COAL RESOURCES IN KENTUCKY

James C. Cobb and James C. Currens
Kentucky Geological Survey

and

Harry G. Enoch
Kentucky Department of Energy

Prepared in cooperation with the Kentucky Department of Energy
William B. Sturgill, Secretary

INFORMATION CIRCULAR 9
SERIES XI, 1982

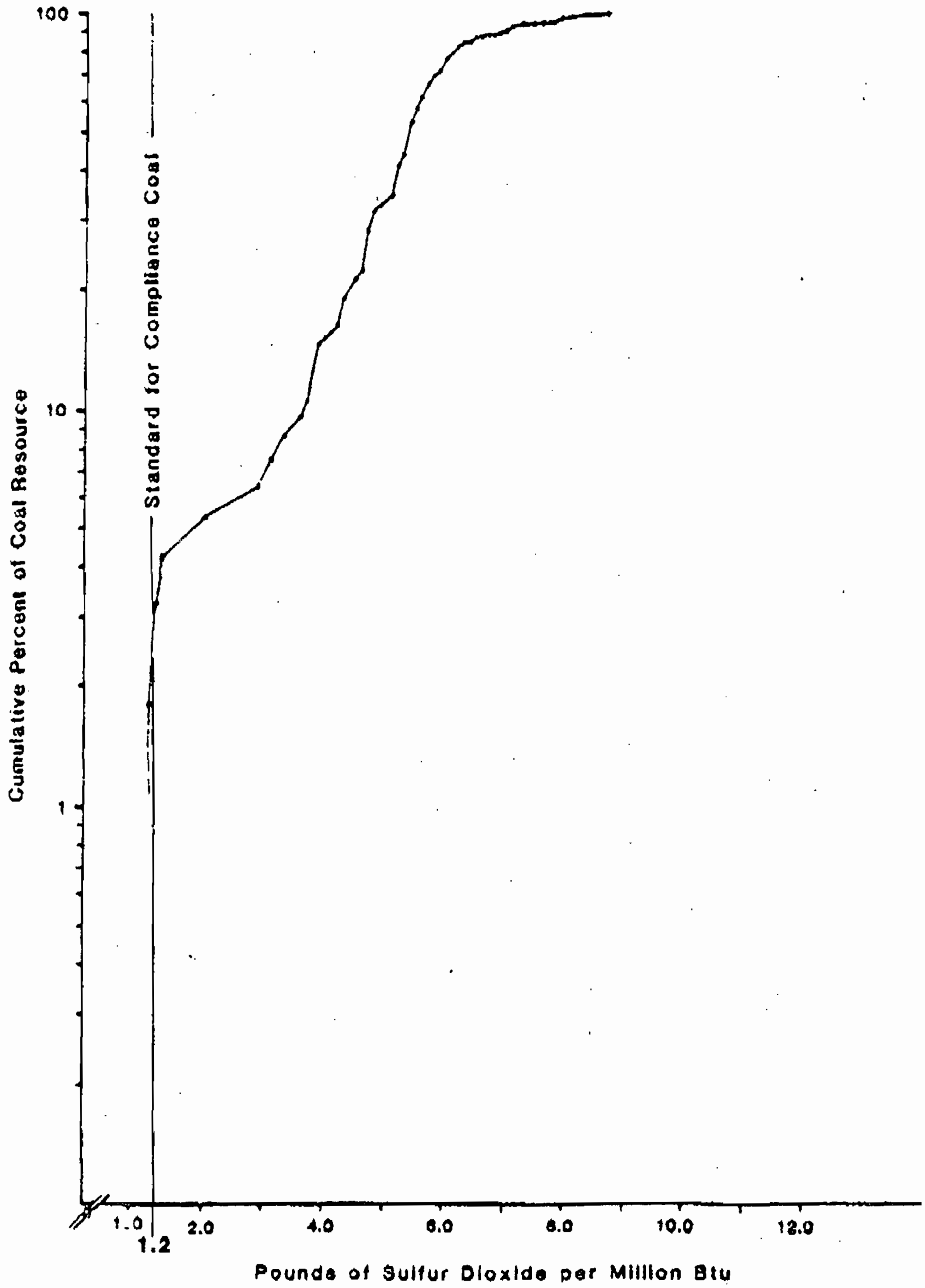

Figure 7. Cumulative probability curve for major western Kentucky coals with respect to the EPA compliance standard.

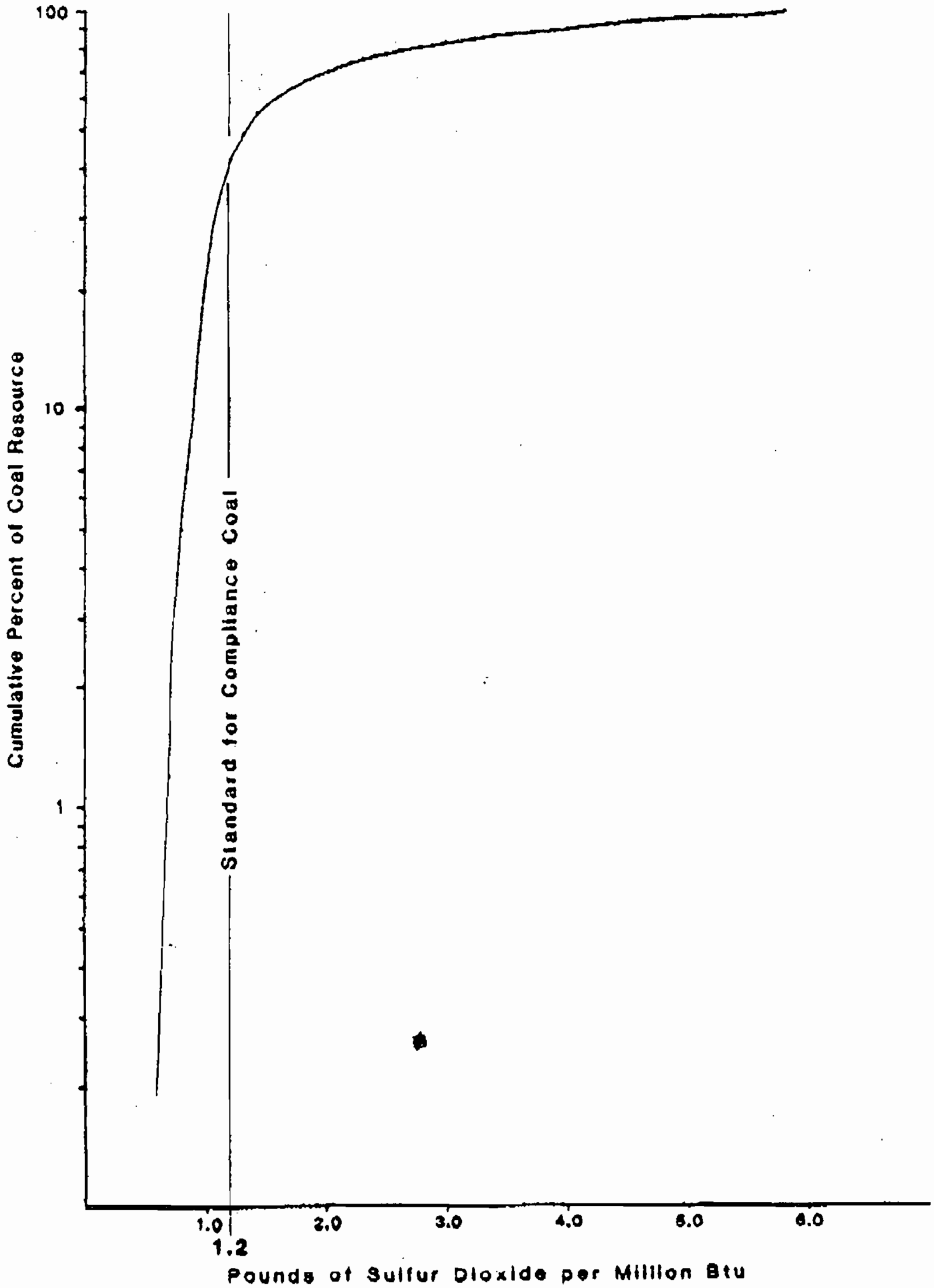

Figure 5. Cumulative probability curve for major eastern Kentucky coals with respect to the EPA compliance standard.

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DOE/EIA 0529

DOE/EIA-0529
Distribution Category UC-98

Estimation of U.S. Coal Reserves by Coal Type

Heat and Sulfur Content

Energy Information Administration
Office of Coal, Nuclear, Electric and Alternate Fuels
U.S. Department of Energy
Washington, DC 20585

Table A3. Estimates of 1987 Recoverable Reserves by Coal Type Mining Method, and State (Continued)
(Million Short Tons)

Btu Content (million Btu/short ton)	Sulfur Content (lbs sulfur/million Btu) ≤ 0.40 Deep	≤ 0.40 Surface	0.41-0.60 Deep	0.41-0.60 Surface	0.61-0.83 Deep	0.61-0.83 Surface	0.84-1.67 Deep
				Kentucky, Western			
≥ 26	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23-25.99	.0	.0	.0	.0	.0	.0	29.6
20-22.99	.0	.0	.0	.0	.0	.0	6.8
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	.0	.0
TOTAL	.0	.0	.0	.0	.0	.0	36.4
				Louisiana			
≥ 26	0.0	0.0	0.0	0.0		0.0	0.0
23-25.99	.0	.0	.0	.0		.0	.0
20-22.99	.0	.0		.0		.0	.0
15-19.99	.0	.0		.0		.0	.0
< 15	.0	.0		.0		.0	.0
TOTAL	.0	.0	.0	.0	.0	.0	.0
				Maryland			
≥ 26	0.0		29.6	3.1	51.6	9.2	109.5
23-25.99	.0		.0	.0	.0	.0	.0
20-22.99	.0		.0	.0	.0	.0	.0
15-19.99	.0		.0	.0	.0	.0	.0
< 15	.0		.0	.0	.0	.0	.0
TOTAL	.0	.0	29.6	3.1	51.6	9.2	109.5
				Missouri			
≥ 26	0.0	0.0	0.0		0.0	0.0	0.0
23-25.99	.0	.0	.0		.0	.0	.0
20-22.99	.0	.0	.0		.0	.0	.0
15-19.99	.0	.0	.0		.0	.0	.0
< 15	.0	.0	.0		.0	.0	.0
TOTAL	.0	.0	.0	.0	.0	.0	.0
				Montana			
≥ 26	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23-25.99	.0	.0	.0	.0	.0	.0	.0
20-22.99	188.8	.0	229.4	.0	38.1	.0	113.9
15-19.99	16,411.9	12,860.3	10,260.5	3,168.0	7,724.2	3,821.3	2,415.3
< 15	.0	1,440.2	.0	2,880.4	.0	4,522.9	.0
TOTAL	16,600.7	14,300.5	10,489.9	6,048.3	7,762.2	8,344.2	2,529.3

See footnotes at end of table.

Table A3. Estimates of 1987 Recoverable Reserves by Coal Type Mining Method, and State (Continued)
(Million Short Tons)

Btu Content (million Btu/short ton	Sulfur Content (lbs sulfur/million Btu) 0.84-1.67	1.68-2.50		> 2.50		TOTAL	
	Surface	Deep	Surface	Deep	Surface	Deep	Surface
				Kentucky, Western			
≥ 26	0.0	233.2	18.6	104.1	3.2	337.3	21.8
23-25.99	88.0	913.2	470.8	4,506.7	856.6	5,449.4	1,415.3
20-22.99	37.3	929.1	440.3	1,312.3	421.6	2,248.2	899.2
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	.0	.0
TOTAL	125.3	2,075.5	929.6	5,923.0	1,281.4	8,034.9	2,336.3
				Louisiana			
≥ 26	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23-25.99	.0	.0	.0	.0	.0	.0	.0
20-22.99	.0	.0	.0	.0	.0	.0	.0
15-19.99	.0	.0	0	.0	.0	.0	.0
< 15	406.9	.0	.0	0	.0	.0	406.9
TOTAL	406.9	.0	.0	.0	.0	.0	406.9
				Maryland			
≥ 26	14.8	67.0	18.3	0.0	0.0	257.7	45.3
23-25.99	.0	112.9	18.7	.0	.0	112.9	18.7
20-22.99	.0	.0	.0	.0	.0	.0	.0
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	.0	.0
TOTAL	14.8	179.9	37.0	.0	.0	370.6	64.0
				[illegible]ouri			
≥ 26	0.0	0.0	0.[illegible]	8.4	2[illegible]	8.4	27.4
23-25.99	.0	19.3	93.[illegible]	129.4	96.[illegible]	148.8	1,077.3
20-22.99	.0	3.3	53.2	638.2	1,9[illegible]	641.6	1,984.6
15-19.99	.0	.0	.0	.0	[illegible]	.0	.0
< 15	.0	.0	.0	.0	.0	.0	.0
TOTAL	.0	22.7	146.7	776.0	2,942.5	798.7	3,089.2
				Montana			
≥ 26	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23-25.99	.0	.0	.0	.0	.0	.0	.0
20-22.99	.0	74.4	.0	104.5	.0	748.1	.0
15-19.99	956.8	365.5	117.6	392.2	137.0	37,569.6	21,061.0
< 15	1,197.0	.0	1,440.2	.0	720.1	.0	12,200.8
TOTAL	2,153.8	439.9	1,557.8	496.7	857.2	38,317.7	33,261.8

See footnotes at end of table.

Table A3. Estimates of 1987 Recoverable Reserves by Coal Type Mining Method, and State (Continued)

(Million Short Tons)

Btu Content (million Btu/short ton	Sulfur Content (lbs sulfur/million Btu)						
	≦0.40 .0.40		0.41-0.60 .82 - 1.2		0.61-0.83 1.22-1.66		0.84-1.67 1.68-3.34
	Deep	Surface	Deep	Surface	Deep	Surface	Deep
Illinois							
≧ 26	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23-25.99	.0	.0	.0	.0	951.1	37.5	2,341.1
20-22.99	.0	.0	.0	.0	63.2	2.6	745.2
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	.0	.0
TOTAL	.0	.0	.0	.0	1,014.3	40.1	3,086.2
Indiana							
≧ 26	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23-25.99	.0	.0	126.9	26.6	56.3	7.0	300.3
20-22.99	.0	.0	162.1	51.2	127.2	26.4	359.7
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	.0	.0
TOTAL	.0	.0	289.0	77.8	183.4	33.4	660.0
Iowa							
≧ 26	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23-25.99	.0	.0	.0	.0	.0	.0	.0
20-22.99	.0	.0	.0	.0	.0	.0	.0
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	.0	.0
TOTAL	.0	.0	.0	.0	.0	.0	.0
Kansas							
≧ 26	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23-25.99	.0	.0	.0	.0	.0	.0	.0
20-22.99	.0	.0	.0	.0	.0	.0	.0
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	.0	.0
TOTAL	.0	.0	.0	.0	.0	.0.	.0
Kentucky, Eastern							
≧ 26	157.1	35.0	1,508.2	303.2	692.6	117.7	302.2
23-25.99	40.3	9.4	325.3	96.5	557.7	216.5	287.2
20-22.99	.0	.0	.0	.0	37.9	28.1	102.2
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	0	.0	.0	.0	.0	.0
TOTAL	197.4	44.4	1,833.6	399.7	1,288.2	362.2	691.6

See footnotes at end of table.

Table A3. Estimates of 1987 Recoverable Reserves by Coal Type Mining Method, and State (Continued)

(Million Short Tons)

3.76 – 5.83 5.00

Btu Content (million Btu/short ton	Sulfur Content (lbs sulfur/million Btu) 0.64-1.67 Surface	1.68-2.50 Deep	1.68-2.50 Surface	> 2.50 Deep	> 2.50 Surface	TOTAL Deep	TOTAL Surface
Illinois							
≥ 26	0.0	56.0	4.9	0.0	0.0	56.0	4.9
23-25.99	142.5	3,321.9	732.5	2,572.8	396.6	9,186.9	1,309.2
20-22.99	70.1	1,139.5	1,106.2	19,112.5	2,593.4	21,060.4	3,772.3
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	.0	.0
TOTAL	212.7	4,517.4	1,843.6	21,685.3	2,989.9	30,303.3	5,086.4

Btu Content (million Btu/short ton	0.64-1.67 Surface	1.68-2.50 Deep	1.68-2.50 Surface	> 2.50 Deep	> 2.50 Surface	TOTAL Deep	TOTAL Surface
Indiana							
≥ 26	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23-25.99	22.0	521.8	163.0	874.2	176.9	1,879.4	415.5
20-22.99	109.7	614.8	.0	1,136.7	199.3	2,400.5	386.5
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	.0	.0
TOTAL	131.7	1,136.6	163.0	2,010.9	376.2	4,279.9	802.1

Btu Content (million Btu/short ton	0.64-1.67 Surface	1.68-2.50 Deep	1.68-2.50 Surface	> 2.50 Deep	> 2.50 Surface	TOTAL Deep	TOTAL Surface
Iowa							
≥ 26	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23-25.99	.0	.0	.0	.0	.0	.0	.0
20-22.99	.0	101.1	312.6	834.5	.0	935.7	312.6
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	.0	.0
TOTAL	.0	101.1	312.6	834.5	.0	935.7	312.6

Btu Content (million Btu/short ton	0.64-1.67 Surface	1.68-2.50 Deep	1.68-2.50 Surface	> 2.50 Deep	> 2.50 Surface	TOTAL Deep	TOTAL Surface
Kansas							
≥ 26	0.0	0.0	0.0	0.0	46.9	0.0	46.9
23-25.99	.0	.0	168.8	.0	104.0	.0	272.7
20-22.99	.0	.0	52.0	.0	296.6	.0	348.6
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	.0	.0
TOTAL	.0	.0	220.8	.0	447.5	.0	668.3

Btu Content (million Btu/short ton	0.64-1.67 Surface	1.68-2.50 Deep	1.68-2.50 Surface	> 2.50 Deep	> 2.50 Surface	TOTAL Deep	TOTAL Surface
Kentucky, Eastern							
≥ 26	84.6	145.3	33.9	39.1	6.6	2,844.4	580.8
23-25.99	131.0	38.9	20.7	56.1	21.6	1,305.5	495.6
20-22.99	59.3	.0	.0	.0	.0	140.1	87.4
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	.0	.0
TOTAL	274.9	184.1	54.6	95.2	28.0	[illegible]	1,163.8

See footnotes at end of table.

Table A3. Estimates of 1987 Recoverable Reserves by Coal Type Mining Method, and State (Continued)
(Million Short Tons)

Btu Content (million Btu/short ton)	Sulfur Content (lbs sulfur/million Btu)						
	≦ 0.40		0.41-0.60		0.61-0.83		0.84-1.67
	Deep	Surface	Deep	Surface	Deep	Surface	Deep
	South Dakota						
≧ 26	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23-25.99	.0	.0	.0	.0	.0	.0	.0
20-22.99	.0	.0	.0	.0	.0	.0	.0
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	103.6	.0
TOTAL	.0	.0	.0	.0	.0	103.6	.0
	Tennessee						
≧ 26	0.0	0.0	72.4	40.9	41.0	24.7	35.0
23-25.99	.0	.0	.0	.0	.0	.0	105.8
20-22.99	.0	.0	.0	.0	.0	.0	.0
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	.0	.0
TOTAL	.0	.0	72.4	40.9	41.0	24.7	140.9
	Texas						
≧ 26	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23-25.99	.0	.0	.0	.0	.0	.0	.0
20-22.99	.0	.0	.0	.0	.0	.0	.0
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	646.5	.0
TOTAL	.0	.0	.0	.0	.0	646.5	.0
	Utah						
≧ 26	78.5	1.1	105.1	0.7	0.0	0.0	0.0
23-25.99	353.2	7.3	199.5	4.0	86.7	1.5	.0
20-22.99	.0	.0	448.7	28.1	537.0	17.7	909.1
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	.0	.0
TOTAL	431.7	8.3	753.3	32.8	623.7	19.2	909.1
	Virginia						
≧ 26	137.3	45.7	455.9	210.0	210.4	100.9	107.9
23-25.99	35.0	2.4	74.7	9.4	89.7	78.6	.0
20-22.99	.0	.0	.0	.0	.0	.0	.0
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	.0	.0
TOTAL	172.4	48.1	530.6	219.5	300.1	179.5	107.9

See footnotes at end of table.

Table A3. Estimates of 1987 Recoverable Reserves by Coal Type Mining Method, and State (Continued)

(Million Short Tons)

Btu Content (million Btu/short ton)	Sulfur Content (lbs sulfur/million Btu) 0.84-1.67	1.68-2.50		> 2.50		TOTAL	
	Surface	Deep	Surface	Deep	Surface	Deep	Surface
South Dakota							
≧ 26	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23-25.99	.0	.0	.0	.0	.0	.0	.0
20-22.99	.0	.0	.0	.0	.0	.0	.0
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.8	.0	172.4	.0	.0	.0	278.7
TOTAL	.8	.0	172.4	.0	.0	.0	276.7
Tennessee							
≧ 26	20.5	63.1	42.2	0.0	0.0	211.6	128.2
23-25.99	77.6	.0	.0	.0	.0	105.8	77.6
20-22.99	.0	.0	.0	.0	.0	.0	.0
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	.0	.0
TOTAL	98.1	63.1	42.2	.0	.0	317.4	205.8
Texas							
≧ 26	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23-25.99	.0	.0	.0	.0	.0	.0	.0
20-22.99	.0	.0	.0	.0	.0	.0	.0
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	6,221.0	.0	3,733.7	.0	412.1	.0	11,013.4
TOTAL	6,221.0	.0	3,733.7	.0	412.1	.0	11,013.4
Utah							
≧ 26	0.0	0.0	0.0	0.0	0.0	193.6	1.8
23-25.99	.0	.0	.0	.0	.0	639.4	12.7
20-22.99	86.5	221.1	35.6	311.6	34.5	2,427.6	202.[illegible]
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	.0	.0
TOTAL	86.5	221.1	35.6	311.5	34.5	3,250.6	217.0
Virginia[1]							
≧ 26	50.7	0.0	0.0	0.0	0.0	911.5	[illegible]
23-25.99	.0	.0	.0	.0	.0	199.4	90.4
20-22.99	.0	.0	.0	.0	.0	.0	.0
15-19.99	.0	.0	.0	.0	.0	.0	.0
< 15	.0	.0	.0	.0	.0	.0	.0
TOTAL	50.7	.0	.0	.0	.0	1,110.9	497.5

See footnotes at end of table.

16:30: 1 8/20/91

INTEGRATED AIR POLLUTION CONTROL SYSTEM COSTING PROGRAM------------

UC STANTON UNIT 2
989 EPRI ECONOMIC PREMISES OUC ECON EVAL CRITERIA

USER INPUT SUMMARY

BOILER SIZE: 440. MW WALL FIRED, DRY BOTTOM
CAPACITY FACTOR:100.0 % 310. DEG.F
CONSTRUCTION STATUS OF CONTROL SYSTEM: NEW

COAL CLEANING LEVEL: RUN-OF-MINE SORTED AND SCREENED.
COAL CHARACTERISTICS AT THIS CLEANING LEVEL:

HHV (BTU/#):	12400.0
SULFUR CONTENT (%):	2.50
ASH CONTENT (%):	12.00
COST ($/TON):	.00
CHLORINE CONTENT (%):	.11
MOISTURE CONTENT (%):	7.50
VOLATILE MATTER CONTENT (%):	13.50
FIXED CARBON CONTENT (%):	67.00

ASH CHARACTERISTICS AT THIS CLEANING LEVEL:

NA2O CONTENT (%):	.60
ALKALINITY (%):	6.50
FE2O3 CONTENT (%):	20.00

CONTROL SYSTEM CONFIGURATION:

1 - LOW NOX COMBUSTION

ECONOMIC PREMISES (TVA/EPRI): EPRI

INTEGRATED AIR POLLUTION CONTROL SYSTEM COSTING PROGRAM

USER INPUT SUMMARY (CONTINUED)

PARAMETER FILE USED: C:\TEMP\STANTON.EPR

BATCH DATA FILE USED: C:\TEMP\STANTON.EPR

THE FOLLOWING CHANGES WERE MADE TO THE PARAMETER FILE FOR THIS RUN:

NEW VALUE	DESCRIPTION
62.00	Percent NOx Reduction; Determined by LNC Method if 0. (LNB/OFA)

LOW NOX BURNERS

LOW-NOX, STAGED COMBUSTION BURNERS ARE PROVIDED FOR PULVERIZED-COAL, WALL-FIRED, DRY BOTTOM BOILERS. FOR EXISTING BOILERS, ALL RETROFIT CONSIDERATIONS ARE ACCOUNTED FOR IN THE COST ESTIMATES.

BOILER/SYSTEM PERFORMANCE

UNIT THERMAL EFFICIENCY..................	87.5%
BOILER NET HEAT RATE.....................	9881.2 BTU/KWH
HEAT INPUT...............................	4347.7 MMBTU/H
COAL USE.................................	175.3 TONS/H
ANNUAL COAL CONSUMPTION..................	1.5357E+06 TONS/YR
IAPCS ENERGY PENALTY.....................	.0 BTU/KWH
SYSTEM NET GENERATION....................	440.0 MW

SYSTEM MATERIAL BALANCE
(100% CAPACITY CONDITION)

	UNCONT-ROLLED	AIR HEATER EXIT
FLUE GAS, 1000 LB/H :	5088.	5086.
FLUE GAS, 1000 ACFM :	1566.	1566.
TEMPERATURE,DEG.F :	310.	310.
MOISTURE, LB/H :	228014.	228014.
ALKALINITY, LB/H :	2325.	2325.
PARTICULATE, LB/H :	35764.	35764.
SO2, LB/H :	17093.	17093.
NO2, LB/H :	3682.	1399.
CO2, LB/H :	653385.	653385.

EMISSION SUMMARY

POLLUTANT	LB/HR	PERCENT REDUCTION	LB/MMBTU	PPM(V)
PARTICULATE	35764.	.0	8.226	
SO2	17093.	.0	3.931	1511.
NO2	1399.	62.0	.322	264.
CO2	653385.	.0	150.282	

INSTALLED CAPITAL COSTS JANUARY, 1997

LOW NOX COMBUSTION------------------------$ 2761800

TOTAL DIRECT CAPITAL COSTS>>>>>>>>>>>>>>>>>>>>>>$ 2761800

INDIRECT COSTS-----------------------------$ 795600

GENERAL FACILITIES (8.0%)...$ 220900
ENGINEERING (8.0%)..........$ 220900
PROJECT CONTINGENCY (.0%)..$ 0
PROCESS CONTINGENCY (10.0%)..$ 276200

TOTAL PLANT COST (TPC)..........$ 3479800
TOTAL PLANT INVESTMENT (3.0yr).$ 3556100

2.2%

Should be 7yrs
to get Approx 7%

ROYALTY ALLOWANCE.........$ 0
PREPRODUCTION COSTS.......$ 77600
INVENTORY CAPITAL.........$ 0
INITIAL CATALYST..........$ 0
LAND......................$ 0

TOTAL CAPITAL REQUIREMENT>>>>>>>>>>>>>>>>>>>>*$ 3633700*

TOTAL SYSTEM COST>>>>>>>>>>>>>>>>>>>>>>>>>>>>$ 8.26/KW

ANNUAL OPERATING COSTS JANUARY, 1997

ITEM	QUANTITY		RATE		ANNUAL COST
PERATING AND SUPERVISORY LABOR					
AINTENANCE LABOR	.696E+05	$	.40	$	27800
PERCENT OF TPC = 2.00					
AINTENANCE MATERIAL	.696E+05	$	.60	$	41800
DMIN. & SUPPORT LABOR	.278E+05	$	.30	$	8300
ONSUMABLES					
IXED COMPONENT	.440E+06 KWY		.18 $/KWY	$	77900
OTAL FIRST YEAR O&M EXPENSE				$	77900
EVELIZED CARRYING CHARGES	3633700 $		7.90 %	$	287100
USBAR COST OF POWER				$	365000
EVELIZED FIRST YEAR O&M	77900 $		1.69	$	131400
EVELIZED CARRYING CHARGES	3633700 $		7.90 %	$	287100
EVELIZED ANNUAL REQUIREMENTS				$	418500

IRST YEAR BUSBAR COST OF POWER	.09 MILLS/KWH
EVELIZED ANNUAL BUSBAR COST OF POWER	.11 MILLS/KWH

OST/TON OF PARTICULATE REMOVED	.00 $/TON
COST/TON OF SO2 REMOVED	.00 $/TON
COST/TON OF NOX REMOVED	41.86 $/TON

INTEGRATED AIR POLLUTION CONTROL SYSTEM COSTING PROGRAM-------------

UC STANTON UNIT 2 $500 catalyst cost
989 EPRI ECONOMIC PREMISES OUC ECON. EVAL. CRITERIA

USER INPUT SUMMARY

BOILER SIZE: 440. MW WALL FIRED, DRY BOTTOM
CAPACITY FACTOR:100.0 % 310. DEG.F
CONSTRUCTION STATUS OF CONTROL SYSTEM: NEW

COAL CLEANING LEVEL: RUN-OF-MINE SORTED AND SCREENED
COAL CHARACTERISTICS AT THIS CLEANING LEVEL:

HHV (BTU/#):	12400.0
SULFUR CONTENT (%):	2.50
ASH CONTENT (%):	12.00
COST ($/TON):	.00
CHLORINE CONTENT (%):	.11
MOISTURE CONTENT (%):	7.50
VOLATILE MATTER CONTENT (%):	13.50
FIXED CARBON CONTENT (%):	67.00

ASH CHARACTERISTICS AT THIS CLEANING LEVEL:

NA2O CONTENT (%):	.60
ALKALINITY (%):	6.50
FE2O3 CONTENT (%):	20.00

CONTROL SYSTEM CONFIGURATION:

1 - LOW NOX COMBUSTION

2 - SELECTIVE CATALYTIC REDUCTION

ECONOMIC PREMISES (TVA/EPRI): EPRI

INTEGRATED AIR POLLUTION CONTROL SYSTEM COSTING PROGRAM

USER INPUT SUMMARY (CONTINUED)

PARAMETER FILE USED: C:\TEMP\STANTON.EPR

BATCH DATA FILE USED: C:\TEMP\STANTON.EPR

THE FOLLOWING CHANGES WERE MADE TO THE PARAMETER FILE FOR THIS RUN:

NEW VALUE	DESCRIPTION
412.5	SCR Catalyst Unit Cost, $/ft3 (1982 $)

LOW NOX BURNERS

LOW-NOX, STAGED COMBUSTION BURNERS ARE PROVIDED FOR PULVERIZED-COAL, WALL-FIRED, DRY BOTTOM BOILERS. FOR EXISTING BOILERS, ALL RETROFIT CONSIDERATIONS ARE ACCOUNTED FOR IN THE COST ESTIMATES. THE SCR SYSTEM CONSISTS OF VERTICAL REACTOR VESSELS PLACED BETWEEN THE ECONOMIZER AND AIR HEATER OR DOWNSTREAM A THE PARTICULATE CONTROL. A SCR SYSTEM IS EQUIPPED WITH HOPPER BOTTOMS TO REMOVE ASH THAT SETTLES OUT. AN ECONOMIZER BYPASS (COLD-SIDE) OR A FLUE GAS TO FLUE GAS HEAT EXCHANGER (HOT-SIDE) SUPPLIES HOT GAS TO THE REACTORS TO MAINTAIN SUFFICIENT TEMPERATURE FOR THE REACTION. AIR HEATER MODIFICATIONS TO MINIMIZE THE EFFECTS OF AMMONIA SALTS ON THE AIR HEATER ELEMENTS ARE PROVIDED. SOLID WASTE (SPENT CATALYST) IS DISPOSED OF IN A CONVENTIONAL MANNER SIMILAR TO OTHER COAL COMBUSTION PRODUCTS. THIS SCR SYSTEM IS DESIGNED FOR A NOX REMOVAL EFFICIENCY OF 47.00 % AT A NH3:NOx STOICHIOMETRIC RATIO OF .49 YIELDING A NH3 SLIP RATE OF 1.95 %.

FANS

THE TOTAL SYSTEM PRESSURE DROP IS 5.0 IN. H20. THE SYSTEM REQUIRES 3 FAN(S) RATED AT 627. HP EACH.

BOILER/SYSTEM PERFORMANCE

UNIT THERMAL EFFICIENCY..................	87.5%
BOILER NET HEAT RATE......................	9881.2 BTU/KWH
HEAT INPUT................................	4347.7 MMBTU/H
COAL USE..................................	175.3 TONS/H
ANNUAL COAL CONSUMPTION..................	1.5357E+06 TONS/YR
IAPCS ENERGY PENALTY.....................	7.5 BTU/KWH
SYSTEM NET GENERATION....................	439.7 MW

SYSTEM MATERIAL BALANCE
(100% CAPACITY CONDITION)

	UNCONT-ROLLED	AIR HEATER EXIT
FLUE GAS, 1000 LB/H :	5088.	5086.
FLUE GAS, 1000 ACFM :	1566.	1566.
TEMPERATURE,DEG.F :	310.	310.
MOISTURE, LB/H :	228014.	241651.
ALKALINITY, LB/H :	2325.	2325.
PARTICULATE, LB/H :	35764.	35802.
SO2, LB/H :	17093.	17074.
NO2, LB/H :	3682.	741.
CO2, LB/H :	653385.	653385.

EMISSION SUMMARY

POLLUTANT	LB/HR	PERCENT REDUCTION	LB/MMBTU	PPM(V)
PARTICULATE	35802.	-.1	8.235	
SO2	17074.	.1	3.927	1509.
NO2	741.	79.9	.171	140.
CO2	653385.	.0	150.282	

INSTALLED CAPITAL COSTS JANUARY, 1997

```
LOW NOX COMBUSTION------------------------$  2761800

SELECTIVE CATALYTIC REDUCTION-------------$ 20434000

   NH3 STORAGE & INJECTION---$   1018000

   REACTOR-------------------$  11191200

   FLUE GAS HANDLING---------$   6647800

   AIR HEATER MOD/NEW--------$   1577100

-------------------------------------------

FANS--------------------------------------$  5551300

TOTAL DIRECT CAPITAL COSTS>>>>>>>>>>>>>>>>>>>>>$ 28747100

INDIRECT COSTS----------------------------$ 19368700

     GENERAL FACILITIES ( 8.0%)...$   2299800
     ENGINEERING ( 8.0%)..........$   2299800
     PROJECT CONTINGENCY (  .0%)..$         0
     PROCESS CONTINGENCY (10.0%)..$   2874700

TOTAL PLANT COST (TPC)..........$  36221400
TOTAL PLANT INVESTMENT ( 7.0yr).$  38674300

     ROYALTY ALLOWANCE.........$     102200
     PREPRODUCTION COSTS.......$     987200
     INVENTORY CAPITAL.........$     134000
     INITIAL CATALYST..........$   10643400
     LAND......................$      27600

                                              *************
TOTAL CAPITAL REQUIREMENT>>>>>>>>>>>>>>>>>>>>*$  50568700*
                                              *************

TOTAL SYSTEM COST>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>$  114.93/KW
```

ANNUAL OPERATING COSTS JANUARY, 1997

ITEM	QUANTITY		RATE			ANNUAL COST
)PERATING AND SUPERVISORY LABOR						
;YSTEM	.370E+04	MANHR	28.08	$/HR	$	104000
\NALYSIS	.219E+04	MANHR	28.08	$/HR	$	61600
IAINTENANCE LABOR	.138E+07	$	.40		$	551700
PERCENT OF TPC = 3.81						
IAINTENANCE MATERIAL	.138E+07	$	.60		$	827600
\DMIN. & SUPPORT LABOR	.717E+06	$	.30		$	215200
:ONSUMABLES						
3OLIDS DISPOSAL, DRY	.952E+02	TONS	12.96	$/TON	$	1200
VATER	.360E+04	K GAL	.94	$/K GAL	$	3400
;TEAM	.708E+04	K LB	5.89	$/K LB	$	41700
:LECTRICITY	.847E+07	KWH	61.76	mil/KWH	$	522900
:ATALYST	.397E+04	FT3	647.88	$/FT3	$	2569400
\MMONIA	.111E+04	TONS	211.25	$/TON	$	234700
'IXED COMPONENT	.440E+06	KWY	4.00	$/KWY	$	1760100
/ARIABLE COMPONENT	.385E+10	KWH	.88	mil/KWH	$	3373300
TOTAL FIRST YEAR O&M EXPENSE					$	5133400
,EVELIZED CARRYING CHARGES	50568700	$	7.90	%	$	3994900
3USBAR COST OF POWER					$	9128300
,EVELIZED FIRST YEAR O&M	5133400	$	1.69		$	8660000
,EVELIZED CARRYING CHARGES	50568700	$	7.90	%	$	3994900
,EVELIZED ANNUAL REQUIREMENTS					$	12654900

'IRST YEAR BUSBAR COST OF POWER	2.37 MILLS/KWH
,EVELIZED ANNUAL BUSBAR COST OF POWER	3.28 MILLS/KWH

:OST/TON OF PARTICULATE REMOVED	-75282.15	$/TON
COST/TON OF SO2 REMOVED	155371.70	$/TON
COST/TON OF NOX REMOVED	982.71	$/TON

INTEGRATED AIR POLLUTION CONTROL SYSTEM COSTING PROGRAM-------------

UC STANTON UNIT 2 $500 catalyst cost,100% CF, 70% SCR
989 EPRI ECONOMIC PREMISES OUC ECON. EVAL. CRITERIA

USER INPUT SUMMARY

BOILER SIZE: 440. MW WALL FIRED, DRY BOTTOM
CAPACITY FACTOR:100.0 % 310. DEG.F
CONSTRUCTION STATUS OF CONTROL SYSTEM: NEW

COAL CLEANING LEVEL: RUN-OF-MINE SORTED AND SCREENED
COAL CHARACTERISTICS AT THIS CLEANING LEVEL:

HHV (BTU/#):	12400.0
SULFUR CONTENT (%):	2.50
ASH CONTENT (%):	12.00
COST ($/TON):	.00
CHLORINE CONTENT (%):	.11
MOISTURE CONTENT (%):	7.50
VOLATILE MATTER CONTENT (%):	13.50
FIXED CARBON CONTENT (%):	67.00

ASH CHARACTERISTICS AT THIS CLEANING LEVEL:

NA2O CONTENT (%):	.60
ALKALINITY (%):	6.50
FE2O3 CONTENT (%):	20.00

CONTROL SYSTEM CONFIGURATION:

1 - LOW NOX COMBUSTION

2 - SELECTIVE CATALYTIC REDUCTION

ECONOMIC PREMISES (TVA/EPRI): EPRI

INTEGRATED AIR POLLUTION CONTROL SYSTEM COSTING PROGRAM

USER INPUT SUMMARY (CONTINUED)

PARAMETER FILE USED: C:\TEMP\STANTON.EPR

BATCH DATA FILE USED: C:\TEMP\STANTON.EPR

THE FOLLOWING CHANGES WERE MADE TO THE PARAMETER FILE FOR THIS RUN:

NEW VALUE	DESCRIPTION
70.00	NOx Efficiency, % (scr) - calculated If Zero (SCR)
412.5	SCR Catalyst Unit Cost, $/ft3 (1982 $)

LOW NOX BURNERS

LOW-NOX, STAGED COMBUSTION BURNERS ARE PROVIDED FOR PULVERIZED-COAL, WALL-FIRED, DRY BOTTOM BOILERS. FOR EXISTING BOILERS, ALL RETROFIT CONSIDERATIONS ARE ACCOUNTED FOR IN THE COST ESTIMATES. THE SCR SYSTEM CONSISTS OF VERTICAL REACTOR VESSELS PLACED BETWEEN THE ECONOMIZER AND AIR HEATER OR DOWNSTREAM A THE PARTICULATE CONTROL. A SCR SYSTEM IS EQUIPPED WITH HOPPER BOTTOMS TO REMOVE ASH THAT SETTLES OUT. AN ECONOMIZER BYPASS (COLD-SIDE) OR A FLUE GAS TO FLUE GAS HEAT EXCHANGER (HOT-SIDE) SUPPLIES HOT GAS TO THE REACTORS TO MAINTAIN SUFFICIENT TEMPERATURE FOR THE REACTION. AIR HEATER MODIFICATIONS TO MINIMIZE THE EFFECTS OF AMMONIA SALTS ON THE AIR HEATER ELEMENTS ARE PROVIDED. SOLID WASTE (SPENT CATALYST) IS DISPOSED OF IN A CONVENTIONAL MANNER SIMILAR TO OTHER COAL COMBUSTION PRODUCTS. THIS SCR SYSTEM IS DESIGNED FOR A NOX REMOVAL EFFICIENCY OF 70.00 % AT A NH3:NOx STOICHIOMETRIC RATIO OF .72 YIELDING A NH3 SLIP RATE OF 1.95 %.

FANS

THE TOTAL SYSTEM PRESSURE DROP IS 5.0 IN. H20.
THE SYSTEM REQUIRES 3 FAN(S) RATED AT 627. HP EACH.

BOILER/SYSTEM PERFORMANCE

UNIT THERMAL EFFICIENCY..................	87.5%
BOILER NET HEAT RATE.....................	9881.2 BTU/KWH
HEAT INPUT...............................	4347.7 MMBTU/H
COAL USE.................................	175.3 TONS/H
ANNUAL COAL CONSUMPTION..................	1.5357E+06 TONS/YR
IAPCS ENERGY PENALTY.....................	7.5 BTU/KWH
SYSTEM NET GENERATION....................	439.7 MW

SYSTEM MATERIAL BALANCE
(100% CAPACITY CONDITION)

	UNCONT-ROLLED	AIR HEATER EXIT
FLUE GAS, 1000 LB/H :	5088.	5086.
FLUE GAS, 1000 ACFM :	1566.	1566.
TEMPERATURE,DEG.F :	310.	310.
MOISTURE, LB/H :	228014.	239510.
ALKALINITY, LB/H :	2325.	2325.
PARTICULATE, LB/H :	35764.	35820.
SO2, LB/H :	17093.	17066.
NO2, LB/H :	3682.	420.
CO2, LB/H :	653385.	653385.

EMISSION SUMMARY

POLLUTANT	LB/HR	PERCENT REDUCTION	LB/MMBTU	PPM(V)
PARTICULATE	35820.	-.2	8.239	
SO2	17066.	.2	3.925	1508.
NO2	420.	88.6	.097	79.
CO2	653385.	.0	150.282	

BEST AVAILABLE COPY

INSTALLED CAPITAL COSTS JANUARY, 1997

LOW NOX COMBUSTION-----------------------$		2761800
SELECTIVE CATALYTIC REDUCTION-------------$		20717800
NH3 STORAGE & INJECTION---$	1301800	
REACTOR-------------------$	11191200	
FLUE GAS HANDLING---------$	6647800	
AIR HEATER MOD/NEW--------$	1577100	
FANS--------------------------------------$		5551300
TOTAL DIRECT CAPITAL COSTS>>>>>>>>>>>>>>>>>>>>>$		29030900
INDIRECT COSTS----------------------------$		19485200
GENERAL FACILITIES (8.0%)...$	2322500	
ENGINEERING (8.0%)..........$	2322500	
PROJECT CONTINGENCY (.0%)..$	0	
PROCESS CONTINGENCY (10.0%)..$	2903100	
TOTAL PLANT COST (TPC)..........$	36579000	
TOTAL PLANT INVESTMENT (7.0yr).$	39056100	
ROYALTY ALLOWANCE.........$	103600	
PREPRODUCTION COSTS.......$	1006900	
INVENTORY CAPITAL.........$	155600	
INITIAL CATALYST..........$	10643400	
LAND......................$	27600	
TOTAL CAPITAL REQUIREMENT>>>>>>>>>>>>>>>>>>>>*$		50993200*
TOTAL SYSTEM COST>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>$		115.89/KW

ANNUAL OPERATING COSTS JANUARY, 1997

ITEM	QUANTITY		RATE			ANNUAL COST
)PERATING AND SUPERVISORY LABOR						
;YSTEM	.370E+04	MANHR	28.08	$/HR	$	104000
ıNALYSIS	.219E+04	MANHR	28.08	$/HR	$	61600
IAINTENANCE LABOR	.139E+07	$	.40		$	557400
PERCENT OF TPC = 3.81						
IAINTENANCE MATERIAL	.139E+07	$	.60		$	836100
ıDMIN. & SUPPORT LABOR	.723E+06	$	.30		$	216900
:ONSUMABLES						
;OLIDS DISPOSAL, DRY	.952E+02	TONS	12.96	$/TON	$	1200
IATER	.360E+04	K GAL	.94	$/K GAL	$	3400
;TEAM	.104E+05	K LB	5.89	$/K LB	$	61300
:LECTRICITY	.847E+07	KWH	61.76	mil/KWH	$	522900
:ATALYST	.397E+04	FT3	647.88	$/FT3	$	2569400
ıMMONIA	.163E+04	TONS	211.25	$/TON	$	344800
'IXED COMPONENT	.440E+06	KWY	4.04	$/KWY	$	1776000
'ARIABLE COMPONENT	.385E+10	KWH	.91	mil/KWH	$	3503000
'OTAL FIRST YEAR O&M EXPENSE					$	5279000
,EVELIZED CARRYING CHARGES	50993200	$	7.90	%	$	4028500
;USBAR COST OF POWER					$	9307500
,EVELIZED FIRST YEAR O&M	5279000	$	1.69		$	8905700
,EVELIZED CARRYING CHARGES	50993200	$	7.90	%	$	4028500
,EVELIZED ANNUAL REQUIREMENTS					$	12934200

'IRST YEAR BUSBAR COST OF POWER	2.41 MILLS/KWH
,EVELIZED ANNUAL BUSBAR COST OF POWER	3.36 MILLS/KWH

:OST/TON OF PARTICULATE REMOVED	-52363.48	$/TON
COST/TON OF SO2 REMOVED	108065.40	$/TON
COST/TON OF NOX REMOVED	905.32	$/TON

PM
8-26-91
Atlanta, Ga.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

4APT-AEB

AUG 23 1991

Ms. Penny Ensley
Orlando City Hall
400 South Orange Avenue
Orlando, FL 32801

Dear Ms. Ensley:

This letter is to confirm our plans for conducting a public hearing concerning a proposed modification of a Prevention of Significant Deterioration (PSD) permit for the Orlando Utilities Commission (OUC). During a telephone discussion with Mr. Scott Davis of my staff, the following dates and times were reserved by the U.S. Environmental Protection Agency, Region IV, for the hearing:

LOCATION: Orlando City Council Chambers

October 29, 1991	6:00 - 11:00 PM
October 30, 1991	9:00 AM - NOON

A public notice concerning the proposed permit modification will be published in the Orlando Sentinel on September 15, including these dates and times. In the event a public hearing is not requested, we will notify you by telephone and in writing to cancel our reservation. We would appreciate a written reply from your office acknowledging receipt of this letter.

Thank you for your assistance in this matter. If you have any questions, please contact Scott Davis at (404) 347-5014.

Sincerely yours,

Jewell A. Harper

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

cc: Clair Fancy, Florida DER
Barry Andrews
Preston Lewis
Buck Oven
Max Linn
8-28-91 PM

RECEIVED

AUG 28 1991

Division of Air
Resources Management

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV
345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

AUG 22 1991

4APT-AEB

RECEIVED
AUG 26 1991
Division of Air
Resources Management

Mr. Charles Collins
Florida Department of Environmental Regulation
Central Florida District Office
3319 Maguire Boulevard
Suite 232
Orlando, FL 32803-3767

Dear Mr. Collins:

This letter is to confirm our plans for sending your office materials relevant to an upcoming public notice and comment period with respect to a Prevention of Significant Deterioration (PSD) permit modification for the Orlando Utilities Commission (OUC).

During a telephone discussion with Mr. Scott Davis of my staff, you indicated it would be workable for us to send to your office a copy of the administrative record of the modification request to be available for review by the public for the 30 day public comment period (September 15 through October 15). The administrative record will include the PSD permit, the Best Available Control Technology (BACT) preliminary determination and all materials submitted by OUC. We will indicate in the public notice that record reviewing can be conducted during normal operating hours (8:00 AM to 5:00 PM) and that copies can be made only by appointment at your offices, as requested by you. The public notice will be published in the Orlando Sentinel on September 15; we will send all the pertinent OUC material prior to that date.

Thank you for assisting us in this matter. If you have any questions, please contact Scott Davis at (404) 347-5014.

Sincerely yours,

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

cc: Clair Fancy, FL DER
Barry Andrews } 8-27-91 RAR
Preston Lewis }
Buck Oven } 8-28-91 RAR
Max Linn }

Printed on Recycled Paper

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

4APT-AEB

AUG 16 1991

RECEIVED
AUG 22 1991
Division of Air
Resources Management

Mr. Clair H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental
Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Orlando Utilities Commission, Stanton Energy Center (PSD-FL-084)

Dear Mr. Fancy:

As you know, EPA is in the process of preparing a preliminary determination and draft permit modification for the previously issued Prevention of Significant Deterioration (PSD) permit for the Stanton Energy Center of the Orlando Utilities Commission. The purpose of the modification is to extend the commence construction date for Unit #2, which was previously permitted as part of a phased construction permit (PSD-FL-084). The original permit was issued by EPA on June 10, 1982. At the request of OUC, the federally issued permit is being modified rather than allowing the permit to expire and permitting Unit #2 under the Florida PSD regulations. It is therefore necessary for EPA to process the modification under federal regulations.

We are aware that Florida is reviewing the modification under the Florida Site Certification Act as a separate action. As stated in our letter to Jim Crall of OUC on January 28, 1991, we view the federal PSD process to be separate from the Site Certification process. It is our understanding, however, that FDER wishes to include EPA's preliminary determination as part of the Site Certification Hearing Report. To that end we are presenting you with a tentative schedule for issuing a prelimary determination.

August 23, 1991 - Internal Draft of Preliminary Determination

August 26, 1991 - Briefing of EPA senior management

September 15, 1991 - Publishing of Public Notice

October 29-30, 1991 - Public Hearing, if requested

As discussed between you and Mr. Brian Beals of my staff on August 16, 1991, we will provide a copy of our preliminary determination for internal review only by FDER prior to the public notice date. If you have any further questions or suggestions on this issue, please do not hesitate to contact Mr. Brian Beals of my staff at (404) 347-5014.

Sincerely yours,

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

cc: P. Lewis
B. Owen
C. Collins, C Dist.
CHF/13A

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

4APT-AEB

AUG 16 1991

Mr. Clair H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Orlando Utilities Commission, Stanton Energy Center (PSD-FL-084)

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Sincerely yours,

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

ORLANDO UTILITIES COMMISSION
500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 32802 • 407/423-9100

August 14, 1991

Carol M. Browner, Secretary
Department of Environmental Regulation
Twin Towers Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RECEIVED
AUG 16 1991
Division of Air Resources Management

Dear Secretary Browner:

RE: Orlando Utilities Commission
Supplemental Site Certification Application (SSCA)
for Stanton Energy Center, Unit 2
DOAH Case No. 91-1813 EPP

The Orlando Utilities Commission (OUC) and 13 other municipalities throughout the state are joint applicants for approval of the Curtis H. Stanton Energy Center, Unit 2, SSCA filed simultaneously with the Florida Department of Environmental Regulation and the Florida Public Service Commission on March 15, 1991. OUC, et al., are the first Florida applicants to utilize the supplemental site certification process authorized under Florida Statutes Section 403.517.

The final certification hearing for Stanton Unit 2 is scheduled to begin on September 23, 1991. Richard Donelan of the DER legal staff advised Larry Keesey of the law firm representing OUC, Young, van Assenderp, Varnadoe & Benton, on August 13, 1991, that DER would request that the final hearing be rescheduled. OUC must oppose any such action by DER, for reasons that we would like to discuss in detail at a meeting with you. A preliminary statement of these reasons is provided below for your consideration.

The supplemental application process provides an expedited review for certifying additional electrical generating units on sites such as the Stanton Energy Center which were previously certified for a subsequent facility. Stanton Unit 1, a 440 megawatt coal-fired electrical generating plant, was certified by the Governor and Cabinet in 1982 to be located on a 3,280 acre site 14 miles east-southeast of Orlando with an ultimate generating capacity of approximately 2,000 megawatts. Stanton Unit 2 will be the second coal-fired unit located on the site, and except for the addition of more stringent environmental controls, it will replicate Unit 1, which has been in operation since 1987. Unit 1 has had an outstanding environmental record and is internationally recognized as one of the best-run coal plants in the country.

Section 403.517(1)(a)6., Florida Statutes, requires that a supplemental application be processed in time for final disposition by the Siting Board within 215 days of filing. OUC did not oppose the DER's initial schedule filed with the Hearing Officer which has already extended this statutory time period by approximately two months. The Hearing Officer, therefore, scheduled a final hearing to commence on September 23, 1991, which means the Siting Board will not hear this matter until December 1991.

As the first applicants to utilize a supplemental site certification application, we have attempted to make this process work. OUC provided all information requested to every agency involved in this matter. All agencies, except DER, filed their reports on August 6, 1991. DER's report is not due until August 23, 1991. Up to this point, we believe we have had the cooperation of all agencies, including DER, in trying to implement this process for the first time in the manner and spirit prescribed by the Legislature.

In addition to providing the DER and other agencies with all requested information, OUC recently spent $13,000 to advertise the final certification hearing in the <u>Orlando Sentinel</u> and two other newspapers. No agency report or staff person, including DER's, have told us that our application is not sufficient. Therefore, we were very surprised and disturbed to hear from Richard Donelan on August 13, 1991, only 40 days before the hearing, that the Department of Environmental Regulation plans to formally request the Hearing Officer to continue the hearing to some unspecified date in the future.

During the phone conversation with Mr. Donelan, he stated that he has been instructed to seek a continuance of the hearing for several reasons. In all candor, the reasons do not justify this extreme action. Mr. Donelan indicated that a continuance was needed because DER staff have not made an assessment of the Best Available Control Technology (BACT) that should be applied to limit air emissions resulting from the operation of Stanton Unit 2. Mr. Donelan stated that the EPA Regional IV Office in Atlanta had been "chosen" by OUC to issue a PSD Permit for Unit 2, rather than DER. He said that since the EPA's BACT decision would not be available until August 30, 1991, which is seven days after the DER final report is due to be issued on August 23, 1991, it would not be appropriate to proceed with the September 23, 1991, hearing date. Mr. Donelan did not state in any context that DER found our application to be insufficient, or required any more information to review.

OUC is opposed to the DER's requested rescheduling of the September 23, 1991, certification hearing date. OUC urges that before DER files such an extension request, OUC be given the opportunity to meet with you to explain its position. OUC does not understand why your agency appears to have adopted this course. We do not believe valid reasons for a continuation exist, either for any deficiency of the application or for any public policy reason, if there is an honest and unbiased consideration of our position.

We hope that you will immediately schedule a meeting at which we can explain why a continuance is not in the interest of either OUC or the people of the State of Florida. If you are traveling, we would be happy to go to any location where you happen to be to meet with you for an hour, over breakfast, lunch, dinner, or at any time you are willing to grant us the opportunity to discuss this issue. We simply request the opportunity of explaining to you our position and learning directly from you why DER apparently feels this action is necessary. We need to know that you fully understand and have a sound basis for an action that may have devastating consequences to OUC and the municipalities that have filed this supplemental site certification. In summary, some of the points we would like to make at our meeting involve the following aspects of our application:

1. The original Curtis H. Stanton Energy Center project consisted of Units 1 and 2, for which OUC obtained a phased prevention of significant deterioration (PSD) construction permit from EPA. The EPA's PSD permit for the project was structured to allow two units, with phased construction over an estimated 10 years. The PSD permit requires OUC to request EPA's reevaluation of BACT for any phased unit at least 18 months prior to commencement of construction. Therefore, the Atlanta Region IV will issue the BACT determination for Unit 2 as a result of the phased construction permit issued for Units 1 and 2 in 1982.

2. By letter to OUC's Jim Crall dated January 28, 1991, from Jewell Harper, Chief of the Air Enforcement Branch, the Region IV EPA office stated that the BACT determination and extension of the construction permit by the EPA is a separate and distinct process from Florida's supplemental site certification application process that OUC is also presently involved in. A copy of the letter was sent to Mr. C. H. Fancy, Chief of DER's Bureau of Air Regulation. Because this process is separate and legally distinct from the EPA review, there is no requirement for DER to await the decision of EPA before proceeding with the site certification hearing.

3. According to Mr. Donelan, the Atlanta EPA office has advised DER that the BACT determination will be available on August 30, 1991. Although this is seven days after the DER "final" report is due, it is in plenty of time for the report to be amended, if necessary, so the hearing officer is advised of the EPA's current position at the DOAH hearing commencing on September 23, 1991, in Orlando.

4. OUC anticipated the BACT issue and met with DER staff to discuss how the process would work. We discussed with your staff how these potential problems could be met so that Florida's DOAH hearing process could continue. We held meetings with Buck Oven and Barry Andrews in Tallahassee and Barry Andrews attended our last meeting in Atlanta with EPA. This matter was anticipated, addressed, and we thought resolved in good faith several weeks ago in that meeting.

5. Public Service Commissioner Michael Wilson, in his Recommended Order dated July 26, 1991, found that there was a need for the Stanton Energy Center, Unit 2. In a very strongly worded order, Commissioner Wilson found that the 440 megawatts (net) generating capacity of Unit 2 is needed, not only by Orlando Utilities Commission, but also by the municipalities that are joint applicants in this project, and by the State. Commissioner Wilson found that the proposed power plant will contribute to the State's electric system reliability and integrity. He also found that Stanton 2 will provide for fuel diversity for each of the utilities involved, further contributing to the electric system reliability and integrity. He also found that Stanton 2 is the most cost-effective alternative available to meet the Petitioners' 1997 need for firm capacity and energy. Commissioner Wilson concluded by stating that the record shows that Petitioners' need is

part of a larger statewide and peninsular Florida need for power in 1997.

6. Commissioner Wilson's Recommended Order found that delay would be expensive and threaten the reliability of the applicants' system for providing safe, economical electricity to their customers. Commissioner Wilson, at Finding of Fact #15, stated: "There will be adverse consequences to OUC, FMPA and KUA and their customers if Stanton 2 is not completed in the approximate time frame requested. Each utility will fall below its reliability criteria unless Stanton 2 is completed by 1997. In addition, due to Stanton 2 being a replication of Stanton 1, the $23 million in savings associated with Stanton 2 would be jeopardized, and the benefit of lower cost capacity and an opportunity for each system to diversify its fuel mix would be delayed. In this regard, it was established that for OUC alone, a one year delay in Stanton 2 would represent an additional cost of about $9 million on a cumulative present worth basis."

7. OUC has provided all relevant information requested by all agencies in a timely, responsive manner. No agency personnel, including DER's representatives that we have been dealing with, have stated that the information provided to date is insufficient for an evaluation. OUC has made every effort to maintain the September 23 hearing date, and that date has been noticed in the <u>Orlando Sentinel</u> and other papers (See copy attached).

In conclusion, we believe that we deserve further explanation and justification of DER's apparent position. This needs to be given to OUC and the municipalities involved in this important public project before the DER instructs its attorney to request a continuance of the September 23 hearing date. We are ready and willing to meet with you at any time and place throughout the State of Florida, or any available site of your choosing, where we can discuss this matter with you.

Sincerely,

Thomas B. Tart

Thomas Brogden Tart
General Counsel

cc: Mayor Bill Frederick
Richard Donelan, Esq.
C. H. Fancy, DER, Air
Barry Andrews, DER, Air
Larry Keesey, Esq.
Jon C. Moyle, Esq.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV
345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

4APT-AEB

JAN 28 1991

JAN 91

OUC

Mr. James S. Crall, Director
Environmental Division
Orlando Utilities Commission
500 South Orange Avenue
P.O. Box 3193
Orlando, Florida 32802

RE: Orlando Utilities Commission, Stanton Energy Center (PSD-FL-084)

Dear Mr. Crall:

In a meeting on December 21, 1990, between you and your representatives, FDER, and representatives of EPA Region IV, you raised several questions concerning the procedures necessary to modify the existing Prevention of Significant Deterioration (PSD) permit for the Stanton Energy Center. The purpose of the modification will be to change the start construction dates for Unit 2 as part of a phased construction permit. As committed to you by my staff at the meeting, we are providing you with answers to your procedural questions as follows:

1. What level of air quality analysis will be required for the modification?

Based upon the air quality analysis previously completed for Unit 2 and discussions between Mr. Lew Nagler of EPA with Mr. Max Linn of FDER, it was agreed that there would not be a need to repeat the air quality analysis in full provided that the stack parameters remain unchanged from the previous application. The modeling that needs to be done should be based on the new emission rate for Unit 2 using the critical meteorological periods identified from the earlier refined impact analysis.

2. What level of preconstruction monitoring will be required?

Our PSD monitoring rules allow for the use of monitoring data collected within the past three years. It is our feeling that the data for 1986-87 would satisfy this requirement. In addition, we believe that the regional ozone monitors would satisfy the preconstruction monitoring requirements for VOC emissions.

3. Are the EPA issued PSD permits processed separately from the Florida Site Certification Process? (i.e., can a PSD permit be issued by EPA independent of what stage the Florida Site Certification process is in?)

EPA views the PSD process to be totally separate from the State's Site Certification Process; therefore, after analysis and recommendation by FDER, EPA will issue a preliminary determination and give the opportunity for public comment. After such time, a final determination and PSD permit will be issued.

Mr. Crall, thank you for contacting EPA early in the process so that any outstanding issues may be resolved prior to any critical junctures. We look forward to your continued cooperation throughout the permitting process. Should you have any additional questions concerning the modelling or monitoring issues, please contact Mr. Lew Nagler of my staff at (404) 347-2904. Any other questions may be directed to Mr. Gregg Worley of my staff, also at (404) 347-2904.

Sincerely yours,

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

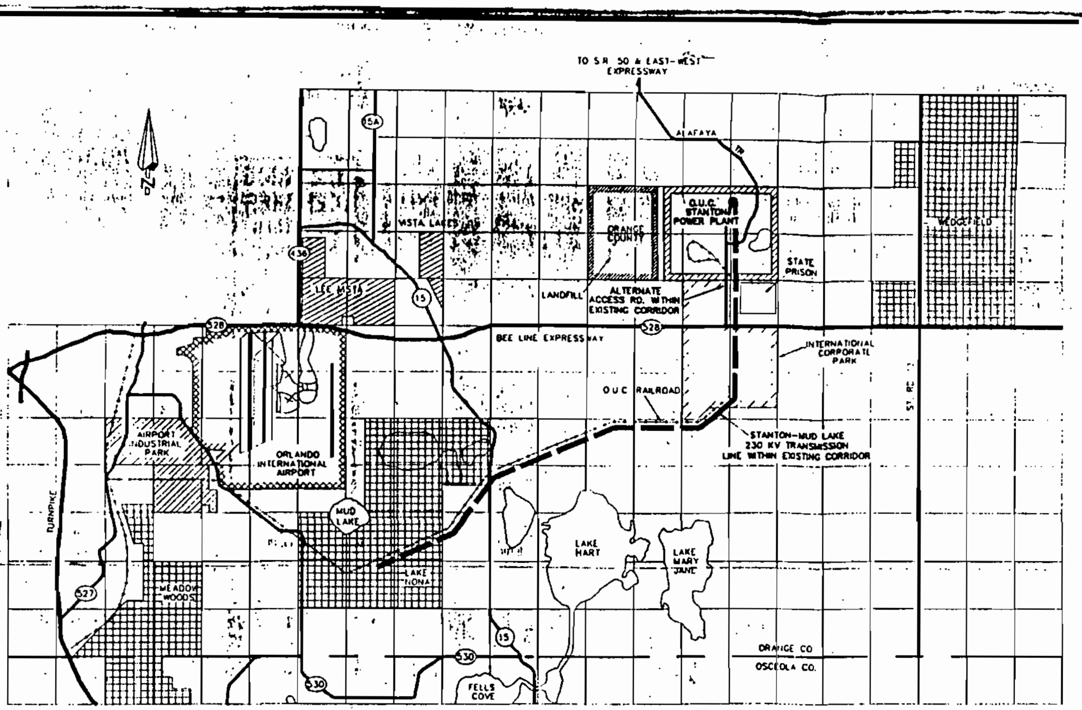
cc: Mr. C.H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Mr. Steven M. Day
Black & Veatch
1500 Meadow Lake Parkway
Kansas City, Missouri 64114

Notice of Certification Hearing

On A Supplemental Application To Construct And Operate The Second Electrical Generating Unit On An Existing Power Plant Site Located Near Orlando, Florida.

Stanton Energy Center Unit 2 Hearing To Begin At 10:00 a.m. On September 23, 1991 At Orlando City Hall. Public Testimony And Comments Will Be Heard Beginning At 6:00 p.m. September 24, 1991.



1. On March 15, 1991, Orlando Utilities Commission, Florida Municipal Power Agency and Kissimmee Utility Authority filed a supplemental application (DER Application No. PA 81-14B) for authorization to construct and operate the second electrical generating unit to be located on an existing site east of Orlando, Florida. This proposed unit is known as the Curtis H. Stanton Energy Center, Unit 2. Orlando Utilities Commission's application is now pending before the Florida Department of Environmental Regulation and other agencies, pursuant to the Florida Electrical Power Plant Siting Act, Chapter 403, Part II, Florida Statutes (1990).

2. The site of the proposed Stanton Unit 2 and its associated facilities is a 3,280 acre parcel of land located in the unincorporated area of Orange County. This site is the location of the existing Curtis H. Stanton Energy Center, Unit 1, a 440 megawatt coal fired power plant that has been in operation since 1987. The 3,280 acre site was certified by the Florida Siting Board in 1982 for approximately 2,000 megawatts of generating capacity. The proposed Stanton Unit 2 will occupy approximately 9 acres of the previously certified 3,280 acre site and it will be located adjacent to the existing Stanton 1 facility. The site is located approximately 9 miles east-northeast of the Orlando International Airport, 6 miles north of Lake Mary Jane, approximately 1 mile north of the Beeline Expressway. The geographic coordinates of the center of the site are 28° 29' North latitude and 81° 10' West longitude. The location of the site is depicted on the map accompanying this notice.

3. Stanton Unit 2 will be a 465 megawatt gross, 440 megawatt net, pulverized coal fueled steam/electric unit, which will essentially replicate the existing Stanton 1. New Stanton Unit 2 facilities will include sulfur dioxide removal equipment, electrostatic precipitator, chimney, cooling tower, and an expansion of the cooling tower blowdown treatment system presently serving Unit 1. Other facilities previously constructed for Stanton Unit 1 will also be used for Stanton Unit 2. These include on-site ponds and basins; materials handling and storage systems for coal, oil, limestone, lime and combustion wastes; administration building; warehousing; and other common support facilities. Of the additional water needed for operation of Stanton Unit 2, approximately 95% will be provided by effluent from the Orange County Easterly Subregional Wastewater Treatment Plant, and the remaining 5% will be obtained by increasing withdrawals from existing on-site wells presently serving Stanton 1.

4. In order to integrate the power from the Stanton Unit 2 into the Orlando Utilities Commission transmission system, a new 230 kV transmission line will be required which will be located within the previously certified railroad corridor. The Stanton-Mud Lake 230 kV transmission line will originate at the existing Stanton Energy Center 230 kV Substation and will interconnect into the existing OUC transmission line 7-0615 near Mud Lake. The new Stanton-Mud Lake transmission line will be approximately 14 miles in length and will be constructed within the existing and previously certified Orlando Utilities Commission Coal Haul Railroad/Utility Corridor from the Stanton Energy Center to its interconnection with the existing transmission line 7-0615. This corridor was certified as part of the 1981-1982 site certification proceeding for the Stanton Energy Center.

5. The Florida Department of Environmental Regulation, the Florida Public Service Commission and other state, regional, and local agencies are evaluating the Supplemental Site Certification Application for the Stanton Unit 2 and preparing reports on the project. The application for certification is available for public inspection at the following places during their usual business hours:

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION
Office of Siting Coordination
Twin Towers Office Building
2600 Blairstone Road
Tallahassee, Florida 32399-2400
(904) 488-1344

ORLANDO UTILITIES COMMISSION
500 South Orange Avenue
Orlando, Florida 32801
(407) 423-9100

ORANGE COUNTY PUBLIC LIBRARY
Planning and Local Government Department
101 East Central Boulevard
Orlando, Florida 32801

The business addresses of the applicants for the project are as follows:

ORLANDO UTILITIES COMMISSION
500 South Orange Avenue
Orlando, Florida 32801

FLORIDA MUNICIPAL POWER AGENCY
7201 Lake Ellenor Drive
Orlando, Florida 32809

KISSIMMEE UTILITY AUTHORITY
8 Broadway
Kissimmee, Florida 34741

6. Pursuant to Section 403.508, Florida Statutes, a certification hearing will be conducted by a Hearing Officer appointed by the Florida Division of Administrative Hearings, at Orlando City Hall, 400 South Orange Avenue in Orlando, Florida, beginning on September 23, 1991, at 10:00 a.m. The hearing will continue from day-to-day until completed. The Hearing Officer will receive comments and testimony from the parties, the public, and the affected agencies at the certification hearing. The Hearing Officer will take written or oral testimony on the effects of the proposed electrical power plant and on any other matter appropriate for consideration by the Siting Board. The need for the proposed facility has been previously addressed by the Florida Public Service Commission in a separate hearing.

7. If any party intends to use written direct testimony at the certification hearing, the written testimony must be filed by September 13, 1991, with delivery to all parties no later than noon on September 14, 1991.

8. Those wishing to intervene in these proceedings, unless appearing on their own behalf, must be represented by an attorney or other person who can be determined to be qualified to appear in administrative proceedings pursuant to Chapter 120, Florida Statutes, or Chapter 17-103.020, Florida Administrative Code. Persons wishing to become a party to this proceeding must file with the Hearing Officer either a Notice of Intent to become a party or a Petition to Intervene in these proceedings at least thirty (30) days prior to the certification hearing, as provided in Section 403.508(4), Florida Statutes.

9. Any person, organization or other entity intending to participate as a party in this proceeding must file their Petition to Intervene or Notice of Intent to be a Party on or before August 23, 1991. No additional party will be authorized to participate in these proceedings if such party has not filed its Petition or Notice as described above by that date with the Hearing Officer at the following address:

Diane K. Kiesling, Hearing Officer
Division of Administrative Hearings
The Desoto Building
1230 Apalachee Parkway
Tallahassee, Florida 32399-1550

All submittals should refer to DOAH Case No. 91-1813 EPP. Copies of such submittals should be forwarded by U.S. Mail to all of the other parties to this proceeding, including the Department of Environmental Regulation and the Orlando Utilities Commission. For a list of parties and further information concerning the power plant siting process, contact Mr. Hamilton S. Oven, Jr., at the Florida Department of Environmental Regulation, 2600 Blairstone Road, Twin Towers Office Building, Tallahassee, Florida 32399-2400 or call (904) 488-1344.

10. Certification of this second electrical generating unit would allow construction and operation of a new source of air pollution. The Florida Department of Environmental Regulation's review will include an assessment of the best available control technology (BACT) necessary to control the emission of air pollutants from this source. Orlando Utilities Commission has proposed to include low NOx burners, a cold-side electrostatic precipitator, followed by a flue gas scrubber, and then dispersion by chimney as equipment to achieve BACT for Stanton Unit 2.

11. Stanton Unit 2 received a prevention of significant deterioration (PSD) permit from U.S. EPA in 1982 as part of a phased construction project. Orlando Utilities Commission is currently seeking an amendment to this permit separately from this certification process.

12. Persons wishing to comment publicly on issues related to the construction and operation of the Stanton Unit 2 plant may do so at the certification hearing or by submitting written comments to the Hearing Officer and DER as specified above. At the commencement of the Certification Hearing on September 23, 1991, the Hearing Officer will announce that members of the public may appear and give comments and testimony regarding the construction or operation of Stanton Unit 2 beginning at 6:00 p.m. on September 24, 1991, at the City Commission Chambers in the Orlando City Hall.

ORLANDO UTILITIES COMMISSION

FLORIDA MUNICIPAL POWER AGENCY

KUA

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ORLANDO UTILITIES COMMISSION
500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 32802 • 407/423-9100

August 15, 1991

Mr. Gregg M. Worley
Air, Pesticides and Toxics
Management Division
U. S. Environmental Protection
Agency, Region IV
345 Courtland Street, N. E.
Atlanta, GA 30365

Re: Orlando Utilities Commission SEC Unit 2
BACT (PSD-FL-084)

Dear Mr. Worley:

Per our conversation of August 14, 1991, I am submitting the additional information you advised would be helpful in your analysis.

Your comments and OUC's responses include:

1. <u>Telephone Comment:</u>

Page 3, paragraph 3 of OUC's response of August 2, 1991 did not contain all the details of vendor quotes as previously requested.

<u>Response:</u>

Unit No.2 is a duplication of Unit No.1 and, therefore, B&W was contacted for the quote. The quote is attached (Attachment I) along with a more recent telephone memorandum (Attachment II) discussing the SO_2 to SO_3 conversion rate and catalyst type. It is my understanding that the 5 ppm ammonia slip is a guarantee and represents the maximum degradation before changeout of the catalyst begins.

2. <u>Telephone Comment:</u>

The Takehara Power Station has been operating with SCR while firing 2.5% sulfur coal since 1981.

<u>Response</u>

According to Joy Technologies (Attachment III), Takehara was specified with 15 different fuels of which all were low sulfur except for one which was 2.5 percent sulfur. This 2.5 percent sulfur coal was fired for a several month trial burn and has not been fuel of choice for a ten year period.

It is my further understanding that by 1985 Takehara's old generation catalyst was replaced with the high reactivity type which is similar to B&W's (Attachment I).

3. <u>Telephone Comment:</u>

You requested additional details regarding fly ash sold at Stanton Unit No.1.

<u>Response:</u>

In 1991 (through July), we sold 62.87 percent of the fly ash generated and used 37.13 percent in fixation of the scrubber sludge. Conversion Systems, Inc., who operates this process, also manages our ash sales.

As we discussed, if you can expedite the preliminary determination and draft permit so that DER has it available on or before August 23, both OUC and DER will appreciate your efforts.

Thank you.

Very truly yours,

J. S. Crall, Director
Environmental Division

JSC:rc
Attachment

cc: W. H. Herrington
T. B. Tart
S. M. Day (B&V)
C. M. Fancy (FDER)

RECEIVED **BEST AVAILABLE COPY**

JUL 29 1991

BLACK & VEATCH

Babcock & Wilcox

a McDermott company

13000 Wyandotte Street
Kansas City, MO 64145
(816) 941-2073

ATTACHMENT I

Project 16805	
Files 62.340101	
Date 7-29-91	
DISTRIBUTION	
LTS	X
DOS	X
File	

July 26, 1991

Black & Veatch
P O Box 8405
Kansas City, MO 64114

Attention: Mr. Morgan Fagan

RE: Orlando Utilities Commission
Stanton Energy Center
B&V Ref: 16805
B&W Ref: RB-621
SCR Budget Price

Gentlemen:

In confirmation of our telephone conversation this morning, we are pleased to reiterate that for an approximate price for a SCR to install behind this referenced unit, guaranteeing five PPM ammonium slip would be:

Fifteen Million Nine Hundred Thousand Dollars..........................$15,900,000

The erection price to go with that material price is $2,000,000.

As we discussed, this is based upon the boiler modifications included to install this SCR between the economizer outlet and the air heater inlet. This would put it in a high dust application. For your information and use, approximately $2,000,000 of the material price and $300,000 of the erection price is to make modifications to the boiler to handle this installation, such as the ductwork to and from the SCR as well as a larger airheater to protect from ammonia sulfate.

In order to guarantee an ammonia slip to two PPM, the material price would increase to approximately:

Two Million Three Hundred Thousand Dollars.........................$ 2,300,000

and the erection price by roughly $300,000.

The scope of supply that we have used for these figures are shown on Attachment 1. We have also enclosed a sketch showing the sizing of this SCR. Once we receive a quality sketch, we will submit it to you. The dimensions are not easy to read since this was sent to us by thermofax.

This SCR design is based on the following conditions:

Flue Gas Flow (Econ Outlet)	-	4,465,600 lb/hr
Gas Temperature	-	700° F
SCR inlet NOx	-	0.32 lb/mmbtu
SCR efficiency	-	80%
Ammonia slip	-	5 ppm

For the 5ppm slip on the base unit at the end of a two year guarantee period, the SCR system was sized as follows:

Catalyst volume	-	$488m^3$
Catalyst pressure drop	-	2.5 in H^2O
Anhydrous Ammonia Consumption	-	425 lb/hr

As we discussed, we recommend the high dust application over the low dust application due to the additional capital and operating expenses associated with the low dust application such as:

1. Gas-gas heat exchanger required
2. Duct burner to reheat flue gas
3. Difficult component configuration
4. Additional flue and ducts
5. Fuel requirements for duct burner
6. Added system pressure drop
7. Increased system complexity

If you have any additional questions or comments, we will be happy to discuss them with you at your convenience.

Very truly yours,

BABCOCK & WILCOX
a McDermott company

J. A. Shildmyer
District Manager

JAS:jf

SELECTIVE CATALYTIC REDUCTION SYSTEM DESCRIPTION

SCOPE OF SUPPLY

One (1) SCR system including the following:

* One (1) vertical SCR reactor chamber including transitions, integral support steel and test connections.
* Plate-type catalyst with sample catalyst.
* Reactor access panel for catalyst installation and removal.
* Ammonia injection grid.
* Ammonia dilution and mixing system, including piping, valves, and instruments.
* Engineering.
* Ammonia storage and vaporization.
* Flue modifications.
* Air heater modifications.
* Erection.

ITEMS TO BE SUPPLIED BY OTHERS

* Instrument air.
* Gaseous ammonia.
* Steam.
* Foundations, anchor bolts, concrete work and grouting.
* Hookup of air, steam and electric power.
* Interconnecting piping from ammonia storage to the ammonia dilution and mixing skid.
* Structural steel, platforms, stairs.
* Continuous emissions monitoring system.

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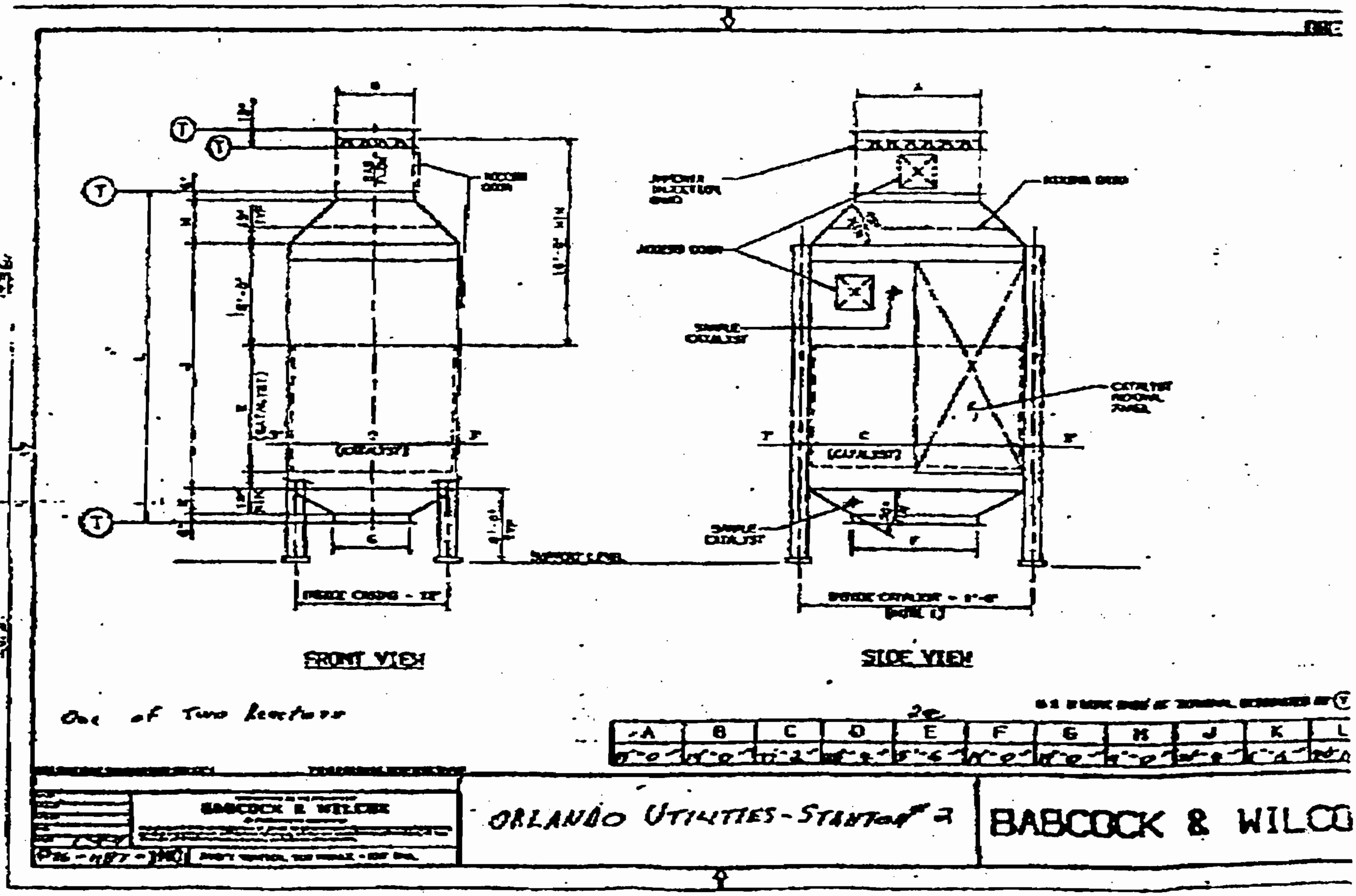

ATTACHMENT II

BLACK & VEATCH

TELEPHONE MEMORANDUM

Orlando Utilities Commission
Stanton Energy Center, Unit 2
Steam Generator - SCR

B&V Project 16805
B&V File 62.3401.01
August 14, 1991
2:30 p.m.

To:	John Clifton
Company:	Babcock & Wilcox
Phone No.:	216-860-1989
Recorded by:	D. D. Schultz

Babcock & Wilcox (B&W) reported that the conversion of SO_2 to SO_3 in the SCR ranged from .5 percent to .6 percent.

B&W was not sure what a "New" vs "Old" catalyst referred to. The catalyst included in B&W's quote is a type X. This catalyst is not new for this type of application.

lts

cc: J. Crall (OUC)
S. M. Day
J. R. Cochran
H. E. Smith
E. C. Windisch
A. W. Ferguson
Project File

ATTACHMENT III

BLACK & VEATCH

TELEPHONE MEMORANDUM

OUC
SEC 2
NO_x Catalyst
Takehara (Japan)

B&V Project 16805.030

August 14, 1991
4:30 p.m.

FACSIMILE TRANSMISSION

To: Sharon Kilborn - Marketing
Company: Joy Technologies
Phone No.: 818-301-1171

Recorded by: A. W. Ferguson

Odette Zourhalsen - FGD 818-301-1125
Alan Kissam - NO_x 818-301-1166
Ted Barrons - NO_x expert (out of office)

Takehara was specified with 15 different fuels, all but the 2.5% S were low sulfur. They burned 2.5% sulfur coal as a trial burn (a few months) but not necessarily all the time. Rest of the time have been using low S coal. (Confidential information provided to B&V shows historical fuel is about 1.5% S or less.) The paper by E. S. Behrens shows inlet SO_2 levels of 1100 ppm SO_2 which is appropriate for 1.0% to 1.5% sulfur coal despite that Takehara Unit 1 was designed for 2.5% S coal.

High reactivity catalyst was installed in 1983 - 1985 time period. Prior to installing this catalyst, the original was tubular catalyst. Joy's contract replaced the tabular catalyst and installed high reactivity bed which is still operating. This new catalyst was installed prior to the test burn on the 2.5% sulfur coal. This is a second generation of catalyst, similar to new offering for SCR applied to new units.

dm

cc: Don Schultz

ORLANDO UTILITIES COMMISSION

500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 32802 • 407/423-9100

RECEIVED

AUG 2 ; 1991

Division of Air
Resources Management

August 15, 1991

Mr. Gregg M. Worley
Air, Pesticides and Toxics
Management Division
U. S. Environmental Protection
Agency, Region IV
345 Courtland Street, N. E.
Atlanta, GA 30365

Re: Orlando Utilities Commission SEC Unit 2
BACT (PSD-FL-084)

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Response:

Unit No.2 is a duplication of Unit No.1 and, therefore, B&W was contacted for the quote. The quote is attached (Attachment I) along with a more recent telephone memorandum (Attachment II) discussing the SO_2 to SO_3 conversion rate and catalyst type. It is my understanding that the 5 ppm ammonia slip is a guarantee and represents the maximum degradation before changeout of the catalyst begins.

2. Telephone Comment:

The Takehara Power Station has been operating with SCR while firing 2.5% sulfur coal since 1981.

Response

According to Joy Technologies (Attachment III), Takehara was specified with 15 different fuels of which all were low sulfur except for one which was 2.5 percent sulfur. This 2.5 percent sulfur coal was fired for a several month trial burn and has not been fuel of choice for a ten year period.

It is my further understanding that by 1985 Takehara's old generation catalyst was replaced with the high reactivity type which is similar to B&W's (Attachment I).

3. Telephone Comment:

You requested additional details regarding fly ash sold at Stanton Unit No.1.

Response:

In 1991 (through July), we sold 62.87 percent of the fly ash generated and used 37.13 percent in fixation of the scrubber sludge. Conversion Systems, Inc., who operates this process, also manages our ash sales.

As we discussed, if you can expedite the preliminary determination and draft permit so that DER has it available on or before August 23, both OUC and DER will appreciate your efforts.

Thank you.

Very truly yours,

J. S. Crall, Director
Environmental Division

JSC:rc
Attachment

cc: W. H. Herrington
T. B. Tart
S. M. Day (B&V)
C. M. Fancy (FDER)

ORLANDO UTILITIES COMMISSION
500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 32802 • 407/423-9100

August 2, 1991

Ms. Jewell A. Harper
Chief, Air Enforcement Branch
U. S. Environmental Protection Agency
Region IV
345 Courtland Street, N.E.
Atlanta, GA 30365

Dear Ms. Harper:

RE: Orlando Utilities Commission
SEC Unit 2
Permit Modification (PSD-FL-084)

Enclosed are OUC's responses to the questions your staff raised regarding our submittal, as transmitted in your letter of July 2, 1991.

The staff and management of OUC appreciate the frank and efficient working relationship that our staffs have developed during this project.

Please have Gregg Worley give Jim Crall a call at (407) 423-9141 if it would be helpful to have an additional meeting prior to your preparation of the preliminary determination and draft permit.

Very truly yours,

Thomas Tart

Thomas Brogden Tart
General Counsel

cc: Gregg Worley, EPA
Nancy Pommelleo, Esq., EPA
Hamilton S. Oven, FDER
Clair M. Fancy, FDER

AUG 2 91

COMMENT:

(Reference EPA Region IV staff July 2, 1991 letter to Mr. James P. Crall of the Orlando Utilities Commission.)

"The SO2 emission limit which you have proposed is 0.32 lb/MMBTU on a thirty-day rolling average, based on a design coal with a maximum sulfur content of 2.5% and a control system removal efficiency of 92%. The presentation made by your consultant gave the basis of this estimate as a statistical analysis utilizing a computer model which estimated that the reduction level that could be achieved with 99% confidence limit over a thirty-day rolling average would be 92%. The assumptions made for this model include the use of 95% as the "target" removal efficency since this is the highest guaranteed by any vendor. What is the basis for the vendor guarantee of 95%? It would seem that the 95% removal number, if it was guaranteed by the vendor, is the result of experience and analysis rather than a "target" number which is the starting point of the analysis."

RESPONSE:

(Reference July 12, 1991 memorandum from M. F. McClernon to E. C. Windisch, B&V File 16805.32.0402.)

The information concerning performance tests and guarantees included here is based on the "offer to ABB" and is not finalized in a conformed document at this time. It does, however, represent the current state of negotiated agreement.

"Target", as referred to in the BACT analysis, implies conditions achieved when parameters that might be responsible for variation in SO2 removal rate are held in strict design tolerance levels, i.e "on target." These parameters include slurry pH, L/G ratio, limestone grind and quality, coal quality, gas flow magnitude and distribution, scrubber slurry liquid phase alkalinity, spray distribution, module pressure drop, mist eliminator cleanliness, and makeup water quality. When these conditions meet target, "target removal efficiency" results.

EPA has requested information on how "target removal", as described above and used in the computer simulation model, relates to the "manufacturer's guarantee." (The manufacturer's guarantee of 95 per cent removal efficiency has been used as target removal in the computer modeling.) EPA has also raised questions of whether a 95 per cent removal efficiency "guarantee" might not actually represent a "confidence limit", based on manufacturer experience and analysis, that assures consistent success in achieving 95 per cent removal, and indicates a target substantially higher than 95 per cent.

To answer these questions, it is informative to examine conditions that constitute "meeting guarantee."

The guarantee test times are basically at the discretion of the manufacturer. He is allowed to pre-test, inspect, and adjust the system until he is satisfied with it's performance. This ensures that all performance parameters are "on target" before the test begins. Limestone grind is tested for fineness; limestone is quality tested for minimum 90 per cent calcium carbonate content and available alkalinity of 1.0; "design" coal, blended to specified quality levels, is brought in specifically for the test; scrubber slurry pH is carefully controlled to a specified level optimum for the design coal(s); load (and consequently gas flow, temperature, and SO2 content) is held constant for the duration of the test; gas flow is checked both by experimental measurement and stoichometric flow calculation, and averaged for accuracy; the number of spray pumps operating is held constant; spray nozzles are clean and in unworn condition for uniform spray distribution; mist eliminator blades are in clean condition; ductwork and damper settings are clean and tuned for uniform gas flow distribution; makeup water is monitored for quality; and buffering of scrubber liquor is allowed (and monitored) through addition of adipic acid at maximum additive rate.

Under these controlled conditions, SO2 removal rate is monitored for a period of four (4) hours. Three such tests are performed and averaged at each load condition. Since the three tests are not necessarily consecutive, the manufacturer can adjust the system for each sample to assure "target" conditions. If an average removal efficiency of 95 per cent is achieved, the performance guarantee is met.

The test, as described above, basically is one that "guarantees" a "target" removal efficiency of 95 per cent. That is, when chemistry and process condition "targets" are achieved, 95 per cent average removal efficiency is "guaranteed" to result. This is the exact form of the simulation model, and the correct format for representation of the guarantee.

Several questions may be raised concerning the form of guarantee as described above. First, is a four-hour test a fair test of the system's performance? Deviation away from 95 per cent can only be caused by deviation away from "target" conditions. Although it is acknowledged that this variation is a "normal" part of day-to-day operation, the magnitude and rate of these variations are not completely within the control of the manufacturer. For his own protection, the manufacturer will only guarantee performance under controlled conditions. Test result variation is therefore only a function of measurement error propagation and minor fluctuations in "target" conditions, and is relatively small. The system either meets, or does not meet guarantee, and four hour tests are a sufficient and appropriate time frame to establish this condition.

Second, what level of expected performance is necessary for a manufacturer to prudently (or "confidently") guarantee 95 per cent removal efficiency? (This question is actually irrelevant to the engineer or owner at time of design, since the answer not guaranteed. It is interesting, however, to analyze the situation.)

From the manufacturer's point of view, a guarantee is not an absolute assurance that promised performance will be met. It is a single component of an overall risk evaluation. He must evaluate the benefits of success (his profit) against the consequences of failure (liquidated damages.) No real project presents a zero probability of either of these states. The most instructive example of this may be that the OUC Stanton Unit 1 scrubber, using similar (two hour) tests in a similar environment, did not meet guarantee requirement of 90 per cent removal at high sulfur design coal conditions.

At 95 per cent removal efficiency, the chemistry of the system has essentially been pushed to the limit, and remaining gains in efficiency are basically a fairly unpredictable function of uniformity in spray, inter-module and intra-module flow distribution, and fortuitous combinations of off-design conditions. A manufacturer with a true 95 per cent expected removal efficiency (50 per cent confidence) can expect a statistical distribution of random four-hour removal efficiencies characterized as follows for normal, non-outage hours:

4-Hour Removal Efficiency	Per Cent of Time	Cumulative % of Time
88	0.0000	0.0000
89	0.0002	0.0002
90	0.0006	0.0007
91	0.0039	0.0046
92	0.0376	0.0422
93	0.2127	0.2549
94	0.4164	0.6713
95	0.2700	0.9412
96	0.0552	0.9964
97	0.0035	0.9999
98	0.0001	1.0000

(These figures are based on OUC Stanton Unit 2 scrubber model predictions using 100 per cent availability and a target/guarantee removal efficiency performance level of 95 per cent.)

During normal, non-outage hours of operation, the scrubber is removing 95 per cent or more of the SO2 about 33 per cent of the time. Because of the high levels of autocorrelation in 4-hour performance levels, prediction of near term operation levels can be made with high levels of confidence. That is, if it observed that the scrubber is operating at 95 per cent on a given day (indicating target conditions), it is probable that those levels will be sustained for several days. The probability of a scrubber with 95 per cent target removal (zero design margin) passing the 95 per cent guarantee performance test is very high. Further, if the manufacturer should not pass the test, he simply "adjusts" the system, and calls for a new test.

The following summary points may be made. The scrubber performance test is a series of three short-term (4 hour) tests. This test is appropriate and sufficient to assure that under controlled (target) conditions, a guaranteed (target) removal efficiency will be achieved. No design margin is guaranteed, and no design margin (or confidence limit) is required to assure high likelihood of passing the guarantee test. Accordingly, the use of guarantee level as "target" in the computer simulation model is the most appropriate value available.

Supplemental NO_x BACT Analysis

The original Best Available Control Technology (BACT) analysis for the Orlando Utilities Commission C. H. Stanton Unit 2 was submitted on March 15, 1991 as part of the Supplemental Site Certification Application. This supplemental NO_x BACT analysis addresses specific issues identified by the Environmental Protection Agency in letter dated July 2, 1991. Assumptions regarding plant, fuels and evaluation criteria remain the same as presented in that document. The substantive issues identified for further information submittal included the effects of low NO_x burners on carbon losses, and a detailed technical and economic evaluation for installation of a selective catalytic NO_x emission reduction (SCR) system on Stanton 2. The following discussion addresses these specific issues identified.

1.0 Boiler Carbon Losses

Low NO_x burners reduce NO_x emissions by effectively staging combustion. Unfortunately, this results in less efficient combustion, increasing levels of unburned combustibles. This will be exhibited by higher fly ash carbon contents. It is estimated by the boiler manufacturer that unburned carbon levels will increase from 0.3 percent for burners designed to meet a New Source Performance Standard NO_x emission of 0.60 lb/MBtu to 0.4 percent for low NO_x burners designed to meet a NO_x emission of 0.32 lb/MBtu. This corresponds to a coincidental increase in fly ash carbon contents from 2.9 percent to 3.8 percent for low NO_x burners.

ASTM has established standard specifications for the use of fly ash as a mineral admixture in concrete (designation C618-91). These specifications indicate that fly ash with carbon contents up to 6 percent are allowed to be used as concrete admixture. Accordingly, fly ash carbon losses from the use of low NO_x burners will not prohibit the sale of fly ash from Stanton 2.

2.0 Selective Catalytic Reduction

Selective catalytic reduction systems limit NO_x emissions by injecting ammonia upstream of a catalytic reactor. The ammonia molecules in the presence of the catalyst dissociate reducing a significant portion of the NO_x into nitrogen and water. SCR systems may potentially reduce NO_x emissions by as much as 70 to 90 percent.

The ammonia is received and stored as a liquid. The ammonia is vaporized and subsequently injected into the flue gas by either compressed air or steam carrier. The optimum ammonia injection temperature occurs between 650 and 750 F. Therefore, the system is logically located between the economizer outlet and the air heater inlet. An economizer bypass may be required to maintain the reactor temperature during low load operation. This will reduce boiler efficiency at lower loads.

2.1 Coal Fired SCR Experience

Selective catalytic reduction (SCR) systems were first used in Japan during the 1970's. Through 1990, 40 SCR systems were operating on 10,852 MW of coal fired utility service. Japanese SCR systems were operated to achieve between 70 and 80 percent NO_x reduction with ammonia slip less than 10 ppm. Coals burned in the Japanese boilers have low sulfur (less than one percent) and low ash (less than 10 percent) contents.[1]

In response to acid rain legislation, SCR was retrofitted to 129 German coal fired boilers totalling 30,625 MW. Most of the Japanese and German SCR systems are generally operated to achieve 80 percent NO_x reduction to meet a NO_x emission limit of approximately 100 ppm while maintaining ammonia (NH_3) slip emissions to below 5 ppm. Similar to Japanese SCR experience, coals burned at these facilities have relatively low sulfur (0.7 to 1.2 percent) and low ash contents.[2]

To date, there are no coal fired boilers using SCR systems in the United States. However, a 140 MW coal fired pulverized coal boiler with SCR was recently permitted in New Jersey. For that facility NO_x emissions were limited to a maximum of 0.17 lb/MBtu based on the use of low NO_x burners and SCR. The facility will not operate for two to three years. Therefore, it is not possible to presently evaluate the effectiveness of SCR at facilities burning U.S. coals.

It is OUC's belief that the SCR technology is insufficiently developed for use on Stanton 2 based on inexperience with U.S. coals (detailed in subsequent sections). However, since the precedent has been established for use of SCR on a pulverized coal fired plant, this BACT analysis will evaluate SCR on a technical, economic, environmental, and energy basis. Based on the New Jersey facility, the analysis will be based on the use of low NO_x burners followed by an SCR system designed to limit NO_x emissions to 0.17 lb/MBtu.

There are two SCR system configurations that can be considered for application on pulverized coal boilers. A high dust application locates the SCR before the particulate collection equipment, typically between the economizer outlet and the air heater inlet. A low dust or cool side application is located downstream of the particulate and flue gas desulfurization control equipment.

The high dust application requires the SCR to be located between the economizer outlet and the air heater inlet in order the required SCR operating temperature of approximately 650 F to 750 F. The low dust application of SCR would locate the catalyst downstream of the particulate control and flue gas desulfurization equipment. Less catalyst volume is needed for the low dust application since the majority of the particulate and SO_2 has been removed. However, a major disadvantage of this alternative is a requirement for supplemental fuel firing to achieve sufficient flue gas operating temperatures. There is only a limited amount of low dust SCR experience worldwide. Considering the developmental nature of this alternative, this analysis will only consider the use of high dust SCR systems.

2.2 SCR Technology Status

The Japanese and European experience with SCR cannot be blindly applied to U.S. facilities. There remain two significant uncertainties about design, performance, operating parameters, and cost of SCR systems. First, U.S. utility power plants operate under more variable loads. Second the amounts and types of sulfur, ash, and trace elements in U.S. coals are different from those in coals consumed in Japan and Europe.[3 4]

Variable load conditions results in variable temperatures in the SCR reactor. At lower temperatures SCR reaction efficiencies drop off markedly resulting in either lower NO_x reduction or additional ammonia slip emissions.

Japanese and German SCR experience has been with coals with relatively low sulfur and ash contents. Combustion of higher sulfur coals will result in the emission of larger quantities of sulfur trioxide (SO_3). In addition, SCR catalysts oxidize SO_2 resulting in an increase in SO_3 emissions of between 50 and 100 percent.[5 6]

Sulfur trioxide in the presence of ammonia will form ammonia sulfate and ammonia bisulfate salts. Resultant particle diameters are on the order of 1 to 3 microns (potentially increasing plant PM10 emissions).[7] Ammonia bisulfate can foul the catalyst's micropore structure limiting reactivity.[8] In addition, ammonia bisulfate is a sticky substance which can deposit on downstream equipment. Ammonia bisulfate will tend to liquefy at a temperature of about 410 F in the intermediate baskets of the air heater. Once liquefied it solidifies in nodules in the space between the intermediate and cold end baskets. The result can be increased pressure drop, and eventual plugging (resulting in decreased unit reliability). Off-line water washings are necessary to remove the soluble deposits. Cold-end sootblowers are not generally effective in reaching and removing these deposits on-line. To alleviate this problem in Japan and Germany, recent SCR designs have limited ammonia slip emissions to between 3 and 5 ppm.[9] Based on the relatively high sulfur concentrations of coals under consideration for C. H. Stanton Unit 2 it may be necessary to limit ammonia slip to 2 ppm, further limiting maximum SCR effectiveness to somewhere between 60 and 70 percent NO_x reduction.

Increased SO_3 concentrations lead to an increase in the acid dew point. Hence higher air heater exit temperatures and decreased boiler efficiency will result from the use of SCR.[10]

A number of alkali metals and trace elements (especially arsenic) poison the catalyst significantly affecting reactivity and life.[11] Average arsenic concentrations for U.S. coals are three times the worldwide average.[12] Other elements such as sodium and potassium can also poison the catalyst by neutralizing the active acid sites. Poisoning of the catalyst does not occur immediately but is a continual process over the life of the catalyst. As the catalyst becomes deactivated more NH_3 must be injected to compensate and meet NO_x emission limits. This will result in an increased amount of NH_3 slip. Increased NH_3 slip will in turn result in additional ammonia salt formation and fouling of downstream equipment.

A significant quantity of ammonia slip from SCR system will condense onto fly ash. The ammonia content of the fly ash can have an impact on waste disposal or marketing practices. At elevated pH, ammonia in the fly ash will be released possibly leading to odorous emissions. While eastern U.S. coals are not inherently alkaline, fixation with alkaline species from the wet limestone scrubber or when used as admixture for cement manufacturing will result in ammonia releases.[13]

Fly ash NH_3 concentrations greater than 100 mg/kg fly ash results in noticeable odor and resultant rejection by the cement industry. Testing has indicated that for a coal with seven percent ash ammonia slip must be limited to below 2 ppm to avoid any potential problem.[14 15 16] Currently, SCR system suppliers will only guarantee ammonia slip levels of 5 ppm for a period of two years. It is likely that initial ammonia slip emissions will be below the 2 ppm criteria. However, as the catalyst ages ammonia slips will approach the guaranteed 5 ppm value. Accordingly, it is a possibility that Stanton 2 will lose fly ash sales should SCR be required.

2.3 SCR Economic Evaluation

Table 2.3-1 lists the estimated total capital and annual cost for installation of a SCR NO_x emission reduction system on C. H. Stanton Unit 2. The table lists all costs for a complete SCR system designed to meet a NO_x emission limit of 0.17 lb/MBtu. Costs presented in the table are based on manufacturers estimates for Stanton 2. The economic criteria used are identical to those used in the original BACT analysis.

The total capital cost for installation of a SCR system on Stanton 2 is estimated to be $31.2 million. The capital costs include ammonia receiving, storage, and injection equipment, catalyst, and balance of plant equipment. Ammonia receiving and storage equipment will primarily consist of ammonia truck receipt equipment, onsite ammonia storage tanks, piping and pumps to transport ammonia to the storage tanks, and foundations (including spill containment dikes). Ammonia injection equipment include ammonia vaporizers, air compressors or dilution air fans to provide a carrier medium, injections nozzles or headers, and associated piping and controls. Catalyst costs include four layers of catalyst, housing, maintenance access provisions, and associated transition ductwork. Balance-of-plant costs include air heater modifications to accommodate operational problems associated with unreacted ammonia and SO_3 in the flue gas stream, personnel safety equipment, boiler modification costs to accomodate the SCR catalyst reactor, and incremental ID fan capacity to overcome draft losses.

Table 2.3-1. SCR Capital and Annual Costs		
	2-Year Catalyst Life	2/4-Year Catalyst Life
	($1,000)	($1,000)
Capital Costs:		
Equipment	13,900	13,900
Field Labor	1,700	1,700
Balance of Plant	2,680	2,680
Total	18,280	18,280
Contingency	1,830	1,830
Escalation	3,340	3,340
Direct Capital Cost	23,450	23,450
Indirects	3,750	3,750
Interest During Construction	4,000	4,000
Total Capital Cost	31,200	31,200
Levelized Annual Costs:		
Operating Personnel	190	190
Maintenance	12,670	8,650
Additive	600	600
Energy	800	800
Demand	100	100
Loss in Fly Ash Sales	1,080	1,080
Fly Ash Landfill Costs	320	320
Boiler Efficiency Impact	910	910
Annual Operating Cost	16,670	12,650
Fixed Charges	2,460	2,460
Total Annual Cost	19,130	15,110
NO_x Emissions Reduced, tpy	2,810	2,810
Incremental Reduction Cost, $/ton	$6,810	$5,380

Levelized annual operating costs listed in Table 2.3-1 include operating personnel, maintenance, ammonia additive, electric energy and demand costs, and lost fly ash sales as well as the resulting fly ash disposal costs. The total levelized annual operating cost for installation of a SCR system on Stanton 2 is estimated to be \$16.7 million assuming the maximum guaranteed catalyst life of 2 years. If a somewhat less conservative assumption is made that the first two layers of the catalyst have a life of two years and the last two layers have a life of four years the levelized annual operating cost decreases to \$12.7 million.

Operating personnel costs include two full time equivalent personnel to operate the SCR system and associated auxiliaries. Maintenance costs are primarily related to the replacement of spent catalyst. Manufacturers typically provide a two year catalyst guarantee for coal fired applications. Ammonia costs are based on NO_x reduction requirements and the resulting molar ratios of ammonia to NO_x.

Energy costs reflect the energy required to operate air compressors and ammonia vaporizers. Energy costs also include the additional ID fan energy that would be necessary to overcome the added pressure drop from the catalyst. The demand cost is included to reflect the cost of building additional generating capacity into the unit to account for the capacity comsumed by the additional ID fan power requirements.

Stanton 1 has historically been capable of selling all ash production for use in the concrete industry. It was expected that Stanton 2 would be similarily capable. However should an SCR system be required, the potential for fly ash sales from Stanton 2 would greatly reduced due to ammonia contamination. As a result, this contaminated fly ash must be disposed of in an onsite landfill, incurring additional cost. For the purposes of costs presented in Table 2.3-1 it has been assumed that only 50 percent of these sales would be lost on the average (periodic catalyst replacements may result in cyclic possibilities for fly ash sales).

The total levelized annual cost for a SCR system on Stanton 2 would be \$19.1 million based on a maximum guaranteed catlyst life of two years. These costs result in an incremental NO_x reduction cost of \$6,810 per ton to achieve an outlet emission of 0.17 lb/MBtu as compared to a low NO_x burner NO_x emission of 0.32 lb/MBtu. If a less conservative assumption is made regarding catalyst life incremental NO_x reduction costs are lowered to \$5,380 per ton.

2.4 SCR Environmental Evaluation

Areas surrounding Stanton 2 are classified as attainment areas for nitrogen oxide emissions. Modeling analyses based on a NO_x emission rate of 0.32 lb/MBtu indicate ambient impacts below impacts predicted in the original Stanton 1 Site Certification Application.

Operation of a SCR system to meet a NO_x emission limitation of 0.17 lb/MBtu will result in ammonia slip emissions of between 2 and 10 ppm. Catalyst manufacturers will guarantee ammonia slip emissions of 5 ppm or less during the first two years of operation. When catalyst surfaces are relatively new ammonia slips will be very low. However, as the catalyst ages and becomes either deactivated or blinded, ammonia slip emissions will increase. As mentioned previously, should ammonia slip emissions exceed 2 ppm it is likely that all fly ash sales would be lost.

Use of SCR results in a 50 to 100 percent increase in SO_3 emissions. Unreacted ammonia and sulfur trioxide can react to form ammonia bisulfate and ammonia sulfate salts. These particulates will generally be smaller than 10 microns, and thereby, potentially increase PM_{10} emissions. Sulfur trioxide emissions that do not react with ammonia will exit the unit as sulfuric acid mist emissions.

Ammonia is a hazardous material. Therefore, ammonia must be handled and stored with extreme care. Storage and use of ammonia on-site will increase the likelyhood of hazardous or fatal accidents. Recent projects in California required to use ammonia have had difficulty obtaining local permits allowing ammonia use.

2.5 SCR Energy Evaluation

A SCR system consumes electrical energy for SCR auxiliary system operation and for incremental ID fan demand to overcome SCR draft losses. This energy requirement is approximately 1,870 kW. This represents approximately 0.5 percent of total plant power output.

2.6 Conclusions

Advances in the control of NO_x from pulverized coal boilers enable the project to lower anticipated NO_x emissions from the Stanton 1 emission limit of 0.6 lb/MBtu to 0.32 lb/MBtu. Selective catalytic reduction systems are insufficiently developed for use on pulverized coal fired boilers buring U.S. coal.

However, a recently permitted pulverized coal fired facility incorporated the use of low NO_x burners followed by a SCR system. This facility is not in operation.

The total levelized annual cost for a SCR system on Stanton 2 would be $19.1 million based on a maximum guaranteed catalyst life of two years. These costs result in an incremental NO_x reduction cost of $6,810 per ton to achieve an outlet emission of 0.17 lb/MBtu as compared to a low NO_x burner NO_x emission of 0.32 lb/MBtu. If a less conservative assumption is made regarding catalyst life incremental NO_x reduction costs are lowered to $5,380 per ton.

Since SCR systems are not demonstrated on plants burning U.S. coals it is likely that plant reliability would be reduced if an SCR system were used. These reliability decreases are likely to result from secondary effects such as air heater fouling by ammonia sulfate deposits. Previous experience with initial transfer of flue gas desulfurization technology resulted in increased plant forced outage rates of between 5 and 15 percent. In addition use of a more speculative technology will likely result in a reduction of bond rating for OUC of between 15 and 30 points. Considering the range of these cost impacts incremental NO_x reduction would increase to between $9,200/ton and $13,700/ton assuming a two year catalyst life.

The preceding discussion strongly supports that on the basis of technical, economic, energy, and environmental considerations, combustion controls designed to meet a NO_x emission requirement of 0.32 lb/MBtu represents BACT for Stanton 2 and SCR should not be applied to this installation.

References

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4. J. E. Damon, "Updated Technical and Economic Review of Selective Catalytic NO_x Reduction Systems,", United Engineers & Constructors, 1988.

5. T. Mori, "Operating Experience of SCR Systems at EPDC's Coal Fired Power Stations,", Electric Power Development Co., presented at the 1989 EPA/EPRI Joint Symposium on Stationary Combustion NO_x Control, March 1989.

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9. J. E. Damon.

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14. P. Necker.

15. B. Schonbucher, "Reduction of Nitrogen Oxides from Coal-Fired Power Plants by Using the SCR Process," EVS Germany, presented at the 1989 EPA/EPRI Joint Symposium on Stationary Combustion NO_x Control, March 1989.

16. J. M. Koppius-Odink, et al, "The First DeNOx Installation in the Netherlands," presented at the 1989 EPA/EPRI Joint Symposium on Stationary Combustion NO_x Control, March 1989.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

JUL 02 1991

4APT-AEB

Mr. James P. Crall, Director
Environmental Division
Orlando Utilities Commission
500 South Orange Avenue
P.O. Box 3193
Orlando, Florida 32802

RE: Orlando Utilities Commission SEC Unit No. 2 (PSD-FL-084)

Dear Mr. Crall:

This is to acknowledge receipt of your request for a modification to your previously issued Prevention of Significant Deterioration (PSD) permit transmitted by letter dated March 18, 1991, as well as the additional information submitted with your letter dated June 20, 1991. I want to take this opportunity to thank you for the effort you and your staff have gone to in order to facilitate the review process for this project. The information presented by your consultants in our meeting of June 7 was quite helpful. After reviewing the information you have submitted along with the application, our staff has raised the following questions and concerns.

Sulfur Dioxide BACT

The SO_2 emission limit which you have proposed is 0.32 lb/MMBTU on a thirty-day rolling average, based on a design coal with a maximum sulfur content of 2.5% and a control system removal efficiency of 92%. The presentation made by your consultant gave the basis of this estimate as a statistical analysis utilizing a computer model which estimated that the reduction level that could be achieved with a 99% confidence limit over a thirty-day rolling average would be 92%. The assumptions made for this model include the use of 95% as the "target" removal efficiency since this level is "the highest guaranteed by any vendor. What is the basis for the vendor guarantee of 95%? What is the confidence limit for this guarantee? Over what averaging time has the vendor guaranteed 95% removal? It would seem that the 95% removal number, if it was guaranteed by the vendor, is the result of experience and analysis rather than a "target" number which is the starting point of the analysis.

Nitrogen Oxides BACT Analysis

The control technology which OUC has proposed as BACT for the PC boiler is the use of in-furnace combustion control (low NO_x burners) to achieve a NO_x emission level of 0.32 lb/MMBTU. The application stated that OUC intends to sell the fly ash resulting from the combustion of coal to the concrete industry.

> What is the resulting carbon loss from the utilization of low NO_x burners?
>
> To what extent does the carbon content of the fly ash increase as a result of the utilization of low NO_x burners to achieve a level of 0.32 lb/MMBTU?
>
> How does the increased carbon content of the fly ash affect the salability of the fly ash?

The use of selective catalytic reduction (SCR) on Stanton Unit No. 2 was dismissed in the application based on "the complete lack of SCR experience with these [Eastern United States] coals." Stated concerns include the sulfur content of the design coal and ammonia slip. As you may know, the new generation of SCR catalysts are generally sulfur resistant. For example, the Takehara Power Station has been operating with SCR while firing 2.5% sulfur coal since 1981. The NO_x removal rate is 80% and ammonia slip is minimized, thus there has been no evidence of ammonia salts fouling equipment downstream. (E.S. Brehens, et. al., SCR Operating Experience on Coal-Fired Boilers and Recent Progress, 1991 Joint Symposium on Stationary Combustion NO_x Control - EPA/EPRI, March 25-28, 1991)

There are numerous pilot studies being conducted to study the utilization of SCR on eastern U.S. coals. These include the study at TVA Shawnee, the study by the Southern Company in conjunction with Georgia Power, and the planned study at TVA Kingston Unit No. 9. In addition, the Chambers Cogeneration facility, located in New Jersey, was permitted in December of 1990 and required SCR on each of two PC boilers. Many facilities in both Japan and Germany will have nearly 20 years of operating experience with SCR by the time Stanton Unit No. 2 starts up in 1997.

The literature suggests that an ammonia slip level of 1 ppm is achievable through proper design and in fact is the target rate of many of the German applications. With the low ammonia slip, the concerns relating to the formation of an ammonia chloride plume and the formation of ammonium salts are alleviated. In addition, with low ammonia slip, the fly ash is not contaminated and remains a high quality salable product. (H. Maier, et. al., Operating Experience With Tail-End and High-Dust DeNO$_x$ Techniques at the Power Plant of Heilbronn, 1991 Joint Symposium on Stationary Combustion NO$_x$ Control-EPA/EPRI, March 25-28, 1991)

As far as the reliability of a SCR system in coal-fired service, the German and Japanese units have been able to limit maintenance on the SCR system to scheduled shutdowns of the unit. In other words, the SCR systems have roughly the same reliability as the FGD systems. The keys to a successful system appear to be the utilization of second generation catalysts which minimize the conversion of SO_2 to SO_3; the use of steam assisted soot blowers in the air heater; and, the use of reliable ammonia monitors to minimize ammonia slip.

Based on the available literature and the fact that SCR has already been permitted in the U.S. for a PC boiler as the result of a BACT analysis, it would appear that SCR is indeed technically feasible. In addition, due to the development of second generation catalysts, the capital costs for installing SCR continue to decrease. In order to make an educated judgement as to whether SCR is applicable to Stanton Unit No. 2, it is necessary to obtain vendor quotes with guarantees on NO$_x$ reduction, ammonia slip, and SO_2 to SO_3 conversion. To that end we are requesting that you obtain vendor quotes for an SCR system based on the following parameters.

Conventional Boiler with uncontrolled NO$_x$ emissions of 0.45 lb/MMBTU in order to minimize the carbon content in the fly ash such that the ash remains a salable product;

NO$_x$ reductions of 80%;

Ammonia slip initially limited to 1 ppm with a maximum degradation to 5 ppm before changeout of the catalyst modules begins;

The design coal presented in your application;

Evaluate both the high dust and tail-end configurations. Although the use of a tail-end system substantially extends the catalyst life, there is a heat rate penalty associated with reheating the flue gas. An assessment should be made of the heat rate penalty vs. the extended catalyst life.

In summary, we feel that these issues need to be addressed before a preliminary determination can be made. If you have any questions on these comments, please contact Mr. Gregg Worley of my staff at (404) 347-5014.

Sincerely yours,

Jewell A. Harper, Chief
Air Enforcement Branch
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cc: B. Andrews, FDER
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